THIS DOCUMENT IS IMPORTANT AND REQUIRES YOUR IMMEDIATE ATTENTION. If you are in any doubt about the contents of this document or the action you should take, you should immediately consult a person authorised for the purposes of the Financial Services and Markets Act 2000 (as amended) who specialises in advising on the acquisition of shares and other securities.

This document is an AIM admission document prepared in accordance with the AIM Rules for Companies in connection with the proposed admission to trading of the Common Shares on AIM. This document contains no offer to the public within the meaning of the FSMA and, accordingly, it does not comprise a prospectus for the purposes of the Prospectus Rules and has not been approved by or filed with the FCA pursuant to section 85 of FSMA and a copy has not been delivered to the FCA under regulation 3.2 of the Prospectus Rules. No offer of securities to the public (for the purposes of section 102B of the Financial Services and Markets Act 2000) is being made in connection with the Placing.

Application will be made for the Enlarged Share Capital to be admitted to trading on AIM. It is expected that Admission will become effective and that trading in the Enlarged Share Capital on AIM will commence at 8.00 a.m. on 8 August 2018.

Although the whole text of this document should be read, the attention of persons receiving this document is drawn to the section headed "Risk Factors" contained in Part 5 of this document. All statements regarding the Group's business, financial position and prospects should be viewed in light of the risk factors set out in Part 5 of this document.

AIM is a market designed primarily for emerging or smaller companies to which a higher investment risk tends to be attached than to larger or more established companies. AIM securities are not admitted to the Official List of the UK Listing Authority. A prospective investor should be aware of the risks of investing in such companies and should make the decision to invest only after careful consideration and, if appropriate, consultation with an independent financial adviser. Each AIM company is required pursuant to the AIM Rules for Companies to have a nominated adviser. The nominated adviser is required to make a declaration to the London Stock Exchange on admission in the form set out in Schedule Two to the AIM Rules for Nominated Advisers. Neither the London Stock Exchange nor the UK Listing Authority have examined or approved the contents of this document.

JADESTONE ENERGY INC.

(Incorporated in Canada under the laws of British Columbia with company registration number BC0350583)

Acquisition of the Montara Assets

Placing of up to 239,711,474 new Common Shares at a price of 35p to raise approximately US$110 million, before expenses

Admission of the Enlarged Share Capital to trading on AIM

NOMINATED ADVISER, JOINT BOOKRUNNER AND JOINT BROKER

STIFEL

JOINT BOOKRUNNER AND JOINT BROKER

BMO Capital Markets

The Company, the Directors and the Proposed Director, whose names appear on page 6, accept responsibility for the information contained in this document and for compliance with the AIM Rules for Companies. To the best of the knowledge and belief of the Directors (who have taken all reasonable care to ensure that such is the case) the information contained in this document is in accordance with the facts, and does not omit anything likely to affect the import of such information.

This document does not constitute an offer to sell or an invitation to subscribe for, or the solicitation of an offer to buy or to subscribe for, Common Shares in any jurisdiction in which such an offer or solicitation is unlawful and this document is not to be forwarded, distributed, mailed or otherwise transmitted in or into Australia, Canada, Japan, the Republic of South Africa and their respective territories and possessions (together, the "**Prohibited Territories**") or to any national, resident or citizen of the Prohibited Territories or to any corporation, partnership or other entity created or organised under the laws thereof, or to any persons in any other country outside the United Kingdom, where such distribution, forwarding or transmission may lead to a breach of any legal or regulatory requirement. This document is not to be forwarded, distributed, mailed or otherwise in or into the United States, its territories or possessions, subject to certain limited exceptions. The distribution of this document in other jurisdictions may be restricted by law and therefore persons into whose possession this document comes should inform themselves about and observe any such restrictions. The issue of the Common Shares has not been and will not be registered under the applicable security laws of the Prohibited Territories and, unless an exemption under such laws is available, the Common Shares may not be offered for sale or subscription or sold or subscribed directly or indirectly within the Prohibited Territories for the account or benefit of any national, resident or citizen of the Prohibited Territories.

The issue of the Common Shares has not and will not be registered under the United States Securities Act of 1933, as amended (the "**US Securities Act**") or with any securities regulatory authority of any state or other jurisdiction of the United States and the Common Shares may not be offered for sale or subscription or sold or subscribed directly or indirectly within the United States except pursuant to an exemption from, or in a transaction not subject to, registration under the US Securities Act. There will be no public offering of the Common Shares in the United States. Any failure to comply with these restrictions may constitute a violation of the securities laws of such jurisdictions.

In Canada, this document is for distribution only to "accredited investors" as defined in National Instrument 45-106 – Prospectus Exemptions.

Stifel Nicolaus Europe Limited ("**Stifel**"), which is authorised in the United Kingdom by the FCA for the conduct of investment business, is acting as nominated adviser, joint bookrunner and joint broker for the purposes of the AIM Rules exclusively for the Company and no one else in connection with the Institutional Placing and Admission and will not be responsible to any other person for providing the protections afforded to customers of Stifel, or for advising anyone other than the Company on the contents of this document or any matter referred to herein. The responsibilities of Stifel, as nominated adviser, are owed solely to the London Stock Exchange and are not owed to the Company or to any Director or any other person and accordingly no duty of care is accepted in relation to them. No representation or warranty, express or implied, is made by Stifel as to, and no liability whatsoever is accepted by Stifel in respect of, any of the contents of this document (without limiting the statutory rights of any person to whom this document is issued).

BMO Capital Markets Limited ("**BMO**"), which is authorised in the United Kingdom by the FCA for the conduct of investment business, is acting as joint bookrunner and joint broker exclusively for the Company and no one else in connection with the Institutional Placing and Admission and will not be responsible to any other person for providing the protections afforded to customers of BMO, or for advising anyone other than the Company on the contents of this document or any matter referred to herein. No representation or warranty, express or implied, is made by BMO as to, and no liability whatsoever is accepted by BMO in respect of, any of the contents of this document (without limiting the statutory rights of any person to whom this document is issued).

Copies of this document will be available during normal business hours on any day (except Saturdays, Sundays, bank and public holidays) free of charge to the public at the offices of Bryan Cave Leighton Paisner LLP at Adelaide House, London Bridge, London EC4R 9HA from the date of this document to the date one month from the date of Admission. A copy of this document will also be available on the Company's website – http://www.jadestone-energy.com/.

Forward-looking Statements

Certain statements in this document are forward looking statements and information (collectively "forward looking statements"), within the meaning of the applicable Canadian securities legislation, as well as other applicable international securities laws. The forward looking statements contained in this document are forward-looking and not historical facts.

Some of the forward looking statements may be identified by statements that express, or involve discussions as to expectations, beliefs, plans, objectives, assumptions or future events or performance (often, but not always, through the use of phrases such as "will likely result", "are expected to", "will continue", "is anticipated", "is targeting", "estimated", "intend", "plan", "guidance", "objective", "projection", "aim", "goals", "target", "schedules", and "outlook" or other similar expressions that are predictive or indicative of future events or the negative thereof).

There are statements in this document which are forward looking statements. In particular, forward-looking statements in this document include, but are not limited to, each of the forward looking risk factors contained in Part 5 of this document.

Because actual results or outcomes could differ materially from those expressed in any forward looking statements, investors should not place any reliance on any such forward looking statements. By their nature, forward looking statements involve numerous assumptions, inherent risks and uncertainties, both general and specific, which contribute to the possibility that the predicted outcomes will not occur. Some of these risks, uncertainties and other factors are similar to those faced by other oil and gas companies and some are unique to Jadestone. If one or more of these risks or uncertainties materialise, or if any underlying assumptions prove incorrect, the Company's actual results may vary materially from those expected, estimated or projected.

In addition, statements relating to "reserves" and "resources" are deemed to be forward looking statements as they involve the implied assessment based on certain estimates and assumptions that the reserves or resources described can be profitably produced in the future. There are numerous uncertainties inherent in estimating quantities of reserves and resources and in projecting future rates of production and the timing of development expenditures. The total amount or timing of actual future production may vary from reserve, resource and production estimates.

Certain information in this document is "financial outlook" within the meaning of applicable securities laws. The purpose of this financial outlook is to provide readers with disclosure regarding the Company's reasonable expectations as to the anticipated results of its proposed business activities. Readers are cautioned that this financial outlook may not be appropriate for other purposes.

Although the Company believes that the expectations reflected by the forward looking statements presented in this document are reasonable, the Company's forward looking statements have been based on assumptions and factors concerning future events that may prove to be inaccurate. Those assumptions and factors are based on information currently available to the Company about itself and the businesses in which it operates. Information used in developing forward looking statements has been acquired from various sources including third party consultants, suppliers, regulators and other sources.

The Company's condensed consolidated interim unaudited financial statements for the quarter ended March 31, 2018 which are set out in Appendix 4 of this document and other documents filed with securities regulatory authorities (accessible through the SEDAR website www.sedar.com) describe risks, material assumptions and other factors that could influence actual results.

New factors could emerge from time to time and it is not possible for the Company to predict all of such factors and to assess in advance the impact of each such factor on the Company's business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statement. These factors include, but are not limited to, those described in Part 5 of this document entitled "Risk Factors" which should be read in conjunction with the other cautionary statements that are included in this document. The impact of any one factor on a particular forward-looking statement is not determinable with certainty as such factors are dependent upon other factors, and the Company's course of action would depend upon management's assessment of the future considering all information available to it at the relevant time. Any forward-looking statement speaks only as of the date on which such statement is made and, except as required by applicable securities laws, the Company undertakes no obligation to update any forward-looking statement to reflect events or circumstances after the date on which such statement is made or to reflect the occurrence of unanticipated events.

All subsequent written and oral forward-looking statements attributable to the Group or individuals acting on behalf of the Group are expressly qualified in their entirety by this paragraph. Prospective investors should specifically consider the factors identified in this document which could cause actual results to differ before making an investment decision.

Market and financial information

The data, statistics and information and other statements in this document regarding the markets in which the Company operates, or its market position therein, is based upon the Company's records or are taken or derived from statistical data and information derived from the sources described in this document. In relation to these sources, such information has been accurately reproduced from the published information, and, so far as the Directors are aware and are able to ascertain from the information provided by the suppliers of these sources, no facts have been omitted which would render such information inaccurate or misleading. Certain financial data has also been rounded. As a result of this rounding, the totals of data presented in this document may vary slightly from the actual arithmetical totals of such data. All times referred to in this document are, unless otherwise stated, references to London time.

United States securities law

The Common Shares have not been and will not be registered under the US Securities Act or the securities laws of any US state or other jurisdiction and will not be offered or sold within the United States except pursuant to an exemption from, or in a transaction not subject to, the registration requirements of the US Securities Act and such other applicable securities laws. With limited exception, the Common Shares are only being offered and sold outside the United States in reliance on Regulation S under the US Securities Act. No public offering of the Common Shares is being made in the United States.

The Common Shares have not been approved or disapproved by the US Securities and Exchange Commission (the "**SEC**") or by any US state securities commission or authority, nor has any such US authority passed on the accuracy or adequacy of this document. Any representation to the contrary is a criminal offence.

Information to Distributors

Solely for the purposes of the product governance requirements contained within: (a) EU Directive 2014/65/EU on markets in financial instruments, as amended ("**MiFID II**"); (b) Articles 9 and 10 of Commission Delegated Directive (EU) 2017/593 supplementing MiFID II; and (c) local implementing measures (together, the "**MiFID II Product Governance Requirements**"), and disclaiming all and any liability, whether arising in tort, contract or otherwise, which any "manufacturer" (for the purposes of the Product Governance Requirements) may otherwise have with respect thereto, the Common Shares have been subject to a product approval process, which has determined that the Common Shares the subject of the Institutional Placing are: (i) compatible with an end target market of retail investors and investors who meet the criteria of professional clients and eligible counterparties, each as defined in MiFID II; and (ii) eligible for distribution through all distribution channels as are permitted by MiFID II (the "**Target Market Assessment**"). Notwithstanding the Target Market Assessment, Distributors should note that: the price of the Common Shares may decline and investors could lose all or part of their investment; the Common Shares offer no guaranteed income and no capital protection; and an investment in the Common Shares is compatible only with investors who do not need a guaranteed income or capital protection, who (either alone or in conjunction with an appropriate financial or other adviser) are capable of evaluating the merits and risks of such an investment and who have sufficient resources to be able to bear any losses that may result therefrom. The Target Market Assessment is without prejudice to the requirements of any contractual, legal or regulatory selling restrictions in relation to the Institutional Placing. Furthermore, it is noted that, notwithstanding the Target Market Assessment, the Joint Bookrunners will only procure investors who meet the criteria of professional clients and eligible counterparties.

For the avoidance of doubt, the Target Market Assessment does not constitute: (a) an assessment of suitability or appropriateness for the purposes of MiFID II; or (b) a recommendation to any investor or group of investors to invest in, or purchase, or take any other action whatsoever with respect to the Common Shares.

Each distributor is responsible for undertaking its own target market assessment in respect of the Common Shares and determining appropriate distribution channels.

CONTENTS

DIRECTORS, SECRETARY AND ADVISERS

Directors	Mr. Alexander Paul ("Paul") Blakeley, *Executive Director, President and Chief Executive Officer* Mr. Dennis Joseph McShane, *Chairman* Mr. Robert Alexander Lambert, *Deputy Chairman* Mr. Iain Archibald McLaren, *Non-Executive Director* Mr. Eric Lincoln Schwitzer, *Non-Executive Director* Mr. Cedric Christian Joseph Fontenit, *Non-Executive Director* Mr. David Loven Neuhauser, *Non-Executive Director* whose business address is at the Company's registered office: Suite 1000, 595 Howe Street Vancouver BC V6C 2T5 Canada
Proposed Director	Mr Daniel ("Dan") Patrick Young, *Chief Financial Officer and Proposed Executive Director* whose business address is at the Company's registered office: Suite 1000, 595 Howe Street Vancouver BC V6C 2T5 Canada
Company Secretary	Mr. Neil Prendergast
Registered Office	Suite 1000, 595 Howe Street Vancouver BC V6C 2T5 Canada
Principal place of business	Keppel Towers, #15-05/06 o 10 Hoe Chiang Road Singapore
Company website	http://www.jadestone-energy.com/
Telephone number	+65 6324 0359
Nominated Adviser, Joint Bookrunner and Joint Broker	Stifel Nicolaus Europe Limited 150 Cheapside London EC2V 6ET UK
Joint Bookrunner and Joint Broker	BMO Capital Markets Limited 95 Queen Victoria St London EC4V 4HG UK
Solicitors to the Company as to Canadian law	DuMoulin Black LLP Suite 1000, 595 Howe Street Vancouver BC V6C 2T5 Canada
Solicitors to the Company as to English law	Bryan Cave Leighton Paisner LLP Adelaide House London Bridge London EC4R 9HA UK
Legal Advisers to the Company as to Australian law	Gilbert & Tobin Level 35, Tower Two International Towers Sydney 200 Barangaroo Avenue Barangaroo NSW 2000 Australia

Legal Advisers to the Company as to Bermuda law	Zuill & Co Continental Building, 25 Church Street Hamilton HM 12 Bermuda
Legal Advisers to the Company as to BVI law	Harney Westwood & Riegels Craigmuir Chambers, PO Box 71 Road Town Tortola VG1110 British Virgin Islands
Legal Advisers to the Company as to Indonesian law	IAB&F Law Intiland Tower 9th Floor, Jl. Jenderal Sudirman 32, Jakarta Pusat 10220 Indonesia
Legal Advisers to the Company as to Philippine law	PJS Law 10th Floor 8 Rockwell Hidalgo corner Plaza Drive Rockwell Center Makati City 1200, Philippines
Legal advisers to the Company as to Singapore law	Wong Tan & Molly LIM LLC 80 Robinson Road, #17-02, Singapore 068898
Legal advisers to the Company as to Vietnamese law	VILAF Suite 404 – 406, MPlaza Saigon 39 Le Duan, District 1 Ho Chi Minh City, Vietnam
Solicitors to the Nominated Adviser and Joint Bookrunners	Dentons UK & Middle East LLP One Fleet Place London EC4M 7WS UK
Auditors	Deloitte & Touche LLP 6 Shenton Way #33-00 OUE Downtown 2 Singapore 068809
Registrars	Computershare Investor Services Inc. 510 Burrard Street 4th Floor Vancouver, BC V6C 3B9 Canada
Competent Person	ERC Equipoise Pte Ltd 50B Tras Street #03-02 Singapore 078989
Depositary	Computershare Investor Services Plc The Pavilions Bridgwater Road Bristol BS13 8AE UK
Financial PR Consultants	Capital Market Communications Limited 107 Cheapside London EC2V 6DN

PLACING STATISTICS AND EXPECTED TIMETABLE OF PRINCIPAL EVENTS

Placing Statistics

Placing Price	35p
Number of Placing Shares	239,711,474
Number of Common Shares in issue at the date of this document	221,298,004
Number of Common Shares in issue immediately following Admission *	461,009,478
Proceeds of the Placing receivable by the Company before expenses	£83.9 million
Proceeds of the Placing receivable by the Company after expenses	£78.5 million
Market capitalisation of the Company at the Placing Price following Admission*	£161.4 million
ISIN Code	CA46989Q1000
LEI Number	254900E4GCXW63X26Q32
SEDOL	BDDVW60
TIDM	JSE

* *assuming no options are exercised between the date of this document and Admission*

Expected Timetable of Principal Events

Publication of this document	3 August 2018
Admission effective and dealings commence in the Common Shares on AIM	8.00 a.m. on 8 August 2018
CREST accounts credited (as applicable)	8.00 a.m. on 8 August 2018
Despatch of definitive share certificates (as applicable)	By 22 August 2018
Completion of the Acquisition	September/October 2018

All references to times in this document are to the time in London, unless otherwise stated.

Part 1

INFORMATION ON THE GROUP

1 INTRODUCTION

Overview

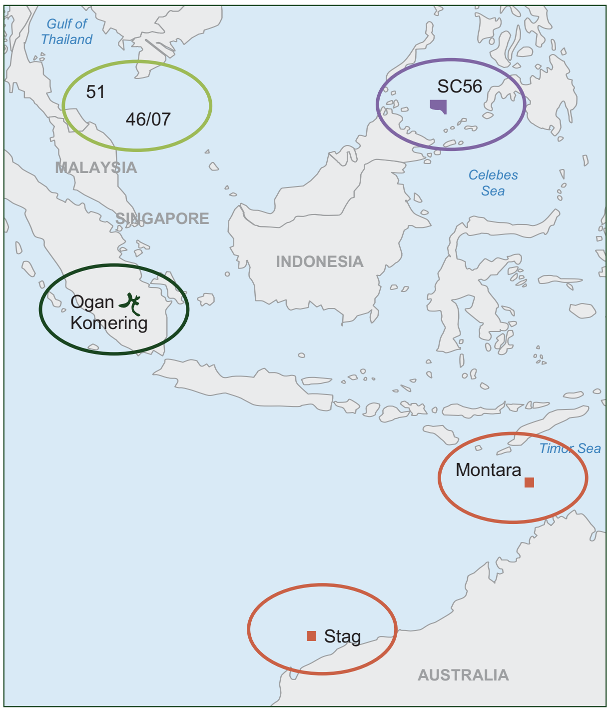
Jadestone is an independent oil and gas production and development company focused on the Asia-Pacific region. The Company has an acquisitive strategy and is focused on growth and creating value through identifying, acquiring, developing and operating assets throughout the Asia-Pacific region.

Jadestone currently has a portfolio of oil and gas production, development and exploration assets in Western Australia, Vietnam and the Philippines. The Company is focused on creating value through leveraging the significant experience and track-record of its management team to maximise value from Jadestone's existing asset base through production and cost optimisation, and on identifying acquisitions that offer significant value both at the time of purchase and through potential organic development. The Directors' objective is to create a leading independent Asia-Pacific-focused upstream oil and gas company that generates significant shareholder returns through capital growth and, in the short to medium term, dividends.

Since the current management team joined the Company in June 2016, the Company has established a balanced portfolio of operated producing and development assets and exploration assets and continues to actively pursue acquisition opportunities. On 15 July 2018 the Company signed a binding Sale and Purchase Agreement to acquire the Montara Assets, located in shallow water offshore Australia, from PTTEP Australasia. 2P reserves attributed to Jadestone's current assets were 17.1 MMbbls of oil and its total 2C resources were 11.8 MMbbls of oil and 465.3 Bscf of gas as of 31 December 2017.

The Montara Assets 2P reserves were 28.2 MMbbls of oil and condensate as of 31 December 2017.

Map of Assets



Source: Jadestone Energy Inc.

Note: The Company ceased to hold an interest in Ogan Komering following the issue of the new PSC on 20 May 2018. The Company is currently in negotiations to acquire an interest in this PSC.

Company Strategy

Jadestone's strategic objective is to build a balanced, resilient portfolio of production and development assets with multiple opportunities for reinvestment in order to increase annual cash flows, whilst maintaining a strong balance sheet, delivering value to shareholders through both capital growth and, in the medium term, dividends. Jadestone will apply the following four key principles:

(a) to acquire assets with production and/or discovered resources in the Asia-Pacific region;

(b) to realise additional value from existing producing assets through superior operating capabilities, cost control and incremental brown field development;

(c) to move its existing discoveries to production into the Asia-Pacific region's energy-short markets; and

(d) to add additional reserves and production volumes through undertaking low risk in-field and near-field exploration.

The Asia-Pacific region consists of numerous mature hydrocarbon basins with assets operated in many cases by national oil companies, oil majors and large cap independents. The Company believes that this presents an opportunity to acquire assets with significant unrealised value.

Jadestone's management's proven ability to extract value from oil and gas producing assets through the life cycle in the Asia-Pacific region, including a specialisation as a second phase operator, positions the Company well to take advantage of this opportunity.

The strategy also enables Jadestone to capitalise on the significant latent opportunity to monetise undeveloped gas discoveries in the region into the domestic regional markets where there is significant and growing demand and a supply shortfall, which has resulted in attractive pricing for producers.

The Company utilises its end-to-end technical and commercial capabilities to maximise value and returns. These capabilities include:

- a differentiated approach to subsurface interpretation and reservoir management;
- a constant drive to identify and execute on opportunities for innovative and disciplined reinvestment;
- a meticulous focus on optimising production processes and facilities management whilst maintaining a strong focus on health, safety, social and environmental matters;
- the application of a more nimble approach to decision making;
- rigorous cost control in operations and throughout the Group;
- the application of deep in-region commercial skills; and
- utilising long standing stakeholder relationships in the region.

These core strengths enable Jadestone to add value by unlocking stalled projects, lowering operating costs, maximising production and reserves, and extending field life.

This has so far been demonstrated by the acquisition of, and operational and performance improvements implemented and/or identified at, Stag and Ogan Komering and the proposed Acquisition of the Montara Assets.

Management Track-Record

Jadestone's senior management have a deep understanding of both the oil and gas industry and the Asia-Pacific region with over 230 years' combined industry experience and 139 years' combined operating experience in the Asia-Pacific region. As the former Executive Vice President of Talisman Energy's Asia-Pacific & Middle East operations (2005 to 2015), Jadestone's CEO Paul Blakeley, alongside other members of the Jadestone management team, was responsible for leading Talisman Energy from being a two-asset business with production of circa 45 mboe/d into a business generating free cash flows in excess of US$500 million per annum on production of circa 150 mboe/d, with circa 500 MMboe 2P reserves and an estimated net asset value of over US$6 billion.

The Jadestone management team not only has a demonstrable track-record of identifying and executing on highly accretive acquisitions, but also of realising significant value from existing assets through operational excellence, which has already been demonstrated by the significant operational improvements, cost reductions and production stabilisation at the Group's Stag asset. The Directors intend to leverage management's significant acquisition and operating experience to generate value from Jadestone's current and future assets.

Producing Assets

On completion of the transfer of operatorship of the Montara Assets, Jadestone will have two 100 per cent owned and operated developed producing assets, Montara and Stag. Both fields are located offshore Western Australia. Combined production from the assets was 12.8 mbbls/d and average opex per barrel was US$29.9 across both assets for the year ended 31 December 2017. 2P reserves were 45.2 MMbbls (gross and net) as at 31 December 2017.

Stag is currently producing at circa 3.6 mbbls/d following the workover of the 45H well.

The Montara Assets are currently producing approximately 10.3 mbbls/d. This follows a prolonged shut-in of the Skua-10ST2 and Swift N1 subsea wells due to communication issues to these wells following the annual shutdown, causing the overall production to fall below plan. Communication, via a subsea umbilical, to these shut-in wells was restored in late June 2018 and they are now back on production at the current rates (from 7 mbbls/d when the subsea wells were shut-in). Production is still not fully optimised and stable following the start-up of the two subsea wells with all fields not fully available at all time. The Company expects the combined rate to increase over the near term before reaching the expected stable production rates for each field.

The Company has already identified multiple operational improvements at the Montara Assets and believes it can execute these improvements to increase production, whilst also reducing fixed operating costs by up to 20 per cent. The Company has already made significant cost savings at Stag, reducing fixed operating costs by 35 per cent, cutting sustaining capital expenditure and stabilising production. The Company is now focused on increasing production at Stag through drilling infill wells over the next two years and completing well workovers.

Montara Assets

The Montara Assets comprise three separate fields which are Montara, Skua and Swift/Swallow, produced through a centralised FPSO, the Montara Venture, which is owned by PTTEP Australasia and will be transferred to Jadestone on completion of the Acquisition. Following completion of the Acquisition and transfer of operatorship, Jadestone will hold a 100 per cent operating interest in the Montara Assets. As at 31 December 2017, the Montara Assets had 2P reserves of 28.2 MMbbls of oil (gross and net) and is currently producing between approximately 10.3 mbbls/d with all available wells (Montara wells, Skua-10ST2 and Swift N1) back on production. Jadestone is acquiring the Montara Assets for consideration of US$195 million prior to customary working capital adjustments and certain contingent pay-out options. The transaction is structured as an asset acquisition, thereby limiting Jadestone's exposure to any residual liabilities associated with the Seller's businesses in Australia.

The limited number of qualified offshore operators in Australia looking to deploy second phase specialisation, and Jadestone's recently proven ability to obtain regulatory approvals, in particular approval as operator culminating in the transfer of operatorship of Stag in July 2017, proved a significant competitive advantage when engaging with the seller.

The acquisition price represents a 32 per cent discount to the NPV10 of the 1P reserves as estimated by ERCE; a 59 per cent discount to the NPV10 of the 2P reserves and a 75 per cent discount to the NPV10 of the 3P reserves. Free Cash Flow pay back of the acquisition price (before adjustment and contingent consideration) is estimated to be two years based on the assumptions used by ERCE.

Jadestone has identified numerous opportunities to unlock additional value through the application of Jadestone's capabilities as outlined above. These identified value opportunities include cost reductions, operational efficiencies and investment programmes which are not being pursued by the current operator.

The Company plans to drill two in-fill wells targeting identified 2P reserves of 3.5 MMbbl as part of the 2019 work program. These wells are included in ERCE's reserves case for the Montara Assets. A further three in-fill targets, not included in ERCE's reserves case, have been identified by Jadestone management targeting 5.3 MMbbl. The intention is to drill these in-fill targets as part of a 2020 or 2021 work programme. The Company has also identified numerous operational improvements on the production facilities to increase efficiency, including: gas lift compressor reliability; gas lift optimisation and implementing gas lift to the well head platform wells; introducing the remote reset function on the well head platform; resetting the process parameters to prevent frequent process trips; and carrying out a safety/production critical spares review. In addition, various operating expenditure savings have been identified, such as: integrated operations planning; introduction of cargo tank washing; shared logistics contracts on supply boats and helicopters, along with the synergies of operating two assets from one support team.

Reflecting on the savings obtained at Stag to date, the Company is confident of its ability to deliver significant additional value creation at the Montara Assets following a successful transition period and subject to the required investment by the Company.

Stag

Jadestone is the 100 per cent owner and operator of the producing Stag oil field located offshore Western Australia in the Carnarvon Basin. Stag and its associated infrastructure (excluding the leased FSO) were acquired by Jadestone on 11 November 2016 for a headline price of US$10 million plus customary working capital adjustments and potential contingent payments. At acquisition Stag had 2P reserves of 14.6 MMbbls oil and since that time Jadestone has increased 2P reserves to 17.1 MMbbls (gross and net), net of circa 1.6 MMbbls of production between the acquisition and 31 December 2017.

Since completing the Stag acquisition the focus of the Jadestone operating team has been to optimise production operations, reduce costs and identify and execute a work programme to increase production. In executing these initiatives, Stag has seen production stabilise and then increase to a current level of 3.6 mbbls/d (up from an average of 2.6 mbbls/d in Q2 2017), operating costs (excluding workover) reduce from US$43/bbl (for the first half of 2017) to US$32/bbl (for the second half of 2017, following transfer of operatorship to the Company in July 2017) and workover and other sustaining capital costs reduce by circa 50 per cent. This uplift in production and cost reduction was seen notwithstanding the MBC incidents, further details of which are set out in Section 9 of Part 1 of this document.

The Company has been able to achieve these gains through a re-organisation of management structures and processes; incentivisation of the workforce towards safe production operations; re-negotiation of contracts; and a reduction in workover duration and cost.

The Company is now focused on increasing production and intends to drill five in-fill wells by the end of 2020 (being four producers and one water injector), targeting an average of 1.1 MMbbls of oil for each producing well, which also provides additional reserves from the field as a whole through field life extension. The initial production rate of each well is expected to be circa 1.2 mbbl/d before following a natural decline rate. The additional production derived from the first infill well to be drilled is expected to further reduce 2019 per unit operating costs (excluding workovers) to US$25.9/bbl and enhance cash flow resiliency, even at low oil prices.

Development Assets

Vietnam

Overview of assets:

Jadestone has a 70 per cent operated working interest in two PSCs, Block 51 PSC and Block 46/07 PSC (which the Group has applied to extend), both in the Malay-Tho Chu basin offshore Vietnam. The Company has made three gas/condensate discoveries on its acreage, being Tho Chu and U Minh on Block 51, and Nam Du on Block 46/07. Jadestone's working interest in these blocks will increase to 100 per cent once the blocks are amended for PVEP's relinquishment of its 30 per cent interest in these blocks, effective 1 May 2017.

As at 31 December 2017, these Blocks had gross 2C resources of 496.8 Bscf (347.8 Bscf net to Jadestone) of gas and 11 MMbbl (7.7 MMbbl net to Jadestone) of oil and condensate.

In November 2017, the Company submitted revised Outline Development Plans for the U Minh and Nam Du fields for approval, which was received from the Ministry of Industry and Trade in May 2018. The Company currently anticipates developing these two fields in a phased manner, with overall project sanction targeted for H2 2019. Ahead of project sanction, the Company is working on the front-end engineering and design, negotiation of commercial gas sales agreements and field development planning.

The Company intends to use an existing 18 inch pipeline, with 215 MMscf/d of capacity, owned by PetroVietnam, which is in close proximity to the fields and would be used to evacuate gas from the fields to an existing power complex and fertiliser plant in Southern Vietnam. This pipeline currently evacuates gas from the Repsol (heritage Talisman) operated PM-03 CAA Block which lies immediately to the south of Block 46/07. This field is currently in decline, which is expected to result in sufficient ullage within the pipeline, which the Company intends to seek to utilise.

The U Minh and Nam Du fields 2C contingent resources are 171.3 Bscf (gross) and 119.9 Bscf (net to Jadestone) gas and 1.6 MMbbl (gross) and 1.1 MMbbl (net to Jadestone) oil and condensate. Project sanction is currently expected in H2 2019. Jadestone management have used this data, together with estimates for capex and opex, to calculate an aggregate NPV10 of US$246 million for the U Minh and Nam Du fields.

The Tho Chu field will be subject to a later development plan.

Exploration

The Philippines

The Company has a 25 per cent working interest in the Block SC-56 in the Sandakan Basin in the Sulu Sea, offshore the Philippines, in partnership with the Operator, Total. Four wells have been drilled in the licence to date resulting in two significant gas discoveries amounting to 2C resources of 469.6 Bscf gross (117.5 Bscf net to Jadestone) of natural gas and 2C resources of 5.4 MMbbl gross (1.4 MMbbl net to Jadestone) of oil and condensate. Jadestone is carried by Total for the remaining exploration commitment well on this block. Further details of the farm-out agreement are set out in paragraph 12.7 of Part 11 of this document, including details of an ongoing dispute regarding the prospect which Total had committed to drill.

PNOC is the 100 per cent owner of SC-57 in offshore Palawan Island in the Philippines. Jadestone has agreed to acquire a 21 per cent working interest in this contract. CNOOC INT has also agreed to acquire a 51 per cent working interest and to become operator. Executive Order No. 556 (‘‘**EO 556**’’) dated 17 June 2006, effectively banned PNOC from entering into farm-in/farm-out agreements with foreign companies in relation to the exploration, development and production of crude oil. Section 1 of EO 556 states that there shall be no ‘‘farm-in’’ or ‘‘farm-out’’ contracts awarded by any government agency, including the PNOC. In a letter dated 12 January 2011, DOE allowed the force majeure condition under Section 26.1(b) of the SC-57 to be enforced starting end of Sub-phase 1 (15 March 2008) until the farm-in agreements are approved by the President.

Other business development

Ogan Komering

Jadestone acquired a 50 per cent non-operated working interest in the Ogan Komering PSC, a heritage Talisman asset, from Repsol in March 2017. Ogan Komering is located onshore South Sumatra, Indonesia. The production rate of the block in the three months ended 31 March 2018 averaged 1,447 boe/d net to Jadestone (three months ended 31 December 2017: 1,413 boe/d net to Jadestone), with a gas-to-oil ratio of approximately 65 per cent oil and 35 per cent gas. The Ogan Komering PSC expired on 28 February 2018 and a temporary cooperation contract was entered into, continuing the PSC terms pending the issue of the new PSC on 20 May 2018, at which time Jadestone ceased to hold an interest in Ogan Komering. The carrying value of the Ogan Komering PSC under oil and gas properties on the Company’s balance sheet is fully depleted.

A new gross split PSC for Ogan Komering, effective 20 May 2018, was signed by Pertamina, Indonesia’s upstream regulator SKKMIGAS, and the Minister of Energy and Mineral Resources, awarding a 100 per cent participating interest to Pertamina. Jadestone, as the prior partner in the PSC with Pertamina, has been directed to proceed with direct negotiations for participation in the new PSC with Pertamina. Jadestone is progressing its discussions with Pertamina for participation in the new gross split PSC and, based on current negotiations, the Board expects to reach satisfactory binding terms during Q4 2018, with participation to be effective from the commencement of the new PSC on 20 May 2018. To the extent Jadestone participates in the PSC, it will not be the operator of Ogan Komering and it would have less than a 40 per cent interest in the PSC. However, until definitive documentation is entered into, there can be no assurance that Jadestone will be successful in its negotiations for participation in the PSC or the terms on which any such participation may be available to Jadestone.

Jadestone will seek an independent reserves evaluation for the Ogan Komering PSC if and once the Company’s participation is confirmed in the new PSC, expected later this year.

05-01b & c – Vietnam

The Company announced on 9 August 2016 that it had signed a SPA with Teikoku, a wholly-owned subsidiary of Inpex Corporation, as seller, for the acquisition of a 30 per cent non-operated working interest in the Blocks 05-1b & c PSC.

On 22 February 2018, Teikoku delivered to Jadestone a purported notice of termination of the SPA, despite Teikoku having received a waiver from PetroVietnam, of its statutory pre-emption rights, held under Vietnamese law. The Company has not accepted Inpex's alleged termination, and views the obligations of both parties under the SPA as continuing. The Company maintains its rights under the SPA and is assessing its options, including remedies available through legal action.

Further details of the acquisition agreement are set out in paragraph 12.6 of Part 11 of this document, including details of an ongoing dispute regarding Teikoku's proposed termination. In the event that the Company is successful in asserting its rights to acquire an interest in 05-01b & c the Company will need to raise additional funds in order to pay the consideration and related capital expenditure prior to completion of the acquisition of those assets.

Other acquisition opportunities

Jadestone continues to evaluate inorganic growth opportunities in its core basin areas within the Asia-Pacific region in line with its strategy.

2 FINANCING OF THE ACQUISITION

The Company will finance the consideration, being US$195 million, for the acquisition of the Montara Assets through US$80 million of equity, raised from the net proceeds of the Placing and US$120 million of debt under the RBL Facility, underwritten by the Commonwealth Bank of Australia and Société Générale. The RBL Facility has a three year term and is priced at LIBOR plus three per cent. The Company believes the debt to equity ratio of the Acquisition, being circa 62 per cent debt to 38 per cent equity, represents a prudent level of leverage to ensure balance sheet strength, even during a period of low oil prices. The debt also represents just 25 per cent of the NPV10 of US$479.5 million of the Montara Assets and will leave the group with a *pro forma* net debt to EBITDA ratio for the year ended 31 December 2017 of 0.73:1, following repayment of the existing Convertible Facility. Details of the RBL Facility Agreement, the Placing Agreement and the Subscription Agreements which will be used to fund the Acquisition are set out in paragraphs 12.1, 12.3 and 12.4 of Part 11 of this document respectively.

3 HISTORY AND BACKGROUND

On 21 April 2015, the Company completed a reverse takeover of Mitra Energy Limited immediately prior to changing its name from "Petra Petroleum Inc." to "Mitra Energy Inc.". Following this acquisition the Company's assets primarily consisted of exploration and pre-development assets in Southeast Asia (Philippines, Vietnam and Indonesia).

On 8 June 2016, the Company announced changes to its board of directors and senior management. Paul Blakeley, Cedric Fontenit and David Neuhauser joined the Board. Paul Blakeley was appointed as Executive Chairman and Michael Horn was appointed as Interim CEO.

On 26 July 2016, the Company announced that its wholly-owned subsidiary Jadestone Australia had signed a definitive sale and purchase agreement with Quadrant Energy and Santos Offshore Pty Ltd. for the acquisition of a 100 per cent interest in the Stag Oilfield for total cash consideration of US$10 million plus adjustments to reflect an economic effective date of 1 July 2016 and potential contingent payments. Closing of the Stag Oilfield acquisition occurred on 11 November 2016.

On 9 August 2016, the Company announced that its wholly-owned subsidiary Mitra Energy (Vietnam 05-1) Pte Ltd. had signed a definitive sale and purchase agreement with Teikoku Oil (Con Son) Co. Ltd. for the acquisition of a 30 per cent working interest in Blocks 05-1b & c Production Sharing Contract for total cash consideration of US$14.3 million subject to normal closing adjustments. The proposed Block 05-1b & c Acquisition was subject to a statutory pre-emption right held by PetroVietnam under Vietnamese law. On 9 February 2018, PetroVietnam notified Teikoku that it had waived the pre-emption right and directed the parties, on behalf of the Government of Vietnam, to proceed to completion of the Block 05-1b & c Acquisition. Subsequent to that waiver and direction, Teikoku purported to terminate the sale and purchase agreement. The

Company does not accept the alleged termination. The Company maintains its rights under the sale and purchase agreement and is assessing its options, including remedies available through legal action.

On 6 December 2016, the Company changed its name from "Mitra Energy Inc" to its current name of "Jadestone Energy Inc." and changed its trading symbol on the TSX-V to "JSE". The name change to Jadestone Energy Inc. was made to emphasise a new strategic focus on oil and gas development and production, differentiating itself from Mitra Energy Inc's exploration-led strategy.

On 13 March 2017, the Company announced that its wholly-owned subsidiary, Jadestone Energy International Holdings Inc., had acquired a 50 per cent interest in the Ogan Komering Production Sharing Contract in Sumatra, Indonesia for a total purchase price of US$5.8 million, subject to working capital and other customary adjustments. The Ogan Komering PSC expired on 28 February 2018 and a temporary cooperation contract was entered into continuing the PSC terms pending the issue of the new PSC on 20 May 2018, at which time Jadestone ceased to hold an interest in Ogan Komering.

On 27 June 2017, the Company announced that Paul Blakeley had assumed the role of Chief Executive Officer while retaining his position as Executive Chairman, and that Michael Horn had taken on the role of Executive Vice-President Corporate and Business Development.

On 11 December 2017, the Company announced that Dennis McShane had been appointed a Director and assumed the role of Non-Executive Chairman, and that Paul Blakeley remained as an Executive Director and the Chief Executive Officer.

On 16 July 2018, the Company announced that its wholly-owned subsidiary, Jadestone Energy (Eagle) Pty Ltd had entered into an agreement to acquire the Montara Assets on and subject to the terms and conditions of the Acquisition Agreement, further details of which are set out in paragraph 3.1 of Part 4 of this document. Details of the RBL Facility Agreement entered into on 2 August 2018, the Placing Agreement and the Subscription Agreements which will be used to fund the Acquisition are set out in paragraphs 12.1, 12.3 and 12.4 of Part 11 of this document respectively.

A summary of the key events in the history of the Company prior to the current management joining the Company is set out in paragraph 2.1 of Part 11 of this document.

4 KEY STRENGTHS

Proven regional management team

- Proven in-region management team with a track record of value creation and generating returns for shareholders.
- End-to-end capabilities through the upstream operating life cycle, with second phase specialisation and a history of safe operations.
- Deep technical expertise in reservoir optimisation, production and facilities management, ongoing cost discipline developed at oil majors and large-cap E&P.

Focused fit-for-purpose strategy

- Focus on highly investable low cost and high margin markets in Asia-Pacific, which offer complex yet stable jurisdictions, high GDP growth rates, rising domestic gas demand and prices, and established gas infrastructure.
- Well positioned to take advantage of the retrenchment by majors and independents in the region and fill the growing vacuum for a nimble and capable operator.
- Focused strategy consistent with management's in-region track record, operating experience, technical knowledge and relationships.
- Leveraging management's proven track record of accretive business development and successful integration and portfolio rationalisation, to a growing opportunity set in the region.

Attractive cash generative production portfolio

- Focused and resilient production. Following completion of the Acquisition and success of the near term infill well campaign, free cashflow-positive production of approximately 12-15 mbbl/d, even at low oil prices, capable of supporting the Company's development plans and the introduction of a dividend policy in the short to medium term.

- Stable OECD exposure in a favourable tax and royalty regime.

Attractive near-term value catalysts

- Portfolio of high return quick payback investment opportunities including in-fill drilling in both Stag and Montara Assets.
- 12 per cent increase in uptime and circa 25 per cent decrease in operating costs at Montara Assets targeted within 12 months of assuming operatorship. Jadestone management estimate that this will increase annual production by circa 1.7 mbbls/d in 2019.
- Currently in direct and bilateral negotiations with Pertamina to enter into the new gross split Ogan Komering PSC, a 25 year heritage Talisman and Jadestone asset.

Value accretive development portfolio

- 171.3 Bscf (gross) shallow water gas produced via existing infrastructure with anticipated ullage into a growing and gas short power market with an additional 31.1 Bscf from the Southern Channel at Nam Du.
- 18.2 mboe/d (gross) peak production expected to be sold via long term fixed price and fixed escalation take or pay contracts.

5 DIRECTORS, PROPOSED DIRECTOR AND EMPLOYEES

The Board and the Group's senior management have significant experience in establishing, growing, financing and subsequently monetising early stage oil & gas companies across the Asia-Pacific region. The Board is comprised of one executive Director based in Singapore and six non-executive Directors based in Canada, the United Kingdom, the United States of America and Monaco. The Company intends to appoint Daniel Young (the chief financial officer of the Company) as a further executive director, based in Singapore, with effect from, and conditional on, Admission.

Pursuant to the Nomination Rights Agreement between the Company and Ontario Teachers' Pension Plan Board, a significant shareholder of the Company, Ontario Teachers' Pension Plan Board has a right to nominate one director for so long as Ontario Teachers' Pension Plan Board holds at least five per cent of the issued and outstanding Shares. Such nominee will also have the right to be a member of any executive committee of the board of the Company. The Ontario Teachers' Pension Plan Board has not exercised its nomination right pursuant to the Nomination Rights Agreement.

Pursuant to a relationship agreement entered into between the Company, Tyrus and the Tyrus Fund, with effect from Admission, Tyrus will be entitled to nominate one director to the board of the Company and has designated Cedric Fontenit as its nominee. A summary of the relationship agreement is set out in paragraph 12.5 of Part 11.

5.1 Directors

Mr. Dennis McShane, Non-Executive Director and Chairman

Mr. McShane, aged 63, has over 35 years' experience in finance, oil and gas, and mining sectors in the US, Europe, Africa, and Australia. Over his career he has been involved in numerous transformational corporate transactions as director or advisor. He was the Executive Director of Strategy for Ophir plc, having previously served as Senior Independent Director during its IPO and he was Executive Director of Finance and Strategy leading the IPO of Ferrexpo plc. Prior to this, he was a Managing Director with JPMorgan Chase. He currently serves as a non-executive director of a private US based service sector company. Mr McShane became a Director and Chairman of the Company on 10 December 2017.

Mr. A. Paul Blakeley, Executive Director and Chief Executive Officer

Mr. Blakeley, aged 64, holds a B.Sc (Hons) in geology and chemistry from Bedford College (University of London). In 2002 he was conferred as an Officer of the Order of the British Empire (OBE) by H.M. Queen Elizabeth II for services to the oil industry in the UK. Mr. Blakeley has over 40 years of industry experience in the energy sector, most recently from 1994 to July 2015 with Talisman Energy Inc. As Executive Vice-President Asia-Pacific and Middle East, Mr. Blakeley was responsible for Talisman's Asia-Pacific operations. Mr. Blakeley became a Director and was appointed Executive Chairman of the Company on 7 June 2016 and was appointed Chief Executive Officer of the Company on 27 June 2017.

Mr. Robert Lambert, Non-Executive Director and Deputy Chairman

Mr. Lambert, aged 69, is an international energy executive with over 45 years' experience in the international exploration and production business. Mr. Lambert was formerly CEO and President of the Company when it was Petra Petroleum Inc. He is a chartered geologist and has held numerous operational and management positions in the US, Europe, North Africa, West Africa, South East Asia and the Caspian region primarily with Conoco Inc. Mr. Lambert was a Non-Executive Director of Eland Oil and Gas plc from 2012 to 2016 and was Chief Executive of GB Petroleum Ltd. from 2005 to 2010. Mr. Lambert became a Director of the Company on 5 May 2011.

Mr. Iain McLaren, Non-Executive Director

Mr. McLaren, aged 67, has significant experience in the oil and gas sector and until May 2018 was Senior Independent Director and Chair of the Audit Committee for Cairn Energy plc. He is currently Chairman of F&C UK High Income Trust plc as well as the director of various other companies. He is a past President of the Institute of Chartered Accountants of Scotland and was a partner of KPMG for 28 years until 2008. Mr. McLaren was previously a director of Mitra Energy Ltd. and upon completion of the reverse takeover became a Director of the Company on 21 April 2015.

Mr. Eric Schwitzer, Non-Executive Director

Mr. Schwitzer, aged 67, has over 35 years' experience within the investment banking and natural resources sector and is currently Vice Chairman of Lincoln Peck Financial Inc. He is the former managing partner of Enterprise Capital Inc. and has extensive experience in the Canadian capital markets, having been a director of various Canadian publicly listed companies over the past 12 years. Mr. Schwitzer became a Director of the Company upon completion of the reverse takeover on 21 April 2015.

Mr. Cedric Fontenit, Non-Executive Director

Mr. Fontenit, aged 42, is a senior member of the investment team at Tyrus Capital S.A.M. Over the course of his eighteen-year career in investment banking and hedge fund industry, he has gained extensive experience in advising on and structuring mergers and acquisitions and investments. Mr. Fontenit joined Tyrus Capital in 2009, where he has had significant investment experience in the oil and gas and mining industries. He became a Director of the Company on 7 June 2016.

Mr. David Neuhauser, Non-Executive Director

Mr. Neuhauser, aged 48, has extensive capital markets and merger and acquisition experience and is the founder and managing director of the event-driven hedge fund Livermore Partners in Chicago. He has invested in and advised global public companies for the past 20 years and has a strong track record of enhancing intrinsic values through restructuring and strategic initiatives. He became a Director of the Company on 7 June 2016.

5.2 **Proposed Director**

Mr. Daniel Young, Chief Financial Officer

Mr. Young, aged 48, is a CFA charter holder and a Chartered Accountant and has more than 20 years' experience in senior oil and gas and natural resources investment banking, advisory and consulting roles. Prior to joining Jadestone, Mr. Young was with Wood Mackenzie, the global energy sector consultancy group, where he was Senior Vice President, and Head of APAC Consulting. Prior to that, he worked for 13 years in JP Morgan's global energy investment banking coverage/mergers and acquisitions group. Mr. Young was appointed as Chief Financial Officer of the Company on 18 January 2017.

5.3 **Employees**

At the date of this document, the Group has 67 employees.

The table below shows the geographical breakdown of employees by their main activity.

Country	Total No. of Employees	Management	Engineering	Sales	Accounting	Administration
Singapore	7	6	0	0	0	1
Malaysia	14	1	6	0	3	4
Vietnam	8	0	1	0	4	3
Indonesia	5	1	0	1	0	3
Australia	33	1	29	0	1	2

A number of the employees engaged in Stag offshore operations are subject to a collective bargaining arrangement pursuant to an enterprise agreement.

As at 31 December 2017, 162 individuals were engaged in respect of the Montara Assets as follows:

Employment Category	Total No. as at 31 December 2017
Employee	119
Secondee	12
Contractor	31
Total	**162**

Under the Acquisition Agreement, Jadestone is only acquiring the Montara Assets.

6 SUBSTANTIAL SHAREHOLDER

The Tyrus Fund, a fund for which Tyrus acts as an investment manager owns 109,705,247 Common Shares, which following the Placing will represent 23.8 per cent of the Enlarged Share Capital. As such, the Tyrus Fund will have significant influence over the Company following the Placing.

The Company is satisfied that it is capable of carrying on its business independently of the Tyrus Fund and Tyrus, and that all transactions and relationships between the Company, the Tyrus Fund and Tyrus are and will continue to be at arm's length and on a normal commercial basis.

To ensure that this is the case, the Company has entered into a relationship agreement with the Tyrus Fund and Tyrus (a summary of which is set out in paragraph 12.5 of Part 11). If a conflict of interest arises between the Tyrus Fund and/or Tyrus and the Company, Cedric Fontenit, a director of the Company and an employee of Tyrus, subject to the terms of the relationship agreement will take no part in the Board's decisions on the matter.

Effective 2 November 2016, the Tyrus Lender, an entity for which Tyrus acts as investment manager and adviser, entered into the Convertible Facility with Jadestone, pursuant to which the Tyrus Lender agreed to advance, and may require the Company to draw down, up to US$28.0 million upon and subject to the terms and conditions of the Convertible Facility. Any principal amount advanced under the Convertible Facility may be converted into Common Shares or non-voting Class B Shares at the option of the Tyrus Lender at a conversion price of CAD0.50 per share.

As of the date hereof, the Company has drawn down the Convertible Facility by a total of US$15.0 million. On 1 August 2018, the Company and the Tyrus Lender agreed that conditional upon Admission occurring no later than 10 August 2018 and the Tyrus Lender receiving payment no later than 5 Business Days after the Company receives the proceeds of the Company Placing, the Company would redeem the Convertible Facility following Admission by paying $17,450,000 to the Tyrus Lender and that the Convertible would terminate on receipt of such payment and that the associated security will be released.

The Tyrus Lender has also agreed that it will not convert any Principal Amount into shares, declare an event of default or exercise any right of enforcement under the Convertible Facility or require the Company to draw down any additional sums and the Company has agreed not to request any further advances, in each case unless Admission does not occur by 10 August 2018 or the Company does not make the payment to the Tyrus Lender five Business Days after the Company receives the proceeds of the Company Placing.

7 SUMMARY OF THE GROUP'S RESERVES AND RESOURCES

Table 1-1: Summary of Oil Reserves

Licence	Field	Gross Reserves (MMstb)			Working Interest	Net Reserves attributable to Jadestone (MMstb)			Operator
		1P	2P	3P	(%)	1P	2P	3P	
AC/L7	Montara	8.9	14.9	20.5	100 *	8.9	14.9	20.5	Jadestone *
AC/L8	Skua	4.0	6.9	9.5	100 *	4.0	6.9	9.5	Jadestone *
AC/L8	Swift/Swallow	4.2	6.4	8.4	100 *	4.2	6.4	8.4	Jadestone *
WA-15-L	Stag	10.8	17.1	22.7	100	10.8	17.1	22.7	Jadestone
Total		**27.9**	**45.3**	**61.1**		**27.9**	**45.3**	**61.1**	

*Subject to the completion of the acquisition of PTTEP AA's 100% interest in AC/L7 and AC/L8

1. The effective date is 31st December 2017.
2. ''Gross Reserves'' represent a 100% total of the estimated technically recoverable oil within the licence period. ''Gross Reserves'' include volumes attributable to third parties and government and thus contain volumes which are not attributable to Jadestone.
3. ''Net Reserves attributable to Jadestone'' are the ''Gross Reserves'' multiplied by Jadestone's working interest in the field/asset.

Table 1-2: Summary of Net Present Values

Field	Case	After Tax Discounted Cash Flow ($US MM)				
		NPV0	NPV5	NPV10	NPV15	NPV20
Montara Assets*	1P	231.5	278.7	287.3	279.9	266.3
	2P	480.3	509.7	479.5	436.4	394.5
	3P	1043.3	921.0	792.8	683.6	595.3
Stag	1P	6.6	25.2	29.6	28.7	26.1
	2P	94.0	97.0	84.2	70.2	58.3
	3P	135.0	141.7	122.1	101.3	84.1

*Subject to the completion of the acquisition of PTTEP AA's 100% interest in AC/L7 and AC/L8

1. The NPVs presented in the table above represent all Reserves for the assets evaluated in the CPR.
2. The effective date is 31st December 2017.
3. The net present values associated with the Reserves calculations contained within this report should not be construed as ERCE's opinion of fair market value.

Table 1-3: Summary of Oil and Condensate Contingent Resources

Field	Licence	Country	Gross Contingent Resources (MMstb)			Working Interest	W.I. Contingent Resources (MMstb)			Chance of Development	Operator
			1C	2C	3C	(%)	1C	2C	3C	(%)	
Stag	WA-15-L	Australia	4.8	2.7	0.0	100%	4.8	2.7	0.0	50%	Jadestone
Nam Du	Block 46/07	Vietnam	—	—	—	70%*	—	—	—	—	Jadestone
U Minh	Block 51	Vietnam	0.3	1.6	3.25	70%	0.2	1.1	2.3	85%	Jadestone
Tho Chu	Block 51	Vietnam	3.1	9.4	24	70%	2.2	6.6	16.8	40%	Jadestone
Dabakan	SC56	Philippines	1.1	3.5	13.38	25%	0.3	0.9	3.3	35%	TOTAL
Palendag	SC56	Philippines	0.2	1.9	8.2	25%	0.1	0.5	2.1	35%	TOTAL
Total			**9.5**	**19.1**	**48.8**		**7.6**	**11.8**	**24.5**		

*Subject to a 3% back-in right by a third party at cost

1. ''Gross Contingent Resources'' represent a 100% total of estimated technically recoverable oil and/or condensate. ''Gross Contingent Resources'' include volumes attributable to third parties and government and thus contain volumes which are not attributable to Jadestone.
2. ''W.I. Contingent Resources'' are the ''Gross Contingent Resources'' multiplied by Jadestone's working interest in the field/asset.
3. The ''Chance of Development'' defines the chance that the Contingent Resources will be developed and will reach commercial producing status.
4. Contingent Resources should not be aggregated with Reserves because of the different levels of risk involved and the different basis on which volumes are determined.

Table 1-4: Summary of Gas and Associated Gas Contingent Resources

Field	Licence	Country	Gross Contingent Resources (Bscf)			Working Interest (%)	W.I. Contingent Resources (Bscf)			Chance of Development (%)	Operator
			1C	2C	3C		1C	2C	3C		
Stag	WA-15-L	Australia	—	—	—	100%	—	—	—	—	Jadestone
Nam Du	Block 46/07	Vietnam	64.8	107.4	134.5	70%*	45.4	75.2	94.2	85%	Jadestone
U Minh	Block 51	Vietnam	16.0	63.9	110.1	70%	11.2	44.7	77.1	85%	Jadestone
Tho Chu	Block 51	Vietnam	148.6	325.5	692.2	70%	104	227.9	484.5	40%	Jadestone
Dabakan	SC56	Philippines	131.2	241.0	598.8	25%	32.8	60.3	149.7	35%	TOTAL
Palendag	SC56	Philippines	49.6	228.6	720.1	25%	12.4	57.2	180	35%	TOTAL
Total			**410.2**	**966.4**	**2,255.7**		**205.8**	**465.3**	**985.5**		

*Subject to a 3% back-in right by a third party at cost

1. "Gross Contingent Resources" represent a 100% total of estimated technically recoverable oil and/or condensate. "Gross Contingent Resources" include volumes attributable to third parties and government and thus contain volumes which are not attributable to Jadestone.
2. "W.I. Contingent Resources" are the "Gross Contingent Resources" multiplied by Jadestone's working interest in the field/asset.
3. The "Chance of Development" defines the chance that the Contingent Resources will be developed and will reach commercial producing status.
4. Contingent Resources should not be aggregated with Reserves because of the different levels of risk involved and the different basis on which volumes are determined.

The above tables are all extracted without material adjustment from pages 7 – 9 of the CPR set out on pages 135-137 in Part 6 of this document.

8 SUMMARY FINANCIAL INFORMATION

The following information has been extracted without material adjustment from the audited financial information and unaudited quarterly financial information of the Group contained in Part 7 of this document.

Prospective investors should read the whole of this document and should not rely solely on this summary.

	3 months ended		9 months ended	12 months ended		
US$ '000s	**31 March 2018**	**31 March 2017**	**31 December 2017**	**31 March 2017 (restated)**	**31 March 2016**	**March 2015**
	(unaudited)	*(unaudited)*	*(audited)*	*(audited)*	*(audited)*	*(audited)*
Revenue	20,999	17,210	60,443	35,142	0	0
Loss from operations	(14,917)	(15,653)	(16,088)	(32,601)	(18,600)	(18,559)
Loss before tax	(15,897)	(15,665)	(20,392)	(34,630)	(19,207)	(27,069)
Loss for the year	(16,593)	(19,485)	(14,930)	(36,497)	(19,207)	(27,069)

US$ '000s	**As at 31 March 2018**	**As at 31 March 2017**	**As at 31 December 2017**	**As at 31 March 2017 (restated)**	**As at 31 March 2016**	**As at March 2015**
	(unaudited)	*(unaudited)*	*(audited)*	*(audited)*	*(audited)*	*(audited)*
Cash & Equivalents	9,662	14,478	10,450	14,478	9,117	2,207
Net Assets	91,063	122,692	108,198	122,692	119,368	36,205

The following information has been extracted from the unaudited Historical Financial Information of the Montara Assets contained in Part 8 of this document.

Prospective Investors should read the whole of this document and should not rely solely on the summary.

	12 months ended (unaudited)		
US$ '000s	**31 December 2017**	**31 December 2016**	**31 December 2015**
Net revenue	220,587	235,790	334,619
Production costs	(69,355)	(55,434)	(42,677)
DD&A	(132,890)	(219,185)	(400,993)
Staff Costs	(32,372)	(33,133)	(36,570)
Impairment of assets	—	—	(331,000)
Loss before tax	(19,588)	(83,601)	(482,799)

9 CURRENT TRADING AND PROSPECTS

On 30 May 2018, the Company announced its unaudited results for the quarter ended 31 March 2018 which are set out in Appendix 4 to this document.

Average first half production for the Company to 30 June 2018 comprised 4,174 boe/d, of which liquids constituted 88 per cent, and the remainder natural gas, and noting that the existing Ogan Komering PSC expired on 19 May 2018. The average sales price for Stag oil during the first half of the year was US$70.88/bbl, while Ogan Komering liquids averaged US$63.40/bbl and natural gas was sold at an average price of US$6.34/MMbtu (both for the period to the expiry of the PSC). Revenue for the first half net of royalties but before cashflow hedges was US$34.8 million, and noting that sales volume differs from production volume due to timing of Stag liftings from the FSO. Total cash on hand at 30 June 2018 comprised US$17.3 million, including restricted cash of US$10.7 million.

Stag

For the three months ended 31 March 2018, Stag production averaged 2,654 bbls/d, compared to 2,382 bbls/d for the three months ended 31 March 2017. This represents an increase of 11 per cent from Q1 2017 and is the period during which potential cyclone disruption is at its highest.

During the previous three month period, ended 31 December 2017, production rates from Stag were adversely impacted by a series of MBC incidents where the MBC released, disconnecting the platform from the FSO, resulting in unscheduled production stoppages. As reported in Jadestone's December 2017 quarter results, these MBC incidents caused production to fall below budget, in essence a deferral of production, by about 53 mbbls in the December 2017 quarter. The last of these incidents also affected production volumes in the March 2018 quarter, resulting in production falling below budget/deferred by approximately 16 mbbls for the March 2018 quarter.

In addition, the sudden production stoppages incidents caused damage to several of the facility's ESPs which required three well workovers during Q1 2018, to restore production rates.

The resultant ESP failures caused higher than expected well downtime, resulting in a further production deferment of approximately 51 mbbls based on actual production versus budget. The combined production deferment of approximately 67 mbbls resulted in production for the quarter being circa 745 bbls/d lower than budgeted.

The Company is in discussion with the operator of the vessel, in relation to the financial impact of the MBC events. Meanwhile a number of initiatives have been implemented to reduce the risk of future MBC failures and to improve operational performance. A new MBC has now been installed providing a more robust solution, following a series of stress tests and modifying the placement of the MBC to reduce future potential stress. The Company is seeking recompense from the contractor and through the contractor's insurance.

Jadestone also received notification, on 30 April 2018, of the renewal of the Stag production licence for a further 21 years. This provides the Company with the opportunity to further develop and invest in the field, in order to grow future oil production and deliver additional operational efficiency initiatives.

Indonesia

Ogan Komering PSC (South Sumatra Basin)

For the three months ended 31 March 2018, Ogan Komering PSC production averaged 1,447 boe/d net to Jadestone compared to 1,474 boe/d net to Jadestone for the three months ended 31 March 2017. Ogan Komering PSC was acquired on 9 March 2017. Production was consistent with the business plan. The Ogan Komering PSC expired on 28 February 2018 and a temporary cooperation contract was entered into continuing the PSC terms pending the issue of the new PSC which occurred on 20 May 2018, at which time Jadestone ceased to hold an interest in Ogan Komering. Jadestone, as the prior partner in the PSC with Pertamina, has been directed to proceed with direct negotiations for participation in the new PSC with Pertamina. Jadestone is progressing its participation discussions with Pertamina and the Board expects to reach satisfactory binding terms during Q4 2018, with participation to be effective from the commencement of the new PSC on 20 May 2018. To the extent Jadestone participates in the PSC, it will not be the operator of Ogan Komering and it would have less than a 40 per cent interest in the PSC. However, until definitive documentation is entered into, there can be no assurance that Jadestone will be successful in its negotiations for participation in the PSC or the terms on which such participation may be available to Jadestone.

Montara Assets

The successful completion of an additional producing well, Montara H5-ST2, in October 2017 increased production at the Montara Assets by 3.5 mbbl/d.

The above production rate was subsequently impacted as a result of the annual statutory facility shutdown in March 2018 and April 2018 together with the loss of production associated with the Skua and Swift/Swallow subsea tie-back wells being shut-in to June 2018 due to a failure of the subsea umbilical that provides communication to these wells. The production during this period, which was essentially entirely from the Montara field, amounted to approximately 7 mbbl/d. The successful remediation of the subsea umbilical in late June 2018 resulted in the restoration of the subsea well production and, specifically, production associated with Skua-10ST2 and Swift N1. Production from the fields is currently approximately 10.3 mbbl/d.

In addition to the above maintenance and remediation activities, a well intervention program is planned for September 2018 which should reinstate gas lifting at the Swift 2 and Skua 11 wells, and also add a perforation in Swallow 1. This is expected to result in the restoration of peak production to approximately 5.6 mbbl/d from these wells.

Montara crude is stored in the FPSO for lifting under a crude sale contract with PTTEP. Normal cargo size is around 550,000 bbls but ongoing tank cleaning work and inspections relating to the vessel's class has reduced storage capacity, resulting in more frequent lifting of about 350,000 bbls. The tank cleaning/inspection work is expected to complete in Q3 2018.

Operating costs in Q1 2018, excluding corporate G&A and legal fees which are for the account of the Seller, amount to US$22.8/bbl. It is expected that operating costs will increase in Q2 and Q3 due to the routine annual shut down and non-routine activities referenced above, before returning to normal levels of around US$22/bbl in Q4 2018 before declining further once Jadestone starts to implement its practices.

Further details relating to the Montara Assets are set out in Part 4 of this document.

10 REASONS FOR ADMISSION AND USE OF PROCEEDS

The Company is seeking admission of the Enlarged Share Capital to trading on AIM in order to broaden its shareholder investor base and increase trading liquidity, fund the equity component of the acquisition of the Montara Assets and enhance the profile of the business.

The proceeds of the Placing will be used by the Company for the following purposes:

Purpose	**US$m**
Equity funding component for the acquisition of the Montara Assets	80
Repayment of the Convertible Facility	15
Working capital and transaction costs	10
Partial funding for drilling of one infill well at Stag[1]	5
TOTAL	**110.0**

Note 1: The remainder of the anticipated US$15 million cost is expected to be funded from organically generated cash flow from operations.

As an existing operator in off-shore North-West Australia, the Company believes it is in a strong position to seek approval from NOPTA, the Australian offshore title registrar, for the Acquisition, FIRB approval. However, in the event that any of these approvals or TSX-V approval is not forthcoming or the Acquisition does not otherwise complete, the Company proposes to use the proceeds of the Placing to further its acquisition strategy or accelerate the development of its existing assets. A summary of the Acquisition Agreement is set out in paragraph 3.1 of Part 4 of this document and a summary of the approvals required in connection with the Acquisition is set out in Section 4 of Part 4 of this document.

11 DETAILS OF THE PLACING

The Placing Shares will represent approximately 52 per cent of the Enlarged Share Capital.

The Placing comprises the placing by the Joint Bookrunners, as agents for the Company, of 239,711,474 Placing Shares with institutional and other investors and the Subscription. The Placing will raise approximately £78.5 million net of expenses for the Company.

Between 26 July 2018 and 29 July 2018 the Directors, Livermore and certain members of senior management agreed to subscribe for 1,961,271 Placing Shares at the Placing Price.

The Placing Shares will be issued fully paid and will, on issue, rank *pari passu* with the Existing Common Shares, including the right to receive, in full, all dividends and other distributions thereafter declared, made or paid after the date of issue.

The Terms and Conditions of the Placing are set out in Part 10 of this document. Further details of the Placing are set out in Section 9 and paragraph 12.3 of Part 11 of this document.

12 STOCK OPTION PLAN

The Stock Option Plan was adopted by the Board on 19 August 2015 and approved by the shareholders of the Company on 25 September 2015. The purpose of the Stock Option Plan is to provide an incentive to the Directors, officers, employees and consultants of the Group to continue their involvement with the Group and to increase their efforts on the Group's behalf by allowing the Company to grant Options to Directors, officers, employees and consultants as additional compensation and as an opportunity to participate in the growth of the Company. The granting of such Options is intended to align the interests of such persons with that of the Group and is a common industry practice.

As at the date of this document, 12,432,821 Common Shares are subject to outstanding options granted under the Stock Option Plan, the majority of which vest rateably over a three year period. No options to purchase Common Shares have yet been exercised. The Company has granted, conditional on Admission at C$0.61 per Common Share:

(a) A. Paul Blakeley an Option over 250,000 Common Shares;

(b) Daniel Young an Option over 250,000 Common Shares; and

(c) Options over 1,000,000 Common Shares, in aggregate, to other employees of the Company.

Further details of the Stock Option Plan and the Options granted and to be granted thereunder are set out in Section 5 of Part 11 of this document.

13 TSX-V APPROVAL

Pursuant to the rules of the TSX-V, the Acquisition and Placing are conditional on TSX-V approval. The Acquisition will constitute a ''Fundamental Acquisition'' under TSX-V rules and will require the filing of the following documents with the TSX-V: (i) CPR; (ii) the Acquisition Agreement; (iii) a title opinion; and (iv) a financial plan outlining how the Company proposes to fund the Acquisition. The Company has applied for the approval from TSX-V for the Acquisition and will apply for conditional approval for the Placing prior to Admission.

14 DIVIDEND POLICY

The Company is currently generating revenues and positive operating cash flow from production at the Stag Field and, following Completion of the Acquisition, expects to generate revenues and positive operating cash flow from the Montara Assets.

Following the first anniversary of Completion of the Acquisition, the Company currently intends to introduce a cash dividend. This intention will be subject to the ongoing funding requirements of the business and will be reviewed on an ongoing basis.

The declaration and payment by the Company of any future dividends, and the amount of such dividends, will ultimately be dependent upon the Group's financial condition, future prospects, profits legally available for distribution, the need to maintain an appropriate level of dividend cover, distribution restrictions and financial covenants and other factors deemed by the Board to be relevant at that time, in accordance with the Articles and subject to compliance with the Act.

15 CANADIAN CORPORATE GOVERNANCE

The Company is subject, among other laws and regulations, to instruments published by relevant Canadian securities regulators. One such instrument, NI 58-101 *Disclosure of Corporate Governance Practices*, prescribes certain disclosure by the Company of its corporate governance practices and NP 58-201 *Corporate Governance Guidelines* provides non-prescriptive guidelines on corporate governance practices for reporting issuers such as the Company. This section sets out the Company's approach to corporate governance and addresses the Company's compliance with NI 58-101 and NP 58-201.

As a result of its listing on the TSX-V and being a reporting issuer in the Canadian provinces of British Columbia and Alberta, the Company has already established corporate governance practices and procedures appropriate for a publicly listed company in Canada. The Company complies with Canadian corporate governance standards appropriate for publicly listed companies.

The Company has adopted the Code to be followed by the Company's directors, officers, employees and principal consultants and those of its subsidiaries. The Code is also to be followed, where appropriate, by the Company's agents and representatives, including consultants where specifically required. The purpose of the Code is to, among other things, promote honest and ethical conduct, avoid conflict of interest, protect confidential information and comply with the applicable government laws and securities rules and regulations.

The Company has established an Audit Committee, which meets regularly, a Compensation and Nominating Committee, and with effect from Admission an HSSE Committee each of which is convened as necessary. The mandate and composition of each committee are outlined below.

15.1 **Board structure**

On Admission, the Board will consist of two executive directors and six non-executive directors, all of whom are considered by the Board to be independent in accordance with Canadian corporate governance standards, notwithstanding that Cedric Fontenit is the nominee of and an employee of Tyrus and their nominee on the Board and David Neuhauser is deemed to be interested in the Common Shares in the Company held by Livermore Partners LLC. The Chairman is responsible for leadership of the Board and for the efficient conduct of the Board's function. The Chairman is expected to encourage the effective contribution of all Directors and promote constructive and respectful relations between Directors and senior management. The Directors believe that they have sufficient experience in implementing accounting systems and controls which will provide a reasonable basis for them to make proper assessments as to the financial position and prospects of the Company.

15.2 **Audit Committee**

The Company has adopted a charter for the Audit Committee which establishes the Audit Committee's purpose and responsibilities, establishment and composition, authority, duties and responsibilities. The Audit Committee is comprised of Iain McLaren (chair), Robert Lambert and Eric Schwitzer, all of whom are considered independent in accordance with Canadian corporate governance standards. The Audit Committee's overall goal is to ensure that the Company adopts and follows a policy of proper and timely disclosure of material financial information and reviews all material matters affecting the risks and financial position of the Company. The Audit Committee, *inter alia*, meets with the Company's external auditor and its senior financial management to review the annual and interim financial statements of the Company, oversees the Company's accounting and financial reporting processes, the Company's internal accounting controls and the resolution of issues identified by the Company's auditors.

15.3 **Compensation and Nominating Committee**

The Compensation and Nominating Committee is a committee appointed by the Board which is currently comprised of Eric Schwitzer, Iain McLaren and Cedric Fontenit, each of whom is independent. The Compensation and Nominating Committee assists the Board in identifying new candidates for Board nomination, makes recommendations to the Board with respect to membership on committees of the Board, other than the Compensation and Nominating Committee, assists the Board in setting director and senior executive compensation, develops and submits to the Board, recommendations with respect to other employee benefits as it sees fit and assists the Board with respect to providing continuing education programs for directors. The Compensation and Nominating Committee will meet as often as may be necessary or appropriate in its judgment.

In exercising its mandate, the Compensation and Nominating Committee sets the standards for the compensation of directors, employees and officers based on industry data and with the goal to attract, retain and motivate key persons to ensure the long term success of the Company. Compensation generally includes the three following components: base salary, annual bonus based on performance and grant of stock options. The Compensation and Nominating Committee takes into account the increased competition in the market for its key personnel while also taking into account the performance and objectives set forth for the Company. The Compensation and Nominating Committee annually assesses the contribution and effectiveness of each director, with particular reference to any applicable position description as well as the competencies and characteristics each director is expected to bring to the Board and at the request of a director, will consider and, if deemed advisable, authorize the retaining by any director of an outside advisor for such director at the expense of the Company.

15.4 **HSSE Committee**

The Board has established a Health, Safety, Social and Environmental Committee, to assist the Board in obtaining assurance that appropriate policies and systems are in place to manage effectively the health, safety, environment and community relations risks in relation to the Group's operations and ensure that the Group's activities are planned and executed in a safe and responsible manner. The members of the HSSE Committee are: (i) Paul Blakeley and (ii) Robert Lambert, who have each been appointed for an initial term of three years. The HSSE Committee will report to the Board regarding the Group's health, safety, social and environmental record. The Board will have ultimate responsibility for health, safety, social and environmental matters.

15.5 **Share dealing code**

The Directors will comply with Rule 21 of the AIM Rules and MAR relating to dealing in the Common Shares. The Company has a blackout period policy in respect of its listing on the TSX-V which applies to Directors, officers, employees and consultants of the Company. The Company has adopted, with effect from Admission, a revised policy on trading and confidentiality of insider information for the Directors and certain employees which contains provisions appropriate for a company whose shares are admitted to trading on AIM (particularly relating to dealing during close periods in accordance with Rule 21 of the AIM Rules) and the Company will take all reasonable steps to ensure compliance by the Directors and any relevant employees with such policy.

16 CANADIAN TAKEOVER LAW AND EARLY WARNING REQUIREMENTS

It is emphasised that, although the Common Shares will be admitted to trading on AIM, the Company will not be subject to takeover regulation in the UK and the UK Takeover Code will not apply to the Company. However, Canadian laws applicable to the Company provide for early warning disclosure requirements and for takeover bid rules for bids made to security holders in various jurisdictions in Canada, a summary of which is set out below.

In Canada, securities laws are a matter of provincial/territorial jurisdiction and, as a result, bids are governed by applicable corporate and securities legislation in each province or territory, in addition to policies and instruments implemented by the Canadian Securities Administrators.

In British Columbia where the British Columbia Securities Commission acts as the Company's principal regulator, a takeover bid is defined as an offer to acquire outstanding voting securities or equity securities of a class of an issuer made to one or more persons, any of whom is in British Columbia or whose last address as shown on the books of the issuer is in British Columbia, where the securities subject to the offer to acquire, together with the offeror's securities, constitute in the aggregate 20 per cent or more of the outstanding securities of that class of securities at the date of the offer to acquire but does not include an offer to acquire if the offer to acquire is a step in an amalgamation, merger, reorganization or arrangement that requires approval in a vote of security holders.

It should be noted that one exemption from the aforementioned provision is in the case of a "foreign take-over bid". Such an exemption may be available where (among other criteria):

(a) security holders whose last address as shown on the books of the offeree issuer is in Canada hold less than 10 per cent of the outstanding securities of the class subject to the bid at the commencement of the bid;

(b) the offeror reasonably believes that security holders in Canada beneficially own less than 10 per cent of the outstanding securities of the class subject to the bid at the commencement of the bid;

(c) the published market on which the greatest volume of trading in securities of that class occurred during the 12 months immediately preceding the commencement of the bid was not in Canada;

(d) security holders in the local jurisdiction are entitled to participate in the bid on terms at least as favourable as the terms that apply to the general body of security holders of the same class; and

(e) at the same time as material relating to the bid is sent by or on behalf of the offeror to security holders of the class that is subject to the bid, the material is filed and sent to security holders whose last address as shown on the books of the offeree issuer is in the local jurisdiction.

For a complete description of the foreign take-over bid exemption, please refer to National Instrument 62-104 – Take-over Bids and Issuer Bids, issued by the Canadian Securities Administrators.

Subject to limited exemptions, a takeover bid must be made to all holders of securities of the class that is subject to the bid who are in British Columbia and must allow such security holders 105 days to deposit securities pursuant to the bid. The offeror must deliver to the security holders a takeover bid circular which describes the terms of the takeover bid and the directors of the reporting issuer must deliver a directors' circular within 15 days of the date of the bid, making a recommendation to security holders to accept or reject the bid and the reasons for the recommendation or a statement that the directors are unable to make or are not making a recommendation and the reasons why. While individual provincial securities laws in Canada only regulate offers to residents of that province, the Canadian securities regulators have adopted a policy whereby they may issue a cease trade order against a company if a takeover bid is not made to all Canadian security holders.

Takeover bids must be subject to a minimum tender condition of more than 50 per cent of the outstanding securities of the class subject to the bid (excluding target securities held by the bidder and its joint actors). Additionally, a takeover bid must be extended for 10 days after the bidder satisfies the minimum tender condition and announces its intention to immediately take up and pay for the deposited securities.

Under the BCBCA, under which the Company exists, if within four months after the date of a takeover bid the bid is accepted by the holders of not less than 9/10 of the shares of a company (exclusive of those previously held by the offeror), the offeror may, within five months after making the offer to acquire shares of the company, send written notice to any shareholder who did not accept the offer compelling them to sell their shares on the same terms as contained in the original offer, subject to the right of such shareholder to make application to court, in which case the court may set the price and terms of payment and make such other consequential orders and give such directions as it deems appropriate.

Applicable Canadian securities laws provide that any person who acquires beneficial ownership of, or the power to exercise direction or control over, voting or equity securities of any class of the Company or securities convertible or exchangeable into voting or equity securities of any class which, when added to the acquirer's securities of that class, would constitute 10 per cent or more of the securities of that class is required to disclose the acquisition by preparing and filing an early warning report in the required form along with issuing a press release announcing the acquisition. For every increase or decrease of 2 per cent of such securities thereafter (or upon falling below 10 per cent), a new press release must be issued and a new early warning report must be filed. Canadian securities laws also require the Company to disclose, in its proxy circular sent out for a general meeting, the names of holders known to the Company who beneficially own, directly or indirectly, or who exercise control or direction over, 10 per cent or more of the Company's issued and outstanding Common Shares.

17 TAXATION

General information relating to UK taxation and Canadian taxation implications which may be relevant to holding or dealing in Common Shares are set out in paragraph 11 of Part 11 of this document. These details are intended as a general guide to the current tax position under UK and

Canadian taxation law. **If you are in any doubt as to your tax position, you should contact your professional adviser immediately.**

18 ADMISSION, SETTLEMENT AND DEALINGS

Application will be made to the London Stock Exchange for the Enlarged Share Capital to be admitted to trading on AIM. It is expected that Admission will become effective and that dealings in the Enlarged Share Capital will commence at 8.00 a.m. on 8 August 2018. Definitive share certificates in respect of the Placing Shares (for those Shareholders who elect to take their Placing Shares in certificated form) will be despatched on or before 22 August 2018.

The Company's articles of association permit the holding of Common Shares in uncertificated form in accordance with the CREST Regulations. The system allows shares and other securities to be held in electronic form rather than paper form, although a shareholder can continue dealing based on share certificates and notarial deeds of transfer. For private investors who do not trade frequently, this latter course is likely to be more cost-effective.

The Company, through Computershare, has established a depositary facility whereby depositary interests, representing Common Shares, will be issued to Shareholders who wish to hold their Common Shares in electronic form in CREST. The Company will apply for the Depositary Interests to be admitted to CREST with effect from Admission. Accordingly, settlement of transactions in Common Shares following Admission may take place within the CREST system, if the relevant Shareholders so wish. Depositary Interests will have the same international security identification number (ISIN) as the underlying Common Shares and will not require a separate application for admission to trading on AIM. CREST is a voluntary system and holders of Common Shares who wish to deal on AIM and receive and retain share certificates will be able to do so.

For more information concerning CREST, Shareholders should contact their brokers or Euroclear at 33 Cannon Street, London EC4M 5SB.

Trading in Common Shares or Depositary Interests (as the case may be) on AIM will require Shareholders to deal through a stockbroker or other intermediary who is a member of the London Stock Exchange. Shareholders resident outside the UK should ensure that their stockbroker is either a member of the London Stock Exchange or has in place arrangements allowing them to effect trades on AIM.

It should be noted that if at any time a CREST member requires any further information regarding the depositary arrangement and the holding of Common Shares in the form of Depositary Interests or wishes to withdraw its Depositary Interests from the CREST system and hold shares in dematerialised registered form, they should contact Computershare Investor Services PLC, The Pavilions, Bridgwater Road, BS13 8AE telephone +44(0)370 702 0003 for such further information. Further details of the depositary arrangements are set out in Section 14 of Part 11 of this document.

The Common Shares will remain listed and traded on the TSX-V, with trades settled electronically on the Canadian register through CDS. Common Shares held on the Canadian registry cannot be settled through CREST on AIM and similarly, Common Shares (or depositary interests representing Common Shares) held on the UK registry cannot be settled through CDS on the TSX-V. However, Common Shares held through CDS on the Canadian registry may be transferred into Depositary Interests held through CREST on the UK registry and vice versa.

Shareholders wishing to undertake such a transfer will generally need to contact their broker and allow a reasonable time for the transfer to be effected. Furthermore, Shareholders will need to establish an account with a broker in the market to which they are transferring their Common Shares in order to trade their Common Shares on that market.

The issuance of the Common Shares will not be subject to, or will otherwise be exempt from, the prospectus requirements of the securities legislation of the provinces and territories of Canada. Any certificates issued representing the Common Shares, to Canadian placees only, will include legends in accordance with applicable Canadian securities laws and regulatory policies, in addition to the TSX-V policies, which shall state that unless permitted under securities legislation, the holder of such securities shall not trade them until the date that is four months and a day after the date of distribution thereof. Notwithstanding the imposition of such legends, such settlement restrictions in relation to the Common Shares, to Canadian placees only, will not restrict the trading of Depositary Interests through CREST provided that certain conditions are satisfied in order for the Company to rely upon exemptions from the prospectus and registration requirements under the laws of the Province of British Columbia.

19 LOCK-INS AND ORDERLY MARKET ARRANGEMENTS

Livermore Partners LLC, have agreed pursuant to the terms of a lock-in and orderly market agreement, that (subject to certain limited exceptions) for a period of 12 months from Admission, they will not dispose of any Common Shares (or any interest therein) held as at Admission. In addition, it has agreed that (subject to certain limited exceptions) any disposal of Common Shares in the 12 months thereafter will be (subject to certain exceptions) made through the Joint Bookrunners with a view of maintaining an orderly market in Common Shares.

The Tyrus Fund has agreed pursuant to the terms of a lock-in and orderly market agreement, that (subject to certain exceptions, including with the consent of the Joint Bookrunners or for blocks of at least 10% to a financial institution or strategic investor who enter into a lock-in on the same terms for the remainder of the period) for a period of 12 months from Admission, it will not dispose of any Common Shares (or any interest therein). In addition, it has agreed that any disposal of Common Shares in the 12 months thereafter (subject to the exceptions referred to above and certain other exceptions, including the terms offered by the Joint Bookrunners being competitive including as to the timing of any disposal) will be made through the Joint Bookrunners with a view of maintaining an orderly market in Common Shares.

Pursuant to Rule 7 of the AIM Rules for Companies, the Directors have undertaken, subject to certain limited exceptions, not to dispose of any Common Shares they will hold immediately following Admission for the period commencing on Admission and ending on the date falling 12 months after Admission (the "**Lock-In Period**"). The Directors have also agreed to orderly market provisions for the 12 month period after the expiry of the Lock-In Period.

20 RULE 17 OF THE AIM RULES

When acquiring Common Shares in the Company, shareholders are entitled under Canadian securities laws to categorise themselves as "objecting", Obos or "non-objecting", Nobos. By registering as such, which they usually do through the entity through which they acquired their Common Shares, Obos are noting that they object to their interest and their details being disclosed to the Company, up to ten per cent at which level Canadian securities law makes disclosure mandatory. Nobos on the other hand are noting the fact that they do not object to their shareholdings and their details being disclosed to the Company.

Rule 17 of the AIM Rules requires, *inter alia*, that shareholders notify an AIM listed company once their holding is three per cent or more, and changes thereto (movements through a percentage point upwards or downwards).

The Company has agreed with Stifel and BMO that it will put a resolution to its Shareholders at the next general meeting or annual general meeting (anticipated to be held in May 2019) to change the Company's constitution and require that Shareholders holding three per cent or more of the Company's Common Shares notify the Company thereof and of subsequent changes thereto. Tyrus Fund has undertaken to vote any shares which they hold at the date of such meeting in favour of the resolution.

In the interim, Placees have undertaken to, and Shareholders are requested to notify the Company in accordance with Rule 17 of the AIM Rules and make notifications to the Company without delay of all information that would be required to be notified by them as a shareholder in a company to which the Disclosure Guidance and Transparency Rules published by the FCA applied and the Company was a UK issuer.

21 FURTHER INFORMATION

Prospective investors should read the whole of this document which provides additional information on the Company and not rely on the key or summarised information. In particular, the attention of prospective investors is drawn to Part 5: "**Risk Factors**" of this document which contains certain risk factors relating to any investment in Common Shares, and Part 6: "Competent Person's Report" of this document which contains a copy of the CPR on the Company's material assets.

The technical information contained in this document has been prepared in accordance with the March 2007 SPE/WPC/AAPG/SPEE Petroleum Resources Management System and has been reviewed and approved by ERCE. ERCE has consented to the inclusion of the technical information in this document in the form and context in which it appears.

Part 2

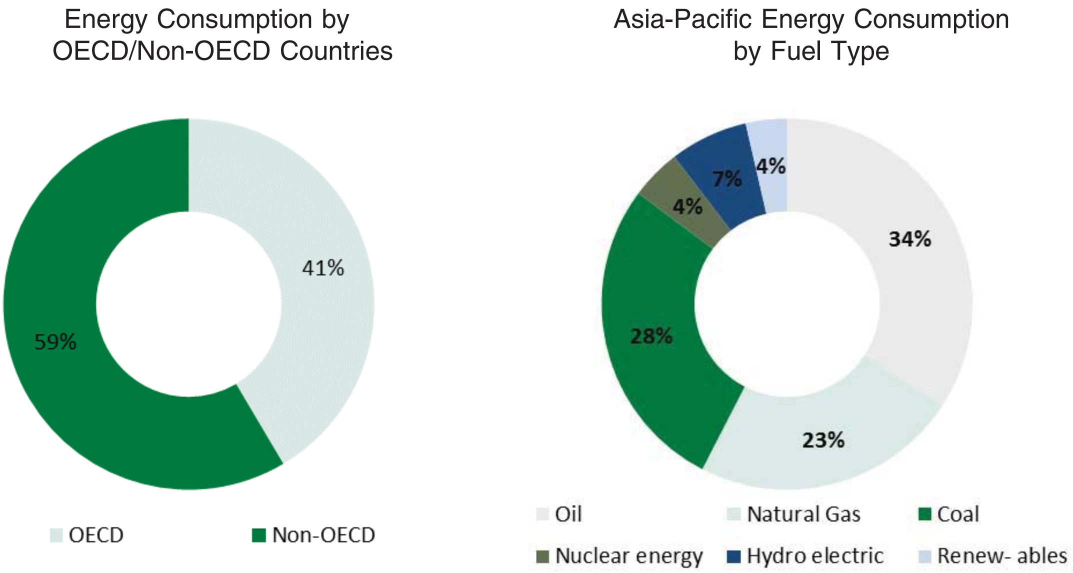
OVERVIEW OF THE OIL & GAS INDUSTRY GLOBALLY AND ASIA-PACIFIC

1 GLOBAL OIL & GAS INDUSTRY

The global consumption of primary energy continues to grow, with consumption increasing by 2.2 per cent in 2017 (versus 1.2 per cent in 2016) Natural gas consumption grew at its quickest rate since 2010, accounting for the largest increase in energy consumption in 2017. Renewables represented the second largest growth segment in energy consumption, growing 17 per cent in 2017, exceeding its 10 year average. The majority of renewables growth came from additional wind power. Oil consumption continued to recover in 2017, growing by 1.8 per cent, the third consecutive year above the ten year average growth rate of 1.2 per cent.

An increasing focus on climate change and a global drive to reduce emissions, has seen an increase in renewables uptake and a reduction in the overall energy mix of more polluting fuel sources such as coal. Although coal consumption saw a 1 per cent growth in 2017, the first growth since 2013, this was driven largely by Indian and Chinese consumption, with OECD consumption falling for the fourth consecutive year. Although there was an overall growth in consumption, coal saw a drop in its position in primary energy usage, making up only 27.6 per cent of primary energy usage, the lowest level since 2004.

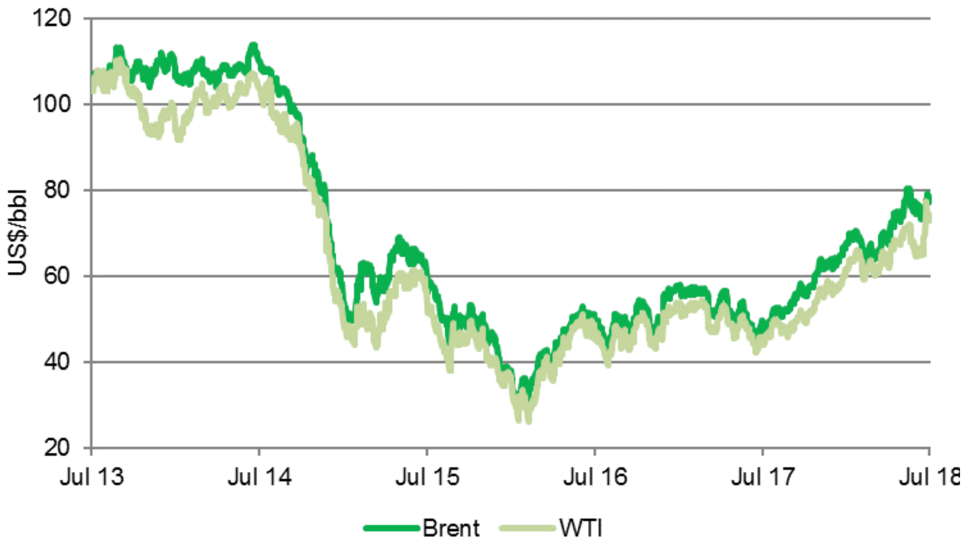
2017 Primary Energy Demand



Source: BP Statistical review (2018)

Oil

Oil prices continued to recover in 2017, with Brent averaging US$54.19 per barrel up from a 2016 average of US$43.73 per barrel. Prices have continued to recover in 2018 with the Brent price sitting at US$79.44 per barrel at the end of June 2018. Prices have been driven by a rise in consumption of 1.7 million barrels per day, with demand significantly outpacing the rise in production of 0.6 million barrels per day. This has reduced the supply demand imbalance that has prevailed for a number of years since the oil price decline in 2014.



Source: BP statistical review (2018)

Production has been limited by an agreement between OPEC members and a number of non-OPEC oil producers to cut output in order to increase prices, as well as significant non-voluntary cuts from countries such as Venezuela and Libya. These reductions came into effect in mid-2017, with a stated aim of keeping the price within a bound of US$60 – US 80/bbl.

An OPEC members' meeting on 22 June 2018 resulted in an agreement between OPEC and cooperating non-OPEC countries to increase production up to 800 mbbl/d from July 2018. Prices have however remained high, with a belief among analysts and the markets that countries may struggle to achieve this production increase. Additionally oil prices have been supported following the breakdown of the Iranian nuclear agreement, with President Trump pulling out of the deal and implementing sanctions, which may potentially reduce Iranian production and export capacity, thus reducing global supply.

Natural Gas

Both consumption and production of natural gas grew strongly in 2017, with consumption up 3 per cent (96 billion cubic meters) and production up 4 per cent (131 billion cubic meters), the fastest rate of growth since the end of the global financial crisis. The growth in consumption was led by Asia and particularly China, whose demand grew by 15.1 per cent or a third of global growth, the Middle East and Europe. Production growth came from Russia, Iran, Australia and China.

Chinese growth has been fuelled in part by the implementation of the Environmental Action Plan, set out in 2013 which focused on improving air quality in the subsequent five years. This saw a significant switch away from coal as an energy fuel into gas, which is cleaner. With the 2018 deadline (year five) approaching, the authorities increased their push to improve air quality. Gas demand is forecast to increase strongly during 2018, however the pace of growth is unlikely to be sustained in the longer term.

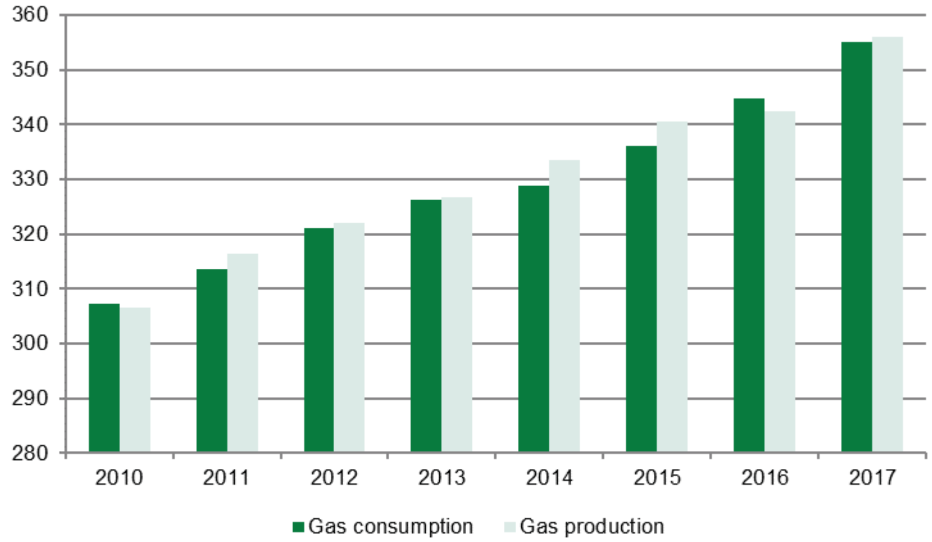
The continued expansion of LNG by over 10 per cent in 2017, the strongest rise since 2010, has also supported the growth in global gas use. LNG has driven a reduction in pricing differentials and an increasing correlation between global gas markets.

The US Henry Hub gas price has increasingly become the anchor price for global gas following the start of US gas exports in early 2016. The significant and sustained over supply of natural gas in the US, driven by shale gas and oil production has depressed prices in the US and led to an export focused strategy for US producers.

Even including transport costs, US LNG has been able to compete and in some cases undercut traditionally high price gas markets such as in the Asia-Pacific region. This has seen gas prices decline and has resulted in a corresponding demand increase as lower prices makes gas a more attractive choice for energy consumers.

There is a belief that these prices are unsustainable, with many US LNG exporters willing to sell gas at a price that covers operating cost, rather than at a price which covers full-cycle costs. This has given them market share, but is likely unsustainable with continued growth in global consumption matching the increased availability of natural gas.

Although LNG has caused a degree of convergence in global gas pricing and a fall in gas prices in global markets, significant differentials remain. US onshore gas prices remain substantially lower than those in other global markets such as in Asia-Pacific. The cost of LNG transport over the cost of gas, typically still results in regional producers selling through fixed (pipeline) infrastructure being able to realise an attractive and competitive price. In the Asia-Pacific region, continued strong economic growth in the regions' economies will likely continue to drive demand for gas and thus support prices.



Source: BP statistical review (2018)

2 ASIA-PACIFIC OIL & GAS INDUSTRY

The Asia-Pacific region is maturing as an oil and gas region with the majority of production circa 68 per cent coming from mid-life and mature fields. There is also a limited number of significant developments, resulting in production being forecast to decline by circa 15 per cent by 2025. Regional production peaked at circa 5.9 MMboe/d in 2010 and has remained steady since.

This is in contrast to the region's growth in demand, with oil and gas consumption both rising, oil consumption has increased by 22.6 per cent between 2010 and 2017 and gas consumption has increased by 33.1 per cent over same period.

Producing assets in the region have traditionally been owned and operated predominantly by the Majors and IOCs with increasing involvement from NOCs. In recent years the region has seen a withdrawal by the Majors and IOCs, accelerated by the decline in oil prices in 2014. The contribution from Majors and IOCs to the regions production has declined from 50 per cent to 37 per cent in the space of a decade and within the last three years they have sold resources of almost 800 MMboe.

Although there has been a withdrawal by Majors, over 57 Bnboe equivalent of discovered undeveloped resource remain, the majority of which is gas, and 40 per cent is considered commercial. Additionally the region, and thus many of these discoveries sit in shallow water, meaning development costs are typically cheaper than deep water. This means many discoveries are well placed to serve the significant and growing gas demand, and the associated attractive pricing, in the region.

3 WESTERN AUSTRALIA

3.1 Overview

Western Australia's petroleum sector comprises crude oil, condensate, LNG, natural gas and LPG. Western Australia remains Australia's premier petroleum producer, producing over 50 per cent of the nation's total petroleum output in energy equivalence terms in 2016.

Western Australia's oil and gas industry is underpinned by significant natural gas reserves developed through four existing LNG projects with an additional development project expected to reach first production in 2018.

3.2 The Western Australian oil industry

Western Australia is Australia's leading oil producing state, accounting for approximately 60 per cent of Australia's total oil production. Despite being Australia's leading producer, regional production is in decline.

In 2016-17, crude oil production volumes reduced by approximately 30 per cent to 33.96 MMbbl, while condensate production decreased by 11 per cent to 37.74 MMbbl. Based largely on the fall in production volumes, the value of crude oil and condensate sales decreased by 18 per cent, the sixth consecutive year oil and condensate sales have fallen.

The State's major crude oil producers operate in the Carnarvon, Perth and Canning basins, additional producing fields are located in the Vincent, Pyrenees, Okha and Mutineer-Exeter basins.

3.3 The Western Australian gas industry

Western Australia is rich in hydrocarbon resources, with 92 per cent of Australia's conventional gas resources held in basins along the State's coastline.

Western Australia's conventional gas reserves are calculated at 130 Tcf, while oil and natural gas liquid reserves are estimated at 1,700 MMbbls. In the Canning Basin alone, recoverable onshore shale gas resources are estimated between 70 and 150 Tcf, with additional shale and tight gas resources in other onshore basins.

The North West Shelf, Australia's first LNG export project, began exporting gas in 1989. It was joined by the Pluto project in 2012, Gorgon project in 2016 and Wheatstone in 2018. The Shell-operated Prelude FLNG development is the remaining key project yet to reach first production, currently expected in 2018.

It is estimated that Western Australia will produce about 56 per cent of all Australian LNG with Australia second only to Qatar in global LNG production, which currently has capacity to produce approximately 77 Mt/a.

Japan, Western Australia's first customer for LNG exports, remains the largest consumer of Western Australian LNG. Western Australia also exports LNG to China, South Korea and Taiwan.

3.4 The Carnarvon Basin and Vulcan Sub-Basin

Carnarvon Basin

The Carnarvon Basin is the main geological feature making up the North West Shelf of Australia. The onshore section of the Carnarvon Basin covers approximately 115,000 square kilometres and the offshore section covers approximately 535,000 square kilometres with water depths up to 3,500 metres.

Oil and gas production areas are located in the Barrow, Dampier and northern Exmouth Sub-basins, where the Macedon natural gas project started production in August 2013. Gas is also produced from the northern Rankin Platform Australia's first LNG project, the North West Shelf Venture.

The Northern Carnarvon Basin is close to the major settlements of Port Hedland, Karratha, Dampier, Onslow, Exmouth and Carnarvon, and the North West Coastal Highway. The Dampier to Bunbury Natural Gas Pipeline and the Goldfields Gas Transmission Pipeline provide a direct connection with the major domestic and industrial markets of southern Western Australia. The basin is also favourably located in relation to the main export markets in Southeast and East Asia.

A large number of Majors, NOCs and independent E&P companies have interests in the Carnarvon Basin, including Chevron, ENI, Shell, Total and it has produced over 1.2 Bnboe since first production.

The Carnarvon Basin has 2P reserves exceeding 27 Bnboe, of which 87 per cent is gas and 13 per cent oil.

Vulcan Sub-Basin

The Vulcan Sub-basin is a northeast-oriented Mesozoic extensional depocentre in the western part of the Bonaparte Basin in the Timor Sea. It is a proven Jurassic hydrocarbon province containing a number of now depleted oil fields, as well as the producing Montara oil field, and the Cash/Maple gas accumulation. The majority of the oil accumulations (including all produced oils) throughout the Vulcan Sub-basin are sourced from the Upper Jurassic lower Vulcan Formation, with waxy oils are found in the southern part of the sub-basin at Maret and Montara, and gases are derived from both Plover and lower Vulcan Formation source rocks.

The Vulcan Sub-Basin has produced over 3.8 Bnboe since first production, with a number of the Majors and NOCs, including Shell, Chevron and PTTEP, taking operated interests in the acreage. Production has been primarily via floating, production, storage and offtake vessel.

The sub-basin has remaining 2P reserves of approximately 1.2 Bnboe.

3.5 Summary of Regulatory and Licensing Regime and Fiscal Framework in Australia

Offshore petroleum activities outside designated Australian state and territory coastal waters are governed by the OPGGS Act and associated regulations. The government departments and statutory authorities involved in administering Australia's offshore petroleum regulatory regime include:

(a) the Joint Authority (which is usually comprised of the responsible Commonwealth Minister and the relevant Western Australia Minister);

(b) NOPTA which is responsible for the administration of offshore petroleum titles on behalf of the Joint Authorities; and

(c) NOPSEMA, which is the Australian Government's independent regulator of occupational health and safety, structural integrity and environmental management for facilities, wells, well-related equipment and petroleum activities in Commonwealth waters and state and Territory waters where regulatory powers and functions are conferred.

Offshore petroleum activities can only be undertaken by registered ''titleholders'', being persons or entities legally entitled to explore, maintain and develop a petroleum resource. Petroleum activities can only occur if a party holds a valid title, which provides holders with an exclusive right to apply for further approvals to conduct safe petroleum operations in the area.

The most common title is a petroleum exploration permit, which allows a titleholder to explore for oil and gas. If an oil and gas resource is found, the petroleum exploration permit holder may apply for a petroleum production licence or a petroleum retention lease if the resource is currently uneconomic. For a party to be awarded a petroleum exploration permit, they must lodge a comprehensive bid detailing the work they propose to undertake to explore the area, along with their financial and technical capability to facilitate the work.

Depending on the activity to be undertaken, infrastructure pipeline licences may also be granted as a form of petroleum title. An infrastructure licence is granted for construction of offshore facilities for the storage and conversion of petroleum, and a pipelines licence is granted for the construction and operation of an export pipeline to transport petroleum to shore or to other facilities. Each are for indefinite terms (subject to termination under the OPGSS Act, which can occur in a number of circumstances).

Production Licences

Production licences are granted to the holder of an exploration permit or a retention lease for the recovery of petroleum following satisfaction by the Minister in the presence of a commercial discovery.

If the permittee considers the discovery to be commercial, the permittee has two years (and up to four years) to apply for a production licence which would allow them to produce petroleum from the licence area. New production licences are issued for an indefinite term ('life of field'), but may be terminated if there is no production for a continuous period of five years. Existing production licences, such as the licence held by the Company are not granted for indefinite terms but may be extended upon approval of an application made to the Joint Authority.

Under Part 2.4 of the OPGSS Act, production licences can be granted by:

(a) approval of an application made by a petroleum exploration permittee or a petroleum retention lessee;

(b) approval of an application made over a surrendered block or a similar block;

(c) exchange of an individual block for another licence that was in force over the same block; or

(d) a change to the boundary of the coastal waters of a State or Territory.

If a petroleum exploration permit is in force, the permittee may, within the two year application period from the time at which the location was declared, apply to the Titles Administrator for the grant by the Joint Authority of a petroleum production licence. The two year application period may be extended by application of the applicant for up to a further two years at the discretion of NOPTA.

Pipeline Licences

A pipeline licence is required to construct, reconstruct, alter and operate a pipeline in an offshore area for the purposes of conveying either petroleum or greenhouse gas substances; to construct and operate pumping stations, tank stations and valve stations associated with the pipeline; and to carry on other operations or works as necessary to the pipeline.

Under Part 2.6 of the OPGSS Act, pipeline licences can be granted by:

(a) the applicant submitting an application for a pipeline licence in accordance with section 217 and the Joint Authority giving the applicant a written notice (offer document) telling the applicant the Joint Authority is prepared to grant the applicant the pipeline licence; and

(b) the applicant makes a request under section 260 within the period applicable.

A pipeline licence remains in force indefinitely, however, may be terminated by the Joint Authority if there are no operations at any time during a continuous period of at least five years.

Obligations of titleholders

Under the OPGGS Act, titleholders must have an environment plan including a WOMP accepted by NOPSEMA prior to commencement of petroleum activity. The OPGGS Act requires that offshore petroleum operations must be carried out in a manner that does not unduly interfere with other marine users' rights and interests.

Obligations of facility operators

Offshore safety regulations require the operator of an offshore facility to prepare a safety case to manage occupational health and safety at a facility and submit such case to NOPSEMA for assessment and acceptance prior to any operations being carried out. A safety case is a document produced by the operator of a facility which identifies the hazards and risks, describes how risks are controlled and describes the safety management system in place to ensure the controls are effectively and consistently applied.

Change of control and registrable dealings

While there is no specific requirement to seek approval under the OPGGS Act to a change of control in an entity which holds a title, licence holders may be required to undertake certain actions in connection with a change in 'operational control', including submitting revised environmental plans or WOMPs to NOPSEMA. NOPSEMA recommends titleholders engage with NOPSEMA to discuss possible compliance issues following transactions which affect operational control of a title. Under the OPGSS Act, titleholders also have to register any 'registrable dealings' which have a prescribed effect in respect of a title. The sub-set of matters which are required to be registered is broad and includes any security interest, sale agreement or option agreement being entered into in respect of the title.

4 VIETNAM

4.1 Overview

Economic and political reform launched in 1986 has spurred rapid economic growth and development, transforming Vietnam from one of the world's poorest nations to a lower middle-income country. Resilient economic performance reflects robust export-oriented manufacturing and the growth of the agriculture industry. The World Bank is quoted as saying "*Vietnam's development record over the last 30 years is remarkable*" which is evident in the country's GDP per capita growth from US$230.87 in 1985 to US$2,170 in 2016.

Vietnam's oil industry is the country's biggest foreign currency earner and a major procurer of imported technology that is responsible for contributing 28-30 per cent to Vietnam's State budget every year. According to BP's statistics, Vietnam ranked 28th among 52 countries in the world that have oil and gas potential. By the end of 2016, proven crude oil reserves were 4.4 Bnboe; ranking it as the largest oil reserves holder in Southeast Asia. Oil production of 335 mboe/d ranks Vietnam fourth amongst the Southeast Asian countries. Oil consumption is on the rise in Vietnam with a CAGR of 6.1 per cent over the past 10 years.

4.2 The Vietnamese oil industry

Vietnamese oil production has been in decline since reaching a peak of 420 mboe/d in 2004 and declined to a 10-year low in 2008. However, a number of new oil developments in the Cuu Long Basin have pushed production up to around 403 mboe/d in 2015. These new oil developments have not managed to significantly slow the downward trend from 2016. This rapid decline is in part due to the giant Bach Ho oilfield in the Cuu Long Basin, which is now in terminal decline. Block 09-1 (Bach Ho/Rong) is still the largest producer, but Block 16-1 (Te Giac Trang) is emerging as a key supplier.

Vietnamese oil production is on a downward trajectory with very few new oil field development projects to slow the decline. This indicates that oil production growth will have to come from in-field investment; this creates room for Jadestone, with its strategy on acquiring producing assets and applying second phase specialisation to create additional value.

Coal is still the primary source of energy consumption in Vietnam, however year-on-year change indicates that the energy consumption landscape is shifting away from coal to oil and new forms of renewable energy, such as Hydro-electricity; oil now accounts for 31 per cent of Vietnam energy consumption.

Oil processing is one of Vietnam's core sectors. The first oil refinery, the Dung Quat refinery, was constructed in 2009 and produced commercial product in May 2010. With a capacity of 6.5 million tonnes/year, PetroVietnam has capabilities across the entire value chain. Further refineries have been constructed, including the 10 million tonnes/year capacity Nghi Son Refinery. These successful refinery projects have enabled PetroVietnam to produce essential products such as gasoline, fertilizer, plastic resins and other chemical products, which has enabled Vietnam to increase the portion of demand met by domestic supply and subsequently reduce its reliance on imports.

4.3 The Vietnamese gas industry

Gas production in Vietnam has historically been consumed domestically. Consumption has grown at a CAGR of 4.2 per cent over the last decade and is expected to continue. Typical consumption avenues include power plants as well as nitrogen production for fertilizer. As a result of this increasing consumption PetroVietnam has invested heavily in the gas industry to develop an integrated gas business from collecting, import, transportation, storage, processing, distribution to trading. Vietnam currently has three main gas transportation and distribution systems: Nam Con Son gas transportation and distribution system, PM3-Ca Mau gas transportation system and Cuu Long gas transportation and distribution system. In its strategy, PetroVietnam will continue to supply 100 per cent of the market share for dry gas and increase its market share of LPG to at least 70 per cent of the total domestic market.

As gas demand has increased over the last two decades, Vietnam's gas production has also risen steadily. Key milestones include the Bach Ho field commencing supply to the Ba Ria power plant in 1995. Future gas production growth is likely to come from two large developments: ExxonMobil's Ca Voi Xanh field in the Song Hong Basin and PetroVietnam's Block B project in the Malay Basin, both are expected to come onstream in 2024. PetroVietnam has set a target gas production of 11-19 Bcm/year from 2015-2025.

4.4 Summary of Regulatory and Licensing Regime and Fiscal Framework in Vietnam

Under the Petroleum Law dated 6 July 1993 of the National Assembly, as amended in 2000 and 2008 (the "**Petroleum Law**"), all petroleum resources in Vietnam are owned by the entire Vietnamese people and collectively managed by the State of Vietnam. The following sets forth a summary of regulatory and licensing regime for petroleum operations in Vietnam.

4.4.1 *Industry Governance Structure*

In Vietnam, petroleum industry is under the principal jurisdiction and management of the following authorities:

(a) the Prime Minister is the highest authority for granting concession right to investors to conduct petroleum operations and production activities in Vietnam;

(b) The MOIT is responsible for, among others, evaluating petroleum contracts and submitting them to the Prime Minister for approval and issuing Investment Registration Certificates ("**IRC**") and amendments thereof to investors; and

(c) Vietnam Oil and Gas Group (PetroVietnam) is the sole State-owned corporation authorised to conduct petroleum activities including entering into petroleum contracts with petroleum investors. In addition, PetroVietnam and its affiliates are also off-takers, service providers for petroleum contracts and *de facto* concession right holders for other petroleum infrastructure projects (such as pipeline).

4.4.2 *Petroleum Contracts (Concession Regime)*

"Petroleum contract" under Vietnamese laws refers to the contract executed between PetroVietnam and other contractor parties for the petroleum exploration and production activities. The Petroleum Law recognizes a petroleum contract in the form of a PSC or a joint venture or another form of cooperation. However, sub-law regulations provide only the PSC model and use of a contract form different from the statutory PSC model is permitted only with the Prime Minister's approval.

On 11 November 2005, the Vietnam's first model PSC was promulgated under Decree No. 139/2005/ND-CP of the Government dated 11 November 2005 ("**2005 Model PSC**") and any PSC shall have to conform to this 2005 Model PSC. From 8 June 2013, this 2005 Model PSC was replaced with Model Petroleum Production Sharing Contract issued under Decree No. 33/2013/ND-CP of the Government dated 24 April 2013 ("**2013 Model PSC**").

4.4.3 *Approval Process*

The key process for entering into a new petroleum contract is as follows:

(a) Step 1: Selection of contractor party:

The selection of a contractor party will be conducted by way of (i) open bidding, (ii) competitive offer or (iii) direct appointment.

(i) Open bidding – This will apply on the principle of international competition and without pre-qualification. This form applies to all cases which do not satisfy the conditions for (ii) and (iii).

(ii) Competitive offer – This will apply in a case where the petroleum block is not included in the approved tendering plan and there are at least two organizations and/or individuals who satisfy the conditions for participation in an open bidding and are interested and propose signing of a petroleum contract.

(iii) Direct appointment – The Prime Minister will decide direct appointment of a contractor party in the case only one organization/individual or consortium satisfying the conditions for participation in an open bidding expresses an interest and makes a proposal to enter into a petroleum contract, or in a special case relating to national sovereignty, borders or islands.

(b) Step 2: Approval of the Prime Minister

After negotiating with the contractor party selected in the process discussed above, PetroVietnam will submit the draft petroleum contract to MOIT for evaluation and submission to the Prime Minister for approval of the draft petroleum contract. After the Prime Minister approves the draft petroleum contract, PetroVietnam and the relevant contractor party will execute the petroleum contract.

(c) Step 3: Approval of the MOIT for issuance of IRC

After PetroVietnam executes the petroleum contract with the relevant contractor party, PetroVietnam will submit the petroleum contract to the MOIT for the issuance of the IRC for the petroleum project.

4.4.4 *Model PSC Terms*

The term, minimum work commitments and fiscal terms for PSCs are to be negotiated individually within the parameters of the Petroleum Law. The 2013 Model PSC, however, provides for the following contractual standard structure:

(a) Production sharing scheme

Profit oil/gas that is the predetermined allocation of oil remaining after payment of royalty oil/gas and cost recovery oil/gas will be shared between PetroVietnam and the contractor parties as agreed in the PSC. It will be calculated quarterly based on the production of oil/gas in barrels per actual production day and shall be adjusted on a final basis after the end of the relevant year.

(b) Key fiscal terms

Below are certain key fiscal obligations of the contractor party:

Royalties: The contractor parties will be subject to royalties that reflect its usage and exploitation of the State's property and are agreed upon as percentage of the amount or value of available oil and/or gas from the contract area in accordance with the main terms and conditions of PSC approved by the Prime Minister.

Bonus, training and research fee: The contractor parties will also be subject to the following compulsory payments: signature bonus, production bonus, data fee, training fee, fund for scientific research and development of oil and gas technology and other payments such as one-off lump sums to be agreed in the PSC and payable by the contractor party to PetroVietnam within 30 days after declaration of the first commercial discovery and after the first commercial production. These bonuses and fees are not cost recoverable and are not deductible for corporate income tax purposes.

Participation of PetroVietnam: PetroVietnam has the option to participate in the PSC up to a certain percentage of the participating interest in the PSC within 90 days after the first commercial discovery. If PetroVietnam exercises this option, the PSC and IRC will be amended to record, among others, the change in the participating interest of the contractor parties. The contractor parties are entitled to recover carried costs corresponding with participating interest of PetroVietnam or its affiliates in the PSC pursuant to the mechanism provided in the PSC.

Assignment and change of control: The contractor parties may assign part or all its participating interest under the PSC to its affiliate with a written notification to PetroVietnam. In case of assignment to a third party, a waiver of pre-emptive right of PetroVietnam and the right of first refusal of other contractor parties will be required. The assignment only takes effect upon approval of the Prime Minister and issuance of the amended IRC recording the change of the participating interests resulting from the assignment. A change of ownership structure or change in control of a contractor party (except for reorganization, internal financial arrangement of that party or consolidation of the parent of that party) will be deemed to be an assignment.

Investment protection and stabilisation: The stabilisation clause has been narrowed substantially over the years. Previously the contractor parties enjoy protection against any adverse effects on their ''economic benefits'' under the PSC. However, the current stabilisation clause of the 2013 Model PSC now only covers royalties, corporate income tax, and export duty. Consequently, the contractor parties may be exposed to changes to environmental protection fees, profit surcharge, value added tax, and any new taxes or fees which may be imposed by the government in the life of the PSC.

Domestic market obligations: The 2013 PSC Model increases the domestic supply obligations of a contractor party, including a requirement to prioritize the sale of all crude oil (not just in emergency cases as under the 2005 Model PSC), and sell a portion of natural gas, within the Vietnam market on prescribed terms at the Government's request.

Contract terms and extension: The term of a PSC includes the ''exploration period'' and the ''production period.''. The term of PSC does not exceed 25 years, during which the exploration period does not exceed five years. In case of encouraged petroleum investment projects and projects for exploration and production of natural gas, the duration of a petroleum contract does not exceed 30 years, of which the exploration period does not exceed seven years. The term of the PSC and of exploration period may be extended up to five years and two years, respectively.

(c) Change of Control

Decree 95/2015/ND-CP of the Government of Vietnam dated 16 October 2015 detailing the implementation of Petroleum Law introduces new reporting obligations in the event of change of ownership of contractor parties holding participating interests in petroleum contracts. In this case, relevant contractor parties must notify PetroVietnam and the MOIT within six months from the date of such change.

In addition to reporting obligations, Circular No. 36/2016/TT-BTC of the Ministry of Finance dated 26 February 2016 attempts to capture capital gains tax ("**CGT**") on transactions resulting in, among others, change of ownership, change of control, or otherwise disposal of all or part of interests, rights and obligations in petroleum contracts of relevant contractor parties holding participating interests in petroleum contracts (except for internal restructuring, financial restructuring of the contractor party or a consolidation by the parent company of such contractor party). Accordingly, a tax filing must be done within six months from the date of any such change discussed above.

5 PHILIPPINES

5.1 Overview of Philippines

Consisting of 7,641 islands the archipelagic country the Philippines is the third largest economy in Southeast Asia. As of January 2018, the country had the second largest population in Southeast Asia and ranked twelfth in the world. GDP per capita has risen from US$565.75 in 1985 to US$2,951.07 in 2016. So strong was the Philippines economic performance in 2017 that only China and Vietnam outperformed them across Asia; year-on-year growth to 2017 was 6.7 per cent with the predominance of this growth anchored in exports. However, reliance on imports continues to grow with growth hitting double digits. The long-term outlook remains positive with economic growth expected to continue growing at 6.7 per cent per annum.

The Philippines ranks as the tenth largest oil and gas producer in Southeast Asia at 7.4 MMboe per annum and has estimated recoverable reserves of 229 MMboe. The industry is in its infancy with the first substantial production coming in 2002. The most notable discovery and development to date is the Shell-operated multi-tcf Malampaya gas/condensate field, which lies in the North Palawan Basin, the only producing basin in the Philippines to date.

Following the discovery of Malampaya in 1992, interest in the offshore basins surrounding the Philippines soared and 36 blocks were licences between 1994 and 1998. However, following disappointing results, only a further 9 blocks have been licenced since then.

5.2 The Philippine oil industry

Oil is the primary energy source consumed in the Philippines; in 2016 19.9 million tonnes oil equivalent were consumed, 6.4 million tonnes oil equivalent greater than the next largest energy source, which was coal. This has cause for major concern as beyond Malampaya there are very few commercial oil fields and the ones that are, Nido, Matinloc, Galoc and North Matinloc, all are significantly matured and near depletion. Consequently, oil production is on the decline from its peak of 23 mboe/d in 2009.

The declining oil production profile set against increasing consumption will require increases in oil imports in order to meet growing demand. Importation of petroleum products increased 11.8 per cent from 2016 to 2017. The Philippine government is eager to reverse this trend of increasing oil imports and this presents an enticing investment case for Jadestone and the Company expects to be able to secure prospective blocks on good fiscal terms.

5.3 The Philippine gas industry

Gas accounts for the majority of remaining reserves and production in the Philippines due to Malampaya. The gas is exported from the field to a gas processing plant at Tabangao, Batangas in South Luzon, which is then routed to three gas-fired power plants. Gas is currently sold exclusively for power generation in Batangas, South Luzon and is supplied to National Power Corporation's 1,200 MW plant in Ilijan and to Gen Corporation's 1,000 MW Santa Rita, 500 MW San Lorenzo San Gabriel (414 MW) and Avion (97 MW) plants.

There are plans further into the future to export LNG and this intention has been signalled by the cabinet-level National Economic Development Authority approval to tender out the construction of the 150 kilometre pipeline from Batangas to Sucat. Assuming a lead time of three to four years, it is estimated that BatMan 1 pipeline will complete by 2019. Another key proposed pipeline is the 140 kilometre Bataan-Manila (or BatMan 2) pipeline to support a LNG regasification terminal at Bataan and supply gas to the Subic and Clark industrial estates. With BatMan 1 delayed, it is understood this pipeline is unlikely to start up before 2025.

There are significant discoveries still to be made in the Philippines. Indications of resource plays not yet discovered can be found in the PNOC Mangosteen discovery drilled in May 2015. The discovery is estimated to hold at least 70 Bscf of recoverable gas; a marker for the upside potential to the country's currently depleting gas reserves.

5.4 Summary of Regulatory and Licensing Regime and Fiscal Framework in the Philippines

The Philippine Constitution grants the State full ownership and control over all natural resources and all potential sources of energy in the Philippines.

Section 2, Article XII of the 1987 Philippine Constitution provides that the exploration, development, and utilization of natural resources shall be under the full control and supervision of the State, and allows it to undertake such activities directly or indirectly through co-production, joint venture, or production-sharing with Filipino citizens, or corporations or associations where at least 60 per cent of the share capital is owned by such citizens. Such agreements may be for a period not exceeding twenty-five years, renewable for not more than twenty-five years, and under such terms and conditions as may be provided by law.

The present Constitution further allows the President to ''enter into agreements with foreign-owned corporations involving their technical or financial assistance for large-scale exploration, development, and utilization of minerals, petroleum, and other mineral oils according to the general terms and conditions provided by law, based on real contributions to the economic growth and general welfare of the country.''

The President shall notify the Congress of every contract entered into in accordance with this provision within thirty days from its execution.

Agreements involving either technical or financial assistance, referred to in Section 2, Article XII of the Philippine Constitution, have been interpreted by the Supreme Court to be service contracts between foreign corporations acting as contractors on the one hand; and on the other, the government as principal or owner of the works. The foreign contractors provide capital, technology and technical know-how, and managerial expertise in the creation and operation of large-scale mining/extractive enterprises; and the government, through its agencies, actively exercises control and supervision over the entire operation. The Supreme Court further provides:

''Such service contracts may be entered into only with respect to minerals, petroleum and other mineral oils. The grant thereof is subject to several safeguards, among which are these requirements: are that the service contract shall be crafted in accordance with a general law; the President shall be the signatory for the Government; and within thirty days of the executed agreement, the President shall report it to Congress to give that branch of government an opportunity to look over the agreement and interpose timely objections, if any.''

The general law is Presidential Decree No. 87, as amended, otherwise known as The Oil Exploration and Development Act of 1972, (''**PD 87**'') provides the main regulatory framework for the exploration and development of indigenous petroleum.

PD 87 allows Government to enter into a service contract with a contractor, who shall be entitled to a service fee for its service and technical assistance, while the Government shall provide for the financing and shall be entitled to all the petroleum produced under the service contract. The service fee of the contractor shall be 40 per cent of the gross income derived from the disposition of the petroleum. In the event that the Government is incapable of financing the petroleum undertaking, the contractor shall furnish services, technology, and financing and the proceeds of the sale of the petroleum produced under the service contract shall be the source of funds for payment of the service fee and the operating expenses due to the contractor. Further, the contractor may be authorised by the service contract to take, dispose of and market either domestically or for export all petroleum produced, subject to filling the domestic requirements on a pro-rated basis. The contractor shall also be in charge of oil field operations on behalf of the Government after determination that petroleum in commercial quantities are present.

Public contracting rounds in petroleum prospective areas

The department of energy in the Philippines ("**DOE**") is mandated to establish, develop, administer, coordinate, supervise and control all plans, programs, projects and activities of the Government relative to the exploration, development, utilization, distribution and conservation of energy products and resources.

Under PD 87, every service contract shall, subject to the approval of the President, be executed by the DOE Secretary, after due public notice, pre-qualification and public bidding or concluded through negotiations. Based on PD 87, the DOE issued department circulars detailing the procedures for defining and nominating prospective contract areas, conducting public contracting rounds in petroleum prospective areas, and awarding the service contracts.

In the public contracting rounds, the DOE determine certain prospective areas within the Philippine territory and exclusive economic zone for competitive contracting rounds. Participants to these public contracting rounds submit bid documents to the DOE negotiating panel which will evaluate the bids on the basis of the proposed work program, financial, legal and technical qualifications of the bidders. DOE will thereafter negotiate the service contract with the winning applicant.

More recently, on 27 December 2017, the DOE issued its regulation adopting the Philippine Conventional Energy Contracting Program (PCECP) of awarding petroleum service contracts covering other frontier areas not covered and offered in any energy contracting round. Applicants may nominate their areas of interest which must be within the range of 50,000 hectares (500 square kilometres) to 750,000 hectares (7,500 square kilometres) for onshore areas, and 80,000 hectares (800 square kilometres) to 1,500,000 hectares (15,000 square kilometres) for offshore areas. The nominated area will then be opened for bid challenge. Alternatively, interested parties may apply and bid for petroleum service contracts on pre-determined areas offered by the DOE during a prescribed period. The highest ranked applicant (either for the nominated areas or pre-determined areas) on the basis of the work program, financial, legal and technical qualifications will be selected. After the selection and evaluation process, the DOE will endorse the awardee and the corresponding service contract area to the President of the Philippines for final approval. Once the President's approval is obtained, the service contract is then executed by the DOE Secretary.

5.5 A typical service contract embodies the following minimum terms and conditions:

Scope: The Contractor assumes all exploration risks such that if no petroleum in commercial quantity is discovered and produced, it will not be entitled to reimbursement of expenses incurred in connection with the contract.

Exploration Period: The exploration period shall be seven years, extendible for three years if the contractor has not been in default in its exploration work obligations. The contract shall lapse unless petroleum has been discovered by the end of the 10th year and the contractor requests a further extension of one year to determine whether it is in commercial quantity, in which event, another extension of one year for exploration may be granted.

If petroleum in commercial quantity has been discovered, the contractor may retain after the exploration period and during the effectivity of the contract 12.5 per cent of the initial area in addition to the delineated production area, subject to payment by contractor of annual rentals on such retained area. Such rentals can be offset against exploration expenditures actually spent on such area.

Production Period: Where petroleum in commercial quantity is discovered during the exploration period in any area covered by the contract, the contract shall remain in force for production purposes during the balance of the ten year exploration period and for an additional period of 25 years, thereafter renewable for a series of five year period but in no case shall such renewal exceed a total of 15 years under such terms and conditions as may be agreed upon by the parties at the time of renewal; provided that: (i) the contractor has not been in default of the approved work program and budget and other obligations; (ii) The term of the contract shall in no case exceed 50 years from the effective date, inclusive of any moratorium or any extension thereof; and (iii) if during the Production Period, the contractor fails to continue production of petroleum for more than one year without prior approval of the Government, then the Government may unilaterally terminate the contract.

Contract Area: The Contractor must relinquish at least 25 per cent of the initial contract area at the end of five years from the effective date of the contract and an additional relinquishment of at least 25 per cent of the initial area at the end of seven years from its effective date. In the event that during the exploration period, the contract delineated any production area, the extent of such production area shall be deducted from the initial contract area for purposes of determining the size of such area that must be relinquished.

Privileges: The DOE Model Petroleum Service Contract and PD 87, as amended, further provide the privileges which are granted to contractors and include: Exemption from all national taxes except Philippine income tax; exemption from all levies, tariffs, duties, on importation of all machinery and equipment to be used exclusively by the contactor in the petroleum operations; exemption from posting of performance/surety bond during the production period; exportation of petroleum subject to the obligation to supply a portion of domestic requirements; entry, upon approval of the Government, of alien technical and specialized personnel and subject to regulations of the Philippine Central Bank (Bangko Sentral ng Pilipinas or BSP), be entitled to certain privileges in respect of repatriation of investments and cost and expenses and foreign exchange Revenues payable to the Government on such petroleum exported; the Filipino Participation Incentive Allowance (FPIA) and exemption from investment requirements of foreign corporations.

Fiscal Terms: From the gross proceeds received from the sale of all petroleum and products extracted under the service contract, the contractor is allowed to recover, in the following order:

(a) Filipino Participation Incentive Allowance: a government subsidy of a minimum of 1.5 per cent and a maximum of 7.5 per cent of gross proceeds, provided that the contractor demonstrates that at least 15 per cent of the participation interest is held by one or more Filipino citizens or companies which are at least 60 per cent held by Philippine nationals.

(b) Recoverable Cost: compensation to the contractors of the actual operating expenditure determined in accordance with specified accounting procedures consisting of:

    (i) a maximum of 70 per cent of gross proceeds or actual expenses per calendar year. If the operating expense exceeds 70 per cent of the gross proceeds, the contractor is entitled to carry over the balance to the succeeding calendar year;

    (ii) 100 per cent of recoverable costs for non-capital expenditures; and

    (iii) capital expenditures depreciated over five to ten years.

(c) Other Allowances: The service contract may likewise contain provisions on allowances and bonus payments to be made by the Contractor to Government once certain initial production thresholds are reached.

    After deduction of the monies detailed above, the net proceeds are shared between the Government at the rate of 60 per cent, and the contractor at 40 per cent The Corporate Income Tax of 30 per cent of the grossed up net proceeds of the contractor is deducted from and paid out of the Government's share.

(d) Assignment: Assignment of the rights and obligations under a service contract is effected through assignment agreements, farm-in or farm-out contracts and are subject to the prior approval of the Government. For the transfer of rights and obligations under a service contract to be valid, there must be a prior approval from the DOE.

    DOE approval shall be automatic for the transfer or assignment of contractual rights to an affiliate of the transferor (or a company which holds directly or indirectly at least 50 per cent of the outstanding shares entitled to vote of one of the companies comprising the contractor), provided that: (i) the contractor submits to Government copies of a written agreement on the corresponding part of its rights and/or obligations to be assigned; (ii) the contractor guarantees in writing the performance of the assigned obligations; and (iii) no such assignment interferes with the performance of the petroleum operations.

    Where the transferee/assignee is a foreign entity, the approval of the President of the Philippines must be obtained, pursuant to the specific requirements under the Philippine Constitution on Financial Technical Assistance Agreements.

Pursuant to Executive Order No. 556 issued on 17 June 2006, which disallowed any farm-in or farm-out contracts awarded by any government agencies, including the Philippine National Oil Company (PNOC). All government agencies, including the PNOC shall follow a strict bidding procedure in forging partnership with interested parties in relation to the exploration, development and production of crude oil. The DOE further provides that the corporate identity of such partner must be beyond question, must clearly show financial capability, and must not be registered in a jurisdiction known to be a haven for money laundering. The government agency, including PNOC, may award a contract only to a true principal group and not to a trader or broker. All negotiations or arrangements entered into by any government agency, including PNOC, which violates the DOE shall be immediately discontinued or cancelled.

6 INDONESIA

6.1 Overview of Indonesia

The largest economy in Southeast Asia, Indonesia – a diverse archipelago nation of more than 300 ethnic groups – has charted impressive economic growth since overcoming the Asian financial crisis of the late 1990s. The country's GDP per capita has steadily risen, from US$857 in the year 2000 to US$3,603 in 2016. Today, according to the World Bank, Indonesia is the world's fourth most populous nation, the world's 10th largest economy in terms of purchasing power parity and a member of the G20.

Indonesia is Southeast Asia's largest oil and gas producer. According to the BP statistical review of world energy 2017, Indonesia has the region's highest remaining reserves estimated at 3.3 Bnbbl and 101 Tcf of gas at the end of 2016, whilst energy consumption in Indonesia continues to be on the rise, with the 2016 growth rate reaching 5.9 per cent.

6.2 The Indonesian oil industry

Indonesian oil production has been in decline since the turn of the decade, as smaller new oil developments have failed to replace output from mature, legacy fields such as the giant Minas and Duri fields in central Sumatra. This decline trend is set to continue, partially offset from 2015 by the ramp-up of production from the 200 mboe/d Banyu Urip field. However, with no other new oil developments of scale planned, future liquids output will increasingly rely on investment in existing fields. This creates room for Jadestone, with its strategy on value creation through reinvestment activities on existing licences.

According to the BP statistical review of world energy 2017, oil remained Indonesia's dominant fuel (41 per cent of primary energy consumption) in 2016, followed by coal (36 per cent) and natural gas (19 per cent). Indonesia produced 55 per cent of its oil consumption in 2016, compared to an oil surplus as recently as 2002.

Indonesia has a total of nine active oil refineries, located in East Kalimantan, Java, Sumatra and West Papua, seven of which are wholly owned and operated by Pertamina. Pertamina began oil refining through its first refinery at Sungai Pakning in Riau, which started operations in 1969, with a capacity of 50 mboe/d. Through a series of acquisitions and capacity expansions, Pertamina has a current refining capacity of over 1,000 mboe/d.

To reduce its reliance on imported petroleum products, Indonesia is increasing domestic product supply by increasing refining capacity through refinery expansions and construction of new grassroots refineries. An upgrade of residual cracking capacity at the Cilacap refinery was brought onstream in September 2015, and a continuous catalytic reformer upgrade is planned for 2018. Further upgrades and expansions are also planned for the Balikpapan, Dumai and Balongan refineries.

Previous efforts for new grassroots refineries were set back by the subsidised domestic market, as it did not provide a sufficient rate of return. However, the Indonesian government has removed subsidies in the retail sector in January 2015 with the fall in global crude oil price. This may again generate interest in new grassroots refinery projects in Indonesia. In August 2016, the Indonesian government launched a regulation enabling the development of private-owned mini-refineries, with capacities up to 20 mboe/d, near upstream production facilities.

6.3 The Indonesian gas industry

Gas in Indonesia has historically been developed for export and accordingly most of the infrastructure investment has been in LNG facilities. There are three LNG plants in operation: Bontang in East Kalimantan, Donggi-Senoro in Sulawesi and Tangguh in West Papua. The Arun facility in North Sumatra ceased operation in 2014 and has been converted into a regasification plant.

Over the last 10 years, the demand for domestic gas has increased. According to the BP statistical review of world energy 2017, in line with the recent oil price downturn, natural gas consumption in Indonesia fell by 7 per cent in 2016 – to its lowest level since 2007 and more than 13 per cent lower than its peak in 2010; while Indonesia gas production dropped for a sixth year in a row by 7.4 per cent (-5.3 Bcm) in 2016 and is now 19 per cent lower than the 2010 production peak.

Sumatra has been the focus of significant gas trunkline development in recent years. Gas used in Chevron Pacific Indonesia's Duri steamflood operations is supplied by a 544 kilometre, 28 inch pipeline from the Grissik gas processing plant, in south Sumatra. This trunkline, currently owned and operated by the PGN-led consortium PT Transportasi Gas Indonesia (TGI), has a capacity of around 430 MMcf/d and started operation in 1998. The South Sumatra West Java pipeline connects the producing fields in Sumatra to the demand centre in Java. The onshore gas pipeline network in west Java is the most extensive in Indonesia. At present, West Java gas trunklines are Pertamina-operated, with PGN owning most of the distribution network. In addition to the pipeline network in Sumatra and Java, gas pipeline infrastructure can also be extensively found in Kalimantan, particularly in the Mahakam delta area, and subsea pipeline system of West Natuna feeds produced gas from fields in West Natuna to regional market of Singapore and Malaysia. Overall, there is well developed gas infrastructure on the major gas producing regions in Indonesia, with further plans to augment transmission on a more local scale in addition to the large scale trunklines.

6.4 Summary of Regulatory and Licensing Regime and Fiscal Framework in Indonesia

The Ministry of Energy and Mineral Resources, which has overall responsibility for the implementation of government policy in the energy sector, incorporates the MIGAS. MIGAS supervises and promotes the optimal utilisation of the oil and gas resources of Indonesia to maximise the benefit for the people and Government of Indonesia. The exploration bid rounds, issuance and relinquishment of blocks fall under MIGAS' direct responsibility.

The upstream regulator, SKKMIGAS, acts as an executive implementing body responsible for conducting supervision of upstream business activities, in order to maximise benefit and revenue to the state. SKKMIGAS's responsibilities included the preparation and offering of work areas to potential investors, assessment and presentation for ministerial approval of new field development plans, approval of development plans for fields already in production, approval of annual work programmes and budgets, monitoring and ministerial reporting on the implementation of cooperation contracts and responsibility for the appointment of sellers for the state's share of oil and gas.

Historically, licences to operate oil and gas fields in Indonesia is awarded in the form of PSCs. There are various vintages of the PSC but each includes the following principle fiscal elements. The differences in the models are in the rates and methods of calculation of some or all of these:

- state participation;
- carry and reimbursement;
- bonuses;
- first tranche petroleum;
- domestic supply obligation;
- cost recovery ceiling;
- depreciation;
- profit sharing;
- income and withholding taxes; and
- investment credit.

On 13 January 2017, the Minister of Energy and Mineral Resources issued Regulation No.08/2017, introducing a new PSC scheme based upon the sharing of a "Gross Production Split". The terms of this Gross Production Split contract are currently still under discussion.

Part 3

THE GROUP'S ASSETS

1 SUMMARY OF THE GROUP'S ASSETS AND FUTURE ASSET OPPORTUNITES

Summary of the Group's assets as at the Latest Practicable Date

Contract area	Date of Expiry	Held by	Place of Operation	Group Effective Working Interest
Stag Oilfield	25 August 2039	Jadestone Energy (Australia) Pty Ltd	Australia	100
SC-56	1 September 2020(1)	Mitra Energy (Philippines SC-56) Ltd	Philippines	25
SC-57	15 September 2020(2)(3)	Mitra Energy (Philippines SC-57) Ltd	Philippines	21(4)
51(10)	11 June 2037 (crude oil) 11 June 2042 (gas)	Mitra Energy (Vietnam Tho Chu) Pte Ltd	Vietnam	100(5)
46/07(9)	30 June 2035	Mitra Energy (Vietnam Nam Du) Pte Ltd	Vietnam	100(6)(7)
127	24 May 2018	Mitra Energy (Vietnam Phu Khanh) Pte Ltd	Vietnam	60
Bone(8)	25 November 2040	Mitra Energy (Indonesia Bone) Ltd	Indonesia	60

Notes

(1) Should a commercial discovery be made the license period under the PSC will extend to 1 September 2055.

(2) Should a commercial discovery be made the license period under the PSC will extend to 15 September 2055.

(3) DOE has allowed a force majeure condition on SC57, until the approval by the President of the transfer of participating interests to CNOOC INT and Jadestone Energy Limited are obtained.

(4) In March 2006 PNOC Exploration Corporation entered into a farm-in agreement with Jadestone, which allows Jadestone to obtain a 21 per cent interest in exchange for paying 30 per cent of the costs during the first two exploration sub-phases in Service Contract 57. Governmental approval for the farm-in remains outstanding due to Executive Order No. 556 dated 17 June 2006, effectively banning PNOC from entering into farm-in/farm-out agreements with foreign companies, which constitutes a force majeure event under SC-57.

(5) Effective 1 May 2017, PVEP relinquished a 30 per cent working interest in this block. The registration of this change is still pending.

(6) Effective 1 May 2017, PVEP relinquished a 30 per cent working interest in this block. The registration of this change is still pending.

(7) Pursuant to a participation agreement with Mitra Energy (Vietnam Nam Du) Pte Ltd dated 3 November 2010, Petroctech Investment Corporation Pte Ltd has the right to acquire, at cost, a 5 per cent interest in any commercial discovery on 46/07, further details of which are set out in paragraph 12.17 of Part 11.

(8) On 4 May 2017, the Company signed a Withdrawal Agreement with Azimuth Indonesia Ltd. ("**Azimuth**") to transfer the Company's 60 per cent working interest and operatorship of Bone PSC to Azimuth. The transfer was effective from 15 April 2017, but remains subject to final government approval.

(9) Subject to the Company fulfilling the requirements during the exploration phase and an application to extend this has been made, see paragraph 2.2 of this Part 3 of this document.

(10) The exploration phase, in connection with the Block 51 PSC, expired on 10 June 2016. On 26 December 2016, the U Minh and Tho Chu fields were approved by the MOIT as SDAs for a period of five years from 11 June 2016.

In respect of the Stag Oil Field, the Company has an indefinite pipeline licence in respect of pipeline WA-6-PL.

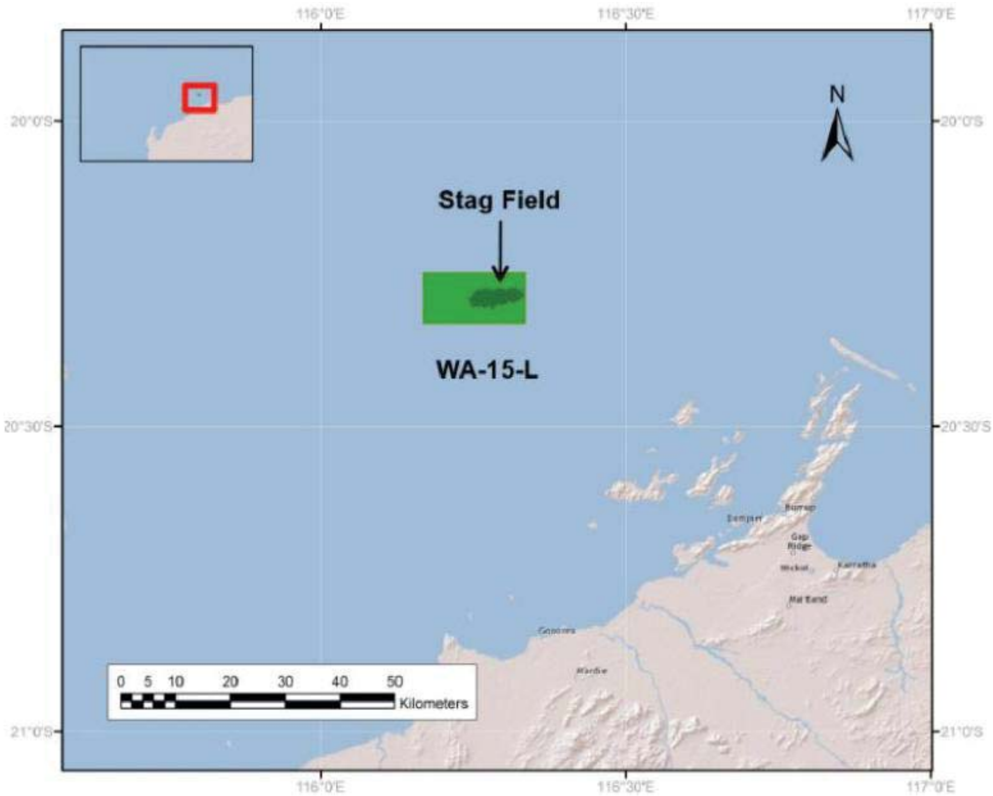
2 THE GROUP'S ASSETS

2.1 Stag Oil Field – Australia

2.1.1 *Overview*

The Stag Oil Field is a developed oil producing asset, located within the boundaries of the WA-15-L Production Licence in the Carnarvon basin, 60 kilometres offshore Western Australia, in a water depth of approximately 47 metres.

Location of the Stag Field, offshore Western Australia



Source: CPR

2.1.2 *Licence details*

Jadestone, through its wholly-owned subsidiary Jadestone Australia, has a 100 per cent operating interest in the Stag Oil Field.

Production licence WA-15-L

Production licence WA-15-L (dated 26 August 1997) ("**WA-15-L**") relates to an active oil resource located in the Northern Carnarvon Basin, offshore Western Australia. This licence is a fixed term production licence which currently has an expiry date of 25 August 2039. The grant of WA-15-L is subject to the Offshore Petroleum and Greenhouse Gas Storage Act 2006 (Cth) ("**OPGGS Act**") and the following conditions:

(a) The licensee shall not construct any installation or install any equipment in the licence area except with and in accordance with the approval in writing of the Commonwealth – Western Australia Offshore Petroleum Joint Authority ("**Joint Authority**").

(b) The licensee shall not abandon, suspend or complete any well except with and in accordance with the approval of the Joint Authority.

(c) The licensee shall at all times comply with the provisions of the OPGGS Act and of any regulations for the time being in force under the OPGGS Act, including any directions given thereunder.

(d) In carrying out its operations in the licence area the licensee must take adequate measures for the protection of the environment.

(e) The licensee must, to the satisfaction of the Joint Authority, continue to appraise and explore the licence area to determine whether additional recoverable petroleum exists in the area and shall exploit such petroleum where economic.

Pipeline Licence WA-6-PL

Pipeline Licence WA-6-PL (dated 26 August 1997 and varied on 8 June 1998) ("**WA-6-PL**") relates to the Stag export pipeline, which runs from the Stag Central Production Facility to the Pipeline End Manifold, located in offshore Western Australia. The approved length of the pipeline licence is 2 kilometres. This licence has an indefinite term (subject to termination pursuant to the OPGGS Act which can occur, for example, if the pipeline is not operated or used for a period of 5 years). The grant of WA-6-PL is subject to the OPGGS Act and the conditions contained in WA-6-PL, which relate to the operation of the pipeline and compliance by the licensee with various specifications for the design, construction, testing and maintenance of the pipeline.

2.1.3 *Reserves*

According to the CPR, as at 31 December 2017, Stag had 2P reserves of 17.1 MMbbls (gross and net) with a value of US$84.2 million (NPV10). The field has 3P reserves of 22.7 MMbbls and 2C oil resources of 2.7 MMbbls (gross and net).

2.1.4 *Geology and sub-surface*

The Stag field is located in the Dampier Sub-Basin of the Northern Carnarvon Basin. The Dampier Sub-Basin evolved from a broad intra-continental basin in the late Palaeozoic, with proven petroleum systems in the Late Triassic, Middle-Late Jurassic and Lower Cretaceous.

The Stag field is dip-closed to the north, pinches out the south and east, and relies on a combination of dip closure and fault seal to the west, separating Stag from the smaller, undeveloped Centaur accumulation.

Hydrocarbons are contained within a combination structural/stratigraphic trapping mechanism of the early Cretaceous M. Australis sandstone, which was deposited in a shallow marine environment.

A number of seismic surveys have been acquired on the acreage, with the first 3D seismic acquired in 1993 and most recently in May 2014.

The gas-oil contact and original oil-water contact lay at 682.5 mTVDSS and 696 mTVDSS respectively. The maximum gross reservoir thickness is approximately 22 metres, found in the area of Well Stag-1, west of the platform. Reservoir quality is good with porosities typically in the range of 18 to 27 per cent and permeability typical of the order of hundreds of millidarcies.

2.1.5 *Development History*

The Stag oilfield was discovered following the drilling of Well Stag-1 in 1993. A further eight appraisal wells have been drilled based on the 1993 3D seismic dataset. In 1995, the first horizontal well was drilled, Well ST6H, which successfully demonstrated the deliverability of a horizontal well in a thin, heavy oil system.

First production from the Stag field came in May 1998 through six horizontal wells (Wells ST6H, ST9H, ST10H, ST11H, ST12H and ST15H), all of which were drilled from a fixed platform. At the same time water injection was carried out through Wells ST13H and ST14H. An ongoing programme of production drilling, appraisal drilling and re-drilling has taken the total well count of the field to 48.

2.1.6 *Facilities and Infrastructure*

The Stag oilfield was developed using a fixed leg, 12 slot manned central processing facility platform with a liquids production capacity of 50 mbbl/d, of which 30 mbbl/d is for oil. This is connected, by an eight inch underwater export pipeline, to a pipeline end manifold and FSO, via a catenary anchor leg mooring buoy. Shuttle tankers transfer the oil from the FSO to shore.

The steel 5,000 tonne deck supporting the living quarters and the production module is built up of a 2,000 tonne steel hull, a 2,000 tonne process module and a 700 tonne living-quarter module for 50 people. It houses facilities for a two-stage oil, gas and water separation system as well as an oil-export pumping system, for transfer to the FSO for fiscal metering. It also incorporates produced water treatment for offshore disposal, as well as seawater-treatment facilities to reduce solids and oxygen pumped with the water into the injection wells.

Two first-stage separators are used and chemicals are injected into the product stream for inhibition and enhanced product separation. An electrostatic coalescer was used prior to crude export to the FSO.

Power supplied by three dual-fuel-generating sets run on either crude oil or diesel. These have a total generating capacity of approximately 4.5MW.

As at 31 December 2017, the Stag field had a total of eleven active production wells, each with ESPs installed, and three active water injection wells.

2.1.7 *Stag acquisition*

The Stag oilfield was acquired by Jadestone through its wholly-owned subsidiary Jadestone Australia on 11 November 2016. At closing a cash consideration of US$10 million (the "**Stag Purchase Consideration**") was paid by Jadestone to Quadrant Energy and Santos Offshore Pty Ltd. The payment was funded from the proceeds of a private placement of Common Shares completed on 7 November 2016.

In addition to the Stag Purchase Consideration, a further US$9.9 million was paid by Jadestone Australia in respect of the settlement of working capital adjustments. Further information regarding the Provisional Business Combination Accounting attributable to the acquisition is included in note 7 to the Financial Statements for the period ended 31 December 2017 set out in Appendix 1 to this document.

2.1.8 *Production*

The Stag oilfield produces a biodegraded oil with a gravity of 19 API. Oil production peaked at approximately 26 mbbl/d in 2000 but has now fallen to approximately 3.6 mbbl/d via 11 production wells. Field water production is approximately 22 mbbl/d and the watercut is approximately 88 per cent.

Stag has seen production stabilise from an average for Q2 2017 of 2,571 bbl/d to the current level of circa 3,600 bbl/d after the July 2018 workover campaign.

During the three month period, ended December 31, 2017, production rates from the Stag oilfield were adversely impacted by a series of MBC incidents where the MBC released, disconnecting the platform from the FSO, resulting in unscheduled production stoppages. As reported in Jadestone's December 2017 quarter results, these MBC incidents caused production to fall below budget, in essence a deferral of production, by about 53,000 bbls in the December 2017 quarter. The last of these incidents also affected production volumes in the March 2018 quarter, resulting in production falling below budget/deferred by approximately 16,000 bbls for the March 2018 quarter.

In addition, the sudden production stoppages incidents caused damage to several of the facility's ESPs which required three well workovers during Q1 2018, to restore production rates.

The ESP failures caused higher than expected well downtime, resulting in a further production deferment of approximately 51,000 bbls based on actual production versus budget. The combined production deferment of approximately 67,000 bbls resulted in production for the quarter being circa 745 bbls/d lower than budgeted.

The Company is in discussion with the operator of the vessel, in relation to the financial impact of the MBC events. Meanwhile a number of initiatives have been implemented to reduce the risk of future MBC failures and to improve operational performance. A new MBC has now been installed providing a more robust solution, following a series of stress tests and modifying the placement of the MBC to reduce future potential stress. The Company is seeking recompense from the contractor and through the contractor's insurance.

The Group and BPS have entered into two cash-settled commodity swap arrangements, as follows:

(a) a swap agreement with an effective date of 1 January 2018 and which expired on 30 June 2018, under which BPS agreed to pay a fixed amount of US$64.6/bbl for a total quantity of 350 mbbls in exchange for a floating price (being the unweighted arithmetic mean of the Brent price for each pricing date during the period of this swap arrangement); and

(b) a swap agreement with an effective date of 1 July 2018 and termination date of 31 December 2018 under which BPS has agreed to pay a fixed amount of US$65.0/bbl for a total quantity of 350 mbbls in exchange for a floating price, as defined above in connection with the first swap.

The Group does not hold any other hedging instruments as at the date of this document.

2.1.9 *Field optimisation*

Although the effective date of the acquisition was 1 July 2016, transfer of operatorship did not occur until 11 July 2017. The acquisition was structured this way to allow the buyer to have the economic benefit of the acquisition whilst engaging with the regulator to be accepted as operator and this asset represents the Company's first asset in Australia operated under a safety case.

Since obtaining operatorship of the asset, Jadestone has reduced operating costs (excluding workovers and repair maintenance) significantly from US$41.23/bbl to US$32.99/bbl. Operating costs (excluding workovers) have reduced to US$37.48/bbl for the first quarter of 2018 from US$51.79/bbl for the same period in 2017 (the period preceding the acquisition). The Board believes that the reduction in operating costs are a result of the following actions taken by the Company since obtaining operatorship: re-organisation of the management structure; implementation of a multi-skilling model; re-negotiation of contracts; review of cost control on capital spending; improved planning and logistics; and campaign maintenance. In addition, the average cost per workover has been reduced to US$1.09 million for the first half of 2018 from US$2.2 million for the same period in 2017.

There is further optimisation planned for future workover costs which is expected to drive a further reduction of between US$0.4 million and US$0.6 million towards the end of this year.

The Company continues to review cost reduction strategies at the Stag oilfield, including infrastructure optimisation.

The Company has planned an infill drilling campaign to drill one new well in 2018, two in 2019 and two in 2020 with an estimated total associated cost of US$112 million.

2.1.10 *Regulatory*

The Company is subject to Australian corporate tax, which is currently charged at the rate of 30 per cent, and PRRT, at 40 per cent, on profits derived from the Stag field. Currently no corporate tax or PRRT is payable by the Company in respect of the Stag field, however, it is anticipated that the Company will have to pay both corporate tax and PRRT over the next year based on current projections. The future PRRT liability in respect of the Stag field may be reduced to the extent that exploration expenditure is incurred in relation to either the Stag field or the Montara Assets.

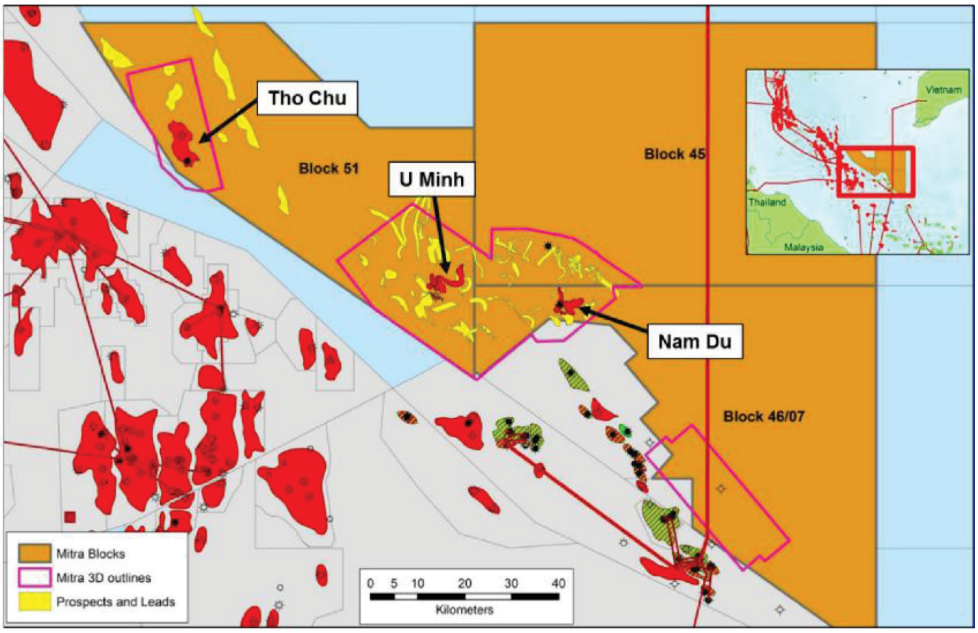
2.2 Nam Du, U Minh and Tho Chu Discoveries – Vietnam

2.2.1 *Overview*

The Nam Du discovery is located within the Block 46-07 PSC (''**Block 46/07**'') on the north-eastern margin of the Malay-Tho Chu Basin, approximately 200 kilometres offshore Vietnam in a water depth of 47.9 metres.

The U Minh and Tho Chu discoveries are located within the boundaries of the Block 51 PSC (''**Block 51**'') in the Malay-Tho Chu Basin, approximately 200 kilometres offshore Vietnam in a water depth of 64 metres.

Location of the Nam Du, U Minh and Tho Chu Discoveries, Block 46/07 and 51 PSCs, offshore Vietnam



Source: CPR

2.2.2 *Licence Overview*

Jadestone, through its wholly-owned subsidiaries Mitra Energy (Vietnam Nam Du) Pte Ltd and Mitra Energy (Vietnam Tho Chu) Pte Ltd, has a 70 per cent operated working interest in the two PSCs. The Company has made two gas/condensate discoveries on its acreage, being Tho Chu on Block 51, and Nam Du on Block 46/07. The process of amending Block 51 and Block 46/07 for PVEP's relinquishment of its 30 per cent interest and withdrawal from the blocks with effect from 1 May 2017 is continuing. This is expected to result in Jadestone having 100 per cent operated working interests.

Exploration phase two of the Block 51 PSC expired on 10 June 2016 and rather than enter exploration phase three, the PSC joint venture parties applied for suspended development area ("**SDA**"), status over both the U Minh and Tho Chu Fields. Jadestone was advised on 26 December 2016 that SDA status had been approved by the Prime Minister of Vietnam for the Tho Chu and U Minh Fields for a five year period from 11 June 2016. The SDA status enables the asset to be retained for up to five years, with a possible further two year extension, pending external events.

For the U Minh Field, the SDA was expected to last only until approval of the ODP, at which point it would become a development/production area. As noted below, ODP approval was granted on 21 May 2018. The Tho Chu Field will remain as an SDA pending clarity on the availability of new pipeline infrastructure which is planned for the area north west of Block 51.

The total term of the Block 46/07 PSC is 25 contract years from 30 June 2010 (extendable) of which the Exploration Period is 5 contract years from 30 June 2010 (extendable). The Block 46/07 Exploration Period (including Phase Two) was extended to 29 June 2018. Under Article 2.1.2 of the Block 46/07 PSC, if there was no commercial discovery at the expiry of the Exploration Period (including any extension), the Block 46/07 PSC would automatically terminate in its entirety. Jadestone made the First Request for a 1-year extension of Phase Two of the Exploration Period starting from 30 June 2018 to 29 June 2019, more than 90 days prior to the expiry as required under the terms of the Block 46/07 PSC. Subsequently, on 25 May 2018, Jadestone submitted the Second Request for a 2-year extension of the Phase Two of the Exploration Period starting from 30 June 2018 to 29 June 2020, as it was requested to do at a meeting with PetroVietnam and the MOIT for the Outline Development Plan (ODP) for the Nam Du gas discovery. The Second Request reflects the timeline under the ODP to drill the remaining commitment well under the Block 46/07 PSC. The ODP was approved by MOIT on 24 May 2018.

Notwithstanding the approval of the ODP, under the Vietnamese law, the Second Request requires approval of the Prime Minister of Vietnam to become effective. MOIT is responsible for coordinating with PetroVietnam and relevant ministries and to make a recommendation to the Prime Minister. Whilst the approval is still being sought, it would be unusual in Vietnam for the PSC to be terminated where an application for extension of the exploration period has been made but the process for the relevant regulatory approvals for such extension have not been completed by the expiry date of the then existing exploration period. Should approval of the Prime Minister be granted, it would record the continuity of the extension from such expiry date through to the newly approved extended date.

2.2.3 *Reserves*

Vietnamese Government compliant Reserve Assessment Reports for both the Nam Du (Block 46/07) and U Minh (Block 51) Fields were approved by the Prime Minister of Vietnam in January 2016.

According to the CPR, as at 31 December 2017, Block 51 and Block 46/07 PSC had gross 2C gas resources of 496.8 Bscf (347.8 Bscf net to Jadestone) and gross 2C liquids resources of 11 MMbbl (7.7 MMbbl net to Jadestone), of which the U Minh Fields and Nam Du Fields comprise gross 2C gas resources of 171.3 Bscf (119.9 Bscf net to Jadestone) and gross 2C liquids resources of 1.6 MMbbl (1.1 MMbbl net to Jadestone). Jadestone management have used the statement of contingent resources in the CPR, together with estimates for capex and opex, to calculate an aggregate NPV10 of US$246 million for the U Minh and Nam Du fields.

At present, no development plan has been submitted for the Tho Chu discovery and contingent resources are consequently classified as Development Unclarified.

2.2.4 *Geology and sub-surface*

The Nam Du Southern Channel reservoir is a fluvial channel of Lower Miocene age. It is approximately 20 metres thick and has two thin coal intervals. The wireline log character shows a coarsening-upwards sequence. The upper 10-15 metres appears to be cleaner from the Gamma Ray response and this is reflected in the interpreted porosity curve as a higher porosity interval.

The reservoir is shown to be part of a low sinuosity channel-point bar system that runs from north east to south west, and is approximately six kilometres in length along the axis and averages approximately one kilometre in width. There is an additional channel chute that splits from the main channel to the west that is approximately 2.5 kilometres long and 250 metres wide.

The U Minh H100 reservoir is a moderately sinuous channel-point bar system of Miocene age, trending downdip from northeast to southwest where it is folded over the U Minh four-way dip closure structure. The channel-point bar complex is at least 12 kilometres long and 1.3 kilometres wide. There is a fault south of Well 46/07-ND-1X which provides a separate area south of the fault. This area has not been drilled and is therefore considered to be prospective resources. The Company will refer to this as the Nam Du Southern Channel. ERCE did not provide an estimate for this volume south of the fault in the CPR.

The Tho Chu reservoirs were deposited in the Lower to Middle Miocene ages. The depositional environment ranges from fluvial to marginal marine. Reservoir sands are typically thin (1-5 metres) and are separated by flooding surfaces that are thought to act as seals. An abundance of coals deposited throughout the Lower to Middle Miocene interval allow for a robust stratigraphic correlation.

2.2.5 *Development history*

The Nam Du field was discovered in April 2013 by exploration Well 46/07-ND-1X, drilled by Mitra Energy (Vietnam Nam Du) Pte Ltd. The well 46/07-ND-1X was drilled to a total depth of 2,297 mMD and discovered gas in two main Miocene fluvial channel reservoirs. A further ten reservoir sandstone intervals were encountered and are mainly gas-bearing. Gas bearing reservoirs have a C02 content of approximately 8 per cent. Only one of these reservoirs, Nam Du Southern Channel, contains enough gas to warrant development and thus is the only reservoir with Contingent Resource estimates. Nam Du Southern Channel has a combination structural/stratigraphic trap, with the channel limits defined by seismic inversion volumes and structural control from 3-way dip closure and fault throw.

U Minh was discovered by exploration Well 51-UM-1X in January 1997, drilled by FINA Exploration Minh Hai B.V. This is the only well on the field.

The Tho Chu discovery was discovered in 2012 by exploration Well 51-TC-1X and later appraised in 2014 by Well 51-TC-2X. In October 2012, Well 51-TC-1X was drilled to a total depth of 3,185 mMD and discovered a total of 55 hydrocarbon pay reservoirs (53 gas/condensate and 2 oil) within a sequence of stacked Lower to Middle Miocene reservoirs deposited in a fluvial to marginal marine environment. Gas bearing reservoirs have a variable CO_2 content, ranging from 10 to 80 per cent The discovery is located in the hanging wall of a major fault zone that defines its eastern boundary. In March 2014, Well 51-TC-2X was drilled approximately 7 kilometres to the north on a second structural crest. The well was drilled to a total depth of 3,114 mMD and penetrated 17 hydrocarbon pay reservoirs (all gas/condensate) over the same Miocene interval as Well 51-TC-1X.

2.2.6 *Route to market and development plan*

There is one remaining commitment well for Block 46/07 which is planned to be drilled as an exploration well on the Nam Du Field to test the Nam Du Southern Channel area. This could firm up further volumes for the Nam Du development. The well is being designed to be suspended as a potential future production well or drilled from the well head platform at the time of development. Mitra Energy (Vietnam Nam Du) Pte Ltd has applied to defer the well beyond the next 12 months, and whilst formal approval to defer has not been received, the ODP, which contemplates such well being drilled as part of the overall development, was approved on 21 May 2018.

The ODPs for the Nam Du and U Minh Fields were submitted to PVEP on 8 November 2016 for endorsement and approval before submission to the MOIT. Subsequent to PVEP's withdrawal from the Blocks and with the support of PVN, Jadestone revised the two ODPs to reflect a standalone development for the combined fields based on Jadestone having a 100 per cent working interest.

Given the approvals of the ODPs, Jadestone is now commencing the Define Phase of the project (front end engineering and design, preparation of a field development plan, and preparation of a gas sales agreement).

In November 2017, the Company submitted revised ODPs for the U Minh and Nam Du fields for approval, which was received from the MOIT in May 2018. The Company currently anticipates developing these two fields in a phased manner, with overall project sanction targeted for H2 2019. Two development plans are being considered as part of this ODP approval process:

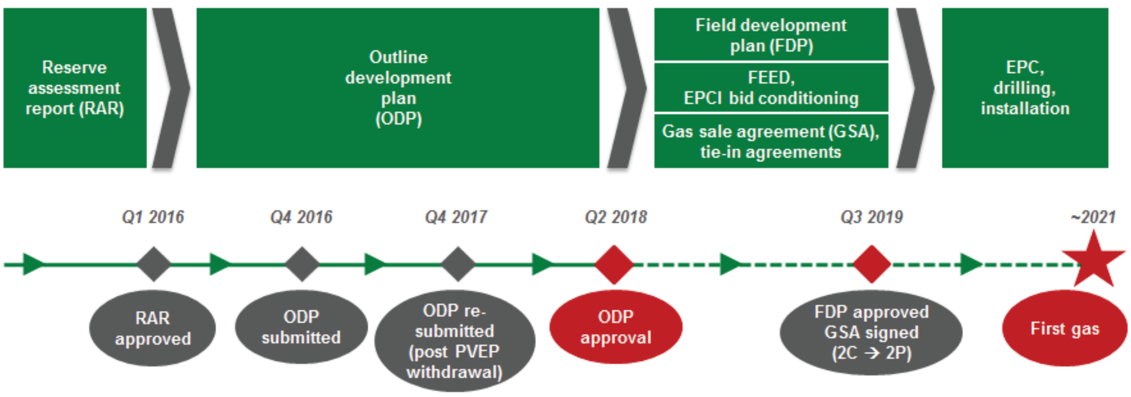
The first proposal is a standalone development combining Nam Du and U Minh, comprising a Central Processing Platform ("**CPP**") or leased FPSO located at Nam Du, with separation, dehydration and compression process equipment. A minimum facilities well head platform would be located over Nam Du and a WHP would be located over U Minh with a multi-phase tie-in pipeline to Nam Du. The gas export line would be via an existing pipeline and liquid export would be via tanker.

The second proposal involves an area development comprising Nam Du, U Minh and the PVEP operated Block 46/13 Khanh My and other discoveries. A minimum facilities WHP would be located on U Minh with a multi-phase tie-in pipeline to Nam Du. A minimum facilities WHP would be located on Nam Du with a multi-phase tie-in pipeline to Khanh My. A CPP would be located at Khanh My with separate gas and liquids export lines to existing infrastructure.

Ahead of project sanction, the Company is working on the front-end engineering and design, negotiation of commercial gas sales agreements and field development planning.

With the delays in the ODP approval, development drilling has been delayed. Jadestone requested a further two-year extension to exploration phase two on 31 May 2018. This extension has not yet been granted and there can be no assurance that it will be granted.

The Company intends to use an existing 18 inch pipeline with 215 MMscf/d of capacity, owned by PetroVietnam, which is in close proximity to the Nam Du and U Minh fields to evacuate gas from the fields to an existing power complex and fertiliser plant in Southern Vietnam. This pipeline currently evacuates gas from the heritage Talisman operated PM-03 CAA Block which lies immediately to the south of Block 46/07. This field is currently in decline, which is expected to result in sufficient ullage within the pipeline, which the Company intends to seek to utilise.



Source: Jadestone Energy Inc.

The Tho Chu field will be subject to a later development plan.

Total capital expenditure of the Nam Du/U Minh development is currently estimated to be in the range of US$240 million to US$275 million, based on the approved ODP and third party pre-FEED studies. Jadestone management estimates for the Nam Du/U Minh wholesale well head gas price, an initially fixed price that is anticipated to have fixed escalation, is in the range of US$8.5/MMbtu to US$9/MMbtu, based on the approved ODP, recent third party gas price negotiations in Vietnam. Jadestone management estimates for operating expenditure for the Nam Du/U Minh development are in the range of US$65 million to US$85 million based on the approved ODP and current pre-FEED planning.

The CPR identified the southern channel as prospective resources, but did not include any volumes estimates or further comments on this prospect. Jadestone management's estimate for the Southern channel gives an unrisked prospective resources of 31.1Bscf and with an estimated NPV10 of

US$76 million. Jadestone management considers this to be a low risk prospect based on the seismic response being similar to what is seen at the discovery well. The already planned development for Nam Du includes all the capacity needed to also produce at the Nam Du southern channel. The optimal plan would be to drill the appraisal/exploration well directly from the well head riser platform which, if successful, can then be completed as a development well. With success for southern channel, the Company's plan would then be to drill only one further development well for Nam Du. To maintain safety of supply, two development wells for Nam Du were already assumed in the cost assumptions so there would be no incremental costs for a southern channel success case.

2.2.7 *Licences and PSCs*

Block 51

Block 51 Investment Certificate

On 11 June 2010 the Vietnamese Ministry of Industry and Trade issued Investment Certificate number 13 in respect of Block 51 Petroleum Production Sharing Contract dated 12 May 2010 which was amended in August 2016. Pursuant to the investment certificate the project implementation location is Block 51, offshore the Socialist Republic of Vietnam; and an operating office may be set up in Ho Chi Minh City, and/or Vung Tau City and/or Hanoi City.

The participating interests are PVEP: 30 per cent and Mitra Tho Chu: 70 per cent. Mitra Tho Chu is the appointed Operator. With respect to PVEP's participating interest, all costs and expenses attributable thereto and to be incurred until declaration of the first commercial discovery shall be borne by Mitra Tho Chu. Mitra Tho Chu shall be entitled to recover such PVEP's carried cost, without interest, from PVEP's share of cost recovery oil and cost recovery gas.

The contract term was 25 years for crude oil and 30 years for natural gas from 11 June 2010 and may be extended in accordance with the laws of Vietnam. The exploration period was 5 years from 11 June 2010 and may be extended in accordance with the laws of Vietnam. The Block 51 PSC terminates upon the expiry of exploration period without any commercial discovery.

Development and production period is as set out in the Block 51 PSC and the Parties to the Block 51 PSC must carry out all responsibilities and obligations, share business results in accordance with the Block 51 PSC, fulfil all other obligations and responsibilities to the State of Vietnam in accordance with the laws of Vietnam.

The Contractor has the responsibility to request sub-contractors to comply with the laws of Vietnam and fulfil all taxes and compulsory financial payments applicable to the sub-contractors in accordance with the laws of Vietnam. During the term of the Block 51 PSC, the Contractor and sub-contractors are entitled to all rights and benefits provided in the Block 51 PSC and shall not be adversely impacted due to any change in the laws of Vietnam.

Production Sharing Contract among PetroVietnam and PVEP and Mitra Tho Chu with respect to Block 51, offshore the Socialist Republic of Vietnam

Type of provision	Summary
Parties	PetroVietnam, PVEP and Mitra Tho Chu
Participating Interests	• Mitra Tho Chu: 70 per cent • PVEP: 30 per cent Mitra Tho Chu is the appointed Operator.
Date of signing	12 May 2010 and amended on 5 May 2016 (with effect from 3 August 2016)
Scope	The Block 51 PSC establishes the principles, terms and conditions under which Mitra Tho Chu is granted the exclusive right to explore for, appraise and produce Petroleum in the Contract Area and conduct Petroleum Operations and all other activities associated therewith or related thereto, including the right to export, sell or dispose of Petroleum in all manners which Mitra Tho Chu has right to do under the Block 51 PSC.
Contract Area	3,632 km2
Term and Extensions	Total term: 25 contract years for Crude Oil and 30 contract years for Natural Gas from 11 June 2010, subject to satisfaction of the Implementation Schedule and may be extended up to five years if mutually agreed by the Parties and approved by the Government.
Exploration Period	5 years from 11 June 2010, and may be extended up to two years. The Exploration Period is divided into three phases: three years for Phase One, one year for Phase Two (if applicable) and one year for Phase Three (if applicable). Phase Two and Phase Three are at the option of the contractor prior to the end of Phase One and Phase Two respectively. The Exploration Period expired on 10 June 2016. On 26 December 2016, the U Minh and Tho Chu fields were approved by the MOIT as SDAs for a period of five years from 11 June 2016.
Management Committee / members	The Management Committee consists of four members, two of whom are from PetroVietnam and the other two members are from Mitra Tho Chu. Mitra Tho Chu shall designate one of its members as Chairman for the meetings of the Management Committee (MCM) before declaration of the first Commercial Discovery and PetroVietnam shall designate one of its members as Chairman for MCMs thereafter.
Management Committee / voting provisions	Each member of the Management Committee shall have one vote. MCMs shall require a quorum of all four members. Except for exploration and appraisal matters before declaration of the first Commercial Discovery which shall be taken by majority of the Management Committee members, decisions of the Management Committee shall be taken by unanimous vote of the members present and the authorised representatives.
Level of State participation	Not applicable.

Type of provision	Summary
Work Programs and Budgets	• Time Limit An annual Work Program and Budget for the Contract Area is required within 60 days of 11 June 2010 and thereafter at least 90 days prior to the beginning of each year or at such other time as may otherwise be mutually agreed by PetroVietnam and Mitra Tho Chu. • Approvals Work Programs and Budgets shall require Management Committee's adoption within 30 days from the date of submission and PetroVietnam's approval within 30 days from the date of submission.
Commercial Discovery and Development Operations	In case of a Commercial Discovery, Mitra Tho Chu shall submit to the Management Committee and PetroVietnam a proposed designated Development Area. After the establishment of any Development Area in the Contract Area, Mitra Tho Chu shall prepare and submit for approval an outline development plan and Development Plan for the Commercial Discovery. Development Operations shall commence no later than 18 months after approval by Prime Minister of the Development Plan for any Commercial Discovery.
Title to Equipment and Facilities owned / leased by Mitra Tho Chu	Title to assets acquired, owned and used by Mitra Tho Chu, exclusively for Petroleum Operations in the Contract Area and charged to Petroleum Operations Costs shall be transferred automatically to PetroVietnam when the total cost of such assets has been fully recovered in accordance with the Block 51 PSC or at the termination date of the Block 51 PSC, whichever is the earlier. Notwithstanding the above, such assets will remain under the control and responsibility of Mitra Tho Chu who shall have the right of exclusive use, free of charge, so long as required for its Petroleum Operations under the Block 51 PSC. All leased assets used for Petroleum Operations shall be retained under control of Mitra Tho Chu.
Employment obligations / localisation requirements	Mitra Tho Chu shall consult with PetroVietnam for the purpose of employing qualified Vietnamese personnel in the conduct of Petroleum Operations and will undertake the schooling and training of Vietnamese personnel for staff positions. Mitra Tho Chu shall make prior use of suitable services, goods and materials from Vietnamese companies in the conduct of Petroleum Operations provided they are competitive in terms of price, quality, delivery time and availability.
Restrictions on disposal of oil/gas	In emergency cases, at the request of Vietnamese Government, PetroVietnam may require Mitra Tho Chu by written notice given 30 days in advance to supply Crude Oil from the portion of Net Oil Production entitled by Mitra Tho Chu to PetroVietnam to meet the domestic consumption needs.
Recovery of Costs	Mitra Tho Chu is entitled to Cost Recovery Oil/Gas up to 50 per cent of the Net Oil/Gas Production in each Quarter. Petroleum Operations Costs shall be recovered from the applicable Cost Recovery Oil/Gas on a first-in-first-out basis. Petroleum Operations Costs which are not recovered in a Quarter may be carried forward to the next succeeding Quarters without interest until fully recovered.

<table>
<tr><th>Type of provision</th><th>Summary</th></tr>
<tr><td>Profit Oil/Gas</td><td>Profit Oil is to be shared as follows:
<table>
<tr><th rowspan="2">Daily average Net Oil Production in Quarter
(in Barrel per day)</th><th colspan="2">Percentage Share (per cent)</th></tr>
<tr><th>Mitra Tho Chu</th><th>PetroVietnam</th></tr>
<tr><td>Up to 20,000</td><td>80 per cent</td><td>20 per cent</td></tr>
<tr><td>Over 20,000 to 50,000</td><td>77 per cent</td><td>23 per cent</td></tr>
<tr><td>Over 50,000 to 75,000</td><td>65 per cent</td><td>35 per cent</td></tr>
<tr><td>Over 75,000 to 100,000</td><td>55 per cent</td><td>45 per cent</td></tr>
<tr><td>Over 100,000 to 150,000</td><td>45 per cent</td><td>55 per cent</td></tr>
<tr><td>Over 150,000</td><td>40 per cent</td><td>60 per cent</td></tr>
</table>
Profit Gas is to be shared as follows:
<table>
<tr><th rowspan="2">Daily average Net Gas Production in Quarter
(in million m^3 per day)</th><th colspan="2">Percentage Share (per cent)</th></tr>
<tr><th>Mitra Tho Chu</th><th>PetroVietnam</th></tr>
<tr><td>Up to 5</td><td>80 per cent</td><td>20 per cent</td></tr>
<tr><td>Over 5 to 10</td><td>73 per cent</td><td>27 per cent</td></tr>
<tr><td>Over 10 to 15</td><td>58 per cent</td><td>42 per cent</td></tr>
<tr><td>Over 15 to 20</td><td>53 per cent</td><td>47 per cent</td></tr>
<tr><td>Over 20</td><td>45 per cent</td><td>55 per cent</td></tr>
</table></td></tr>
<tr><td>Taxation</td><td>• Corporate income tax: 32 per cent of net taxable income;
• Export duty: 10 per cent on Crude Oil and 0 per cent for Natural Gas;
• Value Added Tax: in accordance with VAT laws; and
• Royalties (starting at the production phase):
<table>
<tr><th>Net Oil Production by incremental tranches in Contract Area
(in Barrel per day)</th><th>Rate</th></tr>
<tr><td>Up to 20,000</td><td>8 per cent</td></tr>
<tr><td>Over 20,000 to 50,000</td><td>10 per cent</td></tr>
<tr><td>Over 50,000 to 75,000</td><td>12 per cent</td></tr>
<tr><td>Over 75,000 to 100,000</td><td>17 per cent</td></tr>
<tr><td>Over 100,000 to 150,000</td><td>22 per cent</td></tr>
<tr><td>Over 150,000</td><td>27 per cent</td></tr>
</table></td></tr>
</table>

<table>
<tr><th>Type of provision</th><th>Summary</th></tr>
<tr><td></td><td>
<table>
<tr><th>Net Gas Production in Contract Area
(in million m^3 per day)</th><th>Rate</th></tr>
<tr><td>Up to 5</td><td>0 per cent</td></tr>
<tr><td>Over 5 to 10</td><td>5 per cent</td></tr>
<tr><td>Over 10</td><td>10 per cent</td></tr>
</table>

If the Vietnamese tax laws provide for more favourable tax rates or treatment for petroleum industry, Mitra Tho Chu shall, with the assistance of PetroVietnam, apply for such favourable tax rates and treatment.
</td></tr>
<tr><td>Bonuses</td><td>
● Foreign Party(ies) shall pay to PetroVietnam a signature bonus of USD 500,000 within 30 days after 11 June 2010.
● Foreign Party(ies) shall pay to PetroVietnam USD 1,500,000 within 30 days after declaration of the first Commercial Discovery in the Contract Area.
● Foreign Party(ies) shall pay to PetroVietnam USD 1,500,000 within 30 days after the First Commercial Date in the Contract Area.
● Foreign Party(ies) shall pay jointly to PetroVietnam within 30 days after the daily production of Crude Oil from the Contract Area and/or daily sustainable production of Natural Gas for commercial sale from the Contract Area the first averages above the relevant Production Level indicated in the table below for a period of 30 consecutive days:
<table>
<tr><th>Production Level
(Barrels of Oil Equivalent per Day)</th><th>Bonus amount (USD)</th></tr>
<tr><td>Over 25,000</td><td>2,00,000</td></tr>
<tr><td>Over 50,000</td><td>3,00,000</td></tr>
<tr><td>Over 75,000</td><td>4,00,000</td></tr>
<tr><td>Over 100,000</td><td>5,00,000</td></tr>
<tr><td>Over 150,000</td><td>6,00,000</td></tr>
</table>

Bonuses paid to PetroVietnam shall not be considered as recoverable costs.
</td></tr>
<tr><td>Surrender / Relinquishments</td><td>
● Surrender
Mitra Tho Chu shall surrender 20 per cent of the initial Contract Area if it elects to enter Phase Two. Mitra Tho Chu shall surrender an additional 20 per cent of the initial Contract Area if it elects to enter Phase Three (if applicable). At any time earlier, Mitra Tho Chu shall have the right to surrender an acceptable portion of the Contract Area in accordance with the provisions of the Block 51 PSC.
● Relinquishment
Without prejudice to the provisions of Articles 2.1.4 and 2.1.5 of the Block 51 PSC, before or by the end of the Exploration Period plus any extension thereof, Mitra Tho Chu shall relinquish all remaining parts of the Contract Area excluding certain areas as provided in the Block 51 PSC (e.g. Development Areas and Suspended Development Areas, etc).
</td></tr>
</table>

Type of provision	Summary
Termination and Abandonment	• Several key events: material breaches, automatic termination if no Commercial Discovery has been made in the Contract Area at the end of the Exploration Period, and other circumstances that do not warrant continuation of the Petroleum Operations as provided in the Block 51 PSC. • Cure rights: Where either Party is in material breach of any of its obligations under the Block 51 PSC, the other Party may give notice to the Defaulting Party requiring the Defaulting Party to remedy such breach. • Several consequences of termination: Mitra Tho Chu shall not be relieved from rights and outstanding obligations that have accrued in the period prior to the relinquishment as well as other continuing rights and obligations as contemplated under the Block 51 PSC. If a dispute arises between PetroVietnam and Mitra Tho Chu as to whether a Party in material breach of any of its obligations under the PSC or whether a Party is entitled to terminate the Block 51 PSC, either Party may require that dispute to be submitted for arbitration pursuant to the Block 51 PSC. • Mitra Tho Chu shall, upon written request from PetroVietnam, carry out abandonment of the islands, installations, structures, facilities or wells constructed or drilled for the purposes of the Block 51 PSC, whether by way of plugging, demolition, removal, destruction, conversion, placement on temporary or permanent care and maintenance or other bases in conformity with Generally Accepted International Petroleum Industry Practices.
Assignment, and Pre-emption	• Assignment The sale, assignment, transfer, conveyance or otherwise disposal of all or any of each Contractor Party's rights, interests and obligations under the Block 51 PSC to its Affiliated Company shall require written notification to PetroVietnam and approval by the Prime Minister. The sale, assignment, transfer, conveyance or otherwise disposal of all or any of each Contractor Party's rights, interests and obligations under the Block 51 PSC to third parties shall be subject to the pre-emption right first of PetroVietnam, and then of other Contractor Parties under the joint operating agreement, and approval of the Prime Minister. • PetroVietnam's Pre-emption Right In case of sale, assignment, transfer, conveyance or otherwise disposal of all or any of each Contractor Party's rights, interests and obligations under the Block 51 PSC, PetroVietnam has pre-emption right first in accordance with the Petroleum Law.
Stabilisation	The Government and PetroVietnam shall take all steps necessary to ensure that each of the Contractor Parties will enjoy all rights and benefits conferred as at 11 June 2010 during the term of the Block 51 PSC. If after 11 June 2010, existing laws and regulations are amended, or annulled or new laws and regulations are introduced in Vietnam, or an official interpretation or application of changes of regulations of a law, or license is cancelled, not renewed, or the conditions therefore are revised adversely affecting the economic interest of Mitra Tho Chu and PetroVietnam and PetroVietnam shall, upon notice from Mitra Tho Chu, consult promptly with each other and make such changes to the Block 51 PSC as are necessary both to maintain Mitra Tho Chu's rights, benefits and interest under the Block 51 PSC as at 11 June 2010 and to ensure that any

Type of provision	Summary
	revenues or incomes or profits, including any one or more of the foregoing of Mitra Tho Chu, derived or to be derived under the Block 51 PSC, shall not in any way be diminished in comparison to that which was originally contemplated as a result of such changes of laws or annulment therefrom or their interpretation or application or as a result of such changes, cancellation or non-renewable of approvals or licenses.
Governing law	Applicable laws: laws and regulations of Vietnam. In the absence of a specific Vietnamese law or regulation governing any matter that may be raised, the relevant provisions of international law or Generally Accepted International Petroleum Industry Practices shall apply, provided that they are not contrary to fundamental principles of Vietnamese laws.
Dispute resolution	Differences and disputes related to or arising under the Block 51 PSC shall firstly be settled through negotiations by the Parties within 90 days of any Party's issuance of notice of a dispute. If such dispute cannot be settled through negotiation, it will be resolved by either an arbitration tribunal in Singapore or Expert determination subject to the nature of the dispute.

Block 46/07

Block 46/07 Investment Certificate

On 30 June 2010 the Vietnamese Ministry of Industry and Trade issued Investment Certificate number 14 in respect of Block 46/07 Petroleum Production Sharing Contract dated 28 June 2010 which was amended on 24 June 2013 , 30 May 2014 and 28 May 2015. Pursuant to the investment certificate the project implementation location is Block 46/07, offshore the Socialist Republic of Vietnam and the operating office may be set up in Ho Chi Minh City, and/or Vung Tau City and/or Hanoi City.

The participating interests are PVEP: 30 per cent and Mitra Nam Du: 70 per cent. Mitra Nam Du is the appointed Operator. With respect to PVEP's participating interest, all costs and expenses attributable thereto and to be incurred until declaration of the first commercial discovery shall be borne by Mitra Nam Du. Mitra Nam Du shall be entitled to recover such PVEP's carried cost, without interest, from PVEP's share of cost recovery oil and cost recovery gas.

The contract term was 25 years from 30 June 2010 and may be extended in accordance with the laws of Vietnam. The exploration period was 5 years from 30 June 2010 and may be extended in accordance with the laws of Vietnam. The Block 46/07 PSC terminates upon the expiry of exploration period without any commercial discovery.

The development and production period is set out in the Block 46/07 PSC. The Parties to the Block 46/07 PSC must carry out all responsibilities and obligations, share business results in accordance with the Block 46/07 PSC, fulfil all other obligations and responsibilities to the State of Vietnam in accordance with the laws of Vietnam.

The Contractor has the responsibility to request sub-contractors to comply with the laws of Vietnam and fulfil all taxes and compulsory financial payments applicable to the sub-contractors in accordance with the laws of Vietnam. During the term of the Block 46/07 PSC, the Contractor and sub-contractors are entitled to all rights and benefits provided in the Block 46/07 PSC and shall not be adversely impacted due to any change in the laws of Vietnam.

Production Sharing Contract among PetroVietnam and PVEP and Mitra Nam Du with respect to Block 46/07, offshore the Socialist Republic of Vietnam

Type of provision	Summary
Parties	PetroVietnam, PVEP and Mitra Nam Du
Participating Interests	• Mitra Nam Du: 70 per cent • PVEP: 30 per cent Mitra Nam Du is the Operator under the Block 46/07 PSC
Date of signing	28 June 2010 as amended on 29 March 2013 (effective 24 June 2013), 17 January 2014 (effective 30 May 2014) and 26 February 2015 (effective 28 May 2015)
Scope	The Block 46/07 PSC establishes the principles, terms and conditions under which Mitra Nam Du is granted the exclusive right to explore for, appraise and produce Petroleum in the Contract Area and conduct Petroleum Operations and all other activities associated therewith or related thereto, including the right to export, sell or dispose of Petroleum in all manners which Mitra Nam Du has right to do under the Block 46/07 PSC.
Contract Area	3,280.72 km^2
Term and Extensions	Total term: 25 contract years from 30 June 2010, subject to satisfaction of the Implementation Schedule and may be extended up to 5 years if mutually agreed by the Parties and approved by the Government.
Exploration Period	5 years from 30 June 2010, and may be extended up to two years. The Exploration Period is divided into three phases: three years for Phase One, one year for Phase Two (if applicable) and one year for Phase Three (if applicable). Phase Two and Phase Three are at the option of the contractor prior to the end of Phase One and Phase Two respectively. The Block 46/07 Exploration Period (including Phase Two) was extended to 29 June 2018. Under Article 2.1.2 of the Block 46/07 PSC, if there was no commercial discovery at the expiry of the Exploration Period (including any extension), the Block 46/07 PSC would automatically terminate in its entirety. Jadestone made the First Request for a 1-year extension of Phase Two of the Exploration Period starting from 30 June 2018 to 29 June 2019, more than 90 days prior to the expiry as required under the terms of the Block 46/07 PSC. Subsequently, on 25 May 2018, Jadestone submitted the Second Request for a 2-year extension of the Phase Two of the Exploration Period starting from 30 June 2018 to 29 June 2020, as it was requested to do at a meeting with PetroVietnam and the MOIT for the Outline Development Plan (ODP) for the Nam Du gas discovery as the Second Request reflects the timeline under the ODP to drill the remaining commitment well under the Block 46/07 PSC. The ODP was approved by MOIT on 24 May 2018.

<table>
<tr><th>Type of provision</th><th>Summary</th></tr>
<tr><td></td><td>Notwithstanding the approval of the ODP, under the Vietnamese law, the Second Request requires approval of the Prime Minister of Vietnam to become effective. MOIT is responsible for coordinating with PetroVietnam and relevant ministries and to make a recommendation to the Prime Minister. Whilst the approval is still being sought, it would be unusual in Vietnam for the PSC to be terminated where an application for extension of the exploration period has been made but the process for the relevant regulatory approvals for such extension have not been completed by the expiry date of the then existing exploration period. Should approval of the Prime Minister be granted, it would record the continuity of the extension from such expiry date through to the newly approved extended date.</td></tr>
<tr><td>Management Committee members</td><td>The Management Committee consists of four members, two of whom are from PetroVietnam and the other two members are from Mitra Nam Du.

Mitra Nam Du shall designate one of its members as Chairman for the meetings of the Management Committee (MCM) before declaration of the first Commercial Discovery and PetroVietnam shall designate one of its members as Chairman for MCMs thereafter.</td></tr>
<tr><td>Management Committee / voting provisions</td><td>Each member of the Management Committee shall have one vote. MCMs shall require a quorum of all four members. Any member may be represented and vote by a written and signed proxy of a member absent. Except for exploration and appraisal matters before declaration of the first Commercial Discovery which shall be taken by majority of the Management Committee members, decisions of the Management Committee shall be taken by unanimous vote of the members present and the authorised representatives.</td></tr>
<tr><td>Level of State participation</td><td>Not applicable.</td></tr>
<tr><td>Minimum Work Obligations</td><td>
<table>
<tr><th>Phase of Exploration Period</th><th>Minimum Work Commitment</th><th>Minimum Financial Commitment (in USD)</th></tr>
<tr><td rowspan="2">Phase One
(3 years)</td><td>• Acquisition, processing and interpretation of 300km^2 of 3D seismic data</td><td>3,500,000</td></tr>
<tr><td>• Drill 2 Exploration Wells</td><td>10,000,000/well</td></tr>
<tr><td></td><td>Total:</td><td>23,500,000</td></tr>
<tr><td>Phase Two – optional
(1 year)</td><td>• Drill 1 Exploration Well</td><td>10,000,000</td></tr>
<tr><td>Phase Three – optional
(1 year)</td><td>• Drill 1 Exploration Well</td><td>10,000,000</td></tr>
</table>
</td></tr>
</table>

Type of provision	Summary
Work Programs and Budgets	• Time Limit An annual Work Program and Budget for the Contract Area is required within 60 days of 30 June 2010 and thereafter at least 90 days prior to the beginning of each year or at such other time as may otherwise be mutually agreed by PetroVietnam and Mitra Nam Du. • Approvals Work Program and Budget shall require Management Committee's adoption within 30 days from the date of submission and PetroVietnam's approval within 30 days from the date of submission.
Commercial Discovery and Development Operations	In case of a Commercial Discovery, Mitra Nam Du shall submit to the Management Committee and PetroVietnam a proposed designated Development Area. After the establishment of any Development Area in the Contract Area, Mitra Nam Du shall prepare and submit for approval an outline development plan and Development Plan for the Commercial Discovery. Development Operations shall commence no later than 18 months after approval by Prime Minister of the Development Plan for any Commercial Discovery.
Title to Equipment and Facilities owned / leased by Mitra Nam Du	Title to assets acquired, currently owned and used by Mitra Nam Du, exclusively for Petroleum Operations in the Contract Area and charged to Petroleum Operations Costs shall be transferred automatically to PetroVietnam when the total cost of such assets has been fully recovered in accordance with the Block 46/07 PSC or at the termination date of the Block 46/07 PSC, whichever is the earlier. Notwithstanding the above, such assets will remain under the control and responsibility of Mitra Nam Du who shall have the right of exclusive use, free of charge, so long as required for its Petroleum Operations under the Block 46/07 PSC. All leased assets used for Petroleum Operations shall be retained under control of Mitra Nam Du.
Employment obligations / localisation requirements	Mitra Nam Du shall consult with PetroVietnam for the purpose of employing qualified Vietnamese personnel in the conduct of Petroleum Operations and will undertake the schooling and training of Vietnamese personnel for staff positions. Mitra Nam Du shall make prior use of suitable services, goods and materials from Vietnamese companies in the conduct of Petroleum Operations provided they are competitive in terms of price, quality, delivery time and availability.
Restrictions on disposal of oil/gas	In emergency cases, at the request of Vietnamese Government, PetroVietnam may require Mitra Nam Du by written notice given 30 days in advance to supply Crude Oil from the portion of Net Oil Production entitled by Mitra Nam Du to PetroVietnam to meet the domestic consumption needs.
Recovery of Costs	Mitra Nam Du is entitled to Cost Recovery Oil/Gas up to 50 per cent of the Net Oil/Gas Production in each Quarter. Petroleum Operations Costs shall be recovered from the applicable Cost Recovery Oil/Gas on a first-in-first-out basis. Petroleum Operations Costs which are not recovered in a Quarter may be carried forward to the next succeeding Quarters without interest until fully recovered.

<table>
<tr><th>Type of provision</th><th>Summary</th></tr>
<tr><td>Profit Oil/Gas</td><td>
Profit Oil is to be shared as follows:
<table>
<tr><th rowspan="2">Daily average Net Oil Production in Quarter
(in Barrel per day)</th><th colspan="2">Percentage Share (per cent)</th></tr>
<tr><th>Mitra Nam Du</th><th>PetroVietnam</th></tr>
<tr><td>Up to 20,000</td><td>80 per cent</td><td>20 per cent</td></tr>
<tr><td>Over 20,000 to 50,000</td><td>75 per cent</td><td>25 per cent</td></tr>
<tr><td>Over 50,000 to 75,000</td><td>65 per cent</td><td>35 per cent</td></tr>
<tr><td>Over 75,000 to 100,000</td><td>55 per cent</td><td>45 per cent</td></tr>
<tr><td>Over 100,000 to 150,000</td><td>45 per cent</td><td>55 per cent</td></tr>
<tr><td>Over 150,000</td><td>35 per cent</td><td>65 per cent</td></tr>
</table>
</td></tr>
<tr><td></td><td>
Profit Gas is to be shared as follows:
<table>
<tr><th rowspan="2">Daily average Net Oil Production in Quarter
(in million m^3 per day)</th><th colspan="2">Percentage Share (per cent)</th></tr>
<tr><th>Mitra Nam Du</th><th>PetroVietnam</th></tr>
<tr><td>Up to 5</td><td>80 per cent</td><td>20 per cent</td></tr>
<tr><td>Over 5 to 10</td><td>73 per cent</td><td>27 per cent</td></tr>
<tr><td>Over 10 to 15</td><td>58 per cent</td><td>42 per cent</td></tr>
<tr><td>Over 15 to 20</td><td>53 per cent</td><td>47 per cent</td></tr>
<tr><td>Over 20</td><td>45 per cent</td><td>55 per cent</td></tr>
</table>
</td></tr>
<tr><td>Taxation</td><td>
● Corporate income tax: 32 per cent of its net taxable income;
● Export duty: 10 per cent on Crude Oil and 0 per cent on Natural Gas;
● Value Added Tax: in accordance with VAT laws;
● Royalties (starting at the production phase):
<table>
<tr><th>Net Oil Production by incremental tranches in Contract Area
(in Barrel per day)</th><th>Rate</th></tr>
<tr><td>Up to 20,000</td><td>8 per cent</td></tr>
<tr><td>Over 20,000 to 50,000</td><td>10 per cent</td></tr>
<tr><td>Over 50,000 to 75,000</td><td>12 per cent</td></tr>
<tr><td>Over 75,000 to 100,000</td><td>17 per cent</td></tr>
<tr><td>Over 100,000 to 150,000</td><td>22 per cent</td></tr>
<tr><td>Over 150,000</td><td>27 per cent</td></tr>
</table>
</td></tr>
</table>

<table>
<tr><th>Type of provision</th><th>Summary</th></tr>
<tr><td></td><td>
<table>
<tr><th>Net Gas Production in Contract Area
(in million m^3 per day)</th><th>Rate</th></tr>
<tr><td>Up to 5</td><td>0 per cent</td></tr>
<tr><td>Over 5 to 10</td><td>5 per cent</td></tr>
<tr><td>Over 10</td><td>10 per cent</td></tr>
</table>

If the Vietnamese tax laws provide for more favourable tax rates or treatment for petroleum industry, Mitra Nam Du shall, with the assistance of PetroVietnam, apply for such favourable tax rates and treatment.
</td></tr>
<tr><td>Bonuses and Data Fee</td><td>
● Foreign Party(ies) shall pay to PetroVietnam a signature bonus of USD 500,000 within 30 days after 30 June 2010.
● Foreign Party(ies) shall pay to PetroVietnam USD 2,000,000 within 30 days after declaration of the first Commercial Discovery in the Contract Area.
</td></tr>
<tr><td></td><td>
● Foreign Party(ies) shall pay to PetroVietnam USD 2,000,000 within 30 days after the date of first Commercial Production in the Contract Area.
● Foreign Party(ies) shall pay to PetroVietnam within 30 days after the daily production of Crude Oil from the Contract Area and/or daily sustainable production of Natural Gas for commercial sale from the Contract Area the first averages above the relevant Production Level indicated in the table below for a period of 30 consecutive days:
<table>
<tr><th>Production Level
(Barrels of Oil Equivalent per Day)</th><th>Bonus amount (USD)</th></tr>
<tr><td>Over 25,000</td><td>2,00,000</td></tr>
<tr><td>Over 50,000</td><td>3,00,000</td></tr>
<tr><td>Over 75,000</td><td>4,00,000</td></tr>
<tr><td>Over 100,000</td><td>5,00,000</td></tr>
<tr><td>Over 150,000</td><td>6,00,000</td></tr>
</table>

● Foreign Party(ies) shall pay to PetroVietnam a data fee of USD 100,000 for access to all data and information held by PetroVietnam related to the Contract Area and for right to use such data and information during the term of the Block 46/07 PSC, provided that the ownership of such data and information remains vested in PetroVietnam.
Bonuses and data fee paid to PetroVietnam shall not be considered as recoverable costs.
</td></tr>
<tr><td>Surrender / Relinquishments</td><td>
● Surrender
Mitra Nam Du shall surrender 20 per cent of the initial Contract Area if it elects to enter Phase Two. Mitra Nam Du shall surrender an additional 20 per cent of the initial Contract Area if it elects to enter Phase Three (if applicable). At any time earlier, Mitra Nam Du shall have the right to surrender an acceptable portion of the Contract Area in accordance with the provisions of the Block 46/07 PSC.
</td></tr>
</table>

Type of provision	Summary
	• Relinquishment Without prejudice to the provisions of Articles 2.1.4 and 2.1.5 of the Block 46/07 PSC, before or by the end of the Exploration Period plus any extension, Mitra Nam Du shall relinquish all remaining parts of the Contract Area excluding certain areas as provided in the Block 46/07 PSC (e.g. Development Areas and Suspended Development Areas, etc).
Termination and Abandonment	• Several key events: material breaches, automatic termination if no Commercial Discovery has been made in the Contract Area at the end of the Exploration Period, and other circumstances that do not warrant continuation of the Petroleum Operations as provided in the Block 46/07 PSC. • Cure rights: Where either Party is in material breach of any of its obligations under the Block 46/07 PSC, the other Party may give notice to the Defaulting Party requiring the Defaulting Party to remedy such breach. • Several consequences of termination: Mitra Nam Du shall not be relieved from rights and outstanding obligations that have accrued in the period prior to the relinquishment as well as others continuing rights and obligations as contemplated under the Block 46/07 PSC. If a dispute arises between the PetroVietnam and Mitra Tho Chu as to whether a Party in material breach of any of its obligations under the PSC or whether a Party is entitled to terminate the Block 46/07 PSC, either Party may require that dispute to be submitted for arbitration pursuant to the Block 46/07 PSC. • The Mitra Nam Du shall, upon written request from PetroVietnam, carry out the abandonment of the islands, installations, structures, facilities or wells constructed or drilled for the purposes of the Block 46/07 PSC, whether by way of plugging, demolition, removal, destruction, conversion, placement on temporary or permanent care and maintenance or other bases in conformity with Generally Accepted International Petroleum Industry Practices.
Assignment, and Pre-emption	• Assignment The sale, assignment, transfer, conveyance or otherwise disposal of all or any of each Contractor Party's rights, interests and obligations under the Block 46/07 PSC to its Affiliated Company shall require written notification to PetroVietnam and approval by the Prime Minister. The sale, assignment, transfer, conveyance or otherwise disposal of all or any of each Contractor Party's rights, interests and obligations under the Block 46/07 PSC to third parties shall be subject to the pre-emption right first of PetroVietnam, and then of other Contractor Parties under the joint operating agreement, and approval of the Prime Minister. • PetroVietnam's Pre-emption Right In case of sale, assignment, transfer, conveyance or otherwise disposal of all or any of each Contractor Party's rights, interests and obligations under the Block 46/07 PSC, PetroVietnam has pre-emption right first according to the Petroleum Law.
Stabilisation	The Government and PetroVietnam shall take all steps necessary to ensure that each of the Contractor Parties will enjoy all rights and benefits conferred as at 30 June 2010 during the term of the Block 46/07 PSC.

Type of provision	Summary
	If after 30 June 2010, existing laws and regulations are amended, or annulled or new laws and regulations are introduced in Vietnam, or an official interpretation or application of changes of regulations of a law, or license is cancelled, not renewed, or the conditions therefore are revised adversely affecting the economic interest of Mitra Nam Du and PetroVietnam shall, upon notice from Mitra Nam Du, consult promptly with each other and make such changes to the Block 46/07 PSC as are necessary both to maintain Mitra Nam Du's rights, benefits and interest under the Block 46/07 PSC as at 30 June 2010 and to ensure that any revenues or incomes or profits, including any one or more of the foregoing of Mitra Nam Du, derived or to be derived under the Block 46/07 PSC, shall not in any way be diminished in comparison to that which was originally contemplated as a result of such changes of laws or annulment therefrom or their interpretation or application or as a result of such changes, cancellation or non-renewable of approvals or licenses.
Governing law	Applicable laws: laws and regulations of Vietnam. In the absence of a specific Vietnamese law or regulation governing any matter that may be raised, the relevant provisions of international law or Generally Accepted International Petroleum Industry Practices shall apply, provided that they are not contrary to fundamental principles of Vietnamese laws.
Dispute resolution	Differences and disputes related to or arising under the Block 46/07 PSC shall be first settled through negotiations by the Parties within 90 days of any Party's issuance of notice of a dispute. If such dispute cannot be settled through negotiation, it will be resolved by either an arbitration tribunal in Singapore or Expert determination subject to the nature of the dispute.

2.3 **SC-56 – Philippines**

2.3.1 *Overview*

The Dabakan and Palendag discoveries are located within the boundaries of the SC-56 in the Sandakan Basin, in the Sulu Sea, offshore Philippines, approximately 150 kilometres off the coast of Malaysia, in water depth of approximately 1,802 metres.

2.3.2 *Licence Overview*

Jadestone holds a 25 per cent interest in SC-56 in partnership with operator Total.

In September 2012, Total farmed into SC-56 and assumed a 75 per cent interest, with Jadestone initially remaining as operator. The current exploration period on the block runs until 1 September 2020.

2.3.3 *Geology and sub-surface*

The Dabakan discovery structure is a thrust fault-bound propagation anticlinal fold, located in the anticlinal hanging-wall of a NW-SE trending toe thrust which defines the eastern boundary. The Palendag discovery has a similar structural setting to Dabakan, associated with a separate thrust fault.

2.3.4 *Reserves and Resources*

2.3.5 According to the CPR, as at 31 December 2017, the Dabakan and Palendag discoveries in SC-56 had gross 2C resources of 469.6 Bscf of gas (117.5 Bscf net) and 5.4 MMbbl (1.4 MMbbl net) of oil and condensate. Unrisked prospective resources as at December 31, 2016 were previously estimated by management at 1,849 MMboe.

2.3.6 *Development History*

The Dabakan field was discovered in 2009 by the exploration Well Dabakan-1 in a water depth of 1,802 metres. The Dabakan-1 well was drilled to a total depth of 4,813 mTVDSS. It encountered eight hydrocarbon pay reservoirs (all gas/condensate), all within Late Miocene turbidites deposited in a deep-water setting.

The Palendag field was discovered in 2010 by the exploration Well Palendag-1A in a water depth of 1,937 metres, and sits to the east of Dabakan-1. The Palendag-1A well was drilled to a total depth of 4,724 mTVDSS. It encountered four hydrocarbon pay reservoirs (all gas/condensate), all within a slightly older Late Miocene sequence than in Well Dabakan-1.

Four wells have previously been drilled on SC-56, resulting in the Dabakan and Palendag discoveries.

2.3.7 *Development plan*

In September 2012, Total farmed into SC-56 and assumed a 75 per cent interest, and in August 2014, formally confirmed its intention to drill an exploration well on the Halcon prospect. As a result of the Halcon confirmation, operatorship was transferred to Total effective 25 October 2014. The Company views Halcon as an economically viable prospect with significant resource potential.

Total has subsequently informed Jadestone and the Philippines's Department of Energy that it does not intend to drill an exploration well on the Halcon prospect. In the December 2017 quarter, the Company commenced an arbitration action against Total, with the Singapore International Arbitration Centre, claiming failure by Total to drill the well and resultant damages. Total filed a response to Notice of Arbitration on 17 November 2017 alleging *inter alia* that it had not agreed to drill an exploration well on the Halcon prospect and the Company has subsequently filed a Statement of claim date 12 April 2018. The arbitration process is ongoing.

Further details of the farm-out agreement are set out in paragraph 12.7 of Part 11 of this document and details of the ongoing dispute regarding the Halcon prospect, which Total had committed to drill, are set out in Section 16 of Part 11 of this document. With respect to the arbitration action, the Company has entered into a financing solution agreement with Augusta Ventures Limited, further details of which are set out in paragraph 12.11 of Part 11 of this document.

Total's 2018 work programme for SC-56, as operator, includes a two-phase development study. This includes subsurface geological and geophysical work to revisit resources and development assumptions, to optimise development schemes and minimise technical costs.

2.3.8 *Service Contract*

On 5 August 2005, the Government of the Republic of the Philippines acting through the DOE entered into SC-56 with BHP Billiton Petroleum (International Exploration) Pty Ltd, Amerada Hess (Philippines) Limited, Sandakan Oil II, LLC, and Mitra Philippines (the "**Original Contractors**"). The Secretary of Energy entered into the SC-56 by virtue of a Special Authority dated 1 August 2005 issued by the President of the Philippines to sign, execute and deliver SC-56 on behalf of the Republic.

SC-56 granted to the Original Contractors, the right to undertake Petroleum Operations which, among others, includes the exploration, development, and exploitation of petroleum resources, over a total of 862,000 hectares in the offshore Sandakan Basin, in the Sulu Sea. The area covered by SC-56 has since been reduced to 622,000 hectares or 6,220 square kilometres on 3 October 2014.

Under the SC-56, each Original Contractor originally had a 25 per cent participating interest. Mitra Philippines currently holds a 25 per cent participating interest having acquired a 100 per cent participating interest in SC-56 by 2012 and subsequently assigning and farming-out a 75 per cent participating interest to Total. Details of the assignment agreement and farm-out agreement, each dated 23 August 2012 are set out in paragraph 12.7 of Part 11.

Minimum Work Commitment and Principal Fiscal Terms

Under the terms of SC-56, the Original Contractors shall exert commercially reasonable efforts to perform Exploration Operations within six calendar months from 1 September 2005, (the "**Effective Date**"). The Exploration Operations to be conducted by the Original Contractors are divided into six sub-phases with an aggregate minimum expenditure of US$43,850,000.

At the end of each sub-phase of the exploration period, the contractor shall have the option to: (i) enter the next sub-phase and continue to undertake its obligations; (ii) not enter into the next sub-phase but undertake applicable obligations relating to the designated areas (i.e. production area, appraisal area, moratorium area, gas holding area, petroleum field and any retained exploration area); or (iii) terminate the contract.

In the event Contractor fails to fulfil its work obligations for any exploration sub-phase, the contactor shall pay DOE in USD the cash equivalent of the value of the unfulfilled balance of the work obligations. Failure however to fulfil a sub-phase does not preclude the contractor from entering any subsequent sub-phases or undertaking any other applicable obligations under SC-56. If exploration cost of fulfilled work obligations for a given sub-phase is less than the expected equivalent minimum expenditure, the unspent part shall be deemed as a saving and shall not be paid to the DOE.

Based on the letter of the DOE dated 28 December 2015, the DOE confirmed that all work commitments under sub-phase 7 have been accomplished and completed.

As payment for the assistance, technology, expertise, and financing provided, the Original Contractors are entitled to take in kind each calendar month and separately dispose of: The portion of the monthly sum of petroleum production that is equivalent to all incurred operating expenses and is available for cost recovery purposes, provided that such portion shall not exceed 70 per cent of the monthly sum of petroleum production; 100 per cent of the Filipino Participation Incentive Allowance, if applicable; 40 per cent of the monthly sum of petroleum production that remains after allocations of the same made to offset operating expenses and, if applicable, the Filipino Participation Incentive Allowance; and the DOE shoulders all income taxes for which the Original Contractors is liable for. DOE shall separately pay the income tax of each Contractor and upon payment, shall obtain separate official receipts of taxes so paid in the name of each Contractor.

SC-56 further provides the following payment obligations by Contractor to the DOE: signature bonus of US$50,000 within 60 days from Effective Date; first production bonus of US$300,000 within 60 days from the first date of commencement of commercial production; second production bonus of US$500,000 upon producing 25,000 barrels of oil per day or 250,000,000 cubic feet of natural gas per day; third production bonus of US$1 million upon producing 50,000 barrels of oil per day or 500,000,000 cubic feet of natural gas per day; fourth production bonus of US$2 million upon producing 75,000 barrels of oil per day or 750,000,000 cubic feet of natural gas per day.

Under SC-56, the exploration period is initially for seven years from Effective Date, and extendible for another three years, or until 1 September 2012, extendible up to 1 September 2015. Prior to the end of this exploration period, Mitra Philippines requested for a five year extension, pursuant to the provisions of SC-56. In its letter dated 3 October 2014, the DOE confirmed the extension of the Exploration Period for another five years or until 1 September 2020, to give Mitra Philippines "sufficient time to do additional work to determine the commerciality of the discovering including the exploration of the undrilled prospect portfolio of the block". Where petroleum in commercial quantity is discovered during the exploration period, SC-56 shall continue to be in force and effect in respect of any delineated production area, during the balance of the exploration period, or any extension thereof, and for another production period of 25 years. Thereafter, the production period may be renewed at the contractor's election for a series of five year period, which in aggregate shall in no case exceed a total of 15 years. The total term of SC-56 shall in no case exceed 50 years, including the exploration period and the production period.

SC-56 allows the contractor to seek a moratorium period of five years in the event petroleum is discovered within a delineated petroleum field but the volume of production is deemed insufficient to justify commercial production due to inadequate technology or, in the case of natural gas discovery, the absence of a viable market. During the moratorium period, the corresponding work and expenditure obligations under the contract shall be suspended. contractor shall actively pursue the necessary research to develop and/or identify the technology or markets necessary to produce the discovered petroleum. If by the end of the moratorium period the contractor has not submitted an appraisal work program and neither the technology nor markets have been developed, the contractor shall relinquish the moratorium area without further commitment or obligation under this Contract. The term of SC-56 shall be extended by the applicable moratorium period, but in no case shall the term exceed 50 years.

Work Program and Budget: The work program and budget for a current calendar year, as well as any amendments or revisions thereto, shall be submitted to and approved by the DOE. In the event the DOE withholds approval of the work program and budget, the Contractor may either accept modifications or may dispute the same for settlement by arbitration. The contractor is allowed to incur excess expenditures of no more than 10 per cent per cent of the budgeted amount. The work program and budget for calendar year 2017 for SC-56 amounting to US$1,659,000.00 was approved by the DOE on 4 October 2016. However, in a DOE letter dated 27 June 2017, Total had requested for amendment of the budget for calendar year 2017 ''due to increased expenditures encountered during the Metocean recovery operations'' arising from increased security measures of the survey vessels at and near Block SC-56. The DOE approved the budget amendment amounting to US$2,115,000, including cost for general and administrative expenses and indirect expenditures.

Marketing of Production: The contractor shall have the right to take in kind, market and sell the Government's share of the petroleum produced, together with contractor's participating interest of the contractor's share.

Assets and Equipment: The contractor shall have ownership of all assets, materials, equipment, facilities erected. Cost of utilizing the materials and equipment are charged to the operating cost. Upon termination of SC-56, the DOE shall have ownership of any cost recovered assets, materials, equipment and facilities. Any such materials and equipment that DOE does not elect to retain must be removed and disposed of by the contractor. All data, records, samples and other technical data obtained in the course of performing the petroleum operations shall be vested in the DOE.

Assignment: Provisions on the transfer to affiliates are consistent with the provisions of PD 87. SC-56 further provides that each contractor may assign part or all of its participating interest to any third party, without transfer fee to the Government, provided that such assignment shall be approved in writing by the DOE in advance and provided further that such approval shall not be unreasonably withheld. Any such assignment by a contractor to a third party shall be conditional upon the assignee having delivered to the DOE a guarantee in respect of its obligations and the assignor having been released from that guarantee.

Dispute Resolution and Governing Law: All disputes arising from SC-56 shall be finally and exclusively settled by arbitration in accordance with the Rules of Arbitration of the International Chamber of Commerce then in effect. Venue of arbitration is in the Philippines. SC-56 is governed by Philippine laws.

2.4 Block 127 – Vietnam

Jadestone operates Block 127 with a 100 per cent working interest. The block covers an area of over 9,000 square kilometres and is located at the southern end of the Phu Khanh Basin, off the east coast of Vietnam.

On 16 February 2016, Jadestone requested a further extension to exploration phase one of the PSC in order to complete a farm-out process ahead of committing to exploration drilling in the block. Prime Ministerial approval of the one-year extension was received on 24 May 2016, giving an exploration phase One expiry of 24 May 2017. Despite an unsuccessful farm-out campaign, Jadestone made the decision in Q1 2017 to request a further one-year extension to exploration phase one, with no further material work commitment, in order to continue farm-out efforts, or to relinquish the PSC in May 2018. Approval for this one-year extension to May 2018 was given by the Prime Minister of Vietnam in May 2017. On 4 April 2018, Jadestone gave formal notice to PVN of its intention to relinquish Block 127 at the end of exploration phase one on 25 May 2018 as the prospect identified were not viewed as economically viable in the current market conditions. The relinquishment process is currently on-going and there are no material outstanding work or financial commitments related to the Block.

2.5 Bone – Indonesia

Jadestone, through its subsidiary Mitra Energy (Indonesia Bone) Limited (''**Mitra Indonesia Bone**'') entered into a production sharing contract with Badan Pelaksana Kegiatan Usaha Hulu Minyak dan Gas Bumi (an Indonesian state owned entity) in relation to the Bone Block, Indonesia (the ''**Bone PSC**''). Mitra Indonesia Bone subsequently entered into a joint operating agreement with Azimuth Indonesia Limited (''**Azimuth**'') (the ''**Bone JOA**''). Under the terms of the Bone JOA, Mitra

Indonesia Bone transferred part of its undivided interest in the rights and obligations under the Bone PSC to Azimuth, such that once the Bone JOA came into force, Mitra Indonesia Bone retained a 60 per cent participating interest in the Bone Block and Azimuth Indonesia Limited acquired a 40 per cent interest. The Bone JOA established a regime for implementation of work programmes and budgets on the Bone Block and also established an operating committee to oversee the sharing of production interests in relation to the Bone Block. Mitra Indonesia Bone conducted an environmental baseline study in relation to the Bone Block in accordance with the terms of the Bone PSC, however it was determined following that study that Mitra Indonesia Bone would withdraw from its remaining interest in the Bone Block. Jadestone is currently in the process of withdrawing from and relinquishing its remaining interest in the Bone Block to Azimuth. Further details of the Bone PSC, Bone JOA and the associated withdrawal are detailed in paragraphs 12.27 and 12.28 of Part 11 to this document.

3 FUTURE ASSET OPPORTUNITIES

3.1 Block 05-1b & c – Vietnam

3.1.1 *Overview*

The Dai Nguyet and Sao Vang discoveries are located in the central to west area of Blocks 05-1b and 05-1c ("**Block 05-1b & c**") in the Nam Con Son basin, offshore Vietnam, approximately 350 kilometres south east of Vung Tau City. The blocks cover an area of 1,054 square kilometres with water depths of between 110 and 150 metres.

3.1.2 *Licence Overview*

The PSC for Block 05-1b & c has an overall contract length of 30 years from the effective date of 28 October 2004 with a five-year extension if mutually agreed by all parties and approved by the Vietnamese Government. The PSC initial term of up to seven years is split into three phases with a 20 per cent relinquishment of the block area required at the end of phases one and two.

On 9 August 2016, the Company announced that its wholly-owned subsidiary Mitra Energy (Vietnam 05-1) Pte Ltd. had signed a definitive sale and purchase agreement with Teikoku Oil (Con Con) Co. Ltd. for the acquisition of a 30 per cent working interest in Block 05-1b & c PSC for total cash consideration of US$14.3 million subject to normal closing adjustments. The proposed Block 05-1b & c acquisition was subject to a statutory pre-emption right held by PetroVietnam under Vietnamese law.

On 9 February 2018, PetroVietnam notified Teikoku that it had waived the pre-emption right and directed the parties, on behalf of the Government of Vietnam, to proceed to completion of the Block 05-1b & c Acquisition. Subsequent to that waiver and direction, Teikoku purported to terminate the sale and purchase agreement. The Company does not accept the alleged termination. The Company maintains its rights under the sale and purchase agreement and is assessing its options, including remedies available through legal action.

3.1.3 *Geology and sub-surface*

The reservoirs of the Dai Nguyet ("**DN**") and Sao Vang ("**SV**") discoveries are the Middle Miocene clastics and carbonates of the Thong Mang Cau Formation ("**TMC**") that were deposited in a shallow marine environment. The DN has an additional carbonate reservoir that is part of the same Formation. The TMC Formation is part of the syn-rift to post-rift succession of the Nam Con Son basin. The sediments of the TMC formation consist of interbedded shallow marine sandstones and marine mudstones with occasional thin limestone streaks.

3.1.4 *Development History*

In the DN discovery, gas condensates were first discovered in 2010 with the drilling and well testing of Well DN-1X.

Appraisal drilling of Well DN-2X in 2013 confirmed a potential commercial hydrocarbon accumulation in the discovery's main fault block in the TMC#3, TMC#5, TMC#7 sandstones and the DN Carbonate. The gas condensates have condensate/gas ratios of between 27 and 61 stb/MMscf and oil gravities of between 39 and 44° API. Additionally, the gas phase contains approximately 7 per cent carbon dioxide (CO_2) and levels of hydrogen sulphide (H_2S) measured on test between 7 and 40 parts per million.

In the SV discovery, both gas condensate and light oil were found in 2014 in Well SV-1X and associated side-track Well SV-1XST. The TMC#7, TMC#8, TMC#9, TMC#10, TMC#11 sandstones were found to contain gas condensate with small volumes of oil discovered in the TMC#6 and

TMC#12 reservoirs. The gas condensates have CGRs between 26 and 129 stb/MMscf and oil gravities of between 38 and 42°API. The gas phase contains approximately 5 per cent CO_2 and 6 ppm of H_2S. The oil in the TMC#12 reservoir is a 33° API crude with a gas/oil ratio of 1,650 scf/stb.

3.1.5 *Development plan*

The DN and SV natural gas and condensate discoveries have been fully appraised and are ready for tie-in.

The discoveries are in close proximity to the Nam Con Son gas pipeline which can deliver natural gas to the 3,900 MW Phu My power facility that is generating power to feed the growing needs of the industrial centre of Southeast Vietnam. Jadestone would pay US$9.8 million after the sanction of a project and an additional US$9.8 million upon first production. Management has a proven track record while working at Talisman on projects located directly on offsetting blocks.

A field development plan detailing the development was approved in December 2017. The plan is for phased development of the discoveries through depletion, with initial production from SV commencing in Q3 2019 followed two years later by production from DN. Development consisted of a central processing plant sited over SV with a wellhead platform tied back to the central processing plant. The gas export is planned to be through the NCSP-2 gas pipeline with condensate export to a dedicated leased floating storage and offloading vessel.

Five production wells are planned for the SV discovery with a further four on DN. All wells are to be completed with perforated completions across all zones thus commingling production.

3.2 **SC-57 – Philippines**

3.2.1 *Overview*

In March 2006, PNOC Exploration Corporation entered into a farm-in agreement with Jadestone, which allows Jadestone to obtain a 21 per cent interest in a service contract with the Government of the Republic of the Philippines, in relation to Block SC-57 (‘‘**SC-57 Interest**’’). In consideration for the farm-in, Jadestone agreed to bear 30 per cent of the exploration costs, up to a maximum of US$3 million for the first exploration sub-phase and US$20 million for the second exploration sub-phase, and, where the foregoing caps are exceeded, 21 per cent of such costs. Governmental approval for the farm-in remains outstanding due to Executive Order No. 556 dated 17 June 2006, effectively banning PNOC from entering into farm-in/farm-out agreements with foreign companies, which constitutes a force majeure event under SC-57.

3.2.2 *Service Contract*

On 15 September 2005, the Government of the Republic of the Philippines acting through the DOE entered into SC-57 with PNOC Exploration Corporation (‘‘**PNOC EC**’’). SC-57 granted to PNOC EC, the right to undertake Petroleum Operations which, among others, includes the exploration, development, and exploitation of petroleum resources, over a total of 712,000 hectares or 7,120 square kilometres in the offshore Northwest Palawan.

On 3 March 2006, a farm-in agreement was signed by and between PNOC EC and Jadestone Energy Limited (formerly Mitra Energy Ltd.) (‘‘**JEL**’’) with the latter agreeing to acquire a 21 per cent per cent participating interest. On 3 April 2006, CNOOC International Limited (‘‘**CNOOC INT**’’) farmed into SC-57 agreeing to acquire a 51 per cent per cent participating interest and operatorship. The effectiveness of these farm-in agreements are subject to the approval of the Philippine government, which remains pending to date.

Under section 26 of SC-57, ‘‘Force Majeure’’ refers to events or circumstances that cannot be foreseen, or which, though foreseen, are inevitable, subject to the following conditions: (a) Any failure or delay in the performance of duties or obligations under the SC-57 by either party will be excused to the extent attributable to Force Majeure. In case of delay in operations, all rights and obligations under SC-57 shall be extended for a period equivalent to the period of delay; (b) under section 26.1 (b), the term ‘‘Force Majeure’’ includes Acts of God, unavoidable accidents, acts of war, laws, rules, regulations, and orders issued by the Government, Government agency, strikes, lockouts, or other labour, political, or civil disturbances, hostile acts of hostile forces constituting direct and resinous threat to life and property.

The party who is unable to perform its obligations due to Force Majeure must notify the other party in writing of such fact with reasonable detail as to the cause and nature, and the parties mutually agree what is reasonable within their power to remove such cause.

Only a month after PNOC EC entered into farm-in agreements with JEL and CNOOC INT, then President Gloria Macapagal-Arroyo issued Executive Order No. 556 ("**EO 556**") dated 17 June 2006, effectively banning PNOC from entering into farm-in/farm-out agreements with foreign companies. Section 1 of EO 556 states that there shall be no "farm in" or "farm out" contracts awarded by any Government agency, including the PNOC. Such government agencies must follow strict bidding procedure in forging partnerships with interested parties. Sec. 7 further states that "any and all negotiations or arrangements entered into by any government agency, including the PNOC, which violate this Executive Order, shall be immediately discontinued or cancelled."

Since 2006, PNOC EC's requests for approval of the farm-in agreements have been pending. In a letter dated 12 January 2011, DOE advised PNOC EC that the DOE will again coordinate with the Office of the President on the status and the resolution of the request for approval of PNOC EC's transfer of participating interest to CNOOC INT and JEL. In the same letter, the DOE allowed the force majeure condition under Section 26.1 (b) of the SC-57 to be enforced starting end of Sub-phase 1 (March 15, 2008) until the farm-in agreements are approved by the President.

Set out below is a summary of the key terms of the PSC as amended on 29 December 2005, as they applied prior to the force majeure being declared:

<u>Minimum Work Commitment and Principal Fiscal Terms</u>

Under the terms of SC-57, the Contractor shall begin to perform Exploration Operations within six months from 15 September 2005, the Effective Date of the Contract. The Exploration Operations to be conducted by the Original Contractors are divided into seven sub-phases with an aggregate minimum expenditure of USD 12,700,000.00. Before the end of each sub-phase of the exploration period, except on the seventh sub-phase, the Contractor shall have the option to: (i) enter the next sub-phase and continue exploration; or (ii) conduct only Appraisal Work Program in the Petroleum discoveries awaiting appraisal based on procedures under the Contract and/or Development Operations as approved by the DOE, provided that the minimum obligations during the current exploration sub-phase have been fulfilled and the areas identified to be relinquished under the Contract have been relinquished or (iii) terminate the contract.

In the event Contractor fails to fulfill its work obligations for any exploration sub-phase, the Contactor shall pay DOE in US Dollars the amount it should have spent but did not in direct prosecution of its work obligations. If there are unfulfilled obligations before the end of any sub-phase and the Contractor terminates the Contract, the Contractor shall pay the cash equivalent of the value of the unfulfilled balance of the work obligations for such sub-phase(s). Failure however to fulfill a sub-phase does not preclude the Contractor from entering any subsequent sub-phases or undertaking any other applicable obligations under the Contract. If exploration cost of fulfilled work obligations for a given sub-phase is less than the expected equivalent minimum expenditure, the unspent part shall be deemed as a saving and shall not be paid to the DOE.

SC-57 further provides the following payment obligations by Contractor to the DOE:

(a) signature bonus of U$50,000 within 60 days from Effective Date;

(b) the sum of U$500,000 within 60 days from the first date of commencement of commercial production;

(c) the sum of U$500,000 within 60 days following the end of the 60 day consecutive period of producing 25,000 barrels of oil per day or 250,000,000 cubic feet of natural gas per day;

(d) the sum of U$1,000,000 within 60 days following the end of the 60 day consecutive period of producing 50,000 barrels of oil per day or 500,000,000 cubic feet of natural gas per day; and

(e) the sum of U$2,000,000 within 60 days following the end of the 60 day consecutive period of producing 75,000 barrels of oil per day or 750,000,000 cubic feet of natural gas per day.

<u>Contract Term</u>

Under the SC-57, the exploration period is initially for seven years consisting of seven sub-phases, commencing on 15 September 2005, the Effective Date, and extendible for a maximum of three years. Should the exploration period be extended, such period shall automatically terminate on the last day of extension, unless petroleum is discovered at the end of such extension period. If petroleum is discovered by the end of the original or the extended exploration period, there shall be an additional extension of one year to determine if the petroleum discovered is of commercial quantity.

Where petroleum in commercial quantity is discovered during the exploration period or any extension thereof, SC-57 shall continue to be in force and effect during (i) the balance of the exploration period, or any extension thereof, as the case may be; and (ii) the production period may be renewed for a series of five year periods, which in aggregate shall not exceed a total of 15 years, under such terms and conditions as may be agreed upon by the parties at the time of renewal. In each case provided that the total term of the SC-57 shall in no case exceed 50 years from the Effective Date; and during the Production Period, if the Contractor fails to continue petroleum production for more than one year without the prior approval of the DOE, the DOE may unilaterally terminate SC-57.

SC-57 allows the Contractor to seek a moratorium period of not exceeding three years in the event petroleum is discovered in sufficient quantity but the capability to produce the petroleum in commercial quantity does not yet exist due to inadequate technology. During the moratorium period, the corresponding work and expenditure obligations under the contract shall be suspended. Contractor shall actively pursue the necessary research to develop and/or identify the technology or markets necessary to produce the discovered petroleum in commercial quantity. If during the Moratorium the Contractor and the DOE mutually agree that technology is adequate to produce in commercial quantity the petroleum discovered, then the Contractor has the option to terminate the Moratorium and continue with its obligations under the SC-57 with respect to the Production Area established for the discovered petroleum; or relinquish with finality the said Production Area without further commitment or obligation under SC-57.

Work Program and Budget – Before the end of October of each calendar year, the Contractor shall submit and present to the DOE for review and approval its annual work program and budget for the next calendar year. In the event the DOE requests any modifications on the work program and budget, the parties shall promptly hold meetings to discuss modifications and any modifications mutually agreed by the parties shall be effective immediately. The Contractor must conduct the petroleum operations in accordance with the approved or modified work program and budget. In a letter to the DOE dated 9 May 2008, PNOC EC requested approval to revise the sequence of the work programs of SC-57. The revised work program still includes all the work commitments in the seven sub-phases under SC-57, but the sequence of the commitments is changed such that the G&G studies and the seismic programs are advanced in the first four sub-phases while the three well commitments are reserved for the last three sub-phases of the contract. Further, PNOC EC requested approval for the completed G&G studies to be credited to the second and third sub-phases of the contract. However, in a letter by DOE addressed to PNOC EC dated 13 August 2008, the DOE expressed its preference to retain the sequence of the work programs, and instead cluster the commitments into four sub-phases. As of 13 August 2008, the DOE clarified that the exploration is now in the clustered second sub-phase that includes the conduct of G&G studies, 3D seismic acquisition and drilling of one well which the DOE believes can be completed within a 30-month period.

Marketing of Production: The Contractor shall market the Government share of Petroleum, unless elected otherwise by the DOE. The Contractor shall have the right and privilege to receive in kind and sell the Contractor's portion of the Petroleum produced from the Contract Area.

Assets and Equipment: During the term of SC-57, the Contractor shall acquire and own only such assets and equipment which are reasonably required in carrying out the petroleum operations and approved in the work program. Cost of utilizing the materials and equipment are charged to the operating cost. Upon termination of the Contract, the DOE shall have ownership of any cost recovered assets, materials, equipment and facilities which it elects to retain. Any such materials and equipment that DOE does not elect to retain must be removed and disposed of by the Contractor within one year after termination of the Contract or within the period agreed by the DOE and the Contractor. All data, records, samples and other technical data obtained in the course of performing the petroleum operations shall be vested in the DOE.

Assignment: Provisions on the transfer to affiliates are consistent with the provisions of PD 87. SC-57 further provides that the Contractor may assign part or all of rights and/or obligations to any third party, provided that such assignment shall be approved in writing by the DOE in advance and provided further that such approval shall not be unreasonably withheld.

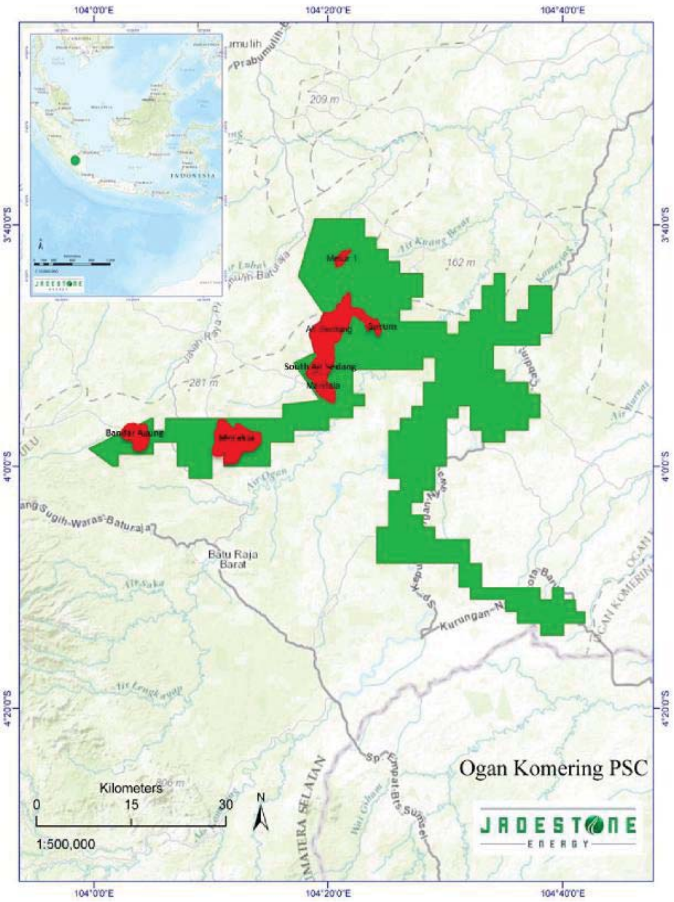
Dispute resolution and Governing Law: All disputes arising from the Contract shall be finally and exclusively settled by arbitration in accordance with the Rules of Arbitration of the International Chamber of Commerce then in effect. Venue of arbitration is in the Philippines. SC-57 is governed by Philippine laws.

3.3 **Ogan Komering – Indonesia**

3.3.1 *Overview*

The 1,155 square kilometres Ogan Komering PSC is located onshore South Sumatra, Indonesia. This area benefits from extensive infrastructure and growing local energy demands and is one in which Jadestone's Management has significant operating experience, technical knowledge and strong relationships with local government bodies.

Location of Ogan Komering



Source: Jadestone Energy Inc.

3.3.2 *Licence Overview*

Jadestone acquired a 50 per cent non-operated working interest in the Ogan Komering PSC, a heritage Talisman asset, from Repsol in March 2017.

The Ogan Komering PSC expired on 28 February 2018. Jadestone and PT Pertamina entered into a settlement agreement on 18 May 2018, pursuant to which the parties have agreed to work towards a final settlement of costs in relation to the expired PSC, associated joint venture agreement and the temporary cooperation agreement which the parties entered into in order to maintain operations at the Ogan Komering oil field. Further details of this settlement agreement are set out in paragraph 12.26 of Part 11 of this document.

A new gross split PSC for Ogan Komering, effective 20 May 2018, was signed by Pertamina, Indonesia's upstream regulator SKKMIGAS, and the Minister of Energy and Mineral Resources, awarding a 100 per cent participating interest to Pertamina. Jadestone, as the prior partner in the PSC with Pertamina, has been directed to proceed with direct negotiations for participation in the new PSC with Pertamina. Jadestone is progressing its discussions with Pertamina for participation in the new gross split PSC and, based on current negotiations, the Board expects to reach satisfactory binding terms during Q4 2018, with participation to be effective from the commencement of the new PSC on 20 May 2018. To the extent Jadestone participates in the PSC, it will not be the operator of Ogan Komering and it would have less than a 40 per cent interest in the PSC.

Jadestone's management has a well-established close relationship with PT Pertamina and are working cooperatively with PT Pertamina on the possibility of Jadestone's future participation in the PSC after the licence's expiry in February 2018 and the temporary cooperation contract which expired in May 2018 following the grant of the new gross split PSC to PT Pertamina.

Until definitive documentation is entered into, there can be no assurance that Jadestone will be successful in its negotiations for participation in the PSC or the terms on which any such participation may be available to Jadestone.

3.3.3 *Ogan Komering Acquisition*

At closing in March 2017, Jadestone paid net cash consideration of approximately US$1.65 million for the transaction (after working capital and other adjustments from the purchase price of US$5.8 million with effective date of 1 August 2016). This post-adjustment cash consideration was paid-out in August 2017, only five months after closing the acquisition. The acquisition of Ogan Komering provided the platform for Jadestone management to further strengthen relationships with PT Pertamina and the Indonesian oil and gas regulators MIGAS and SKKMIGAS. As part of the transaction, Jadestone also acquired an experienced team of employees, many with existing relationships with Jadestone management when in Talisman.

3.3.4 *Geology and sub-surface*

The block is productive in the Guruh, Air Serdang, Suth Air Serdang, and Mandala Fields out of the Batu Raja Formation carbonates and the deeper Talang Akar Formation clastics.

Batu Raja reservoirs are composed of Early Miocene platformal, bank and reef carbonates interbedded with calcareous shales and marls. Large platform carbonates form the base, on which reefal and detrital banks have developed. Calcareous shales and marl form intraformational seals and marine shales of the Gumai Formation form a semi-regional seal above and lateral to Batu Raja reservoirs. Structural-stratigraphic traps are the most common form of Batu Raja play, and consist of reefal or carbonate bank buildups formed on basement highs, and typically associated with anticlinal structures.

Reservoirs in the Pre-Tertiary Basement play consist of combinations of intrusive and metamorphic lithology, with the age ranging from Permian to Cretaceous. The porosity is controlled by fractures, derived from several phases of tectonism and hydrothermal events have resulted in a high porosity zone. Seals are provided by Lahat and Talang Akar shales and the trap is formed from pre-Tertiary faults and a series of Paleogene and Neogene structures generating structural traps.

3.3.5 *Reserves*

Jadestone will seek an independent reserves evaluation for the Ogan Komering PSC upon, and subject to, confirmation of the Company's participation in the new OPSC, expected later this year.

3.3.6 *Development history*

Drilling on Ogan Komering dates back to the 1930s, however no commercial discoveries were made until 1989 when 1,525 kilometres of 2D seismic was shot and the Air Serdang and Mandala fields were discovered. In 1991, 557 kilometres of 2D seismic was shot and a wildcat well drilled on the Guruh prospect, two kilometres east of Air Serdang, tested 30° API oil with gas. In May 1992, a successful appraisal well was drilled on the Guruh field.

In early-1995, a development well on the Air Serdang structure encountered a new, deeper horizon in the Talang Akar Formation which is stratigraphically trapped on the southern flank of Air Serdang. The structure tested 32° API oil at 4 mbbl/d and was brought into production in 1995.

In 1996, 150 kilometres of 2D seismic was acquired over the Metur area. The Metur-1 well, drilled eight kilometres north of the Air Serdang field, successfully tested at 3.3 MMcf/d of gas and 211 bbl/d of condensate over a 24 metre interval from the Talang Akar Formation.

In March 2008, the Metur-3 well was spudded in order to test the western boundaries of the field and was then suspended. The BDA-1 well was drilled in Q1 2014 and tested gas and condensate from several intervals, including granitic basement reservoir rock which was followed by the Jantung Baru-1 and North Meraksa-1X wells drilled in 2015.

The next early development work will be focused mainly on recent gas discoveries in Miocene structure and the Plio-Pleistocene structure in the west.

3.3.7 *Infrastructure and export solution*

Stabilised crude is transported 17 kilometres southwest from the central field facilities, via a Pertamina-operated pipeline, to the Kuang field, which is then fed into the existing Pertamina pipeline network and transported to the Plaju refinery. The eight-inch pipeline has a capacity of 18 to 20 mbbl/d with the use of drag-reducing chemicals.

As part of the gas development plans, a six-inch gas pipeline was built in 2001 from Mandala to Air Serdang. Gas is compressed at Air Serdang and then routed via an eight-inch pipeline to the Beringin station and then to Limau Timur via a 10-inch pipeline, where CO_2 is removed and LPG extracted before being piped to the fertiliser plant at Plaju.

3.3.8 *Production*

Jadestone's net 50 per cent working interest share of production from the Ogan Komering PSC, held up until 20 May 2018, averaged approximately 1,500 boe/d and is weighted approximately 66 per cent oil and 33 per cent gas.

The production rate of the block in the three months ended 31 March 2018 averaged 1,447 boe/d net to Jadestone (three months ended 31 December 2017: 1,413 boe/d net to Jadestone), with a gas-to-oil ratio of approximately 65 per cent oil and 35 per cent gas.

All Ogan Komering gas production was sold to the domestic buyers; Pusri Fertilizer Plant and Pertagas/AAK.

The historical realised gas contract price for Pusri fertilizer plant was US$5.94 MMbtu flat which aligns with the Ministerial Energy and Mineral Resource regulation no. 40/2016. For Pertagas/AAK, the gas was sold at US$8.27 MMbtu when Jadestone entered into the now expired Ogan Komering PSC in March 2017 and escalated at 3 per cent in 2018 at US$8.52 MMbtu. It is expected that all future gas production under the new Ogan Komering gross split PSC, effective 20 May 2018, will be supplied and sold to Pusri Fertilizer plant at US$5.94 MMbtu flat, which aligns with the Ministerial Energy and Mineral Resource regulation no. 40/2016.

Oil produced from Ogan Komering is sold and transported by pipeline to the local Pertamina operated Plaju refinery in Sumatera at an average realised price of Dated Brent minus US$5.10/bbl (for the period March 2017 to May 2018) compared to Jadestone's corporate assumption of Dated Brent minus US$5.50/bbl. Regarding future oil production, the corporate assumption for the Ogan Komering oil price will remain unchanged at Dated Brent minus US$5.50/bbl.

Part 4

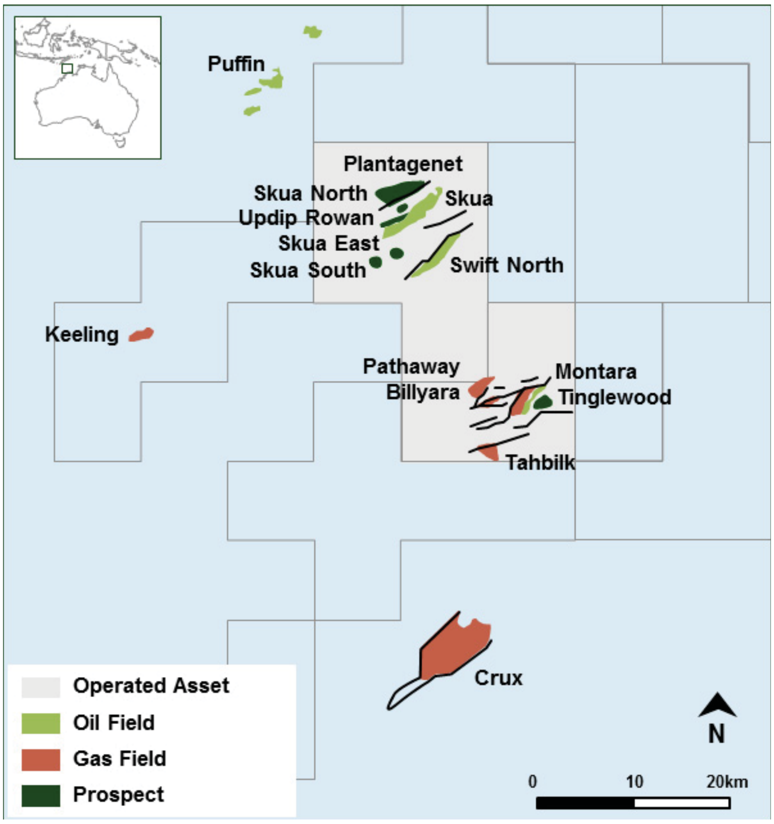
MONTARA ASSETS AND THE MONTARA ACQUISITION

1 MONTARA ASSETS OVERVIEW

1.1.1 *Overview*

The Montara project is located in Production Licences AC/L7 and AC/L8 in the Timor Sea, approximately 690 kilometres west of Darwin, 630 kilometres north of Broome and 250 kilometres north-west from the Kimberley coastline of Western Australia in a water depth of 77 meters. The Montara fields are situated in the prolific Vulcan Sub-basin.

Location of Montara Development



The FPSO has an operational storage capacity of 900,000 barrels and accommodation space for 58 people. The FPSO is moored in the Montara field for the life of the project.

1.1.2 *Ownership & Regulatory Environment*

The Montara Assets are 100 per cent operated and owned by PTTEP Australasia, a wholly owned subsidiary of PTTEP, the upstream arm of Thailand's national oil company. The Montara Assets represents PTTEP's only currently producing field in Australia. The field has generated significant PRRT tax credits (AUD$3.7 billion) under PTTEP which will be transferred under the asset sale. The Company does not anticipate that it will have to pay PRRT over the current projected life of the Montara Assets. The Company will, however, remain liable for Australian corporate tax which is currently charged at the rate of 30 per cent.

PTTEP currently hold the Safety Case, Environment Plan and WOMPs required under Australian legislation.

Montara Incident

On 21 August 2009, a blowout in Well Montara-H1ST1 resulted in an uncontrolled flow of hydrocarbons into the sea that continued for 74 days to 3 November 2009. The cause of the blowout was most likely that hydrocarbons entered Well Montara-H1ST1 through the 9 5/8'' cemented casing and flowed up the inside of the 9 5/8'' casing. The Montara Commission of Inquiry found that at the time Well Montara H1ST1 was suspended, not one well control barrier complied with PTTEP Australasia's own Well Construction Standards. The casing shoe had not been pressure-tested, despite a troublesome cement job, and it is likely that the cement in the shoe had been compromised as it had been over-displaced by fluid, resulting in a 'wet shoe'. Furthermore, although two secondary well control barriers (pressure containing anti-corrosion caps) were due to be installed, only one was installed and it was not tested and verified in-situ as required by the Well Construction Standards.

The Montara Commission of Inquiry deemed that PTTEP Australasia did not observe sensible oilfield practices in the Montara field, and that for this reason the Northern Territory Department of Resources should not have approved the Phase 1B Drilling Programme that commenced in July 2009.

After several proposed solutions including water deluge and surface capping, the blowout was eventually arrested by the drilling of a gas relief well, Montara-H1ST1-RW1. The design and execution of the relief well was regulated by the Northern Territory Department of Resources. The relief well intersected Well Montara-H1ST1 on 1 November 2009 and pumped heavy mud into the well. On 3 November 2009 the flow of hydrocarbons was completely stopped. The relief well later injected 320 barrels of cement into Well Montara-H1ST1 and on 13 January 2010, PTTEP Australasia reported that operations to plug and secure the well were complete.

1.1.3 *Geology and subsurface*

Producing sandstone formations include prolific Plover, Montara and Lower Vulcan formations. All producing formations have high permeability (0.5 – 4 Darcy) and high porosity (18 – 24 per cent).

Production commenced in June 2013 and approximately 23.1 MMbbls have been produced to 31 December 2017. Successful completion of an additional producing well Montara H5-ST2 occurred in October 2017, increasing field production by 3,500 bbl/d. The asset is currently producing 10.3 mbbls/d from six wells in three fields with three further subsea wells expected back online in Q4 2018. The Montara crude is a high quality, light, low-sulphur crude with a 35.5° API, selling at a premium to Brent into Thailand refineries. Gas produced from the field is reinjected via a dedicated injection well to maintain reservoir pressure and maximise oil recovery from the reservoir. A future blow-down of the gas cap could potentially generate longer dated revenue streams and maximise asset utilisation.

Jadestone has identified numerous infill drilling candidates as well as near-field exploration opportunities that may be exploited by the Company to maximise value from the asset.

1.1.4 *Facilities*

The Montara operations involve the extraction of oil using four platform production wells and one gas injector for the Montara field and five subsea production wells for Swift, Skua and Swallow fields. The oil from the subsea wells transported via subsea flowlines to an unmanned wellhead platform and then to the FPSO facility which acts as a hub for the Montara cluster and potentially additional stranded discoveries in the region.

The offshore facilities consist of an unmanned platform (from which the Montara field wells were drilled and are accessed) with eight slots for wells (three horizontal, three tie-backs, one injector and one spare) as well as a manned FPSO facility. The subsea wells from Skua, Swift and Swallow fields as well as the Montara field platform wells all produce to the FPSO where the oil is processed, residual gas is separated and compressed to be reinjected into the Montara field.

The Montara Venture FPSO has been converted from the 140,450 deadweight tonne oil tanker MT Freeway in Jurong Shipyard, Singapore. The conversion was completed in 2009. As part of the conversion the engine, propeller and shaft were removed, the FPSO has therefore essentially been converted to a barge. The conversion also included the installation of an internal submerged turret, production and processing facilities for crude separation, gas compression, gas lift and gas reinjection giving the FPSO an oil production capacity of 40 mbbl/d with a storage capacity of 900,000 bbls.

In addition to the FPSO the Montara development includes a 4-level, 750 tonne well head platform which can fit five production wells and one gas-injection well. Normal cargo liftings taken from the FPSO are circa 550,000 bbl oil. The processing capacity of the FPSO is 40 mbbls/d of oil and 60 mbbls/d of water, where the gas processing system can dehydrate using a glycol contactor process up to 60 MMscf/d, and can reinject up to 50 MMscf/d of gas while also providing gas lift for the oil wells.

The FPSO also has gas processing and compression facilities, enabling the operator to both reinject produced gas back into the field to maintain reservoir pressure and also provide gas lift for all wells.

The FPSO is subject to continuous hull survey, which includes surveys of the cargo and ballast tanks on a five year cycle in order to maintain vessel classification. PTTEP were advised in September 2017 that class would be suspended due to failure to complete hull surveys in the required time. PTTEP was unable to start tank surveys in 2017 and as such Lloyd's Register suspended Class on the vessel on 3 January 2018. An inspection was undertaken on 23 March 2018, following which Lloyd's confirmed that the suspension of Class would be maintained. A work programme has been identified which, once complete, will enable the reinstatement of vessel class. Following the presentation of a detailed plan for completion of the outstanding work scope to Lloyd's on 30 June 2018, Lloyd's, on 2 July 2018, confirmed its agreement of the plan to return the FPSO to Class.

1.1.5 *Reserves and Production*

The Montara assets have gross 2P reserves of 28.2 MMbbls oil (gross and net) and 3P reserves of 38.5 MMbbls oil (gross and net), split as follows between the fields:

- the Montara field, located in production licence AC/L7 has 14.9 MMbbls of gross and net 2P reserves;
- the Skua field, located in production licence AC/L8 has 6.9 MMbbls of gross and net 2P reserves; and
- the Swift/Swallow field, located in production licence AC/L8 has 6.4 MMbbls of gross and net 2P reserves.

1.1.6 *Montara Field*

The Montara field was discovered in 1988 by the Montara-1 well, drilled by BHP Biliton. The field produces from the Upper Jurassic Cycle IV reservoir, which is of excellent quality. In 2009, prior to the commencement of production at the field, there was a blow-out at Well H1.

The field commenced production in June 2013 from three horizontal oil producers, with each well initially producing at rates between 3 and 4 mbbls/d.

In June 2016 the current operator began re-injecting gas into the gas cap through the well Montara G-2, to maintain reservoir pressure. As at 31 December 2017 the well was injecting at an average rate of 10 MMscf/d.

In October 2017, an additional horizontal well, Montara-H5, was brought onstream at an oil rate of 3.5 mbbls/d. The well targets unswept volumes in the southwest of the field.

Current production for the Montara field is 10.3 mbbls/d.

Jadestone is proposing to drill an additional horizontal production well (H6) along the western boundary fault targeting oil north of H5. This infill well will use the one remaining slot on the Montara platform.

A historic charge in relation to the Montara Assets was discharged and has been notified to the Australian Securities and Investments Commission, but has not yet been removed from the National Electronic Approvals Tracking System (NEATS) registry. The underlying charge is no longer valid and is in the process of being removed from the NEATS registry.

1.1.7 *Skua*

Although a thin oil column was intersected in Well Skua-2 in 1985, the main accumulation was not discovered until 1987 by Well Skua-3. A further 5 wells were drilled to December 1991 (Skua-4, -7A, -8, -9 and -9ST1), when the first phase of Skua production commenced.

The Skua field comprises a 48 metre oil column overlain by a small gas column of approximately 10 metres. Hydrocarbons are contained within the Early to Middle Jurassic Plover Formation, the quality of which is excellent.

First production from the Skua field came in December 1991 from three producers, Wells Skua-4, -8 and -9ST1. The field initially produced at approximately 25 mbbls/d, eventually declining to 2.4 mbbls/d. After producing 20.2 MMbbls/d, the field was shut-in in January 1997 due to it being uncommercial. Through this first development stage, the wells were connected to a dedicated FPSO.

In 2011, the then operator produced a field development plan with the intention of bringing the field back onstream, with higher oil prices making the project economic. In March 2014, the field was brought back onstream through two new horizontal wells, Skua-10ST2 and Skua-11, which achieved initial rates of approximately 4 mbbls/d and 2.5 mbbls/d respectively. The field is now produced through the Montara field infrastructure.

Current production for the Skua field is 1.7 mbbl/d through Skua-10ST2 with Skua-11 expected back online at 2.5 mbbl/d in Q4 of 2018.

Jadestone is proposing to drill an additional horizontal production well (Skua-12) on the field's crest in between the Skua-10ST2 and Skua-11 wells. The well will be tied into the existing subsea infrastructure. The Skua-12 well will have a horizontal well section of approximately 650 metres and target unswept oil between the two currently producing wells.

1.1.8 *Swift/Swallow*

The Swift field was discovered in January 1985 by Well Swift-1. The well targeted the Plover Formation but found it to be water bearing. However, excellent hydrocarbon shows were found in an unexpected Rowan sandstone.

A total of four wells have been drilled on the Swift and Swallow fields. This includes one exploration well and three vertical production wells. The Swift field has two production wells, Swift-2 and Swift North-1. The Swift-2 well has had issues with gas lifting and the well is currently shut-in. The Swallow field has a single production well, Swallow-1. The well was completed close to the oil-water contact and water breakthrough occurred very early, with rapid water cut development. The well has been shut-in since April 2016 with plans to add perforation in shallower oil bearing sands.

First production from the Swift field came in October 2013 from Wells Swift-2 and Swallow-1, with Well Swift North-1 later commencing production in April 2014. The field is produced through the Montara field infrastructure.

Current production for the Swift/Swallow field is 3 mbbl/d through Swift N-1 with Swift-2 and Swallow-1 is expected to be back in Q4 of 2018, adding a combined 3 mbbl/d.

1.1.9 *Future development*

There is significant upside associated with the Montara Assets, with ERCE's 3P reserves case including an additional 10.2 MMbbls (gross and net) and an NPV10 uplift of US$313.3 million versus the 2P reserves case. Furthermore, Jadestone has identified several different areas in which it believes it can potentially realise value in the future. Such areas are not included in ERCE's reserves case and include:

- further infill drilling, not included in ERCE's reserves case, have been identified by Jadestone management in the Montara and Skua fields. This includes one further platform well on the Montara field which would be a sidetrack of H4, capturing remaining volume along the northern bounding fault, and two further subsea wells on Skua capturing volumes further north along the crest. Each of these wells would have an initial rate of 3 mbbl/d and targeting a combined rate of 5.3 mbbl/d;
- tie-back additional existing in-field and near-field discoveries as facilities become available, currently the well head facilities are either fully utilised or allocated to existing and near-term production;
- spare capacity in the FPSO means discoveries can be monetised quickly;
- the Company has identified further prospects in the blocks and intends to shoot 3D seismic surveys over the blocks. This is expected to help to further define the existing prospects and identify further prospects across the blocks which the Company may target in the future;
- in the blocks neighbouring the Montara Assets there are multiple oil and gas discoveries and previously suspended fields. Many of these discoveries are currently stranded as they are not of a size that can economically justify a standalone development Currently the Montara Assets infrastructure is the only infrastructure in the area through which these discoveries could potentially be produced. The Company may in the future explore opportunities to monetise these assets which may be through acquisition, farm-in or third party tariff arrangements; and

- within the Company's blocks, there are currently stranded discovered gas resources which are currently not of a size which would make commercialisation economic. However, within neighbouring blocks there are also other similarly stranded gas discoveries and the Company could in the future explore joint development solutions for these discoveries. This will, however, remain subject to pricing, technology and neighbouring activities.

For an overview of the oil and gas industry in Western Australia, see Part 2 of this Document.

2 MONTARA LICENCE

2.1 Production licence AC/L7

The Production licence AC/L7 (granted on 20 March 2007) ("**AC/L7**") relates to an active oil resource located offshore Western Australia. This licence is for an indefinite term. The grant of AC/L7 is subject to OPGGS Act and the following conditions:

(a) the licensee shall not construct any installation or install any equipment in the licence area except with and in accordance with the approval in writing of the Commonwealth – Western Australia Offshore Petroleum Joint Authority ("**Joint Authority**");

(b) the licensee shall not abandon, suspend or complete any well except with and in accordance with the approval of the Joint Authority;

(c) the licensee shall at all times comply with the provisions of the OPGGS Act and of any regulations for the time being in force under the OPGGS Act, including any directions given thereunder;

(d) in carrying out its operations in the licence area the licensee must take adequate measures for the protection of the environment; and

(e) the licensee must, to the satisfaction of the Joint Authority, continue to appraise and explore the licence area to determine whether additional recoverable petroleum exists in the area and shall exploit such petroleum where economic.

2.2 Production licence AC/L8

The Production licence AC/L8 (dated 9 August 2007) ("**AC/L8**") relates to an active oil resource located offshore Western Australia. This licence is for an indefinite term. The grant of AC/L8 is subject to the OPGGS Act and the following conditions:

(a) the licensee shall not construct any installation or install any equipment in the licence area except with and in accordance with the approval in writing of the Commonwealth – Western Australia Offshore Petroleum Joint Authority ("**Joint Authority**");

(b) the licensee shall not abandon, suspend or complete any well except with and in accordance with the approval of the Joint Authority;

(c) the licensee shall at all times comply with the provisions of the OPGGS Act and of any regulations for the time being in force under the OPGGS Act, including any directions given thereunder;

(d) in carrying out its operations in the licence area the licensee must take adequate measures for the protection of the environment; and

(e) the licensee must, to the satisfaction of the Joint Authority, continue to appraise and explore the licence area to determine whether additional recoverable petroleum exists in the area and shall exploit such petroleum where economic.

3 MONTARA ACQUISITION

3.1 Acquisition Agreement

On 15 July 2018, Jadestone Energy (Eagle) Pty Ltd, a wholly-owned subsidiary of the Company, (as buyer) (the "**Buyer**") entered into an acquisition agreement (the "**Acquisition Agreement**") with, amongst others, the Company (as guarantor) and PTTEP Australasia (as seller) (the "**Seller**"). Under the terms of Acquisition Agreement, the Seller has agreed to sell certain assets, comprising the key equipment, facilities and reserves necessary for the proper operation of the Montara oil site, the Montara Assets for a purchase price of US$195 million, subject to working capital adjustments and additional contingent amounts. The Company, being the ultimate holding company of the Buyer, shall guarantee the obligations of the Buyer under the Acquisition Agreement. PTTEP Offshore Investment Company Limited, an affiliate of the Seller, shall guarantee the obligations of the Seller under the Acquisition Agreement.

On completion ("**Completion**") of the Acquisition Agreement, the Seller shall sell and the Buyer shall buy:

(a) a 99 per cent legal and 100 per cent beneficial right, title and interest in the production licences AC/L7 and AC/L8 (the "**Montara Titles**"); and

(b) a 100 per cent legal and beneficial interest in the Montara Assets (excluding the Montara Titles),

(the "**Stage One Assets**").

The remaining 1 per cent interest in the Montara Titles (the "**Stage Two Asset**") shall be held on trust by the Seller, in favour of the Buyer, until the satisfaction of the Stage Two Conditions (defined and described below). The minimum consideration attributable to the Stage One Assets (the "**Purchase Price**") shall be paid by the Buyer to the Seller on Completion. The amount of the Purchase Price is the aggregate of:

(a) the agreed purchase price for each Stage One Asset (the "**Asset Purchase Price**"); plus

(b) the value of the crude oil inventory stored at the Montara site; plus

(c) the agreed capital charge (being the amount of accrued interest (calculated on a daily basis at a rate of 3 per cent above LIBOR) from and including 1 January 2018 (the "**Effective Date**") to, but excluding the date of, Completion, on the Asset Purchase Price)); plus

(d) the amount as specified in the first cash call pursuant to the OTSA (defined in paragraph 3.2 of Part 4) to be entered into in parallel with the Acquisition Agreement between the Buyer and the Seller,

and shall be subject to an upward or downward adjustment attributable to the amount of income receipts received by the Seller, less the operating expenses paid by the Seller in relation to the Montara site, for the period between the Effective Date and Completion.

The Purchase Price shall be subject to further increases, on the occurrence of certain of the following trigger events (the "**Trigger Events**"):

Consideration		**Trigger Event**
(a)	US$5 million	Montara 2018 Production is equal to or greater than 3.55MMbbls but less than 3.75MMbbls.
(b)	US$10 million	Montara 2018 Production is equal to or greater than 3.75MMbbls but less than 3.95MMbbls.
(c)	US$15 million	Montara 2018 Production is equal to or greater than 3.95MMbbls but less than 4.15MMbbls.
(d)	US$20 million	Montara 2018 Production is equal to or greater than 4.15MMbbls but less than 4.35MMbbls.
(e)	US$25 million	Montara 2018 Production is equal to or greater than 4.35MMbbls but less than 4.55MMbbls.
(f)	US$30 million	Montara 2018 Production is equal to or greater than 4.55MMbbls.
(g)	US$20 million	The Average Dated Brent Price in calendar year 2019 is US$80/bbl or higher.
(h)	US$10 million	The Average Dated Brent Price in calendar year 2020 is US$80/bbl or higher.
(i)	US$20 million	Total quantity of hydrocarbons produced from the Montara infill well during the first 12 month period following first commercial production (being sustained production for sale and not for testing or commissioning) from the Montara infill well is equal to or greater than 1.5 MMbbl.
(j)	US$20 million	First commercial gas.

Consideration		Trigger Event
(k)	US$60 million	Any final investment decision to approve a project development plan or development work plan and budget or similar or analogous decision to proceed with development or developments of the Montara Assets where such development or developments have 2P reserves greater than 15.0 MMbbls.

In the table above "**Average Dated Brent Price**" for a particular year is calculated in accordance with the formula A/B, where:

A means the sum of the average of the high and low 'Dated Brent' quotations (data code PCAAS00) as published on 'Platts Sarus' for each day on which the Dated Brent quotation is published; and

B means the number of published days in that calendar year.

The Purchase Price shall be subject to further upward or downward adjustment following the agreement between the Buyer and the Seller of the completion statement.

Completion of the Acquisition Agreement shall be conditional on the following events occurring (the "**Conditions**"):

(a) the dealings evidenced by the ASA and the operator services agreement between the Buyer and the Seller being approved and registered under the Offshore Petroleum and Greenhouse Gas Storage Act 2006 ("**OPGGSA**") against each of the Montara Titles; and

(b) the Buyer receiving approval under the Foreign Acquisitions and Takeovers Act 1975 and the Buyer receiving TSX-V approval under the OPGGSA.

The Seller shall transfer the Stage Two Asset following the occurrence of the following events (the "**Stage Two Conditions**"):

(a) the removal of the Seller as titleholder to the Montara Titles;

(b) the removal of the Seller from the operator register in relation to the Montara site;

(c) the consent of the Commonwealth Minister for the Environment and Energy in relation to the transfer of the Seller's Environmental Approval (defined in the ASA as the approval granted to and held by the Seller under the Environmental and Biodiversity Conservation Act 1999 on 3 September 2003); and

(d) the Seller ceasing to hold safety and environmental operational and management plans in relation to the Montara site,

each of which will become effective on the same date.

The Acquisition Agreement contains customary warranties in relation to capacity and ownership of each of the Montara Assets. In addition there are also customary warranties in relation to the conduct of business of the Seller, compliance with laws and that all material contracts to the operation of the Montara site have been disclosed to the Buyer. The Acquisition Agreement contains an indemnity from the Seller in relation to any latent liabilities incurred or suffered by the Buyer as a result of the major oil and gas leakages which occurred at the Montara site in 2009 (the "**Montara Incident Indemnity**").

The Acquisition Agreement also contains customary limitations on the Seller's liability under the Acquisition Agreement including matters reviewed by the Buyer as part of its due diligence investigations, time limits and financial limitations. The maximum aggregate cap on the Seller's liability for a breach of any of the warranties relating to the ownership of the Montara Assets is up to 100 per cent of the Purchase Price and in the case of a breach by the Seller of any of the other warranties in the Acquisition Agreement (including tax warranties, but excluding the Montara Incident Indemnity) shall be up to 30 per cent of the Purchase Price.

The Acquisition Agreement is governed by the laws of Western Australia.

The Buyer structured the transaction so as to receive the economic benefit of the acquisition as soon as possible. In the interim period pending Jadestone's approval as operator, the Buyer has, through the placement of secondees and other rights under the OTSA (defined in paragraph 3.2 below) the ability to influence significant decisions.

Details of the RBL Facility Agreement, the Placing Agreement and the Subscription Agreements which will be used to fund the Acquisition are set out in paragraphs 12.1, 12.3 and 12.4 of Part 11 of this document respectively.

3.2 **Operator and Transitional Services Agreement**

The Buyer and the Seller (as operator and transitional services provider) have entered into an operator and transitional services agreement (the "**OTSA**") to govern the operation and management of the Montara Assets and the provision of transitional services in the period from Completion (as defined in the Acquisition Agreement). The term of the OTSA shall run until the later of:

(a) the Operator Transfer Date (as defined in the Acquisition Agreement); and

(b) a date to be agreed between the parties.

Under the OTSA, the Seller is responsible for the day-to-day operations required to run the Montara site (the "**Operations**"). The Seller shall perform the Operations with due care and skill, in compliance with all applicable laws and in accordance the approved program and budget (set out in Schedule 3 to the TSA) for the Montara site. Under the OTSA, the Seller shall, before the tenth day of each month, submit an invoice to the Buyer for an amount equal to the Seller's estimate of the aggregate cash requirement for the next ensuing month (each occurrence, being a "**Cash Call**") in order to perform the Operations. Following a Cash Call, the Buyer shall pay the amount of the Cash Call to the Seller by no later than the last business day of the month prior to which the Cash Call relates.

The amount of the first Cash Call shall be dependent on the completion of the Acquisition Agreement. If completion of the Acquisition Agreement occurs before the tenth day of a calendar month, the amount of the first Cash Call, shall be the Seller's estimate of the aggregate cash requirement for the remainder of that month. If completion of the Acquisition Agreement occurs on or after the tenth day of a calendar month, the amount of the first Cash Call shall be the Seller's estimate of the aggregate cash requirement for the remainder of that month, plus the whole of the following calendar month.

In addition to the Operations, the Seller will also provide contract procurement and novation services and network, telecoms and general infrastructure consulting services to the Buyer (the "**Transitional Services**"). The Seller shall provide the Transitional Services with due care and skill, in compliance with all applicable laws and in accordance with the transition plan for the Montara site.

Each party to the OTSA shall have the ability to appoint four representatives to the transition committee, which shall be established by the parties pursuant to the terms of the Acquisition Agreement, to manage the delivery of the Transitional Services.

The OTSA contains customary warranties given by both parties in relation to performance of their obligations under the OTSA. The OTSA contains an indemnity from the Buyer in favour of the Seller in relation to all damages, loss, expense or liabilities suffered by the Seller (and its affiliates, directors and employees) arising out of the delivery of the Operations or Transitional Services.

3.3 **Montara Crude Oil Sale Agreement**

The Crude Oil Sale Agreement dated 25 March 2013 is made between PTTEP Australasia and PTT Public Company Limited ("**PTT**"), as extended by a letter of extension dated 26 April 2018 (the "**Crude Oil Sale Agreement**"). The Crude Oil Sale Agreement relates to the sale by PTTEP Australasia to PTT of the entire crude oils, condensates, natural gas liquids and other hydrocarbons in a liquid state at standard pressure produced from the project comprising the Montara, Skua, Swallow and Swift oil fields and other fields within the Licences.

The current term of the Crude Oil Sale Agreement, as extended, expires on 31 October 2018 although is expected to be extended to 31 March 2021 prior to completion of the Acquisition, at the request of PTT. Each party could request up to three additional separate three year extensions of the term, subject to both parties agreeing on the terms and conditions applicable to the period of extension.

Crude is delivered on an ''as is'' basis. If crude differs materially from the indicative specification provided and the parties do not agree to adjust the crude price, PTT has an ability to refuse to accept crude or accept delivery of the crude subject to PTTEP Australasia being liable to pay compensation if PTT on-sells the crude at a lower price.

Either party may terminate on 30 days' notice where force majeure events persist for a continuous period of 60 days or on three months' written notice where there is a change in legislation which adversely affects a party's rights, powers or remedies under the Crude Oil Sale Agreement and the legislation change cannot be excluded nor an agreement reached between the parties; and for insolvency or default (subject to an applicable cures period in respect of default). The Seller may also elect to terminate if PTT does not agree to a proposed change to the term price.

Term price is calculated on an FOB basis using a formula that incorporates Daily Dated Brent, an average of the Platts Premium/Discount and Rim's Premium/Discount (for Tapis premium over Dated Brent) and a premium which is based on the highest spot market price achieved during the Spot Market Period in accordance with a prescribed bidding process. The premium was fixed at US$0.2825/bbl when the term sale was entered into in 2015. However if PTTEP Australasia considers that the term price does not adequately reflect the market price for the crude, then it may on 30 days' notice: (i) extend or effectively re-instate the Spot Market Period so that the price is recalibrated in accordance with the spot prices achieved during a renewed period of marketing; or (ii) change the term price and, if PTT does not agree to such change, PTTEP Australasia may terminate the agreement with immediate effect.

Assignment by either party requires consent of the other party, not to be unreasonably withheld or delayed. A party will not withhold or delay its consent to an assignment if the assignee has the requisite financial, technical and operational capacity to perform the assignor's obligations under the agreement.

Each party may grant a security interest over its rights under the agreement to a financial institution having a minimum specified credit rating (or similar) without the consent of the other party, provided the security interest does not affect the validity and enforceability of the agreement or the rights and obligations of the other party under the agreement.

PTTEP provides a broad indemnity to PTT for direct loss (including demurrage) arising from PTTEP's failure to observe or perform any of its obligations. PTT provides the same indemnity to PTTEP Australasia plus a number of further specific indemnities, including for pollution and for actions taken by the tanker owner and their personnel (including pollution and property damage). The agreement is governed by the laws of Western Australia.

4 OVERVIEW OF THE REGULATORY APPROVALS REQUIRED IN RELATION TO THE MONTARA ACQUISITION

4.1 Overview

The following Australian regulatory approvals are required in connection with the Acquisition:

(a) receipt of notice under the Foreign Acquisitions and Takeovers Act 1975 (Cth) (''**FATA**'') from the Treasurer of the Commonwealth of Australia to the effect that the Commonwealth Government of Australia does not object to the transactions contemplated by the Aquisition Agreement (''**FIRB Approval**'');

(b) NOPTA approval and registration of the Acquisition Agreement, OTSA and the transfer of the Production Licences AC/L7 and AC/L8 from PTTEP to Jadestone (''**NOPTA Approvals**'');

(c) NOPSEMA approval of Jadestone's safety case, environment plan and a WOMP (''**NOPSEMA Approvals**'');

(d) transfer of the an EPBC Approval (2002/755) from PTTEP to Jadestone (''**EPBC Approval**''); and

(e) registration of the transfer of the FPSO from PTTEP to Jadestone (''**FPSO Transfer**'').

Summaries of the process for obtaining each approval are set out below.

4.2 FIRB Approval

The Australian government screens foreign investment proposals on a case-by-case basis to determine whether a particular proposal is contrary to the national interest. The main laws that regulate foreign investment in Australia are the FATA and the Foreign Acquisitions and Takeovers Regulation 2015 (Cth).

The legislation regulates foreign investment proposals by a ''foreign person''. For the purposes of the Acquisition, Jadestone is considered a foreign person under section 4 of the FATA given it is a corporation in which two or more persons, each of whom is an individual not ordinarily resident in Australia, hold an aggregate substantial interest.

Once an application has been lodged (and FIRB confirms that the application fee has been paid), the general rule is that the Treasurer has 30 calendar days to make a decision and a further 10 calendar days to notify the applicant, subject to this timeframe being extended. If no decision is made then no further orders can be made (that is, the Treasurer cannot prohibit or unwind a transaction if a decision is not made in time).

FIRB Approval is a condition precedent to the Acquisition Agreement. Jadestone lodged its FIRB application on 15 June 2018 and the application fee was paid. On 5 July 2018, FIRB notified Jadestone that it would not be able to complete its assessment of Jadestone's application by the statutory deadline. Jadestone has agreed to a request for extension of the statutory deadline to 3 August 2018.

4.3 NOPTA Approvals

4.3.1 *Overview*

NOPTA is the decision maker for transfer and dealing applications in respect of the Licences. NOPTA can either approve or refuse to approve a transfer and/or dealing and will notify the applicant of the decision by written notice pursuant to section 478 and section 493 of the OPGGS Act.

Transfer or dealings relating to the Licences are of no force until approved and registered, in relation to a particular Licence pursuant to section 472 and section 487 of the OPGGS Act.

The transfer and dealing process involves two stages:

(a) the application, accompanied by the prescribed fee for each Licence, is assessed and either approved or refused by NOPTA. If approved, a memorandum of the approval is stamped on the instruments and any related supplementary instruments; and

(b) approved instruments are registered by NOPTA. Copies of either the approved instrument (or if applicable a supplementary instrument) are placed on the National Electronic Approvals Tracking System, which is a public register.

4.3.2 *Approval and registration of Acquisition Agreement and OTSA as a dealing*

NOPTA must approve and register the dealings in the Licences evidenced by the Acquisition Agreement and the OTSA, pursuant to section 488(4) of the OPGGS Act.

NOPTA may require information regarding the Jadestone's technical and financial capacity to meet the obligations associated with being registered titleholder of the Licences.

The dealings evidenced by the Acquisition Agreement and the OTSA being approved and registered against each of the Licences is a condition precedent under the Acquisition Agreement.

4.3.3 *Approval and registration of a transfer of the Licences*

For the application to approve the transfer of each Licence, the following documentation must be provided to NOPTA:

<u>Documents required</u>

(a) a completed application form;

(b) an instrument of transfer;

(c) a document setting out:

  (i) the technical qualifications of the transferee;

  (ii) details of the technical advice that is or will be available to that transferee; and

(iii) details of the financial resources that are or will be available to that transferee (section 474(b) of the OPGGS Act).

Technical qualifications and advice

NOPTA needs to be satisfied that transferee has sufficient technical capacity to meet the obligations associated with the Licences. These may include:

(a) work program commitments;

(b) capacity to explore and to progress the development of known resources; and

(c) ability to meet the requirements of an accepted field development plan.

4.3.4 *Timing*

An application for approval of a dealing or transfer must be made within 90 days after the day on which the party who last executed the instrument evidencing the dealing so executed the instrument (such as the Acquisition Agreement, OTSA and instruments of transfer), or such longer period as the NOPTA allows.

There is no stipulated time frame under the OPGGS Act by which NOPTA needs to provide its decision. However, NOPTA has indicated its assessment of a transfer or dealing application may be finalised within four to six weeks of receiving all information that is relevant for the assessment.

4.4 **NOPSEMA Approvals**

4.4.1 *Safety case approval*

Safety case contents

Jadestone will apply to NOPSEMA for acceptance of the safety case after execution of the SPA in order for it become operator of the Montara Facilities.

A safety case must comply with the content requirements of the Offshore Petroleum and Greenhouse Gas Storage (Safety) Regulations 2009 (''**Regulations**''), which are technically complex and address each stage in the life of the facility in respect of which the Licences relate.

Jadestone, as the incoming operator, will need to demonstrate that in the development of the safety case there has been effective consultation with, and effective participation of, members of the workforce in order to facilitate informed opinions about the risks and hazards to which they may be exposed on the facility.

Safety case approvals process

The process for approval is as follows:

(a) Pre-submission of safety case

The existing titleholders must notify NOPSEMA in writing that there will be a replacement operator.

If NOPSEMA is satisfied that the replacement operator will have day-to-day management and control of the facility, it will register the replacement operator as the new operator of a ''proposed facility'' (in the meantime, the existing operator will remain registered as an operator of ''the facility''). The existing titleholder will then request that the existing operator be removed from the register at a specified date and time associated with the handover of the operations.

Jadestone, as the new operator, must agree with NOPSEMA on the scope of validation before submitting their new safety case.

(b) Submission of safety case

Jadestone, as the new operator, must submit a new safety case.

NOPSEMA has powers under the Regulations to require the new operator to provide further written information in respect of the contents of the safety case. The new operator will have at least 30 days in which to re-submit the safety case to address the request for additional information.

(c) Estimated timeframe to obtain NOPSEMA's decision

Within 90 days of receiving the safety case, or after receiving the safety case that has been resubmitted to address a request for additional information, NOPSEMA must notify the operator that NOPSEMA has decided:

(i) to accept the safety case;

(ii) to reject the safety case; or

(iii) that NOPSEMA is unable to make a decision (and set out a proposed timetable for its consideration of the safety case).

A failure by NOPSEMA to comply with the above obligations does not affect the validity of a decision by NOPSEMA to accept or reject the safety case.

(d) Handover

Once the new safety case is accepted, arrangements are to be made for the handover of operations, which will coincide with removal of the outgoing operator from the operator register.

4.4.2 *Environmental plan approval*

Environment plan contents

Broadly, the purpose of an environment plan is to identify the proposed petroleum activity's impacts on and risks to the relevant environment and set out control measures to reduce the identified impacts and risks.

Division 2.3 of the Offshore Petroleum and Greenhouse Gas Storage (Environment) Regulations 2009 ("**Environment Regulations**") sets out content required for the environment plan.

Environment plan approval process

Under regulation 17(7) of the Environment Regulations, a new titleholder must submit a proposed revision of the existing environment plan for an activity as soon as practicable if a change in titleholder will result in a change in the manner in which the environmental impacts and risks of an activity are managed. Whether such a change will occur is a technical question for a proposed titleholder. If the change in titleholder will not result in a change in the manner in which the environmental impacts and risks of an activity are managed, the new titleholder will only need to notify NOPSEMA of the change in titleholder.

Under Regulation 10, within 30 days of an environment plan being submitted, NOPSEMA must either accept the plan, notify the titleholder of any relevant criteria in respect of which NOPSEMA is not reasonably satisfied (and set a date by which the titleholder must resubmit the plan), or, if NOPSEMA is unable to make a decision, notify the titleholder of a proposed timetable for consideration of the plan.

Within 10 days of receiving notice that NOPSEMA has accepted an environment plan (whether in full, in part or subject to limitations or conditions), the titleholder must submit a summary of the accepted plan to NOPSEMA (compliant with the requirements under Regulation 11(4) of the Environment Regulations) for public disclosure.

4.4.3 *Well operation management plan ("**WOMP**") approval*

WOMP contents

Under Regulation 5.04 of the Offshore Petroleum and Greenhouse Gas Storage (Resource Management and Administration) Regulations 2011 (Cth) ("**RMA Regulations**"), a titleholder undertaking a well activity in a title area that does not have an accepted WOMP in force for undertaking the well activity commits an offence. Well activities include drilling, well testing, wirelines, workovers, well completion or re-completion, well maintenance and abandonment or suspension of a well.

A WOMP must comply with the contents requirement of Part 5 of the RMA Regulations, as amended by the Offshore Petroleum and Greenhouse Gas Storage Legislation Amendment (Well Operations) Regulation 2015 (Cth) and the corresponding laws of each state or territory, where powers have been conferred upon NOPSEMA.

WOMP approval process

Under Regulation 5.06(2) of the RMA Regulations, a titleholder must give a WOMP to NOPSEMA at least 30 days before the proposed start of a well activity (or such other period as NOPSEMA allows).

Under Regulation 5.07, within 30 days of the WOMP being submitted, NOPSEMA must accept the plan or one or more parts of the plan, reject the plan, or notify the titleholder in writing that it is unable to make a decision without further assessment of the plan (in which case it may request further information and must give the titleholder reasonable opportunity to resubmit the WOMP). Where NOPSEMA undertakes further assessment of the WOMP, it must accept the plan (or one or more parts of the plan) or reject the plan.

4.4.4 *Financial assurance*

Under section 571(2) of OPGGS Act, a titleholder must maintain financial assurance sufficient to give the titleholder the capacity to meet costs, expenses, and liabilities that may result in connection with carrying out a petroleum activity, doing any other thing for the purpose of the petroleum activity, or complying (or failing to comply) with a requirement under the OPGGS Act in relation to the petroleum activity ("**Petroleum Activity Costs**").

Titleholders nominate how they will give the financial assurance, including by way of insurance, self-insurance, a bond, deposit of an amount as security with a financial institution, an indemnity or other surety, a letter of credit from a financial institution and/or a mortgage. Titleholders may use their discretion in determining the form or mix of forms for their specific requirements as long as the form or combination of forms covers the maximum financial assurance required to meet the financial assurance duty.

Provision of the financial assurance will involve quantification of Petroleum Activity Costs.

If the potential environmental consequences of an incident associated with a petroleum activity are considered by NOPSEMA to be unusually high, NOPSEMA may, at its discretion, require the titleholder to fully calculate costs, expenses and liabilities in relation to that incident rather than applying the Australian Petroleum Production and Exploration Association (APPEA) method.

4.5 EPBC Approval

PTTEP Australasia holds the EPBC Approval issued pursuant to section 133 of the Environment Protection and Biodiversity Conservation Act 1999 (Cth) ("**EPBC Act**") which authorises the following action in the Commonwealth marine areas:

> *'To drill and operate Montara 4, Montara 5 and Montara 6 Wells for the purposes of oil production and to re-complete and operate Montara 3 for use as a gas re-injection well in Permit Area AC/RL3, in the Timor Sea approximately 200km from the coast of Western Australia (EPBC 2002/755).'*

For the EPBC Approval to be transferred to Jadestone, PTTEP Australasia and Jadestone need to make a written agreement and submit it to the Commonwealth Minister for the Environment and Energy for approval.

Under section 145B(2) of the EPBC Act, the written agreement does not take effect until the Minister consents in writing to the transfer.

The Commonwealth Department of Environment and Energy has advised that it may take approximately 2 months for the Minister to decide whether to transfer the EPBC Approval.

4.6 FPSO Transfer

For a transfer of title of the FPSO from PTTEP to Jadestone, Jadestone is required to notify the Registrar of Ships of the change of ownership within 14 days. The following steps are required to be taken:

(a) Obtain a bill of sale from the Seller

The bill of sale is proof of the transfer of ownership from PTTEP to Jadestone as the new owner. The bill of sale must be completed by PTTEP and comply with Australian Maritime Safety Authority ("**AMSA**") requirements.

(b) Obtain the original registration certificate

The original registration certificate for the FPSO (issued by AMSA) must be returned to the Australian Shipping Registration Office in order for the transfer of ownership to be completed. If the original registration certificate has been lost, an application will need to be made for a replacement certificate together with a fee.

(c) Complete a declaration of transfer Form 169

In accordance with section 36(3) of the Shipping Registration Act 1981 (Cth), Jadestone will need to complete the Form 169 and submit it to the Australian Shipping Registration Office with the lodgement fee.

(d) Complete a notice of appointment of registered agent

Jadestone will need to appoint a ship manager to manage the day to day running of the ship and provide notification of the ship manager to the Australian Shipping Registration Office.

Part 5

RISK FACTORS

An investment in the Company involves significant risks and is only suitable for investors who are capable of evaluating the merits and risks of such an investment and who have sufficient resources to be able to bear any losses (which may be equal to the whole amount invested) which may result from such an investment. Prospective investors should carefully review and evaluate the risks and the other information contained in this document before making a decision to invest in the Company.

If in any doubt prospective investors should immediately seek their own personal financial advice from their independent professional adviser authorised under FSMA who specialises in advising on the acquisition of shares and other securities or other advisers such as legal advisers and accountants.

If any of the following risks actually occur, the Group's business, financial condition, capital resources, results and/or future operations of the Group could be materially and adversely affected. In such circumstances, the trading price of the Common Shares could decline and investors may lose all or part of their investment. It should be noted that the risk factors listed below are not intended to be exhaustive and do not necessarily comprise all of the risks to which the Group may be exposed now or in the future. Additional risks and uncertainties not currently known to the Board may also have an adverse effect on the Group's business and the information set out below does not purport to be an exhaustive summary of the risks affecting the Group.

Prospective investors should be aware that the value of the Common Shares and the income from them may go down as well as up and that they may not be able to realise their initial investment. In addition, it is possible that the market price of Common Shares in the Company may be less than the underlying net asset value per Common Share.

There can be no guarantee that the Company's investment objectives will be achieved.

References below to the Company are also deemed to include, where appropriate, each member of the Group and, as appropriate, the Group, following the aquisition of the Montara Assets.

1 RISKS RELATING TO THE COMPANY'S BUSINESS

Exploration, development and production risks

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. The long-term commercial success of Jadestone depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, any existing reserves Jadestone may have at any particular time and the production therefrom will decline over time as such existing reserves are exploited. A future increase in Jadestone's reserves will depend not only on its ability to explore and develop any existing properties it may have from time to time, but also on its ability to select and acquire suitable producing properties or prospects. No assurance can be given that Jadestone will be able to continue to locate satisfactory properties for acquisition or participation on economically favourable terms or at all. Moreover, if such acquisitions or participations are identified, management of Jadestone may determine that current markets, terms of acquisition and participation or pricing conditions make such acquisitions or participations uneconomic. There is no assurance that further commercial quantities of oil and natural gas will be discovered or acquired by Jadestone.

Future oil and natural gas exploration may involve unprofitable efforts, not only from dry wells, but from wells that are productive but do not produce sufficient net revenues to return a profit after drilling, operating and other costs and taxes, royalties or their equivalents. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs. In addition, drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions.

While diligent well supervision and effective maintenance operations can contribute to maximizing production rates over time, production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow levels to varying degrees. Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including hazards such as fire, explosion, blowouts, cratering, sour gas releases and spills, any of which could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment or in personal injury. In accordance with industry practice, Jadestone is not fully insured against all of these risks, nor are all such risks insurable. Although the operators of Jadestone's concessions are required to maintain liability insurance in an amount that they consider consistent with industry practice, the nature of these risks is such that liabilities could exceed policy limits, in which event Jadestone could incur significant costs that could have a material adverse effect upon its financial condition. Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including encountering unexpected formations or pressures, premature decline of reservoirs and the invasion of water into producing formations, with losses resulting from the occurrence of any of these risks.

Reserve based lending is exposed to oil price fluctuation and this may have an impact on the Company's borrowing ability

The Company is obtaining new external debt finance under a reserve based lending facility. Reserve-based lending, a type of external financing that is commonly used in the oil and gas industry, is a form of loan made against, and secured by, an oil and gas field or a portfolio of undeveloped or developed and producing oil and gas assets. The amount of the loan facility available to the borrower, and the interest rate applicable to the finance, are based on the value of the borrower's oil and gas reserves, as adjusted from time to time. An RBL loan facility is repaid using the proceeds from sales in the field or portfolio. Oil and gas prices are volatile and can change significantly over the term of an RBL facility (typically three to five years), during which time the lender will typically re-evaluate the borrower's reserves on a periodic basis. While lenders consider several factors to calculate the borrowing base, one of the most significant is the prevailing price of oil and gas and the lenders' judgment on how these prices will move. The price is oil is determined by a number of factors that are beyond the control of the Company, including governmental regulations and geopolitical developments. Although the Company is confident that the RBL Facility will continue to be available for a period and in the amounts that the Company requires to further its strategic objective, there can be no guarantee that a major fluctuation in oil prices will not have a negative impact on the Company's reserves and thus its borrowing base under the RBL Facility.

Leverage Risk

The Company has an existing Convertible Facility although this is intended to be repaid from the proceeds of the Placing and, following the Acquisition and entering into the RBL Facility, the Enlarged Group has increased borrowings and debt service obligations. The Enlarged Group expects that leverage will continue for the foreseeable future. The Directors believe that the level of leverage may reduce over time, however, the degree to which the Enlarged Group will continue to be leveraged could have important consequences for the business, including:

- making it more difficult for the Enlarged Group to satisfy its obligations with respect to its indebtedness;
- restricting the Enlarged Group's ability to make strategic acquisitions or pursue other business opportunities;
- together with the financial and other restrictive covenants under the terms of the indebtedness, limiting the Enlarged Group's ability to obtain additional financing, dispose of assets or pay cash dividends other than as permitted by the terms of the indebtedness;
- requiring the Enlarged Group to sell or otherwise dispose of assets used in the business in order to fund debt service obligations;
- limiting the Enlarged Group's flexibility in planning for, or reacting to, changes in the business and the industry in which it operates;
- placing the Enlarged Group at a competitive disadvantage compared to competitors that have less debt; and
- increasing the Enlarged Group's cost of borrowing.

Any of these consequences or events could have a material adverse effect on the Enlarged Group's ability to satisfy the debt obligations. The Enlarged Group's substantial leverage could materially and adversely affect the business, financial condition and results of operations and prevent the Enlarged Group from servicing payment obligations under the indebtedness. The Enlarged Group will require cash to meet obligations under its indebtedness and sustain the business operations, and the Enlarged Group's ability to do so will depend on many factors beyond its control. The Enlarged Group's ability to meet its obligations under its indebtedness, including making principal, interest and other payments when due, as well as its ability to fund ongoing business operations, will depend upon future operating performance and the Enlarged Group's ability to generate cash, which, in turn, will be affected to some extent by general economic conditions and by financial, competitive, legislative, regulatory and other factors, including those factors discussed in this Part 5 and elsewhere in this document. If, on the maturity date of any of the indebtedness, the Enlarged Group does not have sufficient cash flows from operations and other capital resources to repay and redeem the debt in full or pay other debt obligations, as the case may be, the Enlarged Group may be required to undertake alternative financing plans, such as refinancing or restructuring the debt, selling assets, reducing or delaying capital investments or raising additional debt or equity financing in amounts that could be substantial or on unfavourable terms. The Enlarged Group's access to debt, equity and other financing as a source of funding for operations and for refinancing maturing debt will also be subject to many factors, including the cash needs of the Enlarged Group and the then prevailing conditions in the financial markets, including in the corporate bond, term loan and equity markets. In the longer term, if the Enlarged Group were unable to generate sufficient cash flows to satisfy its debt obligations or to refinance its indebtedness on acceptable terms, or at all, it would materially and adversely affect its business, prospects, financial condition and results of operations, as well as its ability to pay the principal and interest on its indebtedness. Any failure to refinance its indebtedness, on or prior to the applicable maturity date, may result in the Enlarged Group defaulting on such indebtedness.

The Company has engaged in transfer pricing which may be subject to review by taxation authorities

In 2016 and 2017, Jadestone Energy Australia implemented two shareholder loans from its parent company, under the terms of which interest is chargeable by the lender. At the time these loans were entered into external advice, in the form of a transfer pricing study, was obtained to confirm an appropriate interest rate to be charged for this purpose. In light of this advice, the Company considered that the interest rate applicable to these shareholder loans was, at the time of drawdown, supportable from an Australian transfer pricing perspective. However, the Australian Taxation Office has subsequently published a practical compliance guide regarding cross-border related party financing arrangements. Jadestone has not completed a risk assessment in respect of the existing shareholder loans following the publication of this new guidance, and there is a risk, albeit low, that the existing shareholder loans to Jadestone Energy Australia, and the associated documentation, could be subject to scrutiny by the Australian Taxation Office.

Project risks

Jadestone will manage a variety of small and large projects in the conduct of its business. Project delays may delay expected revenues from operations. Significant project cost over-runs could make a project uneconomic.

Jadestone's ability to execute projects and market oil and natural gas will depend upon numerous factors beyond Jadestone's control, including:

- the availability of processing capacity;
- the availability and proximity of pipeline capacity;
- the availability of storage capacity;
- the supply of and demand for oil and natural gas;
- the availability of alternative fuel sources;
- the effects of inclement weather;
- the availability of drilling and related equipment;
- unexpected cost increases;
- accidental events;

- currency fluctuations;
- political uncertainty;
- the availability and productivity of skilled labour; and
- the regulation of the oil and natural gas industry by various governmental agencies, including changes in regulations.

Because of these factors, Jadestone could be unable to execute projects on time, on budget or at all, and may not be able to effectively market the oil and natural gas that it produces.

Delays in business operations

In addition to the risk that Jadestone's customers may make delayed payments to the Company, and the delays by operators in remitting payment to the Company, payments between these parties may be delayed due to restrictions imposed by lenders, accounting delays, delays in the sale or delivery of products, delays in the connections of wells to a gathering system, adjustment for prior periods, or recovery by the operator of expenses incurred in the operation of the properties. Any of these delays could reduce the amount of cash flow available for the business of the Company in a given period and expose the Company to additional third party credit risks.

Title to assets

Jadestone has investigated the rights to explore and exploit the various oil and gas properties it holds or proposes to participate in and, to the best of its knowledge, those rights are in good standing. Although title reviews have been or will be done according to industry standards prior to the purchase of most oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise to defeat the claim of Jadestone which could result in a reduction of the revenue received by Jadestone. Further, no assurance can be given that applicable governments will not revoke, or significantly alter the conditions of, or the financial terms relating to, the applicable exploration and development authorisations and that such exploration and development authorisations will not be challenged or impugned by third parties. There is no certainty that such rights or additional rights applied for will be granted or renewed on terms satisfactory to Jadestone. There can be no assurances that claims by third parties against Jadestone's properties will not be asserted at a future date.

Reserve estimates

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and natural gas liquids (or similar substances) reserves and cash flows to be derived therefrom, including many factors beyond Jadestone's control. The information concerning reserves and associated cash flow set forth in the reserves statement contained in the CPR set out in Part 6 of this document represents estimates only. In general, estimates of economically recoverable oil and natural gas reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of oil and natural gas, actual realized price of oil and gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary from actual results. All such estimates are to some degree speculative, and the classifications or reserves are only attempts to define the degree of speculation involved. For those reasons, estimates of the economically recoverable oil and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues expected therefrom prepared by different engineers, or by the same engineers at different times, may vary. Actual production, revenues, taxes and development and operating expenditures with respect to the Company's reserves will vary from estimates thereof and such variations could be material. Further, the evaluations are based, in part, on the assumed success of the exploitation activities intended to be undertaken in future years. The reserves and estimated cash flows to be derived therefrom contained in such evaluations will be reduced to the extent that such exploitation activities do not achieve the level of success assumed in the evaluation.

Estimates of proved reserves that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves rather than actual production history. Estimates based on these methods are generally less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history and production practices will result in variations in the estimated reserves and such variations could be material. Some of Jadestone's producing wells have a limited production history and thus there is less historical production on which to base the reserves estimates. In addition, a significant portion of Jadestone's reserves may be attributable to a limited number of wells and, therefore, a variation in production results or reservoir characteristics in respect of such wells may have a significant impact upon the Company's reserves.

In accordance with applicable securities laws, ERCE has used forecast price and cost estimates in calculating reserve quantities. Actual future net cash flows will be affected by other factors such as actual production levels, supply and demand for oil and natural gas, curtailments or increases in consumption by oil and natural gas purchasers, changes in governmental regulation or taxation and the impact of inflation on costs. Actual production and cash flows derived therefrom will vary from the estimates contained in the CPR and such variations could be material. The CPR is based in part on the assumed success of activities Jadestone intends to undertake in future years. The reserves and estimated cash flows to be derived therefrom contained in the CPR will be reduced to the extent that such activities do not achieve the level of success assumed in the CPR. The CPR is effective as at 31 December 2017 and has not been updated as at the date of this document, and therefore thus does not reflect changes in Jadestone's reserves and resources since that date.

Contingent and prospective resources are unlikely to be commercially productive in the short or medium term

This document contains estimations of contingent and prospective resources attributable to the Group. Uncertainties exist with respect to the estimation of contingent and prospective resources in addition to those that apply to Reserves. Contingent resources are resources estimated, at a given date, to be potentially recoverable from known accumulations but are not yet considered mature enough for commercial development due to one or more contingencies. Contingent resources may include, for example, projects for which there are no visible markets, or where commercial recovery is dependent upon technology under development, the availability of export routes or where evaluation is insufficient to clearly assess commerciality. Prospective resources are resources estimated, as of a given date, to be potentially recoverable from undiscovered accumulations. Development of contingent and prospective resources, if undertaken, may involve considerable expense and may not result in the discovery of hydrocarbons in commercially viable quantities. Volumes and values associated with contingent and prospective resources should be considered highly speculative and there can be no guarantee that the Group will be able to develop these resources commercially.

Properties with no attributed reserves

The development of properties with no attributed reserves can be affected by a number of factors including, but not limited to, project economics, forecasted commodity price assumptions, cost estimates and access to infrastructure. These and other factors could lead to the delay or the acceleration of projects related to these properties.

Expiration of licences and leases

Jadestone's properties are held in the form of licences, leases and production service agreements and the Company has working interests in these licences, leases and production services agreements. If Jadestone or the holder of the licence, lease or production services agreement fails to meet the specific requirement of a licence, lease or production services agreement, then it may terminate or expire or may not be renewed. There can be no assurance that any of the obligations required to maintain each licence, lease or production services agreement will be met. The termination or expiration of Jadestone's licences, leases or production services agreement or the working interests or the failure to renew such licences, leases or production services agreements including the PSC for Block 46-07 in Vietnam or the working interests therein may have a material adverse effect on Jadestone's results of operations and business.

Operational dependence

Other companies operate certain of the assets in which Jadestone currently has a participating interest and on completion of the Acquisition will do so for an interim period. As a result, Jadestone is dependent on such operators for the timing of activities related to such properties and will be largely unable to control the operations of those assets or their associated costs, which could adversely affect Jadestone's financial performance. Jadestone's return on assets operated by others will therefore depend upon a number of factors that may be outside Jadestone's control, including the timing and amount of capital expenditures, the operator's expertise and financial resources, the approval of other participants, the selection of technology and risk management practices.

Reliance on management and key personnel

Jadestone's success depends in large measure on certain key personnel. The loss of the services of such key personnel could have a material adverse effect on Jadestone. Jadestone does not have any key person insurance in effect for management. The contributions of the existing management team to the immediate and near term operations of Jadestone are likely to be of central importance. Investors must rely upon the ability, expertise, judgment, discretion, integrity and good faith of the management of Jadestone.

Hedging

Jadestone has currently hedged part of its production from the Stag field. Under the RBL Facility, it will also be required to hedge a significant proportion of its future production from the Montara Assets. In addition, from time to time Jadestone may enter into or be required to enter into agreements to receive fixed prices on its oil and natural gas production to offset the risk of revenue losses if commodity prices decline. However, if commodity prices increase beyond the levels set in such agreements, Jadestone will not benefit from such increases on the hedged volumes. Similarly, from time to time Jadestone may enter into agreements to fix the exchange rate of Australian to United States dollars or other relevant currency in order to offset the risk of cost escalation relating to general and administrative costs if the Australian dollar increases in value compared to the United States dollar. It should be noted that in the event of declining oil prices, the Company may not be able to enter into hedging terms on acceptable terms in order to sufficiently protect against downside exposure, and as a result there is a risk that Jadestone may not be able to hedge against reduced cash inflows in such a scenario.

Third Party credit risk

Jadestone may be exposed to third party credit risk through its contractual arrangements with its current or future joint venture partners, marketers of its petroleum and natural gas production and other parties. In the event such entities fail to meet their contractual obligations to Jadestone, such failures could have a material adverse effect on Jadestone and its cash flow from operations. In addition, poor credit and or liquidity conditions in the industry and of joint venture partners may impact a joint venture partner's willingness to participate in Jadestone's ongoing capital programme, potentially delaying the programme and the results of such programme until Jadestone finds a suitable alternative partner.

Availability of equipment, qualified personnel and related costs

Oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment (typically leased from third parties) and qualified personnel in the particular areas where such activities will be conducted. Demand for such limited equipment and qualified personnel or access restrictions may affect the availability of such equipment and qualified personnel to Jadestone and may delay exploration and development activities. To the extent Jadestone is not the operator of its oil and gas properties, Jadestone will be dependent on such operators for the timing of activities related to such properties and will be largely unable to direct or control the activities of the operators. In addition, the costs of qualified personnel and equipment in the area where Jadestone's assets are located may be very high due to the lack of availability of, and demands for, such qualified personnel and equipment in the area.

Conflicts of interest

Certain directors of Jadestone are also directors of other oil and gas companies and as such may, in certain circumstances, have a conflict of interest requiring them to abstain from certain decisions. Conflicts, if any, will be subject to the procedures and remedies of the BCBA.

Limitations of insurance risk

Jadestone's involvement in the exploration for and development of oil and natural gas properties may result in Jadestone becoming subject to liability for pollution, blow outs, property damage, personal injury or other hazards. Although Jadestone seeks to insure itself in accordance with industry standards to address certain of these risks, such insurance has limitations on liability and may not be sufficient to protect Jadestone against the full extent of such liabilities to which it is exposed. In addition, such risks may not in all circumstances be insurable or, in certain circumstances, Jadestone may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or other reasons. The payment of any such uninsured liabilities would reduce the funds available to Jadestone. The occurrence of a significant event that Jadestone is not fully insured against, or the insolvency of the insurer of such event, could have a material adverse effect on Jadestone's financial position, results of operations or prospects.

Income taxes

As the Company is engaged in the oil and natural gas business its operations are subject to certain unique provisions of the Income Tax Act (Canada) and applicable provincial income tax legislation relating to characterisation of costs incurred in their businesses which affects whether such costs are deductible and, if deductible, the rate at which they may be deducted for the purposes of calculating taxable income. Jadestone will file all required income tax returns and believes that it will be in full compliance with the provisions of the Income Tax Act (Canada) and all applicable provincial tax legislation. However, such returns are subject to reassessment by the applicable taxation authority. In the event of a successful reassessment of the Company, whether by re-characterization of costs or otherwise, such reassessment may have an impact on current and future taxes payable.

Jadestone will also be subject to various tax regimes in foreign countries that are subject to changes in legislation and interpretation, including Australia, Vietnam, Indonesia and the Philippines. The Company will file foreign income and other tax returns as are required and believes it will be in full compliance with the relevant foreign legislations.

Litigation risks

In the normal course of Jadestone's operations, it may become involved in, named as a party to, or be the subject of, various legal proceedings, including regulatory proceedings, tax proceedings and legal actions, relating to personal injuries, property damage, property taxes, land rights, the environment and contract disputes. From time to time Jadestone may enter into agreements to fund some or all of the costs associated with such litigation in exchange for a portion of the proceeds which may ultimately be received. The outcome of outstanding, pending or future proceedings cannot be predicted with certainty and may be determined adversely to Jadestone and as a result, could have a material adverse effect on Jadestone's assets, liabilities, business, financial condition and results of operations. Even if Jadestone prevails in any legal proceeding, the proceedings could be costly and time-consuming and may divert the attention of management and key personnel from the Company's business operations, which could adversely affect its financial condition even where Jadestone has obtained litigation funding.

Failure to realise anticipated benefits of acquisitions and disposals

Jadestone makes acquisitions and disposals of businesses and assets in the ordinary course of business. Achieving the benefits of acquisitions depends in part on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner as well as Jadestone's ability to realise the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of the Company. The integration of acquired businesses may require substantial management effort, time and resources and may divert management's focus from other strategic opportunities and operational matters. Management continually assesses the value and contribution of services provided and assets required to provide such services. In this regard, non-core assets are periodically disposed of or relinquished so that Jadestone can focus its efforts and resources more efficiently. Depending on the state of the market for such non-core assets, certain non-core assets of Jadestone, if disposed of, could be expected to realise less than their carrying value on the financial statements of the Company.

Substantial capital requirements

Jadestone anticipates making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. Jadestone's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times or to allow it to undertake or complete future drilling programmes. The ongoing maintenance and operation of assets and equipment in the offshore oil and gas industry, in particular FPSO installations, is heavily capital intensive.

From time to time, due to changes in its circumstances or its business strategy, Jadestone may require additional financing in order to carry out its oil and gas acquisition, exploration and development activities. In particular, the Group may need additional funds in the longer term, outside the period of the working capital statement contained in this document, in order to further fund its exploration and development programmes.

Failure to obtain such financing on a timely basis could cause Jadestone to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If Jadestone's revenues from its reserves decrease as a result of lower oil and natural gas prices or otherwise, Jadestone's ability to expend the necessary capital to replace its reserves or to maintain its production will be impaired. If and to the extent that Jadestone raises new capital through an issuance of new equity in future, this may be dilutive to holders of the Company's then existing Common Shares and could contain rights and preferences superior to those of the Common Shares. Debt financing may involve restrictions on the Group's financing and operating activities. In either case, additional financing may not be available to the Group on acceptable terms. If the Group is unable to raise additional funds as needed, the scope of its operations may be reduced and, as a result, the Group may be unable to fulfil its long-term growth programme, or meet its contractual obligations under its contracts which may ultimately be withdrawn or terminated for non-compliance.

Failure to meet minimum expenditure commitments

Certain of the Company's licences and concessions contain minimum expenditure commitments. In the event that the Company elects to withdraw from such licences before meeting such commitments, or is otherwise unable to meet such commitments, it may suffer financial loss associated with restricted cash sums or penalties. Furthermore, such circumstances may impact the Company's ability to obtain new licences or concessions in the relevant country.

Extraction of financial information provided in respect of the Montara Assets

In addition, the financial information provided in respect of the Montara Assets, as provided by PTTEP Australasia, has been extracted from PTTEP Australasia's Oracle accounting system. As a result, it may not be complete or accurate, as it is outside the control of the Company.

In addition, the financial information in the extracts provided may not be presented on a full IFRS basis and the accounting policies applied in the preparation of such information are likely to differ from those of the Group. As a result, where the information is to form part of the Group's reporting, such information may be materially different.

The Group is subject to cyber risks

The Group is dependent upon the availability, capacity, reliability and security of its information technology infrastructure and its ability to expand and continually update this infrastructure, to conduct daily operations and to successfully integrate future acquisitions into the Group. The Group depends on various information technology systems to estimate reserve quantities, process and record financial data, manage its land base, manage financial resources, analyse seismic information, administer its contracts with its operators and communicate with employees and third-party partners. The Group is at risk of financial loss, reputational damage and general disruption from a failure of its information technology infrastructure or an attack for the purposes of espionage, extortion, terrorism or to cause embarrassment. Any failure of, or attack against, Jadestone's information technology infrastructure may be difficult to prevent or detect, and Jadestone's internal policies to mitigate these risks may be inadequate or ineffective. Jadestone may not be able to recover any losses that may arise from such a failure or attack.

2 RISKS RELATING TO THE INDUSTRY OR COUNTRIES IN WHICH THE COMPANY OPERATES

Volatility of commodity prices

Crude oil prices are unstable and are subject to fluctuation. The Company's revenues, profitability and rate of growth are substantially dependent upon the prevailing prices of, and demand for, oil and natural gas. Prices for oil and natural gas are subject to wide fluctuations in response to changes in the supply of and demand for oil and natural gas, market uncertainty and a variety of additional factors that are beyond the control of the Company. These factors include, but are not limited to:

- global energy policy, including (without limitation) the ability of OPEC to set and maintain production levels and influence prices for crude oil;
- political instability and hostilities;
- domestic and foreign supplies of crude oil and gas;
- the overall level of energy demand;
- weather conditions;
- government regulations;
- taxes;
- currency exchange rates;
- the availability of refining capacity and transportation infrastructure;
- the effect of worldwide environmental and/or energy conservation measures;
- the price and availability of alternative energy supplies; and
- the overall economic environment.

In a period of oil price decline and/or sustained low oil prices, the Company may be required to curtail or cut costs including capital development costs. This may have an impact on the Company's ability to grow *inter alia* production and cash flow and thus its ability to deliver its business plan.

Foreign operations

All of the Company's operations are currently located in Vietnam, the Philippines, Australia and Indonesia. As such, Jadestone's operations, financial condition and operating results could be significantly affected by risks over which it has no control. These risks may include risks related to economic, social or political instability or change, terrorism, hyperinflation, currency non-convertibility or instability and changes of laws affecting foreign ownership, interpretation or renegotiation of existing contracts, government participation, taxation policies, including royalty and tax increases and retroactive tax claims, and investment restrictions, working conditions, fluctuations in rates of exchange, exchange control, exploration licensing, petroleum and export licensing and export duties, government control over domestic oil and gas pricing, devaluation or other activities that limit or disrupt markets and restrict payments or the movement of funds; the possibility of being subject to exclusive jurisdiction of foreign courts in connection with legal disputes relating to licences to operate and concession rights in countries where Jadestone currently operates; and difficulties in enforcing Jadestone's rights against a governmental agency because of the doctrine of sovereign immunity and foreign sovereignty over international operations. Problems may also arise due to the quality or failure of locally obtained equipment or technical support, which could result in failure to achieve expected target dates for exploration operations or result in a requirement for greater expenditure. Jadestone's operations may also be adversely affected by applicable laws and policies of Vietnam, the Philippines, Australia and Indonesia, the effect of which could have a negative impact on Jadestone, including in relation to the uncertain application of laws such as tax laws. Further, Jadestone may not be able to perform all of its obligations under a service contract in respect of Block SC-57 if it cannot be registered to transact business in the Philippines.

Jadestone's operations may be adversely affected by political and economic circumstances in the countries in which it operates

Oil and natural gas exploration, development and production activities are subject to political and economic uncertainties (including but not limited to changes in energy policies or the personnel administering them), changes in laws and policies governing operations of foreign-based companies, expropriation of property, cancellation or modification of contract rights, revocation of consents or approvals, obtaining various approvals from regulators, foreign exchange restrictions, currency fluctuations, royalty increases and other risks arising out of foreign governmental sovereignty, as well as risks of loss due to civil strife, acts of war, guerrilla activities, terrorism, acts of sabotage, territorial (including maritime boundary) disputes and insurrection. In addition, Jadestone is subject both to uncertainties in the application of the tax laws in the countries in which it operates and to possible changes in such tax laws (or the application thereof), each of which could result in an increase in its tax liabilities. These risks may be higher in the developing countries in which Jadestone conducts a majority of its activities.

Jadestone's operations in these areas increase its exposure to risks of local economic conditions, political disruption, civil disturbance, expropriation, piracy and governmental policies that may:

- disrupt its operations;
- require Jadestone to incur greater costs for security;
- restrict the movement of funds or limit repatriation of profits;
- lead to U.S. government or international sanctions; or
- limit access to markets for periods of time.

Some countries in the geographic areas where Jadestone operates have experienced political instability in the past or are currently experiencing instability. Disruptions may occur in the future, and losses caused by these disruptions may occur that will not be covered by insurance. Consequently, Jadestone's exploration, development and production activities may be substantially affected by factors which could have a material adverse effect on Jadestone's results of operations and financial condition. Jadestone's operations may also be adversely affected by laws and policies of the jurisdictions, including the jurisdictions where its oil and gas operating activities are located and other jurisdictions in which it does business, that affect foreign trade and taxation. Changes in any of these laws or policies or the implementation thereof could materially and adversely affect Jadestone's financial position, results of operations and cash flows.

The geographic locations of Jadestone's licences in Southeast Asia may subject Jadestone to an increased risk of loss of revenue or curtailment of production from factors specifically affecting that region

Jadestone's current exploration licences are located in Southeast Asia. Some or all of these licences could be affected should any region experience any of the following factors (among others):

- severe weather, natural or man-made disasters or acts of God;
- delays or decreases in production, the availability of equipment, facilities, personnel or services;
- delays or decreases in the availability of capacity to transport, gather or process production;
- military conflicts or civil unrest; and/or
- international border disputes or heightened geopolitical tensions.

For example, oil and natural gas operations in Jadestone's licence areas in Vietnam or Indonesia may be subject to higher political and security risks than those operations under the sovereignty of the United Kingdom. Jadestone plans to maintain insurance coverage for only a portion of the risks faced from doing business in these regions. There also may be certain risks covered by insurance where the policy does not reimburse for all of the costs related to a loss. Further, as many of Jadestone's licences are concentrated in the same geographic area, a number of licences could experience the same conditions at the same time, resulting in a relatively greater impact on results of operations than they might have on other companies that have a more diversified portfolio of licences.

The development schedule of oil and natural gas projects is capital intensive and can be subject to delays and cost overruns

Projects in the oil and natural gas industry have historically experienced delays and capital cost increases and overruns due to, among other factors, the unavailability or high cost of drilling rigs and other essential equipment, supplies, personnel and oilfield services, as well as mechanical and technical issues. The cost to develop projects has not been fixed and remains dependent upon a number of factors, including the completion of detailed cost estimates and final engineering, contracting and procurement costs and host government and partner cooperation. Construction and operation schedules may not proceed as planned and may experience delays or cost overruns.

The Group's decommissioning liabilities may be onerous and cannot be accurately predicted

The Group, including following Completion, has through its licence interests assumed certain obligations in respect of the decommissioning of its licences and related infrastructure and is expected to assume additional decommissioning liabilities in the future. These liabilities are derived from legislative and regulatory requirements concerning the decommissioning of wells and production facilities and at the appropriate time will require the Group to make provisions for and/or underwrite the liabilities relating to its share of such decommissioning costs. It is difficult to forecast accurately the costs that the Group will ultimately incur in satisfying its decommissioning obligations, particularly as: (i) the costs of decommissioning are highly volatile, being linked to rig rates, as well as oil and gas capital expenditures generally; and (ii) regulations determining the decommissioning standards may change.

The Group does not currently have a sinking fund to meet the costs of decommissioning its current assets. The estimated timing of decommissioning is dependent upon a number of factors and a material reduction in asset profitability may bring forward such timing to a date earlier than originally envisaged. When its decommissioning liabilities crystallise, the Group will be jointly and severally liable for them with current licence partners and, in some jurisdictions, former licence partners. In the event that other partners default on their obligations, the Enlarged Group will remain liable and its decommissioning liabilities could be magnified significantly through such default. Any significant increase in the actual or estimated decommissioning costs that the Enlarged Group incurs may adversely affect its financial condition.

The Group and, following Completion, the Enlarged Group may not be successful in obtaining new licences and assets

Future oil and gas production will to some extent depend on the Group's access to new reserves through exploration, development and acquisitions. The Group has in the past applied for, and been successful in receiving, licence awards in various jurisdictions and plans to continue to make such applications in the future. Failures in licence applications, exploration and development activities or in identifying and finalising transactions to access potential reserves would slow the Group's oil and gas production growth and replacement of Reserves. This, in turn, could have a material adverse effect on the Group's business.

The Group may be subject to financial and operational risks associated with farm-out arrangements

The Group has farmed out in the past, and intends to continue to farm-out, various commitments to third parties in circumstances where such third parties have agreed to take an assignment of an interest in one or more licences in return for paying not only the costs associated with that assigned interest but also a proportion of the costs associated with the Group's retained interest in such licence. Often these costs are associated with the drilling of a well or a development and therefore can be material. There is a risk that the relevant third parties may not meet their obligations under the farm-out agreements, the underlying operations may not meet the conditions of the farm-out or the farm-out counterparty may not be able to fulfil its associated obligations, any of which may mean that the Group may have to re-assume those obligations and bear the full costs associated with its retained interest. This in turn could have a material adverse effect on the Group's business and financial condition.

Ogan Komering PSC re-entry or future payments are not guaranteed and could be more costly than estimated and ultimately not in the interest of shareholders

Pertamina are currently 100% owner and operator of the Ogan Komering PSC, following the new gross split PSC which was signed, effective 20 May 2018, by Pertamina, Indonesia's upstream regulator SKKMIGAS, and the Minister of Energy and Mineral Resources. Jadestone, as the prior partner in the PSC, with Pertamina, has been directed to proceed with direct negotiations for participation in the new PSC.

There can be no assurance that Jadestone will be successful in its negotiations for participation in the PSC or that the terms of participation are economical for Shareholders. Any changes to the timing or quantum of realised costs to re-enter the PSC or futures receipts will impact the future profitability of the Company.

Fluctuations in Oil Prices

Declines in oil prices will adversely affect the Company's financial condition, liquidity and results of operations.

Oil prices have decreased significantly since mid-2014. Although prices have recovered from these lows there is no certainty that prices will not fall again and any prolonged period of low crude oil prices could result in a decision by the Company to suspend or slow exploration and development activities or reduce production levels. Any such actions could have a material adverse effect on the Company's business, financial condition, results of operations and prospects and ultimately on the market price of the Common Shares. In addition, any bank borrowings that may be made available to the Company in the future will be in part determined by the borrowing base of the Company. A sustained material decline in prices from historical average prices could reduce the Company's future potential borrowing base, therefore reducing the level of any bank credit that could be made available to the Company.

Volatility in oil and natural gas prices makes it difficult to estimate the value of producing properties for acquisitions and often causes disruption in the market for oil and natural gas producing properties, as buyers and sellers may have difficulty agreeing on the value of such properties. Price volatility also makes it difficult to budget for and project the return on acquisitions and development and exploitation projects.

Lower commodity prices will also be a factor in the Company's efforts to raise additional capital. Management takes the availability of investment capital into consideration as it evaluates acquisition opportunities so as to minimise the possibility of becoming illiquid by acquiring assets that may require more capital than the Company can provide.

Access to markets

The Company, along with all other oil and gas industry participants, may have reduced access to capital in the future. Although the business and the quality of the asset base of the Company has not deteriorated, the lending capacity of financial institutions may diminish and risk premiums may increase in the future if debt financing was sought. In addition to funds generated from internal operations, future capital expenditures may potentially be financed using external sources including bank borrowings and equity sales. The ability of the Company to access these two external sources of finance is dependent on, among other factors, the overall state of capital and debt markets and investor and bank appetite for investments and lending into the energy industry and into the Company in particular.

To the extent that external sources of capital become limited or unavailable or available only on onerous terms, the Company's ability to make capital investments and maintain existing assets may be impaired, and its assets, liabilities, business, financial condition and results of operations may be materially and adversely affected as a result.

Prices and marketability

The marketability and price of oil and natural gas that may be produced, acquired or discovered by Jadestone is and will continue to be affected by numerous factors beyond its control. Jadestone's ability to market its oil and natural gas depends upon its ability to acquire space on pipelines that deliver natural gas to commercial markets. Jadestone is also affected by deliverability uncertainties related to the proximity of its reserves to gathering systems, pipelines and processing and storage facilities and related to operational problems affecting such pipelines and facilities as well as extensive government regulation relating to price, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and many other aspects of the oil and natural gas business.

Variations in foreign exchange rates and interest rates

The reporting and functional currency of the Company is United States dollars. Substantially all of the Company's operations are in Vietnam, the Philippines, Australia and Indonesia while substantially all of its revenue is invoiced in United States dollars. As a result, the Company is exposed to foreign currency exchange rate risk on some of its activities primarily on exchange fluctuations between the CAD, Australian dollar, Indonesian Rupiah, Vietnamese Dong and the USD.

To the extent that Jadestone determines to engage in risk management activities related to foreign exchange rates in the future, there is a credit risk associated with counterparties with which Jadestone may contract.

The Group's debt facilities are subject to a range of interest rates. Any increase in those interest rates could result in a significant increase in the amount Jadestone pays to service any future debt obligations that the Company establishes. Increased levels of interest payable could negatively impact the market price of the Company's Common Shares.

Competition

The international oil and gas industry is highly competitive in all aspects, including the exploration for and the development of new licence areas. Jadestone operates in a highly competitive environment for acquiring exploratory licences and hiring and retaining trained personnel. Jadestone faces intense competition from independent, technology-driven companies as well as from both major and other independent oil and gas companies in seeking oil and gas exploration and production licences in Vietnam, the Philippines, Australia and Indonesia. These companies may be better able to withstand the financial pressures of unsuccessful drilling efforts, sustained periods of volatility in financial markets and generally adverse global and industry-wide economic conditions, and may be better able to absorb the burdens resulting from changes in relevant laws and regulations, which could adversely affect Jadestone's competitive position. The Company also faces competition in marketing oil and natural gas production, hiring skilled industry personnel and acquiring the equipment and expertise necessary to develop and operate properties. As a result of these and other factors, Jadestone may not be able to compete successfully in an intensely competitive industry, which could cause a material adverse effect on its results of operations and financial condition.

Jadestone may be exposed to liabilities under anti-corruption laws

Jadestone is subject to the FCPA and other laws that prohibit improper payments or offers of payments to foreign government officials and political parties for the purpose of obtaining or retaining business or otherwise securing an improper business advantage. In addition, the United Kingdom has enacted the Bribery Act 2010, and Jadestone may be subject to that legislation under certain circumstances. Jadestone currently does business and may do additional business in the future in countries in which Jadestone may face, directly or indirectly, corrupt demands by officials. Jadestone faces the risk of unauthorised payments or offers of payments by one of its employees, contractors or consultants to government officials. Jadestone has implemented policies and procedures to ensure compliance with the FCPA and other applicable legislation, but those policies may not always prevent any such unauthorised payments, and Jadestone's employees and consultants may engage in conduct for which it might be held responsible. Violations of the FCPA may result in severe criminal or civil sanctions, and Jadestone may be subject to other liabilities, which could negatively affect its business, operating results and financial condition. In addition, the U.S. government may seek to hold Jadestone liable for successor liability for FCPA violations committed by companies in which it invests (for example, by way of acquiring equity interests in, participating as a joint venture partner with, acquiring the assets of, or entering into certain commercial transactions with) or that it acquires.

Environmental risks

Jadestone's current and future operations that are conducted in Vietnam, the Philippines, Indonesia and Australia are subject to environmental regulations promulgated by the respective governments. Should Jadestone initiate operations in other countries, such operations will be subject to environmental legislation in such jurisdictions. Current environmental legislation in Vietnam, Philippines, Indonesia and Western Australia provides for restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil, condensate and natural gas operations. In addition, certain types of operations may require the submission and approval of environmental impact assessments. Jadestone's existing operations are subject to such environmental policies and legislation. Environmental legislation and policy is periodically amended. Such amendments may result in stricter standards and enforcement and in more stringent fines and penalties for non-compliance. Environmental assessments of existing and proposed projects carry a heightened degree of responsibility for companies and their directors, officers and employees. The costs of compliance associated with changes in environmental regulations could require significant expenditures, and breaches of such regulations may result in the imposition of material fines and penalties. In an extreme case, such regulations may result in temporary or permanent suspension of production operations. There can be no assurance that these environmental costs or effects will not have a materially adverse effect on Jadestone's future financial condition or results of operations.

Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require Jadestone to incur costs to remedy such discharge. No assurance can be given that the application of environmental laws to the business and operations of Jadestone will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise adversely affect Jadestone's financial condition, results of operations or prospects.

Environmental requirements

Environmental legislation in Vietnam, the Philippines, Indonesia and Australia provides for restrictions and prohibitions on releases or emissions and regulation of the storage and transportation of various substances produced or utilised in association with certain oil industry operations. This legislation and associated regulations can affect the location and operation of wells and facilities and the extent to which exploration and development is permitted. Applicable environmental laws may impose remediation obligations with respect to property designated as a contaminated site upon certain responsible persons, which include persons responsible for the substance causing the contamination, persons who caused the release of the substance and any past or present owner, tenant or other person in possession of the site. Compliance with such legislation can require significant expenditures and a breach of such legislation may result in the suspension or revocation of necessary licences and authorisations, civil liability for pollution damage, the imposition of fines and penalties or the issuance of clean-up orders.

Environmental legislation and policy is periodically amended. Such amendments may result in stricter standards and enforcement and in more stringent fines and penalties for non-compliance. Environmental assessments of existing and proposed projects carry a heightened degree of responsibility for companies and their directors, officers and employees. The costs of compliance associated with changes in environmental regulations could require significant expenditures, and breaches of such regulations may result in the imposition of material fines and penalties. In an extreme case, such regulations may result in temporary or permanent suspension of production operations and associated activities.

The Group's operations may be subject to delays or disruption due to actions by environmental or other stakeholder groups

The Group's operations may in the future be subject to delays or disruption as a result of actions by environmental or other stakeholder groups. There can be no assurance that actions by non-governmental organisations or other stakeholder or community groups in the future will not result in the revocation of the Group's licences or agreements and/or delays or disruption in the Group's exploration, appraisal, development or production activities, which could have a material adverse effect on the Group's business, results of operations, financial condition and prospects.

The Group will be subject to ongoing health, safety, environmental and security ("HSES") risks

The Group's HSES risks include major process safety incidents, failure to comply with approved legislation or policies, effects of natural disasters and pandemics, exposure to general operational hazards, personal health and safety, strikes, non-governmental organisation activity, terrorism and crime. The consequences of such risks materialising can include injury, loss of life, environmental harm, disruption to business activities and financial loss. Depending on cause and severity, the materialisation of such risks may have a material adverse effect on the Group's business. In addition, failure by the Group to comply with applicable legal requirements or recognised international standards may give rise to significant liabilities. HSES laws and regulations have become more complex and stringent and/or the subject of increasingly strict interpretation or enforcement, particularly since the Montara Incident in 2009, and may become more so over time. There may also be unforeseen environmental liabilities resulting from oil and gas activities which may be costly to remedy. In particular, the acceptable level of pollution and potential clean-up costs and obligations and liability for toxic or hazardous substances for which the Group may become liable as a result of its activities may be impossible to assess against the current legal framework and current enforcement practices of the various jurisdictions. The terms of licences may include more stringent HSES requirements. The obtaining of exploration, development or production licences and permits may become more difficult and/or be the subject of delay by reason of governmental, regional or local environmental consultation, approvals or other considerations or requirements. These factors may lead to delayed or reduced exploration, development or production activity as well as to increased costs and may have a material adverse effect on the Group's business.

Reputational risk

Any environmental damage, loss of life, injury or damage to property caused by the Group's operations could damage the Group's reputation in the regions in which the Group operates. Negative sentiment towards the Group in those regions, including among the local communities and other stakeholders, could result in a lack of willingness of the relevant governmental authorities to grant the necessary licenses or permits to the Group to operate its business, and communities in the areas where the Group is doing business opposing further operations in the area by the Group. Further, the Group's reputation could be affected by actions and activities of other corporations operating in the oil and gas industry, over which the Group has no control.

Alternatives to and changing demand for petroleum products

Fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas, and technological advances in fuel economy and energy generation devices could reduce the demand for crude oil and other liquid hydrocarbons. Jadestone cannot predict the impact of changing demand for oil and natural gas products, and any major changes may have a material adverse effect on Jadestone's business, financial condition, results of operations and cash flows.

The Group may be subject to labour disturbances

Labour disturbances, such as work stoppages or lock-outs, which may involve third party contractors, suppliers and customers, may occur in the future, particularly as the workforce engaged on each of the Stag and Montara Assets is unionised and subject to collective bargaining arrangements. These collective bargaining arrangements are subject to review from time to time and the Group may not be able to negotiate acceptable new bargaining agreements for the unionised Stag and/or Montara workforces, which could result in labour disputes, work stoppages or other disturbances to the status quo. Such disturbances could have a material adverse impact on the Group's production and development schedule and activities in the periods during which they occur. The Group or its contractors may be unable to influence acceptable collective bargaining outcomes or future restructuring agreements or the Group's operations may become subject to material cost increases or additional work rules as a result of any new collective bargaining agreements. If occurrences of the foregoing are material and/or ongoing, they could adversely affect the Group's business, prospects, financial condition and results of operations. In addition, material changes in the minimum wage, or other material changes in labour laws, could have a material adverse impact on the Group's operations. Although the Group is focused on maintaining good relations with its employees and contractors, there can be no guarantee that labour disturbances will not occur.

In the event that Jadestone plans to increase production from the Montara Assets and is not successful, and Jadestone is unable to reduce unit operating costs, if there is a significant fall in the realised oil price (after hedging), the Montara Assets could become uneconomic to produce, leading to a material adverse effect on the Company's ability to service the RBL Facility and, ultimately, continue as a going concern.

3 RISKS RELATING TO THE ACQUISITION AND THE PLACING

The level of operational performance of the Montara Assets has been historically low

The Montara Assets have historically struggled to achieve an availability performance which is acceptable for an asset of this nature and age, largely due to reliability issues and recurrent operational failures occurring on a consistent basis. The Company is of the view that the current condition of the Montara Assets leaves room for improvement in terms of operational availability of the assets. However, there can be no guarantee that the Company will be able to achieve its desired objectives as regards asset performance and operational availability.

The Montara Assets are subject to greater regulatory scrutiny following the 2009 incident

The Montara Incident in 2009 prompted increased regulatory scrutiny on the Montara Assets, primarily from the National Offshore Petroleum Safety and Environmental Management Authority (NOPSEMA) in Australia. This has imposed, and will likely continue to impose, an additional administrative burden on management to ensure full compliance with the existing and any new regulations. There is also a risk that the new safety case may not be accepted should even a single element be challenged by NOPSEMA. The Company is committed to ensuring full compliance with the relevant regulations and safety requirements and will be actively engaging with NOPSEMA regarding its management of the Montara Assets going forward, however there can be no assurance that NOPSEMA will provide favourable decisions.

The Montara Assets have historically incurred higher than industry standard operating costs

The operational expenditure required to maintain the performance of the Montara Assets is considered higher than regional analogues. The Company considers that it can improve general asset availability, reduce operational costs and achieve better standards of asset performance through active management and implementing its plans for the Montara Assets which it has previously successfully deployed in relation to its other assets. There remains a risk, however, that the operational performance and operating costs of the Montara Assets remain higher than optimal for some time until the Company has implemented its asset transition programme.

The acquisition of the Montara Assets by Jadestone requires the approval of NOPTA

Transfer of the legal title to the Montara Assets to Jadestone requires NOPTA to approve the Acquisition Agreement and the transfer of the title. NOPTA will wish to satisfy itself as to Jadestone's financial capability to participate in licence operations and to discharge its licence obligations. Such approval is a condition precedent for completion of the Acquisition Agreement and, accordingly, if not received, the Acquisition will not complete. It is currently anticipated that such approval could take several months to obtain, although Jadestone can provide no assurances that such approval will be received within this anticipated timeframe or indeed be received at all.

The transfer of the operatorship of the Montara Assets to Jadestone requires the approval of NOPSEMA

Whilst Jadestone is already the approved operator of the Stag Assets, in order to become the operator of the Montara Assets, Jadestone requires approval of a new safety case by NOPSEMA and as part of this Jadestone will be required to prepare a new WOMP and EP. Such approval is a condition precedent for the operatorship to transfer to Jadestone under the Acquisition Agreement and, accordingly, if not received, operatorship of the Montara Assets will not transfer to Jadestone. It is anticipated that such approval could take some months to obtain, although Jadestone can provide no assurances that such approval will be received within this anticipated timeframe or indeed be received at all.

Jadestone will need to engage a large number of contractors to manage operations relating to the Montara Assets following transfer of operatorship

The Montara Assets require engagement of a significant number of contractors to provide services to maintain its operations and continued performance. Many of these contracts may not be assignable. Accordingly, in the period between the execution of the Acquisition Agreement and transfer of the operatorship, Jadestone will need to agree terms with new contractors to provide services in place of these existing contractors. This may be a costly and time-consuming task for Jadestone's management which, if not managed successfully, or if the required number of contractors are not available, could result in a material adverse effect on the Enlarged Group's results of operations, financial condition and prospects.

The Group's future prospects will, in part, be dependent on effective integration of the Montara Assets into the Group

The Group's future prospects will, in part, be dependent upon the Group's ability to integrate the Montara Assets into the Group successfully and any other businesses that it may acquire in the future without material disruption to the existing business, including as a result of the integration of operational systems. A failure to successfully manage the integration of the Montara Assets could have a material adverse effect on the Enlarged Group's results of operations, financial condition and prospects.

The Montara Assets currently yield a premium to Brent crude oil

Whilst the market currently pays a premium for the oil produced at the Montara Assets due to its physical characteristics, there can be no assurances that these physical characteristics will continue to be present or that the market will continue to be willing to pay such a premium for oil demonstrating those characteristics. If either of these were to occur then it could impact the Group's revenues which in turn could have a material adverse effect on the Group's business, results of operations, financial condition and prospects.

The Montara Venture FPSO is currently operating under Class Suspension

The Montara Venture FPSO is subject to continuous hull survey, which includes surveys of the cargo and ballast tanks on a five year cycle in order to maintain vessel classification. PTTEP was advised in September 2017 that its classification would be suspended due to failure to complete hull surveys in the required time. Lloyd's Register suspended Class on the vessel on 3 January 2018. Jadestone and PTTEP have agreed a detailed work plan to return the FPSO vessel to Class. It is expected that these works will be completed, and the vessel returned to Class prior to completion of the Acquisition. However, if the Company and/or PTTEP are unable to execute the work programme for any reason, suspension of Class would be maintained. If Class remains suspended for a prolonged period of time, the Australian regulator NOPSEMA may require the production from the Montara fields to be shut-in pending reclassification of the vessel. A prolonged shut-in of the Montara fields could have a material impact on the production, reserves and financial position of the Company.

In addition, the terms of the RBL Facility include a condition precedent regarding the reinstatement of Class, which condition will need to be satisfied or waived prior to drawdown under the RBL Facility. If this condition precedent cannot be satisfied or waived, there is a risk that Jadestone may be unable to drawdown under the RBL Facility and have insufficient funding to complete the Acquisition. However, the Acquisition Agreement will not be capable of completion until PTTEP delivers certain documentation to Jadestone regarding the class reinstatement process.

The Montara incident indemnity may be insufficient or the Seller may be unable to satisfy any claims under the indemnity

The Acquisition Agreement contains an indemnity from the Seller in relation to any latent liabilities incurred or suffered by Jadestone Energy (Eagle) Pty Ltd (as buyer) as a result of the major oil and gas leakages which occurred at the Montara site in 2009 (the "**Montara Incident Indemnity**"). Although the Directors have grounds to believe that the Montara Incident Indemnity will be sufficient to cover any liabilities which the Group may incur in future, there is no guarantee that the Montara Incident Indemnity will be sufficient to cover all potential liabilities which may arise. In addition, there is no guarantee that PTTEP Australasia (as seller) and/or PTTEP Offshore Investment Company Limited (as seller's guarantor) will be able to satisfy any claim which the Buyer successfully makes pursuant to the Montara Incident Indemnity.

The Acquisition and the Placing are subject to a number of conditions that may not be satisfied

The implementation of the Placing and Admission is subject to the satisfaction (or waiver, where applicable) of a number of conditions, including no event having arisen at any time prior to Admission which gives any party a right to terminate the Acquisition Agreement and there not having occurred any material adverse change in relation to the Group and certain approvals, including without limitation, FIRB and TSX-V. There is no guarantee that these (or any other) conditions of the Placing Agreement will be satisfied (or waived, if applicable), in which case the Placing will not be completed. In addition, the Company has entered into the RBL Facility to partially finance the consideration payable by the Company under the Acquisition Agreement. There are a number of conditions to drawdown under the RBL Facility and there is no guarantee that all such conditions precedent will be satisfied, or waived, in accordance with the terms of the RBL Facility. If the RBL Facility does not become unconditional in accordance with its terms, there is a risk that the Company will have insufficient funding to proceed to completion of the Acquisition Agreement.

There is no guarantee that these (or any other) conditions of the Acquisition Agreement will be satisfied (or waived, if applicable), in which case the Acquisition will not be completed. The conditions are summarised in more detail in paragraph 3.1 of Part 4 of this document.

If completion of the Placing and/or the Acquisition does not occur, the Company would nonetheless be obliged to pay certain costs (including due diligence and advisory fees) incurred in connection with the Placing and the Acquisition. In anticipation of the Placing and Completion, the Company will also have invested significant time and resources (including that of the Directors and senior management) and, in the meantime, may not have been able to capitalise on other transaction opportunities.

There is a risk that there may be circumstances where the Placing and Admission have completed, but certain of the remaining conditions under the Acquisition Agreement including, without limitation, receipt of the necessary regulatory approvals, are incapable of satisfaction and/or waiver. In this scenario, the proceeds of the Placing will not be able to be applied in connection with completion of the Acquisition and the Company will retain the proceeds of the Placing to apply to future acquisitions.

There can be no assurance that Jadestone will realise the anticipated benefits of the Acquisition

Jadestone may not realise the anticipated benefits from the Acquisition or may encounter difficulties in achieving the anticipated benefits. The Group is subject to all of the risks set forth in this ''Risk Factors'' section which may impact the Group's ability to realise the benefits which the Directors believe will result from the Acquisition. In addition, if the future financial performance and cash flows generated by the Company are not in line with the Directors' expectations, it may affect the financial performance of the Group. This could reduce the potential benefits arising from the Acquisition, adversely affect the market price of the Common Shares, or have a material adverse effect on the Group's business, financial condition, operating results and prospects.

The due diligence carried out in respect of the Acquisition may not have revealed all relevant facts or uncovered significant liabilities

While the Company conducted due diligence in respect of the Montara Assets with the objective of identifying any material issues that may affect its decision to proceed with the Acquisition, there can be no assurance that all such issues have been identified. The Company also used information revealed during the due diligence process to formulate its business and operational planning. During the due diligence process, the Company is only able to rely on the information that was made available to it. Any information that was provided or obtained from available sources may not have been accurate at the time of delivery and/or remained accurate during the due diligence process and in the run-up to the Acquisition.

More broadly, there can be no assurance that the due diligence undertaken was adequate or accurate or revealed all relevant facts or uncovered all significant liabilities. If the Company considered certain material risks to be commercially acceptable, the Company may be forced to write-down or write-off assets in respect of the Group, which may have a material adverse effect on the Group's business, financial condition or results of operations. In addition, following the Acquisition, the Company may be subject to significant, previously undisclosed liabilities in relation to the Montara Assets that were not known or identified during due diligence and which could have a material adverse effect on the Group's business, financial condition and results of operations.

Acquisition and integration costs may be greater than anticipated

The Company expects to incur a number of costs in relation to the Acquisition, including integration and post-completion costs in order to successfully combine the operations of the Montara Assets into the Group, assuming the Acquisition completes. The actual costs of the acquisition and integration process may exceed those estimated and there may be further additional and unforeseen expenses incurred in connection with the Acquisition. In addition, the Group will incur legal, accounting, financial adviser and transaction fees and other costs relating to the Acquisition, some of which are payable whether or not the Acquisition reaches Completion. Although the Directors believe that the integration and Acquisition costs will be more than offset by the realisation of the benefits resulting from the Acquisition, this net benefit may not be achieved in the short-term or at all, particularly if the Acquisition is delayed or does not complete. These factors could materially adversely affect the business, financial conditions, results of operations and prospects of the Group.

4 RISKS RELATING TO THE COMMON SHARES

It may be difficult to realise an investment on AIM

The Common Shares will be quoted on AIM. The AIM Rules are less demanding than those of the Official List and an investment in a security that is traded on AIM may carry a higher risk than an investment in securities listed on the Official List. The price of publicly traded securities can be highly volatile.

It may be more difficult for an investor to realise his or her investment in the Company than to realise an investment in a company whose shares or other securities are listed on the Official List or other similar stock exchange. Shares held on AIM are perceived to involve higher risks. AIM is a market designed for small and growing companies but its future success and liquidity as a market for Common Shares cannot be guaranteed.

Market price of Common Shares

The price at which Common Shares are traded and the price at which investors may realise their investment are influenced by a large number of factors, some specific to the Company and its operations and some which may affect growth companies or quoted companies generally. Admission to AIM does not imply that there will be a liquid market for Common Shares. Consequently, the price of Common Shares may be subject to fluctuation on small volumes, and Common Shares may be difficult to sell at a particular price, or at all.

Investor sentiment

A number of factors, including concerns about the effects of the use of fossil fuels on climate change and the environment generally, concerns about environmental damage relating to spills of petroleum products during transportation and concerns about indigenous rights, have affected certain investors' sentiments towards investing in the oil and gas industry. As a result of these concerns, some institutional, retail and public investors have announced that they are no longer willing to fund or invest in oil and gas properties or companies or are reducing the amount thereof over time. In addition, certain institutional investors are requesting that publicly-listed oil and gas companies develop and implement more robust social, environmental and governance policies and practices. Developing and implementing such policies and practices can involve significant costs and require a significant time commitment from the Board and management of the Group. Failing to implement the policies and practices as requested by institutional investors may result in such investors reducing their investment in the Group or not investing in the Group at all. Any reduction in the investor base interested or willing to invest in the oil and gas industry and more specifically, the Group, may result in limiting the Group's access to capital, increasing the cost of capital, and decreasing the price and liquidity of the Common Shares.

There is currently no UK market for the Common Shares, notwithstanding the Company's intention to be admitted to trading on AIM

There is currently no UK market for the Common Shares. Although the Company's current intention is that its securities should continue to trade on AIM, it cannot assure investors that it will always do so. In addition, an active UK trading market for the Common Shares may not develop or, if developed, may not be maintained. Investors may be unable to sell their Common Shares unless a market can be established and maintained, and if the Company subsequently obtains a further listing on an exchange in addition to, or in lieu of, the London Stock Exchange, the level of liquidity of the Common Shares may decline.

The Common Shares will be listed on two separate stock markets and investors seeking to take advantage of price differences between such markets may create unexpected volatility in the share price

The Common Shares are already listed and traded on the TSX-V and upon Admission will also be listed and traded on AIM. While the Common Shares are traded on both markets, price and volume levels could fluctuate significantly on either market, independent of the share price or trading volume on the other market. Investors could seek to sell or buy Common Shares to take advantage of any price differences between the two markets through a practice referred to as arbitrage. Any arbitrage activity could create unexpected volatility in both Common Share prices on either exchange and in the volumes of Common Shares available for trading on either market. In addition, holders of Common Shares in either jurisdiction will not immediately be able to transfer such shares for trading on the other market without effecting necessary procedures with the

Company's transfer agents/registrars. This could result in time delays and additional cost for Shareholders.

Dividends

Jadestone has never paid a dividend nor made a distribution on any of its securities. Further, Jadestone may never achieve a level of profitability that would permit payment of dividends or making other forms of distributions to security holders. Any decision to pay dividends on the Common Shares will be made by the board of directors of Jadestone on the basis of Jadestone's earnings, financial requirements and other conditions existing at such future time. In this regard, the Company currently intends to introduce a cash dividend as soon as reasonably practicable after the first anniversary of Completion of the Acquisition. However, this intention will be subject to the Group's financial condition, future prospects, profits legally available for distribution, the need to maintain an appropriate level of dividend cover, distribution restrictions and financial covenants and other factors deemed by the Board to be relevant at that time, in accordance with the Articles and subject to compliance with the Act. Accordingly, there can be no guarantee that the Company will pay any dividend in future.

Issuance of debt

From time to time Jadestone may enter into transactions to acquire assets or the shares of other organisations. These transactions may be financed in whole or in part with debt, which may increase Jadestone's debt levels above industry standards for oil and natural gas companies of similar size.

Depending on future exploration and development plans, Jadestone may require additional equity and/or debt financing that may not be available or, if available, may not be available on favourable terms. Jadestone's articles does not limit the amount of indebtedness that Jadestone may incur. The level of Jadestone's indebtedness from time to time, could impair Jadestone's ability to obtain additional financing on a timely basis to take advantage of business opportunities that may arise.

Dilution and future sales of Common Shares by the Company

Jadestone may, subject to applicable securities laws, its Articles and stock exchange rules, issue additional Common Shares in the future which may dilute a shareholder's holdings in the Company.

The Articles permit the issuance of an unlimited number of Common Shares and an unlimited number of Class B Shares and shareholders will have no pre-emptive rights in connection with such further issuances of either Common Shares or Class B Shares. The directors of the Company have the discretion to determine the terms of issue of further issuances of Common Shares or Class B Shares.

In addition, the terms of the Convertible Facility give the lender the option to require the Company to obtain external debt finance in order to repay the Convertible Facility. If the Convertible Facility is not repaid as expected and if such option was exercised by Tyrus, the Company may need to incur substantial further external borrowings to re-pay the Convertible Facility, which could have a negative impact on the Company's debt-to-equity ratio, credit rating and/or ability to service its other external debt. Alternatively, the lender may exercise its right to convert the Convertible Facility into new common shares in the Company, which may have a significant dilutive impact on the Company's then shareholders depending on the number and issue price of those new common shares.

Additional Common Shares will be issued by the Company on the exercise of options under the Company's stock option plan.

Forward-looking information may prove inaccurate

Investors are cautioned not to place undue reliance on forward-looking information. By its nature, forward looking information involves numerous assumptions, known and unknown risks and uncertainties, of both a general and specific nature, that could cause actual results to differ materially from those suggested by the forward-looking information or contribute to the possibility that predictions, forecasts or projections will prove to be materially inaccurate.

Additional information on the risks, assumptions and uncertainties are found in this document under the heading "Forward looking statements".

Substantial shareholder

The Company has a substantial shareholder, the Tyrus Fund, which on Admission is expected to hold approximately 23.8 per cent of the issued share capital and be able to exercise significant influence over matters requiring shareholder approval, including the election of Directors and significant corporate transactions. This concentration of ownership may have the effect of delaying or deterring a change in control of the Company, could deprive investors of an opportunity to receive a premium for their Common Shares as part of a sale of the Company and might affect the value of the Common Shares. Notwithstanding that the Tyrus Fund has agreed (subject to certain exceptions) not to dispose of any Common Shares for a period of 12 months following Admission, upon expiry of this lock-in the Tyrus Fund may sell all or part of its holdings of Common Shares and any such sale may adversely affect the market price of the Common Shares.

The ability of Shareholders to bring actions or enforce judgements against the Company or the Directors may be limited

The ability of a Shareholder outside Canada to bring an action against the Company may be limited under law. The Company is a limited company incorporated in British Columbia. The rights of holders of Common Shares are governed by Canadian law and by the Company's Articles. These rights differ from the rights of shareholders in typical English companies. A Shareholder outside the United Kingdom may not be able to enforce a judgement against the Company or some or all of the Directors and executive officers. Consequently, it may not be possible for a Shareholder outside Canada to effect service of process upon the Company or the Directors and executive officers within the Shareholder's country of residence or to enforce against the Company or the Directors and executive officers within the Shareholder's country of residence or to enforce against the Company or the Directors and executive officers' judgements of courts of securities laws. There can be no assurance that a Shareholder will be able to enforce any judgements in civil and commercial matters or any judgements under the securities laws of countries other than Canada against the Company or the Directors or executive officers who are residents of the UK or countries other than those in which judgement is made. In addition, English or other courts may not impose civil liability on the Company or the Directors or executive officers in any original action based solely on foreign securities laws brought against the Company or the Directors in a court of competent jurisdiction in England or other countries.

Company not governed by the UK Takeover Code

The Company is incorporated in Canada, and, accordingly, transactions in Common Shares in the Company will not be subject to the UK Takeover Code. As a result, Shareholders will not be afforded the protections of the UK Takeover Code. However, Canadian laws applicable to the Company provide for early warning disclosure requirements in relation to potential takeover bids, further details of which are set out in Section 16 of Part 1 of this document.

COMPETENT PERSON'S REPORT

3 August 2018

The Directors
Jadestone Energy Inc.
Suite 1000, 595 Howe Street
Vancouver BC, V6C 2T5
Canada

Stifel Nicolaus Europe Limited
150 Cheapside
London, EC2V 6ET
United Kingdom

BMO Capital Markets Limited
95 Queen Victoria Street
London, EC4V 4HG
United Kingdom

Dear Sirs,

RE: P3645 – YE2017 Reserves & Resources Report for Australia, Vietnam and Philippines Assets

In accordance with your instructions, ERC Equipoise Pte Ltd ("ERCE") has carried out an independent evaluation for Jadestone Energy Inc ("Jadestone" or the "Company") of assets located in licences AC/L7, AC/L8 and WA-15-L in Australia, Blocks 46/07 and 51 in Vietnam and Block SC56 in the Philippines. Jadestone holds a 100% working interest in WA-15-L, a 70% working interest in Block 46/07 and Block 51 and a 25% working interest in Block SC56. On 15 July 2018, Jadestone entered into a Sales and Purchase Agreement ("SPA") with PTTEP AA to acquire a 100% working interest in licences AC/L7 and AC/L8 in Australia; with operatorship expected to be transferred in 2018/19, subject to regulatory approval.

The asset Reserves & Resources evaluation has an effective date of 31 December 2017. ERCE has reviewed data made available through to 28 February 2018 for the evaluation of the Montara Assets, located offshore Australia in licences AC/L7 and AC/L8. For all other assets, data were available up to 31 December 2017. So far as we are aware, having made reasonable enquiries, no material change in the asset reserves and resources has occurred from 31 December 2017 to the date of this letter which would require any amendment to this Competent Persons Report (CPR).

ERCE has carried out the work using the March 2007 SPE/WPC/AAPG/SPEE Petroleum Resources Management System ("PRMS") as the standard for classification and reporting. A summary of the PRMS is found in Appendix 1 of this report. The full text can be downloaded from www.spe.org/spe-app/spe/industry/reserves/prms.htm.

ERCE is an independent consultancy specialising in geoscience evaluation, engineering and economic assessment. ERCE will receive a fee for the preparation of this report in accordance with normal professional consulting practices. This fee is not dependent on the findings of this CPR or on Admission and ERCE will receive no other benefit for the preparation of this CPR. ERCE does not have any pecuniary or other interests that could reasonably be regarded as capable of affecting its ability to provide an unbiased opinion in relation to the resources and reserves and the projections and assumptions included in the various technical studies completed by the Company, opined upon by ERCE and reported herein.

Neither ERCE nor the Competent Persons who are responsible for authoring this CPR, nor any Directors of ERCE have at the date of this report, nor have had within the previous two years, any shareholding in the Company, the Mineral Assets or Stifel Nicolaus Europe Limited, BMO Capital Markets Limited, or any other economic or beneficial interest (present or contingent) in any of the assets being reported on. ERCE is not a group, holding or associated company of the Company, Stifel Nicolaus Europe Limited or BMO Capital Markets Limited. None of ERCE's partners or officers are officers or proposed officers of any group, holding or associated company of the Company, Stifel Nicolaus Europe Limited or BMO Capital Markets Limited.

No Competent Person involved in the preparation of this CPR is an officer, employee or proposed officer of the Company or any group, holding or associated company of the Company, Stifel Nicolaus Europe Limited or BMO Capital Markets. Consequently, ERCE, the Competent Persons and the Directors of ERCE consider themselves to be independent of the Company, its directors, senior management and Stifel Nicolaus Europe Limited and BMO Capital Markets Limited.

The work has been supervised by Mr Stewart Easton and Mr Simon McDonald. Mr Easton is the General Manager for the Asia Pacific Region, with 24 years of experience in the oil and gas industry. He holds a MSc degree in Basin Evolution & Dynamics from Royal Holloway, University of London and a Bsc (Hons) degree in Geology from Edinburgh University. Mr Easton is a member of the SPE, PESGB and SEAPEX, as well as being a Fellow of the Geological Society of London. Mr McDonald is a Director of ERCE and has over 40 years of experience in the evaluation of oil and gas fields, preparation of development plans and assessment of Reserves. He holds a MSc degree in Petroleum Engineering from Imperial College London and a BSc (Hons) degree in Civil Engineering from Leeds University. He is a Chartered Engineer and President of the Society of Petroleum Evaluation Engineers. Both Mr Easton and Mr McDonald qualify as Competent Persons as defined by the AIM Rules.

ERCE has been informed that the Company is intending to publish an AIM Admission Document in connection with the proposed acquisition of the assets located in production licences AC/L7 and AC/L8 in Australia, associated plant and equipment (including the floating production and storage and offloading (FPSO) vessel and the wellhead platform) and certain related contracts (together, the "Montara Assets") and to seek admission to trading of the Company's shares on the London Stock Exchange's AIM Market ("AIM") ("Admission") as required under the AIM Rules for Companies and that as part of this it is required to include a report on the Company's reserves and resources (including the Montara Assets).

ERCE accepts responsibility for this CPR and for all of the technical information that has been directly extracted from the CPR and reported in the AIM Admission Document to be released by the Company in connection with Admission and to be dated around the same date as this letter.

ERC Equipoise Pte Ltd, 50B Tras Street, #03-02, Singapore 078989
Tel: +65 6332 5161 Email: **info@erce.com**

ERCE declares that it has taken all reasonable care to ensure that the information contained in the CPR and included in the Admission Document is, to the best of its knowledge, in accordance with the facts and contains no omission likely to affect its import.

In accordance with the AIM Rules for Companies, ERCE confirms that the presentation of information contained elsewhere in the Admission Document which relates to information in the CPR is accurate, balanced and not inconsistent with the CPR.

This report is addressed to Jadestone Energy Inc., its Nominated Adviser, Stifel Nicolaus Europe Limited and its joint broker BMO Capital Markets Limited. ERCE understands that this report will be included as part of an AIM admission document to be published by Jadestone (the "Admission Document"). For the purposes of the AIM Rules for Companies, ERCE is responsible for this report as part of the Admission Document and declares that it has taken all reasonable care to ensure that the information contained in this report is, to the best of its knowledge, in accordance with the facts and contains no omission likely to affect its import.

Yours faithfully,

Stewart Easton
General Manager, Asia Pacific Region,
ERC Equipoise Pte Ltd

Evaluation of Hydrocarbon Reserves and Contingent Resources of Jadestone Energy Inc's Assets

PREPARED FOR: Jadestone Energy Inc

BY: ERC Equipoise Pte Ltd

Date of Report: 15 July 2018

ERCE
Independent Energy Experts

Authors: A. Symms, M. Cuthbertson, S. Hattingh, R. Jenner, N. Bani Hassan, J. Ramsay, R. McArthur, J. Preston, A. Becis, J. Ho, Z. Ozarbayeva

Approved by: S. Easton & S. McDonald

Date Released to Client: 15 July 2018

Table of Contents

List of Figures

List of Tables

1. Summary

1.1. Introduction

ERC Equipoise Pte Ltd ("ERCE") was commissioned by Jadestone Energy Inc. ("Jadestone") to prepare an independent Reserves and Resources evaluation of its portfolio of the following assets:

- Australia: AC/L7, AC/L8 and WA-15-L
- Vietnam: Block 46/07 and 51
- Philippines: SC56

The effective date of the asset reserves and resources evaluations contained in this report is 31 December 2017. ERCE has reviewed data made available through to 28 February 2018 for the evaluation of the Montara Assets, located offshore Australia in licences AC/L7 and AC/L8. For all other assets, data were available up to 31 December 2017.

So far as we are aware, having made reasonable enquiries, no material change in the asset reserves and resources has occurred from 31 December 2017 to the date of this document, being 15 July 2018, which would require any amendment to this competent persons report (CPR).

ERCE has no obligation or undertaking to advise any person of any development in relation to the assets which are the subject of this CPR which comes to its attention after the date of this CPR or to review, revise or update the CPR or opinion in respect of any such development occurring after the date of this CPR.

A summary of the licence interests held by Jadestone is given in Table 1-1.

The Montara Assets are located in blocks AC/L7 and AC/L8 offshore Western Australia in a water depth of 77 m and comprise the Montara, Skua and Swift/Swallow fields (Figure 1.1). The Montara field has been on production since June 2013 and has produced 12.6 MMstb oil as of 31 December 2017. The Skua field was first developed and produced between 1991 and 1997 but was shut-in due to sub-commerciality. In March 2014, production recommenced and it has produced 25.4 MMstb oil as of 31 December 2017. The Swift/Swallow field has been on production since November 2013 and has produced 5.3 MMstb oil as of 31 December 2017. The combined current oil production rate for the Montara Assets is approximately 13,750 stb/d, just over half of which comes from the Montara field. Subsequent to the completion of the proposed acquisition of the Montara Assets under the SPA signed on 15 July 2018, Jadestone will hold a 100% working interest in AC/L7 and AC/L8.

The Stag oil field is located within the WA-15-L license in the Carnarvon Basin, approximately 60 km offshore Western Australia in a water depth of 47 m (Figure 1.2). The field has been producing since 1998 and has produced 65.2 MMstb oil as of 31 December 2017. The field had peak oil production of 26,000 stb/d in 2000, and has current production of approximately 3,800 stb/d. Jadestone holds a 100% working interest in licence WA-15-L.

The Nam Du discovery is located within the Block 46-07 PSC ("Block 46/07") on the northeastern margin of the Malay-Tho Chu Basin, approximately 200 km offshore Vietnam in a water depth of 47.9m (Figure 1.3). The field was discovered in 2013 by exploration Well 46/07-ND-1X, drilled by Mitra Energy. Jadestone holds a net working interest of 70% in Block 46/07, with the remaining 30% currently being held by PVEP. Effective May 2017, PVEP relinquished its 30% working interest in Block 46-07. The registration of this change is still pending.

The U Minh and Tho Chu discoveries are located within the boundaries of the Block 51 PSC ("Block 51") in the Malay-Tho Chu Basin, approximately 200 km offshore Vietnam in a water depth of 64 m (Figure 1.3). U Minh was discovered in 1997 by exploration Well 51-UM-1X, which is the only well on the field. Tho Chu was discovered in 2012 by exploration Well 51-TC-1X and later appraised in 2014 by Well 51-TC-2X. Jadestone holds a net working interest of 70% in Block 51, with the remaining 30% currently being held by PVEP. Effective May 2017, PVEP relinquished its 30% working interest in Block 51. The registration of this change is still pending.

The Dabakan and Palendag discoveries are located within the boundaries of Block SC56 in the Sandakan Basin, offshore Philippines, approximately 150 km off the coast of Malaysia (Figure 1.4). The Dabakan field was discovered in 2009 by the exploration Well Dabakan-1 in a water depth of 1802 m. The Palendag field was discovered in 2010 by the exploration Well Palendag-1A in a water depth of 1,937 m, and sits to the east of Well Dabakan-1. Jadestone holds a net working interest of 25% in SC56, with the remaining 75% being held by the operator, TOTAL E&P Philippines BV.

Table 1-1: Licence Summary

Field	Country	Licence	Operator	Jadestone Working Interest	Status	Licence Expiry Date	Licence Area (km2)	Comments
Montara	Australia	AC/L7	Jadestone Energy Inc	100% [1]	Production	Indefinite	252	Current production is circa 7,100 stb/d from 4 wells. Peak production of 15,000 stb/d reached in 2014.
Skua, Swift, Swallow	Australia	AC/L8	Jadestone Energy Inc	100% [1]	Production	Indefinite	420	Current production is circa 6,650 stb/d from 3 wells. Peak production of 25,000 stb/d reached in 1992.
Stag	Australia	WA-15-L	Jadestone Energy Inc	100%	Production	Aug-2039	160	Current production is circa 3,800 stb/d from 11 wells. Peak production of 26,000 stb/d reached in 2000.
Nam Du	Vietnam	Block 46/07	Jadestone Energy Inc	70% [2,3]	Development	Jun-2035	2,622	Development drilling expected to begin in Q1 2021.
U Minh	Vietnam	Block 51	Jadestone Energy Inc	70% [3]	Development	Jun-2035 (oil) Jun-2040 (gas)	2,900	Development drilling expected to begin in Q1 2023.
Tho Chu	Vietnam	Block 51	Jadestone Energy Inc	70% [3]	Appraisal	Jun-2035 (oil) Jun-2040 (gas)	2,900	Further appraisal drilling required before RAR submission can be considered.
Dabakan	Philippines	SC56	TOTAL E&P Philippines BV	25%	Development	Aug-2055	6,220	No defined development scenarios.
Palendag	Philippines	SC56	TOTAL E&P Philippines BV	25%	Development	Aug-2055	6,220	No defined development scenarios.

Notes:

1) Subject to the completion of the acquisition of PTTEP AA's 100% interest in AC/L7 and AC/L8.
2) Subject to a 3% back-in right by a third party at cost.
3) Effective May 2017, Petrovietnam relinquished its 30% interest in the block. The registration of this change is still pending.

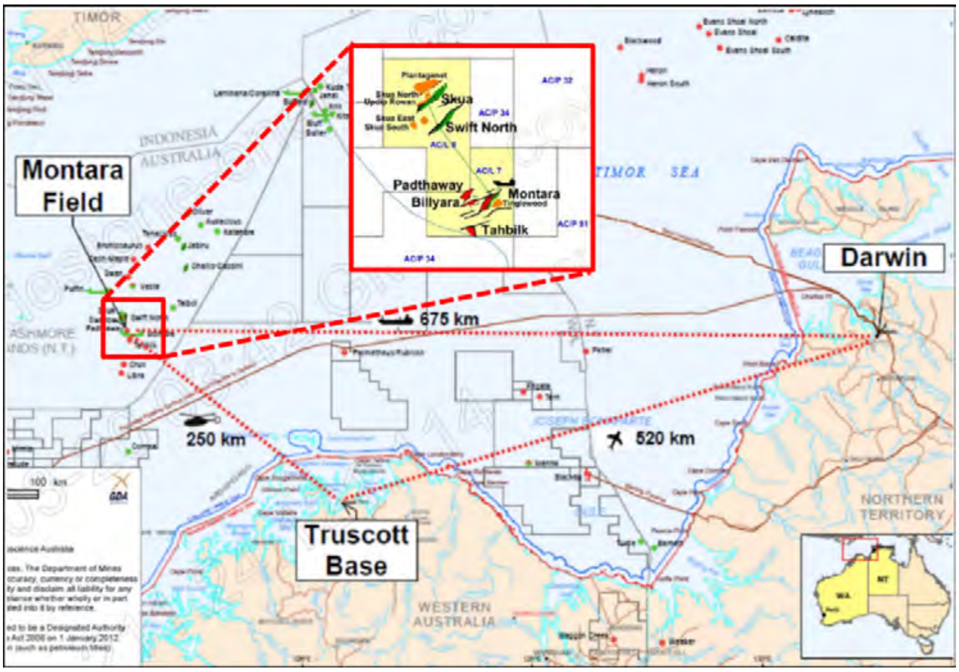


Figure 1.1: Location map of the Montara Assets, AC/L7 and AC/L8, offshore Western Australia

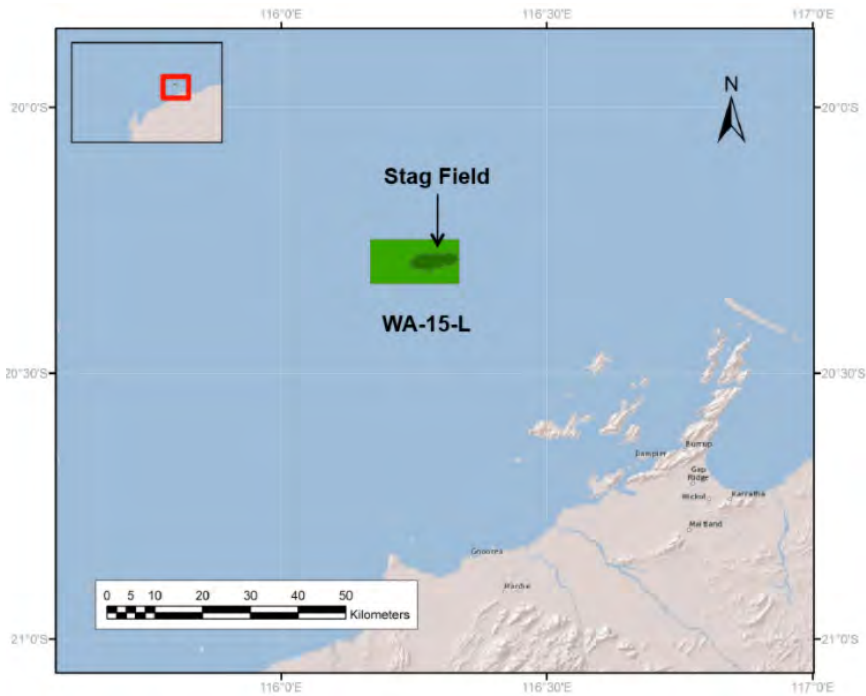


Figure 1.2: Location map of the Stag Field, WA-15-L, offshore Western Australia

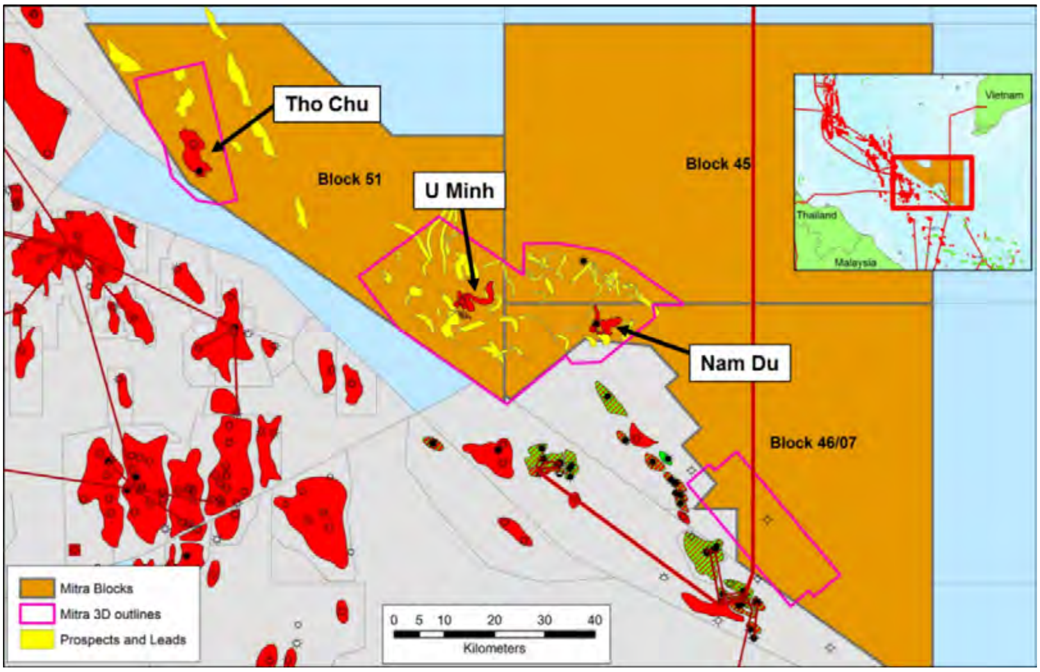


Figure 1.3: Location map of Nam Du, U Minh and Tho Chu Discoveries, Blocks 46/07 & 51, offshore Vietnam

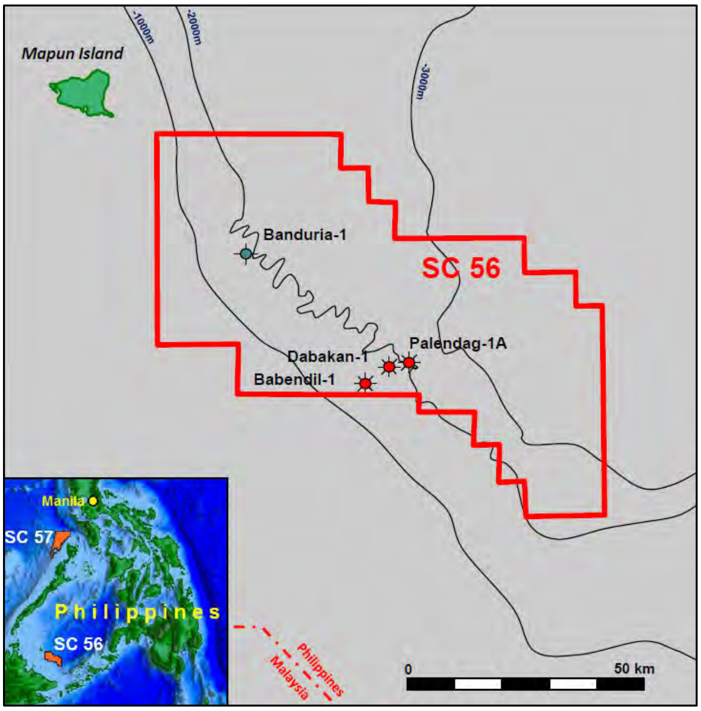


Figure 1.4: Location map of Dabakan and Palendag Discoveries, Block SC56, offshore Philippines

1.2. Data Provided

ERCE was provided with a dataset which comprised:

- Well data, where available, including composite logs, mud logs and end of well reports
- Open-hole well logs and petrophysical interpretation
- Core data and analysis thereof, where available
- Well test data and formation pressure data
- Fluid analysis, including PVT
- Production data, including static and flowing pressure, where available
- Seismic interpretation, time and depth grids for the main producing intervals
- Static and dynamic reservoir models, where available
- Development plans
- TCM/OCM material where relevant
- Management presentations
- Licence information
- 2D and 3D seismic data
- Legal and commercial documentation
- Facilities information
- Financial information

ERCE has relied upon Jadestone for the completeness of all the data provided. ERCE has reviewed data made available through to 28 February 2018 for the Montara Assets, and through to 31 December 2017 for all other assets in this report.

1.3. Work Completed

The dataset provided by Jadestone enabled ERCE to complete a comprehensive review of the:

- Hydrocarbons initially in place, where applicable
- Reserves at 1P, 2P and 3P levels of confidence, where applicable
- Contingent Resources at the 1C, 2C and 3C levels of confidence, where applicable

In the course of the evaluation, Jadestone provided ERCE personnel with information as detailed in Section 1.2. Other engineering, geological or economic data required to conduct the evaluation and upon which this report is based, were obtained from public records and from ERCE non-confidential files. Procedures recommended in the SPE Petroleum Resource Management System ("PRMS") to verify certain interests and financial information were applied in this evaluation. A summary of the PRMS can be found in Appendix 1. In applying these procedures and tests, nothing came to ERCE's attention that would suggest that information provided by Jadestone was not complete and accurate. ERCE reserves the right to review all calculations referred to or included in this report and to revise the estimates in light of erroneous data supplied or information existing but not made available which becomes known subsequent to the preparation of this report.

ERCE has used standard petroleum evaluation techniques in the generation of this report. These techniques combine geophysical and geological knowledge with assessments of porosity and permeability distributions, fluid characteristics, production performance and reservoir pressure. There is uncertainty in the measurement and interpretation of basic data. We have estimated the degree of this uncertainty and determined the range of petroleum initially in place and recoverable hydrocarbons. Our methodology for the evaluation adheres to guidelines outlines in the PRMS to verify certain interests and financial information.

The accuracy of any resources estimates is a function of the quality and quantity of available data and of engineering interpretation and judgment. While resource estimates presented herein are considered reasonable, the estimates should be accepted with the understanding that reservoir performance subsequent to the date of the estimate may justify revision, either upward or downward.

Revenue projections presented in this report are based in part on forecasts of market prices, currency exchange rates, inflation, market demand and government policy which are subject to many uncertainties and may, in future, differ materially from the forecasts utilised herein. Present values of revenues documented in this report do not necessarily represent the fair market value of the reserves evaluated herein.

In the case of discovered resources (Contingent Resources) presented in this report, there is no certainty that it will be commercially viable to produce any portion of the resources.

No site visit was undertaken in the generation of this report.

1.4. Summary of Results

A summary of gross oil Reserves and net oil Reserves attributable to Jadestone are presented in Table 1-2.

Table 1-2: Summary of Oil Reserves

Licence	Field	Gross Reserves (MMstb)			Working Interest (%)	Net Reserves attributable to Jadestone (MMstb)			Operator
		1P	2P	3P		1P	2P	3P	
AC/L7	Montara	8.9	14.9	20.5	100 *	8.9	14.9	20.5	Jadestone *
AC/L8	Skua	4.0	6.9	9.5	100 *	4.0	6.9	9.5	Jadestone *
AC/L8	Swift/Swallow	4.2	6.4	8.4	100 *	4.2	6.4	8.4	Jadestone *
WA-15-L	Stag	10.8	17.1	22.7	100	10.8	17.1	22.7	Jadestone
Total		**27.9**	**45.3**	**61.1**		**27.9**	**45.3**	**61.1**	

**Subject to the completion of the acquisition of PTTEP AA's 100% interest in AC/L7 and AC/L8*

1. The effective date is 31st December 2017.
2. "Gross Reserves" represent a 100% total of the estimated technically recoverable oil within the licence period. "Gross Reserves" include volumes attributable to third parties and government and thus contain volumes which are not attributable to Jadestone.
3. "Net Reserves attributable to Jadestone" are the "Gross Reserves" multiplied by Jadestone's working interest in the field/asset.

The Net Present Values ("NPVs") for the gross oil Reserves at the 1P, 2P and 3P levels of uncertainty are summarised in Table 1-3.

Table 1-3: Summary of Net Present Values

Field	Case	After Tax Discounted Cash Flow ($US MM)				
		NPV0	NPV5	NPV10	NPV15	NPV20
Montara Assets*	1P	231.5	278.7	287.3	279.9	266.3
	2P	480.3	509.7	479.5	436.4	394.5
	3P	1043.3	921.0	792.8	683.6	595.3
Stag	1P	6.6	25.2	29.6	28.7	26.1
	2P	94.0	97.0	84.2	70.2	58.3
	3P	135.0	141.7	122.1	101.3	84.1

**Subject to the completion of the acquisition of PTTEP AA's 100% interest in AC/L7 and AC/L8*

1. The NPVs presented in the table above represent all Reserves for the assets evaluated in this report.
2. The effective date is 31st December 2017.
3. The net present values associated with the Reserves calculations contained within this report should not be construed as ERCE's opinion of fair market value.

A summary of oil and gas Contingent Resources associated with Jadestone's assets are presented in Table 1-4 and Table 1-5, respectively.

Table 1-4: Summary of Oil and Condensate Contingent Resources

Field	Licence	Country	Gross Contingent Resources (MMstb)			Working Interest (%)	W.I. Contingent Resources (MMstb)			Chance of Development (%)	Operator
			1C	2C	3C		1C	2C	3C		
Stag	WA-15-L	Australia	4.8	2.7	0.0	100%	4.8	2.7	0.0	50%	Jadestone
Nam Du	Block 46/07	Vietnam	-	-	-	70% *	-	-	-	-	Jadestone
U Minh	Block 51	Vietnam	0.3	1.6	3.25	70%	0.2	1.1	2.3	85%	Jadestone
Tho Chu	Block 51	Vietnam	3.1	9.4	24	70%	2.2	6.6	16.8	40%	Jadestone
Dabakan	SC56	Philippines	1.1	3.5	13.38	25%	0.3	0.9	3.3	35%	TOTAL
Palendag	SC56	Philippines	0.2	1.9	8.2	25%	0.1	0.5	2.1	35%	TOTAL
		Total	**9.5**	**19.1**	**48.8**		**7.6**	**11.8**	**24.5**	-	-

**Subject to a 3% back-in right by a third party at cost*

1. "Gross Contingent Resources" represent a 100% total of estimated technically recoverable oil and/or condensate. "Gross Contingent Resources" include volumes attributable to third parties and government and thus contain volumes which are not attributable to Jadestone.
2. "W.I. Contingent Resources" are the "Gross Contingent Resources" multiplied by Jadestone's working interest in the field/asset.
3. The "Chance of Development" defines the chance that the Contingent Resources will be developed and will reach commercial producing status.
4. Contingent Resources should not be aggregated with Reserves because of the different levels of risk involved and the different basis on which volumes are determined.

Table 1-5: Summary of Free Gas and Associated Gas Contingent Resources

Field	Licence	Country	Gross Contingent Resources (Bscf)			Working Interest (%)	W.I. Contingent Resources (Bscf)			Chance of Development (%)	Operator
			1C	2C	3C		1C	2C	3C		
Stag	WA-15-L	Australia	-	-	-	100%	-	-	-	-	Jadestone
Nam Du	Block 46/07	Vietnam	64.8	107.4	134.5	70% *	45.4	75.2	94.2	85%	Jadestone
U Minh	Block 51	Vietnam	16.0	63.9	110.1	70%	11.2	44.7	77.1	85%	Jadestone
Tho Chu	Block 51	Vietnam	148.6	325.5	692.2	70%	104	227.9	484.5	40%	Jadestone
Dabakan	SC56	Philippines	131.2	241.0	598.8	25%	32.8	60.3	149.7	35%	TOTAL
Palendag	SC56	Philippines	49.6	228.6	720.1	25%	12.4	57.2	180	35%	TOTAL
Total			**410.2**	**966.4**	**2,255.7**		**205.8**	**465.3**	**985.5**		

**Subject to a 3% back-in right by a third party at cost*

1. "Gross Contingent Resources" represent a 100% total of estimated technically recoverable oil and/or condensate. "Gross Contingent Resources" include volumes attributable to third parties and government and thus contain volumes which are not attributable to Jadestone.
2. "W.I. Contingent Resources" are the "Gross Contingent Resources" multiplied by Jadestone's working interest in the field/asset.
3. The "Chance of Development" defines the chance that the Contingent Resources will be developed and will reach commercial producing status.
4. Contingent Resources should not be aggregated with Reserves because of the different levels of risk involved and the different basis on which volumes are determined.

1.5. Conclusion

It is ERCE's opinion that this CPR provides a fair and accurate representation of the oil and gas reserves to the interests of Jadestone in those certain properties included in this CPR. ERCE considers that the scope of the CPR is appropriate and was prepared to a standard expected in accordance with the Note for Mining and Oil & Gas Companies, within the AIM Rules for Companies, issued by the London Stock Exchange.

2. Montara Assets, AC/L7 & AC/L8, Western Australia

2.1. Montara Field, AC/L7

2.1.1. Introduction

The Montara field lies in production licence AC/L7 in the Vulcan Sub-Basin, approximately 675 km west of Darwin, Australia in a water depth of 77 m (Figure 2.1). At the effective date of this independent evaluation, PTTEP AA is the Operator of the field and holds a 100% working interest. PTTEP AA was formed when PTTEP acquired 100% of Coogee Resources in 2009. Jadestone entered into a SPA with PTTEP AA on 15 July 2018 to acquire a 100% interest in AC/L7 and AC/L8.

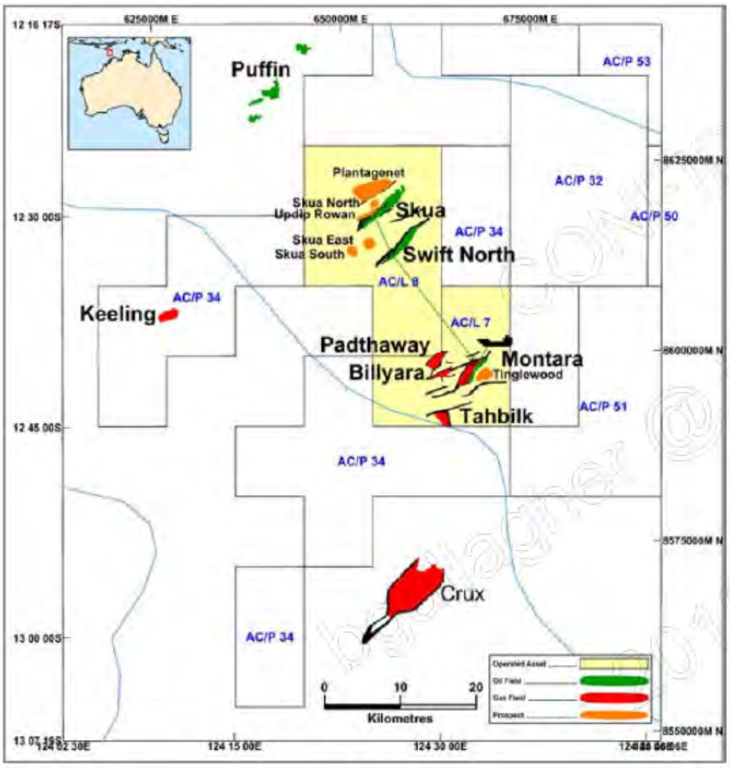


Figure 2.1: Location map of the Montara field, production licence AC/L7

There is no definitive expiry date to production licence AC/L7, with the Operator able to produce the field until it is no longer economic to do so.

The field was discovered in 1988 by Well Montara-1, which was drilled by BHP Billiton. The well intersected 35 m of gas underlain by a 9.5 m oil column. The field was later appraised by Well Montara-2 in 1991, which was drilled to test the southern extent of the field. Well Montara-2 intersected no gas and a 6 m oil column and penetrated the present day oil-water contact ("OWC") at 2,620 mTVDSS. A final appraisal well, Montara-3 was drilled to the north of Well Montara-1 in 2002 and intersected a 13.5 m oil column.

In 1992 the HA8 Montara 3D seismic volume was acquired over the Montara, Bilyara and Padthaway fields. In 2000, the Montara 3D data was reprocessed to produce a PSTM volume that formed the basis for interpretation in the 2011 field development plan. More recently, a PSDM volume was produced and this formed the basis for Jadestone's evaluation.

The Montara field comprises a thin oil rim (~14 m thick) overlain by a significantly larger gas column (~87 m thick). Hydrocarbons are contained within the Upper Jurassic Cycle IV reservoir, which across Montara was deposited in a shallow marine environment. Reservoir quality is excellent, with net reservoir thickness in the order of 30 – 50 m and permeability typically greater than 1,000 mD. The field is bound to the north and west by normal faults and is connected to a strong aquifer to the east and south.

On 21 August 2009, a blowout in Well Montara-H1ST1 resulted in an uncontrolled flow of hydrocarbons into the sea that continued for 74 days to 3 November 2009. The cause of the blowout was most likely that hydrocarbons entered Well Montara-H1ST1 through the 9 5/8" cemented casing and flowed up the inside of the 9 5/8" casing. The Montara Commission of Inquiry ("the Commission") found that at the time Well Montara H1ST1 was suspended, not one well control barrier complied with PTTEP AA's own Well Construction Standards. The casing shoe had not been pressure tested, despite a troublesome cement job, and it is likely that the cement in the shoe had been compromised as it had been over-displaced by fluid, resulting in a 'wet shoe'. Furthermore, the Commission found that although two secondary well control barriers (pressure containing anti-corrosion caps) were due to be installed, only one was and it was not tested and verified in-situ as required by the Well Construction Standards.

The Commission deemed that PTTEP AA did not observe sensible oilfield practices in the Montara field, and that for this reason the Northern Territory Department of Resources ("NT DoR") should not have approved the Phase 1B Drilling Programme that commenced in July 2009.

The blowout was eventually arrested by the drilling of a gas relief well, Montara-H1ST1-RW1. The relief well intersected Well Montara-H1ST1 on 1 November 2009 and pumped heavy mud into the well. On 3 November 2009 the flow of hydrocarbons was completely stopped. The relief well later injected 320 barrels of cement into Well Montara-H1ST1 and on 13 January 2010, PTTEP AA reported that operations to plug and secure the well were complete.

In November 2010, the Australian Resources and Energy Minister released the Report of the Montara Commission of Inquiry. The report contained 100 findings and 105 recommendations aimed to improve the regulation, and its implementation, on well control in Australia in order to prevent similar events occurring in the future, nearly all of which were accepted by the Australian Government.

First production from the Montara field came in June 2013 from three horizontal oil producers, Wells Montara-H2, -H3 and -H4. Each well initially produced at rates between 3,000 and 4,000 stb/d. The wells are drilled from an unmanned platform which is connected to the Montara FPSO via subsea flowlines.

In June 2016, PTTEP AA began re-injecting gas into the gas cap through Well Montara-G2 to provide support to the horizontal wells. The well injects gas at an average rate of 10 MMscf/d.

In October 2017, an additional horizontal well, Montara-H5, was brought onstream at an oil rate of 3,500 stb/d. The well targets unswept volumes in the southwest of the field.

As of 31 December 2017, the Montara field has produced 12.57 MMstb of oil and 12.67 Bscf of gas.

2.1.2. Geology & Geophysics

The seismic data quality over the Montara field is moderate to good. The Top Cycle IV marker is interpreted as a decrease in impedance and corresponds to a strong peak that is consistent across the field (Figure 2.2). The faults bounding the Montara field to the north and west are well imaged. The amplitude of the Top Cycle IV horizon shows a good correspondence with the extent of the gas cap, as would be expected in high quality sands.

Jadestone was able to view the 3D PSDM volume (depth domain only) in a physical dataroom but had no access to it outside of the dataroom, only being permitted to remove screenshots. As such, ERCE was not able to independently review the data but had access to the screenshots. Having reviewed these, we have accepted Jadestone's Top Cycle IV depth structure (Figure 2.3).

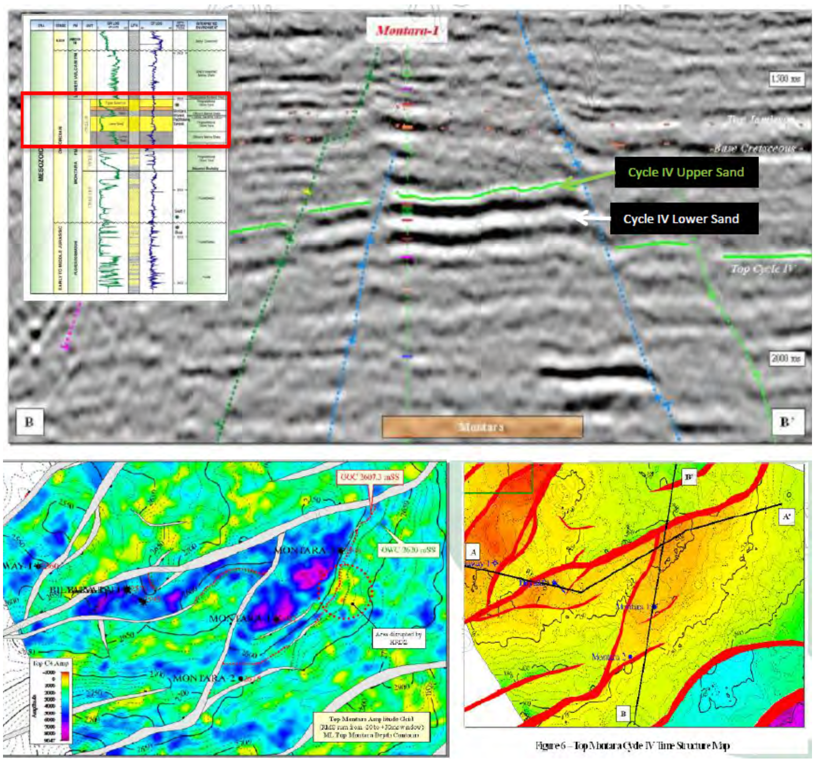


Figure 2.2: North-South PSTM seismic line through the Montara field

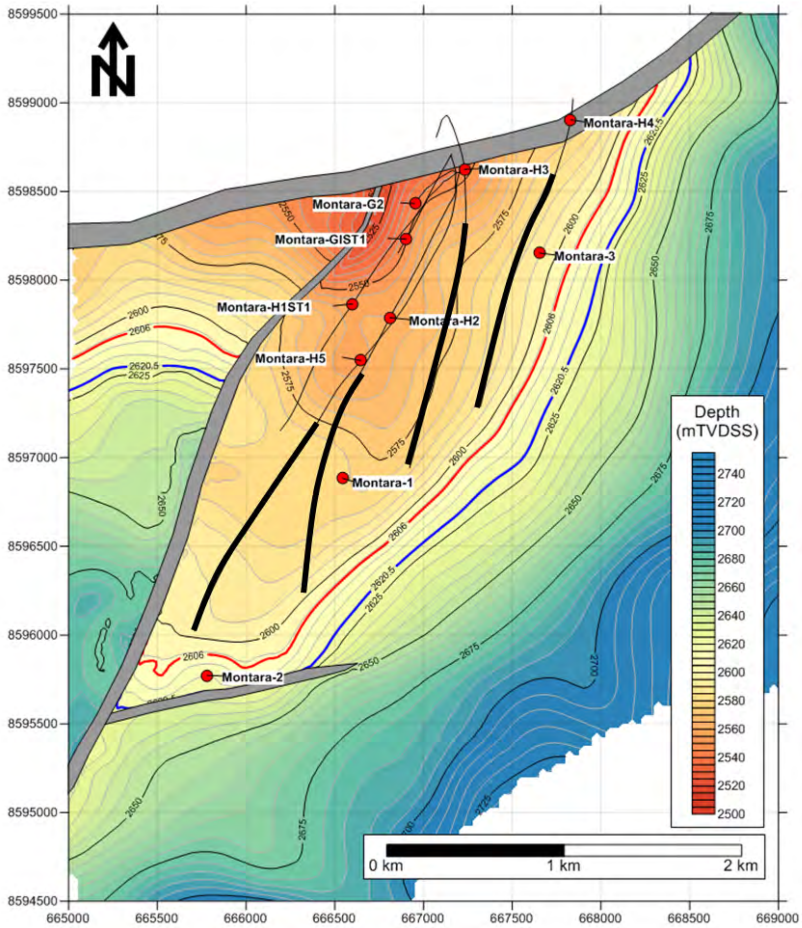


Figure 2.3: Top Cycle IV Depth Surface, Montara field

The Upper Cycle IV unit of the Oxfordian Montara Formation forms the reservoir in the Montara field (Figure 2.4). Within Montara it is separated into three intervals, with only the upper of which contains any significant volumes of hydrocarbons. The upper and intermediate intervals are characterised as a coarsening upward shallow marine parasequence in Wells Montara-1 and -2, with the upper representing the high quality, proximal deposits and the lower consisting of poor quality distal deposits (Figure 2.5). A flooding surface separates these intervals from the lower sand, which is blocky in character and of similar quality to the upper interval. However, the lower sand is below the current OWC and as such is water bearing.

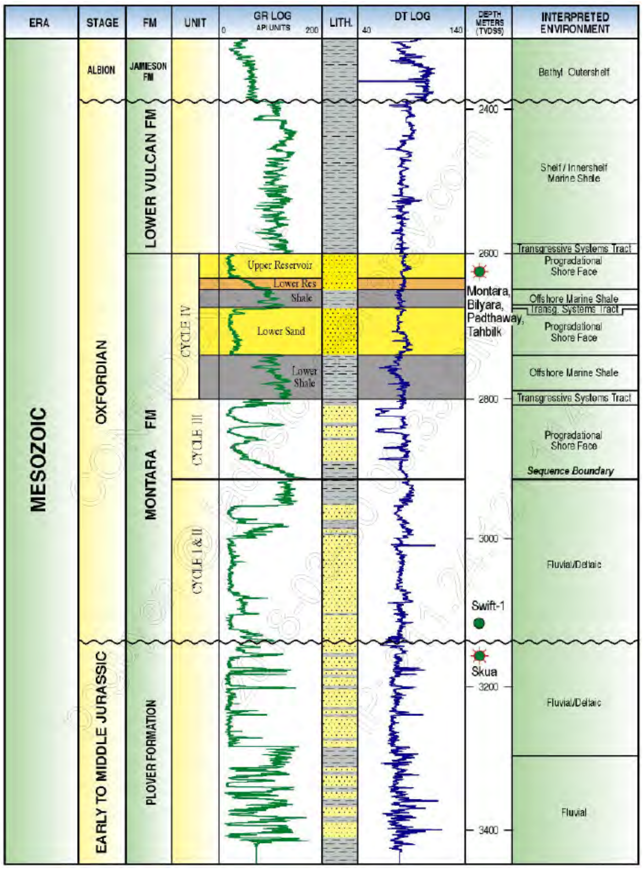


Figure 2.4 Stratigraphic column from Montara-1

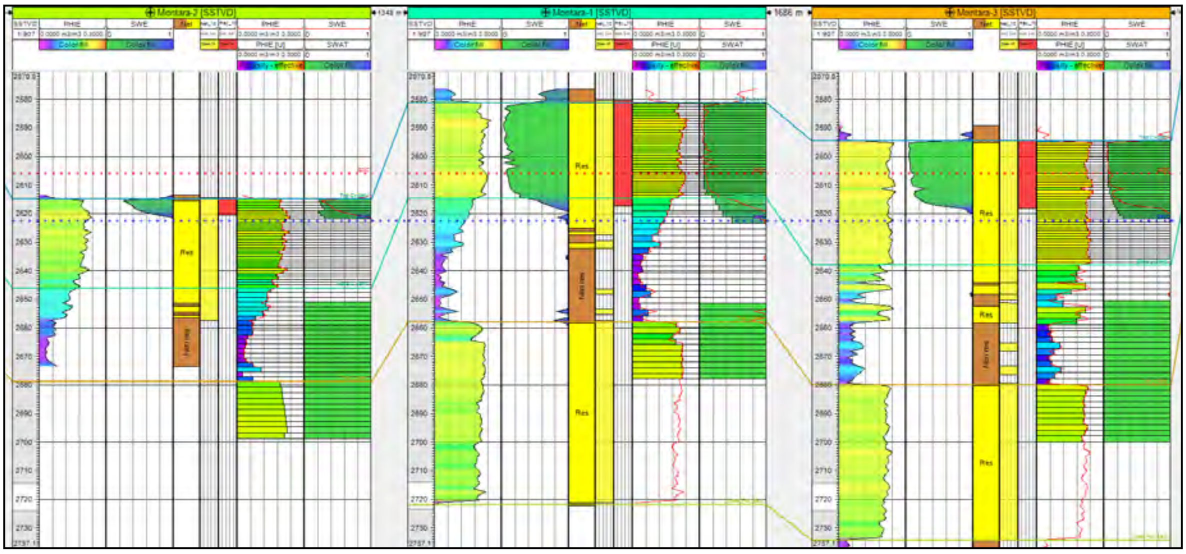


Figure 2.5: NE-SW reservoir correlation through Wells Montara-1, -2 and 3

Core data gathered in Well Montara-2 and other offset wells (Bilyara-1 and Padthaway-1) show the reservoir sand to be of high quality, with porosity and permeability ranging from 19 – 25 pu and 200 – 5,000 mD respectively (Figure 2.6)

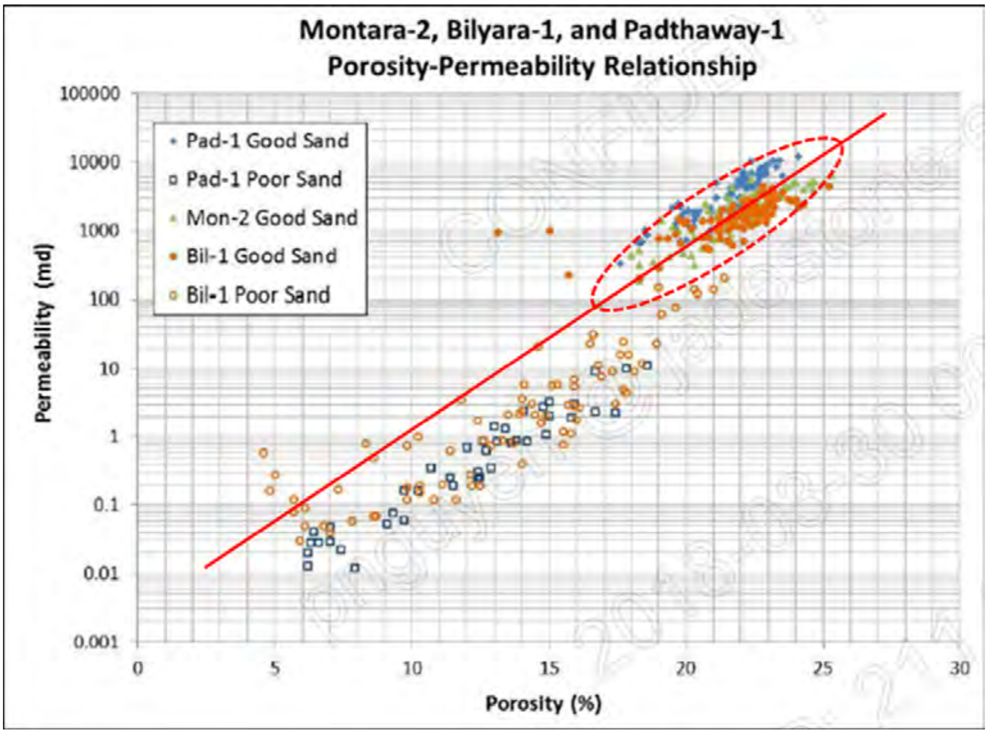


Figure 2.6: Poroperm data from Montara-2 and other offset wells

2.1.3. Petrophysical Analysis

The Operator provided Jadestone with a limited petrophysical dataset. Jadestone was provided with interpreted PHIE and SWE logs for Wells Montara-1, -2, -3 and GIST1, which they used to construct their static models. Raw logs were not available for these wells meaning ERCE could not make an independent evaluation that could be directly compared with the Operator's. However, we were able to make an independent evaluation on Well Montara-G2, which will be described in this section.

2.1.3.1. Shale Volume

Shale volume ("Vsh") was calculated using a linear gamma-ray ("GR") function and the 5th and 95th percentiles. Vsh was also calculated from the neutron-density cross plot (Figure 2.7), and generally gave a good match to Vsh from GR. The minimum of the two methods was used as the final Vsh.

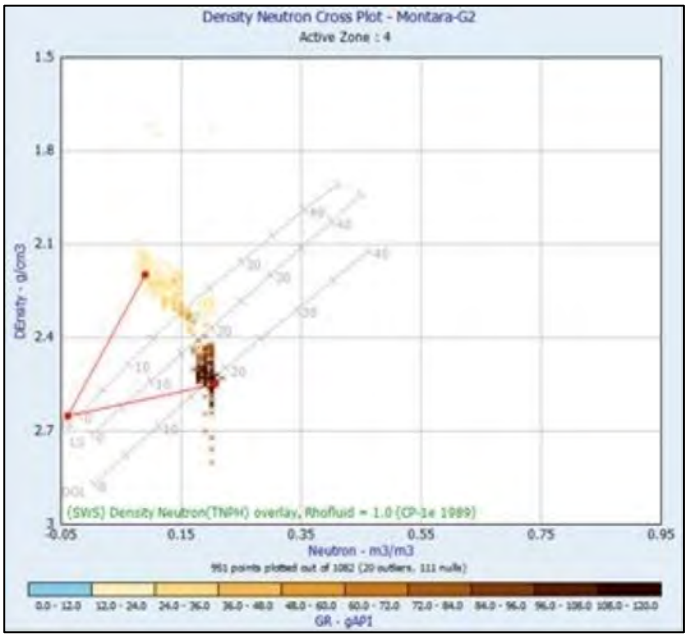


Figure 2.7: Cross plot of neutron vs density for Well Montara-G2 showing points for Vsh

2.1.3.2. Porosity

Total porosity was calculated from the density log, the compressional sonic log and using the neutron-density cross plot technique. Generally, all three were in good agreement, except for areas of bad hole. The density porosity was used preferentially as this gives the best indication of total porosity. The logs were not corrected for any hydrocarbon effect, instead a fluid density was used that takes into account the mud invasion and formation fluids to match expected core porosity ranges.

Effective porosity was calculated by correcting the total porosity from density for the porosity contribution from shale. This method assumes that the porosity in the core is micro-porosity and is not connected, so can be considered effectively part of the rock matrix. Much of the shale interval has very little total porosity due to shale compaction, so the correction has little impact.

2.1.3.3. Water Saturation

Water Saturation ("Sw") was calculated using Archie's equation as the sandstones generally appeared clean. The formation water resistivity ("Rw") was well constrained as all three wells have thick water bearing sands. A water salinity of 110 kppm NaCl was used based on DST water samples from Wells Montara-1 and -3 and a water analysis in Well Skua-6.

2.1.3.4. Reservoir Summary

Although no direct comparison between the Operator's petrophysical curves and our own could be made in Well Montara-G2, our results were in line with the Operator's results in other Montara wells. We have therefore adopted the Operator's PHIE and SWE curves provided to Jadestone and have used these to calculate sums and averages over the reservoir intervals. A 10% effective porosity cut off was used to remove tight, non-net intervals, and a cut off of 70% Sw was used to remove any intervals that would produce water. The results are presented in Table 2-1 and a CPI is shown in Figure 2.8.

Table 2-1: Petrophysical summary of available Montara wells

Reservoir	Well	Gross (m)	Net (m)	Pay (m)	NTG		Gross Average		Net Average		Pay Average	
					Net	Pay	PHIE	SWE	PHIE	SWE	PHIE	SWE
Upper	Montara-1	33.4	33.3	33.3	0.998	0.998	0.217	0.104	0.217	0.103	0.217	0.103
	Montara-2	31.2	30.9	4.8	0.990	0.155	0.199	0.894	0.200	0.905	0.202	0.447
	Montara-3	43.5	43.1	22.9	0.990	0.527	0.228	0.530	0.229	0.533	0.229	0.141
	Montara-GIST1	51.1	51.1	50.7	1.000	0.992	0.199	0.117	0.199	0.117	0.199	0.106
	Bilyara-1ST1	42.8	42.4	42.4	0.991	0.991	0.211	0.124	0.212	0.119	0.212	0.119
Average / Wt. Average		**40.4**	**40.1**	**30.8**	**0.994**	**0.763**	**0.211**	**0.325**	**0.211**	**0.325**	**0.211**	**0.125**
Intermediate	Montara-1	43.3	16.5	2.2	0.381	0.051	0.083	0.950	0.134	0.894	0.172	0.583
	Montara-2	27.5	11.0	0.0	0.399	-	0.082	1.000	0.127	1.000	0.000	0.000
	Montara-3	41.9	20.2	0.0	0.481	-	0.119	0.999	0.164	0.999	0.000	0.000
	Montara-GIST1	30.7	5.6	3.1	0.181	0.101	0.033	0.917	0.119	0.572	0.124	0.270
	Bilyara-1ST1	36.2	12.6	0.5	0.348	0.014	0.078	0.985	0.120	0.963	0.130	0.842
Average / Wt. Average		**35.9**	**13.2**	**1.2**	**0.366**	**0.032**	**0.081**	**0.970**	**0.138**	**0.930**	**0.142**	**0.439**
Lower	Montara-1	63.9	62.7	0.0	0.981	0.000	0.201	0.999	0.202	0.999	0.000	0.000
	Montara-2	-	-	-	-	-	-	-	-	-	-	-
	Montara-3	54.4	53.7	0.0	0.987	0.000	0.210	1.000	0.210	1.000	0.000	0.000
	Montara-GIST1	-	-	-	-	-	-	-	-	-	-	-
	Bilyara-1ST1	35.5	35.1	5.0	0.989	0.141	0.234	0.870	0.235	0.867	0.236	0.170
Average / Wt. Average		**51.3**	**50.5**	**1.7**	**0.985**	**0.032**	**0.211**	**0.970**	**0.212**	**0.969**	**0.236**	**0.170**

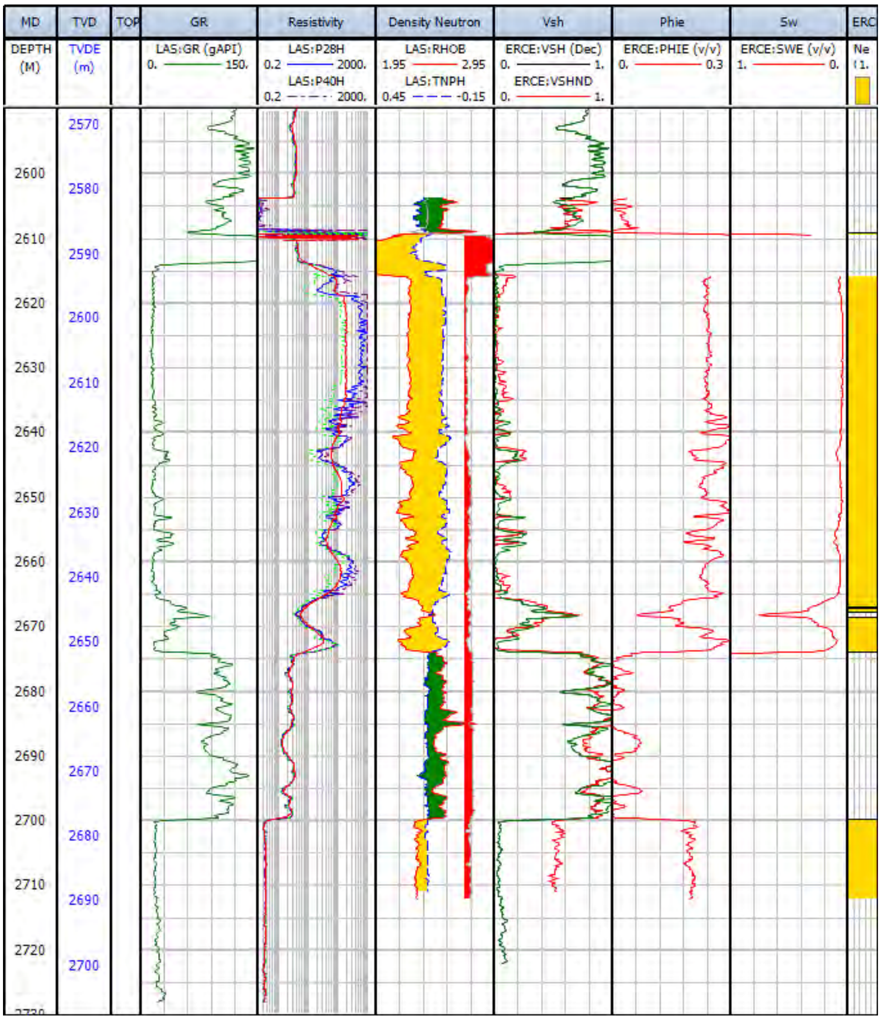


Figure 2.8: Well Montara-G2 CPI showing ERCE interpretation in red curves

2.1.4. **Fluid Contacts**

Pressure data gathered in Well Montara-3 (drilled 2002) shows that the Montara field has been depleted by approximately 10 psi when compared to pressure data from Wells Montara-1 and -2 (drilled in 1988 and 1991) (Figure 2.9). This depletion is thought to be caused by the nearby Skua field, which was on production between 1991 and 1997.

Both sets of pressure data (i.e. before and after Skua production) show that the GOC and OWC are approximately 2,606 mTVDSS and 2,620.5 mTVDSS respectively.

The interpretations of fluid contacts made from pressure data show their present-day position. The Montara field has had a complex history that involves structural tilting to the southwest (in the direction of Well Montara-2) after first migration of hydrocarbons into the structure. After tilting, the hydrocarbons re-equilibrated in the reservoir to their present-day positions. However, beneath the present-day OWC exists a wedge of low saturation oil down to a tilted palaeo-OWC (Figure 2.10), which henceforth will be termed the palaeo oil zone.

The low oil saturation zone contains moveable oil volumes, as demonstrated by a DST in Well Montara-1 over the interval 2,623.9 – 2,630.9 mTVDSS which flowed 496 stb/d of oil and 223 bbl/d of water over 10 hours. Furthermore, an MDT sample at 2,624 mTVDSS in Well Montara-2 collected 500 cc of oil and 21,500 cc of water/filtrate.

The composite logs in Wells Montara-2 and -3 provide evidence for the amount of tilt in the palaeo-OWC across the field. In Well Montara-3 (north), resistivity logs suggest an OWC at 2,620.5 mTVDSS but oil shows are recorded down to 2,623.5 mTVDSS. In Montara-2 (south), resistivity logs suggest an OWC at 2,620.5 m TVDSS but remain high down to 2,630 mTDVSS, where a second, less prominent OWC could be interpreted.

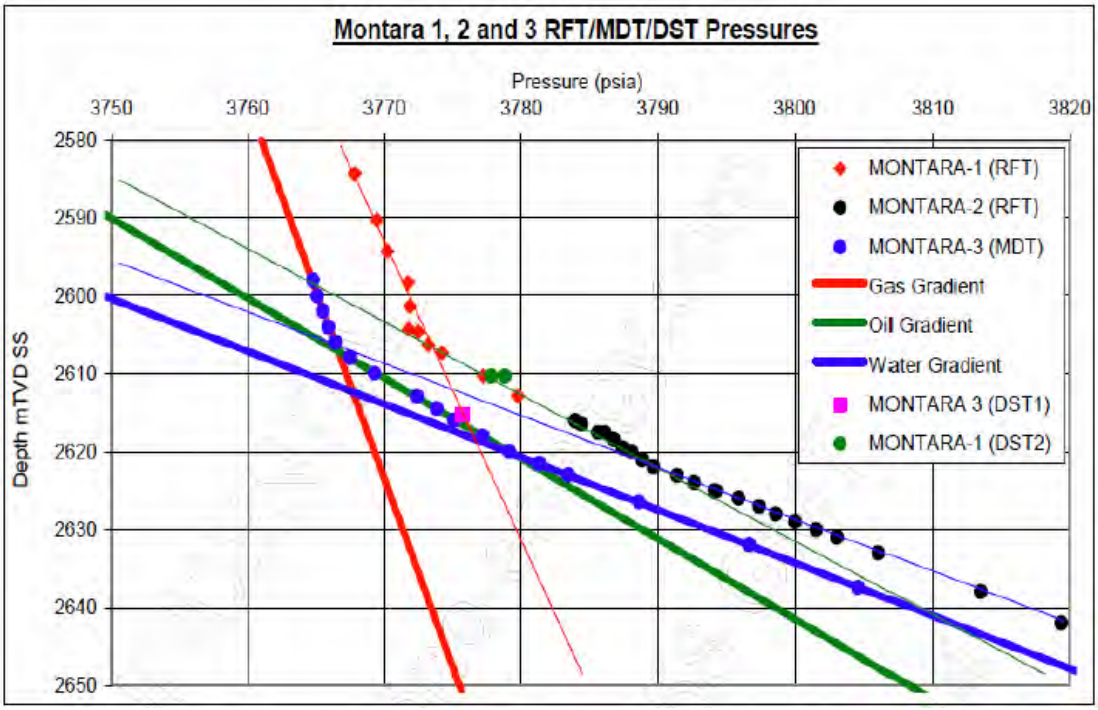


Figure 2.9: Pressure vs depth for Wells Montara-1, -2 and -3

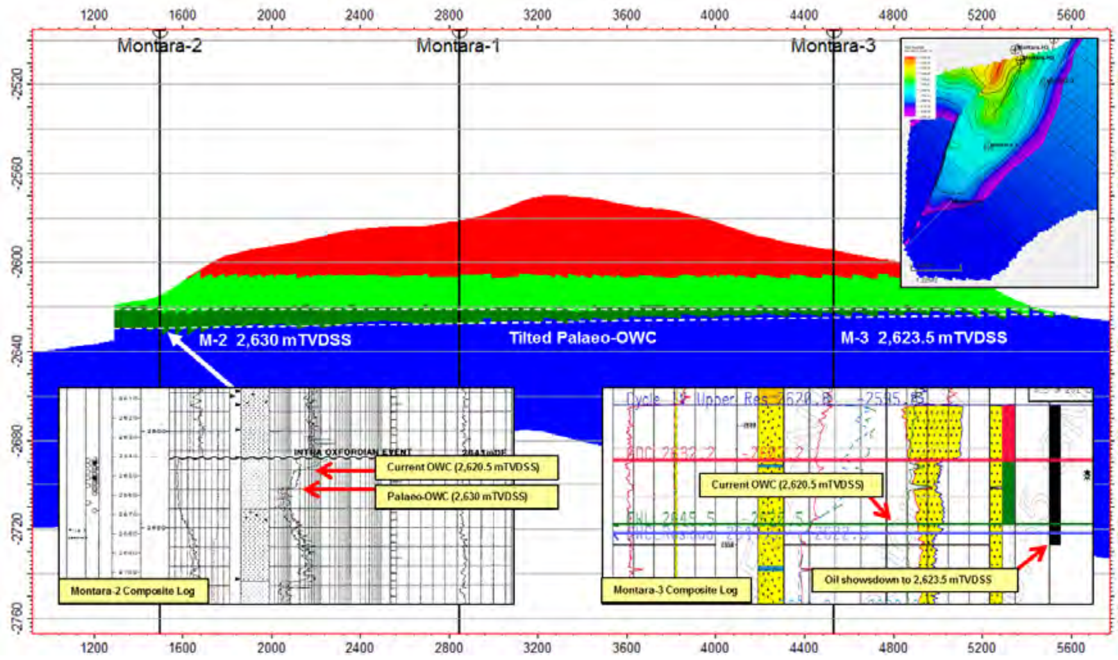


Figure 2.10: Schematic cross section through Montara wells demonstrating tilted palaeo-OWC

2.1.5. **Hydrocarbons in Place**

ERCE's in-place estimates for the Montara field are based on Jadestone's depth surfaces and the petrophysical sums and averages of Wells Montara-1, -2, -3 and -GIST1. Jadestone has created depth surfaces for the base upper interval and top lower interval using well-based isopachs. These were reviewed by ERCE and accepted as reasonable.

We have adopted the GOC used by Jadestone (2,606 mTVDSS) and use an OWC at 2,620.5 mTVDSS to model the oil volume above the present-day contact (Figure 2.11). To model the palaeo oil zone a tilted surface is created that is pinned at 2,630 mTVDSS at Well Montara-2 and at 2,623.5 mTVDSS at Well Montara-3.

Our P50 gross rock volume ("GRV") uses Jadestone's depth surfaces and the contacts described above. We have considered the structural uncertainty associated with the surfaces and contacts and have used a 10% discount to calculate a P90 GRV. The P10 GRV is then calculated by assuming a log-normal distribution defined by the P90 and P50. The resultant P10:P90 GRV ratio is in line with what would be expected for a field with well control and seismic data quality similar to Montara.

The ranges of net-to-gross ratio ("NTG"), porosity and oil saturation used in our volumetric calculation are based on the petrophysical sums and averages of the wells for which Jadestone had digitised PHIE and SWE logs. Each parameter is defined by a normal distribution. The oil saturation in the palaeo oil zone is expected to be lower than in the present-day oil column and we have based this on saturation logs shown in the Operator's field development plan ("FDP").

Our inputs to a probabilistic simulation of stock tank initially in place ("STOIIP") and gas initially in place ("GIIP") volumes is shown in Table 2-2 to Table 2-4 and the results are shown in Table 2-5 and Table 2-6. Note that condensate in-place volumes are calculated by applying a fixed condensate gas ration("CGR") of 22.5 stb/MMscf to GIIP results.

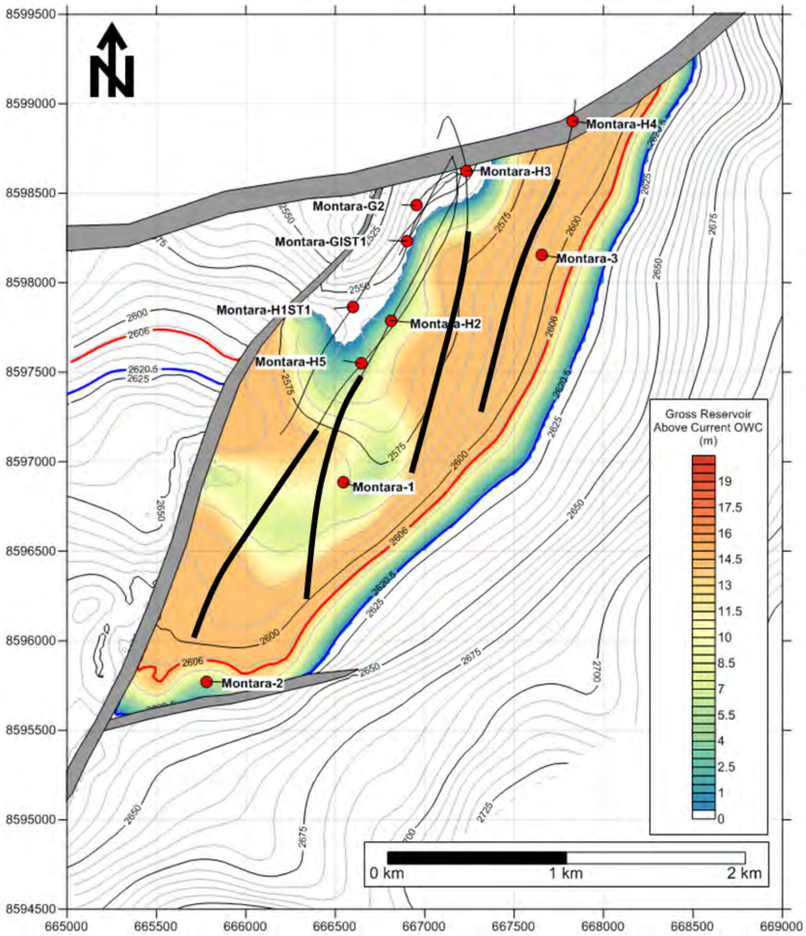


Figure 2.11: Gross reservoir between GOC and current OWC, Upper Reservoir

Table 2-2: Volumetric inputs to probabilistic simulation, Montara field (Present-day Oil Leg)

Zone	Reservoir	GRV (MMm3)			NTG (frac)			PHIT (frac)			So (frac)			Bo (rb/stb)
		Log-Normal			Normal			Normal			Normal			Constant
		P90	P50	P10	P90	P50	P10	P90	P50	P10	P90	P50	P10	P50
Present-day Oil Leg	Upper	44.46	49.40	54.89	1.000	1.000	1.000	0.190	0.211	0.232	0.850	0.900	0.950	1.390
	Intermediate	11.49	12.77	14.19	0.350	0.400	0.450	0.124	0.138	0.152	0.650	0.750	0.850	1.390
	Lower	0.59	0.66	0.73	1.000	1.000	1.000	0.191	0.212	0.233	0.850	0.900	0.950	1.390

Table 2-3: Volumetric inputs to probabilistic simulation, Montara field (Palaeo Oil Zone)

Zone	Reservoir	GRV (MMm3)			NTG (frac)			PHIT (frac)			So (frac)			Bo (rb/stb)
		Log-Normal			Normal			Normal			Normal			Constant
		P90	P50	P10	P90	P50	P10	P90	P50	P10	P90	P50	P10	P50
Palaeo Oil Zone	Upper	12.05	13.39	14.87	1.000	1.000	1.000	0.190	0.211	0.232	0.300	0.350	0.400	1.390
	Intermediate	10.20	11.33	12.59	0.350	0.400	0.450	0.124	0.138	0.152	0.300	0.350	0.400	1.390
	Lower	0.31	0.34	0.38	1.000	1.000	1.000	0.191	0.212	0.233	0.300	0.350	0.400	1.390

Table 2-4: Volumetric inputs to probabilistic simulation, Montara field (Gas Cap)

Zone	Reservoir	GRV (MMm3)			NTG (frac)			PHIT (frac)			Sg (frac)			Bg (rcf/scf)
		Log-Normal			Normal			Normal			Normal			Constant
		P90	P50	P10	P90	P50	P10	P90	P50	P10	P90	P50	P10	P50
Gas Cap	Upper	86.08	95.64	106.27	1.000	1.000	1.000	0.190	0.211	0.232	0.850	0.900	0.950	0.005
	Intermediate	4.84	5.38	5.98	0.350	0.400	0.450	0.124	0.138	0.152	0.650	0.750	0.850	0.005
	Lower	0.01	0.01	0.01	1.000	1.000	1.000	0.191	0.212	0.233	0.850	0.900	0.950	0.005

Table 2-5: Probabilistic STOIIP results, Montara field

Reservoir	STOIIP (MMstb)											
	Present-day Oil Leg				Palaeo Oil Zone				Total			
	P90	P50	P10	Mean	P90	P50	P10	Mean	P90	P50	P10	Mean
Upper	36.6	42.1	48.0	42.2	3.6	4.4	5.4	4.5	40.2	46.5	53.3	46.7
Intermediate	1.9	2.4	2.9	2.4	0.8	1.0	1.2	1.0	2.6	3.3	4.2	3.4
Lower	0.5	0.6	0.6	0.6	0.1	0.1	0.1	0.1	0.6	0.7	0.8	0.7
Total	**38.9**	**45.0**	**51.6**	**45.2**	**4.5**	**5.5**	**6.7**	**5.6**	**43.4**	**50.6**	**58.3**	**50.8**

Table 2-6: Probabilistic free GIIP and Condensate In-Place, Montara field

Reservoir	Free GIIP (Bscf)				Condensate (MMstb)			
	P90	P50	P10	Mean	P90	P50	P10	Mean
Upper	110.1	126.9	144.8	127.2	2.5	2.9	3.3	2.9
Intermediate	1.2	1.6	1.9	1.6	0.0	0.0	0.0	0.0
Lower	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**111.3**	**128.4**	**146.8**	**128.8**	**2.5**	**2.9**	**3.3**	**2.9**

2.1.6. Production Performance

A total of 11 wells have been drilled on the field. This includes three exploration and appraisal wells, two gas injection wells and five horizontal production wells. Of these wells, only one of the gas injection wells (Montara-G2) and four of the horizontal production wells (Montara-H2, H3, H4 and H5) have been utilised. The Montara-H1 well suffered a blow-out on 21 August 2009, which resulted in an estimated 29.6 Mstb of uncontrolled oil flowing from the reservoir. The well was shut on 3 November 2009 via the Montara-H1ST1-RW1 relief well.

Oil production commenced from the Montara field in June 2013. As of 31 December 2017 the four oil producers and the gas injector are active in the Montara field. The field is producing 7,074 stb/day of oil and condensate, with 12.9 MMscf/day of gas at a 51% water cut. The gas injection rate is 8.8 MMscf/day. Peak oil production of 15,030 stb/day was achieved in December 2014. Water breakthrough in the wells occurred in late 2014 and the water cut has steadily increased after this. Gas cap breakthrough first occurred in early 2016 and free gas is produced from each of the Montara-H2, H3 and H4 wells. As of 31 December 2017 the field has produced 12.57 MMstb of oil and 12.67 Bscf of gross gas (7.40 Bscf net of injection). The production history for the Montara field is shown in Figure 2.12.

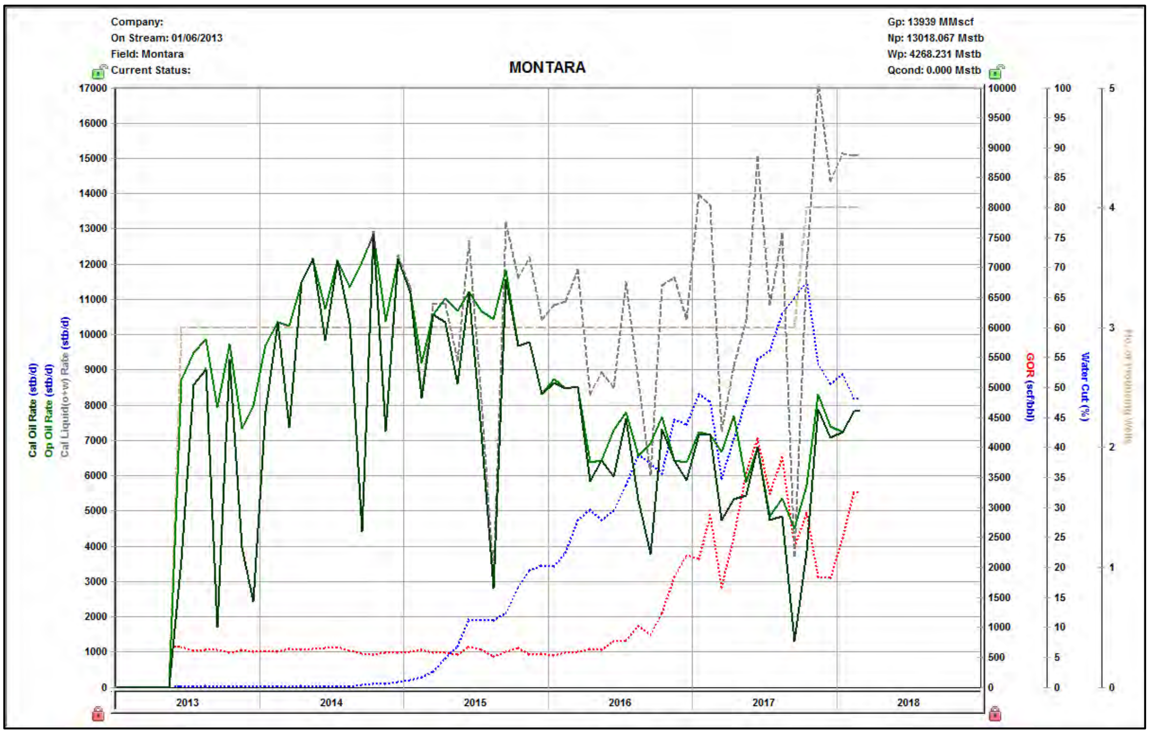


Figure 2.12: Production history of the Montara field

Multiple oil and gas samples were collected during the exploration and appraisal phases, and further information on the oil and gas properties has been collected during the production phase. The oil in the Montara field is light to medium gravity at 35.5^{0} API, specific gravity of 0.847 and viscosity of 0.41 cP. The solution gas oil ratio ("GOR") prior to gas cap breakthrough was approximately 600 scf/stb. The free gas in the gas cap has a gas gravity of 0.70. The initial CGR of the free gas was 22.5 stb/MMscf. Initial reservoir pressure was 3,780 psia with initial temperature of 110^{0} C.

2.1.7. Production Forecasting

2.1.7.1. Production Forecasts – Developed Producing

As of 31 December 2017 there were four wells producing in the field with produced gas reinjected via the Montara-G2 injection well. Wells H2, H3 and H4 have been producing for a number of years and each of the wells shows evidence of production decline. Jadestone has forecast production for these wells using decline curve analysis ("DCA"). ERCE performed its own DCA for these wells and compared the results to Jadestone's. Whilst there were differences for individual wells, in aggregate the Low, Best and High Case forecasts between Jadestone and ERCE were consistent, so ERCE has accepted the Jadestone production forecasts for these wells.

The H5 well has only been on production since October 2017 and production is yet to show evidence of any decline. Therefore, Jadestone has used a full-field simulation model to guide oil recovery and the production forecast for this well. The simulation model was based on Jadestone's static modelling used for volumetric in-place estimation, with dynamic parameters input from Field Development Plan documentation. The model was history matched and used to predict future field performance.

The simulation model history match quality was reasonable, with water and gas breakthrough and evolution generally close to the history. However, the recovery from Well H5 in the simulation model (8.0 MMstb) was higher than the Estimated Ultimate Recovery ("EUR") of the other wells in the field. This is supported by Well H5 being located in a flatter area of the field with less exposure to the aquifer. In addition, the location of Well H5 is a "step-out" into an un-drained area of the field, rather than an infill well. However, Jadestone has identified higher recovery from this well compared to the EUR of the other wells in the field as an uncertainty, and has discounted the production forecast so that Well H5 recovers similar oil volumes to the other producing wells (6.8 MMstb). For the Low and High production forecasts Jadestone incorporated uncertainty based on the variation in the Low to High forecasts for the other existing wells.

ERCE reviewed the model inputs, history match and model outputs, as well as comparing the well recovery against the other wells in the field. Based on this ERCE has deemed the Jadestone recovery estimates and production forecasts for Well H5 as reasonable.

2.1.7.2. Production Forecasts – Undeveloped

Jadestone is proposing to drill an additional horizontal production well (Montara-H6) in the field adjacent to the western bounding fault. The well will be drilled through the single remaining well slot on the wellhead platform. Well H6 will have a horizontal well section of approximately 1,100m and target unswept oil to the west of Wells H2 and H5. The location of the well is shown in Figure 2.13.

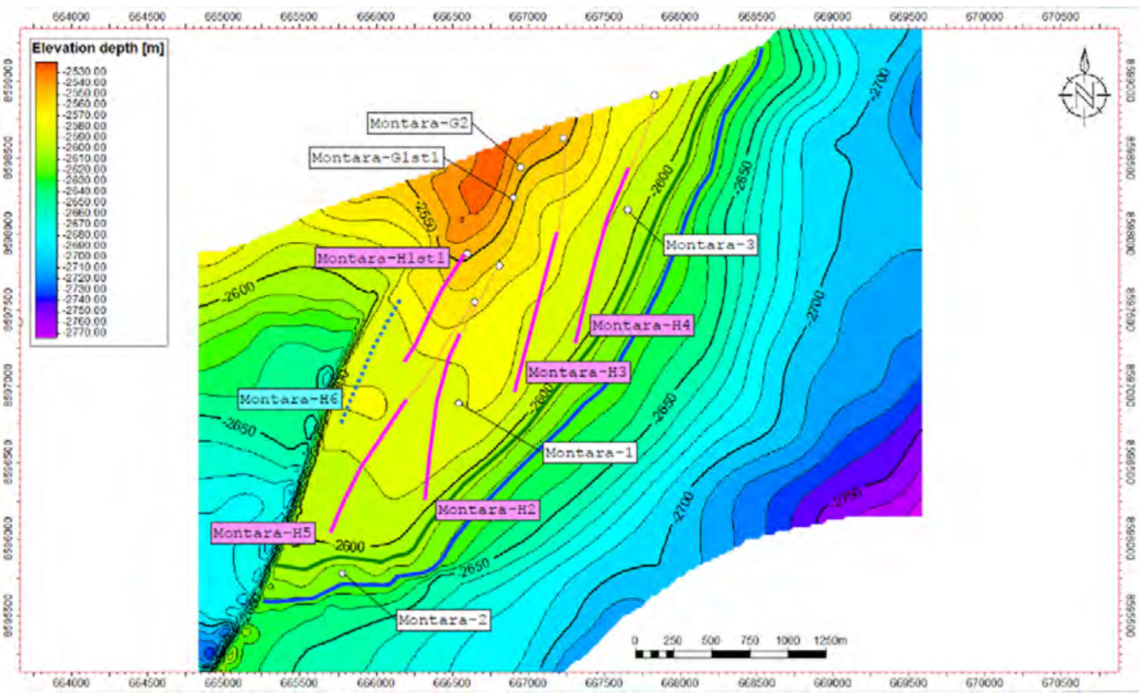


Figure 2.13: Location of the planned Montara-H6 well

The incremental oil recovery and production forecast for Well H6 were estimated by Jadestone by running the Montara simulation model including Well H6. In the simulation model the well initially produces at 3,000 stb/day but declines rapidly. Prior to 2024 the new well "steals" oil production from Wells H2 and H5, which results in an accelerated oil recovery. However, due to this, after 2024 the incremental oil production profile for this well becomes negative until 2030. The incremental oil recovery for the well (1.8 MMstb) is considerably lower than the EUR for the other wells, so Jadestone has not discounted the forecast for Well H6. Similar to Well H5, for the Low and High production forecasts Jadestone incorporated uncertainty based on the variation in the Low to High forecasts for the other wells.

ERCE reviewed the simulation model including Well H6 and the corresponding production forecasts, and has accepted them as reasonable. The forecasts assume a combined fuel and flare rate of 5 MMscf/d, which is consistent with the field history. The forecasts also assume the remainder of the gas is re-injected into the gas cap via Well G2.

2.1.7.3. Recovery

ERCE has estimated the Low, Best and High Case recovery factors for the Montara Field as 48%, 51% and 54%, respectively based on the production forecasts. Despite the gas cap, water drive and thin oil column, ERCE views this range as reasonable since it is supported by the high quality of the reservoir sands, extensive reservoir coverage from horizontal wells and additional oil recovery from the palaeo-oil zone. This range is also supported by the Bream Field, which has been identified as an analogue. The Bream field is located in Bass Strait, Australia and is a high permeability reservoir (multi-Darcy) with a large gas cap, water drive and similar oil column height (13 m) to the Montara field. The estimated recovery factor for the Bream field is between 42% and 58%, dependent on in-place estimates.

Jadestone's forecasts, accepted by ERCE, of the estimated Developed and Undeveloped future production to 31 December 2030, prior to economic modelling, are summarised in Table 2-7.

Table 2-7: Summary of future production estimates for the Montara field

	Low Case Developed Producing (MMstb)	Low Case Developed (MMstb)	Low Case (MMstb)	Best Case (MMstb)	High Case (MMstb)
Forecast Cumulative production at 31 December 2030	21.06	21.06	22.17	27.51	33.09
Cumulative production at 31 December 2017	12.57				
Remaining recoverable oil volumes at 31 December 2017	8.49	8.49	9.60	14.94	20.52

NOTE

1) The volumes shown in the above table are technically recoverable oil volumes and have not been subject to economic modelling.

2.1.7.4. Facilities Overview & Downtime Assumptions

The Montara facilities include a wellhead platform tied back to the Montara FPSO. The wellhead platform also has subsea tie-backs from the Skua and Swift/Swallow fields. The Montara FPSO is capable of processing 100,000 stb/d of liquid (40,000 stb/d oil and 60,000 bbl/d water) and re-injecting 50 MMscf/d of gas. The schematic of the Montara facilities is shown in Figure 2.14.

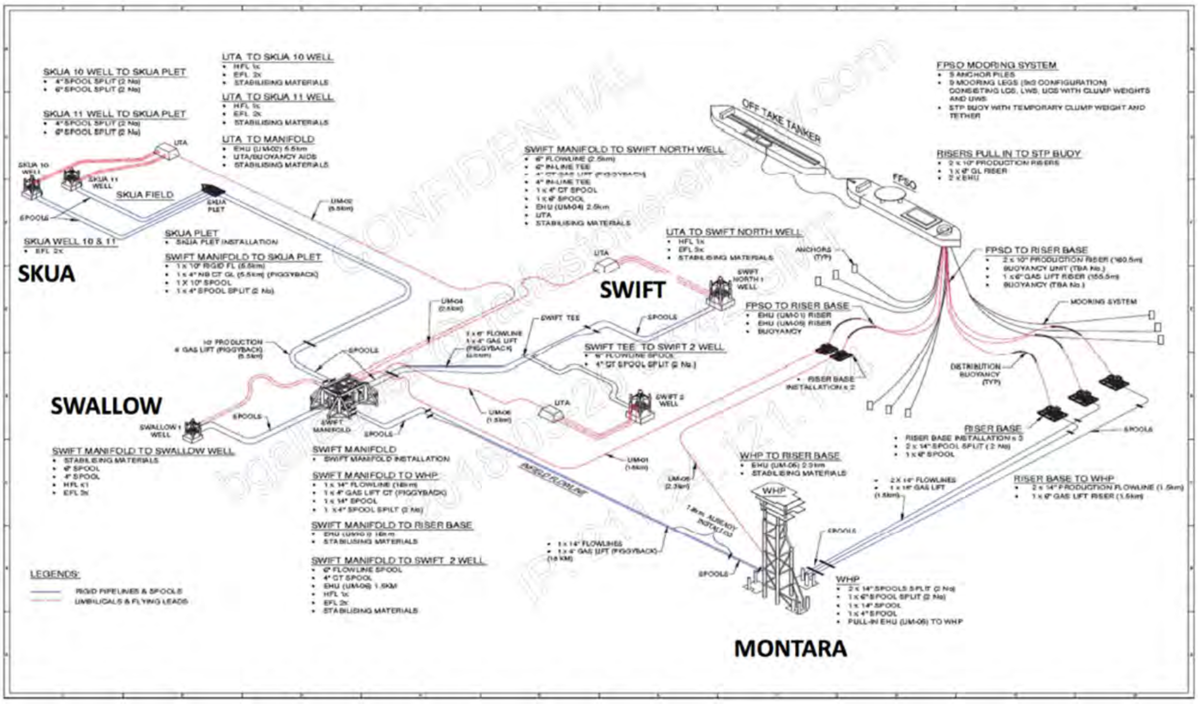


Figure 2.14: Montara project facilities schematic

The Montara FPSO class was suspended under the previous operator by the regulator due to the deferral of inspections and repairs. The Montara FPSO has continued production operations under the suspended status. The inspection work is currently ongoing by Lloyd's Register, with minor repairs undertaken by PTTEP. This is expected to be completed in December 2018, after which it is expected that the class status will be reinstated. ERCE has viewed documentation from Lloyd's Register, as well as the inspection and repair work program, and is satisfied that the suspension and the ongoing work will not affect FPSO operation or impact the production forecasts in this report.

Historical downtime on the Montara project has been variable, with an average of 28% over the past five years. This has been due to the downhole well problems on Wells Swift-2 and Skua-11. Additionally, there have been topsides issues with gas compressor reliability, process trips and slugging.

Jadestone has shown ERCE plans to resolve the downhole well issues in September and October 2018 using an intervention vessel. Also reviewed by ERCE were plans to conduct a compressor review and increase stocking of critical spares, loosen topsides process parameters to reduce the number of trips, and installation of a slug control system. The operator previously had a 21-day annual shutdown, mainly for FPSO inspection. Jadestone plans to change this to a 14-day shutdown every two years. Jadestone has assumed downtime of 10% for the Montara platform wells, and a higher 20% for the subsea tie-back wells. This combined with the bi-annual shutdown is equivalent to a long-term average annual downtime of 17%.

Based on the historical performance of the asset and the explanations provided by Jadestone, ERCE has deemed the Jadestone downtime assumptions going forward as reasonable and has incorporated these into the production forecasts.

2.1.7.5. Production Forecasting

The Low Case Developed Producing, Low Case Developed, Low Case, Best Case and High Case production forecasts are shown below in Figure 2.15 and summarised in Table 2-8.

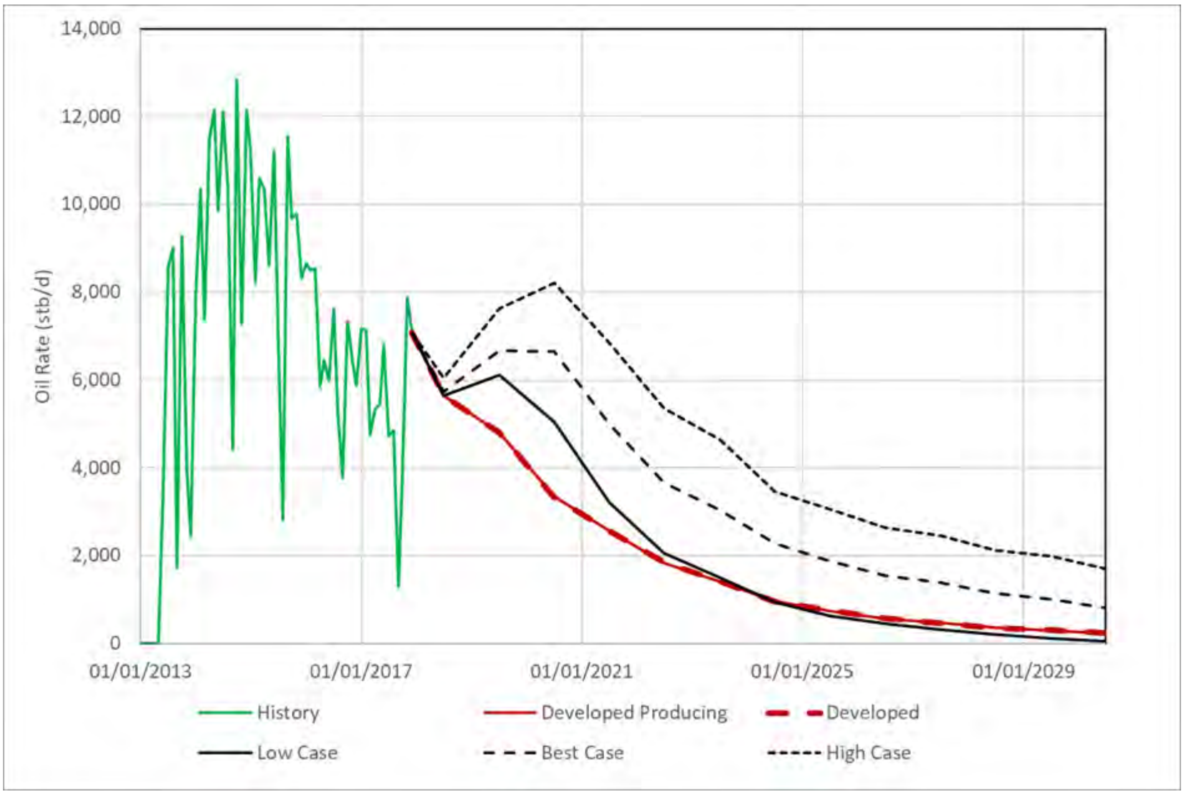


Figure 2.15: Montara field production forecasts

Table 2-8: Montara field production forecasts

	Low Case Developed Producing (stb/d)	Low Case Developed (stb/d)	Low Case (stb/d)	Best Case (stb/d)	High Case (stb/d)
2018	5,641	5,641	5,641	5,729	6,044
2019	4,807	4,807	6,109	6,675	7,626
2020	3,346	3,346	5,050	6,652	8,199
2021	2,560	2,560	3,208	4,997	6,856
2022	1,834	1,834	2,060	3,662	5,348
2023	1,416	1,416	1,503	3,041	4,634
2024	954	954	948	2,282	3,467
2025	741	741	627	1,887	3,054
2026	565	565	442	1,552	2,634
2027	469	469	324	1,383	2,461
2028	362	362	205	1,135	2,126
2029	305	305	121	1,001	1,982
2030	239	239	39	809	1,705
Total (MMstb)	**8.5**	**8.5**	**9.6**	**14.9**	**20.5**

NOTE:

1. Rates shown are technically recoverable oil rates and have not been subject to economic modelling

2.2. Skua Field, AC/L8

2.2.1. Introduction

The Skua field lies in production licence AC/L8 in the Vulcan Sub-Basin, approximately 675 km west of Darwin, Australia in a water depth of 77 m (Figure 2.1). At the effective date of this independent evaluation, PTTEP AA is the Operator of the field and holds a 100% working interest. PTTEP AA was formed when PTTEP acquired 100% of Coogee Resources in 2009. Jadestone entered into a SPA with PTTEP AA on 15 July 2018 to acquire a 100% interest in AC/L7 and AC/L8.

There is no definitive expiry date to production licence AC/L8, with the Operator able to produce the field until it is no longer economic to do so.

Although a thin oil column was intersected in Well Skua-2 in 1985, the main accumulation was not discovered until 1987 by Well Skua-3. A further 5 wells were drilled to December 1991 (Skua-4, -7A, -8, -9 and -9ST1), when the first phase of Skua production commenced.

The Skua 3D seismic survey was acquired in July 1990 and PSDM reprocessing of the survey was undertaken in 2005. This volume formed the basis for Jadestone's evaluation.

The Skua field comprises a 48 m oil column overlain by a small gas column (~10 m). Hydrocarbons are contained within the Early to Middle Jurassic Plover Formation, which across Skua was deposited in a fluvial-dominated deltaic environment. Reservoir quality is excellent, with net reservoir thickness in the order of 20 – 40 m and permeability typically around 1,000 mD. The field structure is described as a rollover anticline at the crest of a northeast-southwest oriented tilted fault block.

First production from the Skua field came in December 1991 from three producers, Wells Skua-4, -8 and -9ST1. The field initially produced at approximately 25,000 stb/d, eventually declining to 2,400 stb/d. After producing 20.2 MMstb, the field was shut-in in January 1997 due to it being uncommercial. Through this first development stage, the wells were connected to a dedicated FPSO.

In 2011, the Operator produced a field development plan with the intention of bringing the field back onstream, with higher oil prices making the project economic. In March 2014, the field was brought back onstream through two new horizontal wells, Skua-10ST2 and Skua-11, which achieved initial rates of approximately 4,000 stb/d and 2,500 stb/d respectively. Production is now tied back to the Montara FPSO via the unmanned Montara wellhead platform.

As of 31 December 2017, the Skua field has produced 25.39 MMstb of oil and 29.58 Bscf of gas.

2.2.2. Geology & Geophyiscs

The seismic data quality over the Skua field is moderate to poor. Several areas of the field are affected by hydrocarbon related diagenetic zones ("HRDZs") that are found in the overlying Pliocene sands. The HRDZs cause pull-ups and image distortion on the seismic data beneath them (Figure 2.16) which leads to significant uncertainty in seismic interpretation and depth conversion.

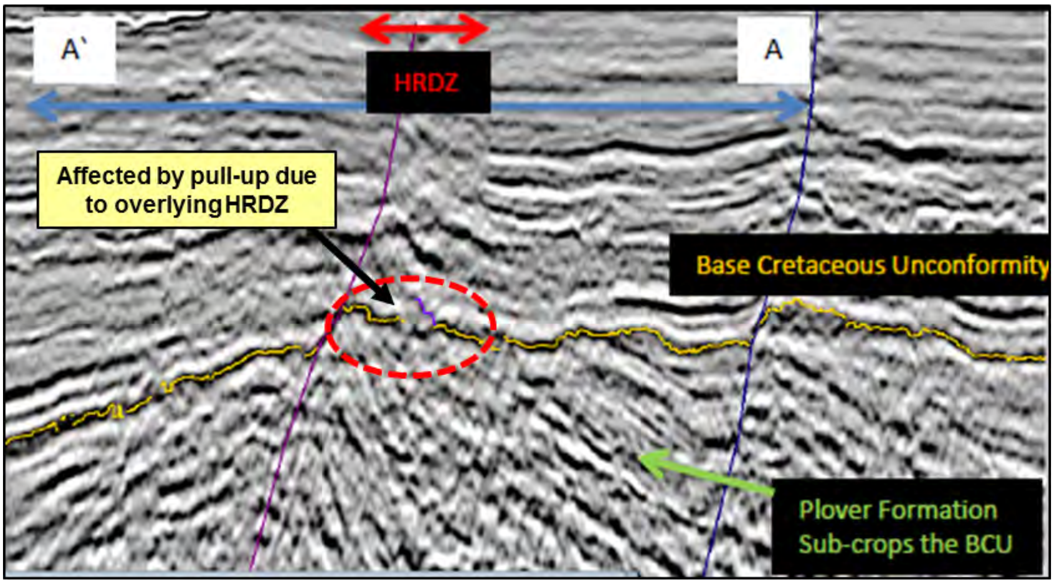


Figure 2.16: NW-SE seismic line showing the effect of overlying HRDZ

HRDZs are common in the Vulcan Sub-Basin and have been studied in-depth in literature. They are formed when faults are re-activated, allowing trapped hydrocarbons to migrate upwards and collect in shallower aquifers, where they are biodegraded. Intense carbonate cementation forms in otherwise poorly cemented sands, causing a strong acoustic impedance contrast. As a result of the breaching and subsequent migration, the Skua field has a significant residual oil column.

Jadestone was able to view the 3D PSDM volume (depth domain only) in a physical dataroom but had no access to it outside of the dataroom, only being permitted to remove screenshots. As such, ERCE was not able to independently review the data but had access to the screenshots. It is the Operator's belief that the PSDM processing has accounted for the pull-up effects caused by the HRDZs but plotting each well's time-depth relationship shows that those wells in the HRDZ areas are clearly still affected, sitting uniformly off a field trend (Figure 2.17). Those wells affected by HRDZs are Wells Skua-3, -7A, -8 and -11.

Jadestone has made corrections to the Operator's TWT and depth maps to account for the effects of HRDZ zones that are based on the time-depth relationships. Jadestone has also adopted corrections made to the Operator's surfaces in the area around Well Skua-10ST2, which in their pre-drill model penetrated two separate peaks separated by a saddle. The saddle was proven to be non-existent, with the well penetrating the reservoir and remaining in the reservoir along its entire horizontal section.

ERCE has reviewed Jadestone's edits to the Operator's surfaces and is in agreement with the corrections made (Figure 2.18).

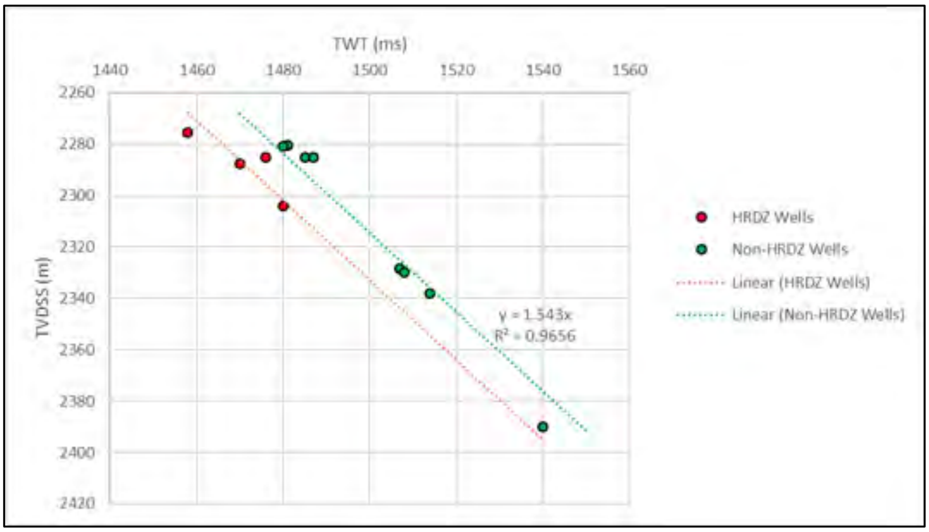


Figure 2.17: Time-Depth relationship for HRDZ and non-HRDZ Skua wells

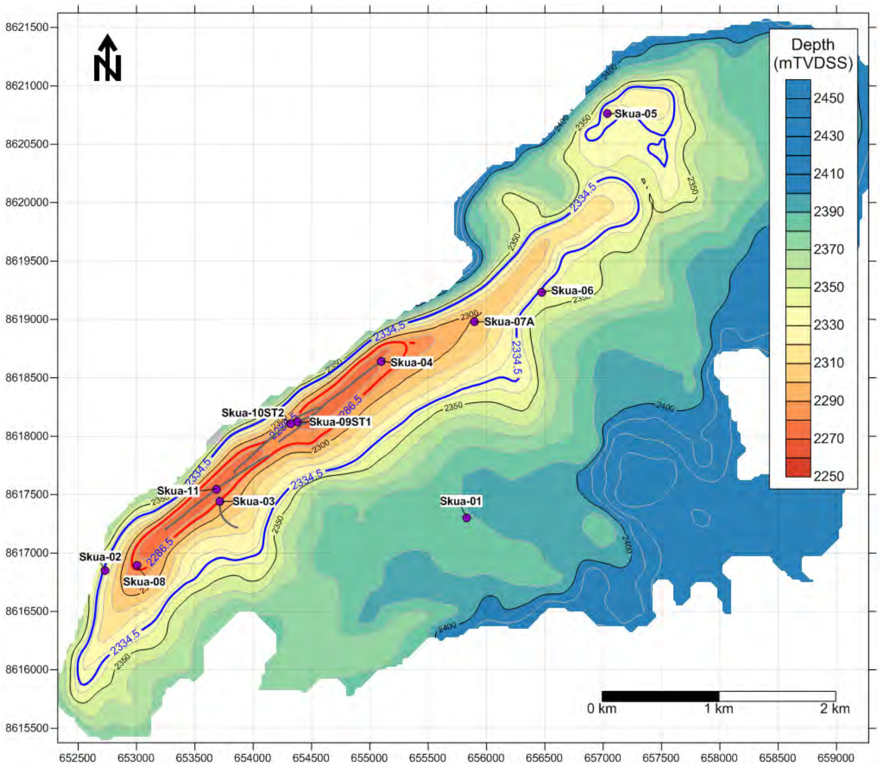


Figure 2.18: BCU Depth Surface, Skua field

The Early to Middle Jurassic Plover Formation forms the reservoir in the Skua field. The reservoir sub-crops the Base Cretaceous Unconformity ("BCU"), which forms the top depth surface. The Plover

Formation was deposited in a prograding fluvial-dominated deltaic environment and consists of stacked fluvial deposits separated by poorer quality floodplain deposits (e.g. crevasse splays, interdistributary bay muds/silts) (Figure 2.19).

The NTG in each well ranges from 60 – 90% (excluding Well Skua-2) with net sand thickness above the OWC between 20 – 40 m. Correlation of individual sand units is difficult across the field. The lateral continuity of sand and shale units is a significant uncertainty in the field that can be better established by studying the field's dynamic performance.

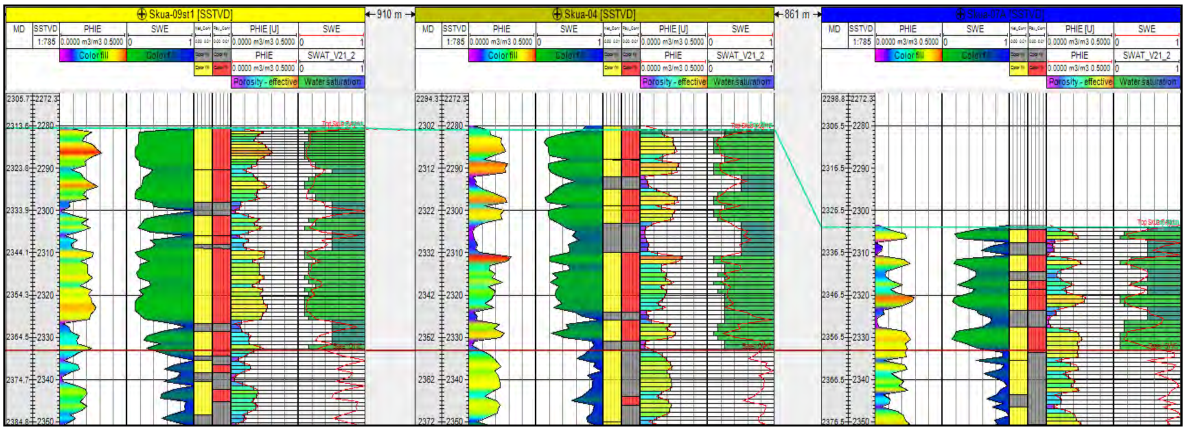


Figure 2.19: Reservoir correlation through Wells Skua-9ST1, -4 and -7A

Cores were cut in Wells Skua-2, -3, -4, -5-8 and -9ST1, providing a rich database that covers much of the field. The core data show the reservoir sand to be of high quality, with porosity and permeability ranging from 18 – 27 pu and 100 – 6,000 mD (Figure 2.20).

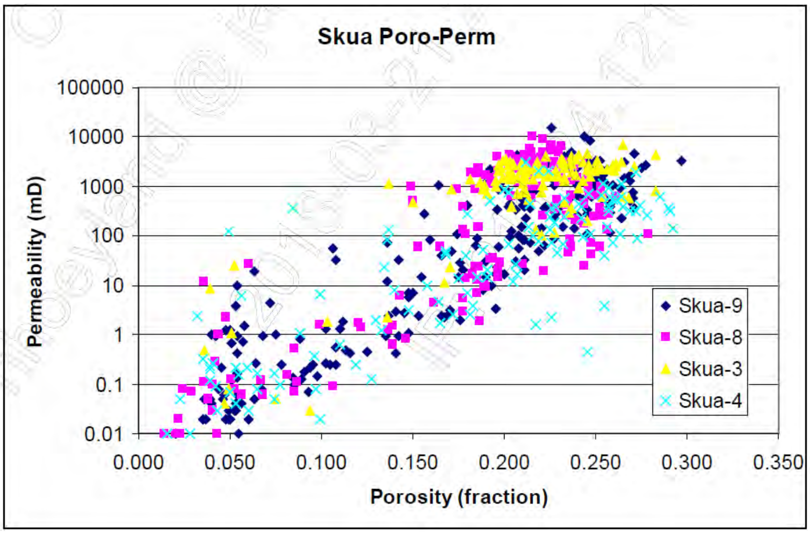


Figure 2.20: Poroperm data from four Skua wells

2.2.3. Petrophysical Analysis

The Operator provided Jadestone with a limited petrophysical dataset. Raw logs were not available for the Skua wells meaning ERCE could not make an independent evaluation. We were able to review the petrophysical methodology outlined in the field development plan and found it to be reasonable. Given that our independent evaluations in the Montara and Swift/Swallow wells were in line with the Operator's, we have assumed that the Operator's PHIE and SWE curves in the Skua field are acceptable.

Reservoir summaries for each well were made using 10% effective porosity cut off to remove tight, non-net intervals, and a cut off of 70% Sw to remove any intervals that would produce water. The results are presented in Table 2-9.

Table 2-9: Petrophysical summary of available Skua wells

Well	Gross (m)	Net (m)	Pay (m)	NTG		Gross Average		Net Average		Pay Average	
				Net	Pay	PHIE	SWE	PHIE	SWE	PHIE	SWE
Skua-02	33.0	2.0	1.0	0.061	0.031	0.040	0.887	0.096	0.796	0.090	0.786
Skua-03	45.5	42.4	42.4	0.930	0.930	0.173	0.222	0.182	0.197	0.182	0.197
Skua-04	52.2	36.6	36.6	0.701	0.701	0.163	0.384	0.201	0.302	0.201	0.302
Skua-07A	29.1	17.8	17.6	0.612	0.603	0.145	0.437	0.201	0.318	0.201	0.318
Skua-08	48.1	42.8	42.5	0.890	0.885	0.179	0.274	0.191	0.251	0.191	0.251
Skua-09st1	52.6	42.3	42.3	0.804	0.804	0.180	0.298	0.202	0.236	0.202	0.236
Skua-10st1	22.7	13.2	10.6	0.582	0.466	0.091	0.677	0.215	0.354	0.217	0.268
Avg / Wt. Avg	**40.4**	**28.1**	**27.5**	**0.696**	**0.681**	**0.148**	**0.411**	**0.195**	**0.264**	**0.195**	**0.255**

2.2.4. Fluid Contacts

Well logs and RFT pressure data from the pre-production wells suggest a GOC between 2,286 – 2,288 mTVDSS and an OWC between 2,330 – 2,335 mTVDSS. The contacts used by the Operator and accepted by Jadestone are 2,286.5 mTDVSS and 2,334.5 mTVDSS. No digital pressure data were available for our evaluation but a review of well reports and composite logs has led us to accept these contacts.

In 1997, a RST-B COR interpretation in Well Skua-8 suggested the OWC had moved up to 2,298.5 mTVDSS in the well. When Well Skua-10ST1 was drilled in 2008, the estimated OWC was between 2,300.6 – 2304 mTVDSS.

2.2.5. Hydrocarbons in Place

ERCE's in-place estimates for the Skua field are based on Jadestone's depth surfaces and the petrophysical sums and averages of Wells Skua-3, -4, -5, -7A, -8, -9ST1 and -10ST1. The base of the Plover reservoir is significantly below the OWC and as such, no base surface is used in the calculation of gross rock volume.

We have adopted the GOC (2,286.5 mTVDSS) and OWC (2,334.5 mTVDSS) used by Jadestone. A map of gross reservoir between the GOC and OWC is shown in Figure 2.21.

Our P50 GRV uses Jadestone's depth surfaces and the contacts described above. A P90 GRV is calculated using a 20% discount to the P50. This is larger than the uncertainty applied in the Montara field to account for the presence of HRDZs across the field. The P10 GRV is then calculated by assuming a log-normal distribution defined by the P90 and P50.

The ranges of NTG, porosity and oil saturation used in our volumetric calculation are based on the petrophysical sums and averages of the wells for which Jadestone had digitised PHIE and SWE logs. Each parameter is defined by a normal distribution. The averages do not include Well Skua-2, which penetrated just 2 m of net reservoir and is off structure. All other wells penetrated significantly thicker reservoir sections.

Our inputs to a probabilistic simulation of in-place volumes is shown in Table 2-10 and Table 2-11 and the results are shown in Table 2-12.

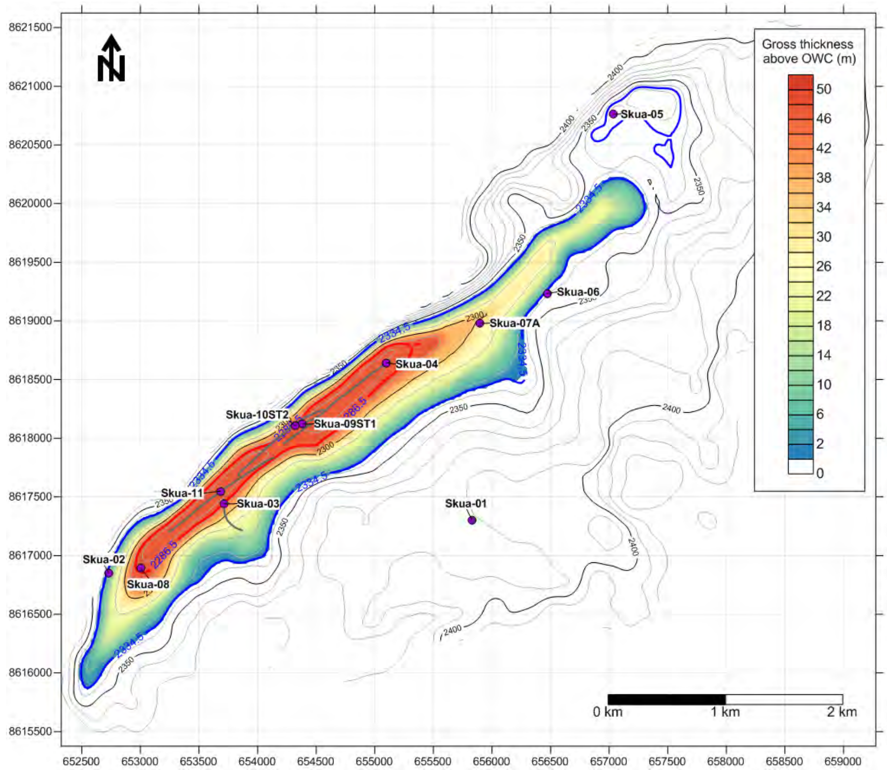


Figure 2.21: Gross reservoir between GOC and OWC

Table 2-10: Volumetric inputs to probabilistic simulation, Skua field (Oil Leg)

Reservoir	GRV (MMm3)			NTG (frac)			PHIT (frac)			So (frac)			Bo (rb/stb)
	Log-Normal			Normal			Normal			Normal			Constant
	P90	P50	P10	P90	P50	P10	P90	P50	P10	P90	P50	P10	P50
Plover	73.78	92.23	115.29	0.700	0.800	0.900	0.185	0.200	0.215	0.750	0.800	0.850	1.470

Table 2-11: Volumetric inputs to probabilistic simulation, Skua field (Gas Cap)

Reservoir	GRV (MMm3)			NTG (frac)			PHIT (frac)			Sg (frac)			Bg (rcf/scf)
	Log-Normal			Normal			Normal			Normal			Constant
	P90	P50	P10	P90	P50	P10	P90	P50	P10	P90	P50	P10	P50
Plover	2.90	3.63	4.54	0.700	0.800	0.900	0.185	0.200	0.215	0.750	0.800	0.850	0.005

Table 2-12: Probabilistic STOIIP and GIIP results, Skua field

Reservoir	STOIIP (MMstb)				GIIP (Bscf)			
	P90	P50	P10	Mean	P90	P50	P10	Mean
Plover	39.5	50.3	63.3	51.0	2.7	3.4	4.3	3.4

2.2.6. Production Performance

A total of 11 wells have been drilled on the field. This includes six exploration and appraisal wells, three vertical production wells and two horizontal production wells. The three vertical production wells have been plugged and abandoned.

Oil production commenced from the Skua field in December 1991. Peak oil production of 24,987 stb/day was achieved in August 1992. The field produced from the three vertical production wells until January 1997 before it was abandoned at 2,424 stb/day at 80% water cut.

The Skua field re-commenced production from the Skua-10ST2 and Skua-11 horizontal production wells in March 2014. Well Skua-11 has shown evidence of poor oil flow due to a lack of gas lift, likely due to a blockage in the downhole gas lift mandrel contributing to the variable field oil production rate since mid-2015. As of 31 December 2017 the two oil producers are producing 3,619 stb/day of oil, with 4.5 MMscf/day of gas at a 77% water cut. As of 31 December 2017 the field has produced 25.39 MMstb of oil and 29.58 Bscf of gas. The production history for the Skua field from 1991 to 1997 is shown in Figure 2.22, whilst production from 2014 onwards is shown in Figure 2.23.

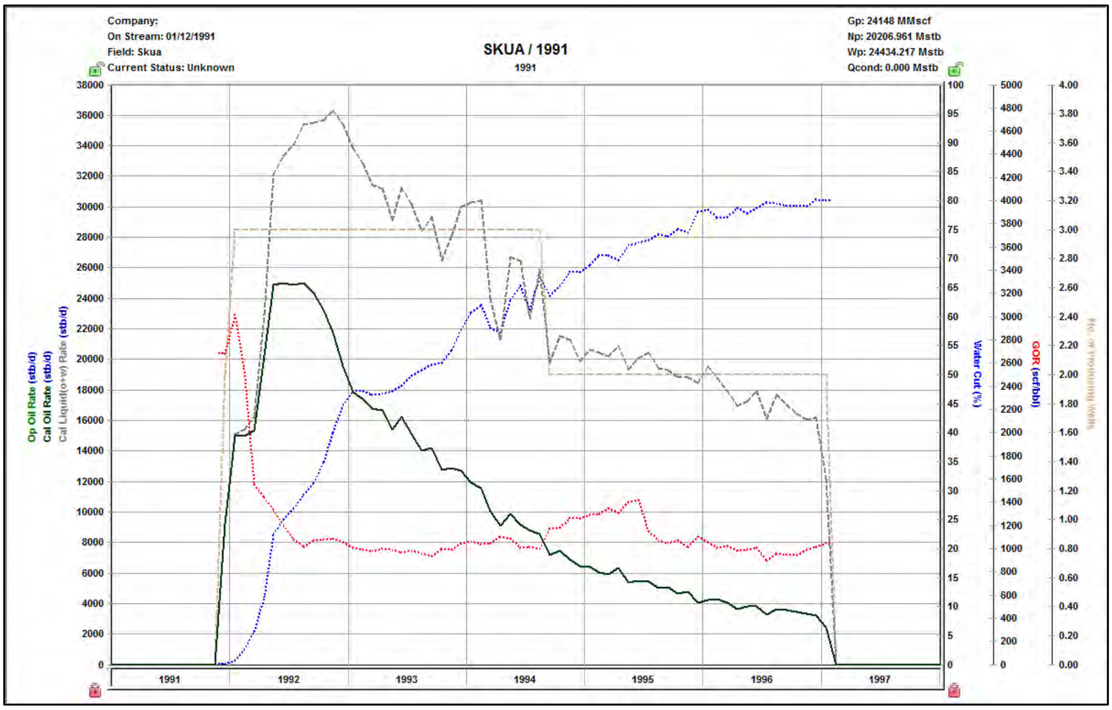


Figure 2.22: Production history of the Skua field, 1991-1997

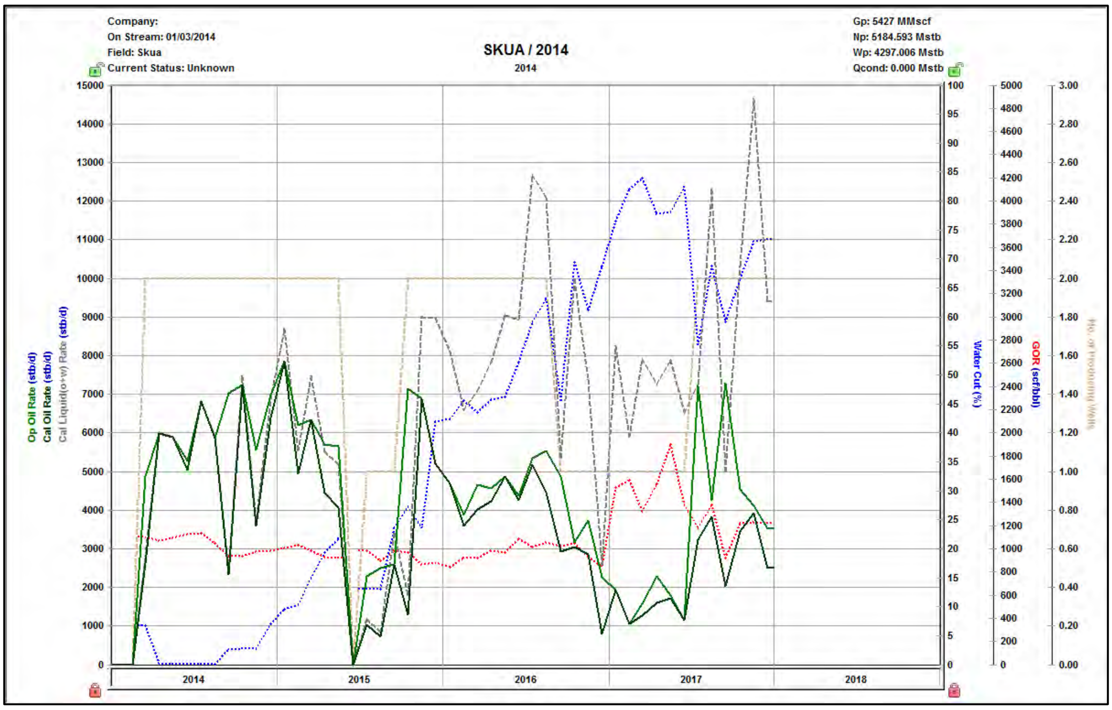


Figure 2.23: Production history of the Skua field, 2014-Present

The oil in the Skua field is light at 42.8° API, specific gravity of 0.812 and viscosity of 0.3 cP. The initial GOR was 1,021 scf/stb. Initial reservoir pressure was 3,350 psia with initial temperature of 96° C.

2.2.7. Recoverable Volumes

2.2.7.1. Production Forecasts – Developed Producing

As of 31 December 2017 there were two horizontal wells producing in the field. Both Wells Skua-10ST2 and Skua-11 have been producing for a number of years and each of the wells shows evidence of production decline. Jadestone has forecast production for these wells using DCA. Jadestone plans to perform an intervention on the Skua-11 well over September and October 2018 to restart gas lift to this well. The Jadestone production forecasts for this well assume a successful workover to restart gas lift to this well.

ERCE carried out DCA on these wells and compared the results to Jadestone's. The Low, Best and High Case forecasts between Jadestone and ERCE were consistent, so ERCE has accepted the Jadestone production forecasts for these wells.

2.2.7.2. Production Forecasts – Undeveloped

Jadestone is proposing to drill an additional horizontal production well (Skua-12) on the field's crest in between Wells Skua-10ST2 and Skua-11. The well will be tied into the existing subsea infrastructure. Well Skua-12 will have a horizontal well section of approximately 650m and target unswept oil between the two currently producing wells. The location of the well is shown in Figure 2.24. Also shown are notional well locations to the northeast of the current wells for additional Wells Skua-13 and Skua-14. These are notional well locations for future field development, but require further technical work and have not been included in the production forecasts.

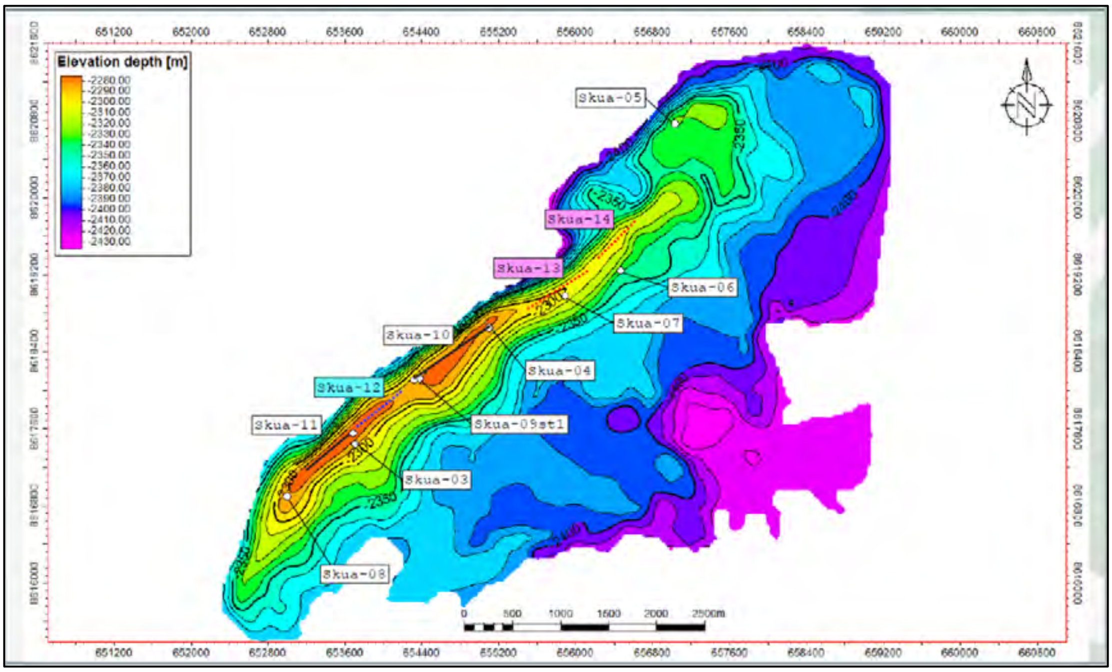


Figure 2.24: Location of the planned Skua-12 well

Jadestone has used a simulation model to guide oil recovery and the production forecast for Well Skua-12. The simulation model was based on Jadestone's static modelling used for volumetric in-place estimation, with dynamic parameters input from Field Development Plan documentation. The model was history matched and used to predict future field performance.

The simulation model history match quality was reasonable, with water breakthrough and evolution generally close to the history. Jadestone ran a simulation case with and without Well Skua-12 to estimate the incremental recovery from the well. For the no infill well case, the recovery of Wells Skua-10ST2 and Skua-11 in the simulation model (6.9 MMstb) was higher than remaining recoverable oil estimated using DCA by 1.7 MMstb. Jadestone interpreted this higher oil production as the model optimistically producing more oil from the crestal location of Well Skua-12. Therefore, the case including Skua-12 infill is likely conservative as Wells Skua-10ST2 and Skua-11 "steal" oil from Well Skua-12 in the model. However, since there is considerable uncertainty with the reservoir sweep in this area, Jadestone has retained the incremental recoverable estimates and production forecast for Well Skua-12 well from the simulation model for the Best Case. For the Low and High production forecasts Jadestone incorporated uncertainty based on the variation in the Low to High forecasts for the other existing wells.

ERCE reviewed the model inputs, history match and model outputs, as well as comparing the well recovery against the other wells in the field. Well Skua-12 is located in a producing area of the field with good well control, and the estimated recovery is lower than the other wells in the field. Based on this ERCE has deemed the Jadestone recovery estimates and production forecasts for Well Skua-12 as reasonable.

2.2.7.3. Recovery

ERCE has estimated the Low, Best and High Case recovery factors for the Skua Field as 76%, 64% and 55%, respectively based on the production forecasts. ERCE views the Low Case recovery factor as too high, and suggests the oil in-place lies between the Best and High Case estimates. High recovery factors are supported by the depleted Jabiru Field, which has been identified as an analogue. The Jabiru field is also located in the Timor Sea, Australia and was a high permeability reservoir (multi-Darcy) with strong water drive similar to the Skua field. The estimated recovery factor for the Jabiru field cited in documentation seen by ERCE was 78% to 80%, dependent on in-place estimates.

The ERCE-accepted estimates of Developed and Undeveloped future production to 31 December 2030 prior to economic modelling are summarised in Table 2-13.

Table 2-13: Summary of future production estimates for the Skua field

	Low Case Developed Producing (MMstb)	Low Case Developed (MMstb)	Low Case (MMstb)	Best Case (MMstb)	High Case (MMstb)
Cumulative production at 31 December 2030	29.27	29.27	30.07	32.27	34.92
Cumulative production at 31 December 2017	25.39				
Remaining production at 31 December 2017	3.88	3.88	4.68	6.88	9.53

NOTE

1) Volumes shown are technically recoverable oil volumes and have not been subject to economic modelling.

2.2.7.4. Production Forecasting

The Low Case Developed Producing, Low Case Developed, Low Case, Best Case and High Case production forecasts are shown below in Figure 2.25 and summarised in Table 2-14. The downtime assumptions detailed in section 2.7.4 have been applied to the production forecasts.

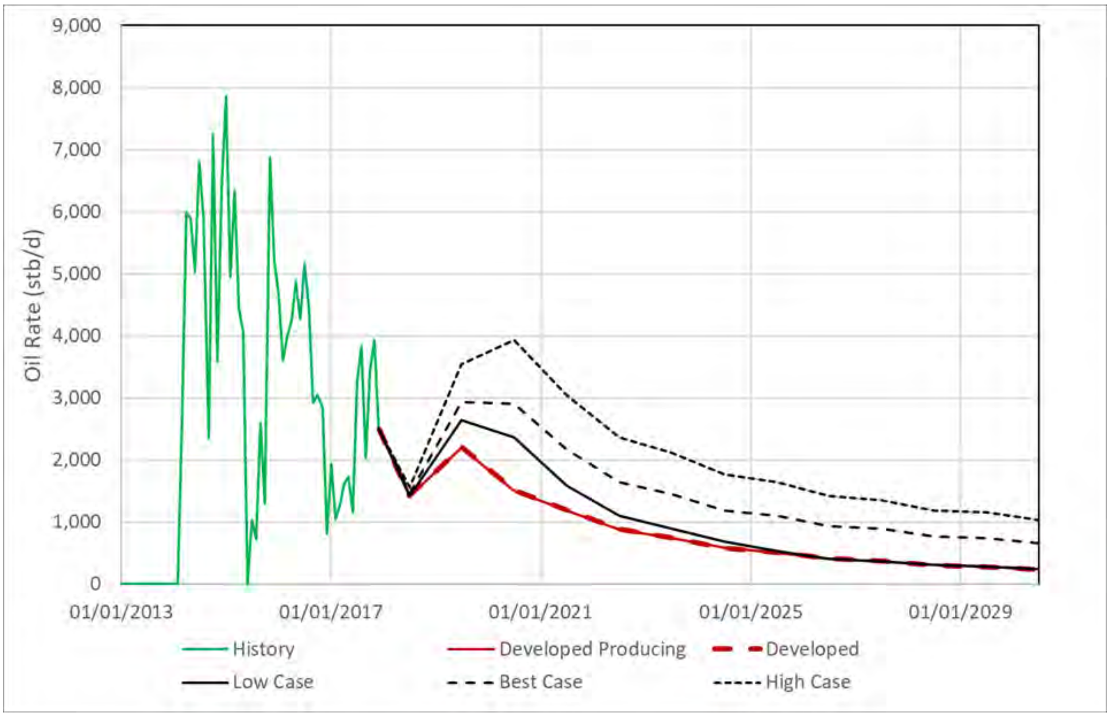


Figure 2.25: Skua field production forecasts

Table 2-14: Skua field production forecasts

	Low Case Developed Producing (stb/d)	Low Case Developed (stb/d)	Low Case (stb/d)	Best Case (stb/d)	High Case (stb/d)
2018	1,423	1,423	1,423	1,468	1,554
2019	2,201	2,201	2,646	2,931	3,538
2020	1,504	1,504	2,370	2,908	3,927
2021	1,185	1,185	1,585	2,167	3,039
2022	883	883	1,098	1,647	2,366
2023	741	741	887	1,443	2,111
2024	580	580	677	1,189	1,764
2025	507	507	528	1,096	1,644
2026	411	411	411	936	1,418
2027	369	369	369	886	1,354
2028	306	306	306	773	1,189
2029	281	281	281	745	1,153
2030	237	237	237	659	1,025
Total (MMstb)	**3.9**	**3.9**	**4.7**	**6.9**	**9.5**

NOTE:

1. Rates shown are technically recoverable oil rates and have not been subject to economic modelling.

2.3. Swift/Swallow Field, AC/L8

2.3.1. Introduction

The Swift field lies in production licence AC/L8 in the Vulcan Sub-Basin, approximately 675 km west of Darwin, Australia in a water depth of 77 m (Figure 2.1). At the effective date of this independent evaluation, PTTEP AA is the Operator of the field and holds a 100% working interest. PTTEP AA was formed when PTTEP acquired 100% of Coogee Resources in 2009. Jadestone entered into a SPA with PTTEP AA on 15 July 2018 to acquire a 100% interest in AC/L7 and AC/L8.

There is no definitive expiry date to production licence AC/L8, with the Operator able to produce the field until it is no longer economic to do so.

The Swift field was discovered in January 1985 by Well Swift-1. The well targeted the Plover Formation but found it to be water bearing. However, excellent hydrocarbon shows were found in an unexpected Rowan sandstone beneath the BCU. No further action was taken until January 2006, when Well Swift North-1 was drilled by Coogee Resources. The well was drilled 1.4 km northeast of Well Swift-1 and penetrated a total 14 m of net oil pay beneath the BCU. A DST over the interval 2,397 – 2,403 mMD flowed at a final rate of 3,075 stb/d of oil and 1.19 MMscf/d of gas.

In April 2006, Well Swallow-1 was drilled 1 km southwest of Well Swift-1. The well encountered hydrocarbons in the Puffin and Plover Formations, including an OWC in the Plover Formation at 2,406 mTVDSS (2,431 mMD). A DST over the interval 2,419 – 2,425 mMD flowed at a final rate of 4,625 stb/d of oil and 2.72 MMscf/d of gas.

In January 2009, Well Swift-2 was drilled as a development well just 350 m north of Well Swift-1. The well penetrated approximately 19 m of net oil pay in the Rowan sandstone and the same OWC as observed in Wells Swift-1 and Swift North-1.

Although the Swift and Swallow wells target the same structure, they penetrate different reservoir accumulations due to the nature of the sub-crop beneath the BCU and as such are often described as separate pools/fields.

The Swift/Swallow field is covered by the Skua 3D seismic survey that was acquired in July 1990. The same PSDM volume, produced in 2005, formed the basis for Jadestone's evaluation.

The Swift pool comprises a 26 m thick oil column contained within the Early to Middle Jurassic Rowan Formation, which was deposited in a shallow marine to deltaic environment. Reservoir quality is excellent, with net reservoir thickness in the order of 15-20 m in Wells Swift-1, Swift-2 and Swift North-1 and permeability typically greater than 1,000 mD. The field structure is similar to the Skua field, described as a rollover anticline at the crest of a northeast-southwest oriented tilted fault block.

The Swallow pool comprises a 31 m thick oil column contained within the Early to Middle Jurassic Plover Formation, which was deposited in a more proximal environment than the Rowan Formation penetrated by the Swift wells. Reservoir quality is excellent, although the upper section of the Plover consists of thinly interbedded sands and shales, leading to uncertainty in their lateral extent.

First production from the Swift/Swallow field came in October 2013 from Wells Swift-2 and Swallow-1, with Well Swift North-1 later commencing production in April 2014. The field reached peak production in July 2015 at approximately 12,500 stb/d but has suffered a number of operational issues since. At present, both Wells Swift-2 and Swallow-1 are shut-in and require workovers to be brought back onstream. Production is tied back to the Montara FPSO via the unmanned Montara wellhead platform.

As of 31 December 2017, the Swift pool has produced 5.17 MMstb of oil and 4.57 Bscf of gas and the Swallow pool has produced 0.14 MMstb of oil and 0.12 Bscf of gas.

2.3.2. **Geology & Geophyiscs**

The seismic data quality over the Swift/Swallow field is moderate to poor. Areas of the field are covered by HRDZs, causing significant pull-up and image degradation (see Section 2.2.2) (Figure 2.26).

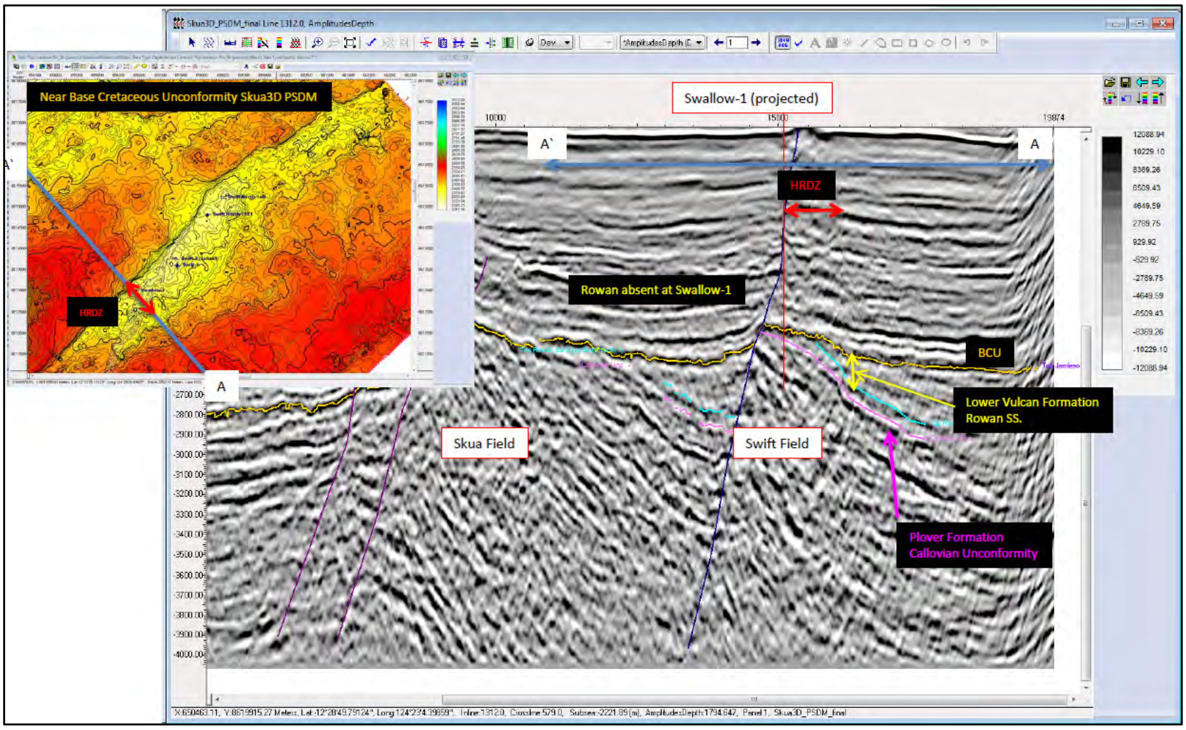


Figure 2.26: NW-SE seismic line through Well Swallow-1 showing effect of HRDZ

Jadestone was able to view the 3D PSDM volume (depth domain only) in a physical dataroom but had no access to it outside of the dataroom, only being permitted to remove screenshots. As such, ERCE was not able to independently review the data but had access to the screenshots. The Operator's BCU depth surface is of poor quality; it does not tie Well Swift-2 and is affected by a series of NW-SE lineations thought to be the result of seismic artefacts (either picking or acquisition). The lineations cause undulations of +-20 m which, given reservoir thickness is of a similar magnitude, can significantly affect the dynamic performance of the field. Jadestone has re-tied the Operator's depth surface to the wells and smoothed out the lineations (Figure 2.27). We have reviewed the steps taken by Jadestone and agree with their methodology.

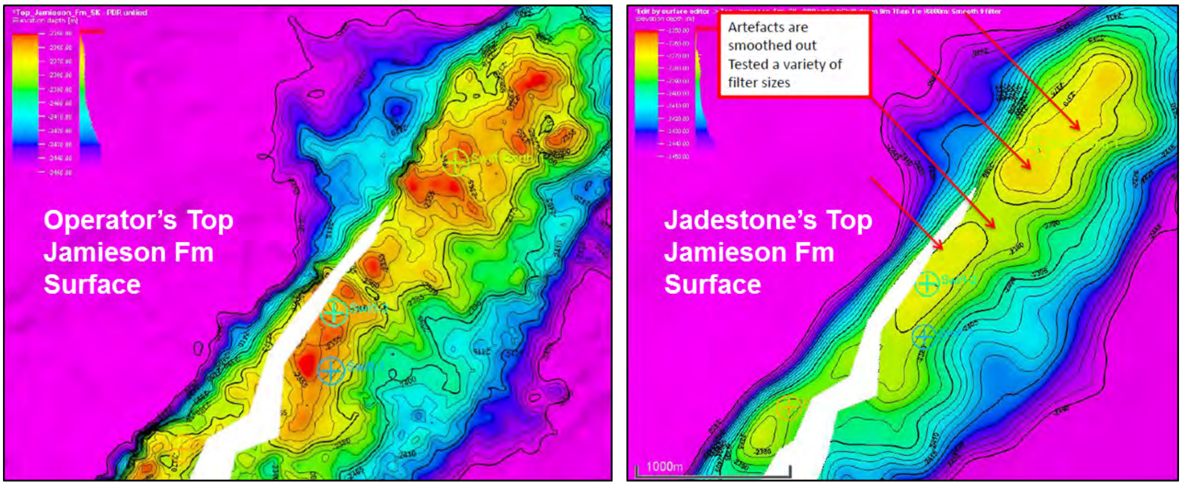


Figure 2.27: Comparison of the Operator's and Jadestone's Top Jamieson Fm depth surface

A depth surface for the Callovian unconformity was also provided to Jadestone by the Operator. As for the BCU, Jadestone has smoothed the surface and re-tied it to the well tops. ERCE has reviewed and accepted these edits.

The Early to Middle Jurassic Rowan Formation forms the reservoir in the Swift pool. The reservoir sub-crops the Base Cretaceous Unconformity ("BCU"), which forms the top depth surface. The Rowan reservoir is separated into an Upper and Lower interval in the Swift pool. At Wells Swift-1 and Swift-2, the Upper interval is eroded and only the Lower interval is penetrated (Figure 2.28). In the aforementioned wells, the Lower interval is a blocky sandstone with a gross thickness of 22 m and a NTG close to 100%. In Well Swift North-1, the petrophysical logs provided by the Operator end within the Lower Rowan. However, composite logs suggest that it has a gross thickness of approximately 35 m. The likely environment of deposition is a fluvial dominated delta.

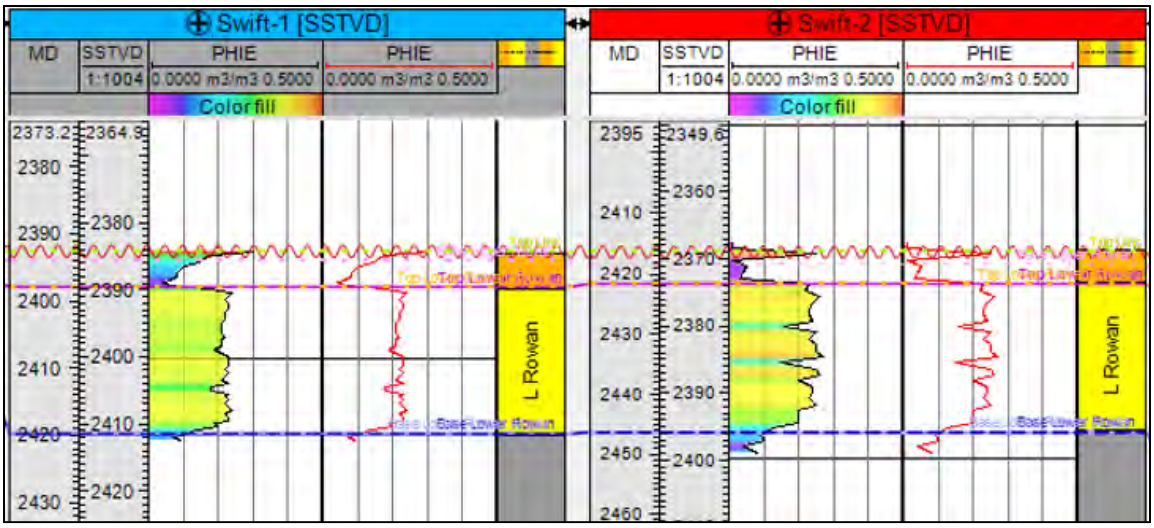


Figure 2.28: Lower Rowan correlation across Wells Swift-1 and -2

The Upper Rowan interval is penetrated by Well Swift North-1, where it has a gross thickness of 17.5 m (Figure 2.29). However, the interval is eroded by the BCU and is expected to thicken towards the northeast. Based on offset well data (Wells Montara-1 and Rowan-1) where a more complete section of the Upper Rowan is penetrated. In these wells, the full Rowan section (Upper and Lower) reaches a gross thickness of 190 – 220 m and in each well, the Upper section has a high NTG. Given the similarities in depositional environment, it is likely that the full Rowan section across the Swift pool was of comparable thickness, and that to the northeast of Well Swift-North-1 the Upper Rowan is likely to have a very high NTG.

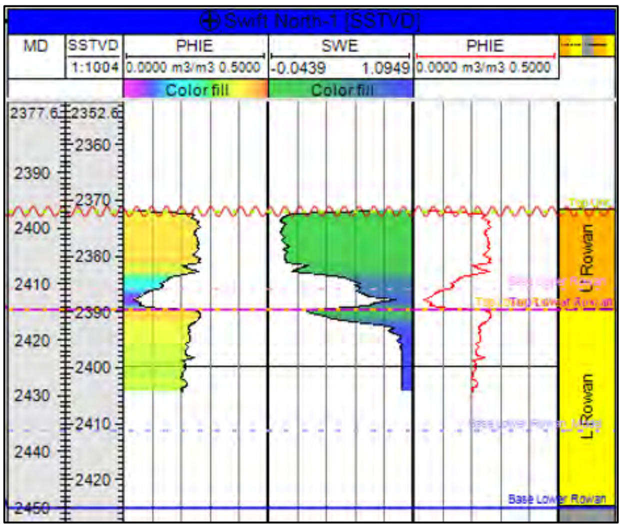


Figure 2.29: Upper and Lower Rowan intervals in Well Swift North-1

Limited core data is available in the Swift wells. The reservoir sand is of high quality, with porosity and permeability ranging from 20 – 25 pu and 100 – 2,000 mD.

The Early to Middle Jurassic Plover Formation forms the reservoir in the Swallow pool. Although present in the Swift wells, it is only hydrocarbon bearing in Well Swallow-1, which intersects approximately 18 m of net oil pay split across the Top and Upper Plover intervals (Figure 2.30). Across the field the Plover Formation has been eroded by the Callovian unconformity, which merges with the BCU towards the southwest. The reservoir sand is of high quality (although slightly poorer than the Rowan reservoirs encountered in the Swift wells) with porosity and permeability ranging from 16 – 25 pu and 100 – 2,000 mD.

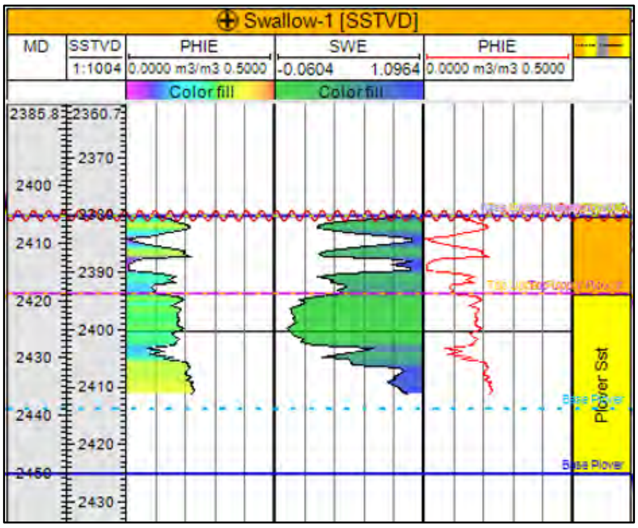


Figure 2.30: Top and Upper Plover intervals in Well Swallow-1

ERCE has reviewed Jadestone's reservoir correlation across the Swift and Swallow pools and has made alterations in certain areas where no petrophysical logs were provided by the Operator. These alterations were made after reviewing the composite logs and other well reports for each well. In general, the result is a thickening towards the northeast (Figure 2.31).

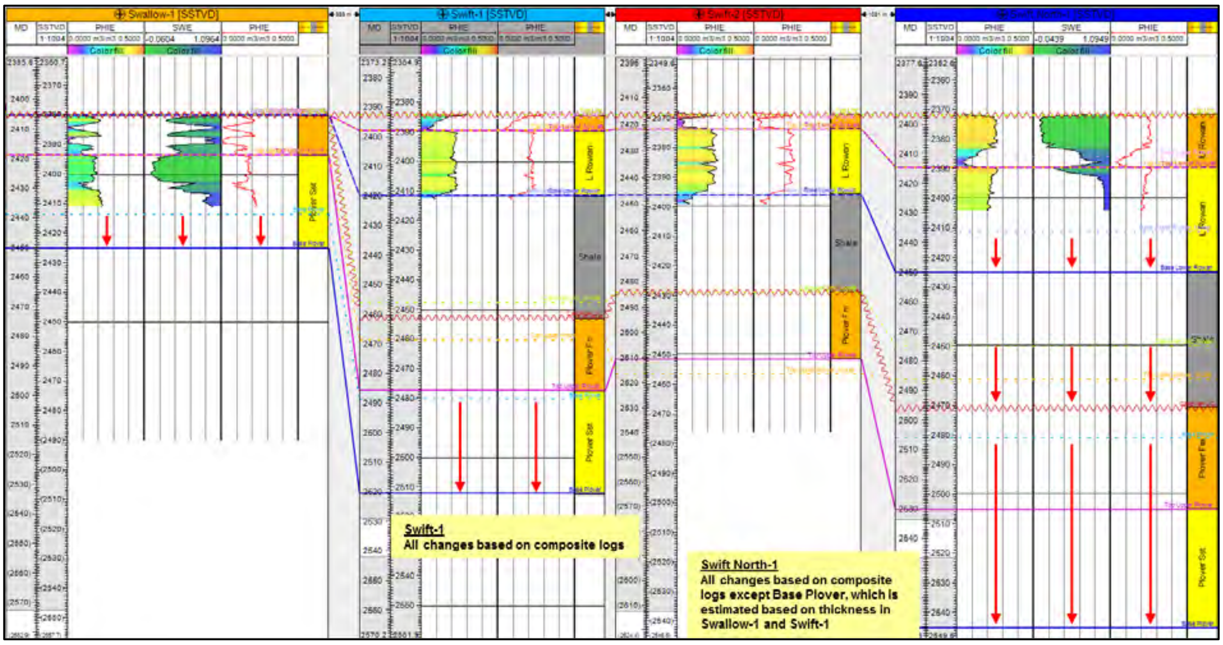


Figure 2.31: Differences in Jadestone and ERCE reservoir correlation. Red arrows show ERCE edits.

2.3.3. Petrophysical Analysis

The Operator provided Jadestone with a limited petrophysical dataset. Raw logs were available in Wells Swift North-1 and Swallow-1 and ERCE has used these to make an independent petrophysical evaluation.

Our methodology is described in detail in Section 2.1.3 of this report.

In Well Swift North-1, an OWC is observed at 2,392 mTVDSS where there is a notable decrease in resistivity and a reversal on the neutron-density crossover. An OWC is also observed in Well Swallow-1 at 2,406 mTVDSS where the same indicators are present.

Our interpretation in each well is in line with the Operator's, as demonstrated in the CPIs in Figure 2.32 and Figure 2.33. We have used the Operator's PHIE and SWE curves to derive reservoir summaries for each well. A 10% effective porosity cut off was used to remove tight, non-net intervals, and a cut off of 70% Sw was used to remove any intervals that would produce water. The results are presented in Table 2-15.

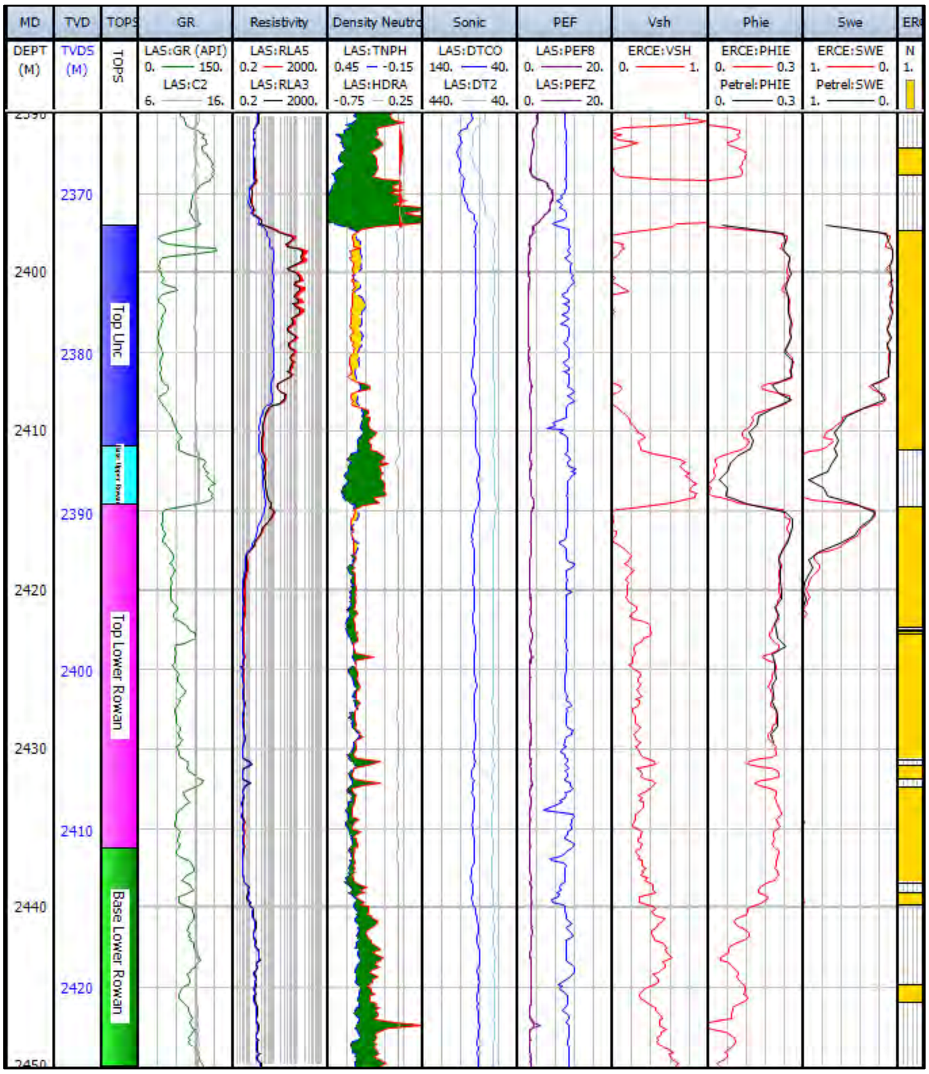


Figure 2.32: Well Swift North-1 CPI showing ERCE (red) and Operator (black) interpretations

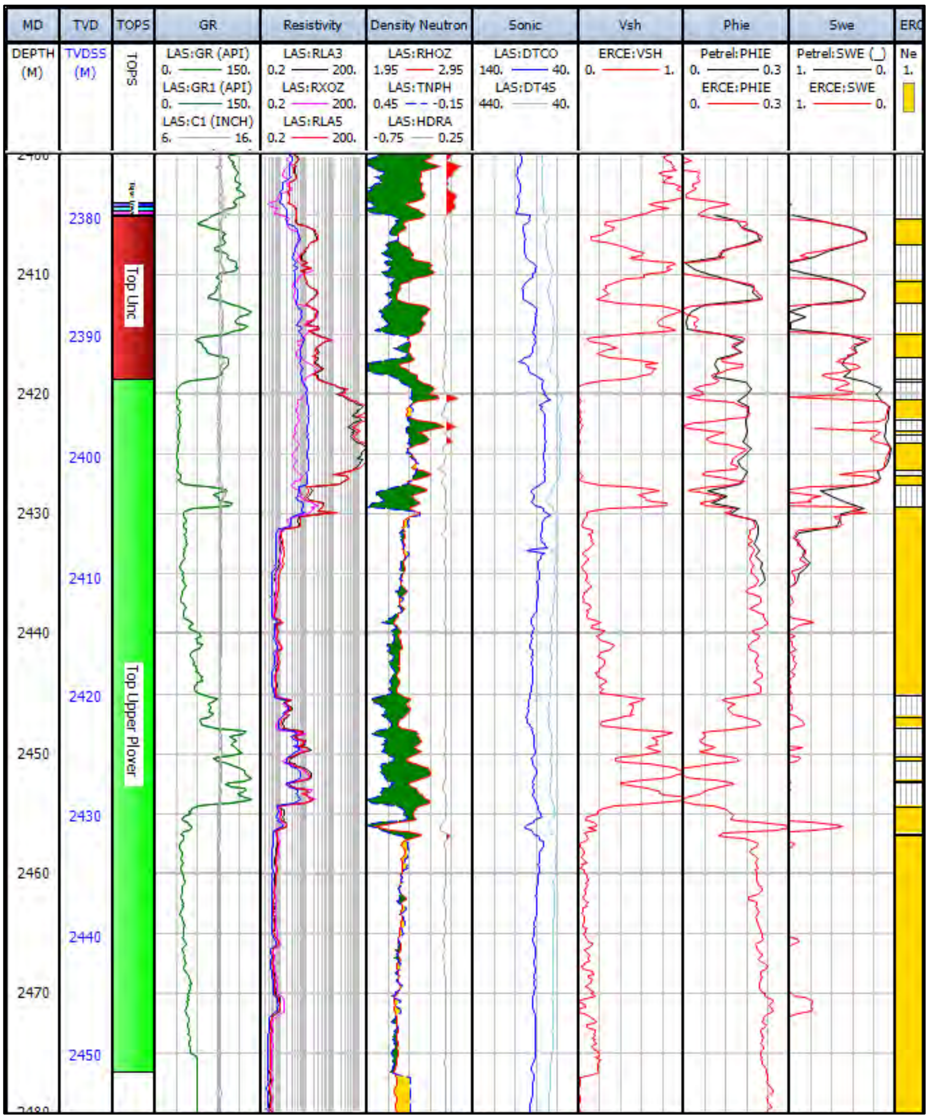


Figure 2.33: Well Swallow-1 CPI showing ERCE (red) and Operator (black) interpretations

Table 2-15: Petrophysical summary of Swift/Swallow wells

Well	Reservoir	Gross (m)	Net (m)	Pay (m)	NTG		Gross Average		Net Average		Pay Average	
					Net	Pay	PHIE	SWE	PHIE	SWE	PHIE	SWE
Swallow-1	T. plover	13.6	7.5	6.6	0.555	0.488	0.114	0.587	0.157	0.451	0.165	0.408
	U. Plover	17.3	16.1	11.4	0.934	0.659	0.179	0.411	0.183	0.406	0.171	0.217
Swift-1	U. Rowan	5.3	1.9	-	0.353	-	0.109	-	0.169	-	0.109	-
	L. Rowan	21.9	21.7	-	0.992	-	0.214	-	0.214	-	0.214	-
Swift-2	U. Rowan	4.7	1.0	-	0.212	-	0.076	-	0.130	-	0.076	-
	L. Rowan	22.1	21.8	-	0.985	-	0.225	-	0.225	-	0.225	-
Swift N-1	U. Rowan	17.5	14.3	14.3	0.814	0.814	0.196	0.310	0.226	0.212	0.226	0.212
	L. Rowan	15.0	15.0	2.7	1.000	0.182	0.222	0.876	0.222	0.876	0.243	0.437

2.3.4. **Fluid Contacts**

Interpretation of well logs in Well Swift-2 suggest an OWC at 2,393.8 mTVDSS, at which point resistivity falls back to that representative of formation water. Pressure and well log data in Well Swift North-1 suggest a slightly shallower OWC at 2,392 mTVDSS (Figure 2.34). It is noted that in the Operator's FDP, it is suggested that the two wells likely share the same contact and that measurement error in Well Swift-2 is the cause of any discrepancy.

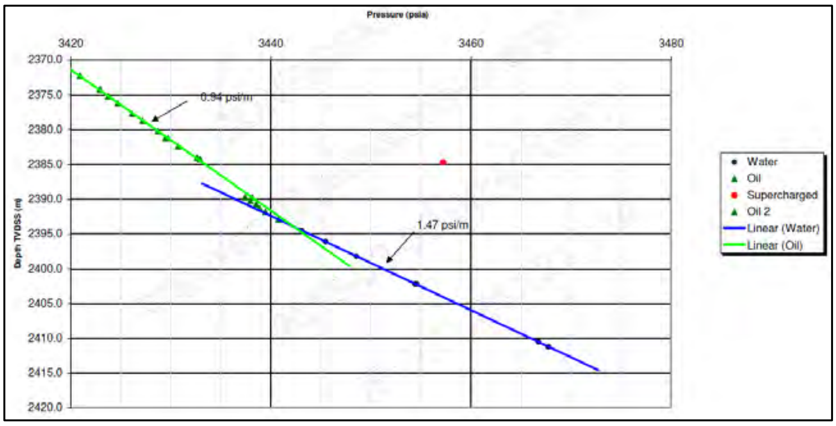


Figure 2.34: MDT pressure data in Well Swift North-1

In the Swallow pool, the OWC is defined by well logs and pressure data from Well Swallow-1. The interpreted OWC is 2,406 mTVDSS (Figure 2.35).

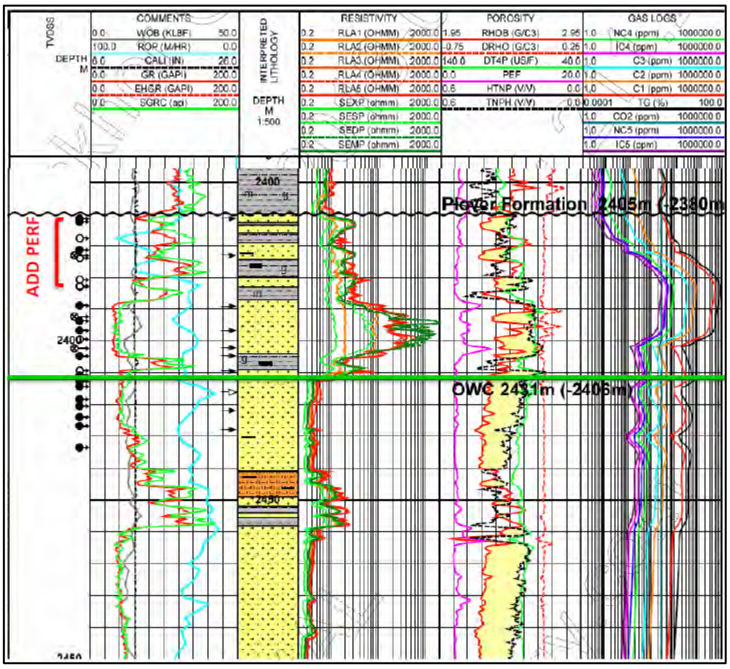


Figure 2.35: Composite log of Well Swallow-1 showing interpreted OWC

2.3.5. Hydrocarbons in Place

ERCE's in-place estimates for the Swift/Swallow field are based on Jadestone's BCU and Callovian Unconformity depth surfaces, our own interpretation of Rowan and Plover isopachs and the petrophysical sums and averages of the wells.

We have adopted the Operator's and Jadestone's interpretation of fluid contacts. For the Swift pool (Rowan) the OWC is 2,392 mTVDSS and for the Swallow pool (Plover), the OWC is 2,406 mTVDSS. A map of gross reservoir above the OWC for the Swift pool is shown in Figure 2.36.

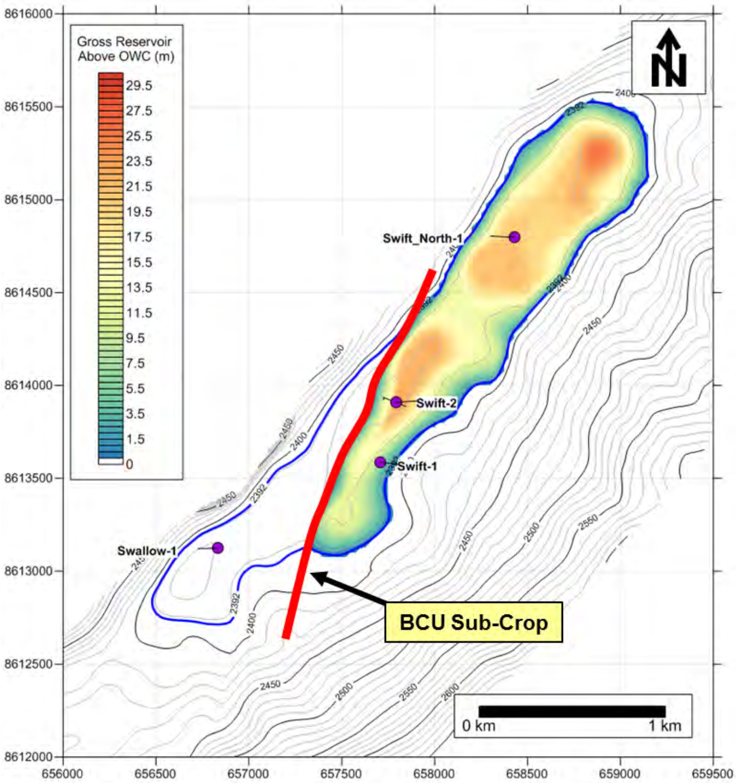


Figure 2.36: Gross reservoir above OWC, Upper & Lower Rowan, Swift field

Our P50 GRV uses Jadestone's Callovian Unconformity depth surface as a starting point. The surface is shifted deeper and tied to the Top Plover, Upper Plover and Base Upper Plover well tops to create depth surfaces for the Swallow pool. The same Callovian surface is shifted shallower and tied to the Base Lower Rowan, Lower Rowan and Upper Rowan well tops to create depth surfaces for the Swift pool. For each of the Rowan horizons, the depth surface is merged with the BCU before isopaching to the next horizon. For the Upper Rowan reservoir, we assume that the maximum gross thickness away from Well Swift North-1 is 190 m. Figure 2.37 shows NE-SW cross section through our depth model (coloured lines) and compares it to Jadestone's (black dashed lines).

Our P90 GRV is calculated using a 20% discount to the P50, based on the poor seismic data and presence of HRDZs across the field. The P10 GRV is then calculated by assuming a log-normal distribution defined by the P90 and P50.

The ranges of NTG, porosity and oil saturation used in our volumetric calculation are based on the petrophysical sums and averages of the wells for which Jadestone had digitised PHIE and SWE logs. Each parameter is defined by a normal distribution.

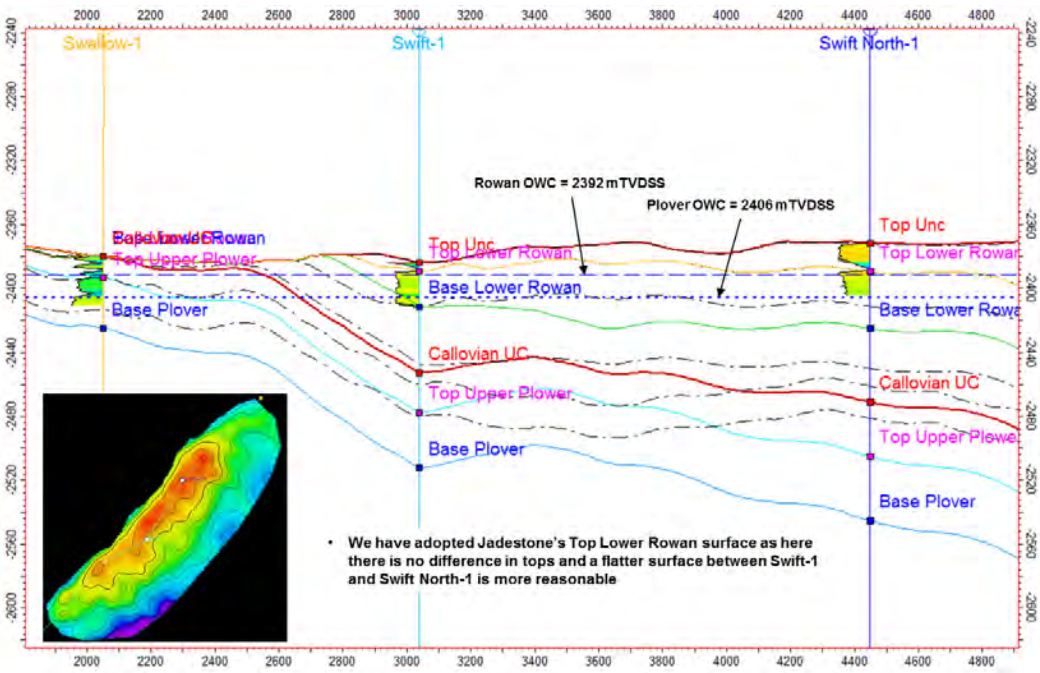


Figure 2.37: NE-SW cross-section through ERCE (coloured) and Jadestone (black dashed) models

Our inputs to a probabilistic simulation of in-place volumes is shown in Table 2-16 and the results are shown in Table 2-17.

Table 2-16: Volumetric inputs to probabilistic simulation, Swift/Swallow field

Reservoir	GRV (MMm3)			NTG (frac)			PHIT (frac)			So (frac)			Bo (rb/stb)
	Log-Normal			Normal			Normal			Normal			Constant
	P90	P50	P10	P90	P50	P10	P90	P50	P10	P90	P50	P10	P50
Upper Rowan	10.83	13.53	16.92	0.903	0.950	0.998	0.203	0.226	0.249	0.800	0.850	0.900	1.250
Lower Rowan	4.12	5.15	6.44	0.903	0.950	0.998	0.198	0.220	0.242	0.750	0.800	0.850	1.250
Top Plover	4.42	5.53	6.91	0.440	0.550	0.660	0.141	0.157	0.173	0.600	0.650	0.700	1.400
Upper Plover	1.29	1.61	2.01	0.720	0.800	0.880	0.165	0.183	0.201	0.750	0.800	0.850	1.400

Table 2-17: Probabilistic STOIIP results, Swift/Swallow field

Reservoir	STOIIP (MMstb)			
	P90	P50	P10	Mean
Upper Rowan	9.9	12.3	15.1	12.4
Lower Rowan	3.5	4.3	5.3	4.4
Swift Total	**13.4**	**16.6**	**20.5**	**16.8**
Top Plover	1.0	1.4	1.8	1.4
Upper Plover	0.7	0.8	1.1	0.9
Swallow Total	**1.7**	**2.2**	**2.9**	**2.3**

2.3.6. **Production Performance**

A total of four wells have been drilled on the Swift and Swallow fields. This includes one exploration well and three vertical production wells. The Swift field has two production wells, Swift-2 and Swift North-1. Well Swift-2 has had issues with gas lifting and the well is currently shut-in. The Swallow field has a single production well, Swallow-1. The well was completed close to the oil-water contact and water breakthrough occurred very early, with rapid water cut development. The well has been shut-in since April 2016.

Oil production commenced from the Swift and Swallow fields in October 2013. Peak combined oil production of 12,522 stb/day was achieved in July 2015. As of 31 December 2017 the one current oil well is producing 3,016 stb/day of oil, with 3.3 MMscf/day of gas at a 70% water cut. As of 31 December 2017 the Swift and Swallow fields have produced 5.31 MMstb of oil and 4.69 Bscf of gas. The production history for the Swift field is shown in Figure 2.38, whilst production from the Swallow field is shown in Figure 2.39.

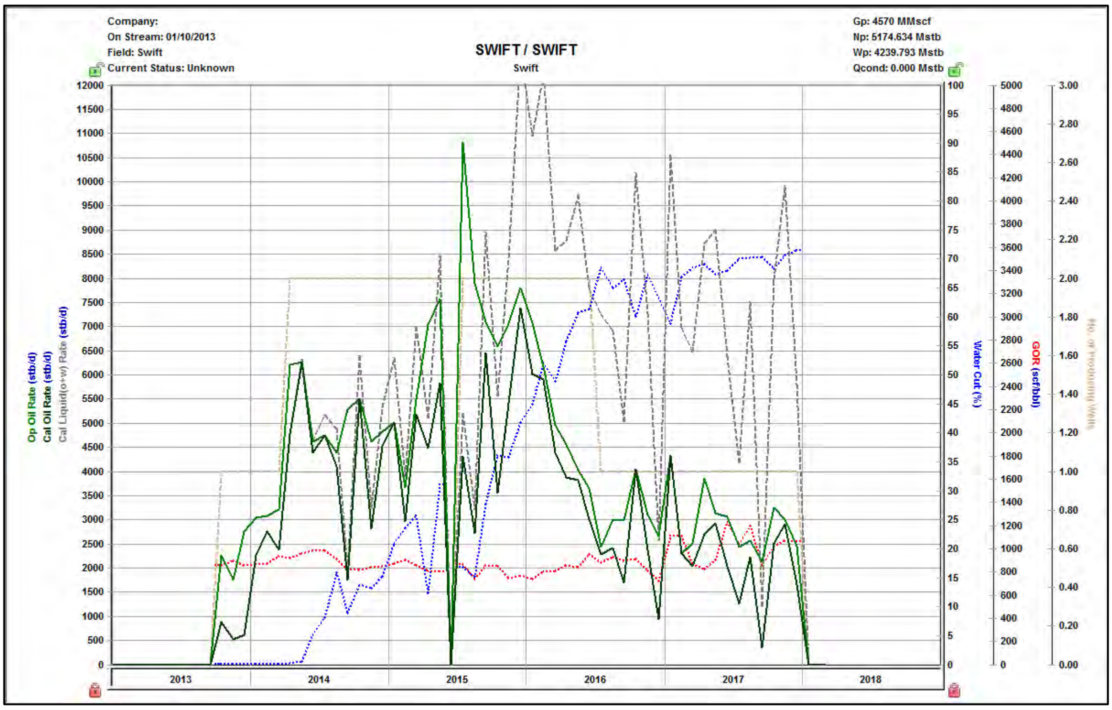


Figure 2.38: Production history of the Swift field

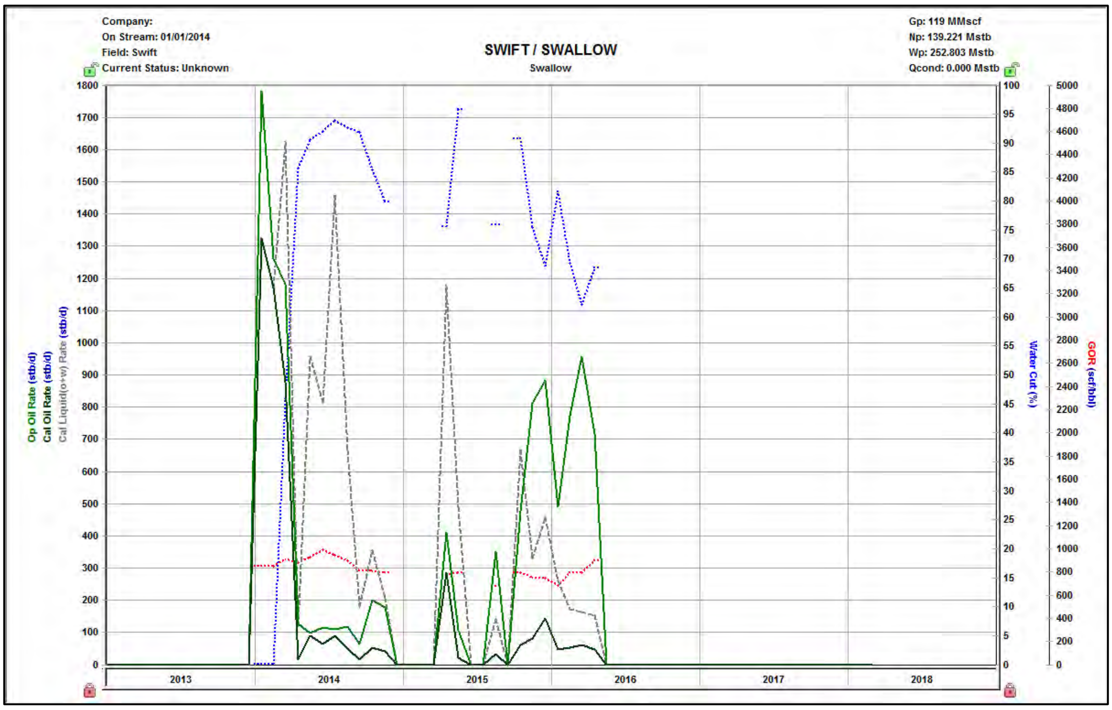


Figure 2.39: Production history of the Swallow field

2.3.7. **Recoverable Volumes**

2.3.7.1. **Production Forecasts – Developed Producing**

As of 31 December 2017 only Well Swift North-1 was producing in the field. The well has been producing since April 2014 and shows evidence of production decline. Jadestone has forecast production for these wells using DCA.

Jadestone has also used a Swift and Swallow field simulation model to guide oil recovery and the production forecast for the Swift North-1 well. The simulation model was based on Jadestone's static modelling used for volumetric in-place estimation, with dynamic parameters input from FDP documentation for both the Swift and Swallow fields. The model was history matched and used to predict future field performance. The simulation model recovered 4.4 MMstb versus the Best Case DCA recovery of 4.7 MMstb. The similar oil recovery from the simulation model supports the Best Case DCA result.

ERCE carried out DCA for these wells and compared the results to Jadestone's. The Low, Best and High Case forecasts between Jadestone and ERCE were consistent. In addition, ERCE reviewed the model inputs, history match and model outputs, and found them to reasonable. ERCE has therefore accepted the Jadestone production forecasts for Well Swift North-1.

2.3.7.2. Production Forecasts – Developed

Wells Swift-2 and Swallow-1 are shut-in and require well interventions before re-commencing production. Since these are subsea wells, this will require an intervention vessel to be mobilised for the well activities. Hence, the recoverable volumes associated with these wells have been classified as Developed Non-Producing.

For Well Swift-2, Jadestone has forecast production using DCA. Due to the gas lift issues for this well, the production decline trend is not clearly apparent. To account for this, the Jadestone Low, Best and High Case forecasts capture a wide uncertainty range. ERCE performed its own DCA for this well and compared the results to Jadestone's. The Low, Best and High Case forecasts between Jadestone and ERCE were consistent, so ERCE has accepted the Jadestone production forecasts for this well.

Jadestone used the Swift and Swallow field simulation model to estimate oil recovery and the production forecast. The simulation model history match quality was reasonable, with water breakthrough and evolution generally close to the history. The workover planned by Jadestone for Well Swallow-1 is to shut-off the lower water producing zones and perforate two identified upper sands (Figure 2.40). The key parameters affecting recovery for this well are the oil-in-place and connectivity of the upper sands to the lower sands. Jadestone ran a range of simulation scenarios with different oil in-place realisations and connectivity to assess the range in possible outcomes. Based on these sensitivities, Jadestone selected three different simulation cases for the Low, Best and High Case production forecasts. ERCE reviewed the model inputs, history match and model outputs, and found them to reasonable. The range of scenarios selected by Jadestone was deemed by ERCE to capture a reasonable range of uncertainty. ERCE has therefore accepted the Jadestone production forecasts for Well Swallow-1.

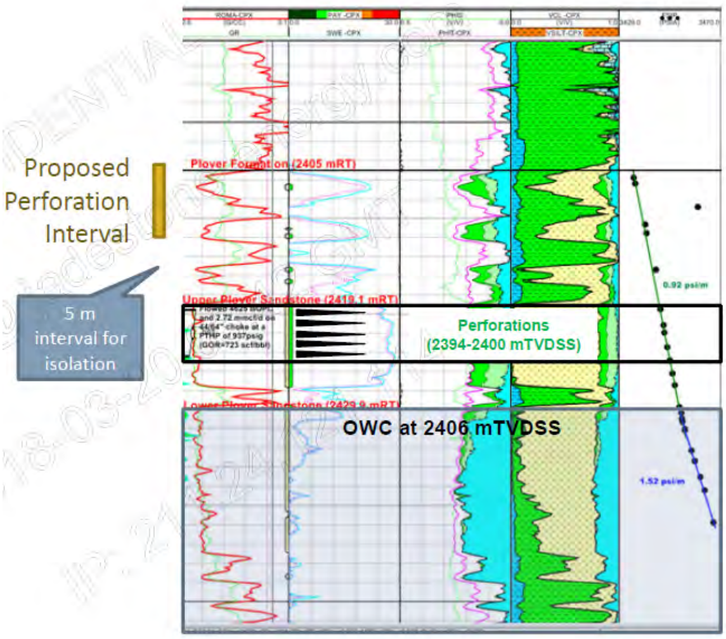


Figure 2.40: Swallow-1 workover proposed perforation interval

2.3.7.3. Recovery

The ERCE-accepted estimates of Developed future production to 31 December 2030 prior to economic modelling are summarised in Table 2-18.

Table 2-18: Summary of future production estimates for the Swift & Swallow fields

	Low Case Developed Producing (MMstb)	Low Case Developed (MMstb)	Low Case (MMstb)	Best Case (MMstb)	High Case (MMstb)
Cumulative production at 31 December 2030	9.09	10.29	10.29	11.74	13.73
Cumulative production at 31 December 2017	5.31				
Remaining production at 31 December 2017	3.78	4.97	4.97	6.42	8.42

NOTE

1) Volumes shown are technically recoverable oil volumes and have not been subject to economic modelling.

2.3.7.4. Production Forecasting

The Low Case Developed Producing, Low Case Developed, Low Case, Best Case and High Case production forecasts are shown below in Figure 2.41 and summarised in Table 2-19. The downtime assumptions detailed in section 2.7.4 have been applied to the production forecasts.

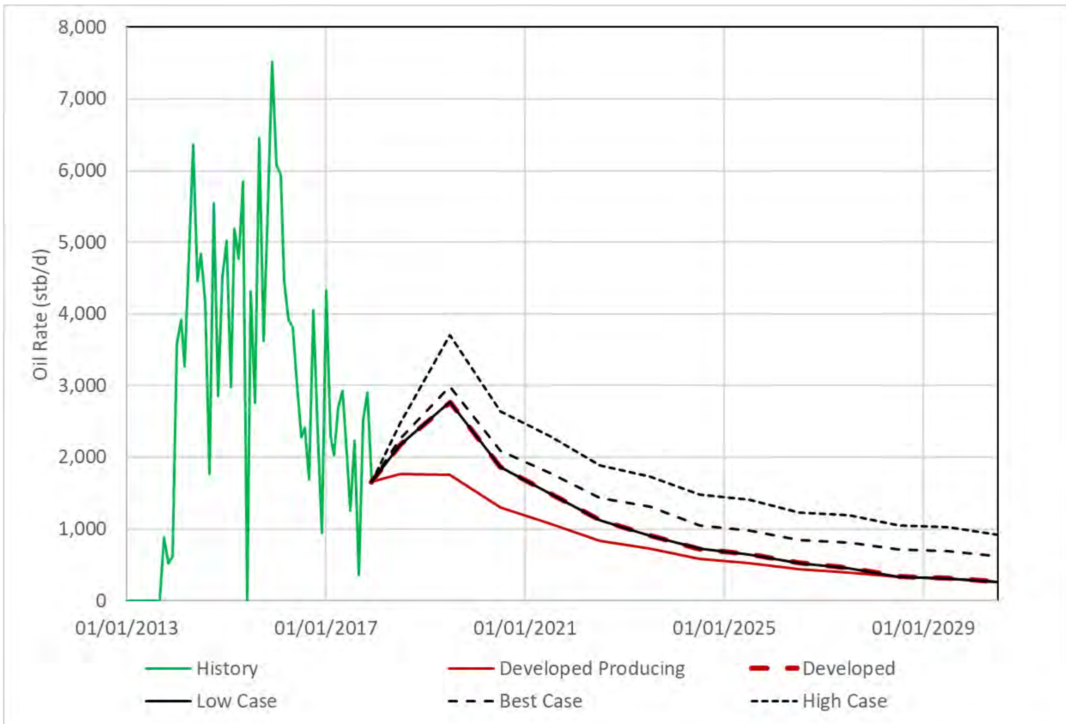


Figure 2.41: Combined Swift & Swallow field production forecasts

Table 2-19: Combined Swift & Swallow field production forecasts

	Low Case Developed Producing (stb/d)	Low Case Developed (stb/d)	Low Case (stb/d)	Best Case (stb/d)	High Case (stb/d)
2018	1,767	2,176	2,176	2,258	2,475
2019	1,759	2,771	2,771	2,992	3,710
2020	1,297	1,865	1,865	2,095	2,642
2021	1,081	1,498	1,498	1,780	2,290
2022	841	1,127	1,127	1,439	1,884
2023	731	909	909	1,309	1,737
2024	589	725	725	1,053	1,486
2025	528	644	644	973	1,409
2026	436	529	529	845	1,232
2027	399	455	455	811	1,189
2028	336	336	336	716	1,053
2029	312	312	312	696	1,029
2030	267	267	267	621	921
Total (MMstb)	**3.8**	**5.0**	**5.0**	**6.4**	**8.4**

NOTE:

1. Rates shown are technically recoverable oil rates and have not been subject to economic modelling.

2.4. Review of Costs

ERCE carried out a review of the information on costs associated with the Montara, Skua, Swift and Swallow fields provided by Jadestone. The information provided consisted of:

- The economic model for the field
- The work program and budget for the period (2018-2019)
- Historical costs for 2017
- The OpEx analysis for 2018 & 2019
- Independent Engineering (Facilities & Asset Integrity) and HSE Due Diligence Report (2018)
- Decommissioning Cost Estimate for Montara (2017)
- Montara Abandonment Provision (2017)

2.4.1. Capital Expenditure

2.4.1.1. Repairs, Maintenance and Remediation Projects

From 2018 onwards, an allowance of 1.0 MM USD per year is budgeted for capital expenditure. ERCE consider this to be an appropriate capital allocation.

2.4.1.2. Drilling

One infill well is planned for each of the Montara and Skua fields. One well is to be drilled in 2Q2019 and the other in 3Q2019. The wells are budgeted at an average of 40.5 MM USD each, in line with the cost of previous wells. An additional 3.0 MM USD is allocated in 3Q2018 for multi-client seismic acquisition over both blocks. ERCE considers that the well costs appear reasonable given previous experience and historic costs.

2.4.2. Operating Expenditure

Operating expenditure includes:

- Surface Operations
- Logistics
- Maintenance, Inspection & Modificiation
- Offshore Manpower
- Non-Routine Activities
- Project general and administration (G&A)
- Corporate G&A

Actual operating expenditure in 2017 was 110.5 MM USD. The budget for 2018 is 109.5 MM USD.

Jadestone is proposing a smaller Operating Expenditure budget for 2019 of 77.2 MM USD. The majority of the savings are attributed to reductions in Non-Routine Activities, Corporate G&A and Project G&A. Smaller incremental reductions are attributed to Surface Operations, Logistics, as well as Maintenance, Inspection and Modification. Jadestone is planning a phased cost reduction to reach a lower Operating Expenditure operating model. This approach leads to an additional 5.8 MM USD included in the 2019 budget relative to future years. From 2020 onwards, Jadestone is proposing an Operating Expenditure budget of 71.4 MM USD. There are minor variations on a yearly basis due to supply chain enhancement and value insurance.

Jadestone assumes lower Operating Expenditure during the last three years of the field's life as surface operations diminish and general administrative costs are reduced. The reduction is 10% in each of the last three years.

ERCE has reviewed all costs estimates, paying particular attention to reductions in Non-Routine Activities, Corporate G&A and Project G&A, and has accepted these costs forecasts as reasonable. ERCE has also taken into consideration that Jadestone has taken considerable learnings from its previous acquisition and transition to operatorship of the Stag oil field, especially with regards to the offshore regulator NOPSEMA. Additionally, the commercial agreement under the proposed transaction with the previous operator allows Jadestone early engagement and faster control of operational decisions, meaning cost-saving measures could be implemented at an earlier than usual stage.

2.4.2.1. Non-Routine Activities

Amounts budgeted for Non-Routine activities related to Operating Expenditures in MM USD are as follows.

Table 2.20: Non-Routine Activities related to Operating Expenditure budget

Year	Cost (MM USD)
2017	*28.3*
2018	29.3
2019	2.0
2020+	1.9

A considerable reduction in Non-Routine Activities is assumed by Jadestone from 2019 onwards. The high historical values in 2017 and budgeted values in 2018 have been associated with well interventions, subsea infrastructure repair and value assurance. 2020 costs are assumed to remain constant until the cost reduced in the final three years of economic production.

Three well interventions (Wells Skua-11, Swift-2 and Swallow-1) are planned in the second half of 2018 using a Light Well Intervention vessel for 9.1 MM USD. In 2017 the flowline connector for Well Skua-11 was repaired for a cost of 14.5 MM USD, along with subsea inspection, maintenance and repair costing 2.7 MM USD. In 2018 a subsea distribution unit and umbilical replacement cost 14.5 MM USD. From 2019, no additional wells or subsea infrastructure requires repair or replacement, so no funds have been allocated to Non-Routine activities.

Value assurance had a historical cost of 9.2 MM USD and a budgeted cost of 7.2 MM USD in 2017 and 2018, respectively. Jadestone has identified significant cost saving opportunities through reduction or completion of these activities. This includes performing fabric maintenance through hiring two roustabouts capable of advanced scaffolding and fabric maintenance, and using crude oil washing machines for tank cleaning during offtakes. Additionally, both the planned cargo tank repairs and the floating hose replacement (plus spare hose) are due to be completed in 2018.

ERCE reviewed the Non-Routine Activity cost assumptions from Jadestone and considers them to be reasonable.

2.4.2.2. Corporate G&A and Project G&A

Amounts budgeted for Project G&A and Corporate G&A related to Operating Expenditures in MM USD are as follows.

Table 2.21: Project G&A and Corporate G&A related to Operating Expenditure budget

Year	Project G&A (MM USD)	Corporate G&A (MM USD)
2017	*7.5*	*6.9*
2018	5.1	0.0
2019	0.0	0.0
2020+	0.0	0.0

For both the Project and Corporate G&A, Jadestone has allocated no funds from 2019 onwards.

Under Project G&A, Jadestone has reduced the allocation from indirect onshore support, terminal costs and legal fees that were associated with previous operator. Jadestone also has assigned no Corporate G&A to the Montara project from the company. The previous operator had allocated 6.9 MM USD in 2018.

ERCE reviewed Jadestone's assumptions with regards to G&A and found them to be reasonable.

2.4.2.3. Other OPEX

Amounts budgeted for Surface Operations; Logistics; Maintenance, Inspection & Modification; Well Services; and Offshore Manpower, are presented in Table 3.6.

Table 2.22: Other Operating Expenditure budget

Year	Costs (MM USD)				
	Surface Operations	Logistics	Maintenance, Inspection & Modification	Well Services	Offshore Manpower
2017	*16.4*	*23.0*	*8.9*	*0.2*	*19.3*
2018	17.4	32.9	9.8	0.3	18.8
2019	14.4	30.4	7.3	0.7	22.4
2020+	13.3	28.1	6.8	0.6	20.7

Historic costs for in some of the Other Operating Expenditure tranches appeared high. Jadestone plans to reduce the cost of Surface Operations by reducing onshore support and removing the allocation of costs by the Darwin Logistics Team under the previous operator. Logistics costs are planned to be lowered by reducing the number of helicopter flights associated with Non-Routine Activities. Additionally, sharing helicopter and boat services with third parties will further reduce these costs. Maintenance, inspection and modification expenditure is planned to be lowered by reducing the number of shut-down days in conjunction with optimising the maintenance strategy and operations. Currently there is a large backlog of maintenance jobs on the FPSO and wellhead platform, and inspections on some facilities are performed too regularly.

Jadestone has recognised that transitioning from the current higher Operating Expenditure operation to a lower cost model will take a period of time. To account for this Jadestone has included a phased cost reduction in their model which results in a 5.8 MM USD higher Operating Expenditure in 2019 compared to 2020. The 2020 costs are assumed to remain constant until the costs are reduced in the final three years of economic production.

ERCE has reviewed Jadestone's plans for reducing the Other Operating Expenditure budget and considers that the anticipated cost reductions associated with these changes are reasonable.

2.4.2.4. Abandonment Costs

For 2018, Jadestone has updated the estimates of abandonment costs, and provided documentation related to these to ERCE. The cost of well abandonment (six subsea wells) is estimated to be 58.0 MM USD. A drilling rig will be used to abandon the subsea wells and set cement plugs in all wells. The cost of abandonment of the facilities is estimated to be 134.8 MM USD, including abandonment of the six platform wells. The total cost of abandonment is thus estimated to be 193 MM USD. The salvage value of the facilities is estimated to be 25 MM USD. ERCE was provided with the previous operator's abandonment report, and their total estimate was within 5% of Jadestone's estimate. ERCE has reviewed the abandonment costs estimated by Jadestone and considers the estimates to be reasonable.

2.5. Review of Economics

ERCE has undertaken economic modelling of the Montara Assets to estimate the Reserves and Net Present Values (NPVs) at the 1P, 2P and 3P levels of uncertainty.

An economic model was provided by Jadestone for the purposes of cash flow modelling. This was audited and found to be in accordance with the current petroleum fiscal regime for Australia. Amendments were made to the model to account for ERCE's oil price and inflation assumptions, cash flow discounting method and economic limit test.

2.5.1. Australia Fiscal Terms

Australia's petroleum fiscal regime consists of a combination of a petroleum resource rent tax ("PRRT"), Corporate Income Tax ("CIT") and royalty-based taxation.

- The PRRT is a profit-based tax levied at 40 percent of net revenues (sales receipts less eligible expenditures) from a project. Starting balances for PRRT expenditure (as at 30 June 2017) were provided by Jadestone.
- CIT is applied at a rate of 30 percent.
- Jadestone management has advised that the Montara Assets are exempt from royalties.

2.5.2. Commercial Assumptions

The following commercial parameters were assumed in the modelling of discounted cash flows and in determining the Reserves for Jadestone.

- We have assumed a long-term Brent oil price of $66/bbl in 2018, rising to $68/bbl from 2020 onwards in real terms, escalated thereafter at 2.0% per annum inflation (Table 2-23). The Montara crude oil is sold under an oil sale contract in place with the previous operator's parent company. Under this contract the crude is sold at a term price basis. As per company guidance based on the term price formula, a 3% premium to Brent has been applied from 2018 onwards.

Table 2-23: Assumed Brent crude oil price deck

Base Case ERCE Brent Assumptions ($/bbl)	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028+
Real (Constant $, 2018)	66	67	68	68	68	68	68	68	68	68	68
Nominal ($ of the day)	67	69	71	73	74	76	77	79	80	82	+2.0% pa
Escalation rate p.a.	*2.00%*										

- A flat annual exchange rate of AUD 1.00 /USD 0.75 has been applied to costs.
- An annual inflation rate of 2.0 per cent per annum has been applied. Capital and operating costs have been determined in 2018 real terms and inflated at the 2.0 per cent inflation rate.
- We have presented Net Present Values discounted at 0%, 5%, 10%, 15% and 20% at the various levels of uncertainty with effect from 31 December 2017.

2.5.3. Reserves and NPVs

Reserves are presented at the 1P, 2P and 3P levels of uncertainty and are based on cumulative production to the economic limit based on the proposed development plan described above. We present the NPVs discounted at 0%, 5%, 10%, 15% and 20% p.a. at the various levels of uncertainty as at 31 December 2017. The NPV calculations are based on the current Australian fiscal terms and are shown in US dollars after tax. Though NPVs form an integral part of fair market value estimations, without consideration for other economic criteria they are not to be construed as ERCE's opinion of fair market value.

Table 2-24 and Table 2-25 summarise the gross and Jadestone net oil Reserves estimates and the respective NPVs for the Montara Assets at the 1P, 2P and 3P levels of uncertainty as at 31 December 2017.

Table 2-24: Summary of Reserves for the Montara Assets

Licence	Field	Gross Reserves (MMstb) *			Net Reserves attributable to Jadestone (MMstb) *			Operator
		1P	2P	3P	1P	2P	3P	
AC/L7	Montara	8.9	14.9	20.5	8.9	14.9	20.5	Jadestone *
AC/L8	Skua	4.0	6.9	9.5	4.0	6.9	9.5	Jadestone *
AC/L8	Swift/Swallow	4.2	6.4	8.4	4.2	6.4	8.4	Jadestone *
Total		**17.1**	**28.2**	**38.5**	**17.1**	**28.2**	**38.5**	

**Subject to the completion of the acquisition of PTTEP AA's 100% interest in AC/L7 and AC/L8*

Table 2-25: Summary of Net Present Values for the Montara Assets

	Post-Tax Net Present Value, Net Jadestone ($US MM) *				
	0%	5%	10%	15%	20%
1P	232	279	287	280	266
2P	480	510	480	436	395
3P	1043	921	793	684	595

**Subject to the completion of the acquisition of PTTEP AA's 100% interest in AC/L7 and AC/L8*

Gross Field Reserves are the gross remaining Reserves of the properties at the 100% working interest. Working Interest Reserves are the remaining Gross Field Reserves of the properties in which the Company has an interest, multiplied by the Company's working interest in the properties. Company Net Reserves are remaining Reserves of the properties in which the Company has an interest.

There is no assurance that the forecast production and cost profiles contained in this report will be attained and variances could be material. The recovery and estimates of the company's oil and natural gas Reserves are estimates only and there is no guarantee that the estimated Reserves will be recovered. Actual volumes recovered may be greater than or less than the estimates stated in this report.

3. Stag Field, WA-15-L, Western Australia

3.1. Field Description

The Stag field is located within the boundaries of the WA-15-L Production Licence ("PL") in the Carnarvon Basin, approximately 60 km offshore Western Australia in a water depth of 47 m (Figure 1.2). The field was discovered in 1993 by exploration Well Stag-1, which intersected a 16 m column of biodegraded 19° API oil at a depth of 680 mTVDSS. Production commenced in 1998, after a PL was granted to Apache Northwest Pty. Ltd. ("Apache") and Santos Offshore Pty. Ltd. ("Santos"). In November 2016, Jadestone acquired a 100% working interest ("WI") in the field through the acquisition of a 33.33% WI from Quadrant Northwest Pty. Ltd. and a 66.67% WI from Santos.

The current PL was recently renewed for a further 21 years from and including August 26th 2018, which extends the expiry date to August 2039.

Hydrocarbons are contained within a combination structural/stratigraphic trapping mechanism of the early Cretaceous M. Australis sandstone, which was deposited in shallow marine environment.

Multiple vintages of seismic data cover the Stag field, with the first 3D seismic survey being acquired in 1993. In 2008, an ocean bottom cable ("OBC") seismic survey was acquired. Most recently, in May 2014, a 3D broadband seismic survey was acquired over an area of 132 km^2. This dataset was PreSDM processed and has given improved lateral resolution and signal-to-noise ratio.

3.2. Development History

Following the discovery of the field in 1993 by Well Stag-1, a further eight appraisal wells were drilled based on the 1993 3D seismic dataset. In 1995, the first horizontal well was drilled, Well ST6H, which successfully demonstrated the deliverability of a horizontal well in a thin, heavy oil system.

The field was developed using a fixed leg, 12 slot manned central processing facility platform with a production capacity of 50,000 bbl/day. A 2km pipeline connects the platform to a CALM buoy which is itself connected to a Floating Storage and Offloading vessel (FSO). Shuttle tankers transfer oil from the FSO to shore.

First production from the Stag field came in May 1998 through six horizontal wells (Wells ST6H, ST9H, ST10H, ST11H, ST12H and ST15H), all of which were drilled from a fixed platform. At the same time water injection was carried out through Wells ST13H and ST14H. An ongoing programme of production drilling, appraisal drilling and re-drilling has taken the total well count of the field to 48.

The field produces a biodegraded oil with a gravity of 19°API. Oil production peaked at approximately 26,000 stb/day in 2000 but has now fallen to approximately 3,800 stb/day via 11 production wells. Field water production is approximately 22,000 bbl/day and the watercut is approximately 88%. All wells require artificial lift to produce are fitted with Electrical Submersible Pumps (ESPs).

As at 31 December 2017, the Stag field has produced 65.2 MMstb of oil.

3.3. Geological Description

The Stag field is located in the Dampier Sub-Basin of the Northern Carnavon Basin (Figure 1.2). The Dampier Sub-Basin evolved from a broad intra-continental basin in the late Palaeozoic, through syn-rift sub-basins in the Jurassic, to a passive margin carbonate shelf in the Cenozoic. A stratigraphic column for the Dampier Sub-Basin is presented in Figure 3.1.

Proven petroleum systems exist of Late Triassic, Middle-Late Jurassic and Lower Creteceous age. Both oil and gas accumulations exist within a range of play types. Oil is sourced from the Upper Jurassic Dingo Claystone, Lower Jurassic marine Murat Siltstone and Lower to Middle Jurassic marine to marginal marine Athol Formation. Structural plays include tilted fault blocks and rollovers, anticlines, drapes and horsts. Stratigraphic plays include pinch-outs, unconformity traps, transgressive sandstone packages and the M. Australis sandstone, which forms the reservoir in the Stag field.

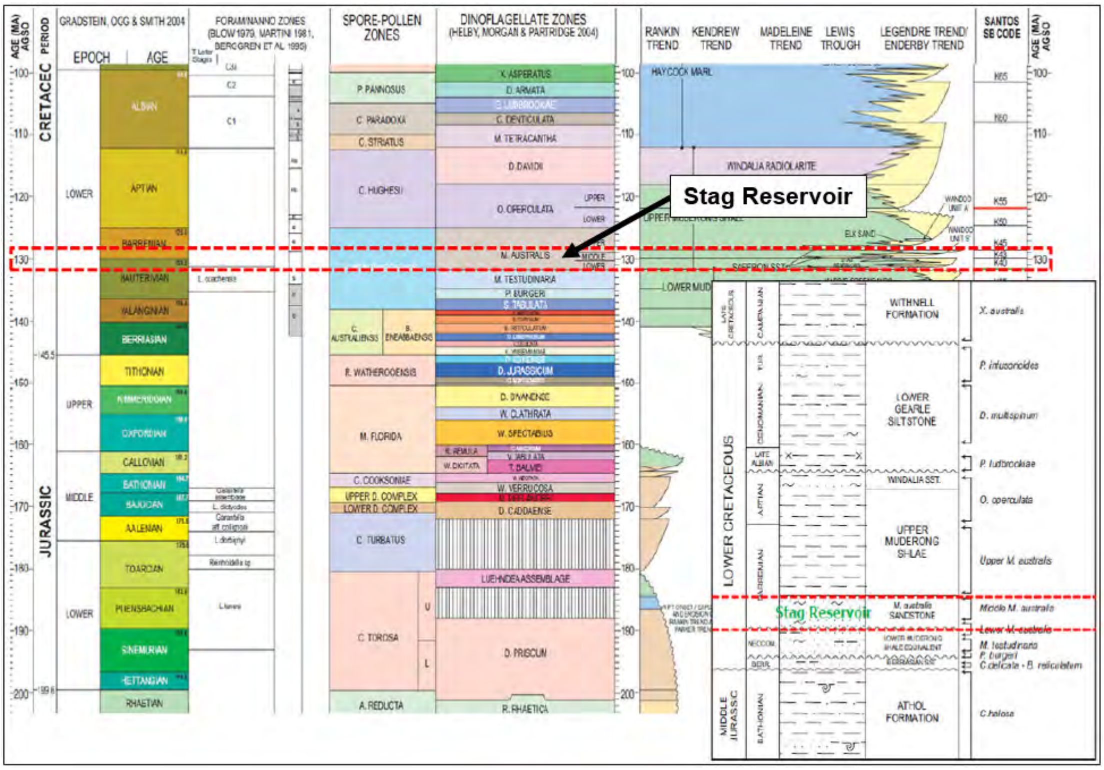


Figure 3.1: Stratigraphic column for the Dampier Sub-Basin

The reservoir was deposited during the Middle M. Australis high-stand as shelfal sheet sands in a distal delta front setting on the Enderby Terrace (Figure 3.2). A subsequent regression resulted in a period of erosion and non-deposition across the shelf, forming the M. Australis sequence boundary. In places, erosive cuts were infilled by the Muderong Shale, resulting in a variable reservoir thickness across the field. The Muderong Shale ultimately forms the seal for the field.

The Stag field is dip-closed to the north, pinches out to the south and east, and relies on a combination of dip closure and fault seal to the west, separating Stag from the smaller, undeveloped Centaur accumulation. The shallow closure has an original oil water contact at 696 mTVDSS, giving a maximum hydrocarbon column height of approximately 25 m. The field originally had a small gas cap with a gas oil contact at 682.5 m giving an initial oil column 13.5 m thick.

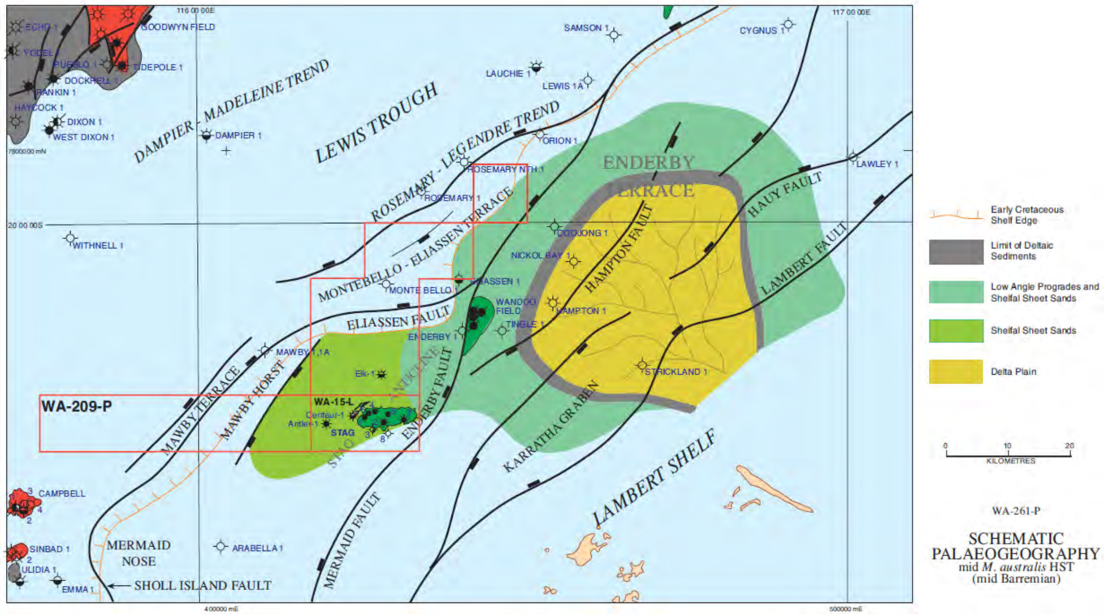


Figure 3.2: Depositional environment of the M. Australis highstand

The maximum gross thickness is approximately 22 m, which is found in the area of Well Stag-1, west of the platform. Reservoir quality is good with porosities typically in the range 18 to 27 % and permeabilities typically of the order of hundreds of millidarcies. In general, there is little variation in reservoir quality across the field, with any differences thought to be controlled by the amounts of glauconite and detrital clays present.

3.4. Geophysical Analysis

A total of three seismic surveys have been acquired in the Stag field: the original, pre-production survey (1993); the OBC survey (2008); and the Broadseis survey (2014). Although the acquisition parameters of the three surveys are not consistent, it is possible that some effects of production from the field are captured qualitatively between the different vintages.

Seismic modelling suggests that there is little seismically detectable differentiation between saturated oil, brine and shale in the reservoir (Figure 3.3). This could explain the lack of field/reservoir delineating amplitudes on near offsets from the 1993 survey. However, the two subsequent surveys both show bright amplitudes across the field on near offsets (Figure 3.4). Possible reasons for this include (a) improved seismic acquisition and processing and/or (b) pressure depletion from production leading to gas coming out of solution and allowing a fluid response. The seismic modelling work does suggest that areas of the field with a gas saturation of only 5% should be able to be differentiated from saturated oil, brine or shale.

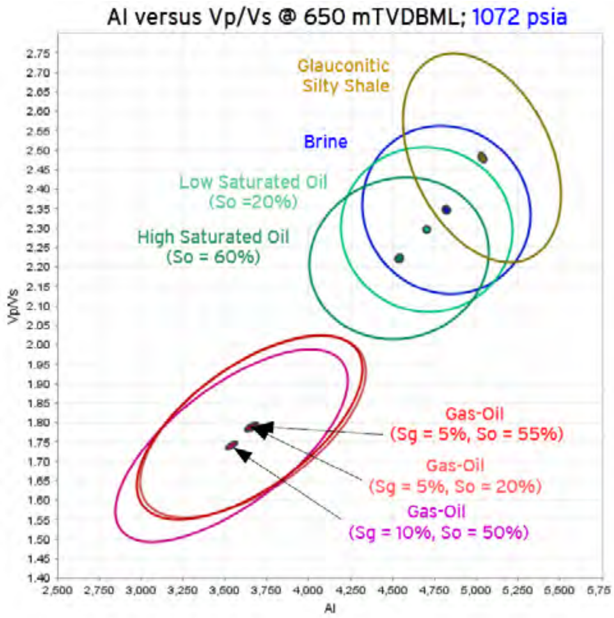


Figure 3.3: AI vs Vp/Vs at 650 mTVDML (1072 psia)

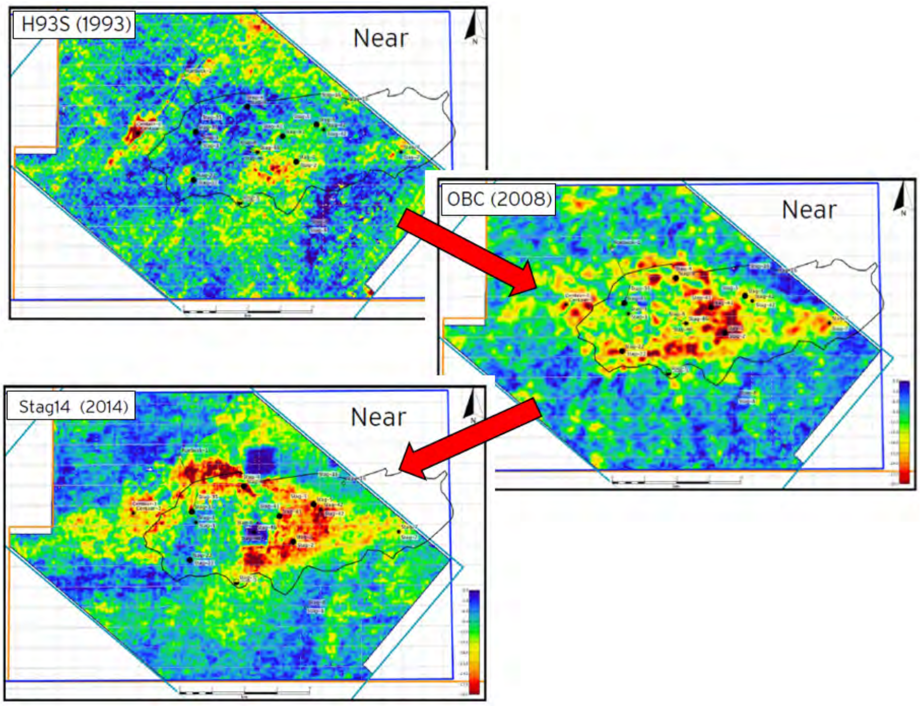


Figure 3.4: Seismic amplitudes on near offsets across the three Stag surveys

Under the gas dissolution model, the remaining areas of dim amplitude are thought to show water sweep through the field. This hypothesis fits with the location of water injection wells and with the location of production wells with high water cuts and low gas rates. It may then be concluded that areas of bright amplitude are suggestive of un-swept oil. If this is correct, the amplitude maps from the 2014 Broadseis survey may be used as a qualitative tool in identifying potential infill locations.

3.5. Petrophysics

Four vertical wells were examined for the petrophysical analysis of the M. Australis reservoir, namely wells Stag-1, -2, -22 and -46.

Composite log suites for all wells were provided although the original raw data files were not available. Nuclear magnetic resonance ("NMR") data have been acquired in Wells Stag-22 and -46 but were not available for our analysis. Core data were available for Wells Stag-1 and -2, although the reliability of core data from Well Stag-1 is poor. Rotary sidewall cores were obtained from Well Stag-22 but no analysis data were available. Final well reports were available for each well as well as the petrophysical results from the analysis performed by the previous field owner, Quadrant.

Our approach was to verify that the analysis as performed by Quadrant was acceptable. Given the mineralogy of the sands and the resulting difficulty in determining shale volume from basic log data, it is considered by ERCE that a total porosity model is more appropriate. However, the results as provided were based on an effective porosity model and hence we have adopted the same type of model, following quality control against a total porosity methodology.

An example CPI for Well Stag-1 is presented in Figure 3.5, which shows a comparison of our own estimates of shale volume, effective porosity and water saturation with those of Quadrant.

3.5.1. Shale Volume

Our evaluation of shale volume ("VSH") uses the Gamma Ray with non-linear function end points selected to obtain an average shale volume consistent with the core. This approach results in lower VSH values than Quadrant's, whose estimates are considered too high when one compares them to the available petrographic point-count clay content data obtained in Wells Stag-1, -2, -3 -4 and -5.

3.5.2. Porosity

A regression of the core data from Well Stag-2 against the log density results in a matrix density of 2.65 g/cc and a fluid density of 1.025 g/cc (a fluid density of 0.8 g/cc was used in the gas leg). Use of these parameters gives a total porosity ("PHIT") that is in close agreement with core plug measurements from Well Stag-2. It is assumed that core plug measurements are representative of PHIT.

The effective porosity ("PHIE") is then determined from PHIT assuming the shale porosity was 30%, such that PHIE = PHIT – VSH*0.3. The shale porosity is based on the porosity where calculated VSH is approximately 100%. Our estimate of PHIE is typically greater than that made by Quadrant (Figure 3.6).

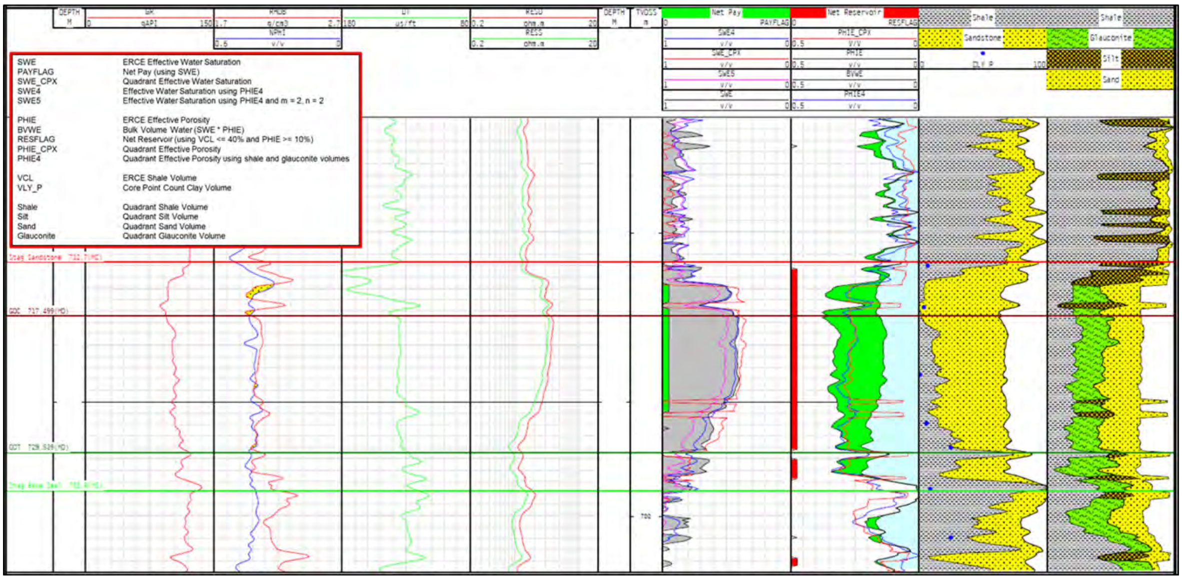


Figure 3.5: CPI for Well Stag-1 showing ERCE and Quadrant interpretations

Some of this difference is a result of our lower VSH estimate. A definitive explanation of the difference is not possible with the information available. It is noted that the February 2017 Quadrant Petrophysics review discusses how the PHIE log results were calibrated with the NMR data in order to match the free-fluid volume (the objective being to remove the micro-porosity in the glauconite). If the glauconite is assumed to have a total porosity of 12 pu and the correction is changed so that PHIE = PHIT – VSH*0.3 – VGLAUC*0.12, then a more reasonable agreement with Quadrant's results can be achieved.

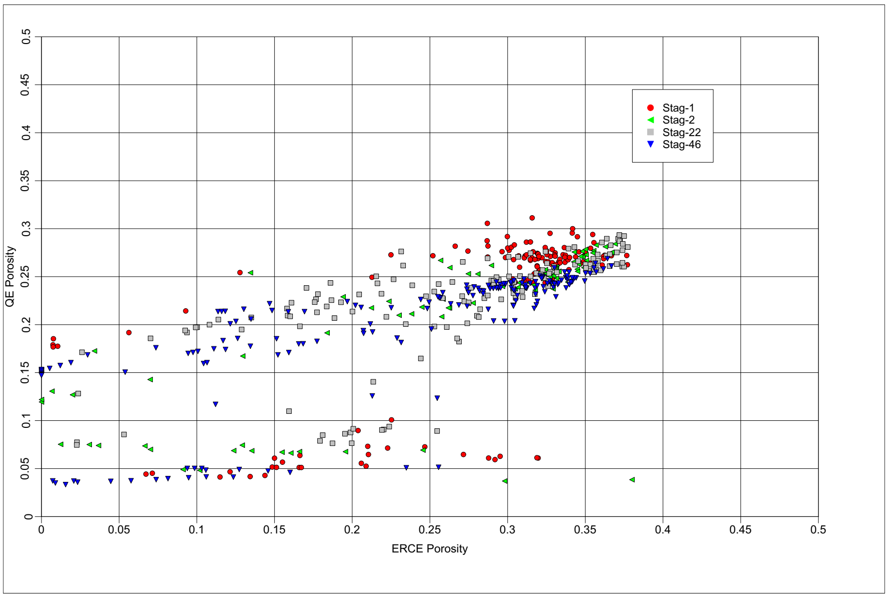


Figure 3.6: Quadrant PHIE (y axis) vs ERCE Phie (x axis)

3.5.3. Water Saturation

No details of Quadrant's determination of Sw were available but a petrophysical report for Well Stag-46 was provided, in which parameters *Rw* (0.185 ohmm at 75°F and 35,000 ppm NaCl) , *a* (1.00), *m* (1.80), *n* (1.83) and *Rsh* (6.6 ohmm) are outlined. It is our opinion that the values of these parameters are reasonable except for that of *Rsh*, which is observed to be approximately 1.0 ohmm in adjacent shales.

Using the parameters stated in the report for Well Stag-46 in combination with Quadrant's VSH and PHIE logs results in Sw logs with a close agreement to those provided for Wells Stag-46 and -22, but values 5-10% higher than those provided in Wells Stag-1 and -2. The reason for this discrepancy is not known.

Quadrant states that its values for *a*, *m*, and *n* are based on offset data. However, it is not known whether or not the offset wells have similar quantities of glauconite to Stag. In some North Sea fields, glauconitic sands have values of *m* and *n* greater than 2, which would result in higher Sw values.

Our own evaluation of Sw has used the parameter values stated above in combination with our own computed VSH and PHIE values. Despite our PHIE being higher, the calculated Sw values are similar to those of Quadrant. This is because the magnitude of the shale correction is reduced in our evaluation.

3.5.4. Petrophysical Cut-Offs

We have derived two sets of petrophysical reservoir summaries for the Stag field. The first approach uses standard industry cut-offs to derive petrophysical summaries for the Stag reservoir. These are VSH < 40%, PHIE > 10% and Sw < 60%.

The second approach employed by ERCE uses a total porosity system with a cut-off of PHIT > 20%. This is based on core poro-perm data from Well Stag-2, which suggests this to be the porosity equivalent to a permeability of 1 mD (Figure 3.7).

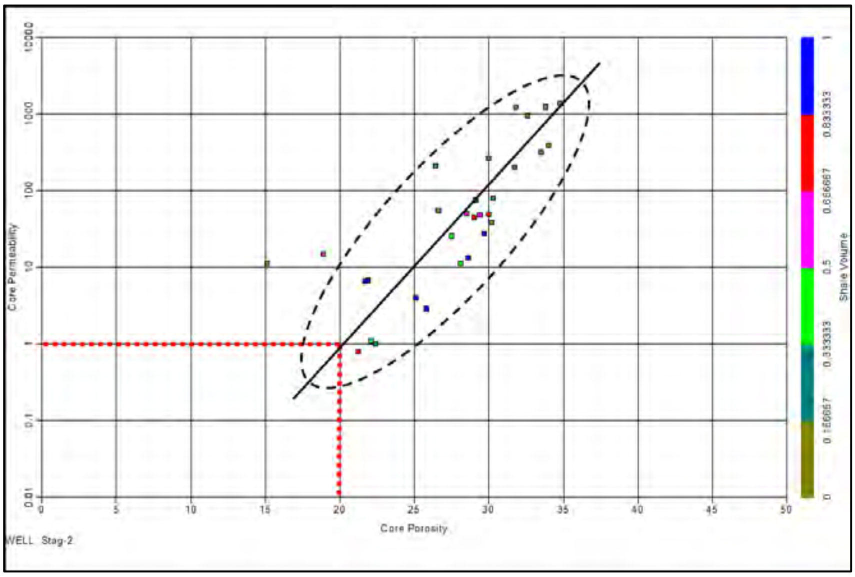


Figure 3.7: Core poro-perm crossplot for Well Stag-2

3.5.5. **Fluid Contacts**

The GOC and OWC in the Stag field are defined on from pre-production well logs (Figure 3.8). The GOC is interpreted to be at 682.5 mTVDSS and is based primarily on the separation observed between the neutron and density curves in Wells Stag-1 and -2. The original OWC is interpreted to be at 696 mTVDSS and is based on the resistivity profile and interpreted Sw curves.

Wells drilled recently indicate that the OWC has moved upwards in the reservoir to approximately 690 mTVDSS (Figure 3.9), although local OWC variations between wells are apparent. It is interesting to note the difference in the residual oil profile below the current oil water contact in Wells Stag-35 and -41.

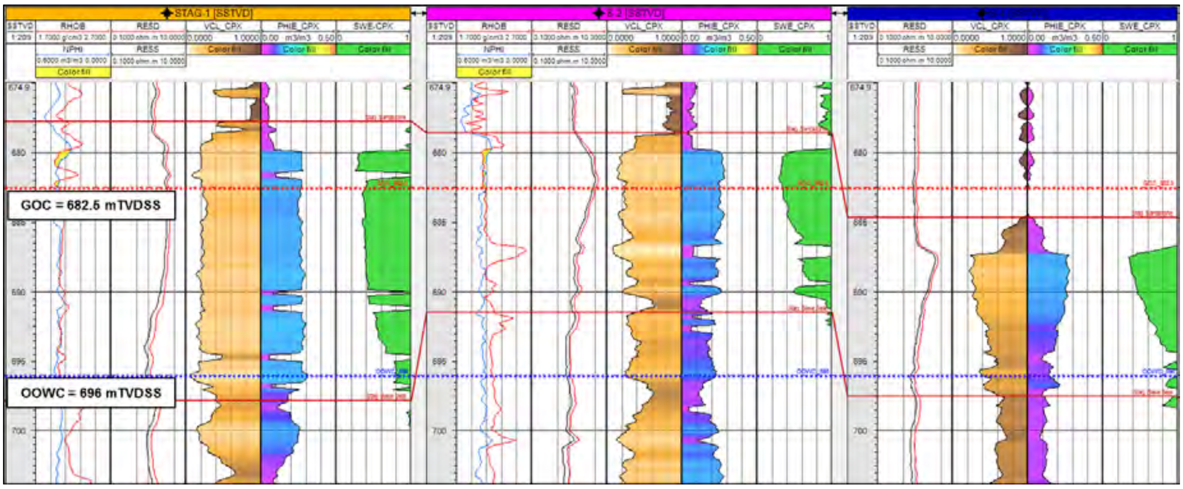


Figure 3.8: Correlation panel for Wells Stag-1, -2 and -4 showing the original GOC and OWC

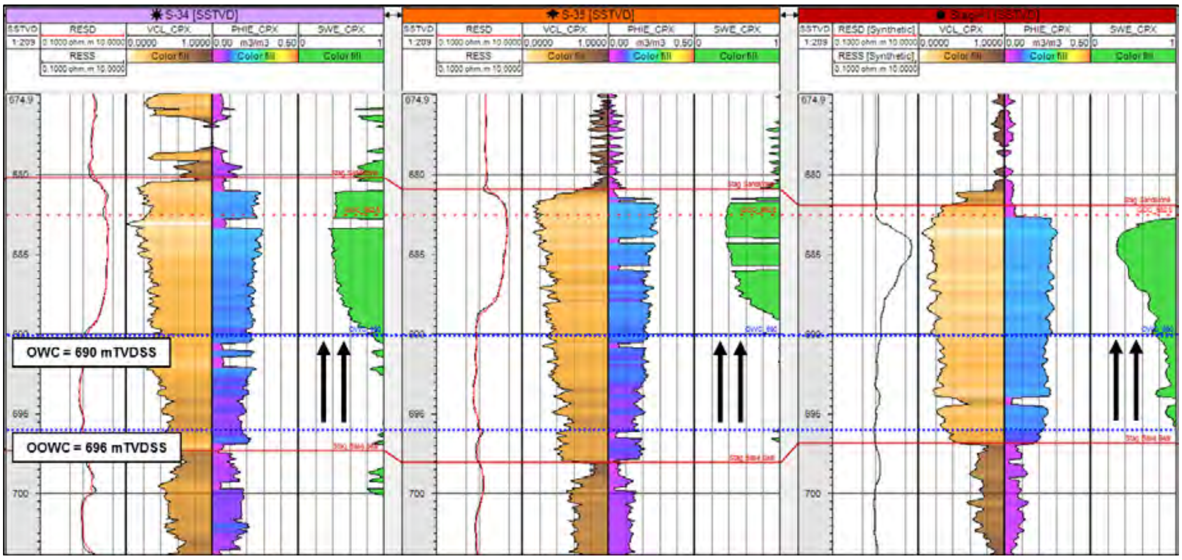


Figure 3.9: Correlation panel for Wells Stag-34, -35 and -41 showing the current OWC

3.6. Hydrocarbons Initially In Place

We have made evaluations of the static and dynamic models of the Stag field provided by Jadestone. The static and dynamic models have been adopted from Quadrant, the previous Operator of the field. Jadestone has made alterations to the dynamic model where deemed necessary, but the static model is unchanged.

Seismic interpretation of the reservoir can be made with confidence, although there is some uncertainty in the identification of sub-seismic undulations that could allow attic oil to exist in the dynamic model. Overall, however, Quadrant's interpretation of the top reservoir is reasonable. There is little uncertainty in depth conversion due to the number of penetrations across the field, which provide sufficient control points. As a result, we have accepted the top reservoir depth surface (Figure 3.10) used in the construction of the static model.

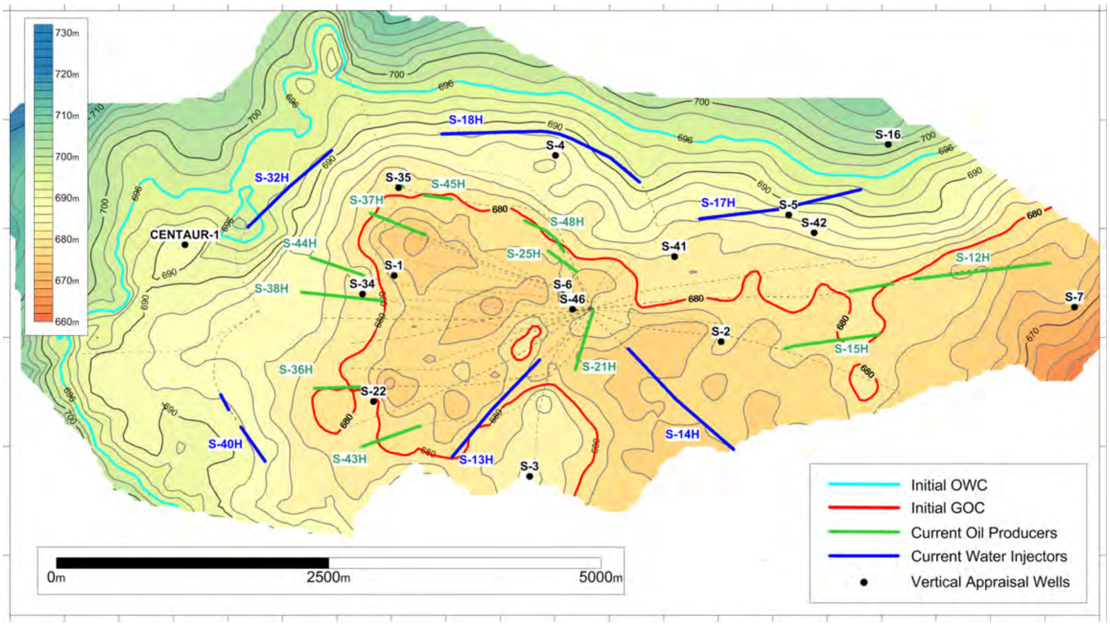


Figure 3.10: Top structure map over the Stag field

An example layer in the model is displayed in Figure 3.11 showing the facies, porosity, permeability and water saturation properties in the model. It was noted that no NTG property is used in the static model, despite the Operator's petrophysical analysis showing that NTG ranges from 70% to 90% in the wells. ERCE calculates a NTG of close to 100% across the reservoir interval when a total porosity methodology is used.

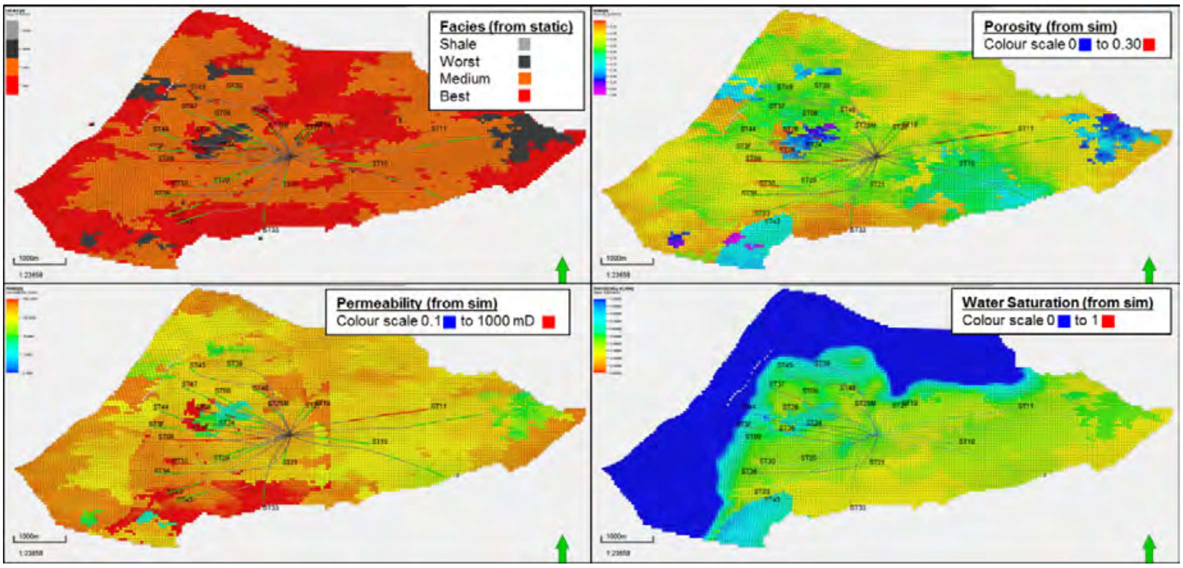


Figure 3.11: Facies, porosity, permeability and water saturation (Z Layer = 20)

Average water saturations from Quadrant's computed logs lie at the upper end of the values used in the static and dynamic models (37 – 44%). A comparison of the hydrocarbon pore thickness ("HCPT"), as calculated by the Quadrant petrophysical analysis, the ERCE total porosity system petrophysical analysis, the static model and the dynamic model, at Wells Stag-1, -2, -22 and -46 is presented in Figure 3.12. ERCE has tested the sensitivity of the hydrocarbon pore volume ("HCPV") to water saturation (using 37% and 44% in the static model). The HCPTs calculated at the well locations in the static and dynamic models are generally in good agreement with Quadrant's and our own petrophysical analyses. Note the lower HCPTs in Well Stag 46 due to the effects of production.

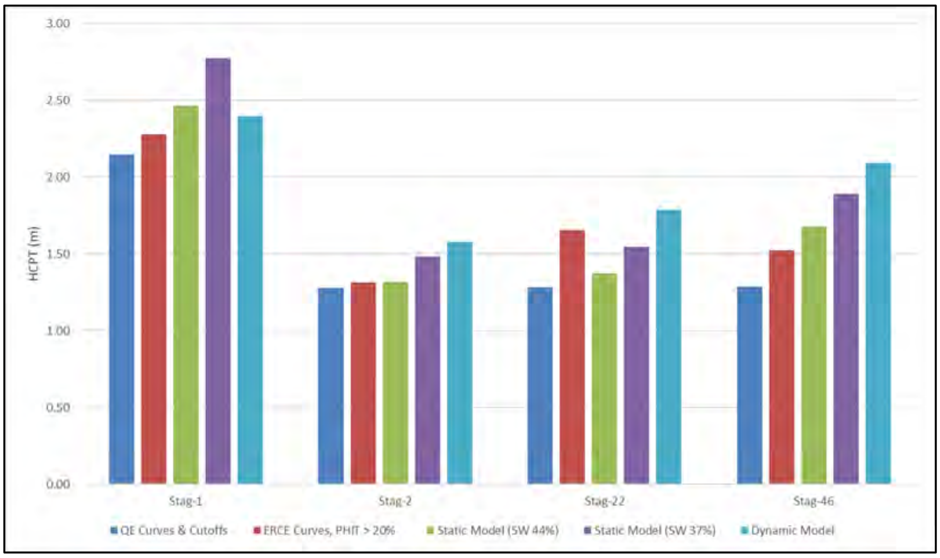


Figure 3.12: Comparison of HCPV at multiple wells as calculated by petrophysical analyses and models

We have found the modelling approach to be reasonable and in line with petrophysical averages from the wells and accept the best STOIIP estimate given by the Quadrant model of 176 MMstb. A summary of the in-place volumes from various cases is presented in Table 3.1. The 'Quadrant Model' is that supplied to Jadestone upon acquisition of the field. The 'Petrel v4' model is the current working static model, in which we have adjusted water saturation and included a NTG cut-off to test STOIIP sensitivity. The 'Dynamic Model' is the current, history matched model used by Jadestone.

Table 3.1: Stag Oil In-Place Summary

Case	OIP (MMstb)
Quadrant model	176
Petrel v4 (Sw = 37%)	182
Petrel v4 (Sw = 44%)	162
Petrel v4 (Sw = 37%, Por > 10%)	158
Dynamic model at initial conditions	174

3.7. Production Performance

Oil production from the Stag field commenced in May 1998 and a total of 24 horizontal production wells and 6 horizontal water injection wells have been drilled to date. As of 31st December 2017, there are 11 active producing wells and three active water injection wells in the Stag field. The production history for the field through March 2016 is shown in Figure 3.13. The figure shows that peak oil production of approximately 26,000 stb/day was achieved in 2000. Gas production peaked early in the field life and then declined as the gas in the gas cap initially present was produced. Water cut has increased gradually during the life of the field to the current value of approximately 88%. As of 31 December 2017, the oil rate is approximately 3,000 stb/day and the water rate approximately 22,000 bbl/day. Cumulative oil production at 31 December 2017 is 65.2 MMstb.

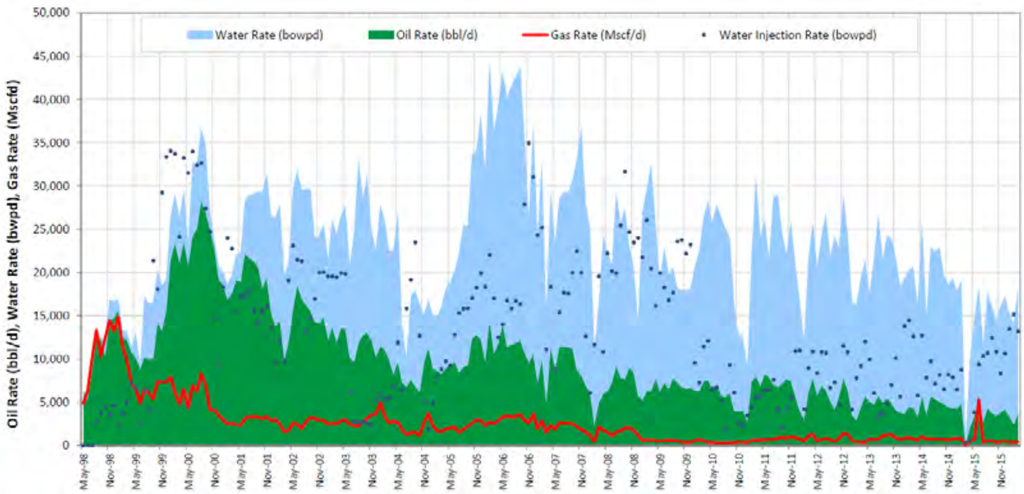


Figure 3.13: Production history of the Stag field.
(Taken from Miro-Quadrant-Santos Management Presentation, May 2016)

Oil production is from the M. Australis reservoir, which demonstrates very good reservoir quality across the field (see Section 3.3).

The field produces a biodegraded oil with a gravity of 18° API and a viscosity at reservoir conditions of 8 cP. The initial GOR was approximately 120 scf/stb. There is a relatively weak aquifer, the effect of which has been supplemented by water injection. The field had an initial gas cap but most of the free gas was produced early in the field life.

3.8. Production Forecasting

3.8.1. Production Forecasts – Developed Producing

As of 31 December 2017, there were nine wells on production in the field with a further two temporarily shut-in, Wells ST-21 and ST-48, for routine pump changeout. There are three active injection wells. ERCE has received confirmation that Wells ST-21 and ST-48 are online as of March 2018 with oil rates similar to before shut in. Therefore, Wells ST-21 and ST-48 have accordingly been included in the Developed Producing forecast category.

We have predicted future production performance for these eleven wells using decline curve analysis.

3.8.2. Production Forecasts – Undeveloped

Jadestone is proposing to drill five further wells in the field, four horizontal producers and one horizontal water injector (Figure 3.14). The four production wells will be drilled from the platform. The injection well will be a subsea injector. Each of the proposed production wells targets an area that is interpreted not to have been efficiently swept by the current well stock.

The dates on which the wells are forecast to come on production are as follows:

- ST-44HST 01 Nov 2018
- ST-PH2-1H 01 Jun 2019
- ST-PH2-WI 01 Jul 2019
- ST-37HST2 01 Jun 2020
- ST-PH1-1H 01 Jul 2020

The production wells fall into two categories. Wells ST-37HST2 and ST-44HST are infill wells targeting pockets of un-swept oil within the main field area. Wells ST-PH1-1H and ST-PH2-1H target volumes of oil outside the well-drilled area, interpreted to contain bypassed oil. Water injection Well ST-PH2-WI is planned to support production Well ST-PH2-1H. The methodologies used to derive the future production attributable to each type of well are discussed below.

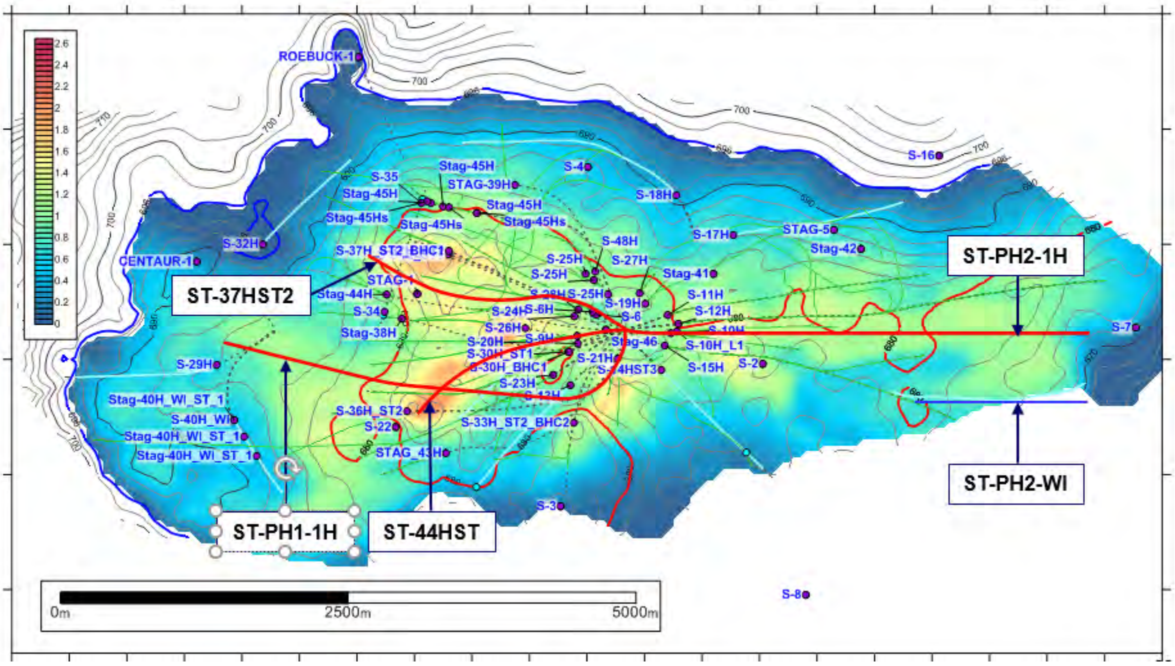


Figure 3.14: Remaining HCPV map showing planned well locations

3.8.2.1. The Role of the Reservoir Simulation Model

A reservoir simulation model was created and history matched by Quadrant while they had an interest in the field. The model has been used by both Quadrant and Jadestone to predict future field performance and the production expected from the new wells to be drilled in the field.

The model is reasonably well history matched. However, it predicts reservoir pressures higher than those measured in the field at the end of the history period. It will therefore tend to over-predict well rates.

Against this backdrop, we have used saturation distributions predicted by the model to assess the future production of the candidate well locations remote from other wells. However, when predicting initial well rates and recoveries, we have calibrated the model information against the performance of nearby wells in all cases.

3.8.2.2. Well ST-PH1-1H and Well ST-PH2-1H

These wells are to be drilled out to the peripheral areas of the field to access volumes of oil that the simulation model predicts to have been bypassed by injected water and aquifer influx. Figure 3.15 and Figure 3.16 are sections through the dynamic model in the areas of the wells showing the water saturation distribution at 1st April 2017. These sections illustrate the volumes of oil being targeted by the two wells.

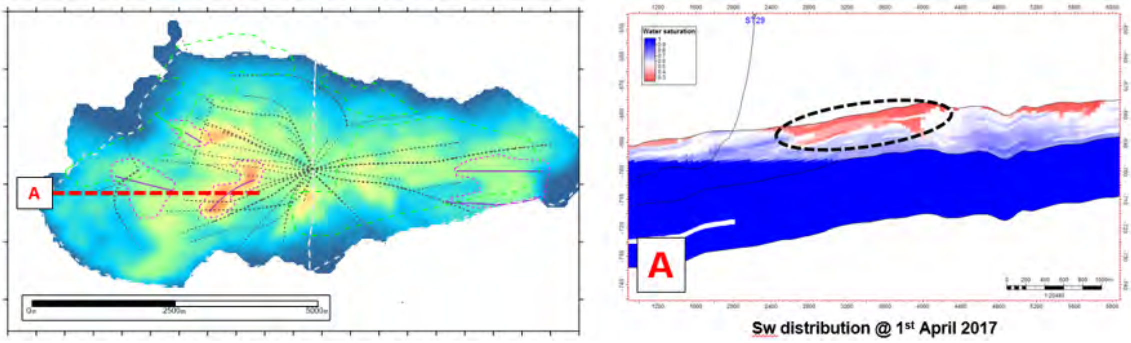


Figure 3.15: Location and water saturations at 1st April 17 at planned Well ST-PH1-1H

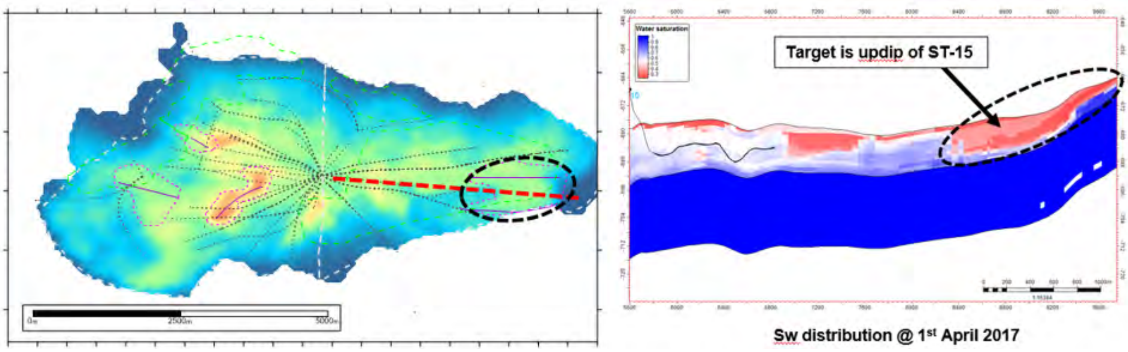


Figure 3.16: Location and water saturations at 1st April 17 at planned Well ST-PH2-1H

We have estimated the recovery attributable to these wells using the following methodology.

- We have constructed high case and low case polygons around each well and including the areas indicated by the model to be relatively un-swept. The high and low case polygons superimposed on a map of HCPV from the simulation model as at 31 March 2017 are shown in Figure 3.17.
- We have used the base case prediction simulation model to determine the STOIIP within the polygons and at 31 March 2017. We have taken the difference to be the production from within the planned wells' drainage areas.
- We have assumed low, mid and high case estimates of recovery factor from the wells' drainage area of 40%, 45% and 50%. These estimates are based on the observation that the overall recovery factor for the field using the current well stock is forecast to be 44%.
- We have calculated the ultimate recovery from each polygon by multiplying the STOIIP by the appropriate recovery factor. We have used the low estimate of recovery factor with the low estimate of STOIIP, the mid estimate of recovery factor with the mid estimate of STOIIP and the high estimate of recovery factor with the high estimate of STOIIP. We have subtracted the difference between the STOIIP in each polygon and the oil in place at 31 March 2017 from the estimates of ultimate recovery to calculate a range of remaining recoveries.

- In predicting the production rate profiles of the wells, we have assumed that the profiles will show the same kind of decline as other wells in the field. For each well, we have scaled the profile appropriately to deliver the reserves attributed to the well by 2039.

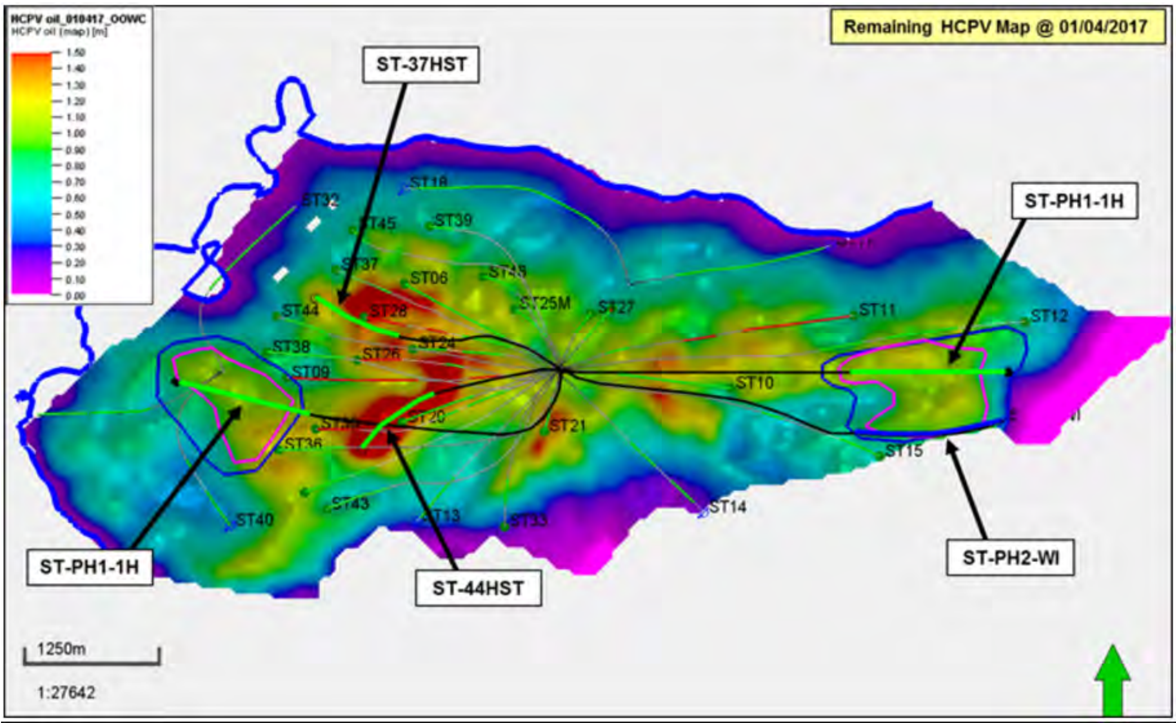


Figure 3.17: Map of hydrocarbon pore volume at 31 March 2017 with drainage area polygons

3.8.2.3. Injection Well ST-PH2-WI

Well ST-PH2-WI is an injection well being drilled primarily to support Well ST-PH2-1H. However, it is expected that the well will accept about 5,000 bbl/day of water while Well ST-PH2-1H is expected to produce 2,000-3,000 bbl/day of liquid. It is expected that the extra water will boost production from Wells ST12 and ST15. We have allowed for this effect by adding a small amount of incremental production to the production profile associated with the additional wells.

3.8.2.4. Well ST-37HST2 and Well ST-44HST

Wells ST-37HST2 and Well ST-44HST are infill wells. Well ST-37HST2 is to be drilled in the northwest of the field, between Well ST44 and Well ST37. Well ST-44HST is to be drilled in the south of the field, between Well ST-08L1 and Well ST-20. The locations of the wells relative to nearby wells are shown in Figure 3.18 and Figure 3.19.

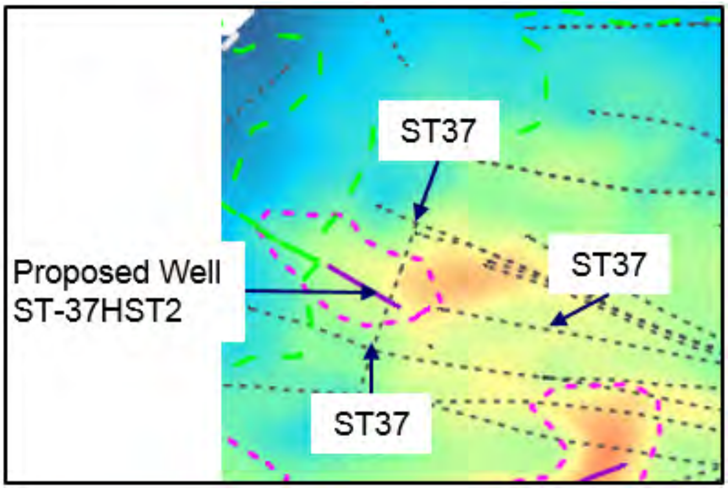


Figure 3.18: Location of Well ST-37HST2 and nearby wells

In assessing the production attributable to these wells, we have used the same methodology as for the Wells ST-PH2-1H and ST-PH1-1H.

In predicting the production rate profiles of the wells, we have assumed that the profiles will have the same form as those of recent infill wells. For each well, we have scaled the profile appropriately to deliver the reserves attributed to the well by 2039.

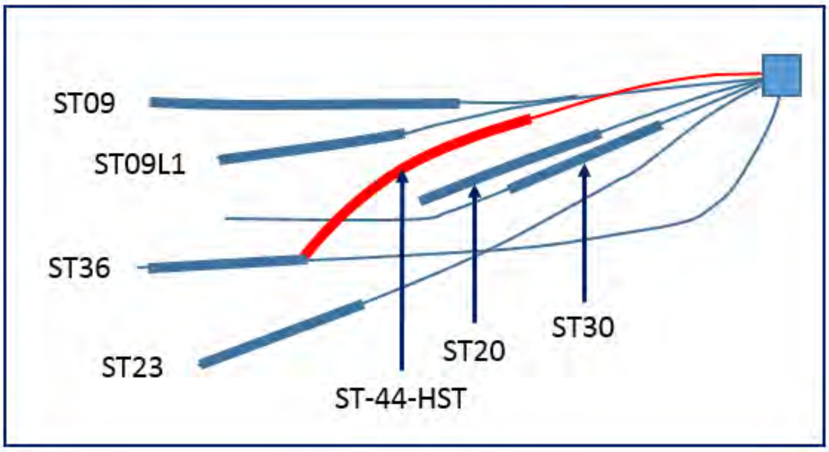


Figure 3.19: Location of planned Well ST-44HST and nearby wells.

3.8.3. Recovery

Our estimates of Developed and Undeveloped future production to 31 December 2039 prior to economic modelling are summarised in Table 3.2.

Table 3.2: Summary of estimates of future production for the Stag field

	Proved Developed Producing (MMstb)	Proved Developed (MMstb)	Low (MMstb)	Best (MMstb)	High (MMstb)
Cumulative production at 31 December 2039	79.6	79.6	82.7	87.4	90.0
Cumulative production at 31 December 2017	65.2	65.2	65.2	65.2	65.2
Remaining production at 31 December 2017	14.4	14.4	17.5	22.2	24.8

NOTES:

1. The figures do not incorporate the results of economic modelling.
2. The figures do not have volumes of oil used as fuel deducted.

3.8.4. Production Profiles

The Developed Producing, Developed, Low, Best and High case production forecasts are shown in Figure 3.20.

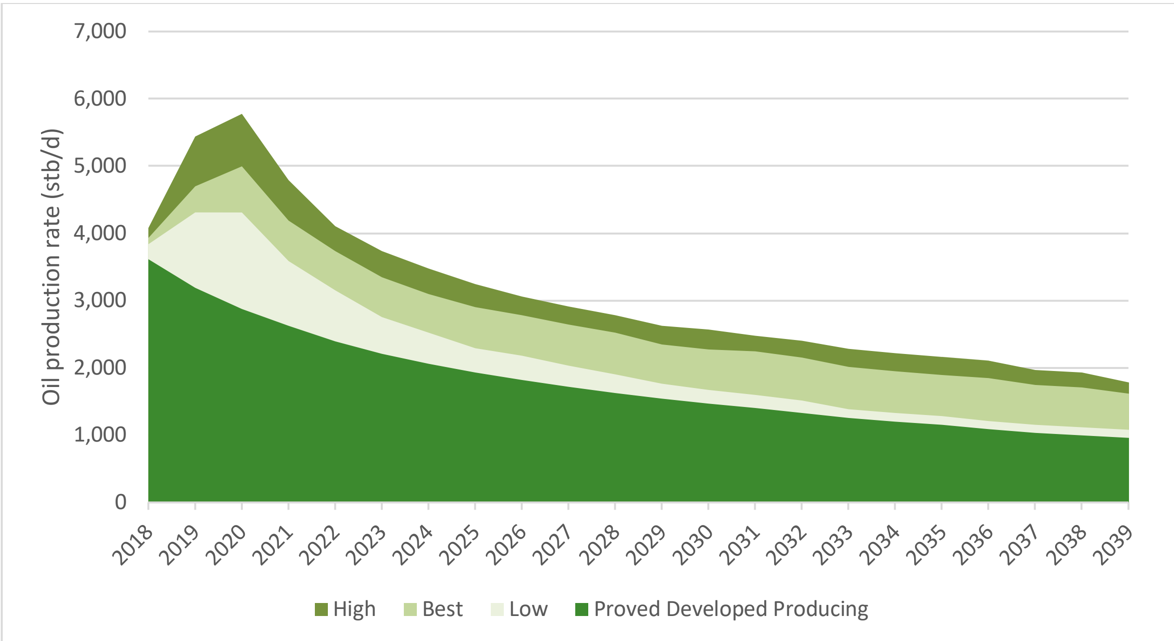


Figure 3.20: Production forecasts for the Stag field

The oil forecasts for the Developed Producing, Developed, Low, Best and High cases prior to economic modelling are shown in Table 3.3.

Table 3.3: Forecasts for Developed Producing, Developed, Low, Best and High estimates

	Proved Developed Producing (stb/d)	Proved Developed (stb/d)	Low (stb/d)	Best (stb/d)	High (stb/d)
2018	3,616	3,616	3,837	3,933	4,083
2019	3,190	3,190	4,311	4,695	5,441
2020	2,873	2,873	4,306	4,996	5,776
2021	2,621	2,621	3,587	4,190	4,787
2022	2,396	2,396	3,149	3,740	4,106
2023	2,205	2,205	2,757	3,350	3,738
2024	2,059	2,059	2,520	3,098	3,475
2025	1,931	1,931	2,292	2,906	3,249
2026	1,818	1,818	2,183	2,782	3,061
2027	1,716	1,716	2,032	2,645	2,910
2028	1,626	1,626	1,904	2,527	2,781
2029	1,543	1,543	1,761	2,344	2,623
2030	1,469	1,469	1,676	2,271	2,566
2031	1,401	1,401	1,600	2,245	2,479
2032	1,328	1,328	1,512	2,152	2,401
2033	1,256	1,256	1,384	2,014	2,283
2034	1,205	1,205	1,330	1,954	2,219
2035	1,157	1,157	1,280	1,898	2,160
2036	1,091	1,091	1,213	1,847	2,103
2037	1,033	1,033	1,154	1,750	1,971
2038	997	997	1,116	1,705	1,928
2039	962	962	1,078	1,619	1,783
Total	**14.4**	**14.4**	**17.5**	**22.2**	**24.8**

NOTES:

1. The profiles shown are cut-off at an individual well rate of 39 stb/day and at 31 December 2039. They do not incorporate the results of economic modelling.
2. The profiles do not have volumes of oil used as fuel deducted.
3. Profiles do not include downtime.

3.8.5. **Fuel usage**

The Stag platform is now gas deficient and oil produced at the wellhead is used as fuel.

As the field production rate falls, we might expect fuel requirements to fall. However, gas production will also fall so the proportion to be contributed by oil will increase. Also, as we expect the liquid production to remain roughly constant, with the falling oil production primarily a result of increasing watercut, the actual drop in energy requirement may be small. There is no real guidance to the future requirement from the historical data. We have therefore assumed that the fuel requirement will remain approximately constant at 154 stb/day. This amount was deducted from the oil production profiles shown in Table 3.3 to calculate the sales oil profiles.

3.9. Review of Costs

We carried out a review of the information on costs associated with the Stag field provided by Jadestone. The information provided consisted of:

- The economic model for the field
- The work programmed and budget for the period (2014-2018)
- The Stag abandonment provision cost estimate (2018)
- Stag JV well abandonment costs (2017)
- The Stag JV AEL decommissioning study
- OPEX analysis for 2017
- The Topsides Inspection report (2016)
- Storage Options Review – Stag Field
- The Life Extension Assessment Summary (multiple documents)

3.9.1. Capital Expenditure

3.9.1.1. Repairs, Maintenance and Remediation Projects

From 2018 onwards, an allowance of 2.0 MM AUD per year is budgeted for capital expenditure. We consider this to be an appropriate capital allocation.

3.9.1.2. Drilling

An infill drilling project is planned to consist of five additional wells. One well is to be drilled in 2018, two in 2019 and two in 2020. The wells are budgeted at an average of 22.4 MM AUD each, in line with the cost of previous wells. We consider that the well costs appear reasonable given previous experience and historic costs.

3.9.2. Operating Expenditure

Operating expenditure includes:

- FSO operations
- Well workovers
- Repairs and maintenance
- Employees and labour
- Contractors and support
- Air, marine and onshore support
- Insurance
- General and administration costs

Actual operating expenditure in 2017 was 73.0 MM AUD. The budget for 2018 is 64.5 MM AUD.

Jadestone is proposing a smaller Operating Expenditure budget for 2019 and onwards of 60.7 MM AUD per year. The savings are attributed to reductions primarily in workover and FSO costs but also maintenance costs and Contractor costs, which appeared high under previous operator.

The current FSO, Dampier Spirit, has been in operation for 20 years and the lease expires in 2024. Jadestone has commission an independent report into the cost of a newly converted FSO. Bare boat charter rates are based on current rates and a 10% reduction crew costs (lower manning) and 25% reduction in repairs and maintenance have been assumed in the total cost estimate.

Jadestone assumes lower Operating Expenditure during the last two years of the field's life as the need for workovers diminishes and general administrative costs are reduced.

ERCE has reviewed all costs estimates, paying particular attention to reductions in workover costs and FSO operations and has accepted these costs forecasts as reasonable.

3.9.2.1. Workovers

Amounts budgeted for Workover related Operating Expenditures in MM AUD are as follows.

Table 3.4: Workover related Operating Expenditure budget

Year	Cost (MM AUD)
2017	16.2
2018	11.6
2019	7.7

2019 costs are assumed to remain constant until the cost reduced in the final two years of economic production.

Typically, five workovers are carried out per year, principally to change out ESPs which have a typical life of two to three years. Costs in 2017 are believed to be atypically high because of a need for unexpected workovers to deal with integrity issues.

Jadestone has carried out two workovers in 2017 (Wells ST21 and ST48) and has achieved significantly reduced costs compared to the previous operator's historical costs. The average cost for the two 2017 workovers was 1.0 MM AUD which is achieved in part through purchasing cheaper pumps and a move to a cheaper workover vessel. Jadestone has phased these cost reductions to their 2018, 2019 and onward forecasts.

3.9.2.2. FSO operations

The current FSO, Dampier Spirit, has been in operation for 20 years and the lease expires in 2024. Jadestone has commissioned an independent report into the cost of a newly converted FSO. Bare boat charter rates are based on current rates and a 10% reduction crew costs (lower manning) and 25% reduction in repairs and maintenance have been assumed in the total cost estimate.

Table 3.5: FSO related Operating Expenditure budget

Year	Bareboat charter (MM AUD)	Operations and maintenance (MM AUD)	Total (MM AUD)
2018 - 2023	6.8	11.2	18.0
2024	6.0	10.4	16.3
2025 onwards	4.4	8.6	13.0

3.9.2.3. Other OPEX

Amounts budgeted for Repairs and Maintenance, Employee and Labour, Contractor and Operator, Air, Marine and Onshore Support, Insurance and G&A are presented in Table 3.6.

Table 3.6: Other Operating Expenditure budget

Year	Costs (MM AUD)						
	Repairs and Maintenance	Employee and Labour	Contractor and Operator	Air, Marine, Onshore Support	Other	Insurance	G&A
2017	3.7	7.3	6.2	7.4	3.4	0.9	4.3
2018	2.6	8.1	3.1	7.0	3.6	1.0	3.9
2019	2.6	8.1	3.1	7.0	3.6	1.0	3.9

2019 costs are assumed to remain constant until the cost reduced in the final two years of economic production.

Historic costs for G&A, Contractors and onshore support appear high. From 2018 onwards, reductions in Maintenance and Contractor costs are planned, driven by reduction in reliance on vendors/Contractors, offshore staff being used in place of mobilising an onshore workforce and a more fit for purpose Management of Change procedure. Further cost reductions are driven by new air support contracts, specifically a new helicopter contract and a new MedEvac contract. We consider that the anticipated cost reductions associated with these changes are reasonable.

3.9.2.4. Abandonment Costs

For 2018, Jadestone has updated its estimates of abandonment costs. The cost of well abandonment (12 platform wells and four subsea water injection wells) is estimated to be 37 MM AUD. Most of the work can be carried out using a workover unit but a drilling rig is required to set the cement plugs. The cost of abandonment of the facilities is estimated to be 78 MM AUD. The total cost of abandonment is thus estimated to be 115 MM AUD.

A fee associated with the termination of the floating supply offloading vessel agreement has been provided by Jadestone and included in the modelling of cash flows.

3.10. Review of Economics

ERCE has undertaken economic modelling of the Stag field to estimate the Reserves and net present values (NPVs) at the 1P, 2P and 3P levels of uncertainty.

An economic model was provided by Jadestone for purposes of economic modelling. This was audited and found to be in accordance with the current petroleum fiscal regime for Australia.

Amendments were made to the model to account for ERCE's oil price and inflation assumptions, cash flow discounting method and economic limit test.

3.10.1. Australia Fiscal Terms

Australia's petroleum fiscal regime consists of a combination of a petroleum resource rent tax (PRRT), Corporate Income Tax (CIT) and royalty-based taxation.

- PRRT is applied at a rate of 40.00%
- CIT is applied at a rate of 30.00%
- Royalties are applied at a rate varying between 10.00% to 12.50% and are generally applied to onshore projects only. The Stag field is located offshore and is therefore exempt from royalties.

3.10.2. Commercial Assumptions

The following commercial parameters were assumed in the modelling of discounted cash flows and in determining the Reserves for Jadestone.

- Effective date of 31 December 2017
- Inflation rate of 2.00% per annum
- The following FX rates were assumed:
    - AUD/USD: 0.75
- Jadestone has provided the following tax loss and carried forward balances which have been incorporated in to modelling the cash flows:
    - Tax loss of 3.3 MM AUD; and
    - Carried forward deductions of 15.6 MM AUD assumed for calculation of PRRT

Table 3.7: Brent price assumptions

Base Case ERCE Brent Assumptions ($/bbl)	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028+
Real (Constant $, 2018)	66	67	68	68	68	68	68	68	68	68	68
Nominal ($ of the day)	67	69	71	73	74	76	77	79	80	82	+2.0% pa

A premium of 1.6% is applied to the Brent forecast above.

3.10.3. Reserves and NPVs

There is no assurance that the forecast production and cost profiles contained in this report will be attained and variances could be material. The recovery and estimates of the company's oil and natural gas Reserves are estimates only and there is no guarantee that the estimated Reserves will be recovered. Actual volumes recovered may be greater than or less than the estimates stated in this report.

Gross Field Reserves are the gross remaining Reserves of the properties at the 100.00% working interest.

Working Interest Reserves are the remaining Gross Field Reserves of the properties in which the Company has an interest, multiplied by the Company's working interest in the properties.

Company Net Reserves are remaining Reserves of the properties in which the Company has an interest.

This section presents a summary of the consolidated cash flows and after-tax cash flow ("ATCF") discounted to the effective date at 0%, 5%, 10%, 15% and 20% at the various levels of uncertainty for all assets with Reserves at the 1P, 2P and 3P levels of uncertainty. The estimated discounted net present values presented in this report should not be construed as ERCE's estimate of fair market value.

The tables below summarise the oil Reserves estimates for the Stag field at the 1P, 2P and 3P levels of uncertainty, and the corresponding NPVs.

Table 3-8: Stag field crude oil reserves as at 31 December 2017

Country	Licence	Field	Gross Reserves (MMstb)			Working Interest (%)	Net Reserves attributable to Jadestone (MMstb)		
			1P	2P	3P		1P	2P	3P
Australia	WA-15-L	Stag	10.8	17.1	22.7	100%	10.8	17.1	22.7
Total			**10.8**	**17.1**	**22.7**		**10.8**	**17.1**	**22.7**

Table 3-9: Stag field net present values as at 31 December 2017

	Post-Tax Net Present Value, Net Jadestone ($US MM)				
	0%	5%	10%	15%	20%
1P	6.6	25.2	29.6	28.7	26.1
2P	94.0	97.0	84.2	70.2	58.3

3.11. Contingent Resources

The oil production forecast for the period between the end of economic production and the end of the production licence, August 2039, has been classified as Contingent Resources. The Contingent Resources for the Stag field and the associated production profiles determined on this basis are shown in Table 3-10. Given the dependence on market factors, we consider the chance of development to be 50%.

Table 3-10: Stag field Contingent Resources as at 31 December 2017

	Fuel usage (stb/d)	1C		2C		3C	
		Gross oil rate (stb/d)	Net oil rate (stb/d)	Gross oil rate (stb/d)	Net oil rate (stb/d)	Gross oil rate (stb/d)	Net oil rate (stb/d)
2018	154	-	-	-	-	-	-
2019	154	-	-	-	-	-	-
2020	154	-	-	-	-	-	-
2021	154	-	-	-	-	-	-
2022	154	-	-	-	-	-	-
2023	154	-	-	-	-	-	-
2024	154	-	-	-	-	-	-
2025	154	-	-	-	-	-	-
2026	154	-	-	-	-	-	-
2027	154	-	-	-	-	-	-
2028	154	-	-	-	-	-	-
2029	154	1,747	1,593	-	-	-	-
2030	154	1,628	1,474	-	-	-	-
2031	154	1,555	1,401	-	-	-	-
2032	154	1,490	1,336	-	-	-	-
2033	154	1,414	1,260	-	-	-	-
2034	154	1,311	1,157	-	-	-	-
2035	154	1,248	1,094	1,752	1,598	-	-
2036	154	1,205	1,051	1,691	1,537	-	-
2037	154	1,152	998	1,634	1,480	-	-
2038	154	1,098	944	1,582	1,428	-	-
2039	154	1,056	902	1,535	1,381	-	-
Total (MMstb)	**-**	**5.4**	**4.8**	**3.0**	**2.7**	**0.0**	**0.0**

4. Nam Du Discovery, Block 46/07, Vietnam

4.1. Discovery Description

The Nam Du discovery is located within the Block 46-07 PSC ("Block 46/07) on the north-eastern margin of the Malay-Tho Chu Basin, approximately 200 km offshore Vietnam in a water depth of 47.9 m (Figure 1.3). The field was discovered in 2013 by exploration Well 46/07-ND-1X, drilled by Mitra Energy. Jadestone holds a net working interest of 70% in Block 46/07, although a third party has a right to a 3% back-in at cost. The remaining 30% working interest is currently held by PVEP. However, effective May 2017, PVEP relinquished its 30% working interest in the block. The registration of this change is still pending.

In April 2013, Well 46/07-ND-1X was drilled to a total depth of 2,297 mMD and discovered gas in two main Miocene fluvial channel reservoirs. A further ten reservoir sandstone intervals were encountered and are mainly gas-bearing. Gas bearing reservoirs have a $C0_2$ content of approximately 8%. Only one of these reservoirs, Channel 22 (also referred to as H_070 or Sand 13_7), contains enough gas to warrant development and thus is the only reservoir with Contingent Resource estimates. Channel 22 has a combination structural/stratigraphic trap, with the channel limits defined by seismic inversion volumes and structural control from 3-way dip closure and fault throw.

A draft Outline Development Plan ("ODP") was first submitted to partner PVEP in December 2015 with revisions made with PVEP throughout 2016. In May 2018, Jadestone received approval from Vietnam's Ministry of Industry and Trade of its ODP for the Nam Du and U Minh gas fields. The approval serves as a formal starting point for the development of these fields.

4.2. Geophysical Evaluation

The Nam Du discovery is covered by a 3D seismic data set acquired in 2010. The 2010 3D volume covers 387 sq km and was processed in 2011 to produce a PSTM (pre-stack time migrated) volume. This volume has been reviewed by ERCE and used in the evaluation of Contingent Resources.

4.2.1. Seismic Interpretation

A post-stack merged time volume (PoSTM Full Stack) across Blocks 46/07, 45 and 51SE provides the basis for Jadestone's seismic interpretation of horizons and faults. Numerous horizons have been interpreted on the volume across the Nam Du discovery but it is the Channel 22 horizon that is the sole focus of this evaluation (Figure 4.1). ERCE has reviewed the interpretation of the Channel 22 horizon and faults in time and found it be acceptable.

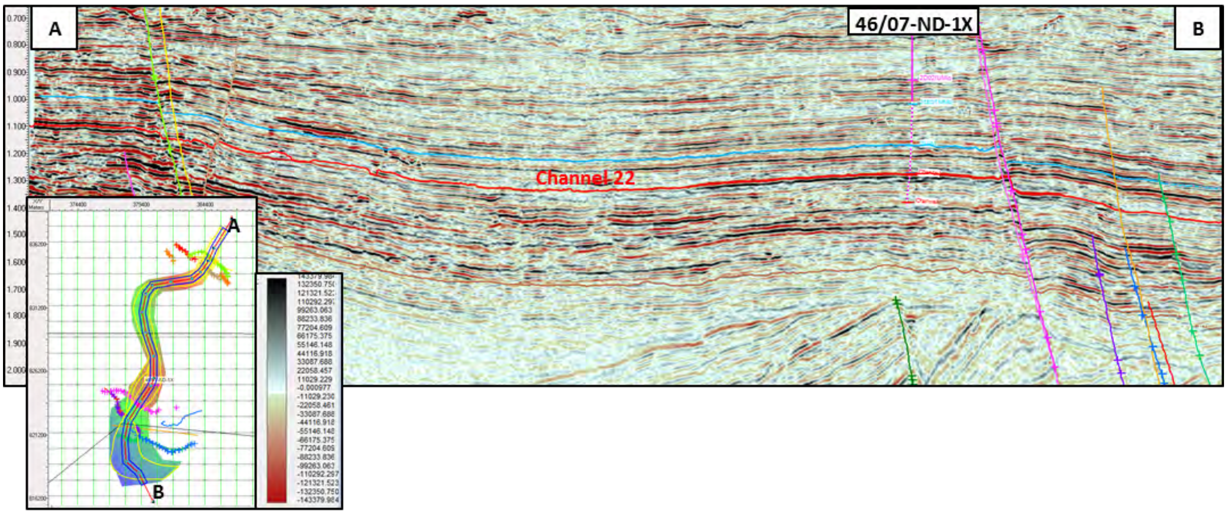


Figure 4.1: Arbitrary line (twt) through the Channel 22 axis

A similarity cube, sliced approximately at the Channel 22 reservoir, shows the channel architecture and helps to define the boundaries of the channel (Figure 4.2). Inspection of the seismic confirms that the chute channel is connected to the main channel where it branches away from it.

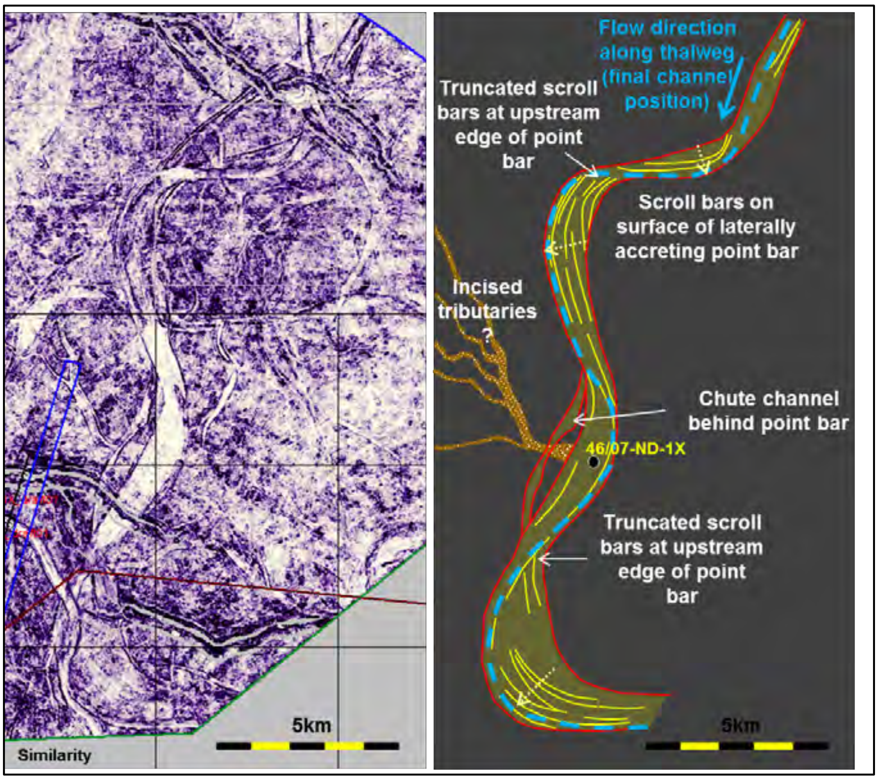


Figure 4.2: Channel 22 reservoir definition, similarity slice at 1.40s
**Source: Jadestone*

4.2.2. **Depth Conversion**

Sonic log data from Well 46/07-ND-1X was used to derive a single layer V0-k velocity model, to depth convert the Channel 22 horizon (highlighted in red on Figure 4.3). The compaction factor values were varied, and values of V0 were optimised for each compaction factor to minimise errors at the wells.

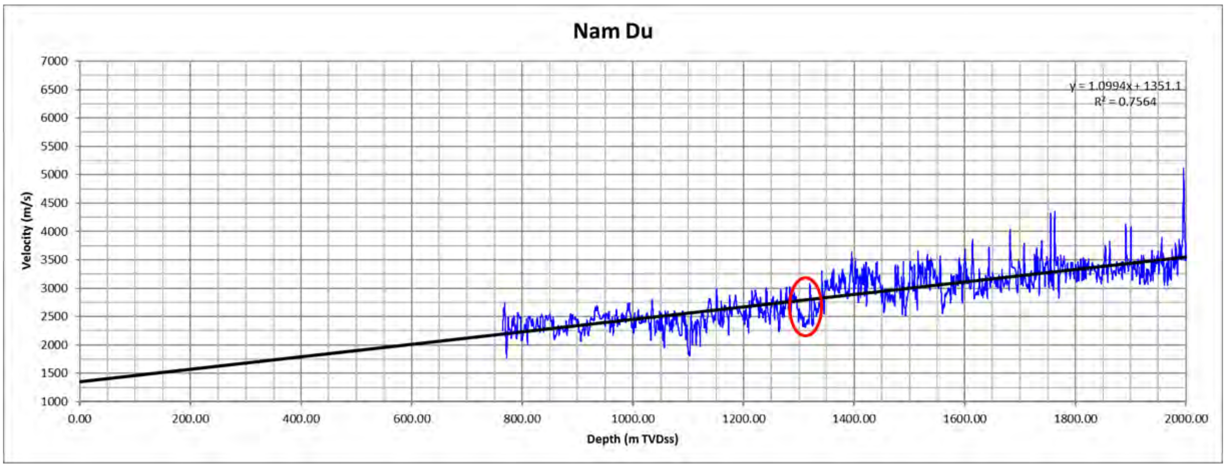


Figure 4.3: V0-k velocity model used in depth conversion. Channel 22 reservoir highlighted in red.

The operator velocity model uses a polynomial function fitted to the VSP data from offset wells, with one "dummy point" inserted so that the 46/07-ND-1X polynomial fits the shallow trend observed in the offset wells (Figure 4.4).

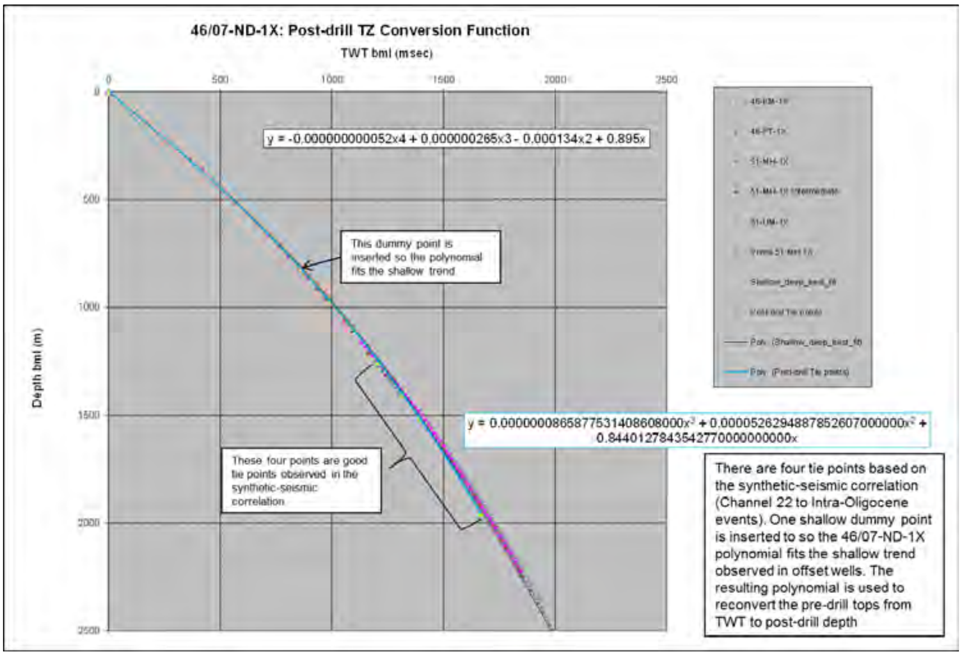


Figure 4.4: Operator 46/07-ND-1X post-drill time-depth curve

There is little difference between the Channel 22 depth structure maps that result from the ERCE single layer V0-k velocity model and from the operator polynomial function. Therefore, ERCE have accepted the depth conversion and resulting Channel 22 depth structure map provided by the operator.

4.2.3. Seismic Inversion

Seismic inversion studies have been performed on the Nam Du seismic data in an attempt to better understand reservoir and hydrocarbon distribution away from the well location. A number of inversion products were produced including P-impedance, Vp/Vs, density, Sw from density and sand probability. A number of these volumes, along with the similarity, were used by the previous operator, Mitra Energy, to define low, best and high case deterministic polygons for the Channel 22 reservoir.

ERCE reviewed the seismic inversion study to evaluate its reliability in mapping reservoir and hydrocarbons away from the well. The Channel 22 reservoir sand is softer than the background shale and thus can be distinguished on the absolute acoustic impedance ("AAI") volume, as well as on the inverted density and Sw volumes (Figure 4.5), although both density and water saturation are over-estimated using the Sw inversion volume for this channel. Since the density and saturation volumes are secondary products in the simultaneous inversion process, the acoustic impedance inversion volume is used to predict the extent of the sands.

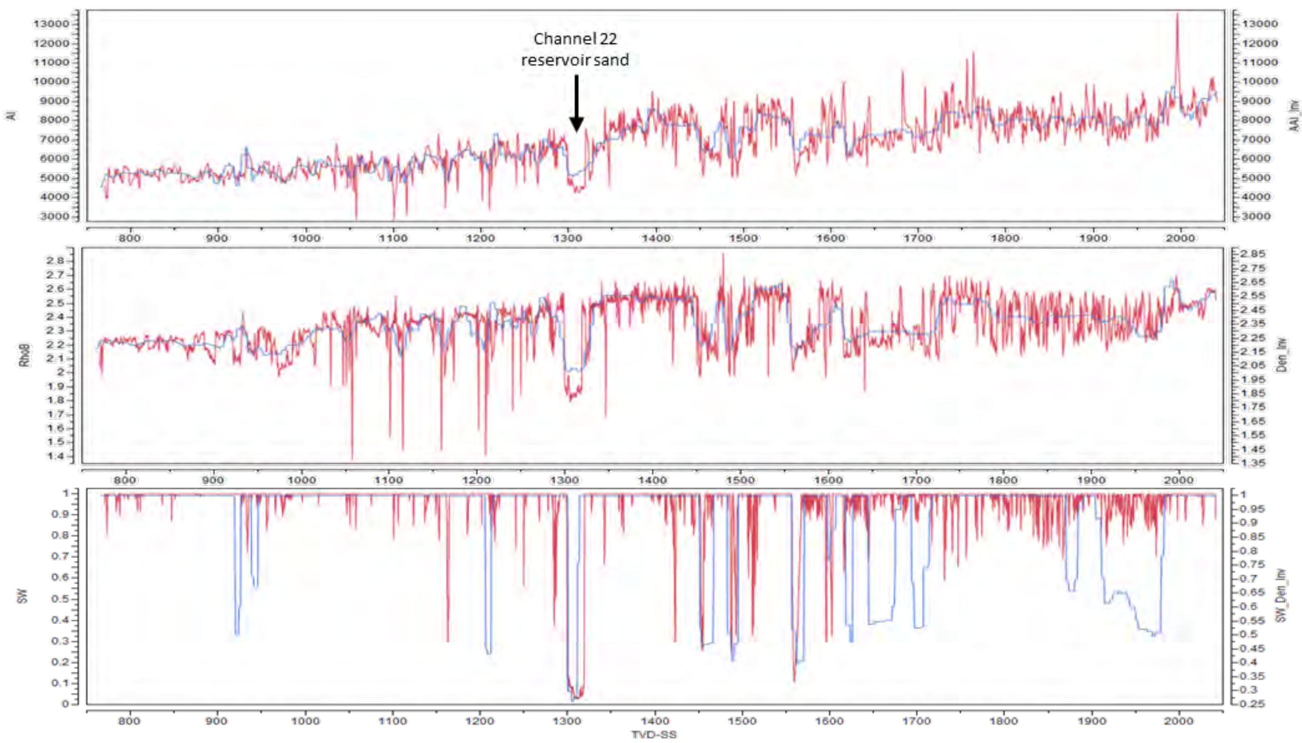


Figure 4.5: AI, density and Sw inversion products predict the Channel 22 sand extent.

Notes:

1. The red curve is the well log and the blue curve is an extracted trace from the respective volume along the well trajectory.

There is a thin layer of coal present at the base of the Channel 22 reservoir sand, with a comparable AAI value on the inverted volume to the overlying sand (Figure 4.6). In theory, a decrease in the thickness of the sand away from the well could virtually amplify the effect of the coal, resulting in an uncertainty-in-the-fluid effect. However, as this sand does not show any significant thinning away from the well location on the northern side of the fault then the amplitude shut off to the north can be attributed to the fluid contact and not due to the dominant effect of coals (Figure 4.7).

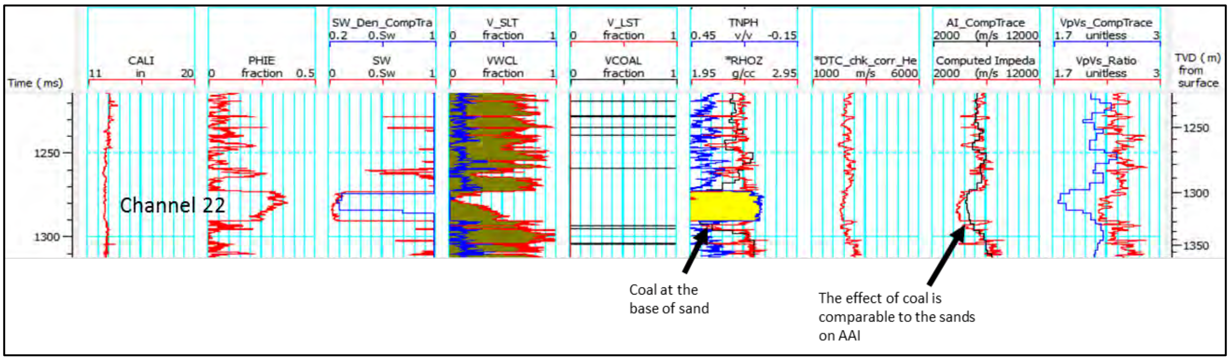


Figure 4.6: Basal coal showing similar impedance response to the sands on the AAI volume

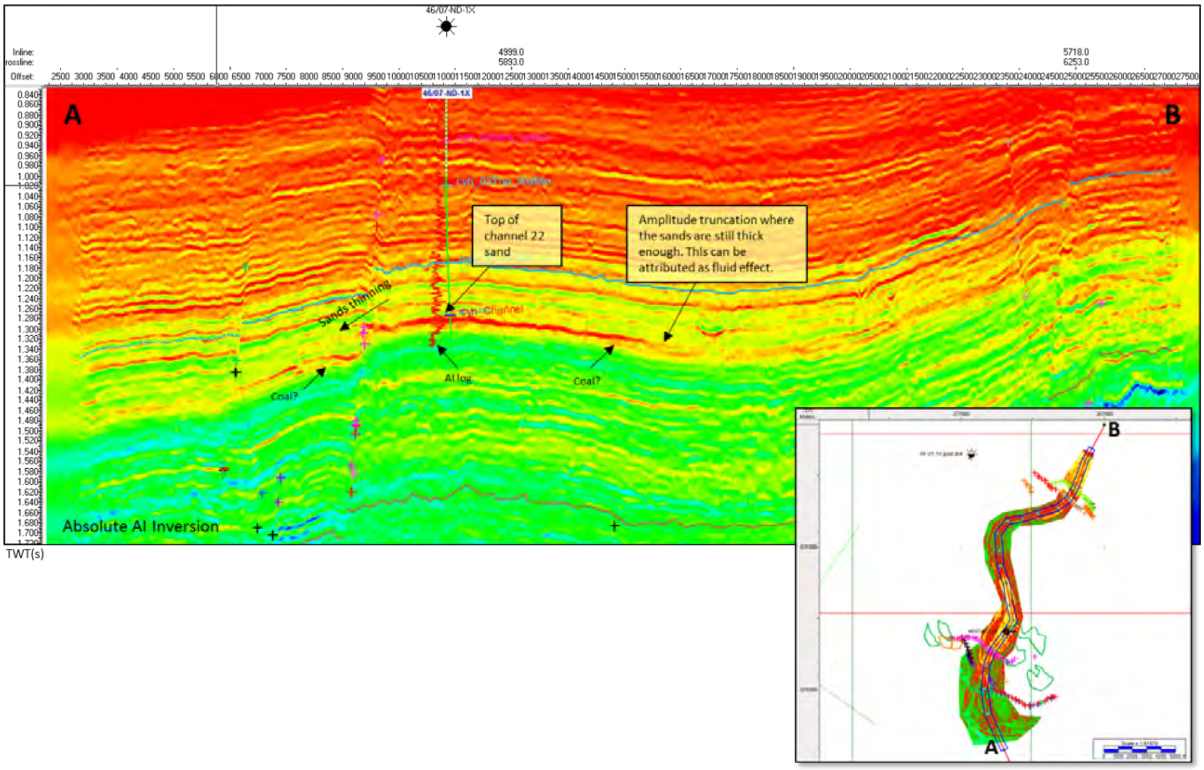


Figure 4.7: AAI volume showing thick sands with the amplitude truncation caused by fluid effects.

4.3. Petrophysical Evaluation

Well 46/07-ND-1X was evaluated over the interval from 805 mMD to total depth (~2275 mMD). The evaluation assumed the interval was a sand/shale sequence. A comparison with the operator's and ERCE's computed petrophysical curves is shown in Figure 4.8 for the Channel 22 reservoir (operator curves are shown in blue and ERCE curves are shown in black).

4.3.1. Data available

A composite log data set was provided (Gamma Ray, Array Induction Resistivity, Sonic and Density/Neutron). Wireline formation pressures were also obtained but that they were not examined as part of this review. Nuclear Magnetic Resonance data was also obtained but these data were not available.

4.3.2. Shale Volume

Shale volume was determined from the Gamma Ray, with a normal linear equation. The uranium free Gamma Ray ("HCGR") curve was used where available with the end-points based on the 2nd and 98th percentile. For comparison purposes, it was also determined from the Density/Neutron crossplot where data was available and was found to be in overall agreement with that from the Gamma Ray. A comparison with the operator derived shale volume, also primarily based on the Gamma Ray, shows good agreement over the Channel 22 reservoir interval.

4.3.3. Porosity

Effective porosity was determined from the Density with hydrocarbon and shale corrections applied. The Density/Neutron crossplot was not used due to the large gas effect on the Neutron which appeared to be greater than that on the Density suggesting very shallow invasion of the drilling mud filtrate. The mud filtrate density was assumed to be 0.9 g/c3 (as the well was drilled with an oil-based mud). Overall agreement can be observed between the operator's and the ERCE computed values with the operator slightly lower in the upper most section of the Channel 22 reservoir.

4.3.4. Water Saturation

Water saturation ("Sw") was determined using the Indonesian equation. In the absence of special core analysis data, the Archie parameters of *a*, *m* and *n* were taken as 1, 1.8 and 1.8 respectively. Formation water resistivity ("*Rw"*) was determined from a Pickett plot that indicated an Rw of 0.86 ohmm at 60 deg. F equivalent to a formation water salinity of 7800 mg/l NaCl. The shale resistivity was taken as 3 ohmm. The well temperature profile was based on the maximum temperatures obtained during the logging. Overall agreement can be observed between the operator's and the ERCE computed values of *Sw*.

4.3.5. Sums and Averages

The same cut-offs as defined by the operator have been used of VSH<50%, PHIE>12.5% and Sw<65%. A visual examination of the data suggests that the definition of pay is not very sensitive to the cut-offs used.

Whilst there is close agreement between the operator's and ERCE's petrophysical interpretation, there are small differences that result in variations in the sums and averages, e.g. a 2 p.u. difference in porosity values. We have therefore used the ERCE sums and averages from our own interpretation for use in volumetric estimates.

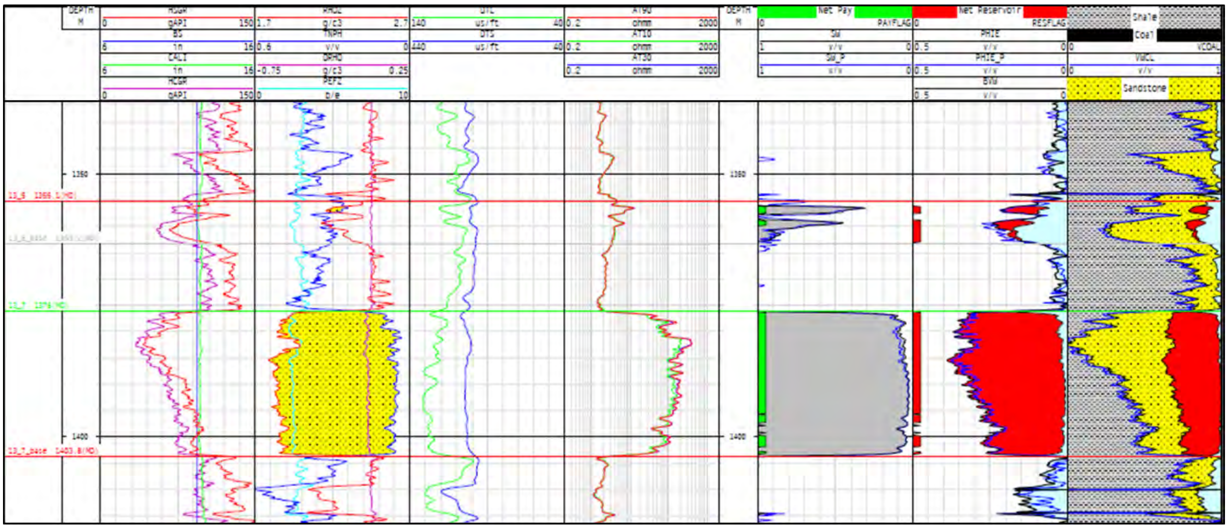


Figure 4.8: Comparison of petrophysical evaluations over Channel 22 reservoir in Well 46/07-ND-1X

4.4. Geological Evaluation

The Nam Du Channel 22 reservoir is a fluvial channel of Lower Miocene age. It is approximately 20 m thick and has two thin (<1m thick) coal intervals. The wireline log character shows a coarsening-upwards sequence. The upper 10-15 m appears to be cleaner from the Gamma Ray response and this is reflected in the interpreted porosity curve as a higher porosity interval.

From the seismic similarity image the reservoir is shown to be part of a low sinuosity channel-point bar system that runs from north east to south west, and is approximately 6 km in length along the axis and averages approximately 1 km in width. There is an additional channel chute that splits from the main channel to the west that is approximately 2.5 km long and 250 m wide. See Figure 4.2.

4.5. Hydrocarbons Initially in Place

Hydrocarbons initially in place have been calculated for the gas-bearing Channel 22 reservoir. We have used a combination structural-stratigraphic approach to calculate a range in gross rock volumes, using polygons and a gross reservoir thickness of 20.45 m from Well 46/07-ND-1X. The area to the south of the fault to the south of Well 46/07-ND-1X has not been drilled and therefore are considered to be prospective resources and no in place volumes have been calculated for this area as part of this evaluation.

The low case GRV is the main channel as defined on the p-impedance volume and limited to the 1353 mTVDSS gas-water contact ("GWC") to the north (Figure 4.9); this contact is from the MDT data (Section 4.6.3). This results in an area of 4.43 km^2 and a GRV of 80.6 MMm^3.

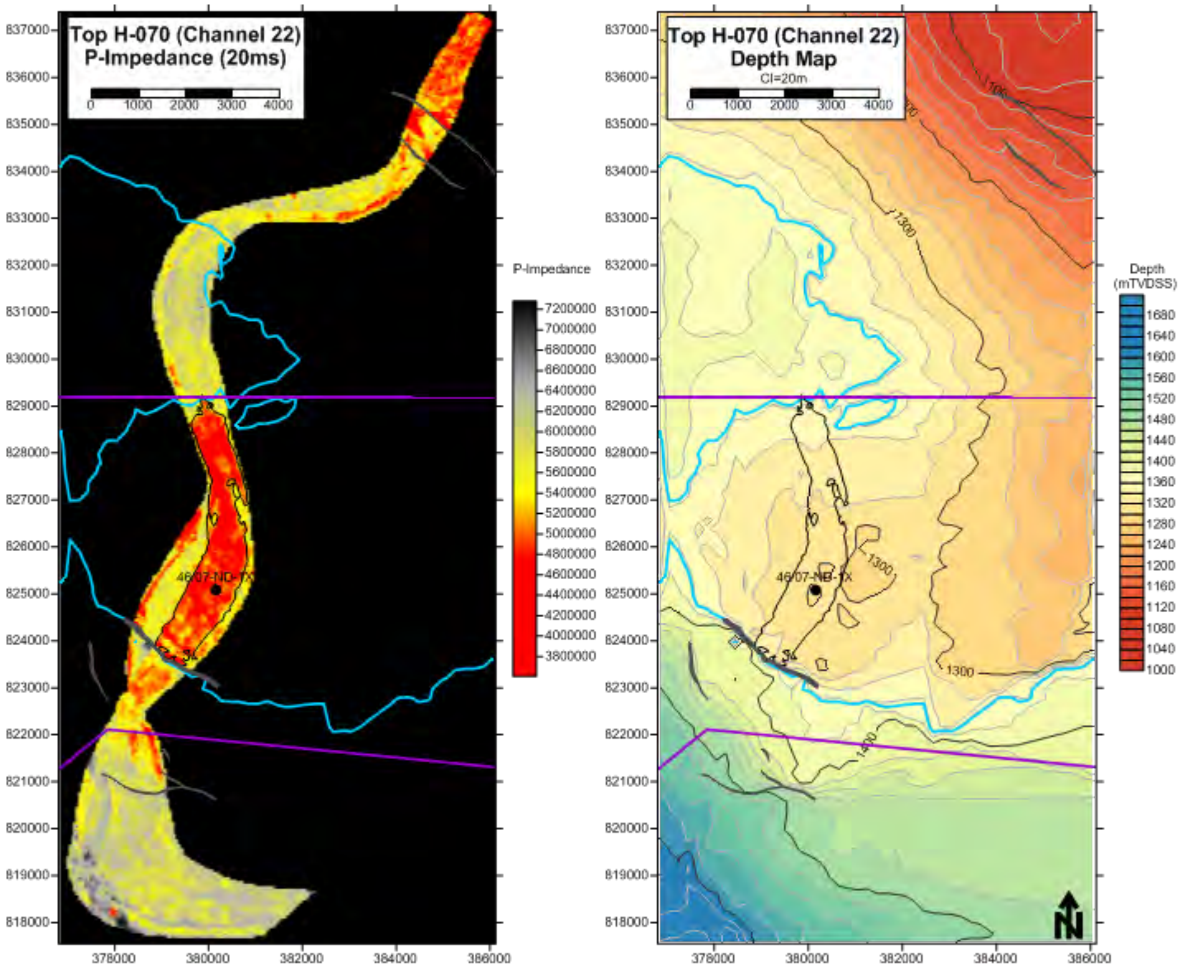


Figure 4.9: Nam Du low case GRV polygon and contact

The mid case GRV is the main channel, plus the channel chute to the west, as defined on the p-impedance volume, and limited to a midway GWC at 1357.5 mTVDSS to the north (Figure 4.10). This results in an area of 6.54 km^2 and a GRV of 121.9 MMm^3.

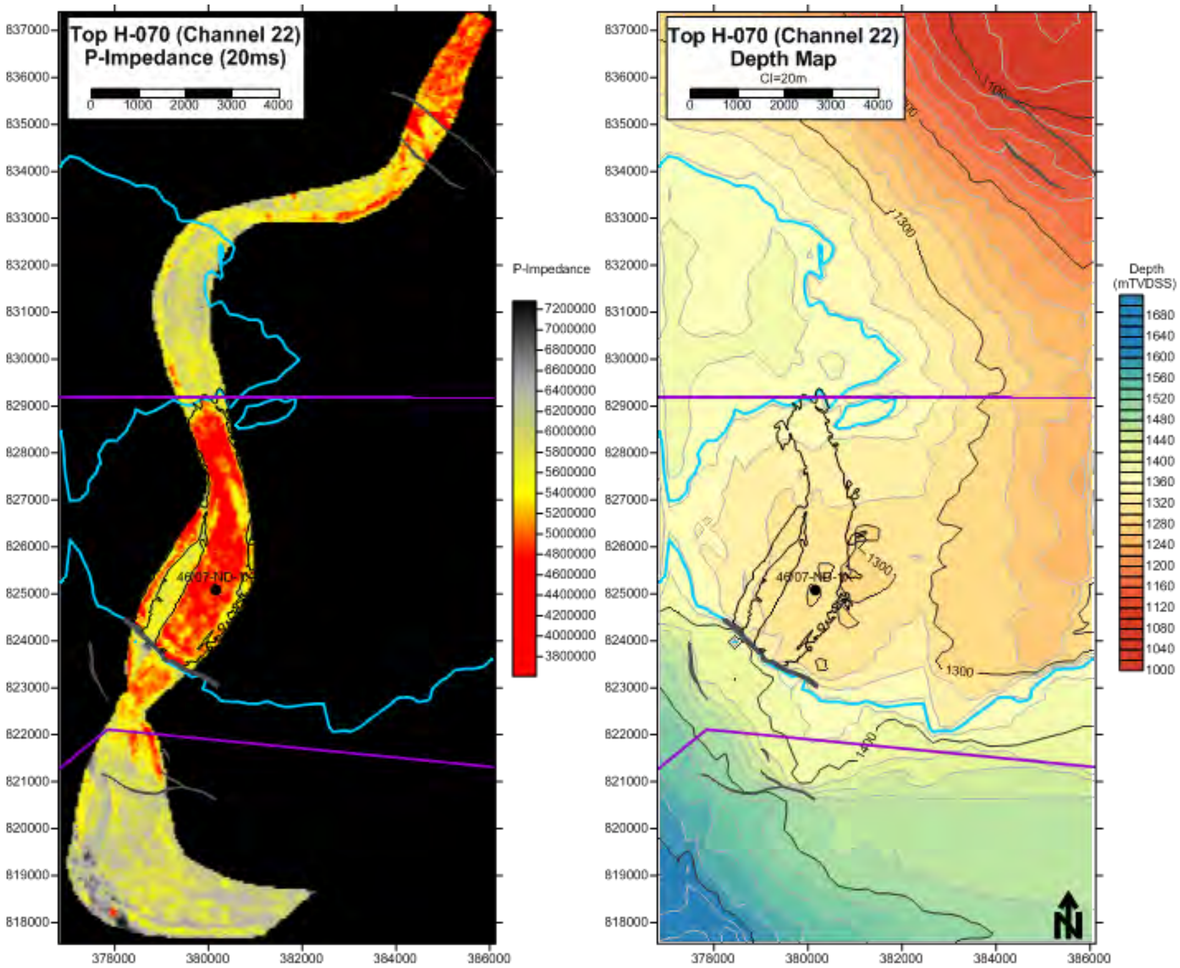


Figure 4.10: Nam Du mid case GRV polygon and contact

The high case GRV is as per the mid case but limited to the north using an MDT contact of 1363.2 mTVDSS (Figure 4.11). This results in an area of 7.96km^2 and a GRV of 139.3 MMm^3.

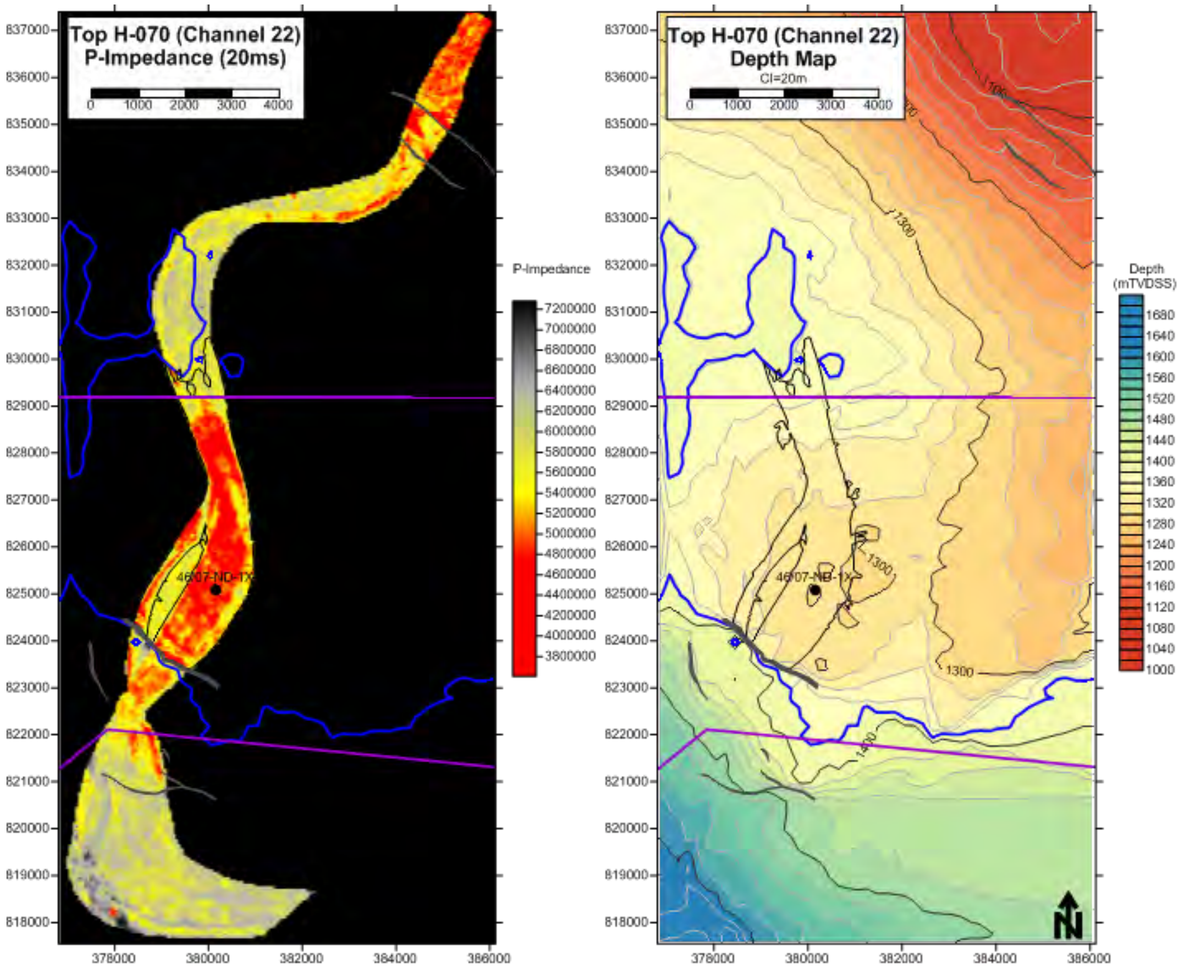


Figure 4.11: Nam Du high case GRV polygon and contact

Other reservoir parameters in Nam Du have been kept constant in the low, mid and high case estimates, as Well 46/07-ND-1X shows Channel 22 to have excellent reservoir quality and the p-impedance implies that there would be a limited reduction in reservoir quality away from the well. The main uncertainty is area/GRV, and this has been varied accordingly as discussed above. The input parameters for the low, best and high volumetric calculations are shown in Table 4-1. The resulting calculation of GIIP is shown in Table 4-2.

Table 4-1: Input parameters for Nam Du volumetric calculations

ERCE Deterministic	Area (km2)	GRV (MMm3)	N/G	Porosity	Sg	GEF	Recovery Factor
Low	4.43	80.6	0.84	0.32	0.95	120.00	75%
Mid	6.54	121.9	0.84	0.32	0.95	120.00	82%
High	7.96	139.3	0.84	0.32	0.95	120.00	90%

Table 4-2: Nam Du gas initially in-place

	GIIP (Bscf)		
	Low	Mid	High
Channel 22	86.4	130.7	149.3

4.6. Reservoir Engineering Evaluation

4.6.1. Well Tests and Permeability

No full-scale drill stem test (“DST”) was performed in the discovery Well 46/07-ND-1X. Dual packer Mini-DSTs were performed in 15_4 and 17_1 reservoir intervals, located at greater depths to the Channel 22 sandstone that is the subject of this report.

Within the Channel 22 sandstone, three single probe mini-DSTs were performed, at depths of 1,378.0 mMD (1,335.5 mTVDSS), 1,390.0 mMD (1,344.4 mTVDSS) and 1,401.5 mMD (1,352.8 mTVDSS). All three min-DSTs showed very high mobility, with values of 22,000, 30,000 and 16,800 mD/cP being interpreted at the three stations by the contractor. Conversion of mobility to permeability depends on the assumptions of the fluids immediately adjacent to the well. If a gas viscosity is used (0.017 cP), then the interpreted permeability ranges from 285 to 510 mD resulting in permeability thickness products of between 17,000 and 30,000 mDft. These values could be higher if account is taken of the presence of mud filtrate in the vicinity of the wellbore.

Mobilities from the seven MDT pre-tests taken in the Channel 22 sands are high, ranging from 117 to 18,000 mD/cP, with an average value of 5,400 mD/cP. These mobility estimates are likely to be less reliable than those estimated from the mini-DSTs and their conversion to permeability is more affected by the composition and saturation of the filtrate surrounding the wellbore.

Permeability estimates were also obtained using a Schlumberger Nuclear Magnetic Resonance (“NMR”) tool. An average NMR permeability for the Channel 22 sandstone of 955 mD is reported in the ODP for the Nam Du field (“MASTER ODP Nam Du - R03_Full”), revision 3 dated November 2016, Table 9. However, whilst NMR logs provide the advantage of continuous coverage, the absolute value of permeability from a NMR log usually require calibration against other sources of permeability.

No core data are available and no direct measurement of permeability is available, but evidence from the MDT pressures and mini-DSTs are that the Channel 22 sandstone intersected by Well 46/07-ND-1X is good reservoir quality with permeability measuring hundreds of millidarcies (mD), and greater than 1,000 mD in places. Whilst an average permeability of 1,000 mD has been used by Mitra for development planning purposes, permeability remains an uncertain parameter and hence production rates forecast by the simulation model based on assumptions relating to permeability are uncertain.

4.6.2. Reservoir Pressures / Fluid Contacts

A gas down to (“GDT”) is observed in Well 46/07-ND-1X in Channel 22 (also referred to as the 13.7 sand) on wireline logs. Multiple Modular Formation Dynamic Tester (MDT) pressure measurements were made throughout the well. There are water points in sands shallower and deeper than Channel 22 and depending on which water line is chose, the GWC can be defined as either 1353 mTVDSS or 1362 mTVDSS (Figure 4.12). The shallower contact is based on a single “fair” gas point in the 13.5 sands immediately above Channel 22, and a log interpretation of a GWC at 1288 mTVDSS in the 13.5 sands. The deeper contact is based on good water points approximately 250m deeper than Channel 22. This is further illustrated in the excess pressure plot in Figure 4.13.

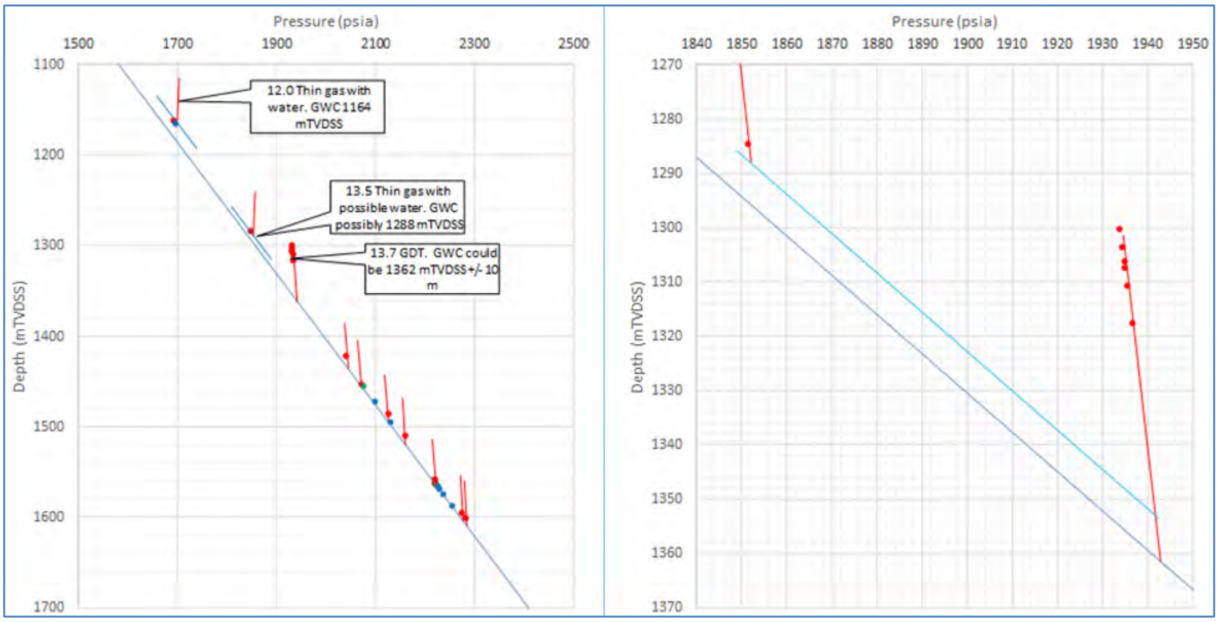


Figure 4.12: Pressure plots for Well 46/07-ND-1X

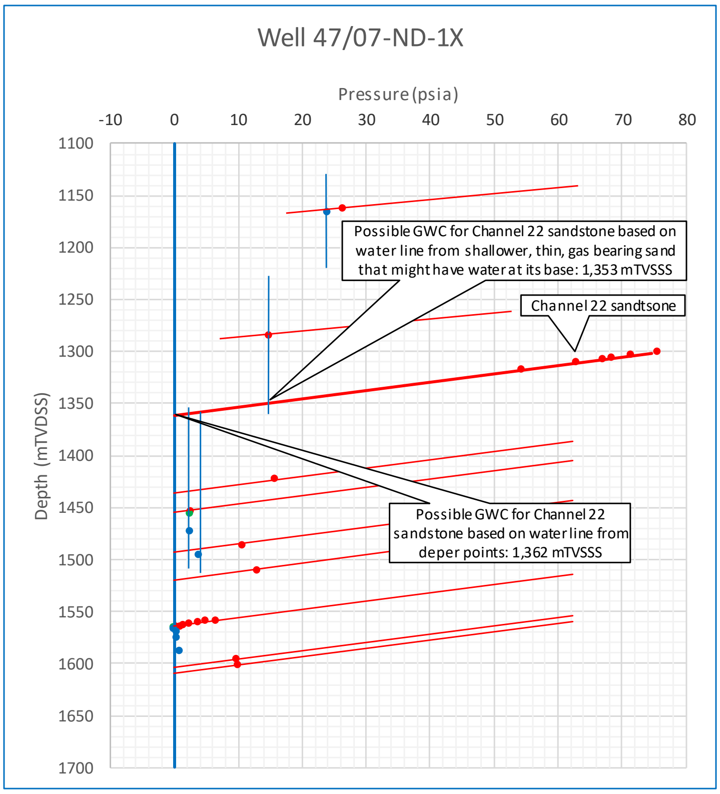


Figure 4.13: Excess pressure plot for Well 46/07-ND-1X

4.6.3. **Fluid properties**

Two laboratory analyses of samples collected with the MDT downhole sampling tool from Well 46/07-ND-1X were made available to ERCE. These samples were taken at depths of 1,378.0 mMD (Sample #1.02) and 1,401.5 mMD (sample#1.03), corresponding to the shallowest and deepest depths at which Mini - DSTs were carried out (report "46.07-ND-1X_QBS PrelimReport.rev0rc - for FVF"). The reported compositional analyses are shown in Table 4-3.

Table 4-3: Compositional analysis of PVT Samples from Well 46/07-ND-1X

Component	Reported molar percentage	
	Sample #1.02	Sample #1.03
N2	1.280	1.280
CO2	3.637	3.658
C1	87.210	87.522
C2	4.753	4.779
C3	1.336	1.343
iC4	0.485	0.486
nC4	0.343	0.343
iC5	0.000	0.000
nC5	0.188	0.186
C6	0.371	0.121
Cyclo-C5	0.008	0.007
C6	0.163	0.154
C7	0.119	0.090
C8	0.081	0.031
C9	0.018	0.001
C10+	0.006	0.000
Total	**99.998**	**100.001**

The PVT reports contain the results of compositional analyses but no PVT experiments are reported. ERCE has used available data to estimate fluid properties for input into the volumetric estimates (Table 4-4). The reservoir pressure is 1,935 psia at a depth of 1,305 mTVDSS and the reservoir temperature is 185 °F. The gas is lean, with the C5+ fraction comprising less than 1%. ERCE has therefore not assigned condensate resources to the Channel 22 sandstone (note that the CGR is shown as zero in Table 4-4). The gas contains approximately 4.9% of non-hydrocarbons (1.3% nitrogen and 3.6% carbon dioxide).

Table 4-4: Gas Properties for Nam Du Channel 22

Nam Du				
Item	Units	Low	Best	High
GEF:	(scf/rcf)	114	120	126
CGR:	(stb/MMscf)	0	0	0
Non-HC gas fraction:		4.9%	4.9%	4.9%

4.6.4. Development Scenarios and Recovery Factors

Mitra Energy has compiled an ODP for the Nam Du field ("MASTER ODP Nam Du - R03_Full", revision 3 dated November 2016). The development plans have not yet been finalised and various options are being considered to tie the development of Nam Du and U Minh into existing infrastructure. Two development scenarios were considered:

Scenario 1: A standalone development combining Nam Du and U Minh, comprising a Central Processing Platform ("CPP") or leased FPSO located at Nam Du, with separation, dehydration and compression process equipment. A minimum facilities Well Head Platform ("WHP") would be located over Nam Du and a WHP would be located over U Minh with a multi-phase tie-in pipeline to Nam Du. Gas export line would be via an existing pipeline. Liquid export would be via tanker.

Scenario 2: An area development comprising Nam Du, U Minh and PVEP operated Block 46/13 Khanh My and other discoveries. A minimum facilities WHP would be located on U Minh with a multi-phase tie-in pipeline to Nam Du. A minimum facilities WHP would be located on Nam Du with a multi-phase tie-in pipeline to Khanh My. A CPP would be located at Khanh My with separate gas and liquids export lines to existing infrastructure.

Jadestone has presented a development option comprising two wells, with the new production wells located updip of the discovery well.

In 2017 Lloyd's Register ("LR") completed a reservoir simulation study and report which included conceptual development plans for both fields. In the case of Nam Du, LR simulated a two-well development, with the wells located updip of the discovery well close to the southern bounding fault. LR coupled the simulator to a GAP model that included the various options for surface pipe networking associated with the different development scenarios.

ERCE has reviewed the simulation model prepared by LR and finds it a reasonable representation of the field in all respects apart possibly from the permeability modelling, which we have identified as an uncertain parameter and appears high in the simulation model. Nonetheless, the permeability does not have a material impact on the recovery factor, which is estimated by the LR simulation model to be 89%, at an abandonment pressure of 200 psia. Refinement of the model and forecasts will be required once the development plan has been finalised.

As numerical simulation models constructed in the pre-development phase before being calibrated by production data frequently overestimate recovery, ERCE has used a value of 90% for the High case (Table 4-5). We have used 80% for the Best case and 70% for the Low case. The spread reflects uncertainty in the development plan and the practical abandonment pressure that will be achieved. Due to its elongated geometric shape and the planned location of the development wells in an up-dip location, the Channel 22 reservoir is unlikely to carry a high risk of water production.

Table 4-5: Recovery factors for Nam Du Channel 22

Nam Du			
Item	Low	Best	High
Gas RF:	70%	80%	90%

4.6.5. Contingent Resource

ERCE has estimated Contingent Resources for Channel 22 of Nam Du by applying our estimates of recovery factors (Table 4-5) to our estimates of GIIP (Table 4-2) probabilistically. Note that we have not assigned condensate resources due to the leanness of the gas. The estimates of Contingent Resources are shown in Table 4-6.

Table 4-6: Nam Du Contingent Resources

	Contingent Resource (Bscf)		
	1C	2C	3C
Channel 22	65	107	134

4.6.6. Chance of Development

In May 2018, Jadestone received approval from Vietnam's Ministry of Industry and Trade of its ODP for the Nam Du and U Minh gas fields. The approval serves as a formal starting point for the development of these fields. Front end engineering and design ("FEED") work and negotiations of a gas sales agreement are due to begin imminently. In light of the recent approval, we have assigned a chance of development of 85%.

5. U Minh Discovery, Block 51, Vietnam

5.1. Discovery Description

The U Minh discovery is located within the boundaries of the Block 51 PSC ("Block 51") in the Malay-Tho Chu Basin, approximately 200 km offshore Vietnam in a water depth of 64 m (Figure 1.3). U Minh was discovered by exploration Well 51-UM-1X in January 1997, drilled by FINA Exploration Minh Hai B.V. This is the only well on the field. Block 51 has separate expiry dates for crude oil and gas, which are June 2035 and June 2040 respectively. Jadestone holds a net working interest of 70% in Block 51. The remaining 30% working interest is currently held by PVEP. However, effective May 2017, PVEP relinquished its 30% working interest in the block. The registration of this change is still pending.

5.2. Geophysical Evaluation

5.2.1. Seismic Interpretation

A post-stack merged time volume (PoSTM Full Stack) across Blocks 46/07, 45 and 51SE provides the basis for Jadestone's seismic interpretation of horizons and faults. Numerous horizons have been interpreted on the volume across the Nam Du discovery but it is the H100 horizon (referred to as the H050 horizon in the interpretation) that is the sole focus of this evaluation (Figure 5.1). ERCE has reviewed the interpretation of the H100 horizon and faults in time and found it be acceptable.

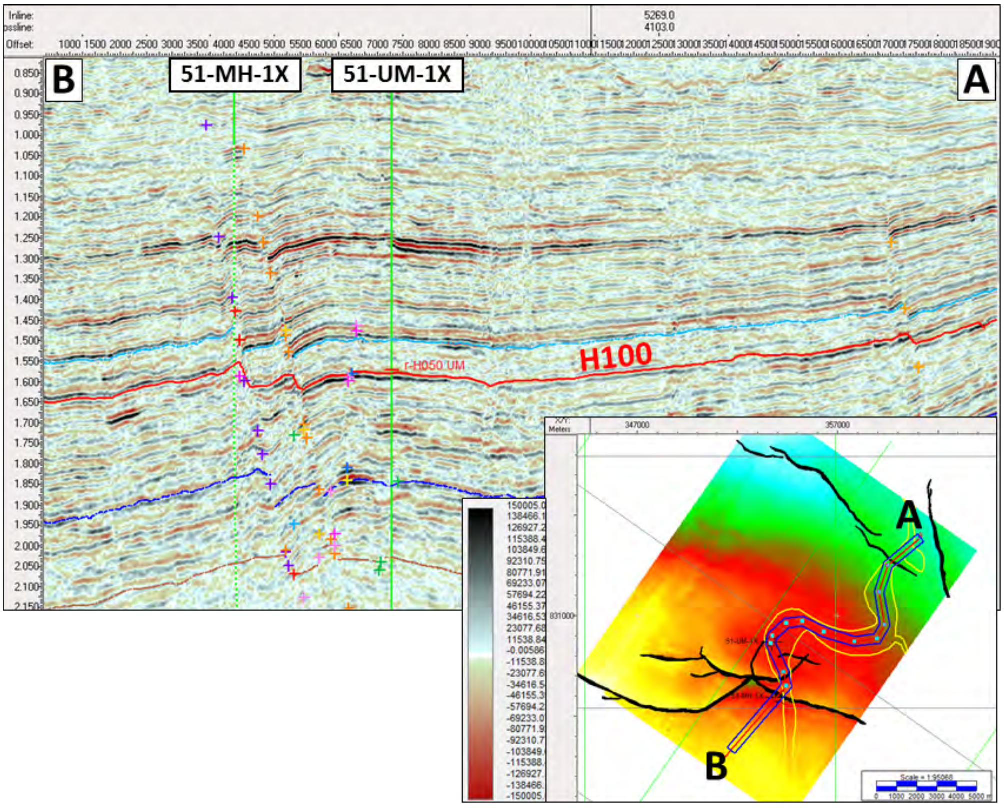


Figure 5.1: Arbitrary line (twt) through the H100 channel axis

A similarity cube, sliced approximately at the H100 reservoir, shows the channel architecture and helps to define the boundaries of the channel (Figure 5.2).

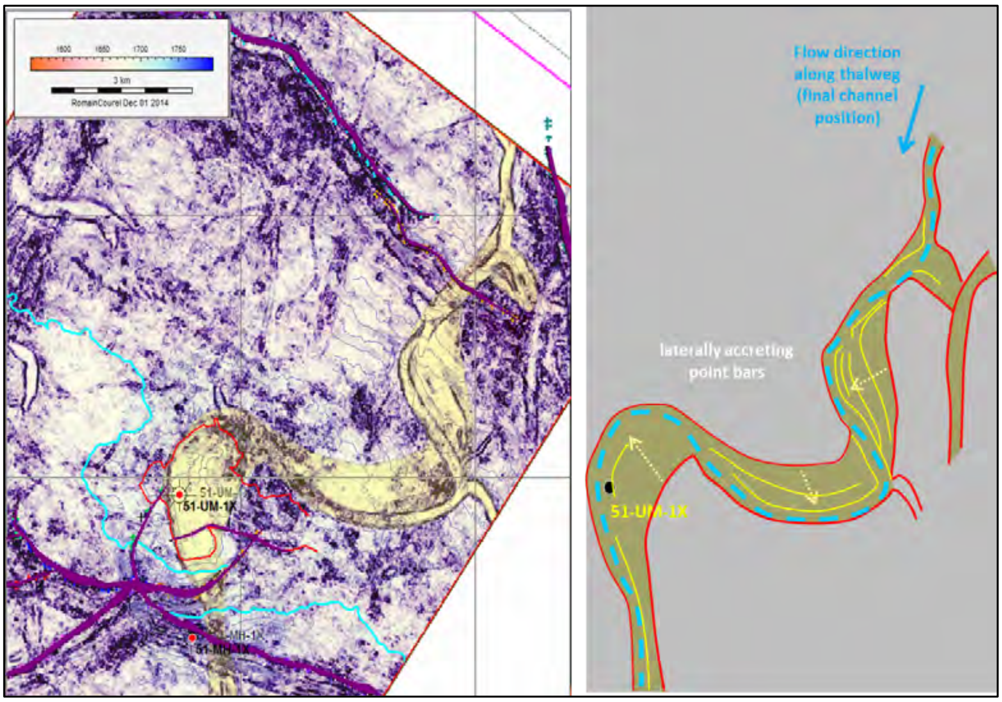


Figure 5.2: H100 reservoir channel definition, similarity slice
**Source: Jadestone*

5.2.2. **Depth Conversion**

Sonic log data from Well 51-UM-1X was used to derive a single layer V0-k velocity model, to depth convert the H100 horizon (highlighted in red on Figure 5.3). The compaction factor values were varied, and values of V0 were optimised for each compaction factor to minimise errors at the wells.

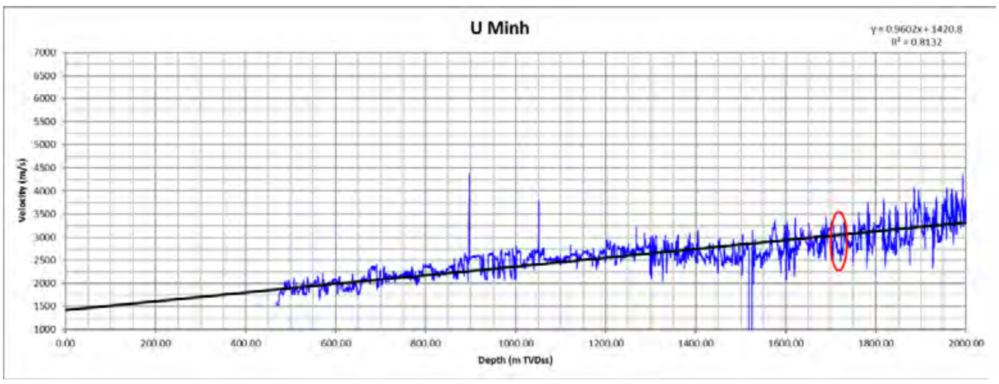


Figure 5.3: V0-k velocity model used in depth conversion. H-100 reservoir highlighted in red.

There is little difference between the H100 depth structure maps that result from the ERCE single layer V0-k velocity model and from the operator depth conversion. Therefore, ERCE have accepted the depth conversion and resulting H100 depth structure map provided by the operator.

5.2.3. Seismic Inversion

Seismic inversion studies have been performed on the U Minh seismic data in an attempt to better understand reservoir and hydrocarbon distribution away from the well location. A number of inversion products were produced including P-impedance, Vp/Vs, density, Sw from density and sand probability. A number of these volumes, along with the similarity, were used by the previous operator, Mitra Energy, to define low, best and high case deterministic polygons for the H100 reservoir. In addition, shallow channels, in the saddle between the seismic amplitudes around Well 51-UM-1X and updip to the north, are proposed to degrade and mask the deeper seismic data, causing the dimmer amplitude response.

ERCE has reviewed the seismic inversion study to evaluate its reliability in mapping reservoir and hydrocarbons away from the well, as well as whether the shallow channels are masking the deeper seismic response. The H100 reservoir sand is softer than the background shale and thus can be distinguished on the AAI trend as they show a relatively strong decrease. Fluids impact the AAI sufficiently to suggest that an amplitude extraction could show fluid content in an untuned interval (Figure 5.4).

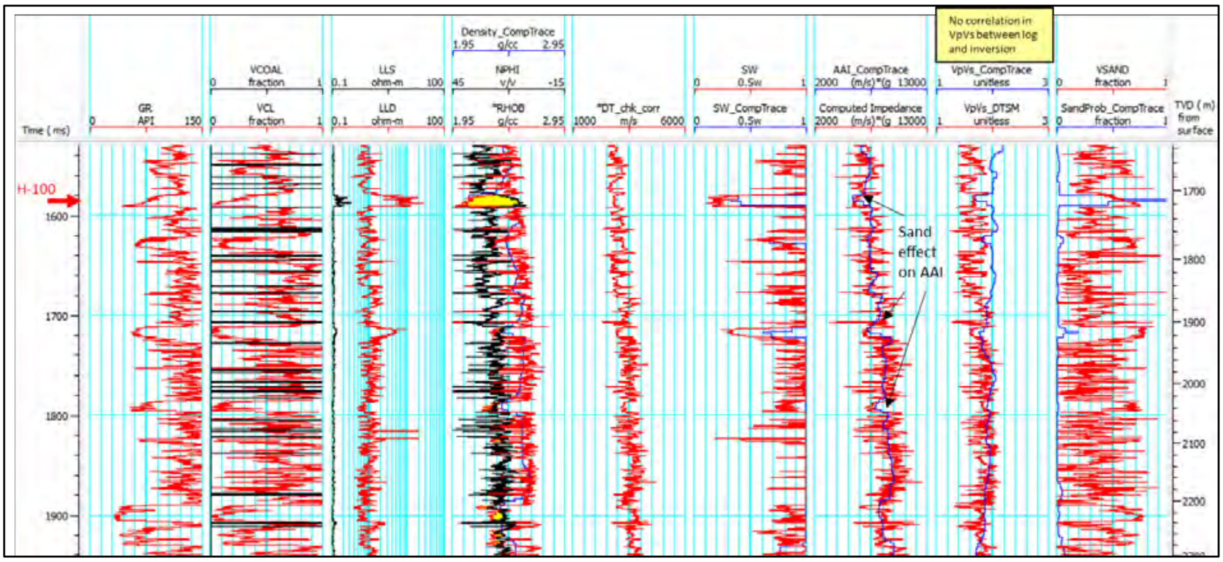


Figure 5.4: Sand identified on the AI log and AAI seismic

Figure 5.5 shows that the amplitude extraction on the gas bearing area at shallow depths can mask the amplitude between the A and B markers (Figure 5.5). The perturbed zone shows the extent to which the amplitudes are distorted at the reservoir depth. This is most likely due to imaging issues as the available 2D lines do not show such an effect.

Figure 5.6 shows the shallow gas channel limits from Figure 5.5 (A and B) projected down to the H100 reservoir depth (marked by C and D). This corridor is relatively clear on the seismic connecting B to D, however it is not so clear on the other side of the channel, i.e. A to C. If the shallow gas channels are masking amplitude responses at the H100 reservoir depth, then we would expect to see a relatively dimmer area between the C and D markers. However, the RMS extraction in Figure 5.6 around a shallower horizon marker (Horizon A) at ca 1250 ms shows no significant change in amplitude response from within to outside the gas effect corridor, and it looks like the shallow gas response is effectively healed before reaching the reservoir level.

Therefore, we conclude that the acoustic impedance inversion can highlight the extent of the H100 reservoir sands, and the shallow gas channels have negligible impact on the amplitudes at the reservoir depth. It is more likely that the dimmer amplitudes indicate that the reservoir is water bearing in that area.

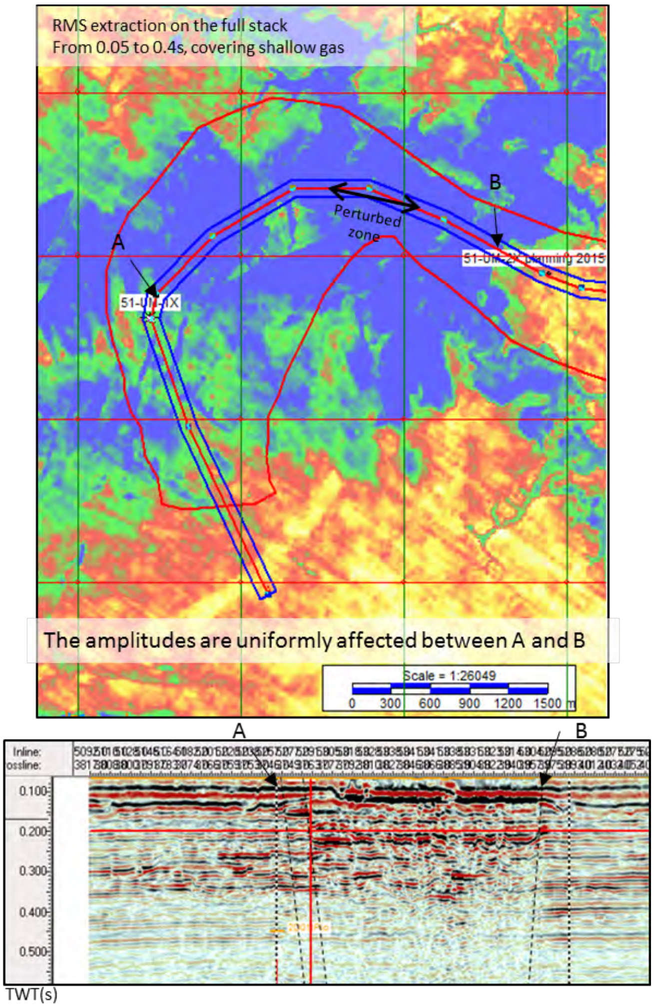


Figure 5.5: Effect of shallow gas channels at shallow levels

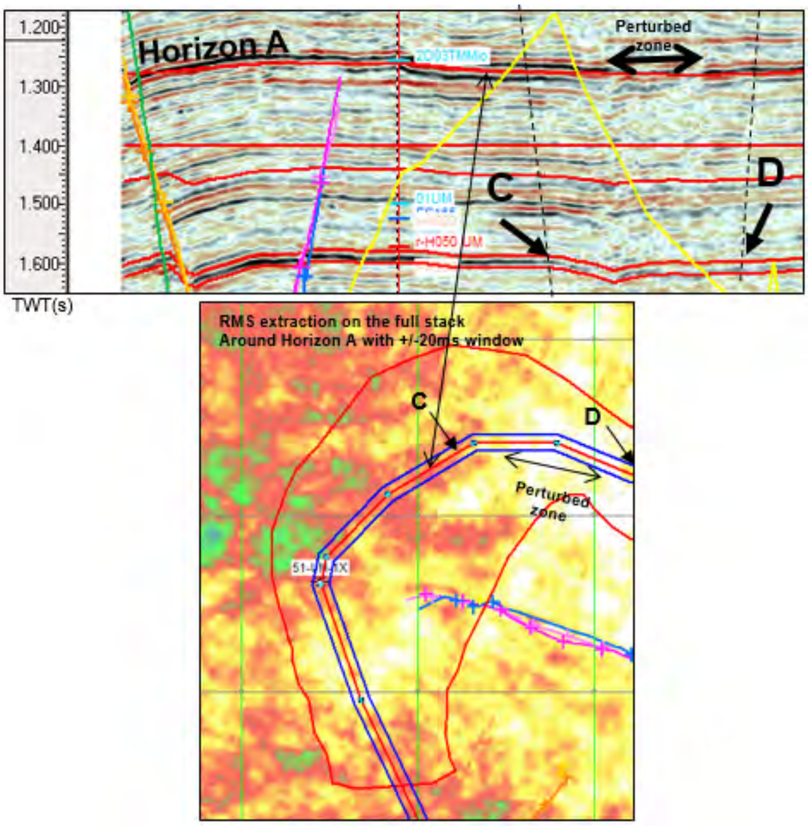


Figure 5.6: RMS extraction at a shallower marker (Horizon A)

5.3. Petrophysical Evaluation

Well 51-UM-1X was evaluated over the interval from 1,300 mMD to total depth at ~2,750 mMD. The evaluation assumed the interval was a sand/shale sequence. A comparison with the operator's and ERCE's computed petrophysical curves is shown in Figure 5.7 for the H100 reservoir (operator curves are shown in blue and ERCE curves are shown in black).

5.3.1. Data available

A composite log data set was provided (Gamma Ray, Dual Laterolog Resistivity, Sonic and Density/Neutron) although no Density/Neutron data were available for 1,300 m to 1,530 m. Wireline formation pressures were also obtained but that they were not examined as part of this review.

5.3.2. Shale Volume

Shale volume was determined from the Gamma Ray, with a normal linear equation. The uranium free Gamma Ray curve was used where available with the end-points based on the 2nd and 98th percentiles. For comparison purposes, it was also determined from the Density/Neutron cross-plot where data was available and was found to be in overall agreement with that from the Gamma Ray. A comparison with the operator derived shale volume, also primarily based on the Gamma Ray, shows good agreement overall albeit the operator shale volume being higher in the H100 reservoir sands. There is a distinct change in the Gamma Ray response in the sands above and below 2,233m MD which this ERCE evaluation has considered to be due to a change in the 0% shale end point; if this assumption is incorrect and a lower end-point is used for the whole interval then the ERCE shale volume would be in closer agreement for the H100 reservoir sands.

5.3.3. **Porosity**

Effective porosity was determined from the Density/Neutron cross-plot with hydrocarbon and shale corrections applied. The mud filtrate density was based on the mud filtrate resistivity as given in the well report and the hydrocarbon density was assumed to be 0.2 g/c3. The hydrocarbon correction was based the calculated Sxo from the flushed zone resistivity tool (MSFL). Overall agreement can be observed between the operator's and the ERCE computed values with the exception of the sands between 1725 m and 2,150m where due to the operator shale volume being higher their effective porosity is lower.

5.3.4. **Water Saturation**

Water saturation was determined using the Indonesian equation. In the absence of special core analysis data, the Archie parameters of *a*, *m* and *n* were taken as 1, 1.8 and 1.8 respectively. Formation water resistivity (Rw) was determined from a Pickett plot that indicated an Rw of 0.39 ohmm at 60 °F equivalent to a formation water salinity of 18,400 mg/l NaCl which is in close agreement with the water sample obtained from DST. The shale resistivity was taken as 2.5 ohmm. The well temperature profile was based on the maximum temperatures obtained during the logging. Overall agreement can be observed between the operator's and the ERCE computed values of Sw with the main exception of the sands between 1,725m and 2,150 m, including the H100 reservoir, where due to the operator porosity being lower their water saturation is higher. An additional difference can be observed due to the operator using a higher value for the saturation exponent of 2 which would result in higher Sw values.

5.3.5. **Sums and Averages**

The same cut-offs as defined by the operator for their mid-case have been used of 40% shale volume, 10% porosity and 65% *Sw.* A visual examination of the data suggests that the definition of pay is not very sensitive to the cut-offs used.

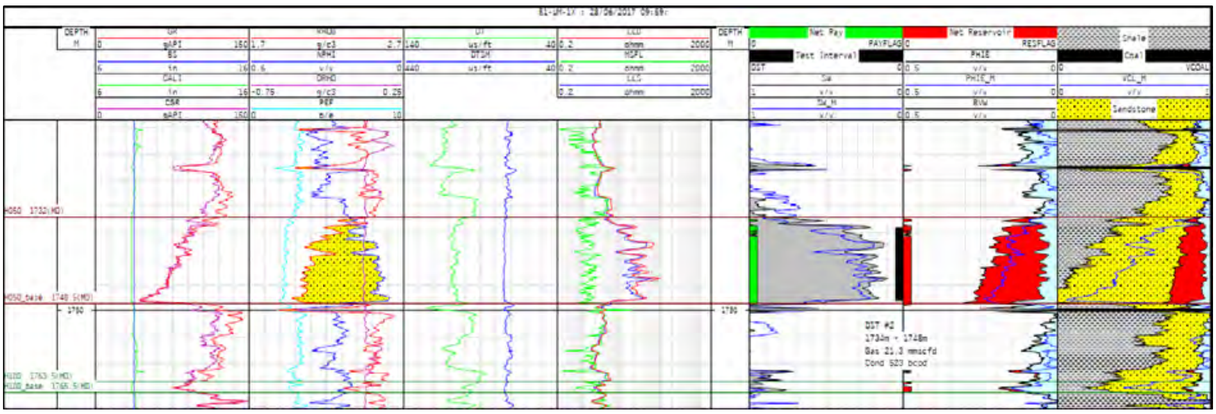


Figure 5.7: Comparison of petrophysical evaluations over the H100 reservoir in Well 51-UM-1X

5.4. Geological Evaluation

The U Minh H100 reservoir is a moderately sinuous channel-point bar system of Miocene age, trending downdip from northeast to southwest where it is folded over the U-Minh four-way dip closure structure. The channel-point bar complex is at least 12 km long and 1.3 km wide (Figure 5.2).

The wireline log character shows a fining-upwards sequence, with lower porosities in the upper sections but still hydrocarbon bearing. There is sufficient throw on the faults to the northeast and southwest to imply that, without further data, hydrocarbon bearing intervals across these faults are not proven to be connected.

5.5. Hydrocarbons Initially in Place

Hydrocarbons in place have been calculated for the gas-bearing H100 reservoir. We have used a combination structural-stratigraphic approach to calculate a range in gross rock volumes, using polygons and a gross reservoir thickness of 16.6m from Well 51-UM-1X.

The low case GRV is defined by the H100 GDT in Well 51-UM-1X at 1,722.4 mTVDSS, within the channel/point-bar complex. This GDT is approximately 1m deeper that the mapped spill point at 1,721.2 mTVDSS (Figure 5.8). This results in an area of 3.01 km^2 and a GRV of 30.1 MMm^3.

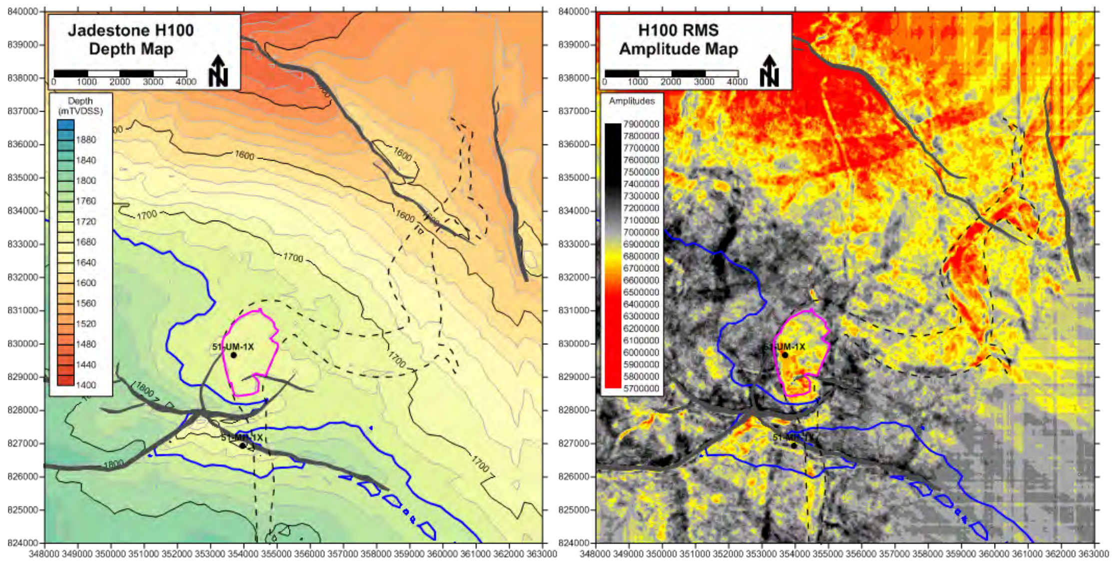


Figure 5.8: U Minh low case GRV polygon

The mid case GRV is calculated using the GWC at 1,741 mTVDSS, which conforms with the extent of the bright amplitudes to the south of Well 51-UM-1X, and using a polygon drawn around the brighter amplitudes in the channel/point-bar complex, following the main flow direction of the channel (Figure 5.9). This polygon extends up dip to the fault to the north. This results in an area of 7.28 km^2 and a GRV of 118.5 MMm^3.

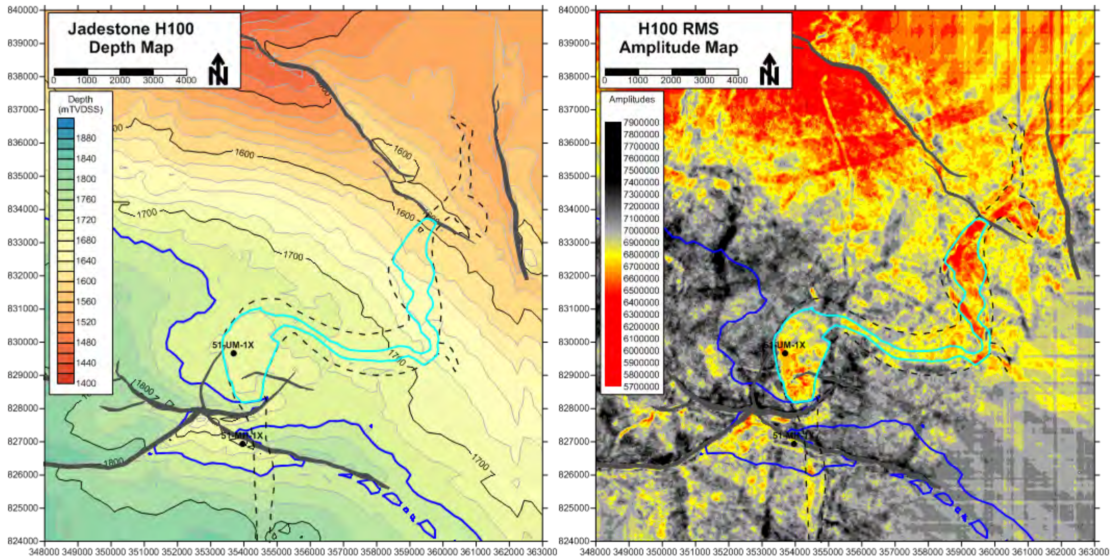


Figure 5.9: U Minh mid case GRV polygon and contact

The high case GRV is calculated using the GWC at 1,741 mTVDSS, which conforms with the extent of the bright amplitudes to the south of Well 51-UM-1X, and using a polygon that capture the whole of the channel/point-bar complex area (Figure 5.10). This polygon extends up dip to the fault to the north. This results in an area of 12.78 km^2 and a GRV of 207.3 MMm^3.

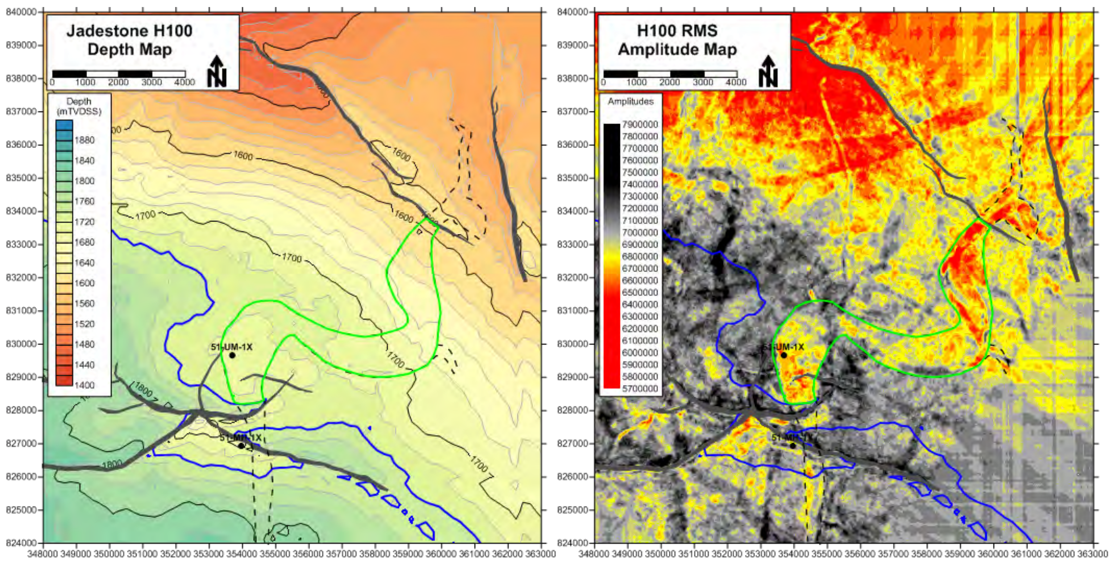


Figure 5.10: U Minh high case GRV polygon and contact

Other reservoir parameters in U Minh, with the exception of N/G, have been kept constant in the low, mid and high case estimates. Net to gross ratio is modelled inversely to account for the dimming in amplitudes away from the well, which may indicate a reduction in reservoir. The other reservoir parameters are kept constant as if reservoir sands are present then they are expected to be of similar quality to that encountered in Well 51-UM-1X. The main uncertainty is area/GRV, and this has been varied accordingly as discussed above. The input parameters for the low, best and high volumetric calculations are shown in Table 5-1. The CGR is discussed in Section 5.6.3 and used to calculate the volume of condensate in place. The resulting calculation of gas and condensate in place volumes are listed in Table 5-2.

Table 5-1: Input parameters for U Minh volumetric calculations

ERCE Deterministic	Area (km2)	GRV (MMm3)	N/G	Porosity	Sg	GEF	Recovery factor	CGR (stb/MMscf)
Low	3.01	30.1	0.9	0.218	0.760	144	0.7	22
Mid	7.28	118.5	0.8	0.218	0.760	144	0.8	27
High	12.78	207.3	0.7	0.218	0.760	144	0.9	32

Table 5-2: U Minh and condensate gas initially in-place

	GIIP (Bscf)			CIIP (MMstb)		
	Low	Mid	High	Low	Mid	High
H100	22.8	79.9	122.3	0.5	2.2	3.9

5.6. Reservoir Engineering Evaluation

5.6.1. Well Tests and Permeability

Two drill stem tests were carried out in the discovery Well 51-UM-1X. One of these, DST#2 was carried out over the H-100 reservoir, the subject of this evaluation. The test was carried out in January 1997 over a perforated interval of 14m from 1,734 to 1,748 mMD.

The zone was perforated and initially flowed for 34 minutes on a 16/64" choke before bring shut in for a 1 hour 28 min initial build up. The well was then cleaned up on a 24/64" choke for 1 hour and was gradually increased until a 64/64" choke size was reached and the flow was diverted to the separator. The well was flowed for 4 hrs 30 minutes were gas flow rates and PVT samples were taken before closing the well for a 12 hour main build up. After the main build-up the well was flowed at another rate for 3 hrs where further gas rates and PVT samples were obtained. A short build up followed lasting 4 hrs 30 mins. For the final flow the well was opened on a 48/64" fixed choke and passed through the separator, where further PVT gas samples were taken. After three hours the choke was gradually increased until the pressure drop between two choke sizes was no longer significant. The final flow rate achieved was 21.3 MMscf/d, with the CO_2 level remaining at 2 to 3 % and no H2S. The maximum flow rate test lasted for 1 hr 38 mins ending with the well being shut in and killed.

ERCE was provided with a copy of the original Schlumberger testing report, which we have reviewed and summarised the results (Table 5-3). Flow rates and bottom hole flowing pressures were steady during each flow period. The well flowed at relatively high rates at small pressure drawdowns, indicating a high permeability reservoir. The CGR values reported in Table 5-3 are subject to uncertainty due to measuring limitations. We have accordingly estimated CGR values for resources estimation from PVT laboratory experimental data.

Jadestone reports a permeability of approximately 770 mD from pressure transient analysis. LR has matched the DST in an Eclipse simulator and has carried out an analytical pressure transient analysis ("PTA") using the commercial software package Saphir. The LR simulation model matches observed data with a kh product of 69,900 mDft, equating to an average permeability of 1,820 mD. The PTA undertaken by LR shows a kh of 84,100 mDft, equating to a permeability of 2,190 mD, with the likely presence of a barrier at a distance of approximately 766 ft from the well. The observed flow rates and drawdowns support the model of a high permeability reservoir. This is borne out by the mobilities from the four MDT pressure measurements made over the H-100 sands, which range from 147 to 30,000 mDft, with an average of 16,000 mDft.

Table 5-3: U Minh H-100 reservoir DST results

Flow period	Choke	BHFP (psia)	Drawdown (psia)	Qg (MMscf/d)	Qc (stb/d)	CGR (stb/MMscf)	PI (MMscf/d/psi)
Main Flow	64/64	2434	36.9	18.9	270	14	0.51
2nd flow	32/64	2460	10.9	8.5	231	27	0.78
3rd flow	48/64	2446	24.7	14.4	464	32	0.58
	112/64	2424	46.9	21.3	523	25	0.45

5.6.2. Reservoir Pressures / Fluid Contacts

The gradient from the MDT gas pressure points from the H100 reservoir and from the deeper water points intersect at 1741 mTVDSS (Figure 5.11). This GWC depth coincides with the amplitude shut off to the south of Well 51-UM-1X.

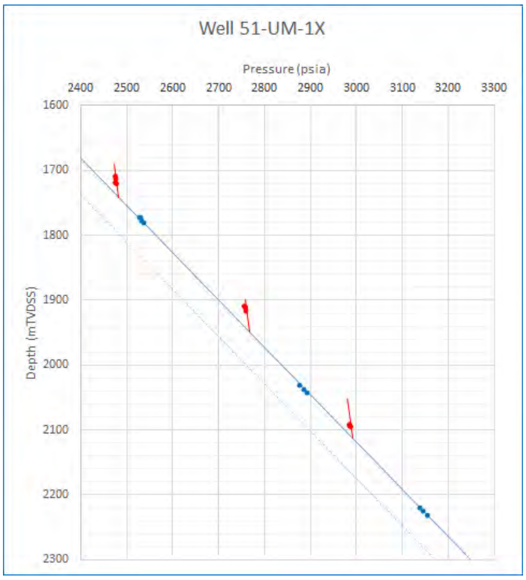


Figure 5.11: Pressure plot for Well 51-UM-1X

5.6.3. Fluid Properties

ERCE was provided with a PVT laboratory containing compositional and PVT laboratory experimental results of a recombined surface sample. The compositional analysis is shown in Table 5-4.

Table 5-4: Compositional Analysis of PVT Samples from Well 51_UM-1X

Component	Reported molar percentage
	Recombined surface sample
N2	2.10
CO2	2.93
C1	78.22
C2	7.81
C3	4.48
iC4	1.11
nC4	1.07
iC5	0.43
nC5	0.33
C6	0.39
C7	0.38
C8	0.31
C9	0.14
C10	0.10
C10+	0.20
Total	**100.00**

The PVT report contain the results of compositional analyses as well as constant composition expansion ("CCE") and constant volume depletion studies ("CVD"). ERCE has used available data to estimate fluid properties for input into the volumetric estimates (Table 5-5). The reservoir pressure is 2,477 psia at a depth of 1,710 mTVDSS and the reservoir temperature is 221 °F.

The gas in the H-100 reservoir of U Minh is fairly lean, but richer in condensate that the Nam Du reservoir, with a condensate yield at initial conditions expected to be in the range of 22 to 32 stb/MMscf. The CCE experiment shows a dew point pressure of 2,215 psia, only 262 psia below the initial pressure, but with very little liquid drop-out occurring below the dew point pressure. The CVD experiment confirms this, with very little change in the composition of produced fluid at each incremental pressure step of the depletion study, suggesting that condensate yield does not change significantly as the pressure depletes, which in turn suggests that the condensate recovery factor will not be significantly smaller than that the gas recovery factor.

The gas contains approximately 5.0% of non-hydrocarbons (2.1% nitrogen and 2.9% carbon dioxide).

Table 5-5: Gas properties for U Minh H-100 reservoir

U Minh				
Item	Units	Low	Best	High
GEF:	(scf/rcf)	137	144	151
CGR:	(stb/MMscf)	22	27	32
Dry gas shrinkage:		2.3%	2.8%	3.3%
Non-HC gas fraction:		5.0%	5.0%	5.0%

5.6.4. Development Scenarios and Recovery Factors

The operator is considering the development of U Minh together with Nam Du. The development concepts are described under Section 4.6.4.

In 2017 LR completed a reservoir simulation study and report which included conceptual development plans for both fields. In the case of U Minh, LR simulated a two-well development. LR coupled the simulator to a GAP model that included the various options for surface pipe networking associated with the different development scenarios.

ERCE has reviewed the simulation model prepared by LR and finds it an reasonable representation of the field in all respects. The LR simulation model estimates the recovery factor to be 89%, at an abandonment pressure of 200 psia. Refinement of the model and forecasts will be required once the development plan has been finalised.

As numerical simulation models constructed in the pre-development phase before being calibrated by production data frequently overestimate recovery, ERCE has used a value of 90% for the High case (Table 5-6). We have used 80% for the Best case and 70% for the Low case. The spread reflects uncertainty in the development plan and the practical abandonment pressure that will be achieved.

Table 5-6: Recovery factor assumptions for U Minh H-100 reservoir

U Minh			
Item	Low	Best	High
Gas RF:	70%	80%	90%
Condensate RF:	65%	74%	83%

5.6.5. Contingent Resources

ERCE has estimated Contingent Resources for H-100 of U Minh (Table 5-7) by applying our estimates of recovery factors to our estimates of GIIP (Table 5-2) probabilistically. The estimates of Contingent Resources are shown in Table 5-7 and Table 5-8.

Table 5-7: U Minh Contingent Gas Resource

	Contingent Resource (Bscf)		
	1C	2C	3C
H100	16.0	63.9	110.1

Table 5-8: U Minh Contingent Condensate Resource

	Contingent Resource (MMstb)		
	1C	2C	3C
H100	0.3	1.6	3.25

5.6.6. Chance of Development

In May 2018, Jadestone received approval from Vietnam's Ministry of Industry and Trade of its ODP for the Nam Du and U Minh gas fields. The approval serves as a formal starting point for the development of these fields. Front end engineering and design ("FEED") work and negotiations of a gas sales agreement are due to begin imminently. In light of the recent approval, we have assigned a chance of development of 85%.

6. Tho Chu Discovery, Block 51, Vietnam

6.1. Discovery Description

The Tho Chu discovery is located within the boundaries of the Block 51 PSC ("Block 51") in the Malay-Tho Chu Basin, approximately 200 km offshore Vietnam in a water depth of 64 m (Figure 1.3). The field was discovered in 2012 by exploration Well 51-TC-1X and later appraised in 2014 by Well 51-TC-2X. Block 51 has separate expiry dates for crude oil and gas, which are June 2035 and June 2040 respectively. Jadestone holds a net working interest of 70% in Block 51. The remaining 30% working interest is currently held by PVEP. However, effective May 2017, PVEP relinquished its 30% working interest in the block. The registration of this change is still pending.

In October 2012, Well 51-TC-1X was drilled to a total depth of 3,185 mMD and discovered a total of 55 hydrocarbon pay reservoirs (53 gas/condensate and 2 oil) within a sequence of stacked Lower to Middle Miocene reservoirs deposited in a fluvial to marginal marine environment. Gas bearing reservoirs have a variable CO_2 content, ranging from 10 to 80%. The discovery is located in the hanging wall of a major fault zone that defines its eastern boundary.

In March 2014, Well 51-TC-2X was drilled approximately 7 km to the north on a second structural crest. The well was drilled to a total depth of 3,114 mMD and penetrated 17 hydrocarbon pay reservoirs (all gas/condensate) over the same Miocene interval as Well 51-TC-1X.

Given the style of deposition it is likely that stratigraphic compartmentalisation exists within the Tho Chu field. It is also possible that the structural crests penetrated by Wells 51-TC-1X and 51-TC-2X form distinct accumulations that are separated by the structural saddle between them. A relay ramp in the fault zone to the east appears to be open at shallower levels, meaning stratigraphic trapping would be required to link the accumulations penetrated at each well. However, at deeper levels the relay ramp is more likely to be breached, leading to the possibility of larger, fault bound 3-way dip closures that include both wells.

At present, no development plan has been submitted for the Tho Chu discovery and Contingent Resources are consequently classified as Development Unclarified.

6.2. Geophysical Evaluation

The Tho Chu discovery is covered by a 323 km^2 3D seismic survey acquired in 2010. This was reprocessed in 2011 to produce a PSTM (pre-stack time migrated) volume. This was again reprocessed in 2013 as a PSDM (pre-stack depth migrated) volume and updated in 2014 using controlled beam migration ("CBM") to incorporate velocity data acquired in Well 51-TC-2X. Later in 2014, Geotrace reprocessed the seismic dataset using a bandwidth extension ("BE").

6.2.1. Seismic Interpretation

The BE volumes provide the basis for Jadestone's seismic interpretation of horizons and faults. In total, seven major seismic horizons are mapped across the Tho Chu field and used in the estimation of resources (Figure 6.1, Figure 6.2). ERCE has reviewed the interpretation of these horizons in time and found it to be acceptable.

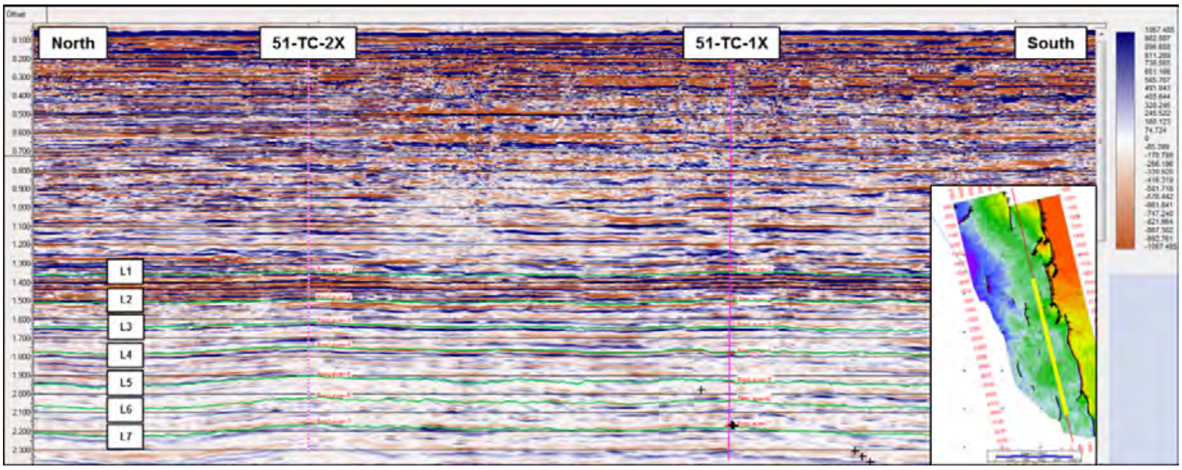


Figure 6.1: Inline 1469 through Tho Chu wells on BE hiloFULL volume

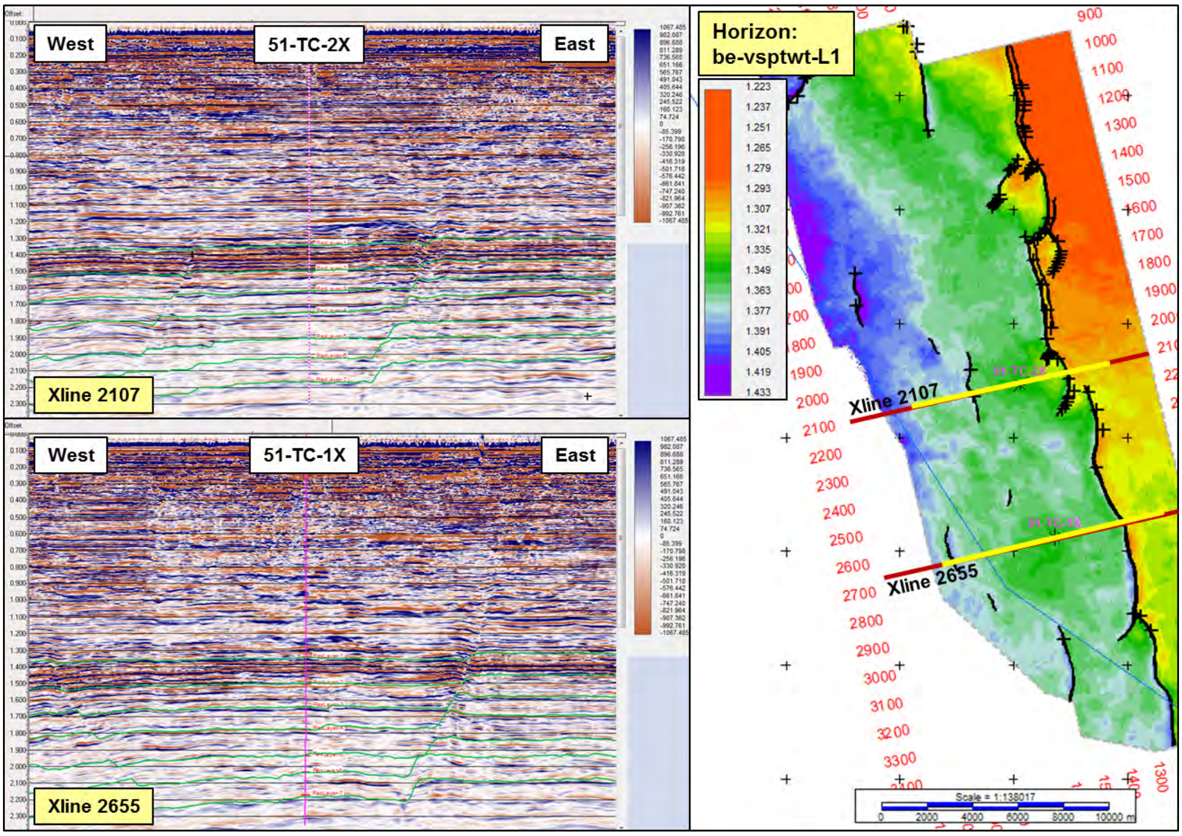


Figure 6.2: Crosslines 2107 (51-TC-2X) and 2655 (51-TC-1X) on BE hiloFULL volume

6.2.2. Depth Conversion

Sonic log data from each well, as well as VSP data from Well 51-TC-2X were used to derive a velocity model. A layered V0-k model (MSL to L1, L1 to L5 and L5 to L8) was used to depth convert the seven major seismic horizons (Figure 6.3). The compaction factors were determined using the VSP data and were fixed; values of V0 were optimised for each layer to minimise errors at the wells.

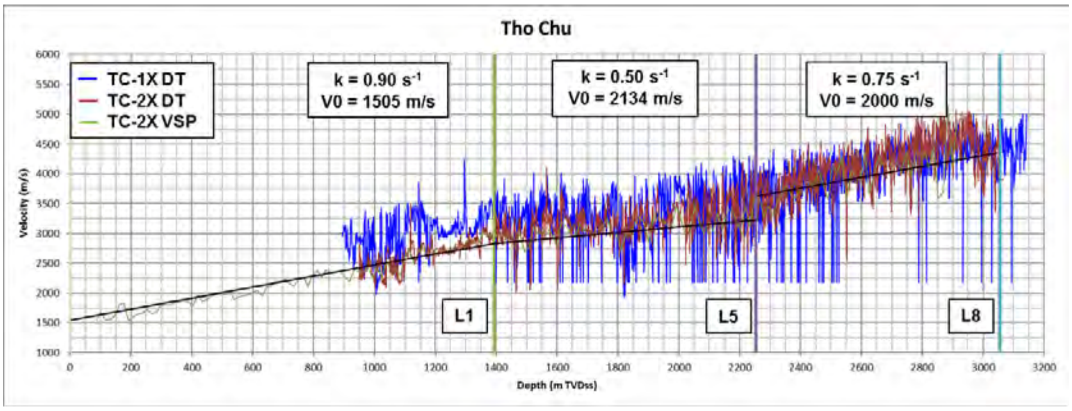


Figure 6.3: Layered V0-k velocity model used in depth conversion

The operator velocity model uses a polynomial function fitted to the VSP data from Well 51-TC-2X and thus creates a generally lower relief structure. Using the ERCE velocity model, it is possible to create separate 4-way dip closures around each well, which could explain the differences in the distribution of hydrocarbons (Figure 6.4). ERCE has used its own set of depth structure maps in the estimation of in-place volumes.

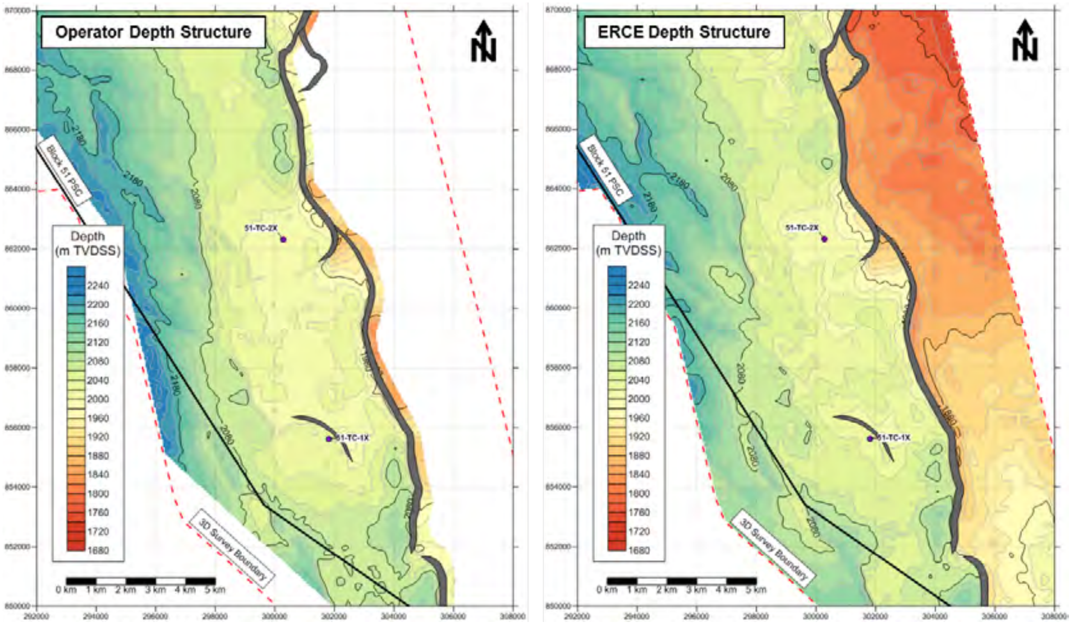


Figure 6.4: Comparison of depth structure maps at top L4 reservoir (C.I. = 20 m)

6.2.3. Seismic Inversion

Seismic inversion studies have been performed on the Tho Chu seismic data in an attempt to better understand reservoir and hydrocarbon distribution away from well control. A number of inversion products were produced including acoustic impedance ("AI"), density, Vp/Vs, sand probability and projection volumes. A combination of these volumes was used by the previous operator, Mitra Energy, to define best and high case deterministic gross rock volumes for individual reservoir zones. In the majority of cases this led to a negatively skewed distribution of resource volumes between the 1C and 3C cases.

ERCE has reviewed the seismic inversion study to evaluate its reliability in mapping reservoir and hydrocarbons away from well control. Reservoir sands in Tho Chu are softer than the background shale and thus distinguishable based on their relative AI values (Figure 6.5). The sand and shale trends approach in shallow intervals as the water saturation, and so the bulk modulus, increases. This leads to uncertainty in the differentiation of sands and shales at shallower intervals.

A comparison of the AAI volume against the calculated AI log in Well 51-TC-1X shows that whilst the AAI volume is able to predict the general trend of the calculated log, it is unable to differentiate between thin sand, shale or coal layers due to a lack of resolution (Figure 6.6).

Although sands, coals and shales can be differentiated on the impedance log, the impedance range in the inverted AAI values shows a significant overlap, supporting the hypothesis that the AAI volume is not a reliable tool in predicting lithology away from well control (Figure 6.7).

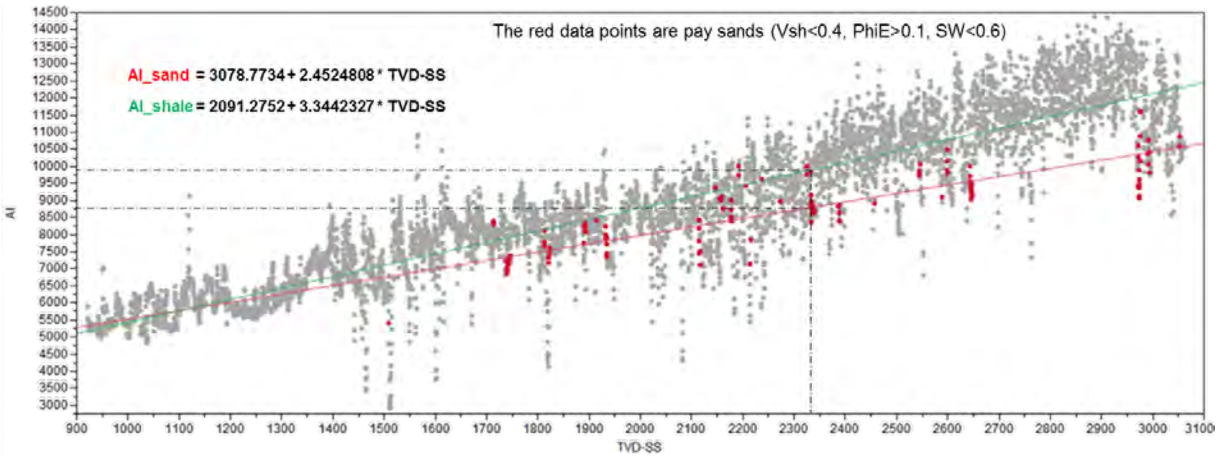


Figure 6.5: Acoustic impedance trends for shales and pay sands for Well 51-TC-1X

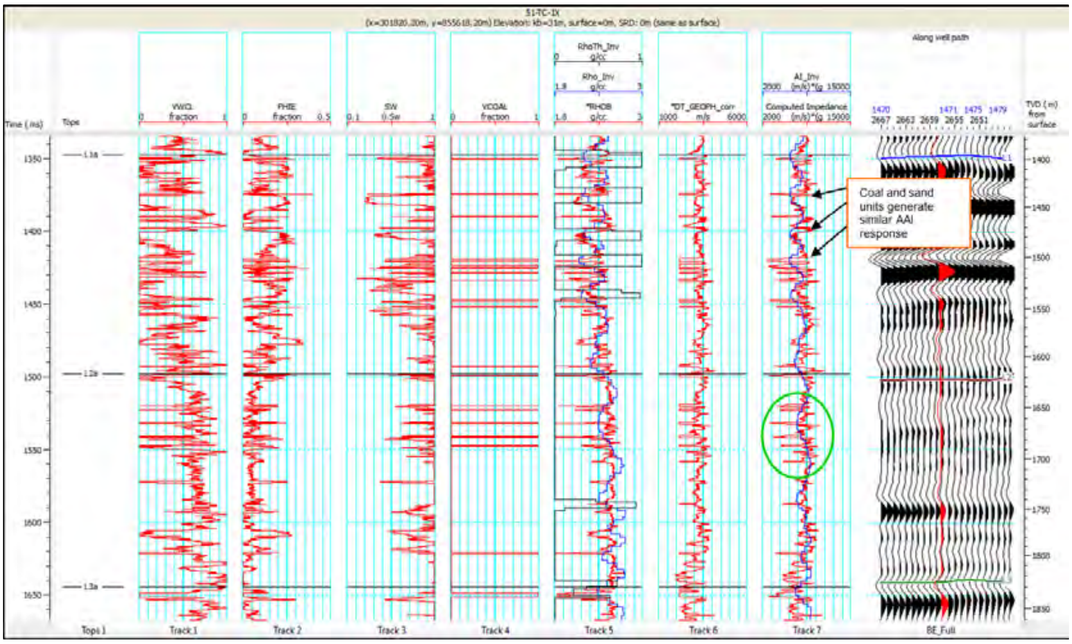


Figure 6.6: Comparison of AI and density volumes against the measured logs in Well 51-TC-1X

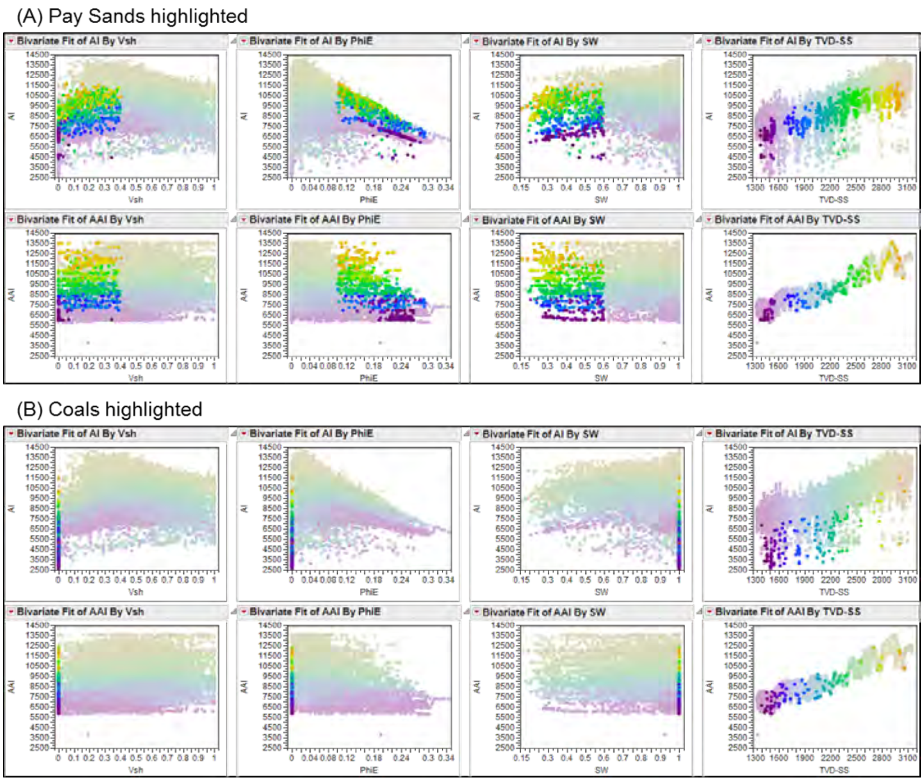


Figure 6.7: Crossplots of AI and AAI against reservoir properties for (A) pay sands and (B) coals in Wells 51-TC-1X and 51-TC-2X. Shading shows true vertical depth

The other inversion volumes used are functions of acoustic impedance and, as such, carry an additional uncertainty arising from the scatter in these relationships. If we are not able to reliably use the acoustic impedance volume to interpret lithology away from wells then it goes to say that all subsequent volumes are equally, if not more, unreliable. This is evident in Figure 6.6, which compares the density log to the density volume.

6.3. Petrophysical Evaluation

Well 51-TC-1X was evaluated over the interval from 1,425 mMD to total depth (3,185 mMD) and Well 51-TC-2X was evaluated over the interval from 975 mMD to total depth (3,114 mMD). The evaluation assumed the intervals evaluated were a sand/shale sequence. A comparison of the operator's and ERCE's computed petrophysical curves is shown in Figure 6.8 for the L4 reservoirs in Well 51-TC-1X (operator curves are shown in blue and ERCE curves are shown in black).

6.3.1. Data available

A composite log dataset was provided which included Gamma Ray, Array Induction Resistivity, Sonic, Density and Neutron logs. Wireline formation pressures were also obtained but they were not examined as part of this evaluation. Nuclear Magnetic Resonance and ECS data was also obtained on Well 51-TC-2X but these data were not available.

6.3.2. Shale Volume

Shale volume was determined from the Gamma Ray, with a normal linear equation. The uranium free Gamma Ray (HCGR) curve was used where available with the end-points based on the 2nd and 98th percentiles; the same parameters were used for the complete analysed interval. The exception was on Well 51-TC-1X where the LWD Gamma Ray was used below 3,035 mMD. A comparison with the operator derived shale volume, based on the Gamma Ray and Density/Neutron cross-plot, shows good agreement overall albeit with the operator shale volume being approximately 10% higher in the sands between 2,200 and 3,050 mMD in Well 51-TC-1X. In practice the difference in shale volume over this section appears to have minimal impact on the results.

6.3.3. Porosity

Effective porosity was determined using from the Density/Neutron with shale corrections applied. Hydrocarbon corrections were not applied as it was considered that the gas effect on the Density and Neutron tools was self-compensating in this case. The mud filtrate density was assumed to be 0.9 g/cc (as the well was drilled with an oil-based mud). Good overall agreement can be observed between the operator's and ERCE's computed values and the computed values in Well 51-TC-2X also agree with the sidewall core porosity values.

6.3.4. Water Saturation

Water saturation was determined using the Indonesian equation. In the absence of special core analysis data, the Archie parameters of *a*, *m* and *n* were taken as 1.0, 1.8 and 2.0 respectively. Formation water resistivity for Well 51-TC-1X was determined from a Pickett plot that indicated an Rw of 0.40 ohmm at 60^{o}F equivalent to a formation salinity of 18,000 mg/l NaCl; the same value was used for Well 51-TC-2X down to 1,900 m MD. Below this depth it was clear that this Rw was too low and hence a higher Rw was used (also determined from a Pickett plot) of 1.05 ohmm at 60°F equivalent to a formation water salinity of 6,300 mg/l NaCl. The operator had considered that the Rw exhibited even more variation and was applicable to both wells and which in general resulted in higher Rw values than used by ERCE. The shale resistivity was varied between 1.0 ohmm and 3.5 ohmm (increasing with depth). The well temperature profile was based on the maximum temperatures obtained during the logging. Overall agreement can be observed between the operator's and ERCE's computed values of water saturation although the operator's values are noticeably higher, by around 10-15% over the lower part of Well 51-TC-1X. This is due to the higher Rw values used by the operator.

6.3.5. Sums and Averages

The same cut-offs as defined by the operator for most of the intervals in its base case have been used of VSH<40%, PHIE>12% and Sw<70%. The operator did use different cut-offs for some of the deeper sands based on fluid mobility data and NMR permeability data. A visual examination of the data suggests that the definition of net pay is not very sensitive to the cut-offs used for the main hydrocarbon bearing intervals. The main impact in varying the cut-offs is in the inclusion (or exclusion) of the thinner beds where the logs may not fully respond to the formation properties.

Given the close agreement between the operator's and ERCE's interpretation of reservoir sums and averages, we have accepted the operator reservoir summaries for use in volumetric estimation.

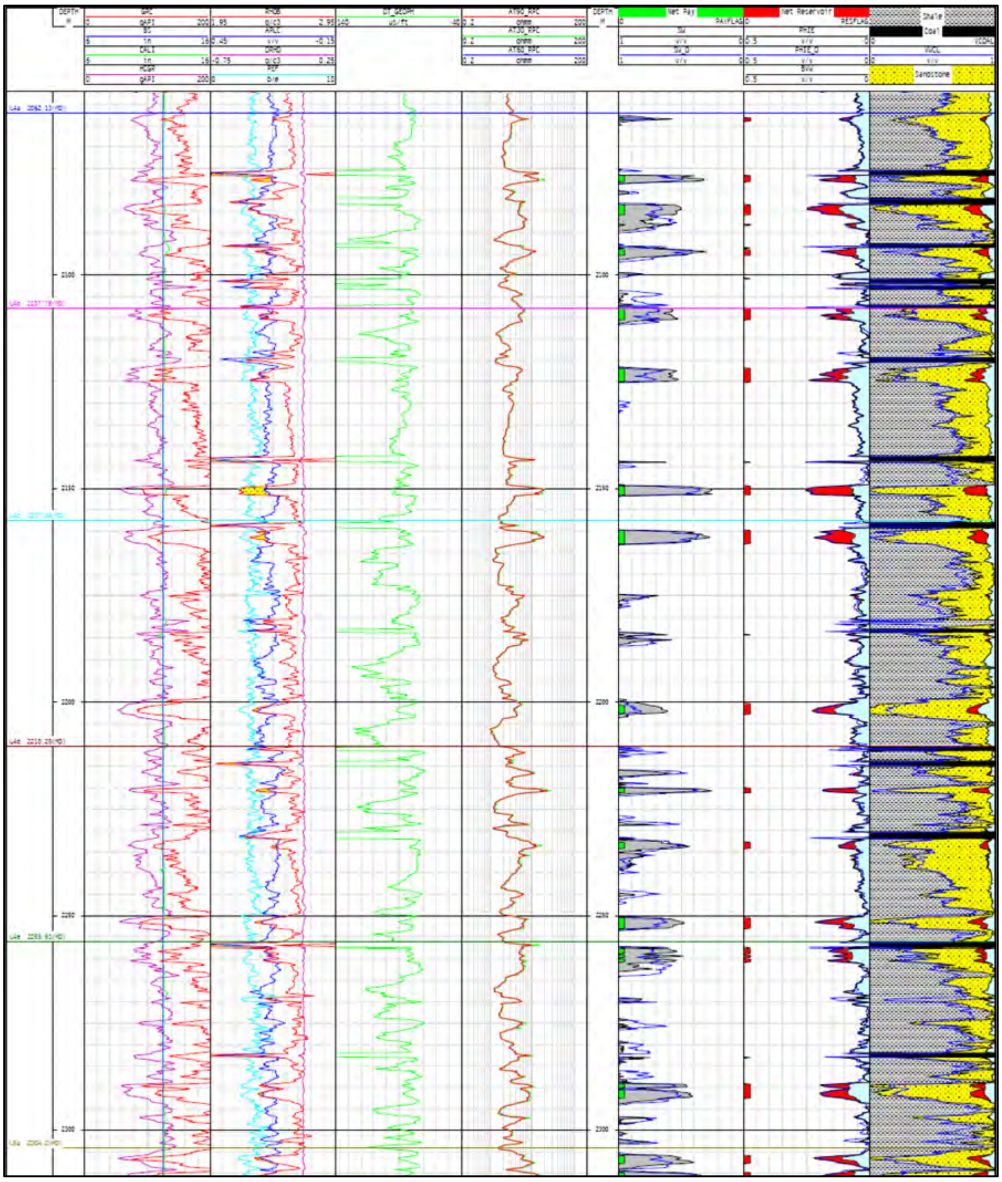


Figure 6.8: Comparison of petrophysical evaluations over L4 reservoirs in Well 51-TC-1X

6.4. Geological Evaluation

The Tho Chu reservoirs were deposited in the Lower to Middle Miocene across the F, H, I and J Groups. The depositional environment ranges from fluvial to marginal marine. Reservoir sands are typically thin (1-5 m) and are separated by flooding surfaces that are thought to act as seals. An abundance of coals deposited throughout the Lower to Middle Miocene interval allow for a robust stratigraphic correlation (Figure 6.9).

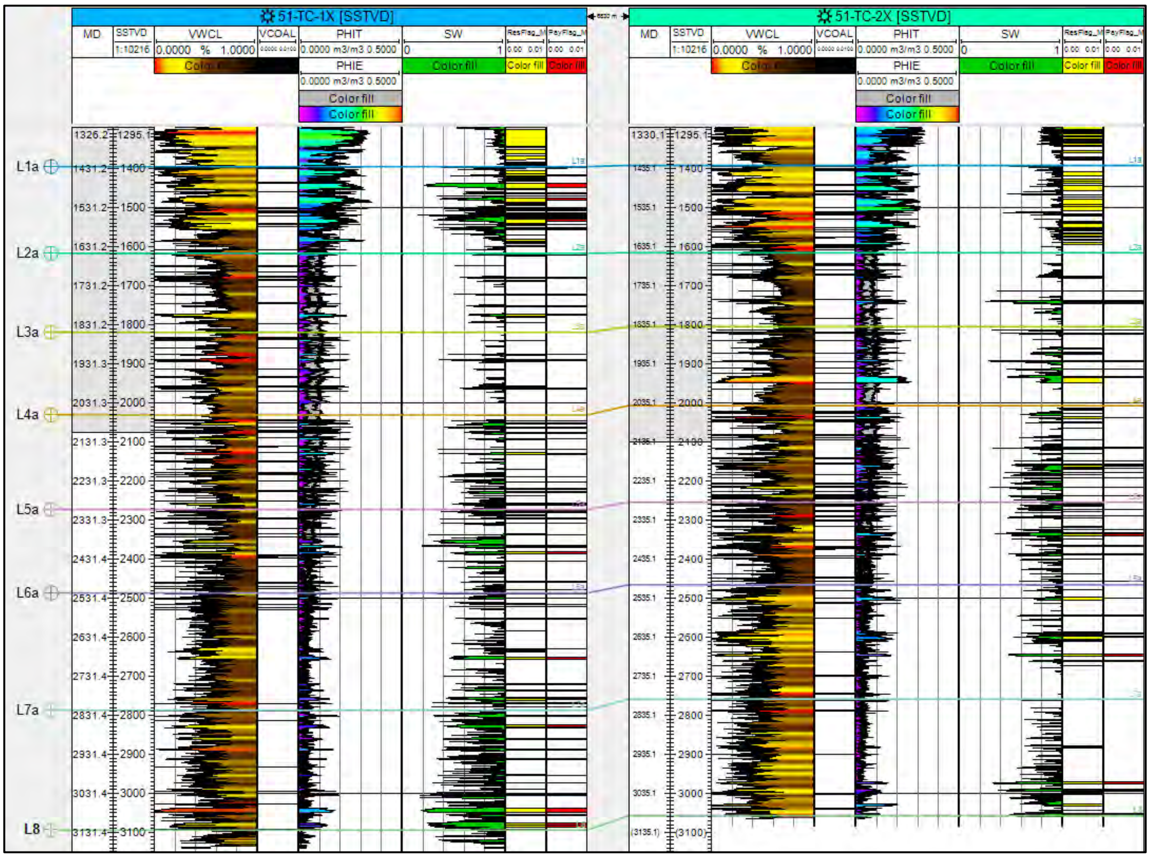


Figure 6.9: Reservoir correlation between Wells 51-TC-1X and 51-TC-2X

The wireline character of individual reservoirs varies according to their depositional environment. Point bars deposited in fluvial settings show sharp bases and a fining-upward character, culminating in silts, shales and occasionally coals. Coastal plain deposits such as crevasse splays and overbanks appear to be common and can show a very variable wireline character. More deltaic deposits such as mouth bars show a coarsening-upward character and are more likely to be succeeded by coals.

The reservoir zonation scheme in Tho Chu is complex, with individual reservoir sands thought to have separate hydrocarbon columns. For simplicity, individual reservoirs are grouped into sub-zones, with as many as ten individual reservoirs grouped together (Table 6-1). This correlation scheme has been reviewed by ERCE and accepted in all places apart from the L7 reservoirs. The revision is based on correlation of flooding surfaces and coals and considers zone thicknesses with respect to the depositional environment (Figure 6.10).

Table 6-1: Reservoir zonation scheme, highlighted sub-zones contribute to volumetric evaluation

Zone	Sub-Zone	Reservoirs
L1	1a	14_2, 14_3, 14_5
	1b/1c	14_6, 14_9, 15_0a
	1d	15_0b, 15_2
	1e	15_3, 15_4, 15_5a
	1f	15_5b, 15_7
	1g	15_8, 15_9, 16_0
	1h	16_0, 16_1, 16_4
L2	2a	16_5
	2b	17_0, 17_1
	2c	17_5
	2d	17_7, 17_8, 18_0
	2e	18_2
L3	3a	18_6, 18_7
	3b*	19_0, 19_1, 19_4, 19_6
	3c	19_8, 19_9
	3d	20_1, 20_2
L4	4a	20_6, 20_7, 20_8, 20_9a, 20_9b, 21_0
	4b	21_2, 21_4, 21_6
	4c*	21_6, 21_7, 21_8, 21_9, 22_2, 22_3a, 22_3
	4d	22_2, 22_3, 22_5a, 22_5b
	4e	22_5b, 22_6, 22_8b, 22_9, 23_0
L5	5a	23_1, 23_2, 23_3, 23_6
	5b	23_8, 23_9, 24_1, 24_3
	5c	24_5, 24_6a, 24_6b, 24_7, 24_8, 25_0a, 25_0b
L6	6a	25_1, 25_2, 25_4, 25_5a, 25_5b, 25_6, 25_8, 25_9a, 26_0
	6b	26_1, 26_2, 26_3, 26_5, 26_8, 27_0
	6c	27_2, 27_3a, 27_3b, 27_5, 27_6a, 27_6b, 27_8, 27_9, 28_0
L7	7a	28_2b, 28_4a, 28_4b, 28_5, 28_7, 28_8, 28_9, 29_1a, 29_1b, 29_2
	7b	29_4a, 29_4b, 29_6, 29_8, 30_0, 30_1, 30_3, 30_4
	7c	30_6, 30_8, 30_9, 31_0a, 31_0b, 31_4, 31_5

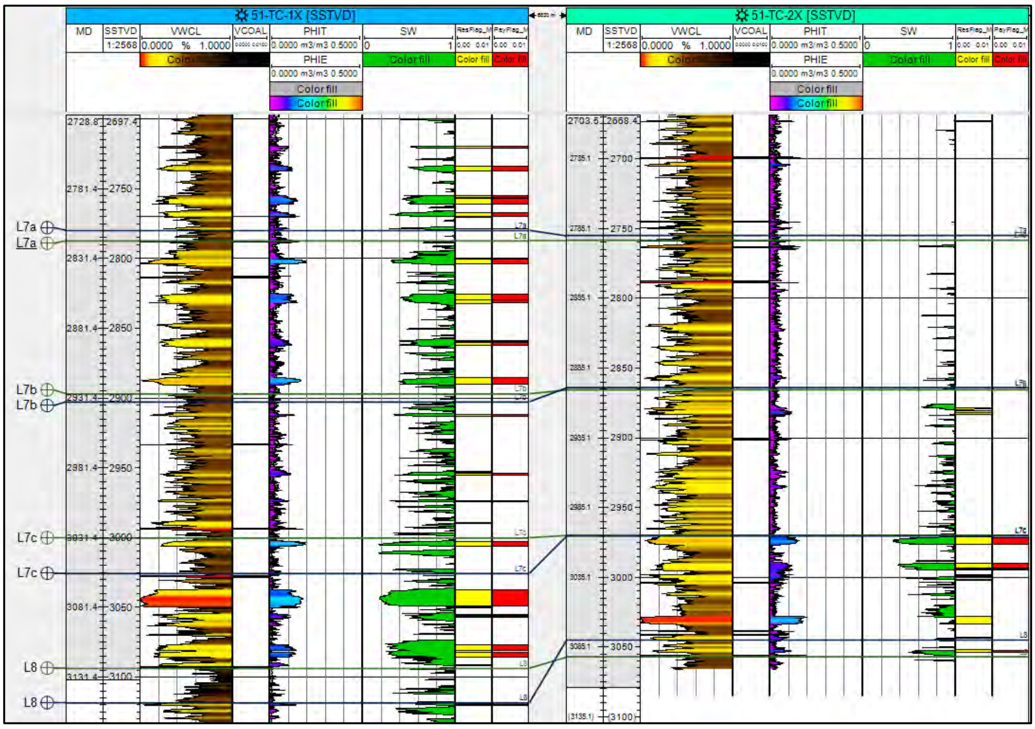


Figure 6.10: Reservoir correlation within the L7 interval (Green = ERCE, Blue = Jadestone)

Given the number of well penetrations and the thin nature of the reservoirs, their lateral continuity is a key uncertainty in the field. The MDT pressures indicate a complicated overpressure regime that shows some correlation with the measured CO_2 content of gas-bearing reservoirs. The overpressure is similar to that seen across the North Malay Basin and is thought to be caused by local gas generation and expansion within isolated systems.

6.5. Hydrocarbons Initially in Place

Hydrocarbons in place have been calculated for 24 sub-zones and are reported separately for each well. Two sub-zones (L4a (TC-1X) and L7a (TC-1X)) contain oil bearing reservoirs, proven by MDT sampling. All other sub-zones are assumed to contain gas and condensate only.

We have used a structural approach to calculate a range in net rock volume using areas and net thicknesses. Stratigraphic trapping was not considered due to the unreliability of seismic inversion volumes. No geometrical shape factor is applied in the calculation of net rock volume as reservoirs are thin.

The high case areas are calculated using our own depth surfaces and the spill points of each major horizon. For horizons L1 to L3, the relay ramp in the eastern bounding fault system is assumed to be open and only 4-way dip closures around each well are considered. For horizon L4 to L7, the relay ramp is assumed to be breached and sealing.

In the L4 reservoirs, MDT pressure data show Well 51-TC-2X to be up to 300 psi lower than Well 51-TC-1X, suggesting the two wells are not in communication. There is a structural saddle between the two wells that has been used to limit areas in the high case.

In the L7 reservoirs, the MDT pressure data show that the gas reservoirs are close to a hydrostatic pressure gradient from surface. Assuming a hydrostatic gradient, the maximum column height of approximately 30 m is possible at the wells. To reconcile column heights inferred by a 3-way fault sealed spill model (approximately 70 – 100 m), the L7 reservoirs would have to be under-pressured by approximately 120 psi. As this is highly unlikely, the high case areas for L7 reservoirs are based on a column height of 30 m at each well. This leads to two separate accumulations.

The low case areas for each interval are calculated using our own depth surfaces and potential gas columns demonstrated by GDTs in the wells. As most reservoirs are <5 m thick, the gas columns inferred by GDTs are very small, and likely represent a P99 gas column. The P90 gas column is calculated as a fraction of the spill column height, where that fraction (0.35) is the average of the GDT column height in the well divided by the spill column height.

Low and high case areas for layers L2, L4 and L7 are shown in Figure 6.11, Figure 6.12 and Figure 6.13 respectively.

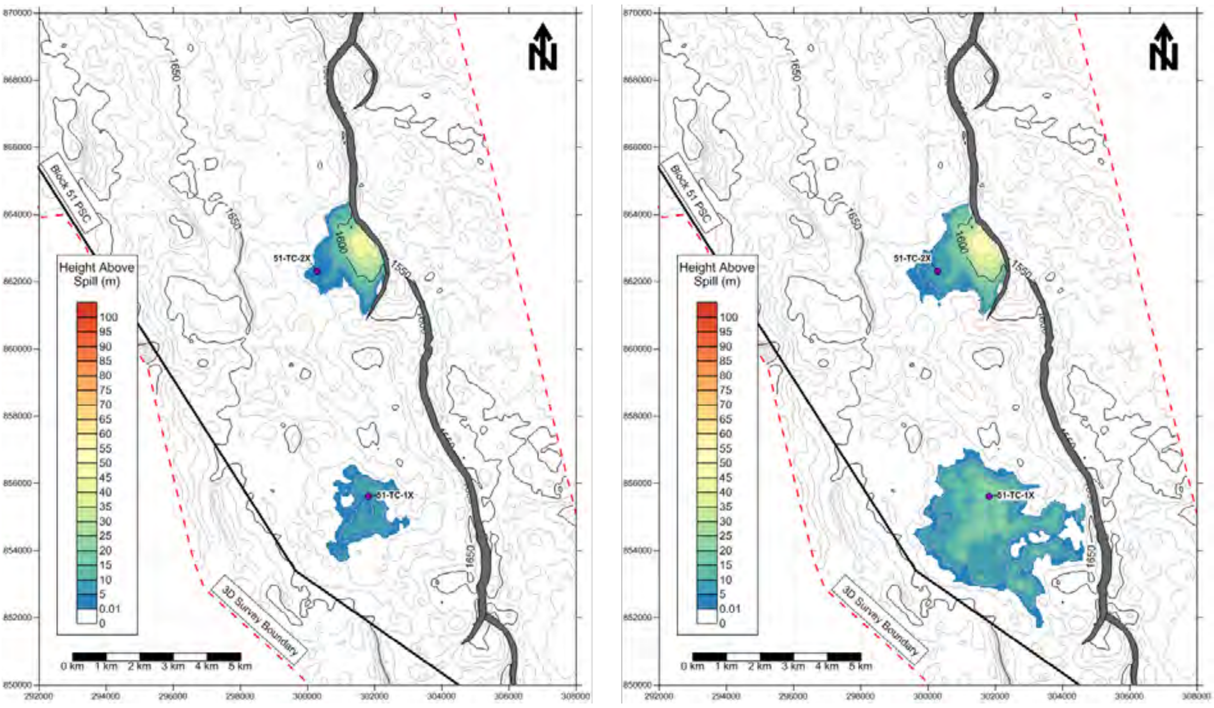


Figure 6.11: Low (left) and high (right) case areas for L2 reservoirs

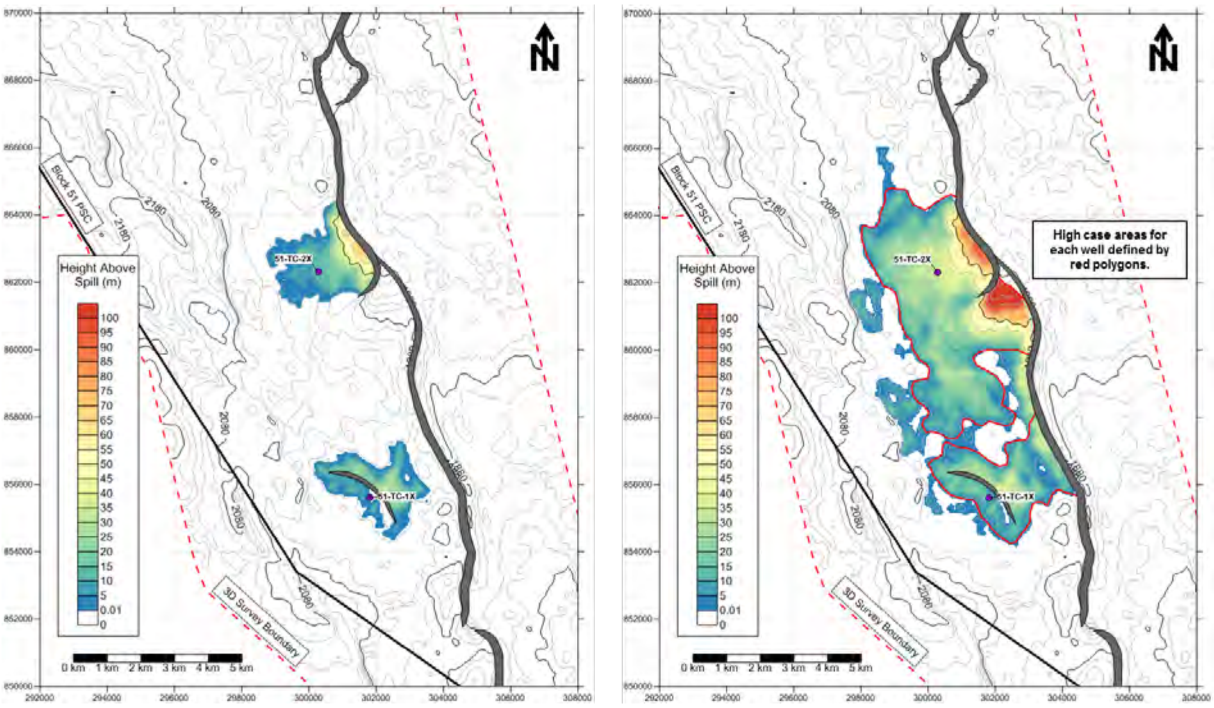


Figure 6.12: Low (left) and high (right) case areas for L4 reservoirs

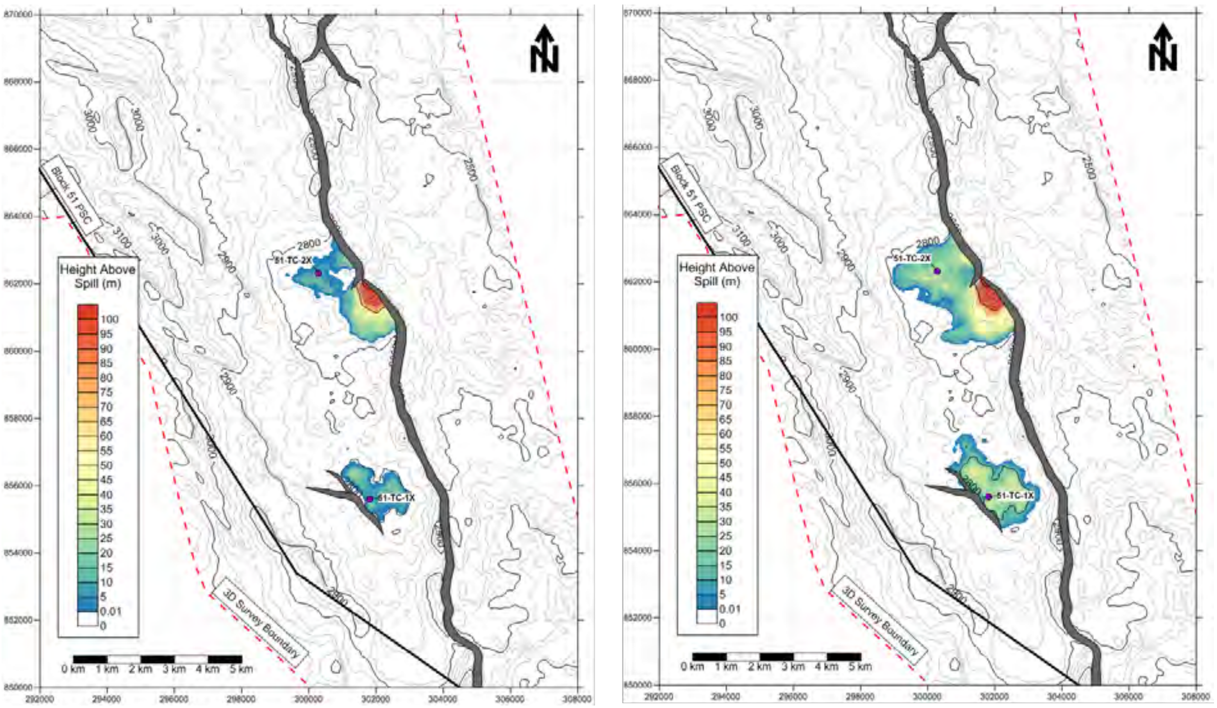


Figure 6.13: Low (left) and high (right) case areas for L7 reservoirs

The net thicknesses used to calculate net rock volume are based on interpreted values in the well and regional analogue data. The low case net thickness for each sub-zone is taken as the sum of interpreted net thickness of hydrocarbon bearing reservoirs within it. The high case uses the regional database, which suggests potential for thicker sands than have so far been penetrated in Tho Chu. The regional data has been separated into two groups based on depositional sequences; Sequence I to IX (L1 – L5) and Sequence X to XIV (L6 – L7). The standard deviation of each group has been added to the low case net pay (well based) to create a high case net thickness.

For the Monte-Carlo simulation, the low and high case areas are taken as the P90 and P10 values and a log-normal distribution is used. The low and high case net thicknesses are taken as the P90 and P10 values and a normal distribution is used.

As the net thickness is used in the calculation of net rock volume, no net to gross is used in the volumetric estimation.

Valued for porosity and water saturation are based on the operator's petrophysical analysis. The P50 case uses the operator's best estimate curves and petrophysical cut-offs. The P90 and P10 cases are then formed by applying -+10% to the P50, which is in line with the uncertainty observed in the analysis. Normal distributions are used in the Monte-Carlo simulation.

The gas expansion factors used by the operator have been evaluated and accepted for use in the P50 case. Due to the inherent complexity of the pressure and temperature regime in Tho Chu, the P90 and P10 cases are formed by applying -+10% to the P50. A normal distribution is used in the Monte-Carlo simulation. The operator has not calculated in-place oil volumes for the two reservoirs that have been tested as oil. We have estimated oil formation volume factors based on the available data for these reservoirs.

Summaries of the input distributions for gas reservoirs in zones L1 to L7 are shown in Table 6-2 to

Table 6-8. A summary of the input distributions for oil reservoirs in zones L4 and L7 is shown in Table 6-9. Probabilistic summaries of the gas and condensate initially in place and the oil and associated gas initially in place are shown in Table 6-10 and Table 6-11.

Table 6-2: Summary of Tho Chu input distributions for Monte-Carlo simulation – L1 Reservoirs

Sub-Zone	Area (km2)			Net Pay (m)			Porosity (frac)			Hydrocarbon Saturation (frac)			GEF (scf/rcf)		
	Log-Normal			Log-Normal			Normal			Normal			Normal		
	P90	P50	P10	P90	P50	P10	P90	P50	P10	P90	P50	P10	P90	P50	P10
1X_L1a	4.2	6.7	10.7	2.3	5.1	7.9	0.21	0.23	0.25	0.50	0.55	0.61	113	125	138
2X_L1a	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1X_L1b	4.2	6.7	10.7	12.6	15.4	18.2	0.20	0.22	0.24	0.35	0.39	0.43	126	140	154
2X_L1b	4.4	5.2	6.1	0.3	3.1	5.9	0.22	0.24	0.27	0.62	0.69	0.76	126	140	154
1X_L1d	4.2	6.7	10.7	8.1	10.9	13.7	0.19	0.21	0.23	0.49	0.54	0.60	133	148	163
2X_L1d	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1X_L1e	4.2	6.7	10.7	3.8	6.6	9.4	0.18	0.20	0.22	0.38	0.42	0.47	132	147	162
2X_L1e	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1X_L1f	4.2	6.7	10.7	11.8	14.6	17.4	0.17	0.19	0.21	0.48	0.53	0.59	131	145	160
2X_L1f	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1X_L1g	4.2	6.7	10.7	5.8	8.6	11.4	0.14	0.15	0.17	0.45	0.50	0.55	133	148	163
2X_L1g	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Table 6-3: Summary of Tho Chu input distributions for Monte-Carlo simulation – L2 Reservoirs

Sub-Zone	Area (km2)			Net Pay (m)			Porosity (frac)			Hydrocarbon Saturation (frac)			GEF (scf/rcf)		
	Log-Normal			Log-Normal			Normal			Normal			Normal		
	P90	P50	P10	P90	P50	P10	P90	P50	P10	P90	P50	P10	P90	P50	P10
1X_L2c	3.1	6.5	13.4	1.5	4.3	7.1	0.14	0.15	0.17	0.51	0.57	0.63	149	166	183
2X_L2c	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1X_L2d	3.1	6.5	13.4	3.4	6.2	9.0	0.17	0.18	0.20	0.28	0.31	0.35	154	171	188
2X_L2d	4.1	4.7	5.4	4.0	6.8	9.5	0.18	0.20	0.22	0.51	0.57	0.62	154	171	188

Table 6-4: Summary of Tho Chu input distributions for Monte-Carlo simulation – L3 Reservoirs

Sub-Zone	Area (km2)			Net Pay (m)			Porosity (frac)			Hydrocarbon Saturation (frac)			GEF (scf/rcf)		
	Log-Normal			Log-Normal			Normal			Normal			Normal		
	P90	P50	P10	P90	P50	P10	P90	P50	P10	P90	P50	P10	P90	P50	P10
1X_L3a	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2X_L3a	3.6	5.4	8.0	1.4	4.2	7.0	0.18	0.21	0.23	0.45	0.50	0.55	155	172	189
1X_L3b	0.5	1.6	4.7	5.6	8.4	11.2	0.19	0.21	0.23	0.40	0.44	0.49	156	173	190
2X_L3b	3.6	5.4	8.0	2.7	5.5	8.3	0.14	0.15	0.17	0.58	0.64	0.70	156	173	190
1X_L3c	0.5	1.6	4.7	2.9	5.7	8.5	0.15	0.17	0.18	0.33	0.37	0.41	162	180	198
2X_L3c	3.6	5.4	8.0	2.3	5.1	7.9	0.19	0.22	0.24	0.42	0.47	0.51	162	180	198

Table 6-5: Summary of Tho Chu input distributions for Monte-Carlo simulation – L4 Reservoirs

Sub-Zone	Area (km2)			Net Pay (m)			Porosity (frac)			Hydrocarbon Saturation (frac)			GEF (scf/rcf)		
	Log-Normal			Log-Normal			Normal			Normal			Normal		
	P90	P50	P10	P90	P50	P10	P90	P50	P10	P90	P50	P10	P90	P50	P10
1X_L4a	4.2	5.7	7.6	7.3	10.1	12.9	0.14	0.15	0.17	0.43	0.48	0.53	173	192	211
2X_L4a	5.4	10.7	21.0	0.3	3.1	5.9	0.14	0.15	0.17	0.43	0.48	0.53	173	192	211
1X_L4b	4.2	5.7	7.6	3.6	6.4	9.2	0.18	0.20	0.22	0.40	0.44	0.49	182	202	222
2X_L4b	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1X_L4c	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2X_L4c	5.4	10.7	21.0	5.0	7.8	10.6	0.16	0.18	0.19	0.41	0.46	0.50	185	206	227
1X_L4d	4.2	5.7	7.6	4.4	7.2	10.0	0.12	0.14	0.15	0.38	0.43	0.47	176	195	215
2X_L4d	5.4	10.7	21.0	2.4	5.2	8.0	0.15	0.17	0.19	0.43	0.47	0.52	176	195	215
1X_L4e	4.2	5.7	7.6	9.1	11.9	14.7	0.13	0.15	0.16	0.43	0.48	0.53	171	190	209
2X_L4e	5.4	10.7	21.0	0.9	3.7	6.5	0.13	0.15	0.16	0.43	0.48	0.53	171	190	209

Table 6-6: Summary of Tho Chu input distributions for Monte-Carlo simulation – L5 Reservoirs

Sub-Zone	Area (km2)			Net Pay (m)			Porosity (frac)			Hydrocarbon Saturation (frac)			GEF (scf/rcf)		
	Log-Normal			Log-Normal			Normal			Normal			Normal		
	P90	P50	P10	P90	P50	P10	P90	P50	P10	P90	P50	P10	P90	P50	P10
1X_L5a	3.5	8.0	18.2	2.1	4.9	7.7	0.14	0.16	0.17	0.41	0.45	0.50	188	209	230
2X_L5a	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1X_L5b	3.5	8.0	18.2	15.6	17.3	18.9	0.11	0.13	0.14	0.49	0.55	0.60	194	216	238
2X_L5b	4.6	8.6	16.1	8.5	10.2	11.9	0.15	0.16	0.18	0.40	0.44	0.48	194	216	238

Table 6-7: Summary of Tho Chu input distributions for Monte-Carlo simulation – L6 Reservoirs

Sub-Zone	Area (km2)			Net Pay (m)			Porosity (frac)			Hydrocarbon Saturation (frac)			GEF (scf/rcf)		
	Log-Normal			Log-Normal			Normal			Normal			Normal		
	P90	P50	P10	P90	P50	P10	P90	P50	P10	P90	P50	P10	P90	P50	P10
1X_L6a	3.0	7.6	19.2	9.6	11.3	12.9	0.11	0.12	0.13	0.38	0.42	0.46	208	231	254
2X_L6a	4.5	9.0	17.9	1.7	3.3	5.0	0.12	0.13	0.14	0.34	0.38	0.42	208	231	254
1X_L6b	3.0	7.6	19.2	7.5	9.2	10.8	0.10	0.12	0.13	0.39	0.43	0.48	200	222	244
2X_L6b	4.5	9.0	17.9	8.2	9.9	11.6	0.13	0.14	0.16	0.37	0.42	0.46	200	222	244
1X_L6c	3.0	7.6	19.2	12.4	14.1	15.7	0.10	0.11	0.12	0.46	0.52	0.57	193	214	235
2X_L6c	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Table 6-8: Summary of Tho Chu input distributions for Monte-Carlo simulation – L7 Reservoirs

Sub-Zone	Area (km2)			Net Pay (m)			Porosity (frac)			Hydrocarbon Saturation (frac)			GEF (scf/rcf)		
	Log-Normal			Log-Normal			Normal			Normal			Normal		
	P90	P50	P10	P90	P50	P10	P90	P50	P10	P90	P50	P10	P90	P50	P10
1X_L7a	1.7	2.5	3.6	15.3	17.0	18.6	0.11	0.12	0.13	0.47	0.52	0.58	185	205	226
2X_L7a	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1X_L7b	1.7	2.5	3.6	7.5	9.2	10.8	0.11	0.12	0.14	0.37	0.41	0.45	184	204	224
2X_L7b	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1X_L7c	1.7	2.5	3.6	23.3	25.0	26.6	0.11	0.12	0.13	0.54	0.60	0.66	182	202	222
2X_L7c	3.5	4.6	6.1	9.9	11.6	13.2	0.11	0.12	0.13	0.54	0.60	0.66	182	202	222

Table 6-9: Summary of Tho Chu input distributions for Monte-Carlo simulation – Oil Reservoirs

Sub-Zone	Area (km2)			Net Pay (m)			Porosity (frac)			Hydrocarbon Saturation (frac)			Bo (rb/stb)		
	Log-Normal			Log-Normal			Normal			Normal			Normal		
	P90	P50	P10	P90	P50	P10	P90	P50	P10	P90	P50	P10	P90	P50	P10
1X_L4c	4.2	5.7	7.6	2.6	5.4	8.2	0.16	0.17	0.19	0.50	0.55	0.61	1.94	2.04	2.14
1X_L7a	1.7	2.5	3.6	3.5	5.2	6.8	0.11	0.12	0.13	0.47	0.52	0.58	1.75	1.84	1.93

Table 6-10: Probabilistic summary of gas & condensate in place

Sub-Zone	GIIP (Bscf)				Condensate IIP (MMstb)			
	P90	P50	P10	Mean	P90	P50	P10	Mean
1X_L1a	7.5	18.2	36.3	20.5	0.1	0.4	1.0	0.5
2X_L1a	-	-	-	-	-	-	-	-
1X_L1b	25.2	42.8	72.9	46.6	0.4	1.0	2.2	1.2
2X_L1b	4.2	13.8	26.6	14.8	0.1	0.3	0.8	0.4
1X_L1d	23.5	41.8	73.1	45.8	0.4	1.0	2.2	1.2
2X_L1d	-	-	-	-	-	-	-	-
1X_L1e	9.0	18.7	35.3	20.8	0.1	0.4	1.0	0.5
2X_L1e	-	-	-	-	-	-	-	-
1X_L1f	29.3	50.2	85.0	54.5	0.5	1.2	2.5	1.4
2X_L1f	-	-	-	-	-	-	-	-
1X_L1g	12.0	22.4	40.3	24.7	0.2	0.5	1.2	0.6
2X_L1g	-	-	-	-	-	-	-	-
1X_L2c	4.3	13.5	34.7	17.3	0.1	0.3	1.0	0.4
2X_L2c	-	-	-	-	-	-	-	-
1X_L2d	5.1	13.2	31.4	16.4	0.1	0.3	0.9	0.4
2X_L2d	12.1	21.4	32.6	22.0	0.2	0.5	1.0	0.6
1X_L3a	-	-	-	-	-	-	-	-
2X_L3a	5.0	13.6	27.4	15.2	0.1	0.3	0.8	0.4
1X_L3b	2.2	7.2	22.9	10.8	0.0	0.2	0.6	0.3
2X_L3b	7.5	16.8	31.3	18.5	0.1	0.4	0.9	0.5
1X_L3c	0.9	3.3	11.0	5.1	0.0	0.1	0.3	0.1
2X_L3c	7.1	16.7	31.8	18.4	0.1	0.4	0.9	0.5
1X_L4a	17.2	27.5	42.2	28.8	0.3	0.7	1.3	0.7
2X_L4a	4.3	16.1	42.3	20.7	0.1	0.4	1.2	0.5
1X_L4b	11.6	22.4	37.6	23.7	0.2	0.5	1.1	0.6
2X_L4b	-	-	-	-	-	-	-	-
1X_L4c	-	-	-	-	-	-	-	-
2X_L4c	20.7	46.7	101.7	55.9	0.3	1.1	2.9	1.4
1X_L4d	8.8	15.8	25.8	16.7	0.1	0.4	0.8	0.4
2X_L4d	10.8	29.0	68.6	35.7	0.2	0.7	1.9	0.9
1X_L4e	20.3	31.2	47.1	32.7	0.3	0.8	1.5	0.8
2X_L4e	5.2	17.7	45.3	22.6	0.1	0.4	1.2	0.6
1X_L5a	6.2	19.3	51.8	25.7	0.1	0.4	1.4	0.6
2X_L5a	-	-	-	-	-	-	-	-
1X_L5b	31.1	72.5	168.2	90.0	0.5	1.7	4.7	2.3
2X_L5b	23.8	46.9	92.4	53.9	0.4	1.1	2.6	1.4
1X_L6a	13.7	35.5	91.8	46.8	0.2	0.8	2.5	1.2
2X_L6a	4.3	11.2	26.3	13.8	0.1	0.3	0.7	0.4
1X_L6b	10.3	26.7	69.7	35.3	0.2	0.6	1.9	0.9
2X_L6b	19.7	41.1	85.1	48.3	0.3	1.0	2.4	1.2
1X_L6c	17.0	43.7	112.4	57.2	0.3	1.0	3.1	1.5
2X_L6c	-	-	-	-	-	-	-	-
1X_L7a	12.2	18.8	28.7	19.8	0.2	0.5	0.9	0.5
2X_L7a	-	-	-	-	-	-	-	-
1X_L7b	5.2	8.2	12.9	8.7	0.1	0.2	0.4	0.2
2X_L7b	-	-	-	-	-	-	-	-
1X_L7c	20.4	31.1	47.5	32.8	0.3	0.8	1.5	0.8
2X_L7c	18.5	26.6	38.1	27.7	0.3	0.7	1.2	0.7
Total	**436**	**901**	**1828**	**1048**	**7.0**	**21.3**	**52.4**	**26.7**

Table 6-11: Probabilistic summary of oil & associated gas in place

Sub-Zone	STOIIP (MMstb)				Assoc. GIIP (Bscf)			
	P90	P50	P10	Mean	P90	P50	P10	Mean
1X_L4c	4.1	8.8	15.2	9.3	5.6	12.1	21.3	12.9
1X_L7a	1.5	2.7	4.4	2.9	1.6	2.7	4.6	3.0
Total	**5.6**	**11.4**	**19.6**	**12.2**	**7.1**	**14.8**	**25.9**	**15.9**

6.6. Reservoir Engineering Evaluation

6.6.1. Well Test Analyses and permeability

No well tests were carried out in either of the two wells intersecting the Tho Chu discovery. However, gas samples were recovered with the MDT tool along with pressure measurements and downhole fluid analysis. Mobilities were estimated by the wireline contractor from pre-test drawdowns of the MDT toll measurements. ERCE screened the MDT data and selected a total of 17 points from each well covering the reservoirs of interest and with satisfactory quality. The mobility of these 34 points ranges from 2 to 570 mD/cP with an average value of 136 mD/cP. There is no noticeable distinction in the values of mobility between the two wells. Conversion of the mobility data to permeability is unreliable as the fluid viscosity required for the calculation is affected by the presence of filtrate and reservoir fluids. Nonetheless, MDT mobilities suggest that reservoir quality is variable and that the sands are poorer quality than the reservoirs of U Minh H-100 and Nam Du Channel 22 reservoirs.

6.6.2. Reservoir Pressures / Fluid Contacts

ERCE selected 17 MDT pressure measurements from each of the two wells, Well 51-TC-1X and Well 51-TC-2X spanning the reservoir intervals of interest (Figure 6.14).

Both wells show similar trends with normal (hydrostatic) pressure down to a depth of approximately 1,700 m TVDSS. Below this depth, the formations are over pressured, to varying degrees. Between approximately 1,700 and 1,800 m there appears to be increasing over pressure in both wells, although all the pressure measurements made over this interval in are in gas bearing sands, so the degree of over pressure of the aquifer is not clear. Between approximately 1,900 and 2,100 mTVDSS, the wells show a reasonably consistent overpressure of approximately 550 psia, based on measurements taken in water zones. Below this depth over the interval from 2,150 to 2,200 mTVDSS, the degree of over pressure is variable, with Well 51-TC-1X over pressure apparently increasing to approximately 650 psia, (although these measurements are not in water bearing intervals) and the over pressure in Well 51-TC-2X decreasing to approximately 250 psia. From 2,200 mTVDSS to approximately 2,450 mTVDSS, both wells apparently show similar degrees of over pressure, approximately 250 psia. Over pressure increases to approximately 400 psia below 2,450 mTVDSS before reducing to what appears to be normal pressure below a depth of approximately 2,900 mTVDSS.

Because the over pressure is variable and there are limited measurements in the water, it is not possible to use the MDT data to identify GWCs in most of the sands. ERCE has used the pressure measurements to guide our estimates of maximum gas column height in our High cases that might be possible without contradicting the measured data.

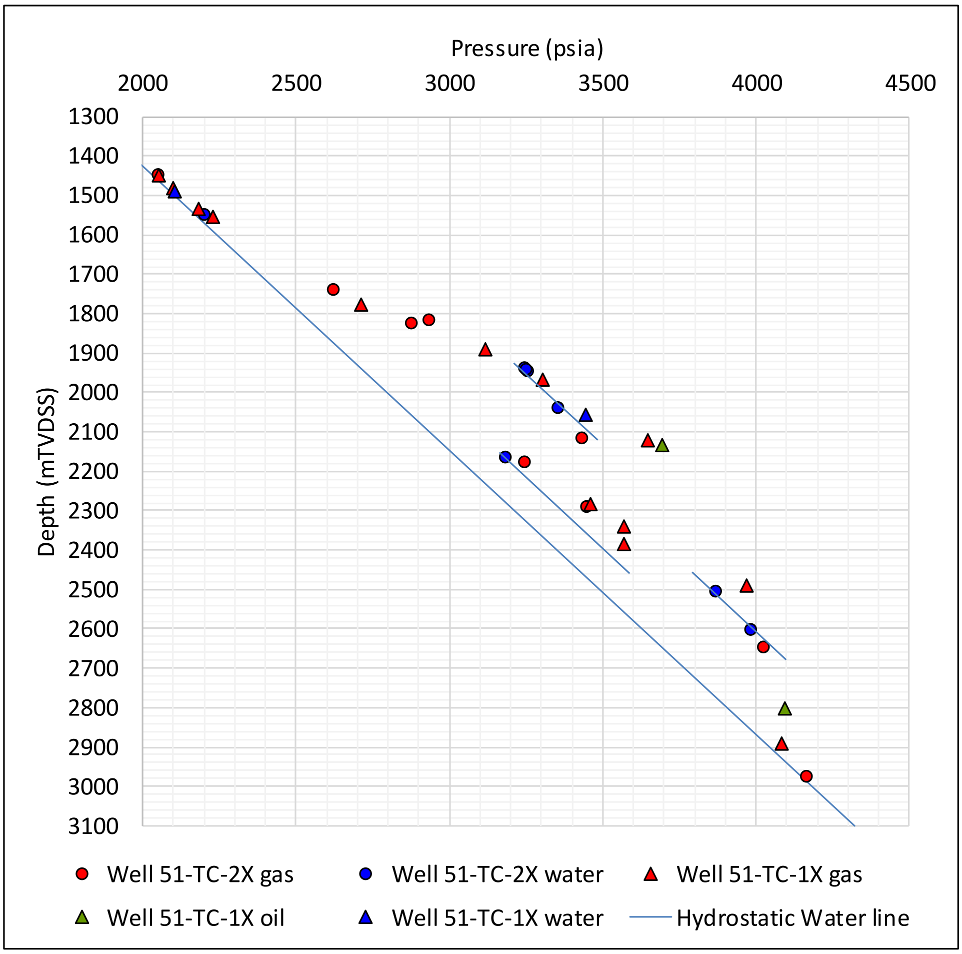


Figure 6.14: Tho Chu MDT reservoir pressure measurements

6.6.3. Fluid Properties

ERCE was provided with a PVT analysis report for Well 51-TC-1X containing compositional analyses and limited PVT experiments for two bottom hole samples, a gas sample from a depth of 2,150.5 mMD and an oil sample from a depth of 2,161.6 mMD. For Well 51-TC-2X, ERCE was provided with a PVT report detailing basic analyses of six downhole samples. The dataset includes estimates of CO_2 content and CGRs. However, all samples were contaminated, with liquid contamination levels of 24 to 78%.

In addition, downhole analysis of reservoir fluids was carried out using the InSitu Fluid Analyzer tool ("IFA"). ERCE was provided with IFA data for Well 51-TC-1X. The IFA tool extracts a reservoir fluid sample and carries out a basic downhole analysis of hydrocarbons, C1, C2, C3-C5 and C6+, an estimate of the GOR and CO_2 content, as well as other physical properties. ERCE was also provided with a diagram showing CO_2 content from an IFA tool run in Well 51-TC-2X. These data have been used to estimate the concentration of CO_2 in the samples. ERCE has used these estimates of CO_2 content to adjust our estimates of Contingent Resources for non- hydrocarbon components.

Fluid properties in the many Tho Chu reservoirs are poorly defined. In particular, the condensate yield is unknown. Reported CGRs from 5 samples from Well 51-TC-2X range widely between 14 and 46 stb/MMscf, with an average of 23 stb/MMscf. However, these are all badly contaminated. CGRs estimated from the IFA analyses of Well 51-TC-1X over the reservoirs of interest range widely between 17 and 73 stb/MMscf, with an average of 38 stb/MMscf. There does not appear to be any relationship between CGR and depth. The data are of questionable reliability and we have therefore not estimated a value of CGR for each individual reservoir interval. We have used an overall range of CGR of 10, 25 and 40 stb/MMscf which we have applied probabilistically to the estimates of GIIP.

Our estimates for the GOR of the two oil bearing reservoirs are based on the two samples taken. For the L4c and L7a reservoirs the GOR is 1,388 scf/stb and 1,034 scf/stb respectively. These values are ranged by +-10% to give P90 and P10 estimates.

6.6.4. **Development Scenarios and Recoverable Volumes**

There is currently no conceptual development plan for Tho Chu. ERCE has therefore estimated ranges of recovery factors that bracket the range of uncertainty that we would expect from a field of this nature. We have used recovery ranges of 50%, 63% and 80% for gas; 25%, 35% and 50% for condensate; 10%, 17% and 30% for oil; and 20%, 32% and 50% for associated gas. Each of these distributions is log-normal.

6.6.5. **Contingent Resources**

The sales gas specification for the Tho Chu field allows 20% CO_2 content. Our estimates of recoverable including CO_2, sales gas and condensate are shown in Table 6-12. Our estimates of recoverable oil, associated gas including CO_2 and associated sales gas are shown in Table 6-13.

6.6.6. **Chance of Development**

It is considered that further appraisal of the Tho Chu discovery is required before any decision on development can be taken. This appraisal would likely take the form of a third well located between the two existing wells. Until the field is further appraised, no Reserves Assessment Report (“RAR”) submission can be considered.

The high CO_2 content of the Tho Chu reservoirs poses a challenge to any development, with specialist facilities required to process produced gas. Development of the Tho Chu discovery must wait for the Block B-O Mon Gas Project, which comprises the development of a gas field and, importantly, a pipeline that will initiate gas production from neighbouring blocks. The Block B-O Mon gas Project has begun the tendering process for offshore facilities and has received technical and commercial bids. An FID on the project is due in late 2018.

ERCE has assigned a chance of development of 40% to the Tho Chu discovery.

Table 6-12: Tho Chu gas & condensate Resource

Sub-Zone	Gas Resource - inc CO2 (Bscf)				CO2	Gas Resource - no CO2 (Bscf)				Sales Gas - 20% CO2 (Bscf)				Condensate Resource (MMstb)			
	1C	2C	3C	Mean	Content	1C	2C	3C	Mean	1C	2C	3C	Mean	1C	2C	3C	Mean
1X_L1a	4.6	11.4	23.7	13.1	66%	1.5	3.9	8.1	4.5	1.9	4.8	10.1	5.6	0.0	0.1	0.4	0.2
2X_L1a	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1X_L1b	15.2	27.0	48.1	29.9	67%	5.0	8.9	15.9	9.9	6.2	11.1	19.9	12.3	0.1	0.4	0.8	0.4
2X_L1b	2.6	8.6	17.4	9.5	67%	0.9	2.8	5.7	3.1	1.1	3.6	7.2	3.9	0.0	0.1	0.3	0.1
1X_L1d	14.1	26.2	48.2	29.3	83%	2.4	4.5	8.2	5.0	3.0	5.6	10.2	6.2	0.1	0.4	0.8	0.4
2X_L1d	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1X_L1e	5.5	11.8	23.2	13.4	75%	1.4	2.9	5.8	3.3	1.7	3.7	7.2	4.2	0.0	0.2	0.4	0.2
2X_L1e	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1X_L1f	17.6	31.5	56.2	34.9	75%	4.4	7.9	14.1	8.7	5.5	9.9	17.6	10.9	0.1	0.4	1.0	0.5
2X_L1f	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1X_L1g	7.2	14.1	26.6	15.8	77%	1.7	3.2	6.1	3.6	2.1	4.1	7.6	4.6	0.1	0.2	0.4	0.2
2X_L1g	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1X_L2c	2.6	8.5	22.5	11.1	66%	0.9	2.9	7.7	3.8	1.1	3.6	9.6	4.7	0.0	0.1	0.4	0.2
2X_L2c	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1X_L2d	3.1	8.3	20.4	10.5	62%	1.2	3.2	7.7	4.0	1.5	3.9	9.7	5.0	0.0	0.1	0.3	0.2
2X_L2d	7.3	13.4	21.8	14.1	62%	2.8	5.1	8.3	5.3	3.5	6.4	10.3	6.7	0.1	0.2	0.4	0.2
1X_L3a	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2X_L3a	3.0	8.5	17.8	9.7	36%	1.9	5.4	11.4	6.2	2.4	6.8	14.3	7.8	0.0	0.1	0.3	0.1
1X_L3b	1.4	4.5	14.8	6.9	26%	1.0	3.3	10.9	5.1	1.3	4.2	13.7	6.4	0.0	0.1	0.2	0.1
2X_L3b	4.6	10.5	20.6	11.8	26%	3.4	7.8	15.2	8.7	4.2	9.7	19.0	10.9	0.0	0.1	0.3	0.2
1X_L3c	0.6	2.1	7.1	3.3	22%	0.4	1.6	5.5	2.5	0.5	2.0	6.9	3.2	0.0	0.0	0.1	0.0
2X_L3c	4.3	10.5	20.9	11.8	22%	3.4	8.2	16.3	9.2	4.2	10.2	20.4	11.5	0.0	0.1	0.3	0.2
1X_L4a	10.2	17.3	28.2	18.5	24%	7.8	13.1	21.4	14.0	9.7	16.4	26.8	17.5	0.1	0.2	0.5	0.3
2X_L4a	2.7	10.1	27.4	13.3	24%	2.0	7.7	20.9	10.1	2.5	9.6	26.1	12.6	0.0	0.1	0.4	0.2
1X_L4b	7.0	14.0	24.9	15.2	29%	5.0	9.9	17.7	10.8	6.2	12.4	22.1	13.5	0.1	0.2	0.4	0.2
2X_L4b	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1X_L4c	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2X_L4c	12.6	29.4	66.2	35.8	13%	11.0	25.6	57.6	31.2	13.7	32.0	72.0	38.9	0.1	0.4	1.1	0.5
1X_L4d	5.3	9.9	17.1	10.7	15%	4.5	8.4	14.5	9.1	5.6	10.5	18.1	11.3	0.0	0.1	0.3	0.2
2X_L4d	6.6	18.2	44.5	22.9	15%	5.6	15.5	37.8	19.4	7.0	19.3	47.3	24.3	0.1	0.2	0.7	0.3
1X_L4e	12.1	19.7	31.5	21.0	51%	5.9	9.6	15.4	10.3	7.4	12.1	19.3	12.9	0.1	0.3	0.6	0.3
2X_L4e	3.2	11.2	29.4	14.5	51%	1.6	5.5	14.4	7.1	2.0	6.8	18.0	8.9	0.0	0.1	0.5	0.2
1X_L5a	3.8	12.2	33.8	16.5	69%	1.2	3.8	10.5	5.1	1.5	4.7	13.1	6.4	0.0	0.2	0.5	0.2
2X_L5a	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1X_L5b	19.0	45.7	109.4	57.7	80%	3.8	9.1	21.9	11.5	4.8	11.4	27.4	14.4	0.2	0.6	1.7	0.8
2X_L5b	14.5	29.6	60.4	34.5	80%	2.9	5.9	12.1	6.9	3.6	7.4	15.1	8.6	0.1	0.4	1.0	0.5
1X_L6a	8.4	22.3	59.6	29.9	80%	1.7	4.5	11.9	6.0	2.1	5.6	14.9	7.5	0.1	0.3	0.9	0.4
2X_L6a	2.6	7.1	17.1	8.8	80%	0.5	1.4	3.4	1.8	0.7	1.8	4.3	2.2	0.0	0.1	0.3	0.1
1X_L6b	6.3	16.8	45.0	22.6	15%	5.4	14.3	38.3	19.2	6.7	17.9	47.8	24.0	0.1	0.2	0.7	0.3
2X_L6b	12.0	25.9	55.5	30.9	15%	10.2	22.0	47.1	26.3	12.8	27.5	58.9	32.9	0.1	0.3	0.9	0.5
1X_L6c	10.4	27.6	72.6	36.6	70%	3.1	8.3	21.8	11.0	3.9	10.3	27.2	13.7	0.1	0.4	1.2	0.5
2X_L6c	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1X_L7a	7.3	11.9	19.2	12.7	55%	3.3	5.3	8.6	5.7	4.1	6.7	10.8	7.1	0.1	0.2	0.3	0.2
2X_L7a	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1X_L7b	3.1	5.2	8.6	5.6	60%	1.2	2.1	3.4	2.2	1.5	2.6	4.3	2.8	0.0	0.1	0.2	0.1
2X_L7b	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1X_L7c	12.1	19.6	31.8	21.0	62%	4.6	7.5	12.1	8.0	5.7	9.3	15.1	10.0	0.1	0.3	0.6	0.3
2X_L7c	10.9	16.8	25.7	17.7	62%	4.1	6.4	9.8	6.7	5.2	8.0	12.2	8.4	0.1	0.2	0.5	0.3
Total	**264**	**567**	**1197**	**671**		**118**	**257**	**548**	**305**	**147**	**322**	**684**	**382**	**2.3**	**7.5**	**19.8**	**9.8**

Table 6-13: Tho Chu oil & associated gas Resource

Sub-Zone	Oil Resource (MMstb)				Assoc. Gas Resource (Bscf)				CO_2	Assoc. Gas Resource - no CO_2 (Bscf)				Assoc. Sales Gas - 20% CO_2 (Bscf)			
	1C	2C	3C	Mean	1C	2C	3C	Mean	Content	1C	2C	3C	Mean	1C	2C	3C	Mean
1X_L4c	0.6	1.5	3.3	1.8	1.5	3.8	7.8	4.3	34%	1.0	2.5	5.2	2.9	1.3	3.1	6.5	3.6
1X_L7a	0.2	0.5	1.0	0.5	0.4	0.9	1.7	1.0	44%	0.2	0.5	1.0	0.6	0.3	0.6	1.2	0.7
Total	**0.8**	**1.9**	**4.3**	**2.3**	**2.0**	**4.6**	**9.6**	**5.3**		**1.2**	**3.0**	**6.1**	**3.4**	**1.6**	**3.7**	**7.7**	**4.3**

7. Dabakan and Palendag Discoveries, SC56, Philippines

7.1. Discovery Description

The Dabakan and Palendag discoveries are located within the boundaries of the Block SC56 in the Sandakan Basin, offshore Philippines, approximately 150 km off the coast of Malaysia (Figure 1.4). The Dabakan field was discovered in 2009 by the exploration Well Dabakan-1 in a water depth of 1802m. The Palendag field was discovered in 2010 by the exploration Well Palendag-1A in a water depth of 1,937m, and sits to the east of Dabakan-1. Jadestone holds a net working interest of 25% in SC56, with the remaining 75% being held by the operator, TOTAL E&P Philippines BV. The current exploration phase in Block SC56 ends in September 2020 and the block expiry is in August 2055.

The Dabakan-1 well was drilled to a total depth of 4,813 mTVDSS. It encountered eight hydrocarbon pay reservoirs (all gas/condensate), all within Late Miocene turbidites deposited in a deep-water setting. The Dabakan discovery structure is a thrust fault-bound propagation anticlinal fold, located in the anticlinal hanging-wall of a NW-SE trending toe thrust which defines the eastern boundary (Figure 7.1).

The Palendag-1A well was drilled to a total depth of 4,724 mTVDSS. It encountered four hydrocarbon pay reservoirs (all gas/condensate), all within a slightly older Late Miocene sequence than in Well Dabakan-1. The Palendag discovery has a similar structural setting to Dabakan, associated with a separate thrust fault (Figure 7.1).

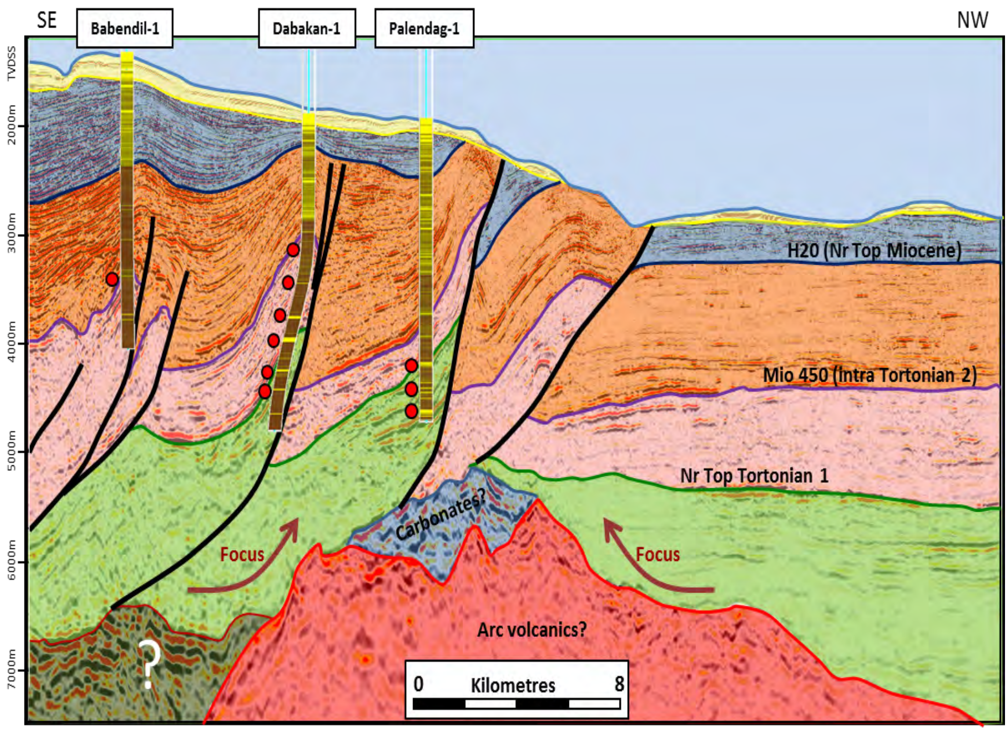


Figure 7.1: Schematic seismic line through Dabakan and Palendag

7.2. Geophysical Evaluation

The Dabakan and Palendag discoveries are covered by a 1,760 km^2 3D seismic survey acquired in 2007, alongside 2006 vintage 2D data. The 3D seismic data was most recently reprocessed in 2014 as a PSDM (pre-stack depth migrated) volume using controlled beam migration ("CBM"). The 3D seismic data are processed as near, mid, and far stacks, alongside a far-shaped impedance cube and an AVO volume. The seismic data are of good quality for interpretation, although loses some quality near to the faults. Seismic lines through Wells Dabakan-1 and Palendag-1 are shown in Figure 7.2 and Figure 7.3 respectively.

7.2.1. Seismic Interpretation

The CBM PSDM volumes provide the basis for the seismic interpretation. In total, six seismic horizons are interpreted across the Dabakan discovery and four horizons are interpreted across the Palendag discovery which are used for estimation of resources. ERCE has reviewed the interpretation of these horizons in depth and finds them acceptable.

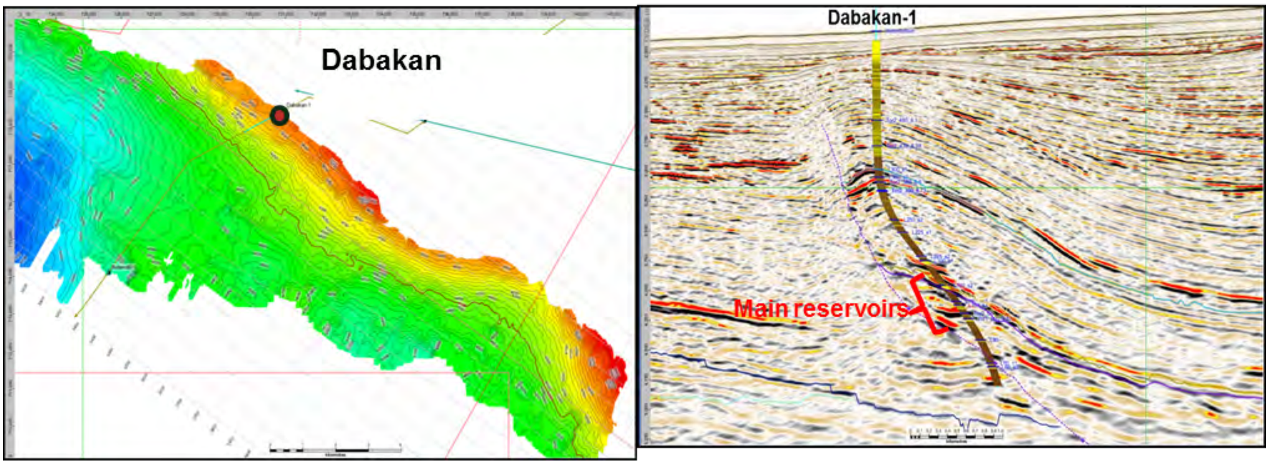


Figure 7.2: Seismic line through Well Dabakan-1

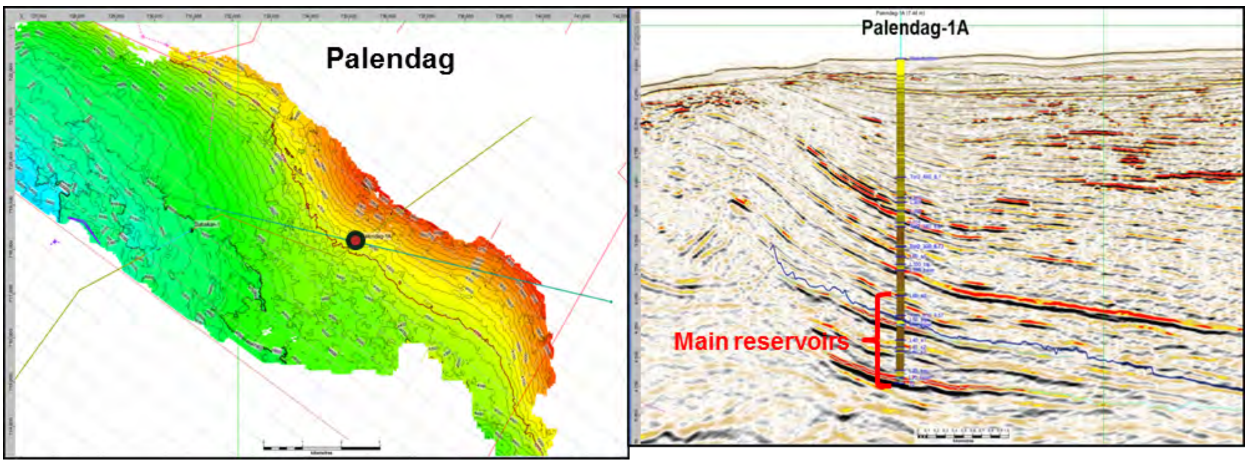


Figure 7.3: Seismic line through Well Palendag-1

7.2.2. Depth Conversion

The seismic interpretation work has been conducted in the PDSM volume, and the depth conversion is therefore carried out within the processing stage. Some horizon interpretations appear not to be tied to the well tops which is potentially a result of depth conversion or poor quality seismic close to faults.

7.2.3. Rock Physics

Rock physics work was undertaken by Ikon in 2011, and indicates the presence of hydrocarbons causes amplitude brightening of >150% in thick sands. The hydrocarbon effect being more pronounced in the far offsets. Tuning thickness was determined as 27.6m. Amplitude brightening in thinner sands can be due to tuning, but will indicate the presence of reservoir sandstone. Ikon further concludes that the tuning induced brightening is significantly less than brightening caused by hydrocarbon presence.

ERCE has conducted independent work rock physics and AVO analysis on the thickest intervals, i.e. L100 S1, S2 and S3 in Well Dabakan-1 and L50 and L20 intervals in Well Palendag-1 to better understand reservoir and hydrocarbon distribution away from the well location. The reservoir sand is softer than the background shale.

We conducted a fluid substitution modelling for these intervals by changing the fluid properties from in-situ measurements to a 100% brine, to analyse the reservoir seismic response in the water leg. We used the same reservoir properties reported on the fluid analysis section of the Ikon's rock physics report, and applied a porosity cut off of 8%. A well-tie analysis on Well Dabakan-1 and Well Palendag-1 shows that a simplified Ricker wavelet with the dominant frequency of 20 Hz can be used to create a synthetic seismogram that replicates the seismic at the well location. We used this wavelet to create pre-stack synthetic gathers for two scenarios of in-situ fluid (Figure 7.4) and fully brine-replaced (Figure 7.5).

Figure 7.4 is the AVO analysis for Well Dabakan-1 L100 S1 as an example. Similar to the Ikon's conclusion, our results show that the amplitudes do brighten with the offset up to three times. This effect can be observed at both top and base L100 S1 reservoir. However, in the brine case, we may expect a polarity reversal from nears to fars and not a very bright amplitude.

We also conducted a wedge modelling to see the effect of tuning on the amplitude (See Figure 7.6). ERCE's tuning thickness is comparable to Ikon's. The reservoir in this case is slightly tuned, but not much affected by amplitude tuning response. Our results also, corroborating the Ikon's conclusion, show that on the far-stack seismic the sands thicker than the tuning thickness have negligible tuning effect compared to the hydrocarbon effect. On the nears, however, the tuning thickness makes a greater contribution.

The L100 S1 is an example where the sand thickness is about the tuning thickness. This conclusion can be applied on other sands with comparable thicknesses. However, it should be emphasized that below the tuning thickness, one can't comment on the amplitudes origin. This specifically applies to for instance the Well Palendag-1 sands that are thin stacked sands.

High case polygons have therefore been drawn around areas of elevated amplitude above background layers as an indicator of reservoir quality sand.

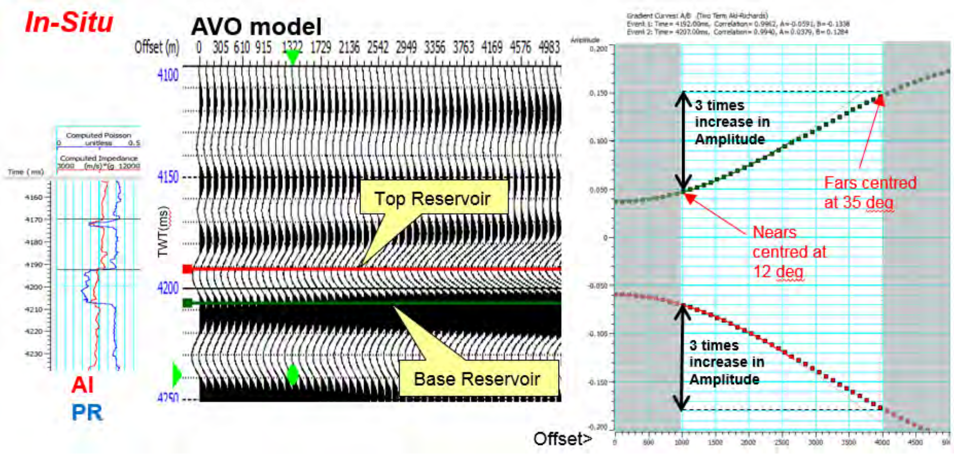


Figure 7.4: Pre-stack modelling and AVO analysis of Well Dabakan-1, L100 S1 sand, in-situ fluid

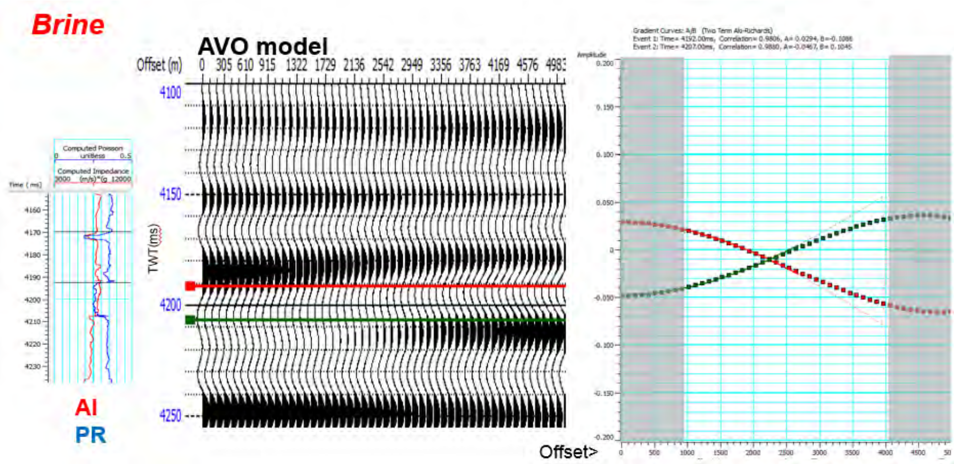


Figure 7.5:Pre-stack modelling and AVO analysis of Well Dabakan-1, L100 S1 sand, substituted brine

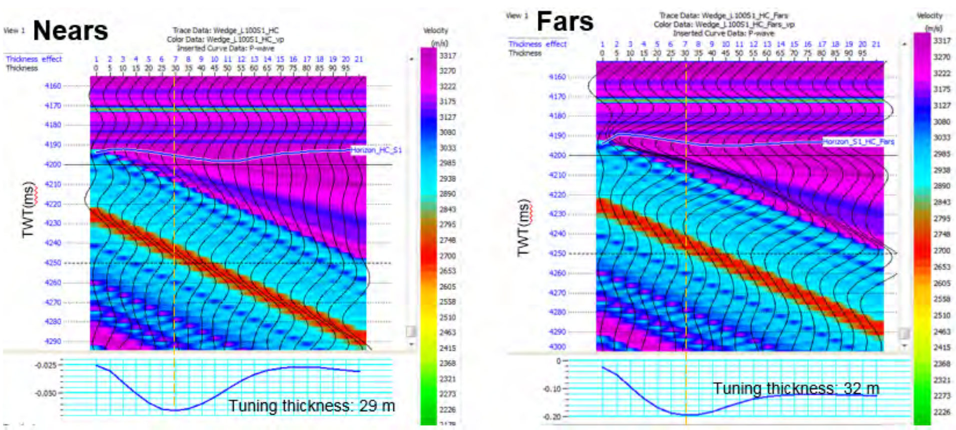


Figure 7.6: Wedge modelling using Well Dabakan-1 logs on nears and fars

7.3. Petrophysical Evaluation

Well Dabakan-1 was evaluated over the interval from 2,900 mTVDSS to total depth at approximately 5,272 mTVDSS. The evaluation assumed the interval was a sand/shale sequence. A comparison of the operator's and ERCE computed petrophysical curves is shown in Figure 7.7 for Well Dabakan-1 (operator curves are shown in blue and ERCE curves are shown in black).

7.3.1. Data available

A composite log data set was provided (Gamma Ray, Resistivity, Sonic and Density/Neutron) that were a combination of wireline and LWD data. Wireline formation pressures were also obtained but that they were not examined as part of this review. Nuclear Magnetic Resonance data were also obtained but these data were not available.

7.3.2. Shale Volume

Shale volume was determined from the Gamma Ray, with a normal linear equation; the end-points were based on the 2% and 98% percentiles varied for different intervals as deemed necessary. A comparison with the operator derived shale volume shows very good agreement (the method used by the operator is not known but it would appear to be based on the Gamma Ray).

7.3.3. Porosity

Effective porosity was determined from the Density/Neutron crossplot with shale corrections applied. The mud filtrate density assumed to be 0.9 g/c3 as the well was drilled with an oil-based mud. A hydrocarbon correction was not applied as it was not considered necessary given the relative response of the Density/Neutron data. Good agreement can be observed between the operator's and the ERCE computed values.

7.3.4. Water Saturation

Water saturation was determined using the Indonesian equation. The Archie parameters of a, m and n were taken as 1, 1.91 (based on the rotary core samples by the original well operator) and 2 respectively. Rw was determined from a Pickett plot that indicated an Rw of 0.123 ohmm at reservoir temperature (no temperature data were available to compute a well temperature profile). A higher Rw of 0.176 ohmm at BHT was determined for the L60 sands that is consistent with the water sample recovered (as per the original ExxonMobil report). The shale resistivity was taken as 2 ohmm. Overall agreement can be observed between the operator's and the ERCE computed values albeit with the operator values being about 5% lower in the main gas bearing sands. With the information available the operator has probably used a lower Rw of 0.11 ohmm (obtained from a wireline formation test sample) as given in the report by ExxonMobil and also a different equation (Modified Simandoux). Using this method and different Rw the discrepancy between the operator and ERCE becomes negligible and as this approach is considered to be just as valid no issues in the operator's evaluation are felt to exist

7.3.5. Sums and Averages

The same cut-offs as the operator have been used in the petrophysical comparison. The operator uses a set of low (Sw <=50%, VCL <=30%, PHIE>=15%), mid (Sw <=60%, VCL <=50%, PHIE>=10%), and high case

(Sw <=70%, VCL <=60%, PHIE>=7%) cut-offs to define their petrophysical range. The cut-off used in the petrophysical comparison is the operator mid-case.

Given the close agreement between the operator's and ERCE's interpretation of reservoir sums and averages, we have accepted the operator reservoir summaries for use in volumetric estimation for Well Dabakan-1. On this basis ERCE also accept the operator interpretation and sums and averages for Well Palendag-1A, as the operator interpretation for this well was undertaken by the same personnel.

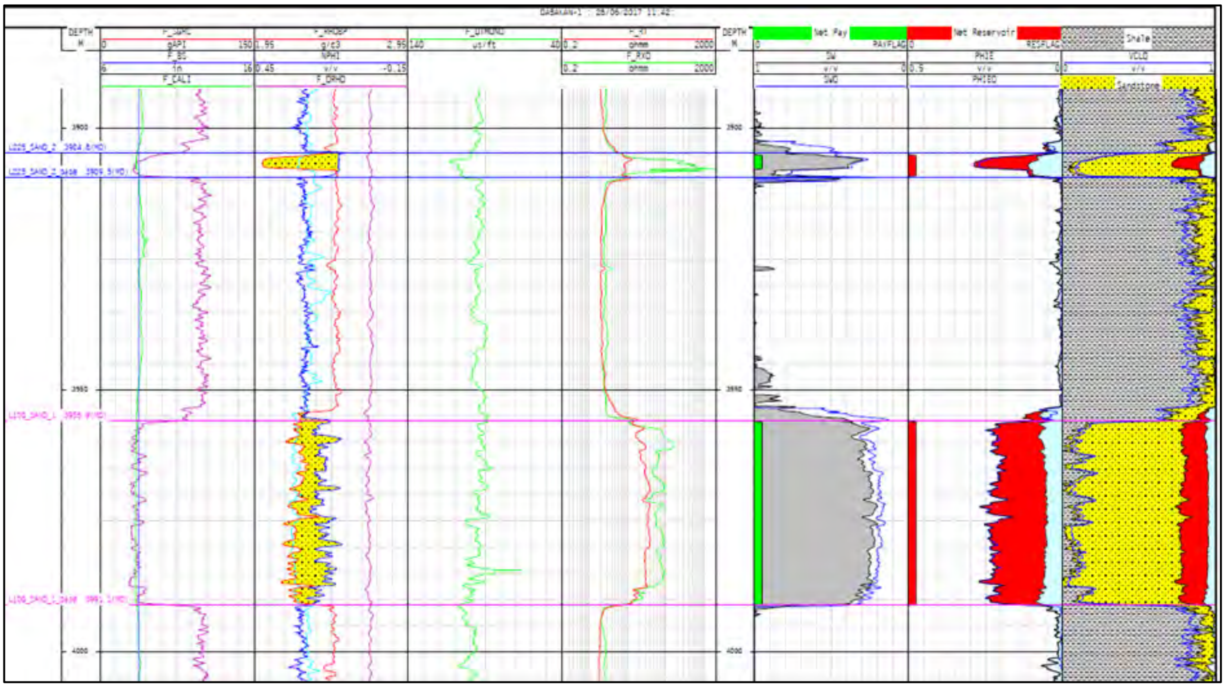


Figure 7.7: Well Dabakan-1 CPI over the L225 S2 and L100 S1 reservoir intervals

7.4. Geological Evaluation

The Dabakan and Palendag reservoirs were deposited in the Late Miocene over the L300, L225, L100, L80, L60, L50, L40 and L20 groups. The reservoirs were deposited as distributary turbidites in a mud-rich system in a shelf/slope deep marine environment.

Reservoir sands have variable thickness (gross 4-45 m), and are separated by shales, which form effective reservoir-seal pairs. The quality of individual reservoirs is also highly variable, from as little as 10% N/G in some of the thinner units, to almost 100% N/G in the well-developed, blocky L100 S Intra sand.

Given the reservoir-seal pairs, each unit is considered to have separate hydrocarbon columns.

7.5. Hydrocarbons Initially in Place

Hydrocarbons in place have been calculated for each of the six gas bearing reservoirs in Dabakan and four gas bearing reservoirs in Palendag separately.

ERCE has used a combination of structural and amplitude mapping to calculate a range in gross rock volumes, using polygon areas, reservoir pay thicknesses and reservoir parameters from Wells Dabakan-1 and Palendag-1A to calculate in place volumes. In all cases the 2C area is calculated as the lognormal between the 1C and the 3C.

The L100 S1 mapped amplitude has not been directly drilled and is therefore considered to be prospective resources and no in place volumes have been calculated for this unit.

The hydrocarbons (gas and condensate) in place for each reservoir interval are detailed below and are summarised in Table 7-1 for Dabakan and in Table 7-2 for Palendag.

Table 7-1: Summary of Dabakan reservoirs GIIP, Contingent Resources and CIIP

Reservoir	GIIP (Bscf)			Contingent Resources (Bscf)			CIIP (MMstb)		
	Low	Mid	High	1C	2C	3C	Low	Mid	High
L300 S1	1.3	10.9	60.6	0.8	7.1	42.4	0.01	0.14	0.99
L225 S1	0.1	0.6	1.9	0.0	0.4	1.3	0.00	0.01	0.05
L225 S2	0.4	3.3	25.5	0.2	2.0	17.9	0.01	0.09	0.86
L100 S1 Intra	57.3	136.9	317.5	43.0	109.5	269.9	1.27	4.05	11.75
L100 S2	122.6	138.9	151.4	85.8	104.2	121.1	2.54	3.84	5.24
L100 S3	1.9	21.2	143.7	1.3	15.9	115.0	0.06	0.85	7.19
L80	0.04	3.0	44.7	0.02	2.0	31.3	0.00	0.12	2.24
Total	**183.6**	**314.9**	**745.3**	**131.2**	**241.0**	**598.8**	**3.9**	**9.1**	**28.3**

Table 7-2: Summary of Palendag reservoirs GIIP, Contingent Resources and CIIP

Reservoir	GIIP (Bscf)			Contingent Resources (Bscf)			CIIP (MMstb)		
	Low	Mid	High	1C	2C	3C	Low	Mid	High
L60 S2	9.57	51.36	274.65	6.7	38.5	219.7	0.13	0.94	6.25
L50	14.28	79.95	201.31	10.0	60.0	161.0	0.09	0.65	2.05
L40 S2	3.95	17.99	103.41	2.8	13.5	82.7	0.06	0.39	2.79
L20	40.15	145.77	301.84	30.1	116.6	256.6	0.92	4.43	11.47
Total	**67.9**	**295.1**	**881.2**	**49.6**	**228.6**	**720.1**	**1.2**	**6.4**	**22.6**

7.5.1. Dabakan L300 S1 Reservoir

The reservoir interval is shown on the CPI in Figure 7.8. The 1C polygon (dashed green) is defined by the GDT (blue line) in Well Dabakan-1 at 2,987 mTVDSS. The 3C polygon (dashed red) is defined by using the closing contour at 3,300 mTVDSS to the north and using the extent of the amplitudes to the south (Figure 7.9). The input parameters are listed in Table 7-3 and the in-place and Contingent Resources are listed in Table 7-4.

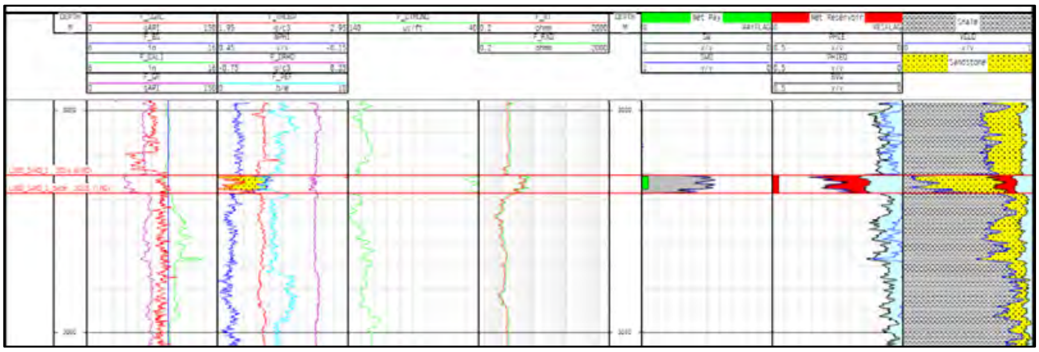


Figure 7.8: Well Dabakan-1 L300 S1 CPI

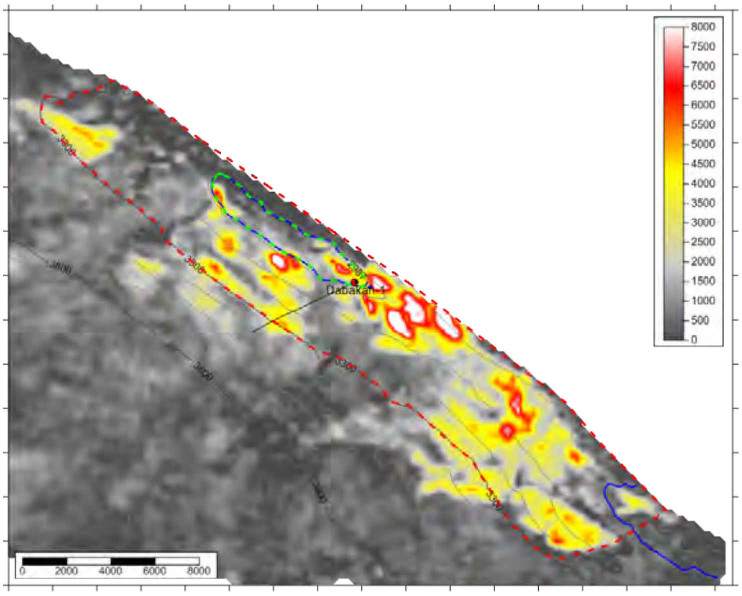


Figure 7.9: Dabakan L300 S1 amplitude extraction and volumetric polygons

Table 7-3: Dabakan L300 S1 input parameters

	Area (km2)	Pay Thickness (m)	Pay Porosity (dec)	Pay Sw (dec)	GEF (scf/rcf)	Rf (dec)	CGR (stb/MMscf)
Low	0.60	1.6	0.268	0.52	327	0.6	9.8
Mid	2.35	2.9	0.279	0.5	323	0.65	13.1
High	9.23	3.6	0.287	0.47	340	0.7	16.3

Table 7-4: Dabakan L300 S1 GIIP, Contingent Resources and CIIP

Dabakan	GIIP (Bscf)			Contingent Resources (Bscf)			CIIP (MMstb)		
	Low	Mid	High	1C	2C	3C	Low	Mid	High
L300 S1	1.3	10.9	60.6	0.8	7.1	42.4	9.8	13.1	16.3

7.5.2. **Dabakan L225 S1 Reservoir**

The reservoir interval is shown on the CPI in Figure 7.10. For this reservoir interval ERCE has adopted the operator polygons, with a minor edit to include Well Dabakan-1 within the volumetric polygons. The 1C polygon (dashed green) is defined roughly by the GDT (blue line) in Well Dabakan-1 at 3,516 mTVDSS; the saddle between the well with an amplitude bright is considered to be part of the depth conversion uncertainty. The 3C polygon (dashed red) is defined by the extent of the amplitudes (Figure 7.11). The input parameters are listed in Table 7-5 and the in-place and Contingent Resources are listed in Table 7-6.

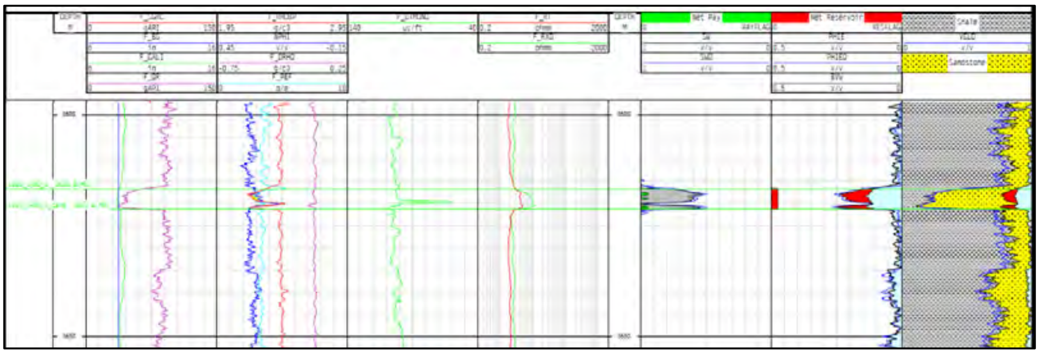


Figure 7.10: Well Dabakan-1 L225 S1 CPI

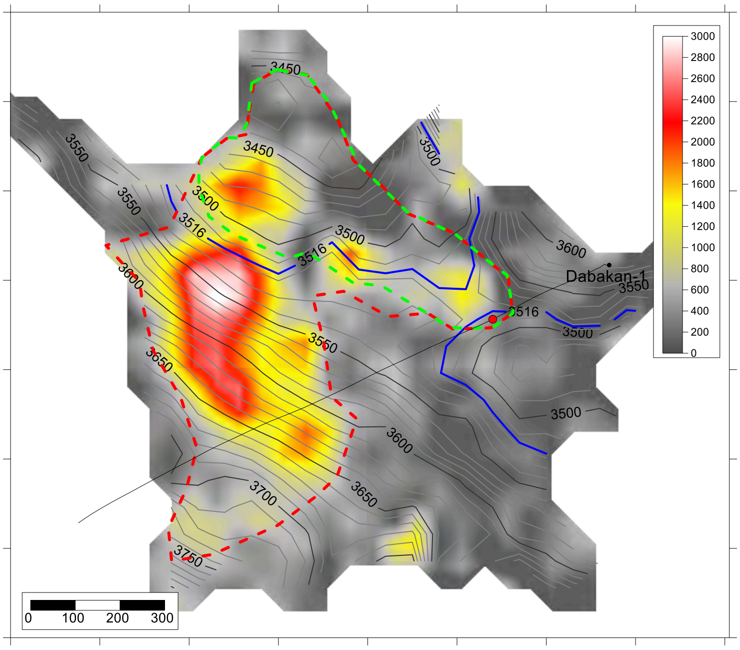


Figure 7.11: Dabakan L225 S1 amplitude extraction and volumetric polygons

Table 7-5: Dabakan L225 S1 input parameters

	Area (km2)	Pay Thickness (m)	Pay Porosity (dec)	Pay Sw (dec)	GEF (scf/rcf)	Rf (dec)	CGR (stb/MMscf)
Low	0.18	0.3	0.223	0.57	304	0.5	17.4
Mid	0.28	1.8	0.235	0.55	320	0.6	23.1
High	0.44	2.7	0.260	0.50	336	0.7	28.9

Table 7-6: Dabakan L225 S1 GIIP, Contingent Resources and CIIP

Dabakan	GIIP (Bscf)			Contingent Resources (Bscf)			CIIP (MMstb)		
	Low	Mid	High	1C	2C	3C	Low	Mid	High
L225 S1	0.1	0.6	1.9	0.0	0.4	1.3	0.00	0.01	0.05

7.5.3. **Dabakan L225 S2 Reservoir**

The reservoir interval is shown on the CPI in Figure 7.12. There is no interpretation provided for this reservoir interval and therefore ERCE completed primary analysis. To capture the uncertainty of areal extent of this reservoir, the 1C area is the same as the 1C for L225 S1 (similar thickness sand), and the 3C area is the same as the 3C for the underlying L100 S1 Intra reservoir (approximately 35m deeper, and 25m net pay). The input parameters are listed in Table 7-7 and the in-place and Contingent Resources are listed in Table 7-8.

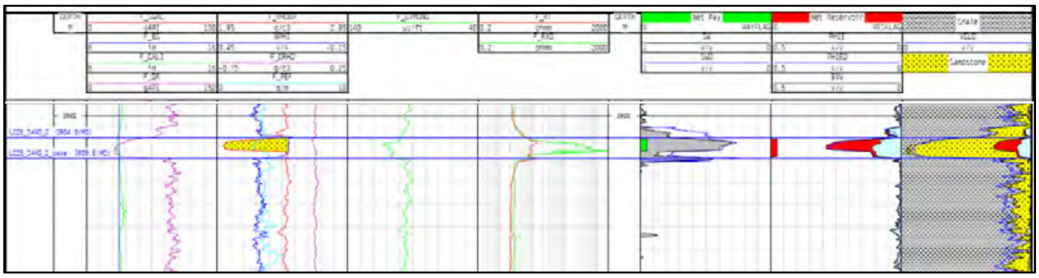


Figure 7.12: Well Dabakan-1 L225 S2 CPI

Table 7-7: Dabakan L225 S2 input parameters

	Area (km2)	Pay Thickness (m)	Pay Porosity (dec)	Pay Sw (dec)	GEF (scf/rcf)	Rf (dec)	CGR (stb/MMscf)
Low	0.18	1.8	0.205	0.37	315	0.5	20.3
Mid	0.99	2.1	0.224	0.36	315	0.6	27.0
High	5.54	2.5	0.244	0.35	315	0.7	33.8

Table 7-8: Dabakan L225 S2 GIIP, Contingent Resources and CIIP

Dabakan	GIIP (Bscf)			Contingent Resources (Bscf)			CIIP (MMstb)		
	Low	Mid	High	1C	2C	3C	Low	Mid	High
L225 S2	0.4	3.3	25.5	0.2	2.0	17.9	0.01	0.09	0.86

7.5.4. **Dabakan L100 Intra Reservoir**

The reservoir interval is shown on the CPI in Figure 7.13. The 1C polygon (dashed green) is defined by the GDT (blue line) in Well Dabakan-1 at 3,776 mTVDSS, and also includes the extent of the amplitude to the southeast. The 3C polygon (dashed red) is defined by the extent of the amplitudes (Figure 7.14). The input parameters are listed in Table 7-9 and the in-place and Contingent Resources are listed in Table 7-10.

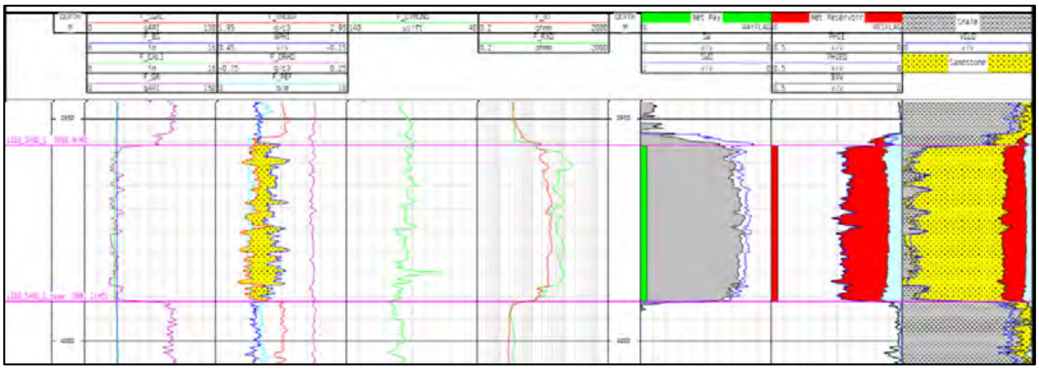


Figure 7.13: Well Dabakan-1 L100 Intra CPI

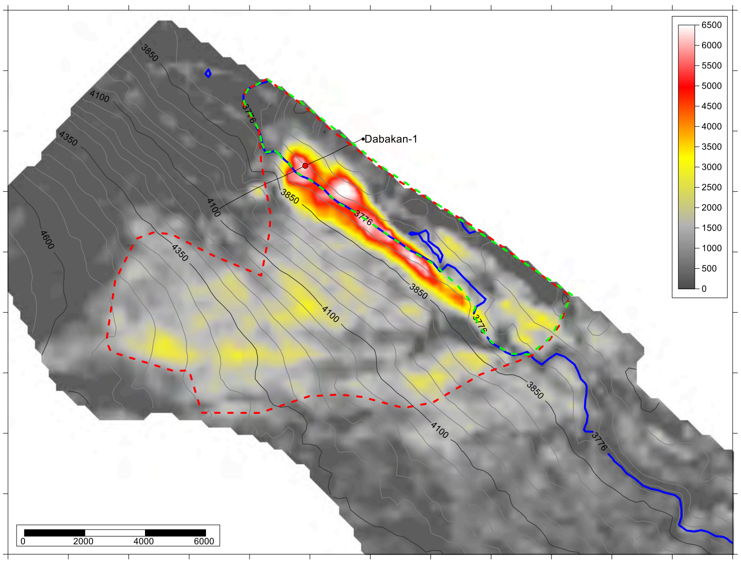


Figure 7.14: Dabakan L100 Intra amplitude extraction and volumetric polygons

Table 7-9: Dabakan L100 Intra input parameters

	Area (km2)	Pay Thickness (m)	Pay Porosity (dec)	Pay Sw (dec)	GEF (scf/rcf)	Rf (dec)	CGR (stb/MMscf)
Low	1.53	24.3	0.199	0.26	312	0.75	22.2
Mid	2.92	24.7	0.219	0.21	312	0.80	29.6
High	5.54	24.7	0.239	0.16	312	0.85	37.0

Table 7-10: Dabakan L100 Intra GIIP, Contingent Resources and CIIP

Dabakan	GIIP (Bscf)			Contingent Resources (Bscf)			CIIP (MMstb)		
	Low	Mid	High	1C	2C	3C	Low	Mid	High
L100 Intra	57.3	136.9	317.5	43.0	109.5	269.9	1.27	4.05	11.75

7.5.5. Dabakan L100 S2 Reservoir

The reservoir interval is shown on the CPI in Figure 7.15, and also shows a log defined GWC at 3,964 mTVDSS. As there is a GWC defined by the logs, the 1C, 2C and 3C polygons are all the same and are defined by the GWC closing contour against the fault (Figure 7.16). The input parameters are listed in Table 7-11 and the in-place and Contingent Resources are listed in Table 7-12.

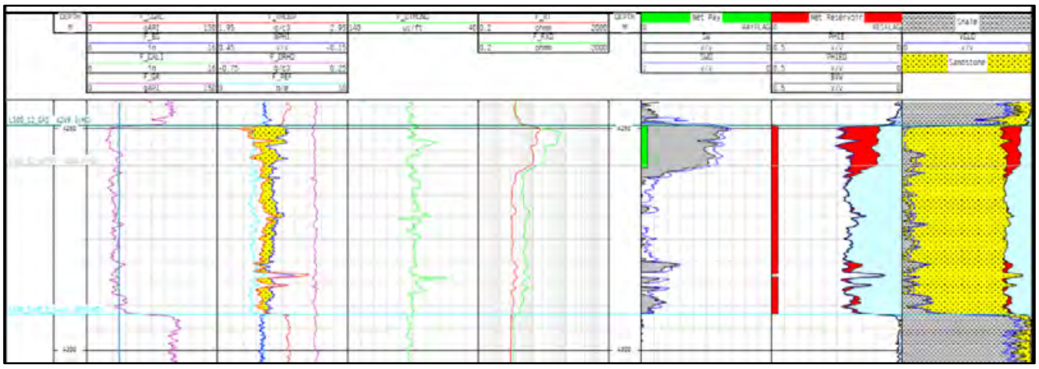


Figure 7.15: Well Dabakan-1 L100 S2 CPI

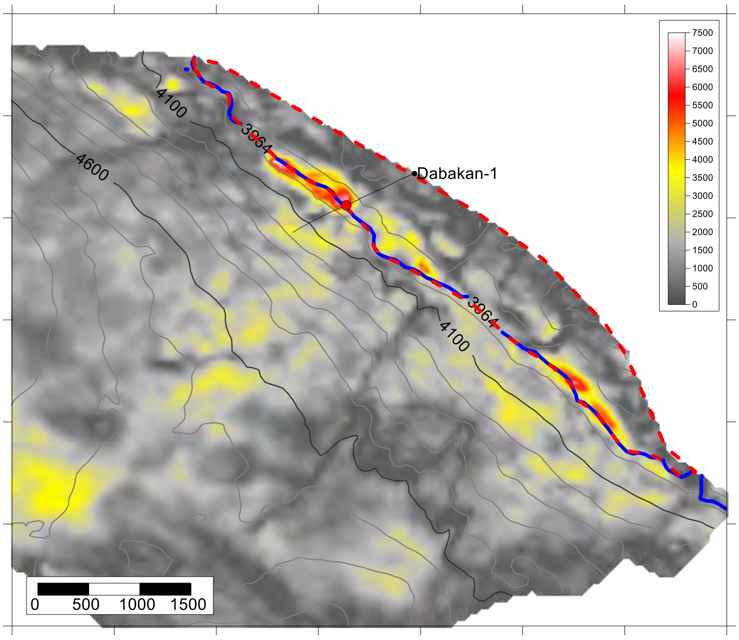


Figure 7.16: Dabakan L100 S2 amplitude extraction and volumetric polygons

Table 7-11: Dabakan L100 S2 input parameters

	Area (km2)	Pay Thickness (m)	Pay Porosity (dec)	Pay Sw (dec)	GEF (scf/rcf)	Rf (dec)	CGR (stb/MMscf)
Low	3.56	28.2	0.201	0.42	315	0.70	20.7
Mid	3.56	29.2	0.203	0.41	315	0.75	27.7
High	3.56	29.6	0.205	0.40	315	0.80	34.6

Table 7-12: Dabakan L100 S2 GIIP, Contingent Resources and CIIP

Dabakan	GIIP (Bscf)			Contingent Resources (Bscf)			CIIP (MMstb)		
	Low	Mid	High	1C	2C	3C	Low	Mid	High
L100 S2	122.6	138.9	151.4	85.8	104.2	121.1	2.54	3.84	5.24

7.5.6. **Dabakan L100 S3 Reservoir**

The reservoir interval is shown on the CPI in Figure 7.17. The 1C polygon (dashed green) is defined by the GDT (blue line) in Well Dabakan-1 at 4,154 mTVDSS with a fault pinch point to the southeast (the blue GDT contour is smoothed over to the northwest where it is miss-picked). The 3C polygon (dashed red) is the closing contour into the fault (Figure 7.18). The input parameters are listed in Table 7-13 and the in-place and Contingent Resources are listed in Table 7-14.

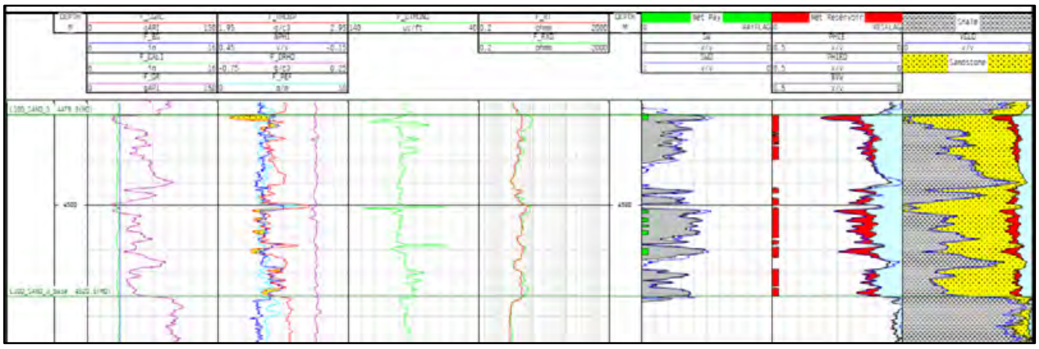


Figure 7.17: Well Dabakan-1 L100 S3 CPI

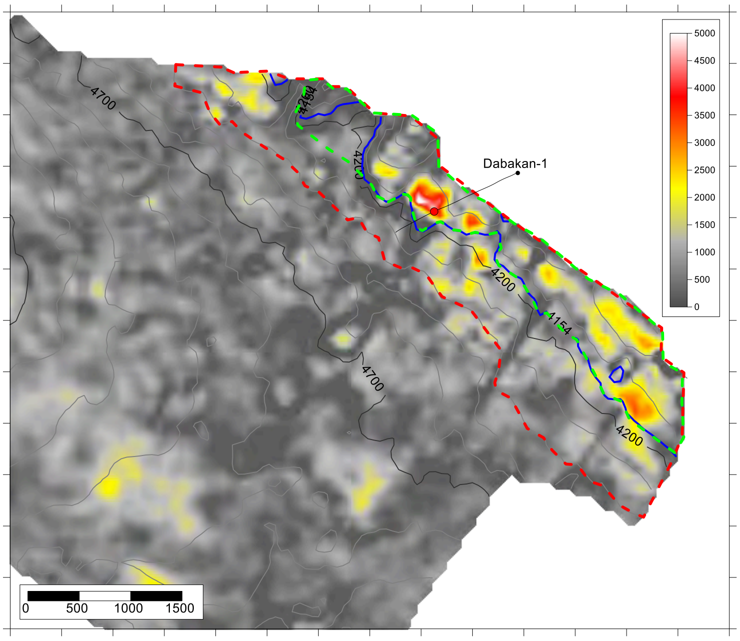


Figure 7.18: Dabakan L100 S3 amplitude extraction and volumetric polygons

Table 7-13: Dabakan L100 S3 input parameters

	Area (km2)	Pay Thickness (m)	Pay Porosity (dec)	Pay Sw (dec)	GEF (scf/rcf)	Rf (dec)	CGR (stb/MMscf)
Low	2.71	0.9	0.175	0.6	330	0.70	40
Mid	4.15	4.3	0.218	0.53	330	0.75	50
High	6.34	12.8	0.280	0.48	330	0.80	60

Table 7-14: Dabakan L100 S3 GIIP, Contingent Resources and CIIP

Dabakan	GIIP (Bscf)			Contingent Resources (Bscf)			CIIP (MMstb)		
	Low	Mid	High	1C	2C	3C	Low	Mid	High
L100 S3	1.9	21.2	143.7	1.3	15.9	115.0	0.06	0.85	7.19

7.5.7. Dabakan L80 Reservoir

The reservoir interval is shown on the CPI in Figure 7.19. The 1C polygon (dashed green) is defined by the GDT (blue line) in Well Dabakan-1 at 4,428 mTVDSS with structural closure against the fault. The 3C polygon (dashed red) is the closing contour into the fault to the northwest and the extent of the amplitudes to the southeast (Figure 7.20). The input parameters are listed in Table 7-15 and the in-place and Contingent Resources are listed in Table 7-16.

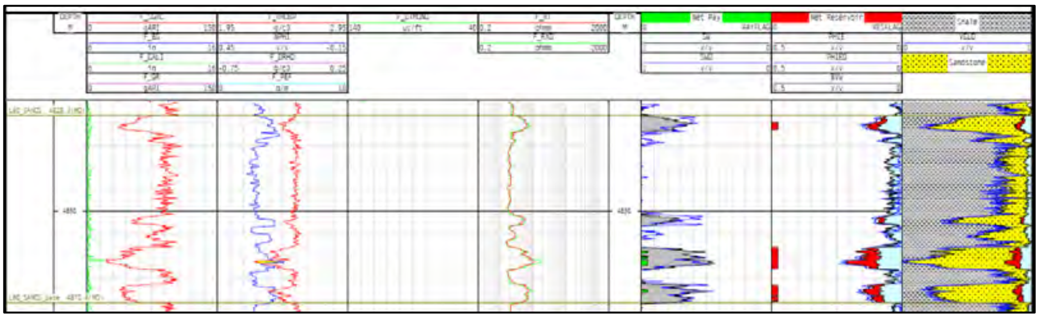


Figure 7.19: Well Dabakan-1 L80 CPI

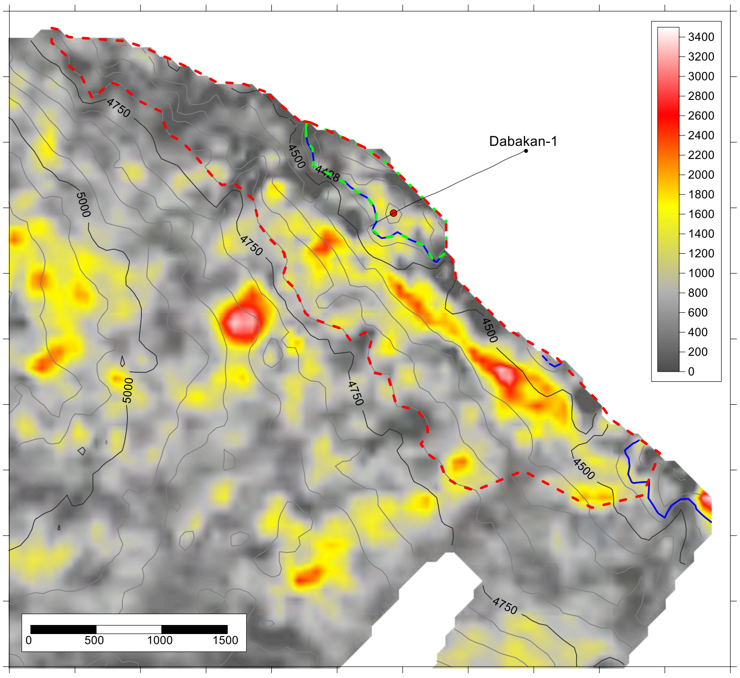


Figure 7.20: Dabakan L80 amplitude extraction and volumetric polygons

Table 7-15: Dabakan L80 input parameters

	Area (km2)	Pay Thickness (m)	Pay Porosity (dec)	Pay Sw (dec)	GEF (scf/rcf)	Rf (dec)	CGR (stb/MMscf)
Low	0.41	0.2	0.140	0.60	325	0.60	30
Mid	1.36	2.6	0.168	0.55	325	0.65	40
High	4.54	6.8	0.235	0.49	325	0.70	50

Table 7-16: Dabakan L80 GIIP, Contingent Resources and CIIP

Dabakan	GIIP (Bscf)			Contingent Resources (Bscf)			CIIP (MMstb)		
	Low	Mid	High	1C	2C	3C	Low	Mid	High
L80	0.04	3.0	44.7	0.02	2.0	31.3	0.00	0.12	2.24

7.5.8. **Palendag L60 Reservoir**

The reservoir interval is shown on the CPI in Figure 7.21. The 1C polygon (dashed green) is defined by the GDT (blue line) in Well Palendag-1A at 3,974 mTVDSS, along with amplitude extent to the southeast and extending to the northwest as far as the saddle adjacent to the fault. The 3C polygon (dashed red) has the same northwest and southeast extents as the 1C polygon, but extends downdip to the 4300 mTVDSS contour (Figure 7.22). The input parameters are listed in Table 7-17 and the in-place and Contingent Resources are listed in Table 7-18.

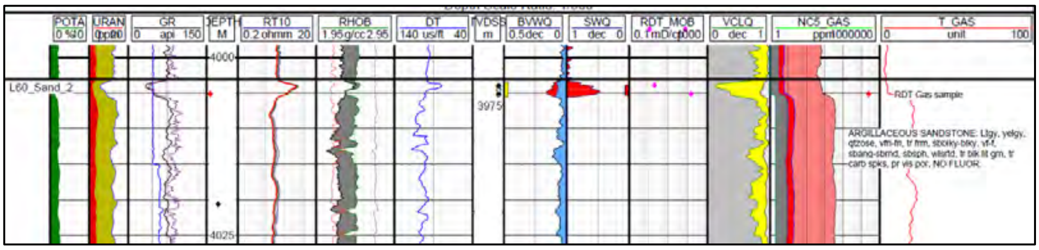


Figure 7.21: Well Palendag-1A L60 CPI

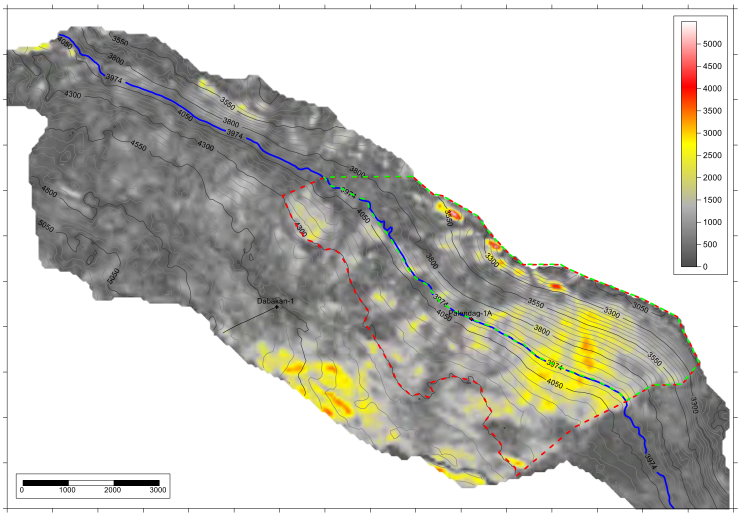


Figure 7.22: Palendag L60 amplitude extraction and volumetric polygons

Table 7-17: Palendag L60 input parameters

	Area (km2)	Pay Thickness (m)	Pay Porosity (dec)	Pay Sw (dec)	GEF (scf/rcf)	Rf (dec)	CGR (stb/MMcf)
Low	14.31	1.0	0.13	0.55	314	0.70	13.7
Mid	19.88	3.2	0.14	0.51	331	0.75	18.2
High	27.61	10.0	0.15	0.47	347	0.80	22.8

Table 7-18: Palendag L60 GIIP, Contingent Resources and CIIP

Palendag	GIIP (Bscf)			Contingent Resources (Bscf)			CIIP (MMstb)		
	Low	Mid	High	1C	2C	3C	Low	Mid	High
L60	9.57	51.36	274.65	6.7	38.5	219.7	0.13	0.94	6.25

7.5.9. **Palendag L50 Reservoir**

The reservoir interval is shown on the CPI in Figure 7.23. The 1C polygon (dashed green) is defined by the GDT (blue line) in Well Palendag-1A at 4,200 mTVDSS, taken into the fault at the saddle contours to the northwest and southeast. The 3C polygon (dashed red) is defined the downdip 4,350 mTVDSS contour to close to the north, and the extent of the amplitudes to the southeast into the saddle (Figure 7.24). The input parameters are listed in Table 7-19 and the in-place and Contingent Resources are listed in Table 7-20.

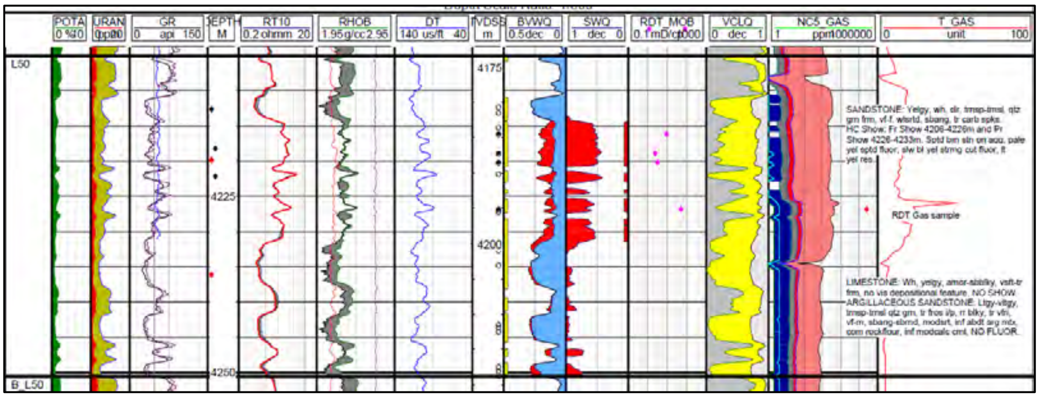


Figure 7.23: Well Palendag-1A L50 CPI

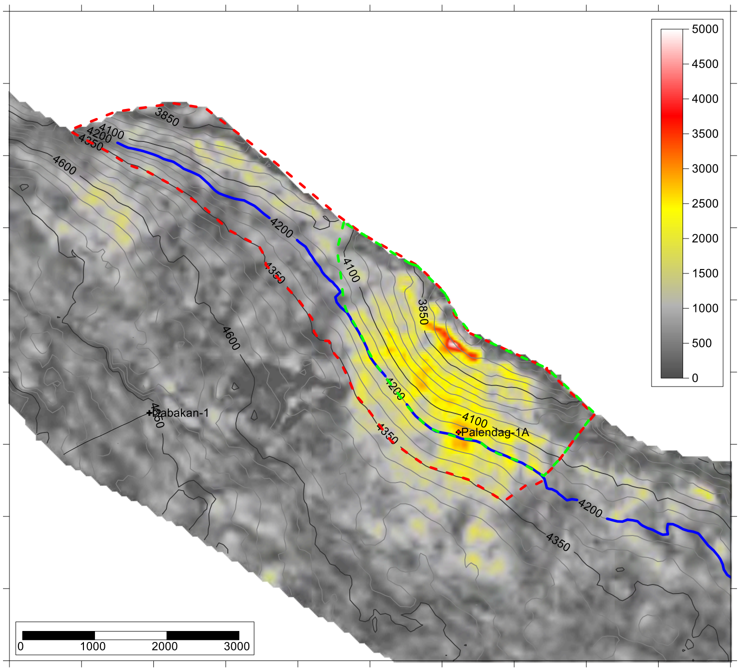


Figure 7.24: Palendag L50 amplitude extraction and volumetric polygons

Table 7-19: Palendag L50 input parameters

	Area	Pay Thickness	Pay Porosity	Pay Sw	GEF	Rf	CGR
	(km2)	(m)	(dec)	(dec)	(scf/rcf)	(dec)	(stb/MMscf)
Low	5.20	3.0	0.18	0.55	316	0.70	6.1
Mid	7.68	9.7	0.19	0.52	332	0.75	8.1
High	11.35	13.1	0.21	0.47	349	0.80	10.2

Table 7-20: Palendag L50 GIIP, Contingent Resources and CIIP

Palendag	GIIP (Bscf)			Contingent Resources (Bscf)			CIIP (MMstb)		
	Low	Mid	High	1C	2C	3C	Low	Mid	High
L50	14.28	79.95	201.31	10.0	60.0	161.0	0.09	0.65	2.05

7.5.10. Palendag L40 S2 Reservoir

The reservoir interval is shown on the CPI in Figure 7.25. The 1C polygon (dashed green) is defined by the GDT (blue line) in Well Palendag-1A at 4,429 mTVDSS, taken into the fault at a saddle point to the southeast and amplitude extent to the northwest. The 3C polygon (dashed red) is defined by the broad extent of the amplitudes, and closing against the fault at the same points as the 1C polygon (Figure 7.26). The input parameters are listed in Table 7-21 and the in-place and Contingent Resources are listed in Table 7-22.

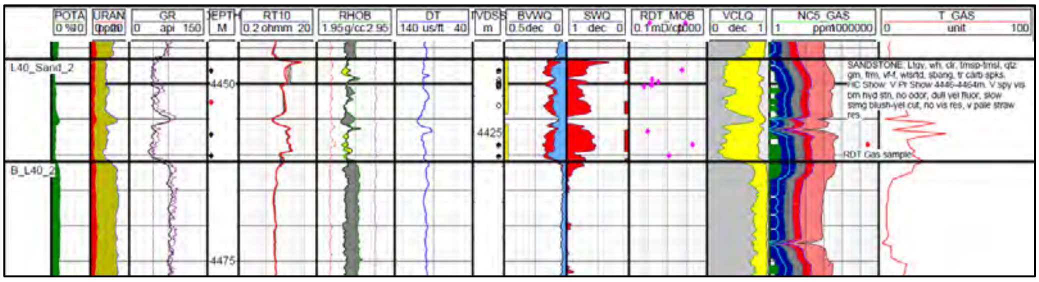


Figure 7.25: Well Palendag-1A L40 S2 CPI

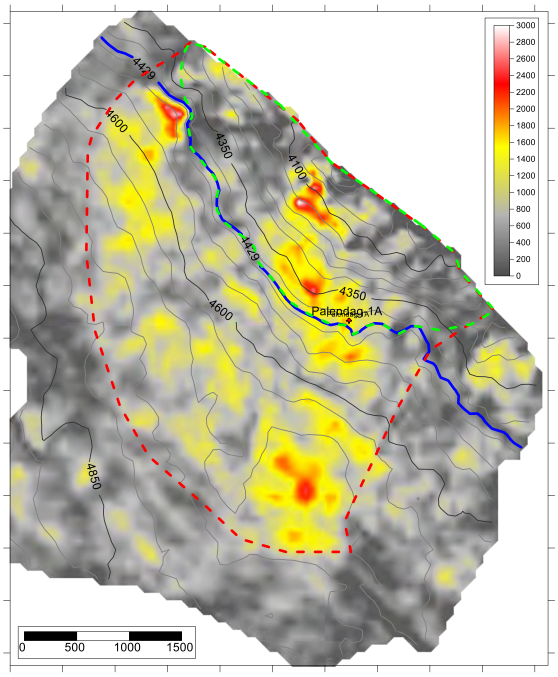


Figure 7.26: Palendag L40 S2 amplitude extraction and volumetric polygons

Table 7-21: Palendag L40 S2 input parameters

	Area (km2)	Pay Thickness (m)	Pay Porosity (dec)	Pay Sw (dec)	GEF (scf/rcf)	Rf (dec)	CGR (stb/MMstb)
Low	3.59	1.5	0.16	0.61	325	0.70	16.2
Mid	6.41	3.0	0.17	0.54	342	0.75	21.6
High	11.46	7.6	0.18	0.48	359	0.80	26.9

Table 7-22: Palendag L40 S2 GIIP, Contingent Resources and CIIP

Palendag	GIIP (Bscf)			Contingent Resources (Bscf)			CIIP (MMstb)		
	Low	Mid	High	1C	2C	3C	Low	Mid	High
L40 S2	3.95	17.99	103.41	2.8	13.5	82.7	0.06	0.39	2.79

7.5.11. Palendag L20 Reservoir

The reservoir interval is shown on the CPI in Figure 7.27. The 1C polygon (dashed green) is defined by the GDT (blue line) in Well Palendag-1A at 4,674 mTVDSS closing into the fault. The 3C polygon (dashed red) is defined by the 4,770 mTVDSS contour and closing with amplitude shut off to the southeast (Figure 7.28). The input parameters are listed in Table 7-23 and the in-place and Contingent Resources are listed in Table 7-24.

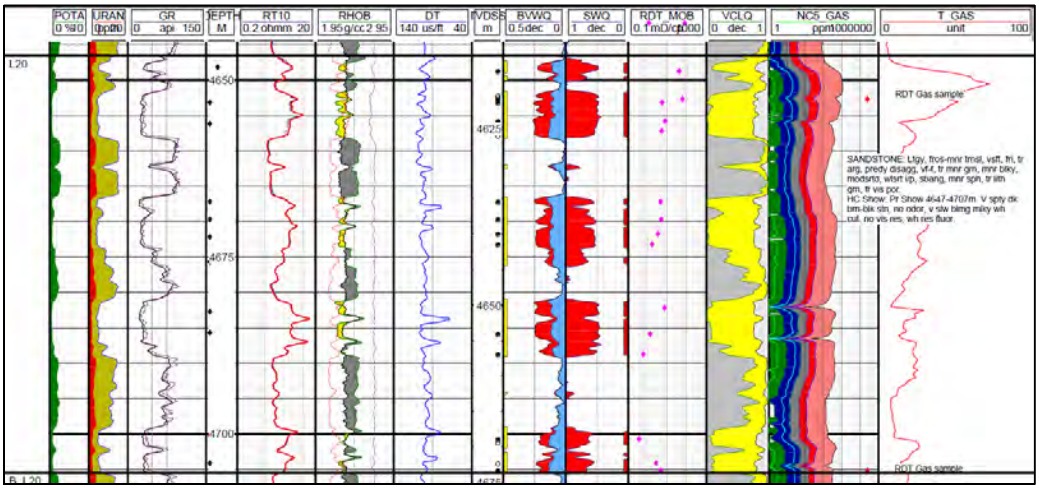


Figure 7.27: Well Palendag-1A L20 CPI

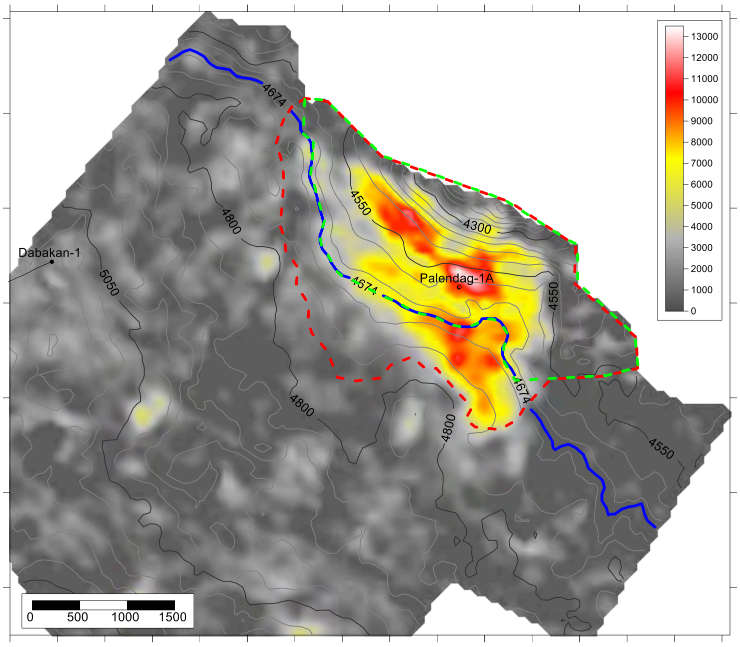


Figure 7.28: Palendag L20 amplitude extraction and volumetric polygons

Table 7-23: Palendag L20 input parameters

	Area (km2)	Pay Thickness (m)	Pay Porosity (dec)	Pay Sw (dec)	GEF (scf/rcf)	Rf (dec)	CGR (stb/MMstb)
Low	4.71	7.9	0.21	0.54	325	0.75	22.8
Mid	5.81	19.3	0.22	0.51	342	0.80	30.4
High	7.16	27.2	0.23	0.48	360	0.85	38.0

Table 7-24: Palendag L20 GIIP, Contingent Resources and CIIP

Palendag	GIIP (Bscf)			Contingent Resources (Bscf)			CIIP (MMstb)		
	Low	Mid	High	1C	2C	3C	Low	Mid	High
L20	40.15	145.77	301.84	30.1	116.6	256.6	0.92	4.43	11.47

7.6. Reservoir Engineering Evaluation

7.6.1. Well Test and Permeability

No DSTs were carried out in either of the wells. No cores were cut and therefore there is no direct measurement of permeability. Downhole samples were collected in both wells across all gas bearing reservoirs (apart from the L225 S1 and L80 reservoirs in Well Dabakan-1), thus confirming the presence of mobile gas.

Pressure measurements made in Well Dabakan-1 with a reservoir description tool ("RDT") give an indication of mobility (Table 7-25). The L225 S1 reservoir appears, from MDT derived mobilitiy, to be relatively poor. All other reservoirs appear to be of fair quality. The L80 reservoir has neither MDT pressures nor a sample. However, the presence of gas is inferred from log data. The reservoir quality of the L80 appears to be relatively poor, based on log character. In contrast log character of the L100 S1 suggests that it is a good quality reservoir and it is also the reservoir with the greatest pay.

MDT pressures were measured in Well Palendag-1 over all gas bearing intervals. Mobilities from these points show the Palendag reservoirs to be of moderate quality (Table 7-25).

Table 7-25: MDT mobility estimates for Dabakan and Palendag

Reservoir	No. of MDT points	Mobility (mD/cP)
Dabakan		
L300 S1	none	
L225 S1	4	5
L225 S2	2	2,980
L100 S1	8	491
L100 S2	6	334
L100 S3	9	147
L80	none	
Palendag		
L100	7	41
L60 S2	2	64
L50	4	52
L40 S2	5	65
L20	13	15

7.6.2. **Reservoir Pressures / Fluid Contacts**

In Well Dabakan-1, MDT pressure measurements were made in all gas bearing reservoir sands apart from the deepest L80 sands and shallowest L300 S1 sands (Figure 7.29). The only interval in which a GWC has been identified on the wireline logs is L100 S2, and it is also the only sand in which water pressure measurements have been made. The MDT pressures show a GWC of approximately 3,964 mTVDSS in the L100 S2 sands (Figure 7.30). They are approximately 1,880 psia over pressured. All the gas bearing sands intersected by Well Dabakan-1 are over pressured, with over pressure increasing with depth. It is therefore not possible to define GWCs for the other sands using MDT pressures. GWCs that could be inferred by extrapolation to the L100 S2 sands are L100 S1 (3,850 mTVDSS) and L225 S2 (3,825 mTVDSS).

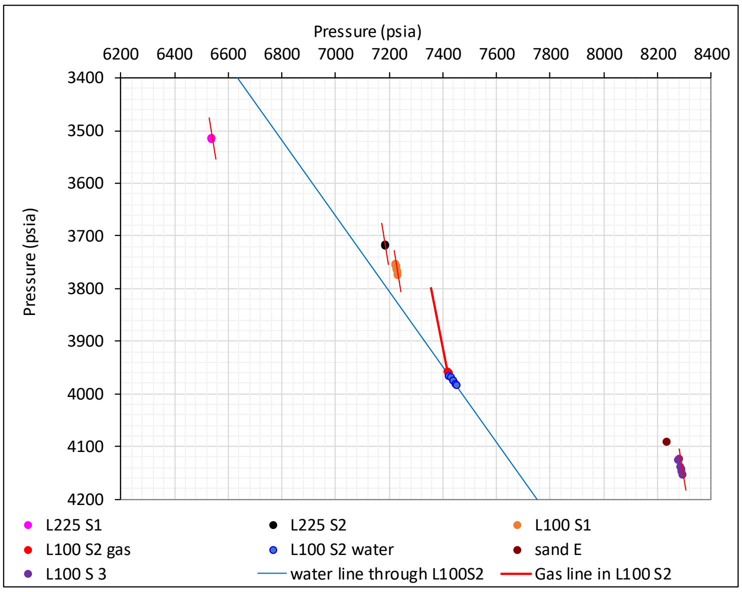


Figure 7.29: Dabakan-1 MDT pressures over all intervals

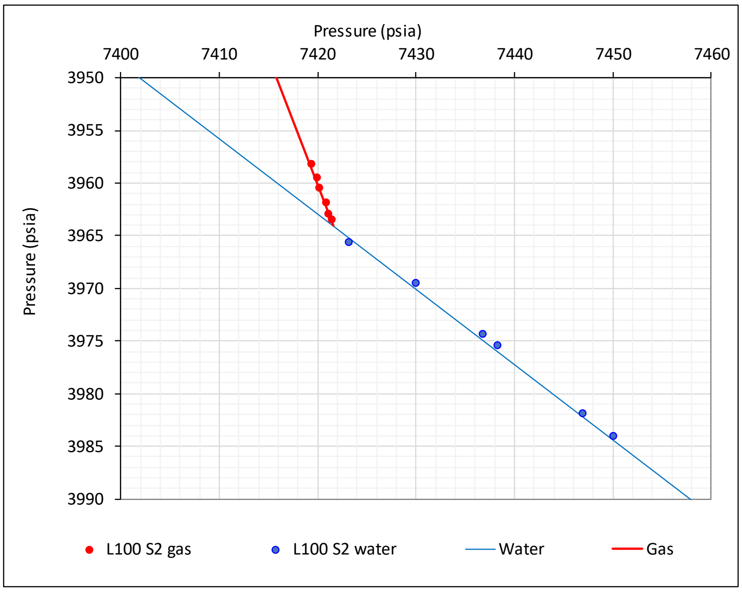


Figure 7.30: Dabakan-1 MDT pressures over L100 S2 sands

RDT pressures were taken in all the gas bearing sands in Well Palendag-1, as well as the two water bearing L40S1 and L40-S3 sands above and below the gas bearing L40-S2 sands (Figure 7.31). The formations are all over pressured, with over pressure increasing with depth from approximately 200 to 300 psia at the shallowest L100 sands to nearly 3,000 psia at the deepest L20 sands. The only sands that are water saturated are the L40S1 and L40 S3 sands that lie above and below the L40 S2 sands. These sands are approximately 2,500 psia over pressured. The L40 S1 and L40 S3 sands appear to lie on the same water line. If the gas pressures in the L40 S2 sands are extrapolated to this water line, a GWC of 4,465 mTVDSS is inferred. No GWCs for other gas bearing intervals can be inferred from the pressure measurements, due to the unknown water pressures.

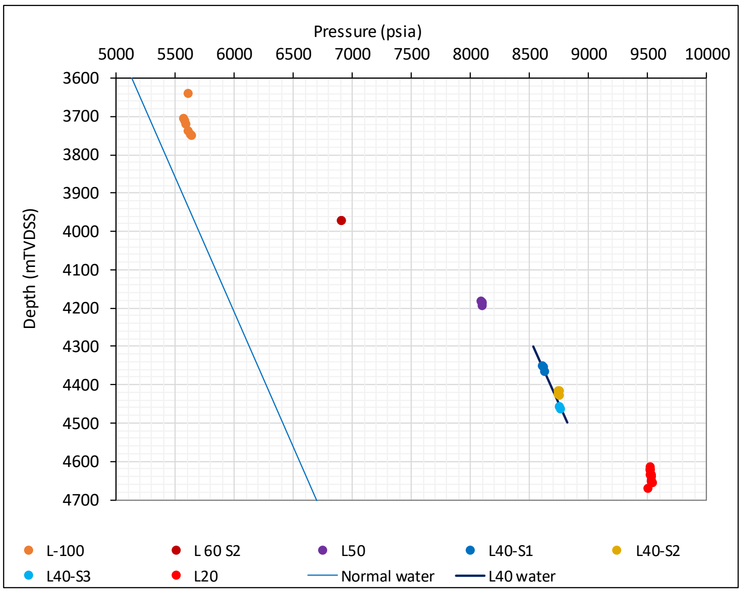


Figure 7.31: Palendag-1 RDT pressures over all intervals

7.6.3. PVT

Good quality downhole fluid samples were obtained from both Well Dabakan-1 and Well Palendag-1A. ERCE was provided with a report for each well.

In Well Dabakan-1 a total of ten samples were analysed, two from each of the sands L300 S1, L225 S1, L100 S1, L100 S2 and L100 S3. The laboratory data are good quality and are comprehensive enough for making reliable estimates of gas expansion factors, CGR and condensate yield as a function of reservoir depletion (Table 7-26). For L100 S2 and L80, for which no PVT reports are available, ERCE used the properties from the closest formations for which data were available.

In Well Palendag-1 a total of nine samples were analysed, four from L20, two from L40 and L50 and one from L60. The laboratory data are good quality and are comprehensive enough for making reliable estimates of gas expansion factors, CGR and condensate yield as a function of reservoir depletion (Table 7-28).

Table 7-26: Fluid properties for Dabakan

Item	Units	Low	Best	High
Dabakan L300 S1				
GEF:	(scf/rcf)	307	323	340
CGR:	(stb/MMscf)	9.8	13.1	16.3
Dry gas shrinkage:		98%	98%	97%
Non-HC gas fraction:		0.2%	0.2%	0.2%
Dabakan L225 S1				
GEF:	(scf/rcf)	304	320	336
CGR:	(stb/MMscf)	17.4	23	28.9
Dry gas shrinkage:		98%	97%	96%
Non-HC gas fraction:		0.7%	0.7%	0.7%
Dabakan L225 S2				
GEF:	(scf/rcf)	302	318	334
CGR:	(stb/MMscf)	20.3	27.0	33.8
Dry gas shrinkage:		97%	96%	96%
Non-HC gas fraction:		0.9%	0.9%	0.9%
Dabakan L100 S1				
GEF:	(scf/rcf)	296	311	327
CGR:	(stb/MMscf)	22.2	29.6	37.0
Dry gas shrinkage:		96%	95%	94%
Non-HC gas fraction:		0.8%	0.8%	0.8%
Dabakan L100 S2				
GEF:	(scf/rcf)	297	313	328
CGR:	(stb/MMscf)	20.7	27.7	34.6
Dry gas shrinkage:		97%	96%	95%
Non-HC gas fraction:		1.0%	1.0%	1.0%
Dabakan L100 S3				
GEF:	(scf/rcf)	310	326	342
CGR:	(stb/MMscf)	30.0	40.0	50.0
Dry gas shrinkage:		96%	94%	93%
Non-HC gas fraction:		1.4%	1.4%	1.4%
Dabakan L80				
GEF:	(scf/rcf)	310	326	342
CGR:	(stb/MMscf)	30.0	40.0	50.0
Dry gas shrinkage:		96%	94%	0%
Non-HC gas fraction:		1.4%	1.4%	1.4%

Table 7-27: Fluid properties for Palendag

Item	Units	Low	Best	High
Palendag L60				
GEF:	(scf/rcf)	314	331	347
CGR:	(stb/MMscf)	13.7	18.2	22.8
Dry gas shrinkage:		99%	98%	98%
Non-HC gas fraction:		0.9%	0.9%	0.9%
Palendag L50				
GEF:	(scf/rcf)	316	332	349
CGR:	(stb/MMscf)	6.1	8.1	10.2
Dry gas shrinkage:		99%	98%	98%
Non-HC gas fraction:		0.8%	0.8%	0.8%
Palendag L40				
GEF:	(scf/rcf)	325	342	359
CGR:	(stb/MMscf)	16.2	21.6	26.9
Dry gas shrinkage:		96%	95%	94%
Non-HC gas fraction:		1.5%	1.5%	1.5%
Palendag L20				
GEF:	(scf/rcf)	325	342	360
CGR:	(stb/MMscf)	22.8	30.4	38.0
Dry gas shrinkage:		96%	95%	94%
Non-HC gas fraction:		1.4%	1.4%	1.4%

7.6.4. Recovery Factors

There are currently no firm plans for the development of the Dabakan and Palendag discoveries. ERCE has therefore applied reasonable ranges of recovery factors for the gas for potential future developments. For condensate, we have coupled the gas recovery factors to CVD experiment based estimates of liquid recovery to derive ranges of recovery factors for condensate. The recovery factors that have been applied to our estimates of GIIP to report Contingent Resources are shown in Table 7-28 for Dabakan and Table 7-29. For estimating gas recovery factors, we have taken into account net pay thickness, NTG and qualitative assessments of reservoir permeability based on MDT and RDT pressure measurements.

Table 7-28: Recovery Factors for Dabakan

Item	Low	Best	High
Dabakan L300 S1			
Gas RF:	55%	65%	75%
Condensate RF:	22%	32%	42%
Dabakan L225 S1			
Gas RF:	50%	60%	70%
Condensate RF:	19%	29%	39%
Dabakan L225 S2			
Gas RF:	55%	65%	75%
Condensate RF:	20%	30%	40%
Dabakan L100 S1			
Gas RF:	70%	80%	90%
Condensate RF:	28%	38%	48%
Dabakan L100 S2			
Gas RF:	65%	75%	85%
Condensate RF:	30%	40%	50%
Dabakan L100 S3			
Gas RF:	60%	70%	80%
Condensate RF:	27%	37%	47%
Dabakan L80			
Gas RF:	55%	65%	75%
Condensate RF:	24%	34%	44%

Table 7-29: Recovery Factors for Palendag

Item	Low	Best	High
Palendag L60			
Gas RF:	55%	65%	75%
Condensate RF:	4%	14%	24%
Palendag L50			
Gas RF:	55%	65%	75%
Condensate RF:	9%	19%	29%
Palendag L40			
Gas RF:	55%	65%	75%
Condensate RF:	20%	30%	40%
Palendag L20			
Gas RF:	65%	75%	85%
Condensate RF:	24%	34%	44%

7.6.5. **Chance of Development**

There is no defined development plan for the Dabakan and Palendag discoveries and as Jadestone are not the operator of SC56 the commitment to and timing of any development is unclear. There is a further risk that any volumes are uneconomic and as such we have assigned a chance of development of 35% to each discovery.

8. Appendix 1: SPE PRMS Guidelines

SPE/WPC/AAPG/SPEE Petroleum Reserves and Resources Classification System and Definitions

The Petroleum Resources Management System

Preamble

Petroleum Resources are the estimated quantities of hydrocarbons naturally occurring on or within the Earth's crust. Resource assessments estimate total quantities in known and yet-to-be-discovered accumulations; Resources evaluations are focused on those quantities that can potentially be recovered and marketed by commercial projects. A petroleum Resources managements system provides a consistent approach to estimating petroleum quantities, evaluating development projects and presenting results within a comprehensive classification framework.

International efforts to standardise the definitions of petroleum Resources and how they are estimated began in the 1930s. Early guidance focused on Proved Reserves. Building on work initiated by the Society of Petroleum Evaluation Engineers (SPEE), SPE published definitions for all Reserves categories in 1987. In the same year, the World Petroleum Council (WPC, then known as the World Petroleum Congress), working independently, published Reserves definitions that were strikingly similar. In 1997, the two organizations jointly released a single set of definitions for Reserves that could be used worldwide. In 2000, the American Association of Petroleum Geologists (AAPG), SPE, and WPC jointly developed a classification system for all petroleum Resources. This was followed by additional supporting documents: supplemental application evaluation guidelines (2001) and a glossary of terms utilised in Resources definitions (2005). SPE also published standards for estimating and auditing Reserves information (revised 2007).

These definitions and the related classification system are now in common use internationally within the petroleum industry. They provide a measure of comparability and reduce the subjective nature of Resources estimation. However, the technologies employed in petroleum exploration, development, production, and processing continue to evolve and improve. The SPE Oil and Gas Reserves Committee works closely with other organizations to maintain the definitions and issues periodic revisions to keep current with evolving technologies and changing commercial opportunities.

The SPE-PRMS consolidates, builds on, and replaces guidance previously contained in the 1997 Petroleum Reserves Definitions, the 2000 Petroleum Resources Classification and Definitions publications, and the 2001 "Guidelines for the Evaluation of Petroleum Reserves and Resources"; the latter document remains a valuable source of more detailed background information.

These definitions and guidelines are designed to provide a common reference for the international petroleum industry, including national reporting and regulatory disclosure agencies, and to support petroleum project and portfolio management requirements. They are intended to improve clarity in global communications regarding petroleum Resources. It is expected that the SPE-PRMS will be supplemented with industry education programs and application guides addressing their implementation in a wide spectrum of technical and/or commercial settings.

It is understood that these definitions and guidelines allow flexibility for users and agencies to tailor application for their particular needs; however, any modifications to the guidance contained herein should be clearly identified. The definitions and guidelines contained in this document must not be construed as modifying the interpretation or application of any existing regulatory reporting requirements.

The full text of the SPE/WPC/AAPG/SPEE Petroleum Resources Management System document, hereinafter referred to as the SPE-PRMS, can be viewed at http://www.spe.org/specma/binary/files6859916Petroleum_Resources_Management_System_2007.pdf

Overview and Summary of Definitions

The estimation of petroleum resource quantities involves the interpretation of volumes and values that have an inherent degree of uncertainty. These quantities are associated with development projects at various stages of design and implementation. Use of a consistent classification system enhances comparisons between projects, groups of projects, and total Company portfolios according to forecast production profiles and recoveries. Such a system must consider both technical and commercial factors that impact the project's economic feasibility, its productive life, and its related cash flows.

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

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

Figure 1-1 is a graphical representation of the SPE/WPC/AAPG/SPEE Resources classification system. The system defines the major recoverable Resources classes: Production, Reserves, Contingent Resources, and Prospective Resources, as well as Unrecoverable petroleum.

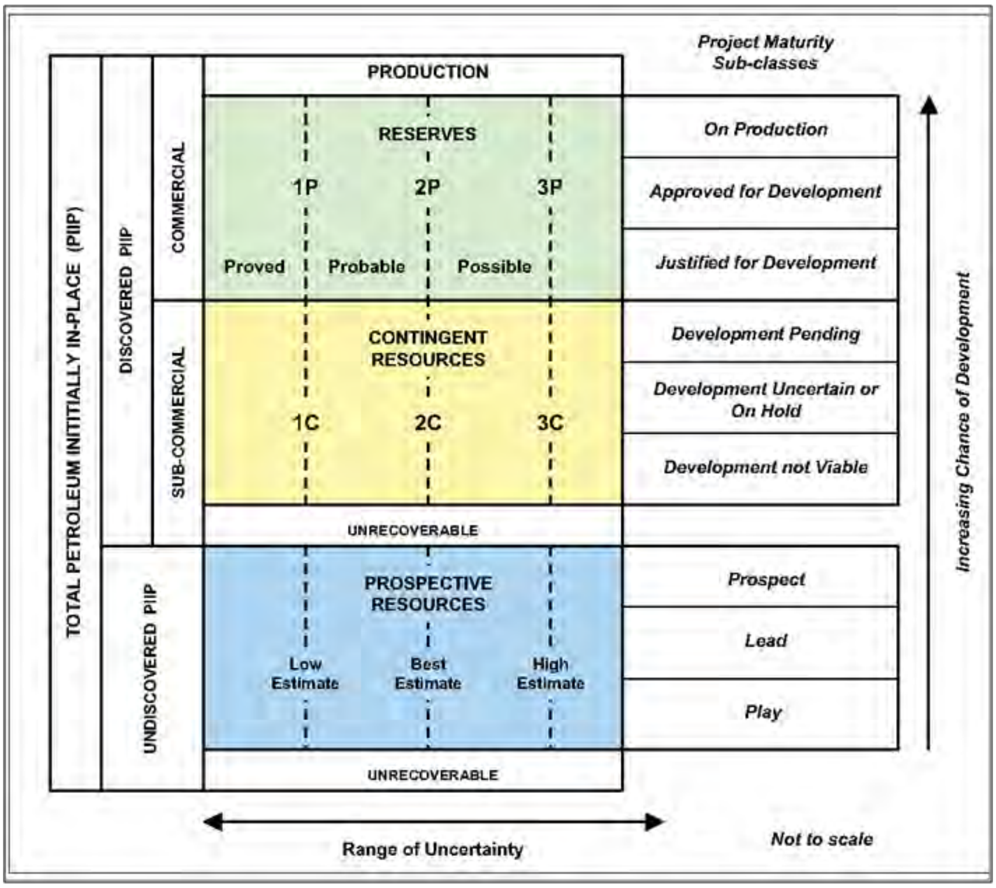


Figure 1-1: SPE/AAPG/WPC/SPEE Resources Classification System

The “Range of Uncertainty” reflects a range of estimated quantities potentially recoverable from an accumulation by a project, while the vertical axis represents the “Chance of Development”, that is, the chance that the project that will be developed and reach commercial producing status.

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

TOTAL PETROLEUM INITIALLY-IN-PLACE

Total Petroleum Initially in Place is that quantity of petroleum that is estimated to exist originally in naturally occurring accumulations.

It includes that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production plus those estimated quantities in accumulations yet to be discovered (equivalent to “total Resources”).

DISCOVERED PETROLEUM INITIALLY-IN-PLACE

Discovered Petroleum Initially in Place is that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production.

PRODUCTION

Production is the cumulative quantity of petroleum that has been recovered at a given date.

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

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 satisfy four criteria: they must be discovered, recoverable, commercial, and remaining based on the development project(s) applied. Reserves are further subdivided in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterised by their development and production status. To be included in the Reserves class, a project must be sufficiently defined to establish its commercial viability. There must be a reasonable expectation that all required internal and external approvals will be forthcoming, and there is evidence of firm intention to proceed with development within a reasonable time frame. A reasonable time frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While five years is recommended as a benchmark, a longer time frame could be applied where, for example, development of economic projects are deferred at the option of the producer for, among other things, market-related reasons, or to meet contractual or strategic objectives.

In all cases, the justification for classification as Reserves should be clearly documented. To be included in the Reserves class, there must be a high confidence in the commercial producibility of the reservoir as supported by actual production or formation tests. In certain cases, Reserves may be assigned on the basis of well logs and/or core analysis that indicate that the subject reservoir is hydrocarbon-bearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation tests.

Proved Reserves

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. The area of the reservoir considered as Proved includes:

the area delineated by drilling and defined by fluid contacts, if any, and

adjacent undrilled portions of the reservoir that can reasonably be judged as continuous with it and commercially productive on the basis of available geoscience and engineering data.

In the absence of data on fluid contacts, Proved quantities in a reservoir are limited by the lowest known hydrocarbon (LKH) as seen in a well penetration unless otherwise indicated by definitive geoscience, engineering, or performance data. Such definitive information may include pressure gradient analysis and seismic indicators. Seismic data alone may not be sufficient to define fluid contacts for Proved Reserves (see "2001 Supplemental Guidelines," Chapter 8). Reserves in undeveloped locations may be classified as Proved provided that the locations are in undrilled areas of the reservoir that can be judged with reasonable certainty to be commercially productive and interpretations of available geoscience and engineering data indicate with reasonable certainty that the objective formation is laterally continuous with drilled Proved locations.

For Proved Reserves, the recovery efficiency applied to these reservoirs should be defined based on a range of possibilities supported by analogs and sound engineering judgment considering the characteristics of the Proved area and the applied development program.

Probable Reserves

Probable Reserves are those additional Reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves.

It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate.

Probable Reserves may be assigned to areas of a reservoir adjacent to Proved where data control or interpretations of available data are less certain. The interpreted reservoir continuity may not meet the reasonable certainty criteria. Probable estimates also include incremental recoveries associated with project recovery efficiencies beyond that assumed for Proved.

Possible Reserves

Possible Reserves are those additional Reserves which analysis of geoscience and engineering data indicate 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.

Possible Reserves may be assigned to areas of a reservoir adjacent to Probable where data control and interpretations of available data are progressively less certain. Frequently, this may be in areas where geoscience and engineering data are unable to clearly define the area and vertical reservoir limits of commercial production from the reservoir by a defined project.

Possible estimates also include incremental quantities associated with project recovery efficiencies beyond that assumed for Probable.

Probable and Possible Reserves

(See above for separate criteria for Probable Reserves and Possible Reserves.)

The 2P and 3P estimates may be based on reasonable alternative technical and commercial interpretations within the reservoir and/or subject project that are clearly documented, including comparisons to results in successful similar projects.

In conventional accumulations, Probable and/or Possible Reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from Proved areas by minor faulting or other geological discontinuities and have not been penetrated by a wellbore but are interpreted to be in communication with the known (Proved) reservoir. Probable or Possible Reserves may be assigned to areas that are structurally higher than the Proved area. Possible (and in some cases, Probable) Reserves may be assigned to areas that are structurally lower than the adjacent Proved or 2P area.

Caution should be exercised in assigning Reserves to adjacent reservoirs isolated by major, potentially sealing, faults until this reservoir is penetrated and evaluated as commercially productive. Justification for assigning Reserves in such cases should be clearly documented. Reserves should not be assigned to areas that are clearly separated from a known accumulation by non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results); such areas may contain Prospective Resources.

In conventional accumulations, where drilling has defined a highest known oil (HKO) elevation and there exists the potential for an associated gas cap, Proved oil Reserves should only be assigned in the structurally higher portions of the reservoir if there is reasonable certainty that such portions are initially above bubble point pressure based on documented engineering analyses. Reservoir portions that do not meet this certainty may be assigned as Probable and Possible oil and/or gas based on reservoir fluid properties and pressure gradient interpretations.

CONTINGENT RESOURCES

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

Contingent Resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent Resources are further categorised in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterised by their economic status.

UNDISCOVERED PETROLEUM INITIALLY-IN-PLACE

Undiscovered Petroleum Initially in Place is that quantity of petroleum that is estimated, as of a given date, to be contained within accumulations yet to be discovered.

PROSPECTIVE RESOURCES

Prospective Resources are those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations.

Potential accumulations are evaluated according to their chance of discovery and, assuming a discovery, the estimated quantities that would be recoverable under defined development projects. It is recognised that the development programs will be of significantly less detail and depend more heavily on analog developments in the earlier phases of exploration.

Prospect

A project associated with a potential accumulation that is sufficiently well defined to represent a viable drilling target.

Project activities are focused on assessing the chance of discovery and, assuming discovery, the range of potential recoverable quantities under a commercial development program.

Lead

A project associated with a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation in order to be classified as a prospect.

Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to confirm whether or not the lead can be matured into a prospect. Such evaluation includes the assessment of the chance of discovery and, assuming discovery, the range of potential recovery under feasible development scenarios.

Play

A project associated with a prospective trend of potential prospects, but which requires more data acquisition and/or evaluation in order to define specific leads or prospects.

Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to define specific leads or prospects for more detailed analysis of their chance of discovery and, assuming discovery, the range of potential recovery under hypothetical development scenarios.

The range of uncertainty of the recoverable and/or potentially recoverable volumes may be represented by either deterministic scenarios or by a probability distribution. When the range of uncertainty is represented by a probability distribution, a low, best, and high estimate shall be provided such that:

• There should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the low estimate.

• There should be at least a 50% probability (P50) that the quantities actually recovered will equal or exceed the best estimate.

• There should be at least a 10% probability (P10) that the quantities actually recovered will equal or exceed the high estimate.

When using the deterministic scenario method, typically there should also be low, best, and high estimates, where such estimates are based on qualitative assessments of relative uncertainty using consistent interpretation guidelines. Under the deterministic incremental (risk-based) approach, quantities at each level of uncertainty are estimated discretely and separately.

These same approaches to describing uncertainty may be applied to Reserves, Contingent Resources, and Prospective Resources. While there may be significant risk that sub-commercial and undiscovered accumulations will not achieve commercial production, it useful to consider the range of potentially recoverable quantities independently of such a risk or consideration of the resource class to which the quantities will be assigned.

Evaluators may assess recoverable quantities and categorise results by uncertainty using the deterministic incremental (risk-based) approach, the deterministic scenario (cumulative) approach, or probabilistic methods (see “2001 Supplemental Guidelines,” Chapter 2.5). In many cases, a combination of approaches is used.

Use of consistent terminology (Figure 1.1) promotes clarity in communication of evaluation results. For Reserves, the general cumulative terms low/best/high estimates are denoted as 1P/2P/3P, respectively. The associated incremental quantities are termed Proved, Probable and Possible. Reserves are a subset of, and must be viewed within context of, the complete Resources classification system. While the categorization criteria are proposed specifically for Reserves, in most cases, they can be equally applied to Contingent and Prospective Resources conditional upon their satisfying the criteria for discovery and/or development.

For Contingent Resources, the general cumulative terms low/best/high estimates are denoted as 1C/2C/3C respectively. For Prospective Resources, the general cumulative terms low/best/high estimates still apply. No specific terms are defined for incremental quantities within Contingent and Prospective Resources.

Without new technical information, there should be no change in the distribution of technically recoverable volumes and their categorization boundaries when conditions are satisfied sufficiently to reclassify a project from Contingent Resources to Reserves. All evaluations require application of a consistent set of forecast conditions, including assumed future costs and prices, for both classifications of projects and categorization of estimated quantities recovered by each project.

9. Appendix 2: Nomenclature

"AAI"	means absolute acoustic impedance
"AI"	means acoustic impedance
"°API"	means degrees API, a measure of oil density
"ATCF"	means after-tax cashflow
"AVO"	means Amplitude variation with Offset
"bbl"	means barrels
"Bcf"	means thousands of millions of standard cubic feet
"BCU"	means Base Cretaceous Unconformity
"Bo"	means oil shrinkage factor or formation volume factor, in rb/stb
"boe"	means barrels of oil equivalent, where 6000 scf of gas = 1 bbl of oil.
"°C"	means degrees Celsius
"CBM"	controlled beam migration
"CCE"	means constant composition expansion
"CGR"	means condensate gas ratio
"CIIP"	means condensate initially in place
"CIT"	means corporate income tax
"CPI"	means computer processed interpretation
"CPP"	means central processing platform
"CVD"	means constant volume depletion
"1C"	means Low Estimate Contingent Resource
"2C"	means Best Estimate Contingent Resource
"3C"	means High Estimate Contingent Resource
"cm"	means centimeter
"cp"	means centipoises
"CPI"	means Computer Processed Information log
"CRA"	means corrosion resistant alloy
"3D"	means three dimensional
"DST"	means drillstem test
"Eg"	means gas expansion factor
"EPT"	means a Shell Internal Audit Process conducted in 2006
"°F"	means degrees Fahrenheit
"FDP"	means field development plan

"FEED"	means front end engineering and design
"ft"	means feet
"ftss"	means feet subsea
"FTHP"	means flowing tubing head pressure
"FSO"	means floating storage and offloading vessel
"FVF"	means formation volume factor
"FWS"	means full wellstream
"g"	means gram
"G&A"	means general & administrative (expenses)
"GDT"	means gas down to
"GEF"	means gas expansion factor
"GIIP"	means gas initially in place
"GOC"	means gas oil contact
"GOR"	means gas oil ratio
"GR"	means Gamma Ray
"GRV"	means gross rock volume
"GSA"	means gas sales agreement
"GWC"	means gas water contact
"HCGR"	means uranium free gamma-ray
"HCPT"	means hydrocarbon pore thickness
"HCPV"	means hydrocarbon pore volume
"IFA"	means in-situ fluid analyser
"IIP"	means initially in place
"Kair"	means air permeability
"kh"	means permeability thickness
"km"	means kilometers
"LNG"	means liquefied natural gas
"LPG"	means liquefied petroleum gas
"m"	means metres
"M" "MM"	means thousands and millions respectively
"MBAL"	means material balance computer programme
"md" or "mD"	means millidarcy
"MD"	means measure depth
"MDT"	means modular formation dynamic tester

“mgal”	means milligal where 1 mGal is one thousandth of 1cm/s2
“MSL”	means Mean Sea Level
“m/s”	means metres per second
"mss"	means metres subsea
“NaCl”	means sodium chloride
“N/G”	means net to gross ratio
“NMR”	means nuclear magnetic resonance
“Np”	means cumulative oil production
“OBC”	means ocean bottom cable
“ODP”	means outline development plan
“ODT”	means oil down to
“OWC”	means oil water contact
“Por” or “Phi”	means porosity
“PHIE”	means effective porosity
“PHIT”	means total porosity
“Proved”	means Proved, as defined in Appendix 1
“Probable”	means Probable, as defined in Appendix 1
“Possible”	means Possible, as defined in Appendix 1
“PRRT”	means petroleum resource rent tax
“PSC”	means Production Sharing Contract
“PoSTM”	means post stack time migration
“PSDM”	means pre stack depth migration
“PTA”	means pressure transient analysis
"1P" or “P”	means Proved
"2P" or “P+P”	means Proved + Probable
"3P" or P+P+P	means Proved + Probable +Possible
“P99”	means 99 per cent probability
"P90"	means 90 per cent probability = Proved
"P50"	means 50 per cent probability = Proved + Probable
"P10"	means 10 per cent probability = Proved + Probable + Possible
“P1”	means one per cent probability
“P0”	means zero per cent probability
“psia”	means pounds per square inch absolute
“psig”	means pounds per square inch gauge

"ppm"	means parts per million
"pu"	means porosity unit
"PVT"	means pressure, volume, temperature
"P/Z"	means pressure divided by gas deviation factor (material balance)
"RAR"	means Reserves Assessment Report (Vietnam)
"rcf"	means cubic feet at reservoir conditions
"RDT"	means reservoir description tool
"res bbl"	means reservoir barrels
"Rs"	means solution gas oil ratio
"Rt"	means true resistivity
"scf"	means standard cubic feet measured at 14.7 pounds per square inch and 60 degrees Fahrenheit
"scfd"	means standard cubic feet per day
"Sg"	means gas saturation
"So"	means oil saturation
"Soi"	means initial oil saturation
"Sor"	means residual oil saturation
"stb"	means a standard barrel which is 42 US gallons measured at 14.7 pounds per square inch and 60 degrees Fahrenheit
"stb/d"	means standard barrels per day
"STOIIP"	means stock tank oil initially in place
"ss" or "TVDSS"	means true vertical depth sub-sea
"Sw"	means water saturation
"TAD"	means tender assisted drilling
"TD"	means total depth
"TVD"	means true vertical depth
"TOC"	means total organic carbon
"twt"	means two way time
"Vshale"	means shale volume
"WF"	means water-flood
"WGR"	means water gas ratio
"WHP"	means wellhead platform
"WOR"	means water oil ratio
"WUT"	means water up to

Part 7

HISTORIC FINANCIAL INFORMATION OF THE COMPANY

Appendix 1 contains the Jadestone Energy Inc. Audited Consolidated Financial Statements for the nine months ended December 31, 2017 and year ended March 31, 2017

Appendix 2 contains the Jadestone Energy Inc. (formerly Mitra Energy Inc.) Audited Consolidated Financial Statements for the years ended March 31, 2017 and March 31, 2016

Appendix 3 contains the Mitra Energy Inc. (formerly Petra Petroleum Inc.) Audited Consolidated Financial statements for the years ended March 31, 2016 and March 31, 2015

Appendix 4 contains the Jadestone Energy Inc. Condensed Consolidated Financial Statements (unaudited) for the three months ended March 31, 2018

Part 8

UNAUDITED HISTORIC FINANCIAL INFORMATION OF THE MONTARA ASSETS

	Year ended 31 December 2015 US$'000	Year ended 31 December 2016 US$'000	Year ended 31 December 2017 US$'000
Gross revenue	334,619	235,790	220,587
Royalties	—	—	—
Net revenue	334,619	235,790	220,587
Production costs	(42,677)	(55,434)	(69,355)
Depletion, depreciation and amortisation	(400,993)	(219,185)	(132,890)
Staff costs	(36,570)	(33,133)	(32,372)
Other expenses	(1,127)	(6,705)	(651)
Impairment of assets	(331,000)	—	—
Other income	745	284	455
Purchase discount	—	—	—
	(811,623)	(314,172)	(234,813)
Finance costs	(5,795)	(5,219)	(5,362)
Loss before tax	**(482,799)**	**(83,601)**	**(19,588)**

Basis of preparation

Audited Financial Statements are not prepared at the Montara Assets or field level by PTTEP. Instead, individual field level financial information has been extracted from PTTEP Australasia's Oracle system to form the above unaudited historical financial information table.

For the purposes of the Acquisition, an individual field level profit and loss account has been extracted from PTTEP Australasia's Oracle systems by extracting expenditure based on legal entity and project code, inclusive of an appropriate allocation of corporate costs.

Costs for projects are broadly split into two categories being direct costs and indirect costs. Direct costs relate to those that benefit a project specifically such as drilling expenditure, geological and geophysical studies, etc. These have been allocated based on the project to which they relate.

Indirect costs are associated with work conducted to support the management and operation of projects, but that are not incurred specifically for a particular project, for example general and administration expenditure. These costs are allocated based on usage, for example man hours captured through time-writing.

The individual field profit and loss account is not subject to external audit and is not wholly prepared in accordance with International Financial and Report Standards (IFRS) given it is a 'carve out' from a larger reporting entity. For example, the profit and loss account has been prepared on a before-tax basis, given the significant challenges of preparing income tax calculations for a standalone part of a larger tax group.

The individual field level profit and loss account was then adjusted for known transactions that are outside the transaction perimeter. In particular, the impact of insurance recoveries and legal actions that relate to periods prior to those presented and are not being transferred with the assets have been excluded from the results.

Crude oil sales

Revenue predominately relates to the sale of crude oil produced through the Montara FPSO in each respective period. The Montara FPSO aggregates crude oil produced from three fields in the Timor Sea being Montara, Skua and Swift/Swallow.

Revenue is measured at the fair value of consideration received or receivable. Sales revenue is recognised when the risks and benefits of ownership have passed to the customer. Crude oil revenue represents revenue from crude oil liftings in the period.

Production costs

Production costs relate mainly to changes to operating supplies, repairs and maintenance, consumables, and transport. They also reflect the impact of movements in inventory in the period.

Depletion, depreciation and amortisation

Oil and gas assets are depreciated to their residual value over the economically recoverable reserves within the area of interest relevant to the oil and gas assets. The units of production basis of depreciation results in a charge for the year that is proportional to the depletion of economically recoverable reserves.

Determining the economically recoverable reserves requires significant judgment about future oil prices, the likelihood of future capital expenditure as well as the geology of the area of interest. These, along with the assets' residual value, are reviewed and adjusted if required at each reporting date.

Other operating expenses

Other operating expenses largely consist of general & administrative expenses. General & administrative expenses comprises of costs incurred for the day to day running of the business which may include staff expenses, fringe benefit tax, bank charges, audit and tax services, external consultants, subscriptions, etc. These costs are allocated to the permit/project either in total if wholly related to the project or based on an allocation methodology if a shared cost. Other operating expenses also includes the impact of write downs to spare parts inventory.

Finance costs

Finance costs represent the unwinding of discounting of the Montara Assets' retirement obligations provision.

Part 9

UNAUDITED PRO FORMA FINANCIAL INFORMATION OF THE GROUP

The unaudited *pro forma* balance sheet set out below has been prepared by Jadestone management for the purpose of illustrating the effect of the Acquisition on the balance sheet of the Company as at 31 December 2017, as if it had taken place on that date. The unaudited *pro forma* balance sheet has been prepared for illustrative purposes only and, by its nature, addresses a hypothetical situation and, does not, therefore, represent the Company's or the Group's actual financial position or results. The unaudited *pro forma* balance sheet has been prepared on the basis set out in the notes below.

The unaudited *pro forma* balance sheet does not constitute financial statements within the meaning of Section 434 of the Companies Act.

Users should read the whole of this document and not rely solely on the summarised financial information contained in this Part 9 of this document.

Assets	**Jadestone net assets as at 31 December 2017 Note 1 US$'000**	**Capital raising (unaudited) Note 2 US$'000**	**Debt financing (unaudited) Note 3 US$'000**	**Montara Acquisition (unaudited) Note 4 US$'000**	**Enlarged Group *pro forma* as at 31 December 2017 (unaudited) US$'000**
Non-current assets:					
Intangible exploration assets	105,673				105,673
Oil and gas properties	62,238		2,400	255,581	320,219
Deferred tax assets	23,821			89,590	113,411
Plant and equipment	648				648
Restricted cash	10,729				10,729
	203,109	0	2,400	345,171	550,680
Current assets:					
Inventories	9,610			34,492	44,102
Receivables and prepayments	4,719			0	4,719
Cash and cash equivalents	10,450	85,508	117,600	(204,007)	9,551
	24,779	85,508	117,600	(169,515)	58,372
Total Assets	227,888	85,508	120,000	175,656	609,052
Equity and liabilities					
Equity:					
Share Capital	364,466	110,000			474,466
Share-based payment and warrants	21,855				21,855
Accumulated losses	(278,123)	(8,655)		(2,577)	(289,355)
	108,198	101,345	0	(2,577)	206,966
Non-current liabilities:					
Provision for asset restoration obligations	84,728			171,033	255,761
Other payables	7,259				7,259
Deferred tax liabilities	200				200
Borrowings	0		120,000		120,000
Contingent consideration				4,200	4,200
Secured convertible bonds	12,770	(12,770)			0
Derivative financial instruments	3,067	(3,067)			0
	108,024	(15,837)	120,000	175,233	387,420
Current liabilities:					
Contingent consideration				3,000	3,000
Borrowings	829				829
Trade and other payables, accruals and provisions	10,837				10,837
	11,666	0	0	3,000	14,666
Total equity and liabilities	227,888	85,508	120,000	175,656	609,052

Notes

1. The net assets of Jadestone as at 31 December 2017 have been extracted without material adjustment from the audited financial statements of the Company set out in Part 7 of this Document.
2. As set out in Section 11 of Part 1, Jadestone is seeking to raise US$110 million through the Placing associated with this Admission Document. This adjustment reflects the proceeds raised from the Placing, net of estimated equity raising costs of US$7 million. Part of the proceeds raised will be utilised to settle the Convertible Facility commitment amounting to US$17.45 million. As a result of the settlement of the Convertible Facility, the resulting book values for Convertible Facility and the related derivative financial instrument will be adjusted down to nil with the corresponding residual loss of US$1.6 million being applied to accumulated losses.
3. As set out in paragraph 12.1 of Part 11, Jadestone has available borrowing facilities of US$120 million. Jadestone will draw down US$120 million to fund the acquisition of the Montara Assets. This adjustment reflects the proceeds raised from this draw down, less transaction costs of two per cent which have been capitalised and form part of oil and gas properties.
4. This adjustment reflects the entries that would have arisen had the Acquisition occurred on 31 December 2017. Unless otherwise stated below, information has been extracted directly from PTTEP Australasia's interim accounting records from its Oracle accounting software and trial balance for the year ended 31 December 2017 and agreed to PTTEP Australasia's audited financial statements in a manner consistent with the preparation of the Unaudited Historical Financial Information on the Montara Assets included in Part 8 of this Document. For the purposes of this *pro forma* financial information, no fair value adjustments have been made to the separate assets and liabilities being acquired, in line with IFRS 3 – Business Combinations, and will be subject to such a redetermination as at the effective date of the transaction.

   Adjustments include:

   - Oil and gas properties are calculated to ensure that no goodwill or gain on bargain purchase is recognised on consolidation which Jadestone management believe to be appropriate given that the Montara Assets are being acquired as part of a competitive sale process. Total consideration for the Montara Assets is estimated to be US$208.6 million (consisting of upfront consideration of US$195.0 million, crude inventory of US$6.4 million and the estimated fair value of contingent consideration of US$7.2 million). Given the assumption of a transaction date of 31 December 2017, it does not include any adjustment for the Agreed Capital Charge or the Net Income Amount, as these both arise due to the passage of time from 31 December 2017 to the date of Completion, and will impact both the consideration and the assets acquired.

     This accounting treatment results in a downward adjustment of US$73.4 million to PTTEP Australasia's book value of the assets. The assets will be re-measured to fair value following completion of the transaction and this may be materially different from the *pro forma* information shown here.
   - Deferred tax assets represent the net deferred tax assets and liabilities relating to the Petroleum Resources Rent Tax ("**PRRT**") in PTTEP Australasia's financial statements, with an upward adjustment of US$20.5 million to reflect the reduction in the book value of oil and gas properties noted above. The adjustment is calculated as the reduction in oil and gas properties multiplied by the Petroleum Resources Rent Tax (PRRT) effective tax rate of 28% (PRRT 40% net of 30% Australian corporation tax). On completion of the transaction, the deferred tax assets will be re-measured based on the temporary differences arising in the completion fair value balance sheet and updated management forecast of the recoverability of PRRT credits at the transaction date.
   - Inventories have been extracted from PTTEP Australasia's Oracle accounting system, and reconciled to the financial statements, as at 31 December 2017, in a manner consistent with the preparation of the Unaudited Historical Financial Information on the Montara Assets included in Part 8 of this document. Crude Oil inventory of US$6.4 million has been recognised at its net realisable value in these accounts. The fair value of spare parts inventory will be determined following the closing of the transaction, therefore a book value of US$28.1 million has been used.
   - Receivables and prepayment balances have been extracted from the Oracle accounting system of PTTEP Australasia and reconciled to the financial statements as at 31 December 2017, in a manner consistent with the preparation of the Unaudited Historical Financial Information on the Montara Assets included in Part 8 of this document.
   - The cash balance adjustment has been calculated to reflect the initial cash outlay of US$201.4 million consideration (upfront US$195.0 million, crude inventory US$6.4 million) and assumed transaction costs of US$2.6 million.
   - Losses reflect management's estimate of transaction costs, as described above.
   - An estimate of the expected fair value of the asset restoration obligation has been based on the provision recognised within the Oracle accounting system of PTTEP Australasia, reconciled to the audited financial statements, and applied in the preparation of the Unaudited Historical Financial Information on the Montara Assets.
   - The contingent consideration balance reflects Jadestone management's estimate of the expected present value of the contingent consideration.

Part 10

TERMS AND CONDITIONS OF THE PLACING

IMPORTANT INFORMATION FOR INVITED PLACEES ONLY

MEMBERS OF THE PUBLIC ARE NOT ELIGIBLE TO TAKE PART IN THE PLACING. THIS DOCUMENT AND THE TERMS AND CONDITIONS SET OUT AND REFERRED TO HEREIN ARE FOR INFORMATION PURPOSES ONLY AND ARE DIRECTED ONLY AT PERSONS SELECTED BY STIFEL NICOLAUS EUROPE LIMITED, ("**STIFEL**") OR BMO CAPITAL MARKETS LIMITED ("**BMO**") AND TOGETHER WITH STIFEL, THE "**BOOKRUNNERS**" AND EACH A "**BOOKRUNNER**") WHO ARE (A) PERSONS IN MEMBER STATES OF THE EUROPEAN ECONOMIC AREA WHO ARE "QUALIFIED INVESTORS", AS DEFINED IN ARTICLE 2.1(E) OF DIRECTIVE 2003/71/EC AS AMENDED FROM TIME TO TIME AND INCLUDES ANY RELEVANT IMPLEMENTING DIRECTIVE MEASURE IN ANY MEMBER STATE (THE "**PROSPECTUS DIRECTIVE**") AND (B) IF IN THE UNITED KINGDOM, PERSONS WHO (I) HAVE PROFESSIONAL EXPERIENCE IN MATTERS RELATING TO INVESTMENTS WHO FALL WITHIN THE DEFINITION OF "INVESTMENT PROFESSIONALS" IN ARTICLE 19(5) OF THE FINANCIAL SERVICES AND MARKETS ACT 2000 (FINANCIAL PROMOTION) ORDER 2005 AS AMENDED (THE "**ORDER**") OR ARE PERSONS WHO FALL WITHIN THE DEFINITION OF "HIGH NET WORTH COMPANIES, UNINCORPORATED ASSOCIATIONS ETC" FALLING IN ARTICLE 49(2)(A) TO (D) OF THE ORDER AND (II) ARE "QUALIFIED INVESTORS" AS DEFINED IN SECTION 86 OF THE FINANCIAL SERVICES AND MARKETS ACT 2000 ("**FSMA**") OR (C) PERSONS TO WHOM IT MAY OTHERWISE LAWFULLY BE COMMUNICATED (ALL SUCH PERSONS TOGETHER BEING REFERRED TO AS "**RELEVANT PERSONS**"). THE TERMS AND CONDITIONS SET OUT HEREIN MUST NOT BE ACTED ON OR RELIED ON BY PERSONS WHO ARE NOT RELEVANT PERSONS.

THE PLACING SHARES ARE NOT QUALIFIED FOR SALE TO THE PUBLIC IN CANADA, AND MAY ONLY BE SOLD TO RESIDENTS OF CANADA PURSUANT TO AN EXEMPTION FROM THE PROSPECTUS REQUIREMENT. PURCHASERS OF PLACING SHARES WHO ARE NOT RESIDENT IN CANADA MAY NOT IMMEDIATELY, EITHER DIRECTLY OR INDIRECTLY, RE-SELL OR RE-DISTRIBUTE THE PLACING SHARES IN CANADA OR TO A CANADIAN RESIDENT.

DISTRIBUTION OF THIS DOCUMENT IN CERTAIN JURISDICTIONS MAY BE RESTRICTED OR PROHIBITED BY LAW. PERSONS DISTRIBUTING THIS DOCUMENT MUST SATISFY THEMSELVES THAT IT IS LAWFUL TO DO SO.

THESE TERMS AND CONDITIONS DO NOT THEMSELVES CONSTITUTE AN OFFER FOR SALE OR SUBSCRIPTION OF ANY SECURITIES IN THE COMPANY.

The Placing Shares (which shall include any Placing Shares as represented by Depositary Interests) have not been and will not be registered under the United States Securities Act of 1933, as amended (the "**US Securities Act**") or under the securities laws of any state or other jurisdiction of the United States and may not be offered, sold, resold or delivered, directly or indirectly, in or into the United States absent registration except pursuant to an exemption from, or in a transaction not subject to, the registration requirements of the US Securities Act. No public offering of the Placing Shares is being made in the United States. Persons receiving this document (including custodians, nominees and trustees) must not forward, distribute, mail or otherwise transmit it in or into the United States.

THE PLACING SHARES HAVE NOT BEEN APPROVED OR DISAPPROVED BY THE UNITED STATES SECURITIES AND EXCHANGE COMMISSION, ANY STATE SECURITIES COMMISSION OR OTHER REGULATORY AUTHORITY IN THE UNITED STATES, NOR HAVE ANY OF THE FOREGOING AUTHORITIES PASSED UPON OR ENDORSED THE MERITS OF THE PLACING OR THE ACCURACY OF THIS DOCUMENT (INCLUDING THIS PART 10). ANY REPRESENTATION TO THE CONTRARY IS A CRIMINAL OFFENCE IN THE UNITED STATES.

This document (including this Part 10) does not constitute an offer to sell or issue or a solicitation of an offer to buy or subscribe for Placing Shares in any jurisdiction in which such offer or solicitation is unlawful and, in particular, is not to be forwarded, distributed, mailed or otherwise transmitted in or into the United States, its territories or possessions, subject to certain limited exceptions. This document is not to be forwarded, distributed, mailed or otherwise transmitted in or into Canada, Australia, Japan, the Republic of South Africa and their respective territories and possessions (together, the "**Prohibited Territory**") or to any national, resident or citizen of the Prohibited Territory or to any corporation, partnership or other entity created or organised under the laws thereof, or to any persons in any other country outside the UK, where such distribution, forwarding or transmission may lead to a breach of any legal or regulatory requirement. No action has been taken by the Company, Stifel, BMO nor any of their respective Affiliates that would permit an offer of the Placing Shares or possession or distribution of this document (including this Part 10) or any other publicity material relating to such Placing Shares in any jurisdiction where action for that purpose is required. Persons receiving this document are required to inform themselves about and to observe any such restrictions.

Persons (including, without limitation, nominees and trustees) who have a contractual or other legal obligation to forward a copy of this document (including this Part 10) should seek appropriate advice before taking any action.

Any indication in this document of the price at which the Common Shares have been bought or sold in the past cannot be relied upon as a guide to future performance. Persons needing advice should consult an independent financial adviser. No statement in this document is intended to be a profit forecast and no statement in this document should be interpreted to mean that earnings per share of the Company for the current or future financial years would necessarily match or exceed the historical published earnings per share of the Company.

Stifel, which is authorised and regulated in the United Kingdom by the Financial Conduct Authority ("**FCA**"), is acting for the Company and for no one else in connection with the Placing and will not be responsible to anyone other than the Company for providing the protections afforded to clients of Stifel or for affording advice in relation to the Placing, or any other matters referred to herein. Any offer or sale of securities in Canada will be made by a person that is registered under applicable Canadian securities laws (which may an Affiliate of Stifel).

BMO, which is authorised and regulated in the United Kingdom by the FCA, is acting for the Company and for no one else in connection with the Placing and will not be responsible to anyone other than the Company for providing the protections afforded to clients of BMO or for affording advice in relation to the Placing, or any other matters referred to herein. Any offer or sale of securities in Canada will be made by a person that is registered under applicable Canadian securities laws (which may be an Affiliate of BMO).

By participating in the Placing, each person who is invited to and who chooses to participate in the Placing by making or accepting an oral or written offer to take up Placing Shares, including any individuals, funds or others on whose behalf a commitment to take up Placing Shares is given (a "**Placee**"), is deemed to have read and understood this document in its entirety (including this Part 10) and to be making or accepting such offer on the terms and conditions, and to be providing (and shall only be permitted to participate in the Placing on the basis that they have provided) the representations, warranties, undertakings, agreements and acknowledgements contained in this Part 10.

All times and dates in this Part 10 are reference to times and dates in London (United Kingdom).

Save for any terms expressly defined in this Part 10, all capitalised and defined terms contained in this Part 10 shall have the same meaning as set out in the document.

EACH PLACEE SHOULD CONSULT WITH ITS OWN ADVISERS AS TO LEGAL, REGULATORY, TAX, BUSINESS AND RELATED ASPECTS OF A PURCHASE OF PLACING SHARES.

Details of the Placing Agreement and the Placing Shares

The Company has entered into a placing agreement (the "**Placing Agreement**") with the Bookrunners. Pursuant to the Placing Agreement, the Bookrunners have, subject to the terms set out in such agreement, agreed to use reasonable endeavours, as agents of the Company, to procure Placees for the Placing Shares. In the event that a Placee procured by the Joint Bookrunners fails to subscribe for all or any of its allocated Shares having confirmed an order (in each case, "**Default Shares**"), the Joint Bookrunners shall be obliged to subscribe for their respective proportion of those Default Shares.

The Placing Shares will, when issued, be subject to the articles of association of the Company, be credited as fully paid and will rank *pari passu* in all respects with each other and with the existing Common Shares in the capital of the Company, including the right to receive all dividends and other distributions declared, made or paid in respect of the Common Shares after the date of issue of the Placing Shares.

The Placing Shares will be issued free of any encumbrance, lien or other security interest.

Application for listing and admission to trading

Application will be made to the London Stock Exchange plc (the "**London Stock Exchange**") for admission to trading of the Placing Shares on AIM ("**Admission**"). It is expected that Admission will become effective on or around 8.00 a.m. on 8 August 2018 (or such later time as the Bookrunners may agree in writing with the Company, being not later than 8.00 a.m. on 10 September 2018 and that dealings in the Placing Shares will commence at that time.

The Company will apply for conditional approval of the TSX Venture Exchange (the "**TSX-V**"), with respect to the Placing Shares, subject only to the satisfaction by the Company of customary post-closing conditions imposed by the TSX-V in similar circumstances. It is expected that admission of the Placing Shares on the TSX-V will become effective on or around 9.00am (EST) on 8 August 2018 (or such other date as the Bookrunners may agree).

Bookbuild

The Bookrunners have conducted a bookbuilding process in respect of the Placing (the "**Bookbuild**") to determine demand for participation in the Placing by Placees. This Part 10 gives details of the terms and conditions of, and the mechanics of participation in, the Placing. No commissions will be paid to Placees or by Placees in respect of any Placing Shares.

The Bookrunners shall be entitled to effect the Placing by such alternative method to the Bookbuild as they may determine.

Participation in, and principal terms of, the Bookbuild

The Bookrunners are arranging the Placing severally, and not jointly, nor jointly and severally, as joint bookrunners and agents for the Company. Participation in the Placing will only be available to persons who may lawfully be, and are, invited to participate by either of the Bookrunners. Each of the Bookrunners and their respective Affiliates (as defined below) is entitled to participate as a Placee in the Bookbuild.

The Bookbuild established the number of Placing Shares to be placed at the Placing Price to Placees whose bids are successful. The number of Placing Shares to be issued was agreed between the Bookrunners and the Company following completion of the Bookbuild.

The Bookrunners may, in agreement with the Company, accept bids that are received after the Bookbuild has closed.

A bid in the Bookbuild will be made on the terms and conditions in this Part 10 and will be legally binding on the Placee by which, or on behalf of which, it is made, and except with the consent of the Bookrunners and the Company will not be capable of variation or revocation after the close of the Bookbuild.

A person who wishes to participate in the Bookbuild should communicate its bid by telephone to its usual sales contact at Stifel or BMO. Each bid should state the number of Placing Shares which the prospective Placee wishes to subscribe for at the Placing Price.

If successful, the relevant Bookrunner will re-contact and confirm orally to prospective Placees following the close of the Bookbuild the size of their respective allocations and a trade confirmation will be dispatched as soon as possible thereafter. The relevant Bookrunner's oral confirmation of the size of allocations and each prospective Placee's oral commitments to accept the same will constitute an irrevocable legally binding agreement in favour of the Company and the relevant Bookrunner pursuant to which each such Placee will be required to accept the number of Placing Shares allocated to the Placee at the Placing Price and otherwise on the terms and subject to the conditions set out in this Part 10 and in accordance with the Company's articles of association. Each Placee's allocation and commitment will be evidenced by a trade confirmation issued to such Placee by the relevant Bookrunner. The terms of this Part 10 will be deemed incorporated in that trade confirmation. Each such Placee will have an immediate, separate, irrevocable and binding obligation, owed to the relevant Bookrunner, to pay it or (as it may direct) one of its Affiliates in cleared funds in pounds sterling an amount equal to the product of the Placing Price and the number of Placing Shares allocated to such Placee on the basis explained below under *"Registration and Settlement"*.

Placees in certain jurisdictions will also be required to execute representation letters and/or other confirmations required by the Bookrunners and/or the Company ("**Investor Confirmations**") in the form provided to them by the Bookrunners and to return those executed Investor Confirmations to the Bookrunners by no later than 5:00 pm on 2 August 2018 failing which their allocation may be cancelled.

The Bookrunners reserve the right to scale back the number of Placing Shares to be subscribed for by any Placee. The Bookrunners also reserve the right not to accept offers to subscribe for Placing Shares or to accept such offers in part rather than in whole. The acceptance of offers shall be at the absolute discretion of each of the Bookrunners and the Company. The Company reserves the right (upon agreement with the Bookrunners) to reduce or seek to increase the amount to be raised pursuant to the Placing.

To the fullest extent permissible by law, none of Stifel, BMO, any holding company thereof, any subsidiary thereof, any subsidiary of any such holding company, any branch, affiliate or associated undertaking of any such company nor any of their respective directors, officers and employees (each an "**Affiliate**") nor any person acting on their behalf shall have any responsibility or liability to Placees (or to any other person whether acting on behalf of a Placee or otherwise). In particular, none of the Bookrunners, any of their respective Affiliates or any person acting on their behalf shall have any liability (including, to the extent legally permissible, any fiduciary duties), in respect of its conduct of the Bookbuild or of such alternative method of effecting the Placing as the Bookrunners and the Company may determine.

Each Placee's obligations will be owed to the Company and to the Bookrunners. Following the oral confirmation referred to above, each Placee will also have an immediate, separate, irrevocable and binding obligation, owed to the Company and the relevant Bookrunner as agent of the Company, to pay to the relevant Bookrunner (or as such Bookrunner may direct) in cleared funds an amount equal to the product of the Placing Price and the number of Placing Shares such Placee has agreed to subscribe for on the basis explained below under *"Registration and Settlement"*.

Irrespective of the time at which a Placee's allocation pursuant to the Placing is confirmed, settlement for all Placing Shares to be subscribed for pursuant to the Placing will be required to be made at the relevant time, on the basis explained below under *"Registration and Settlement"*.

All obligations of the Bookrunners under the Placing will be subject to fulfilment of the conditions referred to below under *"Conditions of the Placing"* and to the Placing not being terminated on the basis referred to below in the section entitled *"Right to terminate under the Placing Agreement"*.

By participating in the Bookbuild, each Placee agrees that its rights and obligations in respect of the Placing will terminate only in the circumstances described below and will not be capable of rescission or termination by the Placee.

The Placing Shares will be issued subject to the terms and conditions of this Part 10 and each Placee's commitment to subscribe for Placing Shares on the terms set out herein will continue notwithstanding any amendment that may in future be made to the terms and conditions of the Placing and Placees will have no right to be consulted or require that their consent be obtained with respect to the Company's or the Bookrunners' conduct of the Placing.

Conditions of the Placing

The Placing is conditional upon the Placing Agreement becoming unconditional and not having been terminated in accordance with its terms.

The obligations of each of the Bookrunners under the Placing Agreement are conditional, *inter alia*, on:

(a) the Acquisition Agreement, the OTSA and the RBL Facility Agreement having been duly executed by the parties thereto and not having lapsed or been terminated or (without the prior consent of the Bookrunners, such consent not to be unreasonably withheld, delayed or conditioned) amended in any respect;

(b) the Placing Shares having been allotted, conditional only on Admission;

(c) the Company having fully performed its obligations under this Agreement to the extent that such obligations fall to be performed prior to Admission;

(d) the warranties to be given by the Company and the Directors pursuant to the Placing Agreement being true and accurate and not misleading as of the date of the Placing Agreement, when repeated immediately before Admission, as though they had been repeated on each day between the date of the Placing Agreement and Admission;

(e) the obligations of the Bookrunners under the Placing Agreement not being terminated in accordance with the terms of the Placing Agreement;

(f) no matter having arisen prior to Admission which might reasonably be expected to give rise to a claim under the indemnities given by the Company for the benefit of the Bookrunners under the Placing Agreement;

(g) there not having arisen or occurred before Admission any matter, fact, circumstance or event such that in the opinion of the Bookrunners (acting in good faith) a supplementary press announcement is required to be published unless a supplementary announcement has been released to a Regulatory Information Service;

(h) approval by the TSX-V; and

(i) Admission taking place not later than 8.00 am on 8 August 2018 or such later date as is agreed in writing between the Company and the Bookrunners, but in any event not later than 8.00 am on 10 September 2018.

If (i) any of the conditions are not fulfilled (or to the extent permitted under the Placing Agreement, waived by the Bookrunners) or become incapable of fulfilment by the relevant time or date specified in the Placing Agreement; or (ii) the Placing Agreement is terminated in the circumstances specified below, the Placing will not proceed and each Placee's rights and obligations hereunder shall cease and determine at such time and no claim may be made by a Placee in respect thereof. None of the Bookrunners, the Company, or any of their respective Affiliates shall have any liability to any Placee (or to any other person whether acting on behalf of a Placee or otherwise) in respect of any decision they may make as to whether or not to waive or to extend the time and/or date for the satisfaction of any condition in the Placing Agreement or in respect of the Placing generally.

The Bookrunners may, in their absolute discretion, waive or extend the time for fulfilment of all or any part of the conditions in the Placing Agreement save for the above condition relating to the occurrence of Admission may not be extended to later than 8.00 am on 10 September 2018. Any such extension or waiver will not affect Placees' commitments as set out in this document (including in this Part 10).

The Placing is not conditional upon the admission of the Placing Shares to the TSX-V.

Right to terminate under the Placing Agreement

If before Admission:

(a) a party (other than the Bookrunners) to the Placing Agreement is in breach of any provision of the Placing Agreement;

(b) the Bookrunners become aware of any circumstance which results in a breach of the warranties given by any party (other than the Bookruners) under the Placing Agreement at the date of this Agreement or which results in or might result in a breach of any of the warranties when repeated in immediately before Admission or which would result in a breach of the warranties if the same were repeated on each day between the date of the Placing Agreement and the date of Admission;

(c) there shall have occurred any significant new factor, mistake or inaccuracy in the information in this document requiring a supplementary admission document to be published by or on behalf of the Company;

(d) there has occurred any material adverse change in the financial position or prospects of the Group on a consolidated basis or the Target Assets;

(e) any announcement or public statement is made (which in the opinion of the Bookrunners has a material impact on the Placing or Admission) without the approval of the Bookrunners;

(f) there is a breach by any party of the Acquisition Agreement, the OSTA or the RBL Facility Agreement which remains unremedied after five (5) business days of such breach having been notified to the such party;

(g) any of the Acquisition Agreement, OSTA and/or the RBL Facility Agreement are terminated or rescinded, or amended or varied in any material respect, in each case without the prior written consent of the Bookrunners (such consent not to be unreasonably withheld, delayed or conditioned);

(h) an event or other matter (including, without limitation, any change or development in economic, financial, political, diplomatic or other market conditions or any change in any government regulation) has occurred or is likely to occur which, in the opinion of the Bookrunners (acting reasonably) is (or will be if it occurs) likely to have a material adverse effect on the business, assets, operations or condition (financial or otherwise) of the Group as a whole or otherwise makes it impractical or inadvisable for the Bookrunners to perform their obligations under the Placing Agreement (and for these purposes "market conditions" includes conditions affecting securities in the business sector in which the Company operates and conditions affecting securities generally, provided however that fluctuations in the market price for oil and gas shall not constitute market conditions for these purposes),

then the Bookrunners shall consult with the Company and the Directors to the extent practicable on whether to terminate this Agreement and if they decide to so terminate (such decision to be at the absolute discretion of the Bookrunners), written notice of this decision shall be made to the Company.

Upon such notice being given, the parties to the Placing Agreement shall be released and discharged (except for any liability arising before or in relation to such termination) from their respective obligations under or pursuant to the Placing Agreement, subject to limited exceptions.

By participating in the Placing, each Placee agrees with the Bookrunners that the exercise by the Bookrunners of any right of termination or other discretion under the Placing Agreement shall be within the absolute discretion of the Bookrunners and that neither of the Bookrunners need make any reference to the Placees in this regard and that, to the fullest extent permitted by law, neither of the Bookrunners shall have any liability whatsoever to the Placees in connection with any such exercise or failure so to exercise.

No prospectus

No prospectus or other offering document has been or will be submitted to be approved by the FCA in relation to the Placing or the Shares. Placees' commitments will be made solely on the basis of their own assessment of the Company, the Placing Shares and the Placing based on the information contained in this document (including this Part 10), and subject to any further terms set forth in the form of confirmation to be sent to individual Placees. Each Placee, by accepting a participation in the Placing, agrees that the content of this document (including this Part 10) is exclusively the responsibility of the Company and confirms to the Bookrunners and the Company that it has neither received nor relied on any information, (other than this document and any supplementary admission document published by the Company subsequent to the date of this document) representation, warranty or statement made by or on behalf of the Company, the Bookrunners (other than the amount of the relevant Placing participation in the oral confirmation given to Placees and the trade confirmation referred to below), any of their respective Affiliates, any persons acting on their behalf and on or the Company's behalf and neither of the Bookrunners, any of their respective Affiliates, any persons acting on their behalf, or the Company will be liable for the decision of any Placee to participate in the Placing based on any other information, representation, warranty or statement which the Placee may have obtained or received (regardless of whether or not such information, representation, warranty or statement was given or made by or on behalf of any such persons).

By participating in the Placing, each Placee acknowledges to and agrees with the Bookrunners for themselves and as agent for the Company that it has relied on its own investigation of the business, financial or other position of the Company in deciding to participate in the Placing. Nothing in this paragraph shall exclude the liability of any person for fraudulent misrepresentation by that person.

Registration and settlement

Settlement of transactions in the Placing Shares (ISIN: CA46989Q1000) following Admission will take place within the CREST system administered by Euroclear UK and Ireland Limited ("**CREST**"), on a delivery versus payment basis with Placing Shares allocated to Placees being allotted and issued to Computershare Investor Services PLC (the "**Depositary**") and the Company procuring that dematerialised depositary interests ("**Depositary Interests**") representing those shares are so delivered, subject to limited exceptions.

The Bookrunners reserve the right to require settlement for and delivery of the Placing Shares to Placees by such other means that they deem necessary, if delivery or settlement is not possible or practicable within the CREST system within the timetable set out in this document or would not be consistent with the regulatory requirements in the Placee's jurisdiction.

Following the close of the Bookbuild, each Placee allocated Placing Shares in the Placing will be sent a trade confirmation in accordance with the standing arrangements in place with the relevant Bookrunner stating the number of Placing Shares allocated to it, the Placing Price, the aggregate amount owed by such Placee to the relevant Bookrunner and settlement instructions.

Settlement of transactions in CREST will take place by the crediting of Depositary Interests to CREST accounts operated by the respective Bookrunner for the Company and the Bookrunners will enter their respective delivery instructions into the CREST system. The input to CREST by each Placee of a matching or acceptance instruction will then allow delivery of the relevant Depositary Interests to that Placee against payment of the Placing Price.

Placees procured by Stifel should settle against CREST ID: 601. Placees procured by BMO should settle against CREST ID: BIMAY. It is expected that such trade confirmation will be dispatched by 5.00 p.m. on 2 August 2018 and that this will also be the trade date. Each Placee agrees that it will do all things necessary to ensure that delivery and payment is completed in accordance with either the standing CREST or certificated settlement instructions which it has in place with the relevant Bookrunner.

It is expected that settlement will be on 8 August 2018 on a delivery versus payment basis in accordance with the instructions set out in the trade confirmation unless otherwise notified by the Bookrunners.

Interest will be chargeable daily on payments not received from Placees on the due date in accordance with the arrangements set out above and at an interest rate of 2% above LIBOR.

Each Placee is deemed to agree that if it does not comply with these obligations: (i) the Company may release itself (if it decides in its absolute discretion to do so) and will be released from all obligations it may have to issue any such Placing Shares to such Placee or at its direction which are then unissued; (ii) the Company may exercise all rights of lien, forfeiture and set-off over and in respect of any such Placing Shares to the fullest extent permitted under its articles of association or otherwise by law and to the extent that such Placee then has any interest in or rights in respect of any such Placing Shares; (iii) the Company or the Bookrunners may sell (and each of them is irrevocably authorised by such Placee to do so) all or any of such Placing Shares on such Placee's behalf and then retain from the proceeds, for the account and benefit of the Company or, where applicable, the Bookrunners (a) any amount up to the total amount due to it as, or in respect of, subscription monies, or as interest on such monies, for any Placing Shares; (b) any amount required to cover any stamp duty or stamp duty reserve tax (together with any interest or penalties) arising on the sale of such Placing Shares on such Placee's behalf; and (c) any amount required to cover dealing costs and/or commissions necessarily or reasonably incurred by it in respect of such sale; and (iv) such Placee shall remain liable to the Company and to the Bookrunners (as applicable) for the full amount of any losses and of any costs which any of them may suffer or incur as a result of it (a) not receiving payment in full for such Placing Shares by the required time; and/or (b) the sale of any such Placing Shares to any other person at whatever price and on whatever terms are actually obtained for such sale by or for it.

If Placing Shares are to be delivered to a custodian or settlement agent, the Placee should ensure that the trade confirmation is copied and delivered immediately to the relevant person within that organisation.

Insofar as Placing Shares are registered in the Placee's name or that of its nominee or in the name of any person for whom the Placee is contracting as agent or that of a nominee for such person, such Placing Shares will, subject as provided below, be so registered free from any liability to UK stamp duty or stamp duty reserve tax. If there are any circumstances in which any other stamp duty or stamp duty reserve tax (including any interest and penalties relating thereto) is payable in respect of the allocation, allotment, issue or delivery of the Placing Shares (or for the avoidance of doubt if any stamp duty or stamp duty reserve tax is payable in connection with any subsequent transfer of or agreement to transfer Placing Shares), neither the Bookrunners nor the Company shall be responsible for the payment thereof. Placees (or any nominee or other agent acting on behalf of a Placee) will not be entitled to receive any fee or commission in connection with the Placing.

Further Terms, Representations, Confirmations and Warranties

By submitting a bid and/or participating in the Bookbuild and Placing, each Placee (and any person acting on such Placee's behalf) irrevocably acknowledges, confirms, undertakes, represents, warrants and agrees (as the case may be) with the Company and each Bookrunner (in its capacity as a bookrunner and agent for the Company, in each case as a fundamental term of its application for Placing Shares) that:

1 it has read and understood this document in its entirety (including this Part 10) and that its participation in the Bookbuild and the Placing and its subscription for Placing Shares will be governed by, and subject to, all the terms, conditions, representations, warranties, acknowledgments, agreements and undertakings and other information contained in this document (including this Part 10);

2 it indemnifies on an after-tax basis and holds harmless each of the Company, the Bookrunners, their respective Affiliates and any person acting on their behalf from any and all costs, claims, liabilities and expenses (including legal fees and expenses) arising out of or in connection with any breach of the representations, warranties, acknowledgements, agreements and undertakings in this document including this Part 10 and further agrees that the provisions of this document (including this Part 10) shall survive after completion of the Placing;

3 none of the Bookrunners, the Company nor any of their respective Affiliates nor any person acting on their behalf has provided it, and will not provide it, with any material or information regarding the Placing Shares or the Company other than the information included in this document (including this Part 10), nor has it requested either of the Bookrunners, the Company nor any of their respective Affiliates or any person acting on their behalf to provide it with any such material or information;

4 the Placing Shares issued pursuant to the Placing to a resident of Canada may not be sold, transferred or otherwise disposed on the TSX-V or, except pursuant to an exemption from the prospectus requirements under Canadian securities laws, to any person in Canada, on the TSX or otherwise into Canada for a period of 4 months and a day following the issuance of the Placing Shares;

5 if a resident of Canada, the Placee acknowledges that if it were to receive a physical share certificate representing the Placing Shares, such physical share certificate would contain the following legends: "UNLESS PERMITTED UNDER SECURITIES LEGISLATION THE HOLDER OF THIS SECURITY MUST NOT TRADE THE SECURITY BEFORE [*INSERT DATE THAT IS 4 MONTHS AND A DAY AFTER THE DISTRIBUTION DATE]*" AND "WITHOUT PRIOR WRITTEN APPROVAL OF THE TSX-V AND COMPLIANCE WITH ALL APPLICABLE SECURITIES LEGISLATION, THE SECURITIES REPRESENTED BY THIS CERTIFICATE MAY NOT BE SOLD, TRANSFERRED, HYPOTHECATED OR OTHERWISE TRADED ON OR THROUGH THE FACILIITIES OF THE TSX-V OR OTHERWISE IN CANADA OR TO OR FOR THE BENEFIT OF A CANADIAN RESIDENT UNTIL [*INSERT DATE THAT IS 4 MONTHS AND A DAY FOLLOWING CLOSING*]"

6 the Placing Shares issued pursuant to the Placing may not be sold, transferred or otherwise disposed on the TSX-V or, except pursuant to an exemption from prospectus requirements under Canadian securities laws, to any person in Canada, on the TSX-V or otherwise into Canada;

7 (i) it is not and, if different, the beneficial owner of the Placing Shares is not, at the time the Placing Shares are acquired a resident of Australia, Canada, Japan or the Republic of South Africa, and (ii) that the Placing Shares have not been and will not be registered under the securities legislation of the United States, Australia, Canada, Japan or the Republic of South Africa and, subject to limited exceptions, may not be offered, sold, taken up, renounced or delivered or transferred, directly or indirectly, in or into those jurisdictions;

8 the content of this document (including this Part 10) is exclusively the responsibility of the Directors and the Company and that neither of the Bookrunners, nor any of their respective Affiliates nor any person acting on their behalf will be responsible for or has or shall have any liability for any information, representation or statement contained in this document including this Part 10 or any information previously or concurrently published by or on behalf of the Company and will not be liable for any Placee's decision to participate in the Placing based on any information, representation or statement contained in this document including this Part 10 or otherwise;

9 the only information on which it is entitled to rely and on which such Placee has relied in committing to subscribe for the Placing Shares is contained in this document (including this Part 10), such information being all that it deems necessary to make an investment decision in respect of the Placing Shares, and that it has relied on its own investigation of the business, financial or other position of the Company in deciding to participate in the Placing and acknowledges that it is has neither received nor relied on any other information given, investigation made or representations, warranties or statements made by either of the Bookrunners or the Company nor any of their respective Affiliates or any person acting on their behalf and neither of the Bookrunners nor the Company nor any of their respective Affiliates or any person acting on their behalf will be liable for any Placee's decision to accept an invitation to participate in the Placing based on any other information, representation, warranty or statement;

10 it has knowledge and experience in financial, business and international investment matters as is required to evaluate the merits and risks of subscribing for the Placing Shares. It further confirms that it is experienced in investing in securities of this nature and is aware that it may be required to bear, and is able to bear, the economic risk of, and is able to sustain, a complete loss of any investment in connection with the Placing. It further confirms that it has had sufficient time to consider and conduct its own investigation with respect to the offer and subscription for the Placing Shares, including relevant tax, legal and other economic considerations and has relied upon its own examination and due diligence of the Company and its affiliates taken as a whole, and the terms of the Placing, including the merits and risks involved, and not upon any view expressed or information provided by or on behalf of either of the Bookrunners;

11 if it is a pension fund or investment company, its acquisition of Placing Shares is in full compliance with applicable laws and regulations;

12 either (i) it has neither received nor relied on any "inside information" as defined in MAR, including any confidential price sensitive information concerning the Company, in accepting this invitation to participate in the Placing; or (ii) if it has received any confidential price sensitive information about the Company in advance of the Placing, it warrants that it has received such information within the market soundings regime provided for in Article 11 of the MAR and associated delegated regulations and has not (a) dealt (or attempted to deal) in the securities of the Company; (b) encouraged, recommended or induced another person to deal in the securities of the Company; or (c) disclosed such information to any person, prior to the information being made publicly available;

13 it understands that (i) none of the Bookrunners, any of their respective Affiliates or any person acting on their behalf has or shall have any liability for public information or any representation; (ii) none of the Bookrunners, any of their respective Affiliates, or any person acting on their behalf has or shall have any liability for any additional information that has otherwise been made available to such Placee, whether at the date of publication, the date of this document or otherwise; and that (iii) none of the Bookrunners, any of their respective Affiliates, or any person acting on their behalf makes any representation or warranty, express or implied, as to the truth, accuracy or completeness of such information, whether at the date of publication, the date of this document or otherwise;

14 neither it, nor the person specified by it for registration as holder of Placing Shares is, or is acting as nominee or agent for, and the Placing Shares will not be allotted to, a person who is or may be liable to stamp duty or stamp duty reserve tax under any of sections 67, 70, 93 and 96 of the Finance Act of 1986 (depositary receipts and clearance services) and the Placing Shares are not being subscribed for in connection with arrangements to issue depositary receipts or to issue or transfer Placing Shares into a clearance system;

15 it is acting as principal only in respect of the Placing or, if it is acting for any other person (i) it is duly authorised to do so and has full power to make the acknowledgments, confirmations, undertakings, representations, warranties and agreements herein on behalf of each such person; and (ii) it is and will remain liable to the Company and/or the Bookrunners for the performance of all its obligations as a Placee in respect of the Placing (regardless of the fact that it is acting for another person). Each Placee agrees that the provisions of this paragraph 15 shall survive the resale of the Placing Shares by or on behalf of any person for whom it is acting;

16 (i) it (and any person acting on its behalf) is entitled to subscribe for the Placing Shares under the laws and regulations of all relevant jurisdictions which apply to it; (ii) it has fully observed such laws and regulations and obtained all such governmental and other guarantees and other consents and authorities which may be required thereunder (including, without limitation, in the case of any person on whose behalf it is acting, all guarantees, consents and authorities to agree to the terms set out or referred to in this document (including this Part 10)) and complied with all necessary formalities to enable it to enter into the transactions contemplated hereby and to perform its obligations in relation thereto; (iii) (if a company) it is a valid and subsisting company and has all necessary capacity and has obtained all necessary consents and authorities to enable it to commit to this participation in the Placing and to perform its obligations in relation thereto (including, without limitation, in the case of any person on whose behalf if it acting, all necessary consents and authorities to agree to the terms referred to in this document (including this Part 10) and will honour such obligations; (iv) it has paid any issue, transfer or other taxes due in connection with its participation in any territory; and (v) it has not taken any action which will or may result in the Company, either of the Bookrunners, any of their respective Affiliates or any person acting on their behalf being in breach of the legal and/or regulatory requirements of any territory in connection with the Placing;

17 it understands, and each account which it represents has been advised, that (i) the Placing Shares have not been and will not be registered under the US Securities Act or under the applicable securities laws of any state or other jurisdiction of the United States; (ii) the Placing Shares will be subscribed for either (a) in an ''offshore transaction'' within the meaning of Regulation S; or (b) in a transaction that is otherwise exempt from, or not subject to, the registration requirements of the US Securities Act; and (iii) no representation has been made as to the availability of any exemption under the US Securities Act or any relevant state or other jurisdiction's securities laws for the reoffer, resale, pledge or transfer of the Placing Shares;

18 (i) its subscription for the Placing Shares has been or will be made either (a) outside the United States in reliance on Regulation S; or (b) in a transaction that is otherwise exempt from, or not subject to, the registration requirements of the US Securities Act, in which case it has executed or will execute a US representation letter substantially in the form provided to it by the Bookrunners (the ''**US Investor Letter**''); (ii) it is not subscribing for any of the Placing Shares as a result of any form of ''directed selling efforts'' within the meaning of Regulation S; (iii) the Placing Shares were not offered to it through any form of general solicitation or general advertising (within the meaning of Rule 502(c) of Regulation D under the US Securities Act); and (iv) it is acquiring the Placing Shares with investment intent and it is not acquiring the Placing Shares with a view to reselling or distributing any such Placing Shares within the meaning of the US Securities Act;

19 it (i) will not reoffer or resell, directly or indirectly, any of the Placing Shares except in accordance with Regulation S under the US Securities Act or pursuant to another exemption from, or in a transaction not subject to, the registration requirements of the US Securities Act; and (ii) understands that upon the initial issuance of, and until such time as the same is no longer required under the US Securities Act or applicable securities laws of any state or other jurisdiction of the United States, any certificates representing the Placing Shares (to the extent such Placing Shares are in certificated form), and all certificates issued in exchange therefore or in substitution thereof, shall bear a legend setting out the restrictions relating to the transfer of the certified security including with respect to the restrictions relating to the United States federal securities law:

20 it will not distribute, forward, transfer, mail or otherwise transmit this document (including this Part 10) or any other materials concerning the Placing (including any electronic copies thereof), in or into the United States;

21 if it is resident in Canada, it is an ''accredited investor'' as defined in National Instrument 45-106 – *Prospectus Exemptions* or Section 73.3 of the *Securities Act* (Ontario), as applicable, and has completed a Canadian certificate of Accredited Investor in the form provided by the Bookrunners;

22 it acknowledges that: (i) no securities commission or similar regulatory authority has reviewed or passed on the merits of the Placing Shares; (ii) there is no government or other insurance covering the Placing Shares; (iii) there are risks associated with the purchase of the Placing Shares and it is aware of the risks and other characteristics of the Placing Shares; and (iv) there are restrictions on its ability to resell the Placing Shares and it is its responsibility to find out what those restrictions are and to comply with them before selling the Placing Shares;

23 if it is in Canada, the funds representing the Placing Price in respect of the Placing Shares which will be advanced by or on behalf of the Placee to the Company hereunder will not represent proceeds of crime for the purposes of the *Proceeds of Crime (Money Laundering) and Terrorist Financing Act* (Canada) (the ''**PCMLTF Act**'') and the Placee acknowledges that the Company may in the future be required by law to disclose the Placee's name and other information relating to the Placing and the Placee, on a confidential basis, pursuant to the PCMLTF Act;

24 to the best of its knowledge, none of the subscription funds to be provided hereunder: (i) have been or will be obtained or derived, directly or indirectly, from or related to any activity that is deemed illegal under the laws of Canada or the United States or any other jurisdiction, or (ii) are being tendered on behalf of a person or entity who has not been identified to it; it shall promptly notify the Company and the Bookrunners with whom the Placee is dealing if it discovers that any such representation ceases to be true, and shall provide the Company and the Bookrunners with appropriate information in connection therewith;

25 it acknowledges that the Company may complete additional financings in the future to develop the proposed business of the Company and to fund its ongoing development. There is no assurance that such financings will be completed or available and if available, that they will be on reasonable terms. Any such future financings may have a dilutive effect on shareholders of the Company at such time, including the Placee, and that if such future financings are not available, the Company may be unable to fund its ongoing development and the lack of capital resources may result in the failure of its business venture;

26 if it is a financial intermediary, as that term is used in Article 3(2) of the Prospectus Directive, the Placing Shares subscribed for by it in the Placing will not be subscribed for on a non-discretionary basis on behalf of, nor will they be subscribed for with a view to their offer or resale to, persons in a member state of the European Economic Area which has implemented the Prospectus Directive other than ''qualified investors'' as defined in Article 2.1(e) of the Prospectus Directive, or in circumstances in which the prior consent of the Bookrunners has been given to the offer or resale;

27 it has not offered or sold and will not offer or sell any Placing Shares to the public in any member state of the European Economic Area except in circumstances falling within Article 3(2) of the Prospectus Directive which do not result in any requirement for the publication of a prospectus pursuant to Article 3 of the Prospectus Directive;

28 it has only communicated or caused to be communicated and will only communicate or cause to be communicated any invitation or inducement to engage in investment activity (within the meaning of section 21 of FSMA) relating to the Placing Shares in circumstances in which it is permitted to do so pursuant to section 21 of FSMA and it acknowledges and agrees that this document has not been approved by either of the Bookrunners in its capacity as an authorised person under section 21 of FSMA and it may not therefore be subject to the controls which would apply if it was made or approved as financial promotion by an authorised person;

29 it has complied and will comply with all applicable provisions of FSMA with respect to anything done by it in relation to the Placing Shares in, from or otherwise involving the United Kingdom;

30 it (i) has complied with its obligations under MAR, the Criminal Justice Act 1993, section 118 of FSMA, and in connection with money laundering and terrorist financing under the Proceeds of Crime Act 2002 (as amended), the Terrorism Act 2000, the Terrorism Act 2006, the Anti-terrorism Crime and Security Act 2001, the Money Laundering, Terrorist Financing and Transfer of Funds (Information on the Payer) Regulations 2017 (each as amended) and the Money Laundering Sourcebook of the FCA, and (ii) is not a person: (a) with whom transactions are prohibited under the Foreign Corrupt Practices Act of 1977 or any economic sanction programmes administered by, or regulations promulgated by, the Office of Foreign Assets Control of the U.S. Department of the Treasury; (b) named on the Consolidated List of Financial Sanctions Targets maintained by HM Treasury of the United Kingdom; or (c) subject to financial sanctions imposed pursuant to a regulation of the European Union or a regulation adopted by the United Nations ((i) and (ii), together, the "**Regulations**") and, if it is making payment on behalf of a third party, that satisfactory evidence has been obtained and recorded by it to verify the identity of the third party as required by the Regulations;

31 if it is in the United Kingdom, it and any person acting on its behalf is a person (i) falling within Article 19(5) of the Order; (ii) falling within Article 49(2)(A) to (D) of the Order; or (iii) to whom this document may otherwise be lawfully communicated and undertakes that it will subscribe for, hold, manage or dispose of any Placing Shares that are allocated to it for the purposes of its business only;

32 if it is in a member state of the European Economic Area, it is a "qualified investor" within the meaning of the Prospectus Directive;

33 no action has been or will be taken by the Company, either of the Bookrunners nor any of their Affiliates or any person acting on their behalf that would, or is intended to, permit a public offer of the Placing Shares in any country or jurisdiction where any such action for that purpose is required;

34 it (and any person acting on its behalf) will pay for the Placing Shares allocated to it in accordance with the terms and conditions of this Part 10 on the due time and date set out herein against delivery of such Placing Shares to it, failing which the relevant Placing Shares may be placed with other Placees or sold as either Bookrunner may, in its absolute discretion, determine and it will remain liable for any amount by which the net proceeds of such sale falls short of the product of the Placing Price and the number of Placing Shares allocated to it and may be required to bear any stamp duty or stamp duty reserve tax (together with any interest or penalties due pursuant to the terms set out or referred to in this document) which may arise upon the sale of such Placee's Placing Shares on its behalf;

35 none of the Bookrunners, any of their Affiliates or any person acting on their behalf is making any recommendations to it or advising it regarding the suitability or merits of any transaction it may enter into in connection with the Placing and that its participation in the Placing is on the basis that it is not and will not be a client of either of the Bookrunners, and none of the Bookrunners, any of their Affiliates or any person acting on their behalf has any fiduciary or other duties or responsibilities to it for providing the protections afforded to their respective clients or customers or for providing advice in relation to the Placing or in respect of any representations, warranties, undertakings or indemnities contained in the Placing Agreement or for the exercise or performance of any of the Bookrunners' respective rights and obligations thereunder, including any right to waive or vary any condition or exercise any termination right contained therein;

36 it has the funds available to pay for the Placing Shares for which it has agreed to subscribe and (i) the person whom it specifies for registration as holder of the Placing Shares will be (a) itself; or (b) its nominee, as the case may be; (ii) neither of the Bookrunners nor the Company will be responsible for any liability to stamp duty or stamp duty reserve tax resulting from a failure to observe this requirement; and (iii) the Placee and any person acting on its behalf agrees to subscribe for the Placing Shares and agrees to indemnify on an after tax basis and hold harmless the Company, each of the Bookrunners and their respective Affiliates in respect of the same on the basis that the Placing Shares will be

allotted to the CREST stock account of the relevant Bookrunner which will hold them as settlement agent as nominee for the Placee until settlement in accordance with its standing settlement instructions with payment for the Placing Shares being made simultaneously upon receipt of the Placing Shares in the Placee's stock account on a delivery versus payment basis;

37 these terms and conditions and any agreements entered into by it pursuant to these terms and conditions (including any non-contractual obligations arising out of or in connection with such agreements), except to the extent expressly specified in such agreement, shall be governed by and construed in accordance with the laws of England and Wales and it irrevocably submits (on behalf of itself and on behalf of any person on whose behalf it is acting) to the exclusive jurisdiction of the courts of England and Wales as regards any claim, dispute or matter arising out of any such contract, except that enforcement proceedings in respect of the obligation to make payment for the Placing Shares (together with any interest chargeable thereon) may be taken by the Bookrunners in any jurisdiction in which the relevant Placee is incorporated or in which any of its securities have a quotation on a recognised stock exchange;

38 it irrevocably appoints any director, officer or employee of the relevant Bookrunner as its agent for the purposes of executing and delivering to the Company and/or its registrars any documents on its behalf necessary to enable it to be registered as the holder of any of the Placing Shares agreed to be taken up by it under the Placing;

39 subject to limited exceptions where permissible under applicable law, it is not a resident of any Prohibited Territory and acknowledges that the Placing Shares have not been and will not be registered nor will a prospectus be cleared in respect of the Placing Shares under the securities legislation of any Prohibited Territory and, subject to limited exceptions, may not be offered, sold, taken up, renounced, delivered or transferred, directly or indirectly, within any Prohibited Territory;

40 any person who confirms to either Bookrunner on behalf of a Placee an agreement to subscribe for Placing Shares and/or who authorises either Bookrunner to notify the Placee's name to the Company's registrar, has authority to do so on behalf of the Placee;

41 the agreement to settle each Placee's subscription for Placing Shares (and/or the subscription by a person for whom it is contracting as agent) free of UK stamp duty and stamp duty reserve tax depends on the settlement relating only to a subscription by it and/or such person direct from the Company of the Placing Shares in question. Such agreement assumes that the Placing Shares are not being subscribed for in connection with arrangements to issue depositary receipts or to issue or transfer the Placing Shares into a clearance service. If there were any such arrangements, or the settlement related to other dealings in the Placing Shares, stamp duty or stamp duty reserve tax may be payable, for which neither the Company nor either of the Bookrunners will be responsible. If this is the case, the Placee should take its own advice and notify the Bookrunners accordingly and agrees to indemnify on an after-tax basis and to hold harmless the Company and the Bookrunners in the event that any of the Company and/or either of the Bookrunners has incurred any such liability to stamp duty or stamp duty reserve tax;

42 the Placing Shares will be issued and/or transferred subject to the terms and conditions set out in this Part 10;

43 when a Placee or any person acting on behalf of the Placee is dealing with the relevant Bookrunner, any money held in an account with the relevant Bookrunner on behalf of the Placee and/or any person acting on behalf of the Placee will not be treated as client money within the meaning of the relevant rules and regulations of the FCA made under FSMA. The Placee acknowledges that the money will not be subject to the protections conferred by the client money rules; as a consequence, this money will not be segregated from the relevant Bookrunners' money in accordance with the client money rules and will be used by the relevant Bookrunner in the course of its business; and the Placee will rank only as a general creditor of the relevant Bookrunner (as the case may be);

44 following Admission, it will make notifications to the Company without delay of all information that it would be requested to notify as a shareholder in a company to which the Disclosure Guidance and Transparently Rules published by the FCA applied as if the Company were a UK issuer;

45 in order to ensure compliance with the Money Laundering, Terrorist Financing and Transfer of Funds (Information on the Payer) Regulations 2017, the Bookrunners (for themselves and as agent on behalf of the Company) or the Company's registrars may, in their absolute discretion, require verification of its identity. Pending the provision to the Bookrunners or the Company's registrars, as applicable, of evidence of identity, definitive certificates in respect of the Placing Shares may be retained at the Bookrunners absolute discretion or, where appropriate, delivery of the Placing Shares to it in uncertificated form may be delayed at the Bookrunners' or the Company's registrars', as the case may be, absolute discretion. If within a reasonable time after a request for verification of identity the Bookrunners (for themselves and as agent on behalf of the Company) or the Company's registrars have not received evidence satisfactory to them, the Bookrunners (or either of them) and/or the Company may, at their absolute discretion, terminate their commitment in respect of the Placing, in which event the monies payable on acceptance of allotment will, if already paid, be returned without interest to the account of the drawee's bank from which they were originally debited;

46 the basis of allocation will be determined by the Bookrunners and the Company at their absolute discretion. The right is reserved to reject in whole or in part and/or scale back any participation in the Placing;

47 it acknowledges and agrees that any Placing Shares that it is allocated in the Placing delivered through CREST will be allotted and issued to the Depositary, and that the Company shall procure that the Depositary shall issue Depositary Interests representing the Placing Shares allocated to it in accordance with the procedures set out under *'Registration and settlement'* herein, and that the Bookrunners shall have no responsibility or liability in respect of the acts of, or failure to act by, the Depositary;

48 it irrevocably authorises the Company and the Bookrunners and any of their respective Affiliates to produce this document pursuant to, in connection with, or as maybe required by any applicable law or regulation, administrative or legal proceeding or official inquiry with respect to the matters set forth herein;

49 its commitment to subscribe for Placing Shares on the terms set out herein will continue notwithstanding any amendment that may in future be made to the terms and conditions of the Placing and that Placees will have no right to be consulted or require that their consent be obtained with respect to the Company's or the Bookrunners' conduct of the Placing;

50 it shall not make any claim against the Company, the Bookrunners, their respective Affiliates or any other person acting on behalf of any of such persons by a Placee to recover any damage, cost, charge or expense which it may suffer or incur by reason of or arising from the carrying out by it of the work to be done by it pursuant hereto or the performance of its obligations hereunder or otherwise in connection with the Placing;

51 it will be liable for any capital duty, stamp duty and all other stamp, issue, securities, transfer, registration, documentary or other duties or taxes (including any interest, fines or penalties relating thereto) payable in or outside the UK by them or any other person on the acquisition by them of any Placing Shares or the agreement by them to subscribe for any Placing Shares;

52 in connection with the Placing, the Bookrunners or any of their Affiliates acting as an investor for their own account may subscribe for Placing Shares in the Company and in that capacity may subscribe for, retain, purchase or sell for their own account such common shares in the Company and any securities of the Company or related investments and may offer or sell such securities or other investments otherwise than in connection with the Placing. Neither of the Bookrunners intends to disclose the extent of any such investment or transactions otherwise than in accordance with any legal or regulatory obligation to do so;

53 the rights and remedies of the Bookrunners and the Company under these terms and conditions are in addition to any rights and remedies which would otherwise be available to each of them and the exercise or partial exercise or partial exercise of one will not prevent the exercise of others;

54 it may be asked to disclose in writing or orally to either of the Bookrunners (i) if he or she is an individual, his or her nationality; or (ii) if he or she is a discretionary fund manager, the jurisdiction in which the funds are managed or owned;

55 neither the content of the Company's website nor any website accessible by hyperlinks on the Company's website is incorporated in, or forms part of, this document (including this Part 10); and

56 the foregoing acknowledgements, agreements, undertakings, representations and warranties referred to above are given for the benefit of each of the Company and the Bookrunners (for their own benefit and, where relevant, the benefit of their respective Affiliates and any person acting on their behalf) and are irrevocable. The Company, the Bookrunners and their respective Affiliates and others will rely upon the truth and accuracy of the foregoing acknowledgements, representations, warranties and agreements and it agrees that if any of the acknowledgements, representations, warranties and agreements made in connection with its acquiring of Placing Shares is no longer accurate, it shall promptly notify the Company and the Bookrunners.

Each Placee, and any person acting on behalf of each Placee, acknowledges and agrees that the Bookrunners and/or any of their respective Affiliates may, at their absolute discretion, agree to become a Placee in respect of some or all of the Placing Shares.

Past performance is no guide to future performance and persons needing advice should consult an independent financial adviser.

All times and dates in this Part 10 may be subject to amendment. The Bookrunners shall notify the Placees and any person acting on behalf of the Placees of any such changes.

Pursuant to the General Data Protection Regulation as implemented in the UK by the Data Protection Act 2018 ("**GDPR**") the Company and the Bookrunners, may hold personal data (as defined in the GDPR) relating to past and present shareholders. Personal data may be retained on record for a period exceeding six years after it is no longer used. The Company and/or the Bookrunners will only process such information for the purposes set out below (collectively, the "**Purposes**"), being to: (a) process its personal data to the extent and in such manner as is necessary for the performance of their obligations under the contractual arrangements between them, including as required by or in connection with its holding of Common Shares, including processing personal data in connection with credit and money laundering checks on it; (b) communicate with it as necessary in connection with its affairs and generally in connection with its holding of Common Shares; (c) provide personal data to such third parties as the Company and/or the Bookrunners may consider necessary in connection with its affairs and generally in connection with its holding of Common Shares or as the GDPR may require, including to third parties outside the EEA; and (d) without limitation, provide such personal data to their respective affiliates for processing, notwithstanding that any such party may be outside the EEA; and (e) process its personal data for the Company's and/or the Bookrunners' internal administration.

By becoming registered as a holder of Placing Shares, each Placee acknowledges and agrees that the processing by the Company and/or the Bookrunners of any personal data relating to it in the manner described above is undertaken for the purposes of: (a) performance of the contractual arrangements between them; and (b) to comply with applicable legal obligations. In providing the Company and/or the Bookrunners with information, it hereby represents and warrants to each of them that it has notified any data subject of the processing of their personal data (including the details set out above) by the Company and/or the Bookrunners and their respective affiliates and group companies, in relation to the holding of, and using, their personal data for the Placing. Any individual whose personal information is held or processed by a data controller: (a) has the right to ask for a copy of their personal information held; (b) to ask for any inaccuracies to be corrected or for their personal information to be erased; (c) object to the ways in which their information is used, and ask for their information to stop being used or otherwise restricted; and (d) ask for their personal information to be sent to them or to a third party (as permitted by law). A data subject seeking to enforce these rights should contact the relevant data controller. Individuals also have the right to complain to the UK Information Commissioner's Office about how their personal information has been handled.

Part 11

ADDITIONAL INFORMATION

1 RESPONSIBILITY

1.1 The Company, the Directors and the Proposed Director, whose name appears at page 6 of this document, accept responsibility for the information contained in this document and for compliance with the AIM Rules for Companies. To the best of the knowledge and belief of the Company and those Directors and the Proposed Director (who have taken all reasonable care to ensure that such is the case), the information contained in this document is in accordance with the facts and does not omit anything likely to affect the import of such information.

1.2 ERCE accept responsibility for the information contained in the CPR. To the best of the knowledge and belief of ERCE (who have taken all reasonable care to ensure that such is the case), the information contained in the CPR is in accordance with the facts and does not omit anything likely to affect the import of such information.

2 INCORPORATION, HISTORY AND STATUS OF THE COMPANY

2.1 The Company was incorporated pursuant to the provisions of the *Company Act* (British Columbia) on 25 August 1988 (transitioning to the BCBCA on 27 July 2005), under the name ''Allan Resources Ltd.''. At that time, the core business of the Company was the development of residential and commercial real estate. The Company changed its name to ''Allan Resources Inc.'' on 12 September 1988. On 8 February 1996, Allan Resources Inc. changed its name to ''Fortress Financial Corporation''. In 2000 and 2001, the Company sold substantially all of its assets and business operations. In the following years, the Company commenced a search for a new line of business or acquisition of assets. As of May 2007, the principal focus of the Company shifted to the acquisition, exploration and development of oil and gas properties located in North America. On 22 August 2007, the Company changed its name from Fortress Financial Corporation to ''Fortress Petroleum Inc.'' On 8 August 2008, Fortress Petroleum Inc. changed its name to ''Petra Petroleum Inc''. On 14 May 2014 the Company and its operating partner Energean signed a lease agreement with the Greek Government for the Ioannina offshore block. The Company acquired a 20 per cent working interest in this block. On 22 January 2015, the Company completed the sale of its principal asset, a 20 per cent working interest in the Ionnina block in North Western Greece to its operating partner, Energean. Following this sale, the Company held no further producing assets or reserves and held the majority of its assets in cash and cash equivalents. On 21 April 2015, the Company completed a reverse takeover of Mitra Energy Limited and immediately prior to completing the reverse takeover, the Company changed its name from Petra Petroleum Inc. to'' Mitra Energy Inc.''. On 6 December 2016, the Company changed its name to ''Jadestone Energy Inc.''.

2.2 The BCBCA governs the Company.

2.3 The Company's legal and commercial name is ''Jadestone Energy Inc.''.

2.4 The head office of the Company is located at Keppel Towers, #15-05/06, 10 Hoe Chiang Road, Singapore. The registered office of the Company is Suite 1000, 595 Howe Street, Vancouver, British Columbia BC V6C 2T5, Canada. The telephone number of the Company's registered office is +1 604-687-1224.

2.5 The address of the Company's website which discloses the information required by Rule 26 of the AIM Rules for Companies is www.jadestone-energy.com.

3 SHARE CAPITAL OF THE COMPANY

3.1 The Company is authorised to issue an unlimited number of Common Shares with no par value and an unlimited number of non-voting Class B Shares with no par value. The ISIN of the Common Shares is CA46989Q1000.

3.2 As at the Latest Practicable Date, the issued share capital of the Company is:

Class of shares	Nominal value	Issued and fully paid
Common Shares	No par value	221,298,004
Class B Shares	No par value	Nil

3.3 The issued share capital of the Company immediately following Admission (assuming that no Options are exercised after the date of this Document) will be:

Class of shares	Nominal value	Issued and fully paid
Common Shares	No par value	461,009,478
Class B Shares	No par value	Nil

3.4 Save as set out below, there have been no changes in the Company's issued shares for the years ending 31 March 2015, 2016 and 2017, the nine month period ended 31 December 2017 and the period from 31 December 2017 to the date of this document:

Date	Issued share capital Number of shares
As at 31 March 2014	17,429,971 Common Shares
As at 31 March 2015	17,429,971 Common Shares
As at 30 June 2015	88,098,004[(i)] Common Shares
As at 30 June 2016	88,798,004 Common Shares
As at 31 December 2016	221,298,004 Common Shares
As at 31 March 2017	221,298,004 Common Shares
As at the Latest Practicable Date	221,298,004 Common Shares

*(i) On April 17, 2015, the Company's shareholders consented to a business combination between the Company and Jadestone Energy Limited (formerly Mitra Energy Limited) ("**JEL**"), pursuant to an arrangement agreement dated March 13, 2015 (the "**Transaction**"). On April 21, 2015 the Company completed the acquisition of all of the outstanding shares of JEL and the Transaction closed. Prior to completing the acquisition, the Company changed its name from Petra Petroleum Inc. to Mitra Energy Inc. and consolidated its share capital on a four (old) for one (new) basis. Following the consolidation and in accordance with a scheme of arrangement duly approved by JEL's shareholders and the Bermuda Supreme Court, the Company issued a total of 17,429,962 common shares to the shareholders of JEL in exchange for all of the outstanding shares of JEL based on a share exchange ratio of 0.62571 of a Company share for each JEL share.*

Concurrent with the closing of the Transaction, the Company acquired all of the outstanding Senior unsecured convertible bonds of JEL. As at closing there was a total of US$51,360,072 in outstanding principal and accrued interest on the bonds. In consideration for the purchase of these bonds, the Company issued a total of 35,808,126 common shares at a deemed issue price of C$1.82 (US$1.43) per share. Upon completion of the Transaction the subscription receipts converted on a one-for-one basis into a total of 17,429,945 post consolidation Common Shares of the Company.

3.5 During the period covered by the historical financial information, the Company has issued and allotted a total of 203,068,033 Common Shares as follows:

Date of issue	Transaction type	No. of Common Shares Issued	Issue price per Common Shares
21 April 2015	Share for share exchange	17,429,962	N/A
21 April 2015	Issue of Common Shares pursuant to conversion of convertible bonds	35,808,126	C$1.82
21 April 2015	Issue of Common Shares on conversion of subscription receipts	17,429,945	N/A
7 June 2016	Private placement	700,000	C$0.49
7 November 2016	Non-brokered private placement	132,500,000	C$0.40

3.6 There are no rights of pre-emption in respect of any of the Company's existing shares.

3.7 As at the Latest Practicable Date, the Company held no Common Shares in treasury.

3.8 Other than the issue of Common Shares pursuant to the Placing and on exercise of the Options the Company has no present intention to issue any new shares in the share capital of the Company.

3.9 The Company does not have in issue any securities not representing share capital.

3.10 No shares of the Company are currently in issue with a fixed date on which entitlement to a dividend arises and there are no arrangements in force whereby future dividends are waived or agreed to be waived.

3.11 Save as disclosed in this paragraph 3, there has been no issue of equity or debt by the Company or any other member of the Group (other than intra-group issues by wholly-owned subsidiaries) in the three years immediately preceding the date of this document.

3.12 Save as disclosed in paragraph 12.3 below, no commissions, discounts, brokerages or other special terms have been granted by the Company or any other member of the Group in connection with the issue or sale of equity or debt of the Company or any other member of the Group in the three years immediately preceding the date of this document.

3.13 Save as disclosed in paragraph 3.15 and paragraph 5 below, on Admission no share or loan capital of the Company or any other member of the Group will be under option or has been agreed conditionally or unconditionally to be put under option.

3.14 The Common Shares will be in registered form. No temporary documents of title will be issued and prior to the issue of definitive certificates, transfers will be certified against the register. It is expected that definitive share certificates for the Common Shares not to be held through CREST will be posted to allottees by 22 August 2018. Common Shares to be held through CREST will be credited to CREST accounts on Admission.

3.15 The Company entered into the Convertible Facility on 2 November 2016 with the Tyrus Lender. Any principal amount advanced under the Convertible Facility, converted into CAD at the then-applicable rate quoted by the Bank of Canada, may be converted on the maturity date of 31 March 2020 (as extended by agreement) into Common Shares or non-voting Class B Shares at the option of the Tyrus Lender at a conversion price of C$0.50 per share (subject to the usual adjustment provisions for convertible loans of this nature); provided that such conversion will not result in the Tyrus Lender together with entities controlled by or controlling the Tyrus Lender, acquiring 50 per cent or more of the outstanding voting securities of Jadestone. The Tyrus Lender also has the option to convert any principal amount owing under the Convertible Facility into Common Shares, the Class B Shares and/or a new class of non-voting common shares (subject to the aforementioned limitation) at any time prior to the maturity date. The Company and the Tyrus Lender have agreed that following Admission the Convertible Facility will be repaid. Further details are set out in paragraph 12.2 of Part 11 of this document.

4 ARTICLES

The following is a summary of certain aspects of the BCBCA and the Company's Articles and Notice of Articles. The Company also remains subject to any stock exchange or securities law requirements that may be applicable to the Company. The Company's current Articles were adopted on 8 January 2007 and were altered on 28 September 2015 and 21 December 2016.

Under British Columbia law, the Company's Notice of Articles and the BCBCA, the Company has unlimited authorised Common Shares and Class B Shares at its disposal. Under the BCBCA there are no pre-emptive rights provided to shareholders of the Company. Prior to the issuance of any new share capital, the Company's board of directors must approve the share issuance by resolution and must determine the price for which the new shares are to be issued. If shares are to be issued for consideration other than cash, the board of directors must determine that the value of the new shares to be issued does not exceed the value of the consideration received by the Company. The board of directors may determine to issue shares at a reasonable discount, provided, however, that under the rules of the TSX-V, the Company may only issue Common Shares at a maximum discount of 25 per cent to the current market price at the time of the announcement of the proposed share issuance if the Company's current market price is lower than CAD0.50, a 20 per cent discount if greater than CAD0.50 but lower than CAD2.00 and a 15 per cent discount if the market price is greater than CAD2.00.

4.1 Objects and purposes of the Company

The Articles place no restriction on the business the Company may carry on.

4.2 Issuance of Securities

The Company is authorised to issue an unlimited number of Common Shares and an unlimited number of Class B Shares (together with the Common Shares, the "**Shares**"). Other than as provided by the BCBCA, no Share may be issued by the Company until it is fully paid. A Share is fully paid when consideration is provided to the Company for the issue of the Share by one or more of the following: (a) past services performed for the Company; (b) property; and (c) money. The directors must, in their discretion, have determined that the value of the consideration received by the Company for such Share is equal to or greater than the issue price set for the Share.

Subject to the BCBCA, the Company may also issue share purchase warrants, options, convertible debentures and rights upon such terms and conditions as the directors determine. Such share purchase warrants, options, convertible debentures and rights may be issued alone or in conjunction with debentures, debenture stock, bonds, shares or any other securities issued or created by the Company from time to time.

4.3 Purchase of Shares by the Company

The Company may, if authorised by a resolution of the directors, purchase, redeem or otherwise acquire any of its Shares at the price and upon the terms determined by the directors unless there are reasonable grounds for believing that the Company is insolvent or the making of the payment or providing the consideration for the purchase, redemption or other acquisition of Shares would render the Company insolvent. If the Company retains a Share which it has redeemed, purchased or otherwise acquired, it may sell, gift or otherwise dispose of the Share including cancelling the Share. While the Company holds its own Shares, it is not permitted to (a) vote the Shares at a meeting of shareholders, (b) pay a dividend in respect of the Shares, or (c) make any other distribution in respect of the Shares.

4.4 Common Shares

4.4.1 <u>Voting Rights</u>

The holders of Common Shares are entitled to receive notice of and to attend any meetings of the shareholders of the Company and, at any meeting of the shareholders of the Company (except meetings at which, pursuant to the BCBCA, only the holders of another class or series of shares of the Company are entitled to vote separately as a class or series) will be entitled to one vote in respect of each Common Share held.

4.4.2 <u>Directors' Authority to Issue</u>

The Articles and Notice of Articles permit the directors to issue an unlimited number of Common Shares without par value.

4.4.3 <u>Dividends</u>

The holders of Common Shares will be entitled to receive dividends if, as and when declared by the board of directors provided that the Common Shares and the Class B Shares will rank equally as to dividends on a share-for-share basis and no dividend will be declared or paid on the Common Shares unless an equivalent dividend, equal in amount and kind per share and payable at the same time and in the same manner, is concurrently declared and paid on the Class B Shares, *pari passu*, without preference or distinction. Any stock dividends declared and paid in respect of the Common Shares will be in the form of additional Common Shares, and any stock dividend declared and paid in respect of the Class B Shares will be in the form of additional Class B Shares.

4.4.4 Liquidation

In the event of the liquidation, dissolution or winding-up of the Company or other distribution of assets of the Company among its shareholders for the purpose of winding-up its affairs (whether voluntary or involuntary), or upon a reduction of capital, the Common Shares and the Class B Shares will rank equally as to priority of distribution on a share-for-share basis, and the holders of the Common Shares will, subject to the rights of the holders of any other class of shares of the Company entitled to receive assets of the Company upon such a distribution in priority to or concurrently with the holders of the Common Shares and the Class B Shares, be entitled to participate equally, share-for-share, with the holders of the Class B Shares in the distribution. Such distribution will be made to the holders of the Common Shares and the Class B Shares in equal amounts and kind per share, payable at the same time and in the same manner, *pari passu*, without preference or distinction.

4.5 Class B Shares

4.5.1 Voting Rights

The holders of Class B Shares will not have any voting rights for the election of directors or for any other purpose and will not be entitled to receive notice of, or to attend, any meetings of the shareholders of the Company, except as expressly provided by the BCBCA.

4.5.2 Directors' Authority to Issue

The Articles and Notice of Articles permit the directors to issue an unlimited number of Class B Shares without par value.

4.5.3 Dividends

The holders of Class B Shares will be entitled to receive dividends if, as and when declared by the board of directors provided that the Class B Shares and the Common Shares will rank equally as to dividends on a share-for-share basis and no dividend will be declared or paid on the Class B Shares unless an equivalent dividend, equal in amount and kind per share and payable at the same time and in the same manner, is concurrently declared and paid on the Common shares, *pari passu*, without preference or distinction. Any stock dividends declared and paid in respect of the Class B Shares will be in the form of additional Class B Shares, and any stock dividend declared and paid in respect of the Common Shares will be in the form of additional Common Shares.

4.5.4 Liquidation

In the event of the liquidation, dissolution or winding-up of the Company or other distribution of assets of the Company among its shareholders for the purpose of winding-up its affairs (whether voluntary or involuntary), or upon a reduction of capital, the Class B Shares and the Common Shares will rank equally as to priority of distribution on a share-for-share basis, and the holders of the Class B Shares will, subject to the rights of the holders of any other class of shares of the Company entitled to receive assets of the Company upon such a distribution in priority to or concurrently with the holders of the Class B Shares and the Common Shares, be entitled to participate equally, share-for-share, with the holders of the Common Shares in the distribution. Such distribution will be made to the holders of the Class B Shares and the Common Shares in equal amounts and kind per share, payable at the same time and in the same manner, *pari passu*, without preference or distinction.

4.5.5 Conversion

Any holder of Class B Shares has the right, at its option and at any time and from time to time, upon giving notice as set out in the Articles, to convert the whole or any part of the Class B Shares held by it into fully paid and non-assessable Common Shares on the basis of one Common Share for each Class B Common Share in respect of which the conversion right is exercised, provided however, that no such conversion will be permitted if the result would be that the Common Shares to be issued to the holder upon the exercise of such conversion right, jointly considered with any Common Shares or other voting securities of the Company held by the holder (and/or by any entity controlling, or controlled by, the holder) at that time, would represent 50 per cent or more of the voting rights attached to all voting securities of the Company then outstanding.

4.5.6 Equal Treatment

The Company will not propose to its shareholders, or enter into any agreement or otherwise commit itself to undertake or support (i) any Corporate Reorganization (as defined below) involving a conversion or exchange of Common Shares into shares, other securities or other property pursuant to any consolidation, merger, amalgamation or arrangement of the Company with or into another body corporate, (ii) any transaction (whether or not such transaction constitutes a Corporate Reorganization) pursuant to which a person or group of persons would acquire more than 50 per cent of the outstanding Common Shares (a "**Change of Control Transaction**"), or (iii) any transaction involving an offer to purchase Common shares that is (or would be, if the offer was made in a Canadian jurisdiction) required, pursuant to applicable securities legislation or the rules of any stock exchange on which the Common shares are then listed, to be made to all or substantially all of the holders of Common shares in a Canadian jurisdiction to which the requirement applies (a "**Common Share Offer**"), unless:

(i) in the case of a Corporate Reorganization involving such a conversion or exchange of Common shares, the holders of the Class B Shares will be treated in the same manner, on a per share basis, as the holders of the Common Shares, including that the amount and kind of shares, other securities or other property receivable in respect of each Class B Share as a result of the Corporate Reorganization is equal to the amount and kind of shares, other securities or other property receivable in respect of each Common Share as a result thereof;

(ii) in the case of a Change of Control Transaction, the holders of the Class B Shares are entitled to participate in the transaction and dispose of their Class B Shares thereunder on the same terms and conditions (including with respect to consideration per share) as the holders of the Common Shares; and

(iii) in the case of a Common Share Offer, the offeror concurrently makes an offer to purchase Class B Shares on the same terms as the Common Share Offer, including with respect to offer price (both amount and kind of consideration), and provided further that: (i) the offer for the Class B Shares is unconditional, except that it may contain a condition to the effect that the offeror is not required to take up and pay for Class B Shares validly deposited to the offer if no Common Shares are purchased pursuant to the contemporaneous Common Share Offer, and (ii) any term or condition of the Common Share Offer pertaining to the minimum number of shares deposited, or the percentage of outstanding shares for which the offer is made, must be based on the aggregate number of Common Shares and Class B Shares, without distinction.

For the purposes of this section 4.5.6, "Corporate Reorganization" means the reclassification or change of outstanding Common Shares into shares of a different class or other securities of the Company pursuant to a change in the authorised share structure of the Company, or a conversion or exchange of outstanding Common Shares into shares, other securities or other property pursuant to any consolidation, merger, amalgamation or arrangement of the Company with or into another body corporate.

4.6 **Alteration of Authorised Share Structure**

Subject to the BCBCA and the Articles, the Company may by a resolution of the directors or by an ordinary resolution of the shareholders, as determined by the directors: (i) create new classes of shares or, if none of the shares of a class are outstanding, eliminate that class of shares; (ii) increase, reduce or eliminate the maximum number of shares of any class that the Company is allowed to issue; (iii) subdivide or consolidate all or any of the unissued, or fully paid issued, shares; (iv) alter the identifying name of any its shares; or (v) by ordinary resolution of the Shareholders, otherwise alter its share or authorised share structure.

4.7 **Additional dividend information**

Subject to the BCBCA, the directors may, from time to time, declare and authorize payment of such dividends as they may deem advisable. The directors need not give notice to any shareholders for any declaration of such dividends. The directors may set a date as the record date for the purpose of determining shareholders entitled to receive payment of a dividend. The record date must not precede the date on which the dividend is to be paid by more than two months.

4.8 Transfer of Common Shares

The Common Shares are freely tradeable.

4.9 Requirement to disclose interests in Common Shares

The Articles do not contain any provisions relating to mandatory disclosure of an ownership interest in the Common Shares above a certain threshold.

It should be noted the Company has agreed with Stifel that it will put a resolution to its Shareholders at the next annual general meeting (anticipated to be held in May 2019) to change the Company's constitution and require that Shareholders holding three per cent or more of the Company's Common Shares notify the Company thereof and of subsequent changes thereto.

4.10 General Meetings

4.10.1 Convening of General Meetings

Subject to the provisions of the BCBCA and the Articles, the directors of the Company must call an annual meeting of shareholders, not later than fifteen months after holding the last preceding annual meeting but no later than six months after the end of the Company's preceding financial year.

The directors may, at any time, call a meeting of shareholders.

Under section 167 of the BCBCA, Shareholders, who at the date on which the requisition is received by the Company hold in the aggregate at least 1/20 of the total issued voting shares of the Company, may requisition a general meeting for the purpose of transacting any business that may be transacted at a general meeting. The requisition must: (1) state the business to be transacted at the meeting; (2) be signed by all requisitioning Shareholders; (3) be delivered to the Company; and (4) otherwise comply with the requirements set out in the BCBCA. If the Company receives a compliant requisition, the directors must call a general meeting to be held not more than 4 months after the date on which the requisition is received to transact the business stated in the requisition, unless: (1) the directors have called a general meeting to be held after the date on which the requisition is received by the Company and have sent proper notice of such meeting; (2) substantially the same business was submitted at a general meeting held not more than the prescribed period before the receipt of the requisition, and any resolution to transact the business at that meeting did not receive the requisite support; (3) the business stated in the requisition does not relate in a significant way to the business/affairs of the Company; (4) the primary purpose for the requisition is securing publicity or enforcing a personal claim or grievance against the company; (5) the business stated in the requisition has already been substantially implemented; (6) the business stated in the requisition, if implemented, would cause the Company to commit an offence; or (6) the requisition deals with matters beyond the Company's power to implement.

4.10.2 Notice of Meeting

Subject to the Articles, the Company must send notice of the date, time and location of any meeting of shareholders (including, without limitation, any notice specifying the intention to propose a resolution as an exceptional resolution, a special resolution or a special separate resolution, and any notice to consider approving an amalgamation into a foreign jurisdiction, an arrangement or the adoption of an amalgamation agreement, and any notice of a general meeting, class meeting or series meeting), in the manner provided in the Articles, or in such other manner, if any, as may be prescribed by a resolution of the directors (whether previous notice of the resolution has been given or not), to each shareholder entitled to attend the meeting, to each director and to the auditor of the Company, unless the Articles otherwise provide, at least the following number of days before the meeting: (a) if and for so long as the Company is a public company, 21 days; (b) otherwise, 10 days.

The Company must send to each of its shareholders, whether or not their shares carry the right to vote, a notice of any meeting of shareholders at which a resolution entitling shareholders to dissent is to be considered specifying the date of the meeting and containing a statement advising of the right to send a notice of dissent together with a copy of the proposed resolution at least the following number of days before the meeting: (a) if and for so long as the Company is a public company, 21 days; (b) otherwise, 10 days.

As a reporting issuer under applicable Canadian securities laws, the Company must set a record date for notice of a meeting which is no fewer than 30 days and no more than 60 days before the meeting.

4.10.3 Record Date for Voting

The directors may set a date as the record date for the purpose of determining shareholders entitled to notice of any meeting of shareholders. The record date must not precede the date on which the meeting is to be held by more than two months or, in the case of a general meeting requisitioned by shareholders under the *Business Corporations Act,* by more than four months. The record date must not precede the date on which the meeting is held by fewer than: (a) if and for so long as the Company is a public company, 21 days; (b) otherwise, 10 days.

If no record date is set, the record date is 5 p.m. on the day immediately preceding the first date on which the notice is sent or, if no notice is sent, the beginning of the meeting.

4.10.4 Quorum

Pursuant to the Articles, quorum for the transaction of business at a meeting of shareholders will be one shareholder present or represented by proxy.

4.10.5 Chairman

The chair of the board of directors, if any, or if the chair of the board of directors is absent or unwilling to act as chair of the meeting, the president, if any, are entitled to preside as chair at a meeting of shareholders.

If, at any meeting of shareholders, there is no chair of the board of directors or president willing to act as chair of the meeting or present within 15 minutes after the time set for holding the meeting, or if the chair of the board of directors and the president, if any, have advised the secretary, if any, or any director present at the meeting, that they will not be present at the meeting, the directors present must choose a director, officer or corporate counsel to be chair of the meeting or if none of the above persons are present or if they decline to take the chair, the shareholders entitled to vote at the meeting who are present in person or by proxy may choose any person present at the meeting to chair the meeting.

4.10.6 Adjournment

The chair of a meeting may, and if so directed by the meeting, must, adjourn the meeting from time to time and from place to place but no business may be transacted at any adjourned meeting other than the business left unfinished at the meeting from which the adjournment took place.

4.10.7 Method of Voting and Demand for Poll

Subject to the BCBCA, every motion put to a vote at a meeting of shareholders will be decided on a show of hands unless a poll, before or on the declaration of the result of the vote by show of hands, is directed by the chair or demanded by any shareholder entitled to vote who is present in person or by proxy.

4.10.8 Taking a Poll

Subject to the Articles, if a poll is duly demanded at a meeting of shareholders, (a) the poll must be taken at the meeting, or within 7 days after the date of the meeting, as the chair directs and in the manner, at the time and at the place that the chair of the meeting directs; (b) the result of the poll is deemed to be the decision of the meeting at which the poll is demanded; and (c) the demand for the poll may be withdrawn by the person who demanded it.

A poll demanded at a meeting of shareholders on a question of adjournment must be taken immediately at the meeting.

On a poll, a shareholder entitled to more than one vote need not cast all the votes in the same way.

4.10.9 Proxies

The Company must, for at least three months after a meeting of shareholders, keep each ballot cast on a poll and each proxy voted at the meeting, and, during that period, make them available for inspection during normal business hours by any shareholder or proxy holder entitled to vote at the meeting. At the end of such three month period, the Company may destroy such ballots and proxies.

If the Company gives notice of a meeting to its shareholders, National Instrument 51-102 *Continuous Disclosure Obligations* requires that a form of proxy be sent to the shareholders at the same time as or before giving the notice and sets out the requirements for such form.

Proxies are to be deposited as per the instructions set out in the information circular accompanying such proxy and a proxy may be revoked by the shareholder who deposited it.

4.11 **Variation of rights**

Subject to the BCBCA, the Company may, by special resolution of the shareholders, create special rights or restrictions for, and attach those special rights or restrictions to, or vary and delete any special rights and restrictions attached to, any class of shares of which shares have been issued and alter its Notice of Articles and Articles accordingly.

4.12 **Constitution of the board**

4.12.1 Number of directors

While the Company is a public corporation (that is, with its securities listed or posted for trading on a stock exchange), the Company must have a minimum of three directors. Otherwise, the number of directors is set by ordinary resolution of the shareholders as approved by the board of directors from time to time.

The directors may, between annual general meetings, appoint one or more additional directors of the Company to serve until the next annual general meeting, but the number of additional directors cannot at any time exceed one-third of the number of directors who held office at the expiration of the last annual general meeting of the Company. Any casual vacancy occurring in the board of directors may be filled by the directors.

4.12.2 Qualification of directors

A director is not required to hold a share in the capital of the Company as qualification for his or her office but must be qualified as required by the BCBCA to become, act or continue to act as a director.

4.12.3 Election or Appointment of Directors

At every annual general meeting, (a) the shareholders entitled to vote at the annual general meeting for the election of directors must elect a board consisting of the number of directors for the time being set under these Articles; and (b) those directors whose term of office expires at the annual general meeting cease to hold office immediately before the election or appointment of directors under paragraph (a), but are eligible for re-election or re-appointment.

No election, appointment or designation of an individual as a director is valid unless that individual (a) consents to be a director in the manner provided for in the BCBCA, or (b) is elected or appointed at a meeting at which the individual is present and the individual does not refuse, at the meeting, to be a director.

If the Company has no directors or fewer directors in office than the number set pursuant to the Articles as the quorum of directors, the shareholders may elect or appoint directors to fill any vacancies on the board of directors.

4.12.4 Term

Directors are elected or appointed to serve until the next annual general meeting of shareholders of the Company.

4.12.5 Ceasing to be a Director

A director ceases to be a director when (a) the term of office of the director expires; (b) the director dies; (c) the director resigns as a director by notice in writing provided to the Company or a lawyer for the Company; or (d) the director is removed from office pursuant to the Articles.

4.12.6 Removal of Directors

The shareholders may remove any director before the expiration of his or her term of office by special resolution. In that event, the shareholders may elect, or appoint by ordinary resolution, a director to fill the resulting vacancy. If the shareholders do not elect or appoint a director to fill the resulting vacancy contemporaneously with the removal, then the directors may appoint or the shareholders may elect, or appoint by ordinary resolution, a director to fill that vacancy.

The directors may remove any director before the expiration of his or her term of office if the director is convicted of an indictable offence, or if the director ceases to be qualified to act as a director of the Company and does not promptly resign, and the directors may appoint a director to fill the resulting vacancy.

4.12.7 Remuneration

The directors are entitled to the remuneration for acting as directors, if any, as the directors may from time to time determine. If the directors so decide, the remuneration of the directors, if any, will be determined by the shareholders. That remuneration may be in addition to any salary or other remuneration paid to any officer or employee of the Company as such, who is also a director.

The Company must reimburse each director for the reasonable expenses that he or she may incur in and about the business of the Company.

If any director performs any professional or other services for the Company that in the opinion of the directors are outside the ordinary duties of a director, or if any director is otherwise specially occupied in or about the Company's business, he or she may be paid remuneration fixed by the directors, or, at the option of that director, fixed by ordinary resolution, and such remuneration may be either in addition to, or in substitution for, any other remuneration that he or she may be entitled to receive.

Unless otherwise determined by ordinary resolution, the directors on behalf of the Company may pay a gratuity or pension or allowance on retirement to any director or to his or her spouse or dependants and may make contributions to any fund and pay premiums for the purchase or provision of any such gratuity, pension or allowance.

4.12.8 Power to appoint alternate directors

Any director (an appointor) may by notice in writing received by the Company appoint any person (an appointee) who is qualified to act as a director to be his or her alternate to act in his or her place at meetings of the directors or committees of the directors at which the appointor is not present unless (in the case of an appointee who is not a director) the directors have reasonably disapproved the appointment of such person as an alternate director and have given notice to that effect to his or her appointor within a reasonable time after the notice of appointment is received by the Company.

4.12.9 Powers and duties of the directors

The directors must subject to the BCBCA and the Articles, manage or supervise the management of the business and affairs of the Company and have the authority to exercise all such powers of the Company as are not, by the BCBCA or by the Articles, required to be exercised by the shareholders of the Company.

4.12.10 Permitted directors' interests

Pursuant to the Articles, a director or senior officer who holds a disclosable interest (as such term is defined in the BCBCA) in a contract or transaction into which the Company has entered or proposes to enter is liable to account to the Company for any profit that accrues to such director or senior officer under or as a result of the contract or transaction only if and to the extent provided in the BCBCA.

A director who holds a disclosable interest in a contract or transaction into which the Company has entered or proposes to enter is not entitled to vote on any directors' resolution to approve such contract or transaction, unless all the directors have a disclosable interest in such contract or transaction in which case any or all of those directors may vote on such resolution.

A director or senior officer who holds any officer or possesses any property, right or interest that could result, directly or indirectly, in the creation of a duty or interest that materially conflicts with that individual's duty or interest as a director or senior officer of the Company, may disclose the nature and extent of the conflict as required by the BCBCA.

4.12.11 Committees

The directors may, by resolution, appoint an executive committee consisting of the director or directors that they consider appropriate, and this committee has, during the intervals between meetings of the board of directors, all of the directors' powers, except (a) the power to fill vacancies in the board of directors; (b) the power to remove a director; (c) the power to change the membership of, or fill vacancies in, any committee of the directors; and (d) such other powers, if any, as may be set out in the resolution or any subsequent directors' resolution.

The directors may, by resolution (a) appoint one or more committees (other than the executive committee) consisting of the director or directors that they consider appropriate; (b) delegate to a committee any of the directors' powers, except the power to fill vacancies in the board of directors, the power to remove a director, the power to change the membership of, or fill vacancies in, any committee of the directors; and the power to appoint or remove officers appointed by the directors; and (c) make any such delegation subject to the conditions set out in the resolution or any subsequent directors' resolution.

4.12.12 Directors and Officer's Liability Insurance

The Company may purchase and maintain insurance for the benefit of any person (or his or her heirs or legal personal representatives) who (a) is or was a director, alternate director, officer, employee or agent of the Company; (b) is or was a director, alternate director, officer, employee or agent of a corporation at a time when the corporation is or was an affiliate of the Company; (c) at the request of the Company, is or was a director, alternate director, officer, employee or agent of a corporation or of a partnership, trust, joint venture or other unincorporated entity; (d) at the request of the Company, holds or held a position equivalent to that of a director, alternate director or officer of a partnership, trust, joint venture or other unincorporated entity; against any liability incurred by him or her as such director, alternate director, officer, employee or agent or person who holds or held such equivalent position.

4.12.13 Board Meetings

The directors may meet together for the conduct of business, adjourn and otherwise regulate their meetings as they think fit, and meetings of the directors held at regular intervals may be held at the place, at the time and on the notice, if any, as the directors may from time to time determine.

4.12.14 Calling of Meeting

A director may, and the secretary or an assistant secretary of the Company, if any, on the request of a director must, call a meeting of the directors at any time.

4.12.15 Notice of Board Meetings

Other than for meetings held at regular intervals as determined by the directors pursuant to the Articles, reasonable notice of each meeting of the directors, specifying the place, day and time of that meeting must be given to each of the directors and the alternate directors by any method set out in the Articles or orally or by telephone.

4.12.16 Quorum

The quorum necessary for the transaction of the business of the directors may be set by the directors and, if not so set, is deemed to be set at a majority of directors or, if the number of directors is set at one, is deemed to be set at one director, and that director may constitute a meeting.

4.12.17 Voting

Questions arising at any meeting of directors are to be decided by a majority of votes and, in the case of an equality of votes, the chair of the meeting does not have a second or casting vote.

4.12.18 Meetings by Telephone or Other Communications Medium

A director may participate in a meeting of the directors or of any committee of the directors (a) in person; (b) by telephone; or (c) with the consent of all directors who wish to participate in the meeting, by other communications medium; if all directors participating in the meeting, whether in person or by telephone or other communications medium, are able to communicate with each other. A director who participates in a meeting in such a manner is deemed for all purposes of the BCBCA and the Articles to be present at the meeting and to have agreed to participate in that manner.

4.12.19 Resolutions in Writing

A resolution of the directors or of any committee of the directors may be passed without a meeting (a) in all cases, if each of the directors entitled to vote on the resolution consents to it in writing; or (b) in the case of a resolution to approve a contract or transaction in respect of which a director has disclosed that he or she has or may have a disclosable interest, if each of the other directors who have not made such a disclosure consents in writing to the resolution.

A consent in writing under this Article may be by signed document, fax, e-mail or any other method of transmitting legibly recorded messages. A consent in writing may be in two or more counterparts which together are deemed to constitute one consent in writing. A resolution of the directors or of any committee of the directors passed in accordance with this Article 18.12 is effective on the date stated in the consent in writing or on the latest date stated on any counterpart and is deemed to be a proceeding at a meeting of directors or of the committee of the directors and to be as valid and effective as if it had been passed at a meeting of the directors or of the committee of the directors that satisfies all the requirements of the *Business Corporations Act* and all the requirements of these Articles relating to meetings of the directors or of a committee of the directors.

4.12.20 Borrowing powers

The Company, if authorised by the directors of the Company, may: (i) borrow money in the manner and amount, on the security, from the sources and on the terms and conditions that the directors consider appropriate; (ii) issue bonds, debentures and other debt obligations either outright or as security for any liability or obligations of the Company or any person and at such discounts or premiums and on such other terms as they consider appropriate; (iii) guarantee the repayment of money by any other person or the performance of any obligation of any other person; and (iv) mortgage, charge, whether by way of specific or floating charge, grant a security interest in, or give other security on, the whole or any part of the present and future assets and undertaking of the Company.

Any bonds, debentures or other debt obligations of the Company may be issued at a discount, premium or otherwise, or with special privileges as to redemption, surrender, drawing, allotment of or conversion into or exchange for shares or other securities, attending and voting at general meetings of the Company, appointment of directors or otherwise and may, by their terms, be assignable free from any equities between the Company and the person to whom they were issued or any subsequent holder thereof, all as the directors may determine.

4.12.21 Indemnification of directors and officers

Subject to the BCBCA, the Company must indemnify a director or officer, a former director or officer, or such other persons as the board may determine, and his heirs and legal representatives, against all costs, charges and expenses, including an amount paid to settle an action or satisfy a judgment, reasonably incurred by him in respect of any civil, criminal or administrative action or proceeding to which he is made a party by reason of being or having been a director or officer of the Company. However, this does not extend to circumstances where a director has liability arising from his or her dishonesty, bad faith or breach of trust. The Company will also indemnify such person in such other circumstances as the BCBCA permits or requires.

4.13 **Officers**

The board may appoint such officers as the board may determine in its discretion. The powers and duties of the officers will be as determined by the board. Officers may be removed from their roles by directors. Unless otherwise removed, officers will continue to hold office until a successor is appointed or their earlier resignation.

5 STOCK OPTION PLAN

The Stock Option Plan was adopted by the Board on 19 August 2015 and approved by the shareholders of the Company on 25 September 2015. The Stock Option Plan is a ''rolling'' stock option plan that allows the Company to issue up to a maximum of 10 per cent of the Company's issued and outstanding Common Shares at any given time. The Stock Option Plan replaced the Company's previous stock option plan which was a 20 per cent fixed stock option plan.

The purpose of the Stock Option Plan is to provide an incentive to the directors, officers, employees, and consultants to continue their involvement with the Company and to increase their efforts on the Company's behalf by allowing the Company to grant options to directors, officers, employees and consultants as additional compensation and as an opportunity to participate in the growth of the Company. The granting of such options is intended to align the interests of such persons with that of the Company and is common industry practice.

The Compensation Committee administers the Stock Option Plan. The Compensation Committee makes recommendations to the Board regarding the number of the stock options to be granted to each executive officer based on the level of responsibility and experience of the individual, the performance of the individual and the number of the stock options previously granted to the individual.

Options, when granted, are exercisable over periods of up to ten years as determined by the Board and are required to have an exercise price which, as determined by the Board in its sole discretion, will not be less than the closing price of the Company's shares traded through the facilities of the TSX-V on the date preceding the date of grant, less any discount permitted by the TSX-V, or if the shares are no longer listed for trading on the TSX-V, then such other exchange or quotation system on which the shares are listed or quoted for trading. The maximum number of Common Shares which may be issued pursuant to options previously granted and those granted under the Stock Option Plan will be 10 per cent of the issued and outstanding Common Shares of the Company at the time of grant. In addition, the number of shares which may be reserved for issuance to any one individual may not exceed 5 per cent of the issued shares on a yearly basis (unless the Company has obtained the requisite disinterested shareholder approval) or not more than 2 per cent of the issued shares on a yearly basis if granted to any one consultant or to any one employee engaged in investor relations activities.

Upon expiry of an option, or in the event an option is otherwise terminated for any reason, the number of shares in respect of the expired or terminated option will again be available for the purposes of the Stock Option Plan.

Options are subject to vesting at the discretion of the Board. The Stock Option Plan provides that if a change of control, as defined therein, occurs, all shares subject to options will immediately become vested and may thereupon be exercised in whole or in part by the option holder.

Any options granted pursuant to the Stock Option Plan will terminate within 90 days of the option holder ceasing to act as a director, officer, employee or consultant of the Company unless such cessation is on account of death. If such cessation is on account of death, the options terminate on the earlier of one year of the option holder's death and the expiration date of the options. Upon retirement, stock options will become fully vested and will terminate on the expiration date of the options.

In accordance with the policies of the TSX-V, a plan with a rolling 10 per cent maximum must be confirmed by Shareholders at each annual general meeting.

Any material amendments to the Stock Option Plan must be approved by a majority of the votes cast by Shareholders.

The following table sets out the grants which have been made and which remain outstanding under the Company's Stock Option Plan as at the Latest Practicable Date and as they are expected to be at Admission.

Issued date	**21-Apr-15**	**7-Jun-16**	**28-Mar-17**	**10-Dec-17**	**29-Mar-18**	**30-Jul-18**(1)	**Total**
Amount	607,821	750,000	7,050,000	175,000	3,300,000	1,500,000	12,432,821
Vesting period	12 months	Equally across 12 months, 24 months, 36 months					
Expiry	21-Apr-25	8-Jun-26	29-Mar-27	10-Dec-27	28-Mar-28	30-Jul-28	
Exercise Price	CAD 1.82	CAD 0.49	CAD 0.47	CAD 0.45	CAD 0.50	CAD 0.61	
Directors							
Dennis McShane, Chairman	—	—	—	175,000	70,000		245,000
A. Paul Blakeley, CEO	—	500,000	2,250,000	—	500,000	250,000	3,500,000
Robert A. Lambert	150,000	—	100,000	—	50,000	—	300,000
Iain McLaren	250,000	—	100,000	—	50,000	—	400,000
David Neuhauser	—	—	100,000	—	50,000	—	150,000
Eric Schwitzer	200,000	—	100,000	—	50,000	—	350,000
Subtotal	600,000	500,000	2,650,000	175,000	770,000	250,000	4,945,000
Proposed Director							
Daniel Young	—	—	650,000	—	300,000	250,000	1,200,000
Management/consultant	7,821	250,000	3,750,000	—	2,230,000	1,000,000	7,237,821
Total	**607,821**	**750,000**	**6,400,000**	**175,000**	**3,000,000**	**1,500,000**	**12,432,821**

(1) Conditional upon Admission.

6 DIRECTORS' AND PROPOSED DIRECTOR'S INTERESTS

6.1 The following table sets forth the number of shares and options of the Company which each Director and Proposed Director beneficially owns, directly or indirectly, or over which control or direction is exercised, as of the date of this document and as expected at the date of Admission.

	Before Admission			**Following Admission**		
Position	**Number of Common Shares**(1)	**Percentage of issued and outstanding Common Shares**(2)	**Number of Options**	**Number of Common Shares**(1)	**Percentage of issued and outstanding Common Shares**(2)	**Number of Options**(4)
Director						
A. Paul Blakeley	1,625,000	0.73 per cent	3,000,000	2,169,798	0.47	3,500,000
Robert A. Lambert	336,000	0.00 per cent	300,000	553,919	0.12	300,000
Eric Schwitzer	500,000	0.00 per cent	350,000	608,959	0.13	350,000
Iain McLaren	3,911	0.00 per cent	400,000	112,870	0.02	400,000
David Neuhauser	31,355,169(3)	14.17 per cent	150,000	31,899,967	6.92	150,000
Cedric Fontenit	Nil	Nil	Nil	Nil	Nil	Nil
Dennis McShane	85,000	0.00 per cent	245,000	302,919	0.07	245,000
Proposed Director						
Daniel Young	Nil	0.00 per cent	950,000	217,919	0.05	1,200,000

Notes:

(1) The information as to Shares beneficially owned or controlled has been provided by the Directors themselves.

(2) On an undiluted basis.

(3) Mr. Neuhauser does not own any Common Shares of the Company directly but, as managing director of Livermore Partners, exercises control or direction over the Common Shares held by Livermore Strategic Opportunities, LP.

(4) Including the grant of options made on 29 July 2018, conditional on Admission.

6.2 As at the date of this document and as expected to be held on Admission, the Company is aware of the following existing shareholders (other than any Director or the Proposed Director) who by virtue of the notifications made to it pursuant to relevant Canadian securities laws, are or will be immediately following Admission be interested, directly or indirectly, in 3 per cent or more of the Company's issued share capital:

	Before Admission			Following Admission		
Name	**Number of Common Shares[(1)]**	**Percentage of issued and outstanding Common Shares[(2)]**	**Number of Options**	**Number of Common Shares**	**Percentage of issued and outstanding Common Shares**	**Number of Options**
Tyrus Capital S.A.M.[(1)]	109,705,247	49.57 per cent	Nil	109,705,247	23.80	Nil
Livermore Partners LLC	31,355,169[(3)]	14.17 per cent	Nil	31,899,967	6.92	Nil
Ontario Teachers' Pension Plan Board	19,353,481	8.75 per cent	Nil	19,353,481	4.20	Nil
West Face Long Term Opportunities Global Master L.P.	15,747,057	7.12 per cent	Nil	15,747,057	3.42	Nil
Odey Asset Management	Nil	0.00	Nil	38,162,911	8.28	Nil
Miton Asset Management Limited	Nil	0.00	Nil	29,660,293	6.43	Nil
Fidelity International	Nil	0.00	Nil	14,989,479	3.25	Nil
Baillie Gifford & Co	Nil	0.00	Nil	14,778,965	3.21	Nil
Capital World Investors	Nil	0.00	Nil	14,643,840	3.18	Nil
GLG Partners	Nil	0.00	Nil	14,016,248	3.04	Nil

Note:

(1) Tyrus does not own any securities of the Company but, as investment manager of the Tyrus Fund, maintains power to exercise control or direction over such number of Common Shares.

(2) On an audited basis, at the Latest Practicable Date.

(3) Mr. Neuhauser does not own any Common Shares of the Company directly but, as managing director of Livermore Partners, exercises control or direction over the Common Shares held by Livermore Strategic Opportunities, LP.

The Company may not have accurate information regarding beneficial Shareholders of the Company as it is not entitled to such information and cannot access such information under Canadian securities laws. Further, under the securities laws of Canada the threshold for the disclosure of interests in the share capital of the Company is 10 per cent. Accordingly, the Company cannot necessarily be aware of interests below this figure.

6.3 Save as disclosed above, the Company is not aware of any person who directly or indirectly, jointly or severally, exercises or could exercise control over the Company nor is it aware of any arrangements, the operation of which may at a subsequent date result in a change of control of the Company.

6.4 None of the Directors, nor the Proposed Director, nor any member of their respective families (as defined in the AIM Rules) has a related financial product (as defined in the AIM Rules) referenced to the Common Shares.

6.5 The persons including the Directors and the Proposed Director referred to above, do not have voting rights that differ from those of other Shareholders.

6.6 Pursuant to the Nomination Rights Agreement between the Company and Ontario Teachers' Pension Plan Board dated 21 April 2015, a significant shareholder of the Company, Ontario Teachers' Pension Plan Board has a right to nominate one director for so long as Ontario Teachers' Pension Plan Board holds at least 5 per cent of the issued and outstanding Shares. Ontario Teachers' Pension Plan Board has not exercised its nomination right pursuant to the Nomination Rights Agreement.

6.7 The Company has entered into a distribution rights agreement (the "**Distribution Rights Agreement**") with the Tyrus Fund, pursuant to which the Tyrus Fund will, provided it owns greater than 10 per cent of the Company's outstanding Common Shares, have the right to require the Company to prepare and file a prospectus in order to permit the Tyrus Fund to sell all, or a portion, of its Common Shares of the Company. The Tyrus Fund will, under the

Distribution Rights Agreement also have the right to sell any of its Common Shares under any Canadian prospectus that the Company elects to prepare and file in order to sell Common Shares from treasury. However, in connection with Admission, the Tyrus Fund have agreed to be bound by a lock-in, further details of which are set out in section 20 of Part 1.

6.8 Other than as disclosed herein, the Company, the Directors and the Proposed Director are not aware of any arrangements, the operation of which may at a subsequent date result in a change of control of the Company.

6.9 The Directors and the Proposed Director currently hold, and have during the five years preceding the date of this document held, the following directorships or partnerships:

Name	Current Directorships / Partnerships	Former Directorships / Partnerships
Robert Lambert	Ipex Energy Limited Inception Energy Limited Hillcrest Petroleum Inc. Oilfield International Capital	GB Petroleum plc Eland Oil and Gas plc
Eric Schwitzer	North West Refining Inc.	Forzani Group Ltd Rio Narcea Gold Mines Ltd
Iain McLaren	F&C UK High Income Trust plc Baillie Gifford Shin Nippon plc Edinburgh Dragon Trust plc Ecofin Global Utilities and Infrastructure Trust plc	Afren plc Cairn Energy plc Scotbeef Limited
David Neuhauser	BNK Petroleum Inc.	
Cedric Fontenit		Adprotel Strand
Dennis McShane	The Advertising Checking Bureau	Ophir Energy plc Ferrexpo plc Midas Resources AG
A. Paul Blakeley		Tiger Energy Upstream Consulting
Daniel Young (Proposed Director)	Licella Holdings Ltd	

6.10 None of the Directors, nor the Proposed Director, have been the subject of any public criticism by any statutory or regulatory authority (including a recognised professional body).

6.11 Save as provided in paragraph 6.12 below, none of the Directors, nor the Proposed Director, has been a director of a company at the time of, or within the 12 months preceding the date of, that company being the subject of a receivership, compulsory liquidation, creditors' voluntary liquidation, administration, company voluntary arrangement or any composition or arrangement with its creditors generally or any class of its creditors.

6.12 Iain McLaren, a director of the Company, was formerly a director of Afren plc, a company formerly listed on the London Stock Exchange. Afren plc was placed in administration within one year of Mr. McLaren ceasing to be a director.

6.13 None of the Directors, nor the Proposed Director, has been a partner of a partnership at the time of, or within 12 months preceding the date of, that partnership being placed into compulsory liquidation or administration or being entered into a partnership voluntary arrangement nor in that time have the assets of any such partnership been the subject of a receivership.

6.14 None of the Directors, nor the Proposed Director, has any unspent convictions relating to indictable offences.

6.15 No asset of any Director, nor the Proposed Director, has at any time been the subject of a receivership.

6.16 None of the Directors, nor the Proposed Director, is or has been bankrupt nor been the subject of any form of individual voluntary arrangement.

6.17 None of the Directors, nor the Proposed Director, is or has ever been disqualified by a court from acting as a director of a company or from acting in the management or conduct of the affairs of any company.

7 DIRECTORS' AND PROPOSED DIRECTOR'S SERVICE AGREEMENTS

7.1 Executive Directors

The Company and Paul Blakeley ("**Mr Blakeley**") entered into a service agreement (the "**Service Agreement**") dated 7 June 2016 pursuant to which Mr Blakeley was employed initially as the Executive Chairman and then as CEO of the Company, with effect from 8 June 2016. The appointment is for an initial term of 3 years and thereafter will continue on a year-by-year basis unless terminated by:

(a) either party for cause (such as fraud or serious misconduct on the part of Mr Blakeley, or insolvency on the part of the Company);

(b) either party without cause; or

(c) the Company, upon a change of control (including liquidation, winding up or a share or asset sale).

Termination of the Service Agreement by the Company under paragraph (b) above shall be on three months' written notice to Mr Blakeley and in the case of paragraph (c), upon or within three months' written notice of the change of control. Termination by Mr Blakeley under paragraph (b) shall be on three months' written notice to the Company.

In all circumstances other than where the Company has terminated the Service Agreement under paragraph (b) above, the Company will also indemnify Mr Blakeley against any losses or expenses arising from his performance of the Service Agreement.

If the Service Agreement is terminated by the Company under paragraph (b) or (c), or by Mr Blakeley under paragraph (a) above, Mr Blakeley is entitled to payment in compensation in the sum of:

1. two years' annual salary;
2. twice the annual performance target amount (being 75 per cent of Mr Blakeley's annual salary);
3. the annual performance target amount for the year preceding the date of notice and a pro-rata amount of the performance target for the year of notice; and
4. US$500,000, to compensate for loss of expatriate benefits.

In addition, the Company will fund Mr Blakeley's legal and taxation advisors up to a maximum amount of US$30,000, if the Service Agreement is terminated by the Company under paragraphs (b) or (c) above or by Mr Blakeley under paragraph (a).

The Service Agreement provides for an annual base salary (subject to annual review) of US$500,000, with a bonus payable at 0-150 per cent of the base salary, subject to the Company's financial performance. Mr Blakeley is also entitled to expatriate corporate benefits including: a foreign service allowance of 15 per cent of annual base salary (and capped at US$30,000 per annum); locations specific tax planning services; a cost of living adjustment of US$9,200/month; monthly rental payment costs (capped at up to US$28,000/month); coverage of all household utility bills; tuition for dependent children; a wellness subsidy of US$5,000 per annum; a company car allowance of up to US$78,000 per annum; an annual visit for Mr Blakeley and his spouse and dependents to the UK and coverage for air fares for up to three visits for dependents who do not accompany Mr Blakeley in Singapore; and coverage of all associated repatriation costs will also be paid for in full following termination of the Service Agreement.

Mr Blakeley shall also receive and shall participate in any pension plan, medical or health plan or other benefit or retirement plan (including a profit sharing plan) as the Company may establish from time to time. Mr Blakeley will also be eligible for life, accident and disability insurance cover. The Service Agreement also contains non-solicitation and competition restrictions for six and twelve months respectively, following termination of Mr Blakeley's employment under the Service Agreement.

7.2 **Non-executive Directors**

The following agreements have been entered into between the non-executive Directors and the Company:

(a) a letter of appointment dated 23 November 2017, as varied by agreement on 31 July 2018, pursuant to which Dennis McShane was appointed by the Company as its non-executive chairman, with effect from 10 December 2017. The appointment is for the period up to the next annual general meeting of the Company where Mr McShane will be subject to re-election and, if re-elected, to further re-election at any subsequent annual general meeting at which either the Articles or the Board may require from time to time. Mr McShane will receive an annual fee of US$125,000, payable quarterly in arrears, and an additional fee of US$10,000, payable on the date of Mr McShane's letter of appointment, for taking a position on the Company's Compensation and Nominating Committee. Either party may terminate the appointment by two months' written notice or immediately on the happening of certain events;

(b) a letter of appointment dated 14 March 2018, as varied by agreement on 31 July 2018, pursuant to which Robert Lambert was appointed by the Company as a non-executive Director with immediate effect. The appointment is for the period up to the next annual general meeting of the Company, where Mr Lambert will be subject to re-election, and if re-elected, to further re-election at any subsequent AGM at which either the Articles of the Board may require from time to time. Mr Lambert will receive an annual fee of US$45,000, payable quarterly in arrears and an additional fee of US$5,000 shall be payable, for taking on membership of the Company's Audit Committee. Either party may terminate the appointment by two months' written notice or immediately on the happening of certain events;

(c) a letter of appointment dated 14 March 2018, as varied by agreement on 31 July 2018, pursuant to which Iain McLaren was appointed by the Company as a non-executive Director with immediate effect. The appointment is for the period up to the next annual general meeting of the Company where Mr McLaren will be subject to re-election and to further re-election and, if re-elected, to further re-election at any subsequent annual general meeting at which either the Articles or the Board may require from time to time. Mr McLaren will receive an annual fee of US$45,000, payable quarterly in arrears and an additional fee of US$10,000 per annum, for taking on membership of the Company's Audit (chair) and Compensation and Nominating Committees. Either party may terminate the appointment by two months' written notice or immediately on the happening of certain events;

(d) a letter of appointment dated 14 March 2018, as varied by agreement on 31 July 2018, pursuant to which Eric Schwitzer was appointed by the Company as a non-executive Director with immediate effect. The appointment is for the period up to the next annual general meeting of the Company where Mr Schwitzer will be subject to re-election and to further re-election and, if re-elected, to further re-election at any subsequent annual general meeting at which either the Articles or the Board may require from time to time. Mr Schwitzer will receive an annual fee of US$45,000, payable quarterly in arrears and an additional fee of US$10,000 per annum, for taking on membership of the Company's Audit and Compensation and Nominating Committees. Either party may terminate the appointment by two months' written notice or immediately on the happening of certain events;

(e) a letter of appointment dated 14 March 2018, as varied by agreement on 31 July 2018, pursuant to which Cedric Fontenit was appointed by the Company as a non-executive Director with immediate effect. The appointment is for the period up to the next annual general meeting of the Company where Mr Fontenit will be subject to re-election and to further re-election and, if re-elected, to further re-election at any subsequent annual general meeting at which either the Articles or the Board may require from time to time. Mr Fontenit does not receive any compensation for acting as a Director. Either party may terminate the appointment by two months' written notice or immediately on the happening of certain events; and

(f) a letter of appointment dated 14 March 2018, as varied by agreement on 31 July 2018, pursuant to which David Neuhauser was appointed by the Company as a non-executive Director with immediate effect. The appointment is for the period up to the next annual general meeting of the Company where Mr Neuhauser will be subject to re-election and, if re-elected, to further re-election at any subsequent annual general meeting at which either the Articles or the Board may require from time to time. Mr Neuhauser will receive an annual fee of US$36,000, payable quarterly in arrears. Either party may terminate the appointment by two months' written notice or immediately on the happening of certain events.

7.3 **Proposed Director**

The Company and Daniel Young ("**Mr Young**") entered into a letter of appointment dated 31 July 2018, pursuant to which Mr Young was appointed by the Company as an executive director, conditional on and with effect from Admission. Either party may terminate the appointment of Mr Young as a director of the Company by two months' written notice or immediately on the happening of certain events.

Mitra Energy (Singapore) Pte. Limited and Daniel Young entered into a service agreement (the "**Service Agreement**") dated 2 November 2016 pursuant to which Mr Young was employed as the Chief Financial Officer of Jadestone. The Service Agreement provides for an annual base salary (subject to annual review) of US$320,000, with a bonus payable at up to 80 per cent of the base salary, subject to the Company's financial performance. Mr Young is also entitled to an additional expatriate allowance of US$30,000 per annum and a cash pension allowance of US$90,000 per annum. The appointment will continue unless terminated by:

(a) either party for cause (such as fraud or serious misconduct on the part of Mr Young, or insolvency on the part of the Company);

(b) either party without cause; or

(c) the Company, upon a change of control (including liquidation, winding up or a share or asset sale).

Termination of the Service Agreement by the Company under paragraph (b) above shall be on three months' written notice and in the case of paragraph (c), upon or within three months' written notice of the change of control.

If the Service Agreement is terminated by the Company under paragraph (b) or (c), or by Mr Young under paragraph (a) above, Mr Young is entitled to payment in compensation in the sum of:

(a) one year's annual salary;

(b) the annual performance target amount (being 40 per cent of Mr Young's annual salary);

(c) the annual performance target amount for the year preceding the date of notice and a pro-rata amount of the performance target for the year of notice; and

(d) US$100,000, to compensate for loss of expatriate benefits.

In addition, the Company will fund Mr Young's legal and taxation advisors up to a maximum amount of US$20,000, if the Service Agreement is terminated by the Company under paragraphs (b) or (c) above or by Mr Young under paragraph (a).

The Service Agreement also contains non-solicitation and competition restrictions imposed on Mr Young for periods of twelve and six months respectively, following termination of Mr Young's employment under the Service Agreement.

7.4 Save as set out above, no Director, nor the Proposed Director, is entitled to any payment on termination for loss of office.

7.5 In addition to the above letters of appointment, the Company has also entered into indemnification agreements with each of the non-executive Directors of the Company. Under the terms of each such indemnification agreement, to the maximum extent permitted by law, the Company will indemnify and hold harmless the applicable non-executive Director from any liabilities or losses incurred in respect of any threatened, pending or completed civil, criminal or investigative proceedings and any costs, charges or expenses incurred by that director in respect of such proceedings, to which the relevant director may be obliged on the basis of his position or on the basis of any action taken or omitted within the scope of their obligations as a director of the Company. This indemnity is subject to the relevant non-executive Director having acted honestly and in good faith and, in the case of a criminal or administrative action, having had reasonable grounds for believing that his conduct was lawful.

7.6 The aggregate remuneration paid (including pension fund contributions and benefits in kind) to the Directors by members of the Group in respect of the year ended 31 December 2017 was approximately US$1,393,653 and breaks down as follows:

Name and Position	Year	Salary, Consulting Fee, Retainer or Commission (US$)	Bonus (US$)	Committee or Meeting Fees (US$)	Value of Perquisites [1] (US$)	Value of all Other Compensation (US$)	Total Compensation (US$)
A. Paul Blakeley[2] *CEO and Director* *Former Executive Chairman*	December 2017 March 2017	372,109 405,226	Nil 134,605	Nil N/A	396,833 315,836	Nil Nil	768,942 855,667
Dennis McShane[5] *Chairman and Director*	December 2017 March 2017	7,392 N/A	Nil N/A	Nil N/A	Nil N/A	Nil N/A	7,392 N/A
Iain McLaren *Director*	December 2017 March 2017	52,500 61,900	Nil Nil	Nil Nil	Nil Nil	Nil Nil	52,500 61,900
Eric Schwitzer *Director*	December 2017 March 2017	41,250 55,750	Nil Nil	Nil Nil	Nil Nil	Nil Nil	41,250 55,750
Robert A. Lambert *Director*	December 2017 March 2017	37,500 76,463	Nil Nil	Nil Nil	Nil Nil	Nil Nil	37,500 76,463
David Neuhauser[6] *Director*	December 2017 March 2017	33,750 36,583	Nil Nil	Nil Nil	Nil Nil	Nil Nil	33,750 36,583
Cedric Fontenit[6] *Director*	December 2017 March 2017	Nil Nil	Nil Nil	Nil Nil	Nil Nil	Nil Nil	Nil Nil
Daniel Young[7] *CFO and Proposed Director*	December 2017 March 2017	262,500 65,374	Nil Nil	Nil Nil	189,819 73,056	Nil Nil	452,319 138,430

Notes:

(1) Includes housing allowances, education, utilities, wellness subsidies and cash pension benefits.

(2) Mr. Blakeley was appointed a director and Executive Chairman of the Company on 7 June 2016 and was appointed CEO of the Company on 15 June 2017. Mr. Blakeley resigned as Executive Chairman of the Company on 10 December 2017.

(3) Mr. Horn was appointed Interim CEO on 7 June 2016 and Executive Vice President, Corporate and Business Development on 15 June 2017. Mr. Horn resigned as Interim CEO on 15 June 2017.

(5) Mr. McShane was appointed as Chairman and a director of the Company on 10 December 2017.

(6) Appointed as a director of the Company on 7 June 2016.

(7) Mr Young was appointed CFO on 18 January 2017.

It is estimated that the aggregate remuneration (including pension fund contributions and benefits in kind but excluding bonuses payable to the Directors by members of the Group in respect of the current financial year (under the arrangements in force at the date of this document) is expected to be US$1,890,048.

8 THE COMPANY AND ITS SUBSIDIARIES

The Company is the holding company of the Group and has the following principal subsidiaries:

Name of company	Place of Incorporation	Per cent of voting rights and shares held	Nature of business
Jadestone Energy (Australia) Pty Ltd	Australia	100	Production of oil
Jadestone Energy (Australia Holding) Pty Ltd	Australia	100	Investment holdings
Jadestone Energy (Eagle) Pty Ltd	Australia	100	Production of oil and gas
Jadestone Energy International Holdings Inc.	Canada	100	Investment holdings
Jadestone Energy (Ogan Komering) Ltd	Canada	100	Production of oil and gas
Jadestone Energy Limited	Bermuda	100	Investment holdings
Mitra Energy Biliton Pte. Ltd.*	Singapore	100	Exploration
Mitra Energy (Philippines SC-56) Ltd.	Bermuda	100	Exploration
Mitra Energy (Philippines SC-57) Ltd.	British Virgin Islands (“**BVI**”)	100	Exploration
Mitra Energy (Indonesia Sibaru) Ltd.*	Bermuda	100	Exploration
Jadestone Energy (Holdings) Ltd.*	BVI	100	Dormant
Mitra Energy (Services) Ltd.*	BVI	100	Dormant
Mitra Energy (Indonesia Bone) Limited**	BVI	100	Exploration
Mitra Energy (Vietnam Con Son) Ltd.*	Bermuda	100	Exploration
Titan Resources (Natuna) Indonesia Limited**	Bermuda	100	Exploration
Jadestone Energy (Singapore) Pte Ltd.	Singapore	100	Investment holdings
Mitra Energy (Vietnam Phu Quy) Pte Ltd.*	Singapore	100	Exploration
Mitra Energy (Vietnam Rang Dong) Pte Ltd.*	Singapore	100	Exploration
Mitra Energy (Vietnam Nam Du) Pte Ltd.	Singapore	100	Exploration
Mitra Energy (Vietnam Tho Chu) Pte Ltd.	Singapore	100	Exploration
Mitra Energy (Vietnam Minh Hai) Pte Ltd.**	Singapore	100	Exploration
Titan Resources (Natuna) Indonesia Ltd.**	Barbados	100	Exploration
Mitra Energy (Vietnam 0-51) Pte Ltd.	Singapore	100	Investment holdings
Mitra Energy (Indonesia North Madura) Pte Ltd.*	Bermuda	100	Exploration
Mitra Energy (Indonesia Titan) Pte Ltd.**	Bermuda	100	Exploration
Mitra Energy (Indonesia Spermonde) Ltd.*	Bermuda	100	Exploration
Mitra Energy (Indonesia NV) Ltd.*	Bermuda	100	Exploration
Mitra Energy (Vietnam Thanh Long) Pte Ltd.	Singapore	100	Exploration
Mitra Energy (Vietnam Phu Khanh) Pte Ltd.**	Singapore	100	Exploration
Jadestone Energy Sdn Bhd	Malaysia	100	Administration
Mitra Energy (Vietnam Song Hong) Pte Ltd.**	Singapore	100	Exploration
Mitra Energy (Indonesia Rombebai) Limited*	Bermuda	100	Exploration

* it is proposed that these companies be dissolved in the next 12 months.
** it is proposed that these companies be dissolved following confirmation from the relevant tax authorities

9 PLACING

Under an agreement dated 3 August (the "**Placing Agreement**") and made between the Company, the Directors and the Joint Bookrunners, the Joint Bookrunners have agreed (conditionally, *inter alia*, on Admission taking place not later than 10 September 2018) as agents for the Company to procure subscribers for 236,954,802 new Common Shares at the Placing Price.

Under the Placing Agreement and subject to its becoming unconditional the Company has agreed to pay the Joint Bookrunners commissions together with corporate finance fees together in each case with any applicable VAT.

The Company will pay certain other costs and expenses (including any applicable VAT) of, or incidental to, the Placing including all fees and expenses payable in connection with Admission, expenses of the registrars, printing and advertising expenses, postage and all other legal, accounting and other professional fees and expenses.

The Placing Agreement contains representations, warranties given by the Company and the Directors and indemnities from the Company to the Joint Bookrunners as to the accuracy of the information contained in this document and other matters relating to the Group and its business. In addition, the Directors have given certain warranties to the Joint Bookrunners regarding the accuracy of the information about themselves contained in this document and certain other matters. The Joint Bookrunners are entitled to terminate the Placing Agreement in certain specified circumstances prior to Admission.

10 UK TAKEOVER CODE

The Company is incorporated in and has its registered office in Canada. Accordingly, transactions involving the Common Shares will not be subject to the provisions of the UK Takeover Code which regulates takeovers in the UK. Shareholders will however have certain protections under Canadian laws in relation to takeovers. Refer to Section 16 of Part 1 above for further details.

11 TAXATION

An investment in the Common Shares may involve a number of complex tax considerations. Changes in law, policy, the practice of the relevant tax authorities or in the interpretation of law could adversely affect returns from the Company to investors. **Any Shareholder or prospective Shareholder who is in any doubt about their taxation position or who may be subject to tax in a jurisdiction other than the UK or Canada is strongly recommended to consult their own professional advisers as to the potential tax consequences of acquiring, holding or selling Common Shares under the laws of their country and/or state of citizenship, domicile or residence.**

A UK Taxation

The following statements are intended only as a general guide to certain UK tax considerations and do not purport to be a complete analysis of all potential UK tax consequences of acquiring, holding or disposing of Common Shares. The following statements are based on current UK legislation and what is understood to be the current practice of HMRC as at the date of this document, both of which may change, possibly with retroactive effect.

Except where expressly stated otherwise, the paragraphs below are intended to apply only to Shareholders: (i) who are for UK tax purposes resident and, if individuals, domiciled in the UK; (ii) to whom split-year treatment does not apply; (iii) who are the absolute beneficial owners of their Ordinary Shares and any dividends paid in respect of them; (iv) who hold their Ordinary Shares as investments (otherwise than through an individual savings account or a pension arrangement) and not as securities to be realised in the course of a trade; and (v) who hold less than 5 per cent of the Ordinary Shares.

The paragraphs below may not apply to certain Shareholders, such as dealers in securities, broker dealers, insurance companies and collective investment schemes, pension schemes, persons who are otherwise exempt from UK taxation and persons who have (or are deemed to have) acquired their Common Shares by virtue of an office or employment or persons who are treated as holding their Common Shares as carried interest or trustees and beneficiaries as regards shares held in trust. Such shareholders may be subject to special rules.

11.1 **Taxation of Chargeable Gains**

11.1.1 UK tax resident individual Shareholders

UK resident Shareholders may be liable to UK taxation of chargeable gains on a disposal of the Common Shares, depending on their individual circumstances and subject to any available exemption or relief.

UK capital gains tax may be payable at a rate of 10 per cent (for 2018/2019) to the extent that individuals are subject to income tax at the basic rate and any chargeable gain does not exceed the unused part of their basic rate income tax band. Where an individual is subject to income tax at the basic rate but any chargeable gain exceeds the unused part of their basic rate income tax band, the rate of capital gains tax on the excess is 20 per cent (for 2018/2019). The rate of capital gains tax for such individuals who are higher or additional rate taxpayers is 20 per cent No indexation allowance is available to such Shareholders, but they may be entitled to an annual exemption from capital gains tax (this is £11,700 for the tax year 2018/2019).

For these purposes, the same thresholds apply for Scottish taxpayer Shareholders as in respect of other Shareholders resident in the United Kingdom. Scottish taxpayer Shareholders may wish to consult their own professional advisers if they are in any doubt as to their tax position in respect of disposals.

HMRC has confirmed that securities dealt with on AIM will not fall to be treated as listed or quoted securities for tax purposes. There are certain reliefs which may be available on disposals of unquoted securities (subject to a number of different requirements in each case) and anyone who requires further information on their availability should consult an appropriate professional adviser.

11.1.2 Non-UK tax resident individual Shareholders

A Shareholder who is not resident for tax purposes in the UK will not generally be subject to capital gains tax on a disposal of Common Shares unless the Shareholder is carrying on a trade, profession or vocation in the UK through a branch or agency and the Common Shares disposed of are, or have been, used, held or acquired for the purposes of such trade, profession or vocation or for the purposes of such branch or agency.

Such Shareholders may be subject to tax under any law to which they are subject to outside of the UK.

An individual Shareholder who has been resident for tax purposes in the UK but who ceases to be so resident or becomes treated as resident outside the UK for a period of five years or less and who disposes of their Common Shares during that period may be liable to capital gains tax on their return to the UK, subject to any available exemptions or reliefs.

11.2 **Taxation of Dividends**

11.2.1 Individual Shareholders

From 6 April 2018 onwards, a UK resident individual Shareholder is not subject to income tax on a dividend received from the Company to the extent that the total amount of dividend income received in the tax year (including the dividend from the Company) does not exceed the annual dividend allowance of £2,000. Dividends within the allowance will still count as taxable income when determining how much of the basic rate band or higher rate band has been used.

Dividend income in excess of the £2,000 allowance will be taxable at the rate of 7.5 per cent to the extent it falls within an individual's basic rate band, but below the threshold for the higher rate of income tax.

To the extent that such dividend income falls above the threshold for the additional higher rate of income tax but below the threshold for the additional rate of income tax, such an individual Shareholder will be subject to tax on that dividend income at the dividend upper rate of 32.5 per cent.

To the extent that such dividend income falls above the threshold for the additional rate of income tax, such an individual Shareholder will be subject to tax on that dividend income at the dividend additional rate of 38.1 per cent.

Dividend income of individuals in tax exempt arrangements such as ISAs should continue to be exempt.

For these purposes, the same thresholds apply for Scottish taxpayer Shareholders as in respect of other Shareholders resident in the United Kingdom. Scottish taxpayer Shareholders may wish to consult their own professional advisers if they are in any doubt as to their tax position in respect of dividends.

11.2.2 Corporate Shareholders

Corporate Shareholders who are UK resident are potentially liable to corporation tax on dividends paid by a UK resident company: most dividends paid on the Common Shares to UK resident corporate Shareholders are likely to fall within one or more of the classes of dividend qualifying for exemption from corporation tax (although the exemptions are not comprehensive and are also subject to anti-avoidance rules). Shareholders within the charge to corporation tax should consult their own professional advisers.

11.2.3 Non-resident Shareholders

A Shareholder resident or otherwise subject to tax outside the UK (whether an individual or a body corporate) may be subject to foreign taxation on dividend income under local law. Shareholders to whom this may apply should obtain their own tax advice concerning tax liabilities on dividends received from the Company.

11.3 **UK Stamp Duty and Stamp Duty Reserve Tax (SDRT)**

11.3.1 No stamp duty or SDRT will arise on the issue or allotment of new Common Shares or the Depositary Interests by the Company pursuant to the Placing.

11.3.2 Transfers of the Common Shares will not be subject to stamp duty reserve tax as long as there is no register of the Common Shars kept in the United Kingdom by or on behalf of the Company.

11.3.3 For as long as Depositary Interests represent interests in non-UK shares admitted to trading on a recognised stock exchange, no stamp duty or SDRT will arise on transfers or agreements to transfer the Depositary Interests by virtue of the exemption granted in the Stamp Duty Reserve Tax (UKI Depositary Interets in Foreign Securities) Regulations 1999 (SI 1999/2383 as amended).

11.3.4 The statements in this paragraph 11.3 apply to any holders of Common Shares irrespective of their residence, summarise the current position and are intended as a general guide only. Special rules apply to agreements made by, amongst others, intermediaries.

B Canadian taxation

The following is a summary of the principal Canadian federal income tax considerations generally relevant to Shareholders who, at all relevant times, for purposes of the Income Tax Act (Canada) the (''**Canadian Tax Act**''): (i) are not resident in Canada and are not deemed to be resident in Canada; (ii) do not use or hold, and are not deemed to use or hold, Common Shares in connection with carrying on a business in Canada; and (iii) hold their Common Shares as capital property.

Shareholders who meet all of the foregoing requirements are referred to in this summary as ''**non-resident Shareholders**'' and this summary applies only to such non-resident Shareholders. Special rules, which are not discussed in this summary, may apply to a non-resident Shareholder that is an insurer that carries on business in Canada and elsewhere or an ''authorized foreign bank'' as defined in the Canadian Tax Act.

This summary is based upon the current provisions of the Canadian Tax Act and the regulations thereunder, the current provisions of the Canada-United Kingdom Income Tax Convention (the ''**UK Treaty**''), and the Company's counsel's understanding of the current administrative policies and assessing practices of the Canada Revenue Agency made publicly available in writing prior to the date hereof. This summary also takes into account specific proposals to amend the Canadian Tax Act announced prior to the date hereof by or on behalf of the Minister of Finance (Canada) (the ''**Proposed Amendments**'') and assumes that the Proposed Amendments will be enacted as proposed. No assurances can be given that the Proposed Amendments will become law.

This summary is not exhaustive of all possible Canadian federal income tax considerations and does not take into account or anticipate any changes in law, administrative policy or assessing practice, whether by legislative, governmental, administrative or judicial action, other than the Proposed Amendments. This summary does not deal with foreign, provincial or territorial income tax considerations, which may differ from the federal considerations.

This summary is of a general nature only and is not, and is not to be construed as, legal or income tax advice to any particular non-resident Shareholder. Each non-resident Shareholder is urged to obtain independent tax advice as to the Canadian income tax consequences of an investment in Common Shares applicable to the non-resident Shareholder's particular circumstances.

11.4 Taxation of Dividends

Any dividend on a Common Share, including a stock dividend, that is paid or credited, or deemed to be paid or credited, by the Company to a non-resident Shareholder will be subject to Canadian withholding tax at the rate of 25 per cent of the gross amount of the dividend. The rate of withholding tax may be reduced under the provisions of an applicable income tax convention between Canada and the country in which the non-resident Shareholder is resident for tax purposes. Pursuant to the UK Treaty, the rate of withholding tax applicable to a dividend paid (or deemed to be paid) on a Common Share to a non-resident Shareholder who is a resident of the United Kingdom for purposes of the UK Treaty (a ''**UK Shareholder**'') will generally be reduced to 15 per cent of the gross amount of the dividend (or 5 per cent in the case of a UK Shareholder that is a company that controls, directly or indirectly, at least 10 per cent of the voting power of the Company). The Company will be required to withhold any such tax from the dividend paid or credited to the non-resident Shareholder and remit the tax directly to the Receiver General for Canada for the account of the non-resident Shareholder.

11.5 Taxation of Capital Gains

A non-resident Shareholder generally will not be subject to tax under the Canadian Tax Act on any capital gain realized by the non-resident Shareholder on a disposition (or deemed disposition) of a Common Share unless the Common Share constitutes ''taxable Canadian property'' to the non-resident Shareholder for purposes of the Canadian Tax Act. Provided that the Common Shares are listed on a ''designated stock exchange'' as defined in the Canadian Tax Act (which includes tiers 1 and 2 of the TSX-V), the Common Shares generally will not constitute taxable Canadian property to the non-resident Shareholder unless at any time during the 60 month period immediately preceding the disposition: (i) the non-resident Shareholder, persons with whom the non-resident Shareholder did not deal at arm's length, partnerships in which the non-resident Shareholder or a person with whom the non-resident Shareholder did not deal at arm's length holds a membership interest directly or indirectly through one or more partnerships, or the non-resident Shareholder together with all such persons, owned 25 per cent or more of the issued shares of any class of the capital stock of the Company; and (ii) more than 50 per cent of the fair market value of the Common Shares was derived directly or indirectly from one or any combination of real or immovable property situated in Canada, ''Canadian resource properties'' (as defined in the Canadian Tax Act), ''timber resource properties'' (as defined in the Canadian Tax Act) or options in respect of, or interests in, or for civil law rights in, such property whether or not such property exists. Further, Common Shares may be deemed to be taxable Canadian property to a non-resident Shareholder for purposes of the Canadian Tax Act in certain circumstances.

Any non-resident Shareholder that would otherwise be subject to Canadian income tax on a capital gain realized on a disposition of a Common Share that constitutes taxable Canadian property to the non-resident Shareholder may be eligible for relief pursuant to an income tax convention between Canada and the country in which the non-resident Shareholder is resident for tax purposes. Non-resident Shareholders who may hold Common Shares as ''taxable Canadian property'' should consult their own tax advisors.

12 MATERIAL CONTRACTS

In addition to the Company's licences and PSC, summaries of which are set out in Part 3 of this document, the following are the only contracts (not being contracts entered into in the ordinary course of business) which have been entered into by members of the Group in the two years immediately preceding the date of this document or which are expected to be entered into prior to Admission and which are, or may be, material or which have been entered into at any time by any member of the Group and which contain any provision under which any member of the Group has any obligation or entitlement which is, or may be, material to the Group as at the date of this document:

Financing

12.1 *RBL Facility Agreement*

Jadestone Energy (Eagle) Pty Ltd (the "**Borrower**"), Jadestone Energy (Australia Holdings) Pty Ltd ("**Holdco**") (as guarantor) and Commonwealth Bank of Australia and Société Générale, Singapore Branch (the "**Lenders**") entered into a facility agreement (the "**RBL Facility**") dated 2 August 2018, pursuant to which the Lenders agreed to lend and the Borrower agreed to borrow up to USD$120 million (the "**Facility Amount**").

The RBL Facility has a term of three years, or such earlier date if the Borrower's total projected oil reserves at the Montara site become equal to or less than 30 per cent of the projected oil reserves, calculated as at the date the Borrower's initial financial model.

The RBL Facility shall require quarterly amortisation payments from 31 December 2018 to 31 March 2021. Early repayment may be required following typical events such as events of default, change in control and illegality. Interest is payable at LIBOR plus 3 per cent per annum. Security is provided over the shares in the Borrower and Holdco and all the assets of the Borrower and Holdco, including but not limited to, the Montara Assets and the Borrower's bank accounts.

Under the RBL Facility, the Borrower will also be required to hedge a significant proportion of its future production from the Montara Assets and maintain a minimum cash balance in an account of US$15 million.

The RBL Facility contains customary covenants for the type of facility, including financial covenants related to financial performance of the Borrower's operations in relation to the Montara Assets, including a restriction of distributions from the Montara Assets where the minimum cash balance in an account is less than US$20 million.

The RBL Facility is subject to certain conditions precedent which have not, as at the Latest Practicable Date, been satisfied, such as TSX-V approval and completion of the Acquisition.

The RBL Facility is governed by the laws of Western Australia.

12.2 *Convertible Facility*

On 2 November 2016, the Tyrus Lender, an entity for which Tyrus acts as investment manager and adviser, (as lender) entered into a convertible note facility with Jadestone (as borrower) pursuant to which the Tyrus Lender agreed to advance up to US$28 million to Jadestone upon and subject to the terms and conditions of this facility. The minimum drawdown amount is US$5 million and integral multiples of US$1 million in excess thereof. The interest rate payable by Jadestone to the Tyrus Lender on each drawdown is 7.5 per cent, with interest on overdue amounts at 12.5 per cent. The Tyrus Lender may also request the Borrower to draw down any undrawn principal.

The Convertible Facility contains customary warranties in relation to capacity and compliance with laws. The Convertible Facility contains customary events of default in favour of the Tyrus Lender such as non-payment of any amounts due to the Tyrus Lender when due, breach of covenant, material adverse, change of control of Jadestone and cross-default.

Any principal amount advanced under the Convertible Facility may be converted into Common Shares or non-voting Class B Shares in the capital of Jadestone, at the option of the Tyrus Lender, at a conversion price of C$0.50 per share, provided that such conversion will not result in the Tyrus Lender, together with entities controlled by or controlling the Tyrus Lender, acquiring 50 per cent or more of the outstanding voting securities of

Jadestone. On 1 August 2018 the Convertible Facility was extended by three months to 31 March 2020. In connection with this extension, the Company has agreed to use all commercially reasonable efforts to procure a listing of the bonds.

The Convertible Facility is governed by the laws of the Province of British Columbia and the laws of Canada. As of the date hereof, the Company has drawn down the Convertible Facility by a total of US$15 million.

In connection with the Convertible Facility, Jadestone granted general and specific security in favour of the Tyrus Lender over certain of its then producing assets.

On 1 August 2018, the Company and the Tyrus Lender agreed that conditional upon Admission occurring no later than 10 August 2018 and the Tyrus Lender receiving payment no later than 5 Business Days after the Company receives the proceeds of the Company Placing, the Company would redeem the Convertible Facility following Admission by paying $17,450,000 to the Tyrus Lender and that the Convertible would terminate on receipt of such payment and that the associated security will be released.

The Tyrus Lender has also agreed that it shall not convert any Principal Amount into shares, declare an event of default or exercise any right of enforcement under the Convertible Facility or require the Company to draw down any additional sums and the Company has agreed not to request any further advances, in each case unless Admission does not occur by 10 August 2018 or the Company does not make the payment to the Tyrus Lender 5 Business Days after the Company receives the proceeds of the Company Placing.

12.3 *Placing Agreement*

The Company, the Directors and the Joint Bookrunners entered into a placing agreement dated 3 August 2018 the Placing Agreement, under the terms of which the Joint Bookrunners have agreed (conditionally, *inter alia*, on Admission taking place not later than 10 September 2018) as agents for the Company to procure subscribers for 236,954,802 new Common Shares at the Placing Price. Subject to the Placing Agreement becoming unconditional in accordance with its terms, the Company has agreed to pay the Joint Bookrunners commissions together with corporate finance fees together in each case with any applicable VAT.

The Company will pay certain other costs and expenses (including any applicable VAT) of, or incidental to, the Placing including all fees and expenses payable by the Joint Bookrunners on behalf of the Company in connection with Admission, including expenses of the registrars, printing and advertising expenses, postage and all other legal, accounting and other professional fees and expenses.

The Placing Agreement contains representations, warranties and indemnities given by the Company to the Joint Bookrunners as to the accuracy of the information contained in this document and other matters relating to the Group and its business. In addition, the Directors have given certain warranties to the Joint Bookrunners regarding the accuracy of the information about themselves contained in this document and certain other matters. The Joint Bookrunners are entitled to terminate the Placing Agreement in certain specified circumstances prior to Admission. The Placing Agreement is governed by the laws of England and Wales.

12.4 **Subscription Agreements**

Between 26 and 29 July 2018, each of Robert Lambert, Iain McLaren, Dennis McShane, Eric Schwitzer, Paul Blakeley, Daniel Young and seven members of Jadestone's senior management, together with Livermore Strategic Opportunities, LP irrevocably agreed to subscribe for an aggregate of 2,756,672 Subscription Shares in connection with the Placing at the Placing Price.

12.5 **Relationship Agreement**

The Company and Tyrus, the Tyrus Fund and Stifel entered into a relationship agreement on 3 August 2018 (the "**Relationship Agreement**"), conditional on Admission.

Under the Relationship Agreement, each of Tyrus and the Tyrus Fund has given certain undertakings, including, to exercise his voting rights, insofar as they are able, as a shareholder to: (i) ensure that transactions entered into between any member of the Group and either or both of Tyrus and the Tyrus Fund (and their associates), are conducted on an arm's length basis and on normal commercial terms; and (ii) that the Group shall be managed for the benefit of the Shareholders and the business of the Group and not solely for the benefit of each of Tyrus and the Tyrus Fund. Under the Relationship Agreement, the Tyrus Fund has a right to nominate one director to the board of the Company.

This Relationship Agreement will come into force on Admission and shall be in force and effective for any period whilst the Shares are admitted to trading on AIM and whilst each of Tyrus or the Tyrus Fund (jointly or individually) hold 20 per cent or more of the rights to vote at a general meeting of the Company. The Relationship Agreement is governed by the laws of England and Wales.

Jadestone

12.6 **Block 05-1b & c SPA**

Mitra Energy (Vietnam 05-1) Pte Ltd ("**Mitra 05-1**"), a wholly-owned subsidiary of the Company, as buyer, and the Company, as guarantor, entered into a sale and purchase agreement (the "**Block 05-1b & c SPA**") on 8 August 2016 with Teikoku, as seller, for the acquisition of a 30 per cent working interest in the Block 05-1b & c PSC (the "**05-1b & c Interest**").

Teikoku and JX Nippon Oil & Gas Exploration Corporation (the "**Partners**"), each hold a 35 per cent working interest in Block 05-1b & c PSC.

The purchase price for the 05-1b & c Interest is the aggregate of:

(a) US$14,300,000; and

(b) a further upward or downward adjustment following the agreement between Mitra 05-1 and Teikoku of the completion statement,

(the "**Initial Block 05-1b & c Consideration**").

In addition to the Initial Block 05-1b & c Consideration, Mitra 05-1 is also required to pay to Teikoku further payments totalling US$108,007,000 (in aggregate), contingent on the occurrence of certain variables, including targets for the extraction of oil and natural gas being met at the Block 05-1b & c oilfields.

Completion of the Block 05-1b & c Acquisition is conditional upon:

(a) the Partners waiving their pre-emption rights in relation to the Interest and providing written consent to the transfer of the 05-1b & c Interest;

(b) Teikoku obtaining the consent of the Partners, in relation to the transfer of the 05-1b & c Interest;

(c) a transfer and assignment agreement in relation to the joint operating agreement and an amendment agreement to the Block 05-1b & c PSC;

(d) a waiver from the Vietnam Oil and Gas Corporation ("**VOGC**"), in relation to its rights to acquire the 05-1b & c Interest by law and the consent of VOGC to the assignment of the 05-1b & c Interest;

(e) approval from the Socialist Republic of Vietnam;

(f) there being no subsisting breach of any of the material contracts in place in relation to the Block 05-1b & c oilfields; and

(g) Mitra 05-1 acquiring an interest of not less than 10 per cent in the Block 05-1b & c oilfields.

Each party to the Block 05-1b & c SPA agrees to use all reasonable endeavours to procure the timely satisfaction of the conditions set out above and shall provide reasonable assistance where required to the other parties towards the satisfaction of such conditions.

The Block 05-1b & c SPA contains customary warranties in relation to capacity and ownership of the 05-1 Interest, compliance with laws and that all material contracts to the operation of the Block 05-1b & c oilfields have been disclosed to Mitra 05-1.

The Block 05-1b & c SPA contains indemnities from Mitra 05-1b & c and Teikoku in relation to any costs, claims or liabilities arising out of the 05-1b & c Interest incurred by Mitra 05-1b & c prior to 1 July 2016 (the "**05-1b & c Effective Date**") for which Teikoku shall reimburse Mitra 05-1b & c and by Teikoku after the 05-1b & c Effective Date, for which

Mitra 05-1b & c shall reimburse Teikoku. Teikoku also agrees to account to Mitra 05-1b & c (on an indemnity basis) for any financial benefits received by Teikoku from the 05-1b & c Effective Date.

The Block 05-1b & c SPA also contains customary limitations on Teikoku's liability under the Block 05-1b & c SPA including matters disclosed to Mitra 05-1b & c, time limits and financial limitations.

The maximum aggregate cap on the Teikoku's liability for a breach of any of the warranties is up to US$58,000,000.

The Block 05-1b & c SPA is governed by the laws of England and Wales.

The Block 05-1b & c SPA is the subject of a dispute as set out in further detail in Section 16 of Part 11 of this document.

12.7 **SC-56 Assignment Agreement and Farm-out with Total**

On 23 August 2012, Mitra Philippines entered into: (1) an assignment agreement and (2) a farm-out agreement, with Total. By virtue of these agreements, Mitra Philippines assigned 75 per cent of its participating interest in SC-56 to Total, subject to the approval of the DOE which was obtained on 8 October 2012.

In consideration for participating interest assigned by Mitra Philippines to Total, the latter bound itself to bear for and on behalf of Mitra Philippines 25 per cent of all costs incurred on and with respect to the 2D and 3D seismic programs, reprocessing of seismic data, deepwater planning studies and G&G studies carried out during the 3 year extension of exploration period (i.e. 3 years from 1 September 2012), (such costs are designated as "**Exploration Program Costs**"), up to the earlier of: a cap of US$2 million; or completion of the minimum work program to be performed during the 3 year extension of exploration period. A further extension to the exploration period to 1 September 2020 has been approved by the Government of the Republic of the Philippines. If petroleum in a commercial quantity is discovered during the exploration period, the SC-56 PSC will remain in force for an additional 25 years.

Further, Total obliged itself to bear all Exploration Program Costs attributable to its 75 per cent interest incurred in the execution of the extension of the exploration work obligations from 1 September 2012. In addition, Total is given the option to pursue the exploration of Block SC-56 and to participate in the first exploration well. If Total takes up its option, Total agrees to bear, for and on behalf of Mitra Philippines, 25 per cent of all well costs of the first exploration well, on top of bearing all well costs attributable to its 75 per cent participating interest. If the first exploration well is successful and a discovery is made, and if Total elects to pursue the appraisal of such discovery and participate in the appraisal well, Total shall bear, for and on behalf of Mitra Philippines 25 per cent of all well costs of the appraisal well, and all well costs attributable to its 75 per cent participating interest.

Total shall have discharged its obligations in respect of the first exploration well or in respect of the appraisal well upon the earlier of: (i) payment by Total of US$18,750,000; (ii) demobilization of the rig following the drilling of the first exploration well; or (iii) plugging and abandonment of the first exploration well. Notwithstanding the occurrence of these events, Total shall remain liable for any well costs arising after the date of such event, up to the amount of US$18,750,000.

Cost recovery provisions are as reflected in the SC-56 JOA. The farm-out agreement is governed by the laws of England. The farm-out agreement and assignment of the 75 per cent participating interest was approved by the DOE on 8 October 2012.

There is ongoing arbitration in relation to SC-56, details of which are set out in paragraph 16 of Part 11 of this document.

12.8 **Total Guarantee in respect of SC 56**

A guarantee dated 6 April 2018 was issued by Total Holdings International BV, a company incorporated under the laws of Netherlands (the "**Total Guarantor**") in favour of the DOE, pursuant to the provisions of SC 56, arising from the farm-out and transfer of 75 per cent participating interest in SC 56 to the Total Guarantor's direct subsidiary, Total.

The Total Guarantor irrevocably guarantees to the DOE the faithful performance by its subsidiary of the amended minimum work programme for the exploration period, extended to 1 September 2020, and all obligations, representations and warranties under the SC 56. The Total Guarantor shall pay DOE on demand, the value of the unfulfilled balance of the work obligations for such sub-phase and generally pursuant to the SC 56, in the event of failure of fulfilling the Contractor's obligations during the 3rd exploration sub-phase. The guaranteed amount is limited to US$7,508,988.50 in aggregate.

The Total Guarantor shall be released from the guarantee and all obligations on the sooner of: (i) full payment of all amounts guaranteed; or (ii) the fulfilment of contractor's obligations under the SC-56. The guarantee is governed by the laws of the Philippines.

12.9 **Jadestone Energy Limited Guarantee in respect of SC 56**

A guarantee dated 10 September 2015 was issued by Jadestone Energy Limited (formerly Mitra Energy Limited) ("**JEL Guarantor**") in favour of the DOE, pursuant to the provisions of SC 56, arising from the farm-out and transfer of 75 per cent participating interest in SC-56 to Total.

The JEL Guarantor irrevocably guarantees to the DOE the faithful performance by its subsidiary, Mitra Philippines, of any or all exploration work obligations for the 5 year exploration period extension, granted by the DEO on 3 October 2014, and all obligations, representations and warranties under the SC 56. The JEL Guarantor shall pay DOE on demand, the value of the unfulfilled balance of the work obligations for such sub-phase and generally pursuant to the SC 56, in the event of failure of fulfilling the Contractor's obligations during the 3rd exploration sub-phase. The guaranteed amount is limited to US$3,550,000 in aggregate.

The JEL Guarantor shall be released from the guarantee and all obligations on the sooner of: (i) full payment of all amounts guaranteed; or (ii) the fulfilment of contractor's obligations under the SC-56. The guarantee is governed by the laws of the Philippines.

12.10 **SC-56 Operating Agreement with Total**

On 8 August 2012, Mitra Philippines and Total entered into an Operating Agreement with respect to the SC-56 ("**SC-56 JOA**"), for purposes of specifying the rights and obligations of the parties and clarifying the roles and responsibilities of the operator. The participating interests of the parties are as follows: (i) Mitra Philippines – 25 per cent; and (ii) Total – 75 per cent.

Under the SC-56 JOA, Mitra Philippines was originally named and designated as the operator. An operator may be removed upon receipt of notice from any non-operator for certain reasons. An operator may also be removed by the decision of the non-operators if it is found to have committed a material breach of the SC-56 JOA or SC-56, and has failed to remedy its breach of obligations within 30 days from receipt of notice informing it of such breach.

On 31 October 2014, the parties entered into an agreement relating to the transfer of operatorship under the SC-56 JOA. Effective on 25 October 2014, Mitra Philippines resigned as operator and Total assumed all rights and benefits attributable as operator. By way of the letter from the DOE dated 06 October 2014, the transfer of operator has been completed. Mitra Philippines has been released and discharged from all liabilities and obligations under or in respect of the SC-56 JOA to the extent attributable to the operatorship at and from 25 October 2014.

Allocation of Costs and Profit Sharing – The Operator shall formulate and propose procedures for the allocation of produced Hydrocarbons every calendar quarter, subject to the approval of the Operating Committee and adherence to specific principles.

Governance: Under the SC-56 JOA, the Operating Committee is composed of representatives of each party holding a participating interest. In this regard, each party shall appoint one (1) representative and one (1) alternate representative to serve as a member of the Operating Committee.

Except as otherwise expressly provided in the SC-56 JOA, all decisions, approvals and other actions of the Operating Committee on all proposals coming before it shall be decided by the affirmative vote of two (2) or more parties which are not affiliates then having collectively at least sixty five percent (65 per cent) of the participating interests, save for certain circumstances where the affirmative vote of two (2) or more parties which are not affiliates then having collectively at least eighty five percent (85 per cent) of the participating interest or unanimity is required.

Exclusive Operations: Except for exclusive operations relating to deepening, testing, completing, sidetracking, plugging back, recompletions or reworking of a well originally drilled to fulfill the minimum work obligations, the declaration of a commercial discovery or the development of, and production from a discovery, no exclusive operations may be proposed or conducted until the minimum work obligations are fulfilled. Operations which are required to fulfill the minimum work obligations must be proposed and conducted as joint operations.

Non-consent: There is a non-consent provision in the SC-56 JOA. If a party voted against any proposal which was approved by the Operating Committee and which could be conducted as an Exclusive Operation then such party shall have the right not to participate in the operation contemplated by such approval.

Default: Any Party that fails to: (1) pay when due its share of Joint Account expenses (including cash advances and interest); or (2) obtain and maintain any security required of such party shall be in default under the SC-56 JOA. The non-defaulting party shall promptly give notice of such default to the Defaulting Party and each of the defaulting Parties. If the Operator is a defaulting party, a meeting of the Operating Committee shall be convened as soon as practicable after Operator's default has continued for eight (8) days from the date of the Default Notice for the purpose of considering whether to remove Operator.

Assignment: Except in the case of a party transferring all of its participating interest, no transfer shall be made by any party which results in the transferor or the transferee holding a participating interest of less than 10 per cent or any interest other than a Participating Interest in the SC-56 and the SC-56 JOA. Each other party shall have the right to acquire the participating interest subject to the terms and condition of the proposed transfer. If no party delivers such counter-notification, the transfer to the proposed transferee may be made under terms and conditions.

Withdrawal: Withdrawal is permitted. Any party not in default may at its option withdraw from the SC-56 JOA by giving notice to all other Parties stating its decision to withdraw. A withdrawing party shall have the right to receive its Entitlement produced through the effective date of its withdrawal and shall be entitled to receive all information to which such party is otherwise entitled under the SC-56 JOA until the effective date of its withdrawal. A withdrawing party shall, following its notification of withdrawal, remain liable only for its share in the costs of joint operations, and exclusive operations in which it has agreed to participate, any minimum work obligations, expenditures related to an emergency occurring prior to the effective date of party's withdrawal, all other obligations and liabilities with respect to acts or omissions under the SC-56 JOA prior to the effective date of such Party's withdrawal for which such Party would have been liable, had it not withdrawn from this Agreement. Notwithstanding the foregoing, a party shall be liable for any operations or expenditures (except any minimum work obligations and emergency prior to the effective date of a Party's withdrawal) it voted against of the Operating Committee vote approving such operation or expenditure.

Applicable law and jurisdiction: The substantive laws of England, exclusive of any conflicts of laws principles that could require the application of any other law, shall govern this Agreement for all purposes, including the resolutions of all Disputes between or among Parties. Further, any dispute arising out of or in connection with this Agreement, including any question regarding its existence, validity or termination, shall be referred to and finally resolved by arbitration in Singapore and in accordance with the Arbitration Rules of the Singapore International Arbitration Centre.

12.11 **SC-56 Financing Solution Agreement**

Mitra Philippines, as borrower, and the Company, as guarantor, entered into a financing solution agreement (''**Financing Agreement**'') on 30 June 2017 with Augusta Ventures Limited (the ''**Lender**''), as lender, and Watson Farley & Williams (Thailand) Limited (the ''**Law Firm**''), as borrower's counsel, in connection with the arbitration action against Total regarding the Halcon prospect.

Under the terms of the Financing Agreement, the Lender has agreed to advance up to an aggregate maximum amount to finance certain of the legal and other costs of Mitra Philippines in connection with the arbitration action. In the event of a successful outcome in the arbitration action, any award must, before payment to Mitra Philippines, first be allocated to repayment of the amount advanced to Mitra Philippines by the Lender and payment of other costs and fees, including interest and success fees.

In the event a settlement is reached between the parties prior to an arbitration award being issued, before payment to Mitra Philippines, the settlement funds must be allocated to repayment of the amount advanced to Mitra Philippines by the Lender and payment of other costs and fees, including interest and success fees.

The Lender's success fee is contingent upon the amount of the facility drawn down during the arbitration and is calculated as a multiple of the amount. All monies allocated to the Lender must be paid prior to distribution of the remaining funds obtained by way of a successful outcome.

In the event Mitra Philippines receives not less than a minimum amount following all payments to the Lender, any deferred fees for legal services by the Law Firm will become due and payable, and will be subject to a 100 per cent uplift. There is a total amount of legal fees which may be deferred in accordance with the arbitration budget.

In the event of an unsuccessful outcome in the arbitration action, the adverse party may be awarded a certain proportion of its arbitration costs, for which Mitra Philippines would be liable. Mitra Philippines is currently in the process of procuring after-the-event insurance for the purposes of insuring against the risk of such an award for adverse costs. The funds to procure this insurance are to be provided by the Lender. Mitra Philippines has given customary representations under the Relationship Agreement in relation to (among other things) capacity and solvency.

Pursuant to the Financing Agreement, in the event that Mitra Philippines does not pay any amount due, or owing from or incurred by Mitra Philippines, to the Lender, (the "**Guaranteed Amount**") the company guarantees to pay the Guaranteed Amount to the Lender on demand. Further, the Company indemnifies the Lender for any costs and disbursements incurred by the Lender in connection with the enforcement of the Guaranteed Amount and in respect of any adverse costs awarded against the Lender in connection with the arbitration action.

The Financing Agreement remains in force and effect until any amount advanced by the Lender and/or the amount of any award pursuant to the arbitration action have been paid out, unless terminated earlier in accordance with its terms. The Financing Agreement is governed by English law.

Pursuant to the SC-56 Service Contract with the DOE, Mitra Philippines is obliged to provide a guarantee amounting to approx. USD 2.5 million to be paid in the event the minimum expected exploration expenditure of approx. USD10 million is not expended towards the exploration of Block SC-56. This risk of liability is included in the arbitration claim.

12.12 SC-56 Service Contract

There is a service contract in place in relation to Block SC-56, details of which are set out in paragraph 2.3.8 of Part 3 of this document.

12.13 SC-57 Farm-in with PNOC Exploration Corporation

On 3 March 2006, PNOC Exploration Corporation ("**PNOC EC**") (as assignor) and Jadestone Energy Limited (formerly Mitra Energy Ltd.) ("**JEL**") (as assignee) entered into a farm-in agreement ("**Agreement**") for purposes of assigning 21 percent of PNOC EC's undivided Participating Interest in SC-57 to JEL. Participating Interest means all the rights, title, interest and obligations under a Joint Operating Agreement and a Service Contract.

Assignment of farm-in interest: Subject to the terms and conditions set in the Agreement and to the DOE's consent to the assignment, the respective Participating Interest of PNOC EC and JEL under the PSC shall be as follows: PNOC EC, 79 per cent and JEL, 21 per cent The Participating Interest shall be adjusted accordingly upon the effectiveness and completion of a farm-in agreement between PNOC EC and CNOOC International Limited

("**CNOOC INT**") (the "**CNOOC INT Farm-In Agreement**") pursuant to which PNOC EC proposes to assign 51 per cent undivided participating interest in the Service Contract from its share of Participating Interest to CNOOC INT.

Conditions precedent: Completion of the assignment and transfer of the farm-in interest is conditional upon the following:

(a) PNOC EC securing all necessary approvals for the assignment and transfer of the Farm-In Interest, including all relevant Government authority;

(b) JEL securing all necessary corporate approvals for the acquisition;

(c) execution of a deed of assignment of the farm-in interest to be entered into between PNOC EC and JEL ("**SC Assignment**"); and

(d) JEL furnishing PNOC EC a confirmed irrevocable standby letter of credit in favour of PNOC EC in an amount equivalent to 30 per cent of the cap for the Exploration Costs for the First Sub-Phase.

CNOOC INT, JEL and PNOC EC have signed the Joint Operating Agreement ("**SC-57 JOA**") and such SC-57 JOA is in full force and effect.

If completion of the conditions precedent had not occured by 30 May 2006 (the "**Completion Deadline**"), the Completion Date was extendible to a date not more than 30 days after the Completion Deadline, unless otherwise agreed upon in writing by the parties.

Consideration and withdrawal: Subject to JEL's right of withdrawal at the end of each Sub-Phase of the Minimum Work Commitment provided for in the SC-57 JOA, JEL shall pay 30 per cent of the Exploration Costs which have been approved under the SC-57 JOA, and which shall be incurred in the First and Second Sub-Phases of the Minimum Work Commitment provided that the Exploration Costs for the corresponding Phase of the Minimum Work Commitment shall not exceed: US$3 million for the First Sub-Phase; and US$20 million for the Second Sub-Phase. Where the caps are exceeded, the parties shall pay the amount in excess in proportion to their respective Participating Interest then in the Service Contract.

Should JEL fail to meet any of the cash calls made by the Operator under the SC-57 JOA, PNOC shall have recourse against the standby letter of credit provided by JEL in respect of the First and Second Sub-Phases.

Any Party shall have the right to withdraw from the Agreement by giving the other Party written notice to that effect 60 days prior to the effectiveness of the withdrawal, in which case the Participating Interest of the withdrawing Party shall be automatically conveyed or transferred to the other/remaining Party.

Joint Operating Agreement: Once the assignment by PNOC EC of its Participating Interest to CNOOC INT pursuant to the CNOOC INT Farm-In Agreement has been completed, CNOOC INT shall be designated as the Operator of the Service Contract to carry out the Petroleum Operations.

Third Party Assignment: There is a prohibition on assignment of any part or all the rights and/or obligations of a Party under the Agreement without prior written notice to the other Party. The Parties shall also have pre-emptive rights to the interest offered to a third party

Termination: The Agreement may be terminated by serving written notice on the following occasions: If Completion shall not occur by the Completion Deadline or extension thereof; If JEL reasonably considers that PNOC EC is in breach of any warranty or other provision of the Agreement; If any Government Authority imposes substantial obligation upon either Party; If an order is made or an effective resolution is passed for the winding up, liquidation, insolvency, administration, reorganization, dissolution, or bankruptcy, or for the appointment of a liquidator, judicial manager, receiver, administrator, trustee or similar officer to a Party.

Law: The Agreement shall be governed by Philippine law. There are provisions on dispute resolution and arbitration using the Rules on Conciliation and Arbitration of the International Chamber of Commerce.

12.14 **SC-57 JOA with PNOC Exploration Corporation**

On 3 April 2006, PNOC EC, CNOOC INT, and JEL entered into the SC-57 JOA for the exploration, development and production of Petroleum in the Contract area, including the treatment, storage, and transportation of the same. The SC-57 JOA became effective on 31 March 2006.

CNOOC INT is designated the Operator and shall operate on a no-profit-no-loss basis whilst acting as Operator in the Contract Area. The Operating Committee shall exercise overall supervision and control of all matters pertaining to the Joint Operations. Each Party shall appoint one representative to the Operating Committee.

Cost Recovery and Disposal of Petroleum: The parties agreed that in the event of commercial production from the contract area, the cost recovery petroleum shall be based on the following order of priority: operating costs; exploration costs; development costs; all costs incurred separately by the parties for the necessary and proper conduct of the Petroleum Operations entitled for cost recovery under the contract; All expenditures incurred under any Sole Risk Project and which does not lead to a commercial Discovery.

Each of the parties shall have the right to take in kind and separately dispose of a percentage, equal to its entitlement to the various categories of Petroleum, or the total quantities of Joint Petroleum produced pursuant to the SC-57 JOA, provided the Operator shall have the right to use in any Joint Operations as much of the Joint Petroleum as may be reasonably required, and the quantities to be so used shall be excluded from the estimates to be provided by the Operator. Each of the parties shall have the right and, at the request of the Operator, the obligation to lift and separately dispose of a percentage equal to its Participating Interest, of all Joint Petroleum produced and stored in any jointly owned storage facilities.

Assignment and Encumbrance: A party may transfer to the other party or parties all or part of its Participating Interests subject to the terms and conditions to be mutually agreed upon by the Parties. A Party may transfer all or part of its Participating Interest to an Affiliate without the consent of the other parties. A party is not prevented from mortgaging, pledging or otherwise encumbering all or part of its interest in the Contract for the purpose of security relating to finance, provided that such party shall remain liable for all obligations relating to such interest, and the encumbrance shall be expressly subordinated to the rights of the other parties.

Withdrawal: Any Party may withdraw from the SC-57 JOA by giving the other party written notice 60 working days prior to the effective date of the withdrawal. Within 20 working days of receipt of such notice, any other party may similarly give notice that it wishes to withdraw from the contract. If all parties shall give such notice, no assignment shall take place, the parties shall be deemed to have decided to abandon the Joint Operations. No party participating in a development Program which the Regulatory Authorities have authorised may withdraw from the SC-57 SC-57 JOA prior to completion of the relevant works comprised in such development program.

The SC-57 JOA is governed by and construed in accordance with the laws of England.

12.15 **SC-57 Service Contract**

There is a service contract in place in relation to Block SC-57, details of which are set out in paragraph 3.2.2 of Part 3 of this document.

12.16 **Block 51 Investment Certificate and PSC**

There is an investment certificate and PSC in place in relation to Block 51, details of which are set out in paragraph 2.2.7 of Part 3 of this document.

12.17 **Block 46-07 Participation Agreement**

PetroTech Investment Corporation Pte. Limited ("**PetroTech**") and Mitra Energy (Vietnam Nam Du) Pte. Limited ("**Mitra Vietnam**") entered into a participation agreement dated 3 November 2010 in relation to participation in Block 46/07. Pursuant to this agreement, Mitra Vietnam granted PetroTech a "back-in" right to participate in the production sharing contract, which Mitra Vietnam and certain co-venturers had previously entered into in respect of Block 46/07. PetroTech can exercise such right within 90 days of the declaration of the first commercial discovery in the Block. This participation agreement contains a number of customary warranties given by each party in favour of the other in relation to matters including solvency, compliance with laws and satisfaction of certain pre-conditions regarding participation in the block. This agreement is governed by the laws of England and Wales.

12.18 **Block 46-07 Investment Certificate and PSC**

There is an investment certificate and PSC in place in relation to Block 46-07, details of which are set out in paragraph 2.2.7 of Part 3 of this document.

12.19 **Block 127 Investment Certificate, PSC and Relinquishment Notice**

Vietnam Oil and Gas Group (the national oil company of Vietnam) entered into a production sharing contract with Mitra Energy (Vietnam Phu Khanh) Pte. Limited in respect of offshore Block 127 on May 17, 2012 (the "**127 PSC**"). Pursuant to the 127 PSC, Mitra Vietnam was granted the right to engage in petroleum exploration, discovery, appraisal and development in the contract area being offshore area 127 (being an area of 9,000 km2, located at the southern end of the Phu Khanh basin, off the east coast of Vietnam) ("**Block 127**"). During the three months ended March 31, 2018, the Company performed a review of its asset base and as a result of that review, the Company decided to relinquish Block 127 at the end of the current exploration phase on May 24, 2018. Having completed all minimum work commitments, Jadestone informed Vietnam Oil and Gas Group of its relinquishment decision on April 4, 2018. The Company is currently proceeding with the relinquishment process, in accordance with all applicable Vietnamese laws and the terms of 127 PSC. Accordingly, the Company has recorded an impairment charge of US$11.9 million during the quarter, thus reducing the book value of 127 PSC to nil.

12.20 **Stag Floating, Storage and Offloading Vessel Agreement and Option to Purchase**

Pursuant to a novation dated 11 November 2016, Jadestone became party to an agreement with Dampier Spirit LLC (part of the Teekay Shipping Corporation) (the "**Contractor**") for the provision of a floating storage and offtake vessel located at the Stag field, known as the Frontier Spirit (the "**FSO Contract**"). The FSO Contract also contains a purchase option in favour of Jadestone which can be exercised upon payment by Jadestone of an agreed purchase price for the vessel, depending on the timing of exercise of the option. The FSO Contract's current term runs until May 2024, including time charter services.

Under the FSO Contract, the Contractor has obligations to provide operational services in respect of the FSO, including time charter, navigation, mooring and operational assistance in consideration for fees charged to Jadestone by reference to the charter rates. If a material change occurs, Jadestone is entitled to terminate the FSO Contract against payment to the Contractor of a termination payment calculated in accordance with a specified payment schedule, to compensate the Contractor for loss of charter. The FSO Contract contains a number of customary warranties, indemnities and liability allocation provisions for a contract of this nature.

12.21 **Crude oil and condensate sale, purchase and marketing agreement**

A crude oil and condensate sale, purchase and marketing agreement was entered into on 4 August 2009 between, on the one hand, Mitra Energy Limited (now called Jadestone Energy Limited), Mitra Energy (Indonesia Sibaru) Limited, Mitra Energy (Biliton) Pte Limited, Mitra Philippines, Mitra Energy (Vietnam Con Son) Limited (together, the "**Mitra Parties**"), and, on the other hand, BP Singapore Pte. Limited ("**BPS**") (the "**BP Crude Sale Agreement**").

Under the terms of the BP Crude Sale Agreement, each of the Mitra Parties and any other associated company of Mitra Energy Limited (within the meaning given by the BP Oil International Limited General Terms and Conditions for Sales and Purchases of Crude Oil) (an "**Associated Party**") which holds (directly or indirectly) an interest in the specified oil production assets, have agreed to sell all present and future crude oil, condensate and natural gas products extracted from certain specified assets which at that time were located in Indonesia, Vietnam, Philippines and Thailand) (the "**Products**") to BPS, which agreed to purchase and then lift and market the Products to prospective third party purchasers on the best prices and terms reasonably obtainable by BPS. BPS shall receive a marketing fee and an operating fee per oil barrel extracted and a marketing fee per tonne of natural gas extracted.

Under the terms of the BP Crude Sale Agreement, the qualifying present and future crude oil, condensate and natural gas products extracted from each new oil field asset purchased by any of the Mitra Parties and any Associated Party shall automatically become subject to terms of the BP Crude Sale Agreement, except in certain circumstances, including where such products are already committed to pre-existing marketing arrangements, where the relevant national oil company has participation rights (including back-in rights) which would override the application of the BP Crude Sale Agreement or in circumstances where the relevant Mitra Party or Associated Party would be obliged to supply those products to the domestic market in which the relevant asset is located. If a further oil field asset is purchased by an Associated Party, each such Associated Party is required to enter into a deed of adherence to the BP Crude Sale Agreement to bring the underlying asset within the remit of the BP Crude Sale Agreement (subject to the exceptions noted above). If an asset which is subject to the BP Crude Sale Agreement is proposed to be sold or otherwise transferred to a third party purchaser, the relevant Mitra Party is required to first disclose to that potential transferee or purchaser the terms of the BP Crude Sale Agreement and include a condition to any such asset sale or transfer transaction that the third party purchaser shall be required to enter into an agreement on the same terms as the BP Crude Sale Agreement with BPS with respect to the relevant asset.

The BP Crude Sale Agreement contains a number of provisions which are customary for arrangements of this nature, including quality control assurance mechanisms in favour of BPS such as vessel auditing and it also imposes obligations on the Mitra Parties to ensure compliance with various operational principles and regulations to ensure that the Products are suitable for sale. Each of the Mitra Parties and BPS have provided certain ongoing representations and warranties regarding matters such as their ongoing solvency and holding the necessary government approvals required to perform their respective obligations under the BP Crude Sale Agreement. The BP Crude Sale Agreement is governed by the laws of England and Wales.

12.22 **Stag SPA**

Jadestone Energy (Australia) Pty Ltd (formerly Mitra Energy (Australia) Pty Ltd) ("**Jadestone Australia**"), a wholly owned subsidiary of the Company, as buyer, and the Company, as guarantor, entered into sale and purchase agreement (the "**Stag SPA**") on 20 July 2016 with Quadrant Energy and Santos Offshore Pty Ltd ("**Santos**") (together the "**Stag Sellers**") for the acquisition (the "**Stag Acquisition**") of a 100 per cent interest in the Stag Oilfield (the "**Stag Asset**").

The purchase price for the Stag Asset was US$10,000,000 (in aggregate) and was paid to each of Quadrant Energy and Stag *pro rata* to their ownership percentage of the Stag Asset in the following amounts:

(a) US$3,333,340 was paid to Quadrant Energy (the "**Quadrant Price**"); and

(b) US$6,666,660 was paid to Santos (the "**Santos Price**"),

(the "**Stag Purchase Consideration**").

Contingent additional consideration may be payable by Jadestone Australia in the following amounts:

(a) US$3,000,000 (if the average crude oil sale price per barrel equals US$80/bbl during the period from 1 January 2017 to 31 December 2017); plus

(b) US$2,000,000 (if the average crude oil sale price per barrel equals US$80/bbl during the period from 1 January 2018 to 31 December 2018); plus

(c) US$7,000,000 (if approval of the acquisition of the Hart oilfield is achieved); plus

(d) US$3,000,000 (if approval of the acquisition of the South Stag oilfield is achieved).

As at the date of this document a further US$9.9m of additional consideration has been paid by Jadestone Australia to the Stag Sellers. The Stag SPA contains customary warranties in relation to capacity and ownership of the respective interests in the Stag Asset held by each of Quadrant Energy and Santos, compliance with laws and that all material contracts to the operation of the Stag oilfield have been disclosed to Jadestone Australia.

The Stag SPA contains indemnities from each of Jadestone Australia, Quadrant Energy and Santos in relation to any costs, charges, claims or liabilities incurred by Jadestone Australia prior to 1 July 2016 (the "**Stag Effective Date**") for which Quadrant Energy and/or Santos shall reimburse Jadestone Australia and by Quadrant Energy and/or Santos after the Stag Effective Date, for which Jadestone Australia shall reimburse Quadrant Energy and/or Santos.

The Stag SPA also contains customary limitations on the Stag Sellers' liability (which is several) under the Stag SPA including matters disclosed to Jadestone Australia, time limits and financial limitations.

The maximum aggregate cap on the Stag Sellers' liability for a breach of any of the warranties is up to the Quadrant Price in relation to Quadrant Energy and up to The Santos Price in relation to Santos.

The Stag SPA is governed by the laws of Western Australia.

12.23 **Stag commodity swap agreement**

Jadestone Australia has entered into a commodity swap agreement with BPS, details of which are set out in paragraph 2.1.8 of Part 3 of this document.

12.24 **Stag licences**

Details of Production licence WA-15-L and Pipeline licence WA-6-PL in respect of the Stag oil field are set out in paragraph 2.1.2 of Part 3 of this document.

12.25 **Ogan Komering sale and purchase agreement**

Jadestone International Holdings Inc. ("**Jadestone International**"), a wholly owned subsidiary of the Company, as buyer, and the Company, as guarantor, entered into sale and purchase agreement (the "**Ogan Komering SPA**") on 9 March 2017 with Repsol Oil & Gas Canada Inc. ("**Repsol**") for the acquisition (the "**Ogan Komering Acquisition**") of the entire issued share capital of Talisman (Ogan Komering) Ltd. ("**TOKL**"). TOKL holds a fifty percent (50 per cent) interest (the "**PSC Interest**") in the Ogan Komering Production Sharing Contract, Sumatra, Indonesia ("**PSC**"). The remaining fifty percent (50 per cent) in the PSC is held by PT Pertamina Hulu Energi Ogan Komering ("**Pertamina Ogan Komering**"), an affiliate of PT Pertamina Persero, Indonesia's national oil company. TOKL, together with Pertamina Ogan Komering, operates the PSC through a joint operated body.

The purchase price in connection with the Ogan Komering Acquisition shall be the aggregate of:

(a) US$5,800,000 (the "**Base Amount**"); plus

(b) any cash calls in relation to the PSC interest; minus

(c) any receipts received by Repsol post-1 July 2016 in connection with the PSC Interest; minus

(d) US$1,907,601 (being the amount of working capital in TOKL at the date of the Ogan Komering SPA),

(the "**Ogan Komering Consideration**").

The Ogan Komering Consideration shall also be subject to an upward or downward adjustment following the agreement between Jadestone International and Repsol in relation to the completion statement.

The Ogan Komering SPA contains customary warranties in relation to title, capacity and ownership of the shares in TOKL, ownership of the PSC Interest, compliance with laws and that all material contracts to the operation of the Ogan Komering oilfield have been disclosed to Jadestone International.

The Ogan Komering SPA contains indemnities from Jadestone International in favour of Repsol (including its directors and its affiliates) in relation to:

(a) any costs, charges, claims, demands, judgments, awards or liabilities (the "**Ogan Komering Losses**") incurred by Repsol (including its directors and its affiliates) after 9 March 2017; and

(b) any Ogan Komering Losses incurred by Repsol as a result of any environmental, abandonment or decommissioning liabilities arising from events occurring before or after the date of the Ogan Komering SPA.

The Ogan Komering SPA also contains customary limitations on Repsol's liability under the Ogan Komering SPA including matters disclosed to Jadestone International, time limits and financial limitations.

The maximum aggregate cap on Repsol's liability for a breach of any of the title and environment warranties is up to 100 per cent of the Base Amount. For all other claims under the warranties (except tax claims) the maximum aggregate cap on Repsol's liability is up to 55 per cent of the Base Amount. For tax claims, the maximum aggregate cap on Repsol's liability is up to US$10,000,000.

The Ogan Komering SPA is governed by the laws of England and Wales.

12.26 **Ogan Komering Settlement Agreement**

Jadestone and PT Pertamina entered into a settlement agreement on 18 May 2018, pursuant to which the parties have agreed to work towards a final settlement of costs in relation to the expired PSC, associated joint venture agreement and the temporary cooperation agreement ("**TCC**") which the parties entered into in order to maintain operations at the Ogan Komering oil field, following the expiry of the PSC and joint venture agreement. The TCC subsequently expired on 19 May 2018 (the "**OK Contract Expiry Date**").

The costs associated with the expired PSC, joint venture agreement and TCC include provision for outstanding working capital requirements made by each of the parties, any obligations to the Minister of Energy and Mineral Resources, the total investment costs incurred by each party and any claims and liabilities which may have arisen, as at the OK Contract Expiry Date. It is anticipated that, pursuant to this settlement agreement, Jadestone will enter into further agreement with PT Pertamina in respect of the settlement of such costs.

Jadestone estimates that approximately US$1.2 million will be due to be paid to the Group as a result of a final settlement between Jadestone and PT Pertamina.

12.27 **Bone JOA with Azimuth Indonesia Limited and PSC**

Mitra Energy (Indonesia Bone) Limited ("**Mitra Indonesia Bone**") and Azimuth Indonesia Limited ("**Azimuth**") entered into a Joint Operating Agreement in relation to the Bone Block, Indonesia on 11 September 2014 (the "**Bone JOA**"). Mitra Indonesia Bone had previously entered into a PSC on 26 November 2010 with Badan Pelaksana Kegiatan Usaha Hulu Minyak dan Gas Bumi in relation to the Bone Block (the "**Bone PSC**"). Pursuant to the Bone JOA, Mitra Indonesia Bone transferred part of its undivided interest in the rights and obligations under the Bone PSC to Azimuth, such that once the Bone JOA came into force, Mitra Indonesia Bone retained a 60 per cent participating interest in the Bone Block and Azimuth Indonesia Limited acquired a 40 per cent interest. The Bone JOA imposes various obligations on both parties and establishes a regime for implementation of work programmes and budgets, and also established an operating committee to oversee the sharing of production interests in relation to the Bone Block. The Bone JOA is governed by the laws of England and Wales.

12.28 **Bone withdrawal agreement**

The Company, through its wholly-owned subsidiary, Mitra Indonesia Bone, held a 60 per cent operating interest in the Bone Block, offshore Sulawesi with Azimuth, holding the remaining 40 per cent

On 4 May 2017, Mitra Indonesia Bone signed a withdrawal agreement with Azimuth, for the transfer of its 60 per cent working interest and operatorship of the Bone PSC to Azimuth. The transfer is effective from 15 April 2017, but remains subject to government approval.

Montara

12.29 Details of the following contracts in relation to the Montara Assets are set out in this document where indicated:

(a) Production licence AC/L7 and Production licence AC/L8, details of which are set out in paragraphs 2.1 and 2.2 of Part 4 of this document respectively.

(b) Acquisition Agreement, details of which are set out in paragraph 3.1 of Part 4 of this document.

(c) Operator and transitional services agreement in connection with the Acquisition, details of which are set out in paragraph 3.2 of Part 4 of this document.

(d) Crude oil sale agreement, details of which are set out in paragraph 3.3 of Part 4 of this document.

13 RELATED PARTY TRANSACTIONS

The related party transactions being transactions which, as a single transaction or in their entirety, are or may be material to the Company and have been entered into by the Company or any other member of the Group during the period commencing on the period covered by historical financial information and up-to-date of this document and terminating immediately prior to the date of this document are set out in/are as follows:

- note 37 in Section A of Part 6, Jadestone Energy Inc. audited consolidated financial statements for the nine months ended December 31, 2017 and year ended March 31, 2017
- note 34 in Section B of Part 6, Jadestone Energy Inc. (formerly Mitra Energy Inc.) audited consolidated financial statements for the Years ended March 31, 2017 and March 31, 2016
- note 24 in Section C Mitra Energy Inc. (formerly Petra Petroleum Inc.) audited consolidated financial statements for the years ended March 31, 2016 and March 31, 2015
- the Subscription Agreements referred to in paragraph 12.4 of Part 11 of this document.
- the repayment of the Convertible Facility referred to in paragraph 12.2 of Part 11 of this document.

Each of the transactions was concluded at arm's length.

14 DEPOSITARY INTERESTS

A depositary agreement between (1) the Company and (2) the Depositary, pursuant to which the Depositary will agree to provide depositary services to the Company was entered into on 31 July 2018. Pursuant to the provision of these services the Depositary entered into a deed poll, details of which are set out below.

The Depositary Interests created pursuant to and issued on the terms of a deed poll to be executed by the Depositary on 17 July 2018 in favour of the holders of the Depositary Interests from time to time (the "**Deed Poll**"). Prospective holders of Depositary Interests should note that they will have no rights in respect of the underlying Common Shares or the Depositary Interests representing them against Euroclear, or its subsidiaries.

Common Shares will be transferred to an account of the Depositary or its nominated custodian (a "**Custodian**") and the Depositary will issue Depositary Interests to participating members.

Each Depositary Interest will be treated as one Common Share for the purposes of determining, for example, eligibility for any dividends, and the Depositary will pass on to the holders of Depositary Interests any stock or cash benefits received by it as holder of Common Shares on trust for such Depositary Interest holder.

Depositary Interest holders will also be able to receive notices of meetings of holders of Common Shares and other notices issued by the Company to its Shareholders.

The Depositary Interests will have the same security code (ISIN) as the underlying Common Shares and will not be required to be admitted separately to trading on the London Stock Exchange.

In summary, the Deed Poll will contain the following provisions:

(a) the Depositary will hold (itself or through the Custodian), as bare trustee, the underlying securities issued by the Company and all and any rights and other securities, property and cash attributable to the underlying securities pertaining to the Depositary Interests for the benefit of the holders of the relevant Depositary Interests;

(b) holders of Depositary Interests warrant, *inter alia*, that the securities in the Company transferred or issued to the Custodian on behalf of the Depositary are free and clear of all liens, charges, encumbrances or third party interests and that such transfers or issues are not in contravention of the Company's constitutional documents or any contractual obligation, law or regulation;

(c) the Depositary and any Custodian shall pass on to the Depositary Interest holders and, so far as they are reasonably able, exercise on behalf of the Depositary Interest holders all rights and entitlements received or to which they are entitled in respect of the underlying securities which are capable of being passed on or exercised. Rights and entitlements to cash distributions, to information, to make choices and elections and to call for, attend and vote at general meetings and any class meetings shall, subject to the Deed Poll, be passed on, within three working days, in the form in which they are received, together with amendments and additional documentation necessary to effect such passing-on, or, as the case may be, exercised in accordance with the Deed Poll;

(d) the Depositary will be entitled to cancel Depositary Interests and withdraw the underlying securities in certain circumstances including where a Depositary Interest holder has failed to perform any obligation under the Deed Poll or any other agreement or instrument with respect to the Depositary Interests;

(e) the Deed Poll contains provisions excluding and limiting the Depositary's liability. For example, the Depositary shall not be liable to any Depositary Interest holder or any other person for liabilities in connection with the performance or non-performance of obligations under the Deed Poll or otherwise except as may result from its negligence or wilful default or fraud or that of any person for whom it is vicariously liable, provided that the Depositary shall not be liable for the negligence, wilful default or fraud of any Custodian or agent which is not a member of its group unless it has failed to exercise reasonable care in the appointment and continued use and supervision of such Custodian or agent. Furthermore, the Depositary's liability to a holder of Depositary Interests will be limited to the lesser of:

    (i) the value of the shares and other deposited property properly attributable to the Depositary Interests to which the liability relates; and

    (ii) that proportion of £10 million which corresponds to the proportion which the amount the Depositary would otherwise be liable to pay to the Depositary Interest holder bears to the aggregate of the amounts the Depositary would otherwise be liable to pay all such holders in respect of the same act, omission or event or, if there are no such amounts, £10 million;

(f) the Depositary is entitled to charge holders fees and expenses for the provision of its services under the Deed Poll;

(g) each holder of Depositary Interests is liable to indemnify the Depositary and any Custodian (and their agents, officers and employees), and hold each of them harmless from and against all liabilities arising from or incurred in connection with, or arising from any act related to, the Deed Poll so far as they relate to the property held for the account of Depositary Interests held by that holder, other than those resulting from the wilful default, negligence or fraud of (i) the Depositary, or (ii) the Custodian or any agent if such Custodian or agent is a member of the Depositary's group or if, not being a member of the same group, the Depositary shall have failed to exercise reasonable care in the appointment and continued use and supervision of such Custodian or agent;

(h) the Depositary may terminate the Deed Poll by giving not less than 30 days' notice. During such notice period, Depositary Interest holders must cancel their Depositary Interests and withdraw their deposited property and, if any Depositary Interests remain outstanding after termination, the Depositary shall, as soon as reasonably practicable, and amongst other things:

  (i) deliver the deposited property in respect of the Depositary Interests to the relevant Depositary Interest holder;

  (ii) at the Depositary's discretion, it may substitute CREST Depositary interests for the Depositary Interests or sell all or part of such deposited property.

It shall, as soon as reasonably practicable, deliver the net proceeds of any such sale, after deducting any sums due to the Depositary, together with any other cash held by it under the Deed Poll *pro rata* to the Depositary Interest holders in respect of their Depositary Interests;

(i) the Depositary or the Custodian may require from any holder information as to the capacity in which Depositary Interests are owned or held by such holders and the identity of any other person with any interest of any kind in such Depositary Interests or the underlying securities in the Company and holders are bound to provide such information requested. Furthermore, to the extent that, *inter alia*, the Company's constitutional documents require the Depositary's disclosure to the Company of, or limitations in relation to, beneficial or other ownership of, or interests of any kind whatsoever in the Company's securities, the Depositary Interest holders are to comply with such provisions and with the Company's instructions with respect thereto.

It should also be noted that holders of the Depositary Interests may not have the opportunity to exercise all of the rights and entitlements available to holders of Common Shares including, for example, the ability to vote on a show of hands. In relation to voting, it will be important for holders of the Depositary Interests to give prompt instructions to the Depositary or its nominated Custodian, in accordance with any voting arrangements made available to them, to vote the underlying Common Shares on their behalf or, to the extent possible, to take advantage of any arrangements enabling holders of the Depositary Interests to vote such Common Shares as a proxy of the Depositary or its Custodian.

15 WORKING CAPITAL

The Directors are of the opinion (having made due and careful enquiry) that, after taking into account the financing facilities available and the net proceeds of the Placing, the working capital of the Group will be sufficient for its present requirements, that is, for at least the period of 12 months from the date of Admission.

16 LITIGATION

Save as disclosed below, no member of the Group is or has been involved in any governmental, legal or arbitration proceedings which may have, or have had during the 12 months preceding the date of this document, a significant effect on the Group's financial position or profitability and, so far as the Directors are aware, there are no such proceedings pending or threatened against any member of the Group.

Dispute in relation to SC-56

Jadestone holds a 25 per cent interest in SC-56 in partnership with operator Total. Four wells have previously been drilled on SC-56, resulting in the Dabakan and Palendag discoveries.

In September 2012, Total farmed into SC-56 and assumed a 75 per cent interest, and in August 2014 formally confirmed its intention to drill an exploration well on the Halcon prospect. As a result of the Halcon confirmation, operatorship was transferred to Total effective 25 October 2014. The Company views Halcon as an economically viable prospect with significant resource potential.

Total has subsequently informed Jadestone that it does not intend to drill an exploration well on the Halcon prospect. In the December 2017 quarter, the Company commenced an arbitration action against Total, with the Singapore International Arbitration Centre, claiming failure by Total to drill the well and resultant damages. Total filed a response to Notice of

Arbitration on 17 November 2017 alleging *inter alia* that it had not agreed to drill an exploration well on the Halcon prospect and the Company has subsequently filed a Statement of claim date 12 April 2018. The arbitration process is ongoing.

The current exploration period on the block runs until 1 September 2020. Total's 2018 work programme for SC-56, as operator, includes a two-phase development study. This includes subsurface geological and geophysical work to revisit resources and development assumptions, to optimise development schemes and minimise technical costs.

With respect to the arbitration action, Mitra Philippines (as borrower) and the Company (as guarantor) have entered into a financing solution agreement with Augusta Ventures Limited (as lender), further details of which are set out in paragraph 12.11 of Part 11 of this document.

Dispute in relation to 05-1

The Company announced on 9 August 2016 that it had signed a definitive SPA with Teikoku, a wholly-owned subsidiary of Inpex Corporation, as seller, for the acquisition of a 30 per cent non-operated working interest in the Block 05-1b & c PSC.

On 22 February 2018, Teikoku delivered to Jadestone a purported notice of termination of the SPA, despite Teikoku having received a waiver from PVN of its statutory pre-emption rights held under Vietnamese law. The Company has not accepted Inpex's alleged termination and views the obligations of both parties under the SPA as continuing. The Company maintains its rights under the SPA and is assessing its options, including remedies which may include taking legal action.

Montara

Save as disclosed below, the Montara Assets are not and have not been the subject of any governmental, legal or arbitration proceedings which may have, or have had during the 12 months preceding the date of this document, a significant effect on the Montara Asset's financial position or profitability and, so far as the Directors are aware, there are no such proceedings pending or threatened against the Montara Assets.

Following the Montara Incident, the Seller was subjected to various instances of attempted litigation from affected governments and other parties. In August 2010, the Government of Indonesia claimed an undefined amount of compensation from the Seller, which the Seller rejected at that time. In May 2017, the Government of Indonesia purported to formally launch action against the Seller for compensation in relation to the environmental damage caused by the Montara Incident, for an amount of circa US$1.9 billion, however it is understood that the Seller has not received any valid statement of claim or other valid documentation relating to this claim. In August 2016 a class action suit was filed against the Seller on behalf of a group of Indonesian seaweed farmers. The Seller has appointed legal counsel to defend this claim however it is understood that no formal evidence has yet been presented by the plaintiffs in this particular action.

Jadestone is acquiring certain assets only and will not assume any of these liabilities under the Acquisition Agreement. Further, Jadestone will receive the benefit of an indemnity from the Seller in connection with any environmental liabilities arising from the Montara Incident.

17 CONSENTS

17.1 Stifel has given and has not withdrawn its written consent to the issue of this document with the inclusion of its name and references to it in the form and context in which they appear.

17.2 BMO has given and has not withdrawn its written consent to the issue of this document with the inclusion of its name and references to it in the form and context in which they appear.

17.3 ERCE has given and has not withdrawn its written consent to the issue of this document with the inclusion of its name and references to it in the form and context in which they appear.

18 GENERAL

18.1 Save as disclosed in Section 9 of Part 1, there has been no significant change in the financial or trading position of the Group since 31 December 2017, the date to which the last audited accounts of the Group were prepared.

18.2 Save as disclosed in Section 9 of Part 1, there has been no significant change in the financial or trading position of the Montara Assets since 31 December 2017, the date to which the last unaudited historical financial information of the Montara Assets was prepared.

18.3 The estimated costs and expenses relating to the Placing (including those fees and commissions referred to in paragraph 9 above) payable by the Company are estimated to amount to approximately £5.4 million (excluding VAT). The total net proceeds of the Placing, after settling fees and expenses, are expected to be approximately £78.5 million.

18.4 Save as disclosed in paragraphs 18.5 and 18.7 below, no government, regulatory authority or similar body, company or person (excluding the Company's professional advisers otherwise disclosed in this document and trade suppliers) has:

(a) received, directly or indirectly, from the Company within the 12 months preceding the date of application for Admission; or

(b) entered into contractual arrangements (not otherwise disclosed in this document) to receive, directly or indirectly, from the Company on or after Admission,

any of the following:

(i) fees totalling £10,000 or more;

(ii) securities in the Company with a value of £10,000 or more calculated by reference to the Placing Price; or

(iii) any other benefit with a value of £10,000 or more at the date of Admission.

18.5 Save as disclosed in this document and paragraph 18.7 below, there have been no payments in excess of £10,000 made by or on behalf of the Company to any government or regulatory body with regard to the acquisition or maintenance of any of the Company's assets, in the 12 months preceding the Latest Practicable Date:

(a) £8,109,757 in aggregate to SKKMIGAS in royalty payments;

(b) £258,962 in aggregate to PetroVietnam in training fees;

(c) £569,035 in aggregate to NOPSEMA in safety case levies and environmental plan levies; and

(d) £23,740 in aggregate to NOPTA in annual levies.

18.6 Save as disclosed below, there have been no payments in excess of £10,000 made to any government or regulatory body with regard to the acquisition or maintenance of the Montara Assets in the 12 months preceding the Latest Practicable date were:

(a) AUD41,690 in aggregate to the Australian Marine Oil Spill Centre;

(b) AUD175,000 in aggregate to the Department of Industry Innovation and Science in Australia; and

(c) AUD1,188,475 in aggregate to the National Offshore Petroleum Safety Authority in Australia.

18.7 The Company has made the following payments in the 12 months preceding the Latest Practicable date:

Name	Nature of relationship with Jadestone	Fees paid
Colin Marshall	Technical adviser	£21,410
Quesnel Holdings Ltd.	Technical adviser	£21,139
Elemental Group Ltd.	Technical adviser	£31,595
Senergy International	Technical adviser	£51,188
Holland Consultants	Technical adviser	£21,206
Worley Parsons (Advisian)	Technical adviser	£44,665
Paul Weir	Operational adviser	£34,865
Triplea Advisors	Operational adviser	£20,734
Buddle Findlay	Legal adviser	£425,833
Herbert Smith Freehills	Legal adviser	£26,754
Gibson, Dunn & Crutcher LLP	Legal adviser	£79,042
Derren Parsons	Financial adviser	£154,336
Luke Garner	Financial adviser	£31,308
PWC Australia	Financial and accounting adviser	£16,527

18.8 The percentage dilution as a result of the Placing is 52 per cent.

18.9 The financial information set out in this document relating to the Group does not constitute statutory accounts. Deloitte & Touche LLP, chartered accountants of 6 Shenton Way, #33-00 OUE Downtown 2, Singapore 068809, have been the auditors of the Company for the three financial years ended 31 March 2015, 31 March 2016 and 31 March 2017 and the nine months ended 31 December 2017 and have given unqualified audit reports on the statutory accounts of the Company for those financial years. The audit partner of Deloitte & Touche LLP is a member of the Institute of Singapore Chartered Accountants.

18.10 Stifel is registered in England and Wales under number 03719559 and its registered office is at 4th Floor 150 Cheapside, London, United Kingdom, EC2V 6ET. Stifel is regulated by the Financial Conduct Authority and is acting in the capacity as nominated adviser, joint bookrunner and joint broker to the Company.

18.11 BMO is registered in England and Wales under number 02928224 and its registered office is at 95 Queen Victoria Street, London, EC4V 4HG. BMO is regulated by the Financial Conduct Authority and is acting in the capacity as joint bookrunner and joint broker to the Company.

18.12 Save as disclosed in Parts 3 and Parts 4 of this document, there are no patents or other intellectual property rights, licences, industrial, commercial or financial contracts or new manufacturing processes which are material to the Group's business or profitability.

18.13 Save as disclosed in Section 9 of Part 1 and paragraph 2.1.8 of Part 3 of this document, the Directors are not aware of any environmental issues that could affect the Company's utilisation of its tangible fixed assets.

18.14 Save as disclosed in Section 9 of Part 1 of this document, the Company is not aware of any significant recent trends in production, sales and inventory, and costs and selling prices since the end of its previous financial year and is similarly not aware of any trends, uncertainties, demands, commitments or events that are reasonably likely to have a material effect on the Company's prospects in its current financial year.

18.15 For each financial year all of the oil and gas revenues have been derived from the Group's operations in Australia and Indonesia.

18.16 Where information contained in this document has been sourced from a third party, the Company confirms that such information has been accurately reproduced and, so far as the Company is aware and is able to ascertain from the information published by that third party, no facts have been omitted which would render the reproduced information inaccurate or misleading.

18.17 Copies of this document will be available for inspection during normal business hours on any day (except Saturdays, Sundays, bank and public holidays) free of charge to the public at the offices of the Company and at the offices of Bryan Cave Leighton Paisner LLP, Adelaide House, London Bridge, London EC4R 9HA from the date of this document to the date one month from the date of Admission.

Dated: 3 August 2018.

DEFINITIONS

The following definitions apply throughout this document, unless the context otherwise requires:

"**2C resources**" means the unrisked best estimate scenario of contingent resources.

"**2P reserves**" means the sum of the proved plus the probable reserves, denotes the best estimate scenario of reserves.

"**Acquisition**" means the acquisition by the Company, through its wholly-owned subsidiary, Jadestone Energy (Eagle) Pty Ltd of the Montara Assets on and subject to the terms and conditions of the Acquisition Agreement.

"**Acquisition Agreement**" means the agreement dated 15 July 2018 between (among others) Jadestone Energy (Eagle) Pty Ltd, a wholly-owned subsidiary of the Company, (as buyer), the Company (as guarantor) and PTTEP Australasia (as seller) to give effect to the Acquisition.

"**Admission**" means the admission of the Common Shares, in issue and to be issued pursuant to the Placing, to trading on AIM becoming effective in accordance with the AIM Rules for Companies.

"**AIM**" means the market operated by the London Stock Exchange.

"**AIM Rules for Companies**" means the AIM Rules for Companies published by the London Stock Exchange from time to time.

"**AIM Rules for Nominated Advisers**" means the AIM Rules for Nominated Advisers published by the London Stock Exchange from time to time.

"**API**" means the American Petroleum Institute.

"**Articles**" means the articles of association of the Company, a summary of which is set out in Section 3 of Part 11 of this document.

"**AUD**" means Australian Dollars, the lawful currency of Australia.

"**BCBCA**" means the British Columbia Business Corporations Act of 2002.

"**Block 05-1b & c Acquisition**" means the acquisition by Mitra Energy (Vietnam 05-1) Pte Ltd, a wholly-owned subsidiary of the Company, of a 30 per cent working interest in Blocks 05-1b and 05-1c Production Sharing Contracts pursuant to a sale and purchase agreement with Teikoku Oil (Con Con) Co. Ltd. dated 9 August 2016.

"**Block 05-1b & c PSC**" means Blocks 05-1b and 05-1c.

"**BMO**" means BMO Capital Markets Limited.

"**BPS**" means BP Singapore Pte. Limited.

"**Brent**" means the worldwide benchmark assessment of the price of physical, light North Sea crude oil.

"**CAD**" or "**C$**" means Canadian Dollars, the lawful currency of Canada.

"**CAGR**" means compound annual growth rate.

"**certificated**" or "**in certificated form**" means not in uncertificated form (that is, not in CREST).

"**CGT**" means capital gains tax.

"**Class B Share**" means a non-voting Class B Share of Jadestone.

"**Code**" means the Code of Business Conduct and Ethics Policy.

"**Common Shares**" means Common Shares of no par value each in the share capital of the Company.

"**Company**" or "**Jadestone**" means Jadestone Energy Inc., a company incorporated in Canada under the Companies Act (British Columbia).

"**Convertible Facility**" means the convertible note facility dated 2 November 2016 between Tyrus Capital Event S.à r.l, an entity controlled by Tyrus, (as lender) and Jadestone (as borrower).

"**CNOOC INT**" means CNOOC International Limited.

"**CPR**" means the competent persons report prepared in accordance with the AIM Rules for Companies by ERCE.

"**CREST**" means the relevant system (as defined in the CREST Regulations) in respect of which Euroclear is the Operator (as defined in the CREST Regulations) in accordance with which securities may be held and transferred in uncertificated form.

"**CREST Regulations**" means the Uncertificated Securities Regulations 2001 (SI 2001/3755).

"**Daily Dated Brent**" means the physical cargoes of crude oil loading in the North Sea on any given day.

"**Dated Brent**" means physical cargoes of crude oil loading in the North Sea that have been assigned specific delivery dates.

"**Depositary**" means Computershare Investor Services Plc of The Pavilions, Bridgwater Road, Bristol BS13 8AE, United Kingdom.

"**Depositary Interests**" or "**DIs**" means a dematerialised depositary interest which represents an entitlement to Common Shares.

"**Directors**" or "**Board**" means the current directors of the Company whose names are set out on page 6 of this document.

"**DOE**" means the Department of Energy of the Philippines.

"**DTRs**" means the Disclosure Guidance and Transparency Rules sourcebook published by the FCA from time to time.

"**Energean**" means Energean Oil & Gas S.A.

"**Enlarged Group**" means the Group as enlarged following completion of the Acquisition.

"**Enlarged Share Capital**" means the issued share capital of the Company immediately following the Placing.

"**EP**" means environmental plan.

"**ERCE**" means ERC Equipoise Pte Ltd.

"**ESP**" means electric submersible pumps.

"**Euroclear**" means Euroclear UK & Ireland Limited, the operator of CREST.

"**E&P**" means exploration and production.

"**FCA**" means the Financial Conduct Authority of the UK.

"**FCPA**" means U.S. Foreign Corrupt Practices Act of 1977.

"**FIRB**" means the Australian Foreign Investment Review Board.

"**First Request**" means the one year extension request from 30 June 2018 to 29 June 2019 submitted by the Company to the MOIT in relation to the Block 46/07 PSC in Vietnam.

"**FLNG**" means floating liquefied natural gas.

"**FPSO**" means the Montara Venture Floating Production Storage and Offloading facility.

"**FSMA**" means Financial Services and Markets Act 2000.

"**FSO**" means floating storage and offloading vessel in relation to the Stag field.

"**GDP**" means gross domestic product.

"**Group**" means the Company and its subsidiary undertakings from time to time.

"**HMRC**" means Her Majesty's Revenue and Customs (which shall include its predecessors, the Inland Revenue and HM Customs and Excise).

"**HSSE Committee**" means Health, Safety, Social and Environmental Committee.

"**IFRS**" means International Financial Reporting Standards as endorsed by the European Union.

"**Institutional Placing**" means the conditional placing by the Joint Bookrunners, on behalf of the Company, of 236,954,802 new Common Shares announced on 3 August 2018 pursuant to the terms and conditions of the Placing Agreement as described in this document.

"**IOCs**" means international oil companies.

"**Jadestone Australia**" means Jadestone Energy (Australia) Pty Ltd.

"**Joint Bookrunners**" means BMO and Stifel.

"**Latest Practicable Date**" means 1 August 2018.

"**LNG**" means liquefied natural gas.

"**Lock-In Period**" means the period commencing on Admission and ending on the date falling 12 months after Admission.

"**London Stock Exchange**" means London Stock Exchange plc.

"**LPG**" means liquefied petroleum gas.

"**Majors**" means Royal Dutch Shell, BP, Exxon Mobil, Chevron Texaco, Total Fina Elf and ConocoPhillips.

"**MAR**" means the EU Market Abuse Regulation No 596/2014.

"**MBC**" means marine breakaway coupling.

"**MIGAS**" means the Directorate General of Oil and Gas, in Indonesia.

"**Mitra Energy**" means Mitra Energy Limited.

"**Mitra Philippines**" means Mitra Energy (Philippines SC-56) Ltd.

"**Mitra Vietnam**" means Mitra Energy (Vietnam Nam Du) Pte. Limited.

"**MOIT**" means the Ministry of Industry and Trade in Vietnam.

"**Montara Assets**" means Production Licences AC/L7 and AC/L8 in the Timor Sea and the centralised FPSO the Montara Venture.

"**Montara Incident**" means the oil and gas leak which occurred in 2009 at the site of the Montara Assets.

"**Money Laundering Regulations**" means the Money Laundering Regulations 2007.

"**NI 58-101**" means the Canadian National Instrument 58-101 Disclosure of Corporate Governance Practices.

"**Nobos**" means those shareholders that are entitled under Canadian securities laws to categorise themselves as "non-objecting" when acquiring Common Shares in the Company.

"**NOCs**" means national oil companies.

"**Nomination Rights Agreement**" means the nomination rights agreement dated 21 April 2015 and entered into between the Company and Ontario Teachers' Pension Plan Board.

"**NOPSEMA**" means the National Offshore Petroleum Safety and Environmental Management Authority of the Commonwealth of Australia.

"**NOPTA**" means the National Offshore Petroleum Titles Administrator of the Commonwealth of Australia.

"**NP 58-201**" means the Canadian National Policy 58-201 Corporate Governance Guidelines.

"**NPV**" means net present value.

"**Obos**" means those shareholders that are entitled under Canadian securities laws to categorise themselves as "objecting" when acquiring Common Shares in the Company.

"**ODP**" means outline development plan.

"**OECD**" means the Organisation for Economic Cooperation and Development .

"**Official List**" means the Official List of the UK Listing Authority.

"**OPEC**" means the Organisation of the Petroleum Exporting Countries.

"**OPGGS Act**" means the Offshore Petroleum and Greenhouse Gas Storage Act 2006 (Cth).

"**Option**" means a common share purchase option.

"**OTSA**" means the operator and transitional services agreement to be entered into between Jadestone Energy (Eagle) Pty Ltd and PTTEP Australasia in relation to the operation and management of the Montara Assets and the provision of transitional services in the period from completion of the Acquisition Agreement.

"**Pertamina**" means PT Pertamina Hulu Energi Ogan Komering.

"**Petroleum Law**" means the Petroleum dated 6 July 1993 of the National Assembly of Vietnam.

"**PetroVietnam**" means PetroVietnam Petroleum Corp.

"**PD 87**" means the Oil Exploration and Development Act of 1972, of the Philippines.

"**Placees**" means subscribers for Placing Shares pursuant to the Institutional Placing.

"**Placing**" means the Institutional Placing and the Subscription.

"**Placing Agreement**" means the agreement dated 3 August 2018 between (1) the Company (2) the Directors and (3) the Joint Bookrunners, relating to the Placing, details of which are set out in paragraphs 9 and 12.3 of Part 11 of this document.

"**Placing Shares**" means the 239,711,474 Common Shares to be issued pursuant to the Institutional Placing and the Subscription Shares, allotment of each being conditional on Admission.

"**PNOC**" means Philippine National Oil Company.

"**Prohibited Territories**" means USA, Australia, Canada, Japan, the Republic of South Africa and their respective territories and possessions.

"**Proposed Director**" means Daniel Young, the chief financial officer, who is to be appointed as an executive director of the Company with effect from, and conditional on, Admission.

"**Prospectus Rules**" means the rules made pursuant to section 73A of the FSMA.

"**PSC**" means production sharing contract.

"**PTTEP**" means PTT Exploration and Production Public Company Limited.

"**PTTEP Australasia**" means PTTEP Australasia (Ashmore Cartier) Pty Ltd.

"**PT Pertamina**" means PT Pertamina Persero.

"**PVEP**" means PetroVietnam Exploration Production Corporation.

"**PVN**" means Vietnam Oil and Gas Group.

"**Quadrant Energy**" means Quadrant Northwest Pty Ltd.

"**Regulation S**" means Regulation S adopted by the SEC under the US Securities Act.

"**SC-56**" means service contract 56 in the Philippines.

"**SC-57**" means service contract 57 in the Philippines.

"**SDA**" means suspended development area.

"**SEC**" means the United States Securities and Exchange Commission.

"**Second Request**" means the two year extension request from 30 June 2018 to 29 June 2020 submitted by the Company to the MOIT in relation to the Block 46/07 PSC in Vietnam.

"**Shareholders**" means holders of Common Shares.

"**SKKMIGAS**" means the Special Taskforce for Upstream Oil and Gas Business Activities, the established executive implementing body responsible for conducting supervision of upstream business activities in Indonesia.

"**SPA**" means the sale and purchase agreement dated 9 August 2016 entered into between the Company and Teikoku for the acquisition of a 30 per cent non-operated working interest in the Block 05-1 PSC.

"**Stifel**" means Stifel Nicolaus Europe Limited.

"**Stock Option Plan**" means the Company's stock option plan which was adopted by the Board on 19 August 2015 and which was approved by the shareholders of the Company on 25 September 2015.

"**Subscription**" means the subscription for the Subscription Shares by certain investors pursuant to the terms of the Subscription Agreements.

"**Subscription Agreements**" means the conditional agreements between the Company and certain investors pursuant to which they have, conditional upon Admission, subscribed for the Subscription Shares as more particularly described in paragraph 12.4 of Part 11.

"**Subscription Shares**" the 2,756,672 Common Shares to be subscribed for pursuant to the Subscription Agreements.

"**subsidiary undertakings**" means as defined in section 1162 of the 2006 Act.

"**Talisman**" means Talisman Energy Inc.

"**Teikoku**" means Teikoku Oil (Con Son) Co., Ltd, a wholly-owned subsidiary of Inpex Corporation.

"**Total**" means Total E&P Philippines B.V.

"**TSX-V**" means the TSX Venture Exchange.

"**Tyrus**" means Tyrus Capital S.A.M.

"**Tyrus Fund**" means Tyrus Capital Event Master Fund Limited, a fund that is managed by Tyrus.

"**Tyrus Lender**" means Tyrus Capital Event S.à r.l., a Société à responsabilité limitée incorporated under the laws of Luxembourg.

"**UK**" or "**United Kingdom**" means the United Kingdom of Great Britain and Northern Ireland.

"**UK Corporate Governance Code**" means the UK Corporate Governance Code published by the Financial Reporting Council.

"**UK Listing Authority**" means the FCA acting in its capacity as the competent authority for the purposes of Part VI of the FSMA.

"**UK Takeover Code**" means the City Code on Takeovers and Mergers published by the Panel on Takeovers and Mergers (as amended from time to time)

"**uncertificated**" or "**in uncertificated form**" means Common Shares recorded on the Company's share register as being held in uncertificated form in CREST and title to which, by virtue of the CREST Regulations, may be transferred by means of CREST.

"**US**" or "**USA**" or "**United States**" means the United States of America, its territories and possessions, any state or political sub-division of the United States of America, the District of Columbia and all other areas subject to the jurisdiction of the United States of America.

"**US$**" or "**USD**" means United States Dollars, the lawful currency of the United States.

"**US Securities Act**" means the US Securities Act of 1933, as amended.

"**VAT**" means value added tax.

"**WOMP**" means well operations management plan.

"**£**" and "**p**" means respectively pounds and pence sterling, the lawful currency of the UK.

All references to legislation in this document are to the legislation of England and Wales unless the contrary is indicated. Any reference to any provision of any legislation shall include any amendment, modification, re-enactment or extension thereof.

Words importing the singular shall include the plural and vice versa, and words importing the masculine gender shall include the feminine or neutral gender.

GLOSSARY OF TERMS

In addition to the glossary of terms set out on page 174 of the CPR (page 302 of this document) the following glossary of terms applies throughout this document, unless the context otherwise requires:

bbl/d	barrels of crude oil per day
Bcm	billion cubic metres of natural gas
Bcm/year	billion cubic metres of natural gas per year
Bnbbl	billion barrels of crude oil
Bboe	billion barrels of oil equivalent
boe/d	barrels of oil equivalent per day
Bscf	billion standard cubic feet
FPSO	floating production and storage offloading unit
km^2	square kilometres
m^2	square meters
M^3	cubic meters
mbbl	thousand barrels of crude oil
mbbls/d	thousand barrels of crude oil per day
mboe	thousand barrels of oil equivalent
mboe/d	thousand barrels of oil equivalent per day
MMbbls	million barrels of crude oil
MMbbls/d	million barrels of crude oil per day
MMboe	million barrels of oil equivalent
MMbtu	million British Thermal Units
MMcf/d	million cubic feet per day
mMD	measured depth in metres
MMscf	million standard cubic feet
MMscf/d	million standard cubic feet per day
Mt/a	metric tonnes per year
mTVDSS	true vertical depth of sub-sea in metres
MW	mega watt
Tcf	trillion cubic feet

JADESTONE ENERGY INC. AUDITED CONSOLIDATED FINANCIAL STATEMENTS FOR THE NINE MONTHS ENDED DECEMBER 31, 2017 AND YEAR ENDED MARCH 31, 2017

Jadestone Energy Inc.

CONSOLIDATED FINANCIAL STATEMENTS

for the nine months ended December 31, 2017 and year ended March 31, 2017

Company Registration No. BC0350583 (Canada)

Jadestone Energy Inc.
MANAGEMENT'S REPORT

The accompanying consolidated financial statements are the responsibility of management. The consolidated financial statements were prepared by management in accordance with International Financial Reporting Standards outlined in the notes to the consolidated financial statements.

Management maintains appropriate systems of internal controls. Policies and procedures are designed to give reasonable assurance that transactions are appropriately authorized, assets are safeguarded and financial records properly maintained to provide reliable information for the presentation of consolidated financial statements.

Deloitte & Touche LLP, an independent firm of chartered accountants, was appointed by the shareholders to audit the consolidated financial statements and to provide an independent professional opinion.

The Audit Committee reviewed the consolidated financial statements with management. The Board of Directors has approved the consolidated financial statements on the recommendation of the Audit Committee.

"A. Paul Blakeley"

A. Paul Blakeley
Director

"Daniel Young"

Daniel Young
Chief Financial Officer

April 24, 2018

Deloitte.

Deloitte & Touche LLP
Unique Entity No. T08LL0721A
6 Shenton Way
OUE Downtown 2
#33-00
Singapore 068809

Tel: +65 6224 8288
Fax: +65 6538 6166
www.deloitte.com/sg

INDEPENDENT AUDITOR'S REPORT TO THE SHAREHOLDERS OF

JADESTONE ENERGY INC.

We have audited the accompanying consolidated financial statements of Jadestone Energy Inc., which comprise the consolidated statement of financial position as at December 31, 2017 and March 31, 2017, and the consolidated statement of profit or loss and other comprehensive income, consolidated statement of changes in equity and consolidated statement of cash flows for the nine month period ended December 31, 2017 and year ended March 31, 2017, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Deloitte.

INDEPENDENT AUDITOR'S REPORT TO THE SHAREHOLDERS OF

JADESTONE ENERGY INC.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial positions of Jadestone Energy Inc. as at December 31, 2017 and March 31, 2017, and of its financial performance and its cash flows for the nine month period ended December 31, 2017 and year ended March 31, 2017, in accordance with International Financial Reporting Standards.

Deloitte & Touche LLP
Public Accountants and
Chartered Accountants
Singapore

April 24, 2018

Jadestone Energy Inc.

CONSOLIDATED STATEMENT OF FINANCIAL POSITION

As at December 31, 2017 and March 31, 2017

ASSETS	Notes	December 31, 2017 US$000	March 31, 2017 US$000 Restated
Non-current assets:			
Intangible exploration assets	18	105,673	104,929
Oil and gas properties	19	62,238	64,334
Deferred tax assets	20	23,821	17,541
Plant and equipment	21	648	680
Restricted cash	25	10,729	669
		203,109	188,153
Current assets:			
Inventories	23	9,610	10,801
Receivables and prepayments	24	4,719	7,039
Cash and cash equivalents	25	10,450	14,478
		24,779	32,318
TOTAL ASSETS		227,888	220,471
EQUITY AND LIABILITIES			
Equity:			
Share capital	26	364,466	364,466
Share-based payment and warrants	27	21,855	21,419
Accumulated losses		(278,123)	(263,193)
		108,198	122,692
Non-current liabilities:			
Provision for asset restoration obligations	28	84,728	77,186
Other payables	29	7,259	6,918
Deferred tax liabilities		200	1,200
Secured convertible bonds	32	12,770	-
Derivative financial instruments	32	3,067	-
		108,024	85,304
Current liabilities:			
Borrowings	30	829	435
Trade & other payables, accruals and provisions	31	10,837	12,040
		11,666	12,475
TOTAL EQUITY AND LIABILITIES		227,888	220,471

The accompanying notes are an integral part of the consolidated financial statements

Jadestone Energy Inc.

CONSOLIDATED STATEMENT OF PROFIT OR LOSS AND OTHER COMPREHENSIVE INCOME

for the nine months ended December 31, 2017 and the year ended March 31, 2017

	Notes	Nine months ended December 31, 2017 US$000	Year ended March 31, 2017 US$000 Restated
Gross revenue	6	60,443	35,142
Royalties		(8,429)	(725)
Net revenue		52,014	34,417
Production costs	7	(43,520)	(36,267)
Depletion, depreciation and amortization	8	(9,986)	(3,896)
Staff costs	11	(9,019)	(10,805)
Other expenses	12	(6,330)	(6,849)
Impairment of assets	13	-	(10,229)
Other income	14	753	239
Purchase discount	10	-	789
		(16,088)	(32,601)
Finance costs	15	(4,304)	(2,029)
LOSS BEFORE TAX		(20,392)	(34,630)
Taxation credit/(expense)	16	5,462	(1,867)
LOSS FOR THE PERIOD/YEAR		(14,930)	(36,497)
Loss per ordinary share:			
Basic and diluted (US$)	17	(0.07)	(0.26)

The accompanying notes are an integral part of the consolidated financial statements

Jadestone Energy Inc.

CONSOLIDATED STATEMENT OF CHANGES IN EQUITY
for the nine months ended December 31, 2017 and the year ended March 31, 2017

	Share capital US$000	Share-based payment reserves US$000	Accumulated losses US$000 Restated	Total US$000
At April 1, 2017	364,466	21,419	(263,193)	122,692
Loss for the period	-	-	(14,930)	(14,930)
Transactions with owners, recognized directly in equity				
Recognition of share-based compensation	-	436	-	436
Total transactions with owners	-	436	-	436
At December 31, 2017	364,466	21,855	(278,123)	108,198
At April 1, 2016	324,748	21,316	(226,696)	119,368
Loss for the year	-	-	(36,497)	(36,497)
Transactions with owners, recognized directly in equity				
Share capital issued (private placement)	39,805	-	-	39,805
Recognition of share-based compensation	-	103	-	103
Share issue costs (private placement)	(87)	-	-	(87)
Total transactions with owners	39,718	103	-	39,821
At March 31, 2017	364,466	21,419	(263,193)	122,692

Jadestone Energy Inc.

CONSOLIDATED STATEMENT OF CASH FLOWS

for the nine months ended December 31, 2017 and the year ended March 31, 2017

	Notes	Nine months ended December 31, 2017 US$000	Year ended March 31, 2017 US$000 Restated
OPERATING ACTIVITIES			
Loss before tax		(20,392)	(34,630)
Adjustments for:			
Depletion, depreciation and amortization	8	9,986	3,896
Finance costs	15	4,247	1,695
Gain on disposal of assets	14	(412)	-
Share-based payment		436	103
Unrealized foreign exchange loss	15	114	339
Impairment of intangible exploration assets		-	8,512
Impairment of materials and spare parts		-	1,717
Purchase discount		-	(789)
Write-back of material and spare parts	14	(29)	-
Interest income	15	(57)	(5)
Inventories written down		-	713
Operating cash flows before movements in working capital		(6,107)	(18,449)
Changes in working capital:			
Decrease in inventories		1,220	11,304
Decrease/(increase) in receivables and prepayments		2,320	(2,354)
(Increase)/decrease in trade & other payables, accruals and provisions		(2,482)	1,116
Cash used in operations		(5,049)	(8,383)
Taxation paid	16	(1,610)	-
NET CASH USED IN OPERATING ACTIVITIES		(6,659)	(8,383)

Jadestone Energy Inc.
CONSOLIDATED STATEMENT OF CASH FLOWS
for the nine months ended December 31, 2017 and the year ended March 31, 2017

	Notes	Nine months ended December 31, 2017 US$000	Year ended March 31, 2017 US$000
INVESTING ACTIVITIES			
Acquisition of Stag Oilfield, net of cash acquired	9	-	(18,494)
Acquisition of Ogan Komering, net of cash acquired	10	-	(1,641)
Payment for oil and gas properties	19	(1,772)	(288)
Proceeds from disposal of intangible exploration asset		400	-
Proceeds from disposal of motor vehicle		12	-
Payment for intangible exploration assets	18	(619)	(4,234)
Payment for plant and equipment	21	(167)	(632)
Interest received		57	5
NET CASH USED IN INVESTING ACTIVITIES		(2,089)	(25,284)
FINANCING ACTIVITIES			
Proceeds from share issuance		-	39,805
Pledge deposit for bank guarantee	25	(10,000)	-
Net drawdown from convertible bonds		14,550	-
Net drawdown on borrowings	30	818	428
Payments for borrowings		(435)	-
Payments of convertible bonds facility expenses	32	-	(560)
Payments of bonds facility standby fees	32	(239)	(115)
Share issuance costs		-	(87)
NET CASH FROM FINANCING ACTIVITIES		4,694	39,471
Effect of translation on foreign currency cash and cash equivalents		26	(443)
NET (DECREASE)/INCREASE IN CASH AND CASH EQUIVALENTS		(4,028)	5,361
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD/YEAR		14,478	9,117
CASH AND CASH EQUIVALENTS AT END OF PERIOD/YEAR		10,450	14,478

1. CORPORATE INFORMATION

Jadestone Energy Inc. (the "Company" or "Jadestone") is an oil and gas company incorporated in Canada. The Company's common shares are listed on the TSX Ventures Exchange ("TSX-V") under the symbol JSE. The financial statements are expressed in United States Dollars ("US$").

The Company and its subsidiaries (the "Group") are engaged in production, development, and exploration and appraisal activities in Australia, Indonesia, Vietnam and the Philippines. The Company's current two producing assets are in the Carnarvon Basin, offshore Western Australia and onshore Sumatra, Indonesia.

The Company's head office is located at Keppel Towers, #15-05/06, 10 Hoe Chiang Road, Singapore 089315. The registered office of the Company is 2600 Oceanic Plaza, 1066 West Hastings Street, Vancouver, British Columbia, V6E 3X1 Canada.

During the nine months ended December 31, 2017, the Company approved a change in its year end from March 31 to December 31. Jadestone's transition period is the nine months ended December 31, 2017. The comparative period is the 12 months ended March 31, 2017.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

BASIS OF PREPARATION

The financial statements have been prepared on a going concern basis and in accordance with the historical cost basis, except as disclosed in the accounting policies below, and are drawn up in accordance with the provisions of International Financial Reporting Standards ("IFRS").

Historical cost is generally based on the fair value of the consideration given in exchange for goods and services.

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date, regardless of whether that price is directly observable or estimated using another valuation technique. In estimating the fair value of an asset or a liability, the Group takes into account the characteristics of the asset or liability which market participants would take into account when pricing the asset or liability at the measurement date. Fair value for measurement and/or disclosure purposes in these consolidated financial statements is determined on such a basis, except for share-based payment transactions that are within the scope of IFRS 2 *Share-based Payment*, leasing transactions that are within the scope of IAS 17 *Leases*, and measurements that have some similarities to fair value but are not fair value, such as net realisable value in IAS 2 *Inventories*, or value in use in IAS 36 *Impairment of Assets*.

In addition, for financial reporting purposes, fair value adjustments are categorised into Level 1, 2 or 3 based on the degree to which the inputs to the fair value adjustments are observable and the significance of the inputs to the fair value measurement in its entirety which are described as follows:

- Level 1 inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities that the Group can access at the measurement date;
- Level 2 inputs are inputs, other than quoted prices included within Level 1, that are observable for the asset or liability, either directly or indirectly; and
- Level 3 inputs are unobservable inputs for the asset or liability.

APPLICATION OF NEW AND REVISED INTERNATIONAL FINANCIAL REPORTING STANDARDS (IFRSs)

Amendments to IFRSs that are mandatorily effective for the current period

In the current period, the Group adopted amendments to IAS7 *Cash flow statements*, that were mandatorily effective for an accounting period that began on or after April 1, 2017.

The application of these amendments to IAS7 had no material impact on the Group's consolidated financial statements.

New and revised IFRSs in issue but not yet effective

The Group has not applied the following new and revised IFRSs that are relevant to the Group, and were issued, but not effective:

Amendments to IFRS 2	Share-based payment: classification and measurement of share-based payment transactions (1)
IFRS 9	Financial instruments (1)
IFRS 15	Revenue from contracts with customers (and the related clarifications issued) (1)
IFRS 16	Leases (2)
Amendments to IFRSs	Annual improvements to IFRS 2014-2016 cycle (1)

(1) Effective for annual periods beginning on or after January 1, 2018, with earlier application permitted

(2) Effective for annual periods beginning on or after January 1, 2019, with earlier application permitted

Management anticipates that the adoption of the above IFRSs, IFRIC and amendments to IFRSs in future periods will not have a material impact on the financial statements of the Group in the period of their initial adoption except for the following:

IFRS 9 *Financial instruments*

IFRS 9 was issued in December 2014 to replace IAS 39 *Financial Instruments: Recognition and Measurement* and introduced new requirements for (i) the classification and measurement of financial assets and financial liabilities, (ii) general hedge accounting, and (iii) impairment requirements for financial assets.

Key requirements of IFRS 9:

- All recognised financial assets that are within the scope of IAS 39 are now required to be subsequently measured at amortised cost or fair value. Specifically, debt instruments that are held within a business model whose objective is to collect the contractual cash flows, and that have contractual cash flows that are solely payments of principal and interest on the principal outstanding are generally measured at amortised cost at the end of subsequent accounting periods. Debt instruments that are held within a business model whose objective is achieved both by collecting contractual cash flows and selling financial assets, and that have contractual terms that give rise on specified dates to cash flows that are solely payments of principal and interest on the principal amount outstanding, are measured at fair value through other comprehensive income ("FVTOCI"). All other debt instruments and equity investments are measured at fair value through profit and loss ("FVTPL"), at the end of subsequent accounting periods. In addition, under IFRS 9, entities may make an irrevocable election, at initial recognition, to measure an equity investment (that is not held for trading) at FVTOCI, with only dividend income generally recognised in profit or loss;

- With some exceptions, financial liabilities are generally subsequently measured at amortised cost. With regard to the measurement of financial liabilities designated as at FVTPL, IFRS 9 requires that the amount of change in fair value of such financial liability that is attributable to changes in the credit risk, be presented in other comprehensive income, unless the recognition of the effects of changes in the liability's credit risk in other comprehensive income would create or enlarge an accounting mismatch to profit or loss. Changes in fair value attributable to the financial liability's credit risk are not subsequently reclassified to profit or loss;

- In relation to the impairment of financial assets, IFRS 9 requires an expected credit loss model, as opposed to an incurred credit loss model under IAS 39. The expected credit loss model requires an entity to account for expected credit losses and changes in those expected credit losses at each reporting date to reflect changes in credit risk since initial recognition. In other words, it is no longer necessary for a credit event to have occurred before credit losses are recognised; and

- The new general hedge accounting requirements retain the three types of hedge accounting mechanisms currently available in IAS 39. Under IFRS 9, greater flexibility has been introduced to the types of transactions eligible for hedge accounting, specifically broadening the types of instruments that qualify for hedging instruments and the types of risk components of non-financial items that are eligible for hedge accounting. In addition, the effectiveness test has been overhauled and replaced with the principle of an economic relationship. Retrospective assessment of hedge effectiveness is also no longer required. Enhanced disclosure requirements about an entity's risk management activities have also been introduced.

Management is currently assessing and has yet to complete the detailed analysis on the possible impact of the initial application of IFRS 9. It is therefore impracticable to disclose any further information on the known or reasonably estimable impact to the Group's financial statements in the period of initial adoption.

IFRS 16 *Leases*

IFRS 16 introduces a comprehensive model for the identification of lease arrangements and accounting treatments for both lessors and lessees. IFRS 16 will supersede the current lease guidance, including IAS 17 *Leases* and the related interpretations, when it becomes effective.

IFRS 16 distinguishes leases and service contracts on the basis of whether an identified asset is controlled by a customer. Distinctions of operating leases (off balance sheet) and finance leases (on balance sheet) are removed for lessee accounting, and are replaced by a model where a right-of-use asset and a corresponding liability have to be recognised for all leases by lessees (i.e. all on balance sheet) except for short-term leases and leases of low value assets.

The right-of-use asset is initially measured at cost, and subsequently measured at cost (subject to certain exceptions) less accumulated depreciation and impairment losses, adjusted for any remeasurement of the lease liability. The lease liability is initially measured at the present value of the lease payments that are not paid at that date. Subsequently, the lease liability is adjusted for interest and lease payments, as well as the impact of lease modifications, amongst others. Furthermore, the classification of cash flows will also be affected as operating lease payments under IAS 17 are presented as operating cash flows; whereas under the IFRS 16 model, the lease payments will be split into a principal and an interest portion which will be presented as financing and operating cash flows respectively. Furthermore, extensive disclosures are required by IFRS 16. The Group's operating lease arrangements are disclosed in Note 35.

A preliminary assessment indicates that these arrangements will meet the definition of a lease under IFRS 16, and hence the Group will recognise a right-of-use asset and a corresponding liability in respect of all these leases unless they qualify for low value or short-term leases under IFRS 16.

Management is currently assessing and has yet to complete the work on the possible impact of implementing IFRS 16. It is therefore impracticable to disclose any further information on the known or reasonably estimable impact to the Group's financial statements in the period of initial application. Management does not plan to early adopt the above new IFRS 16.

BASIS OF CONSOLIDATION

The consolidated financial statements incorporate the financial statements of the Company and enterprises controlled by the Company and its subsidiaries. Control is achieved where the Company:

- Has power over the investee;
- Is exposed, or has rights, to variable returns from its involvement with the investee; and
- Has the ability to use its power to affect its returns.

The Company reassesses whether or not it controls an investee if facts and circumstances indicate that there are changes to one or more of the three elements of control listed above.

When the Company has less than a majority of the voting rights of an investee, it has power over the investee when the voting rights are sufficient to give it the practical ability to direct the relevant activities of the investee unilaterally. The Company considers all relevant facts and circumstances in assessing whether or not the Company's voting rights in an investee are sufficient to give it power, including:

- The size of the Company's holding of voting rights relative to the size and dispersion of holdings of the other vote holders;
- Potential voting rights held by the Company, other vote holders or other parties;
- Rights arising from other contractual arrangements; and
- Any additional facts and circumstances that indicate that the Company has, or does not have, the current ability to direct the relevant activities at the time that decisions need to be made, including voting patterns at previous shareholders' meetings.

Consolidation of a subsidiary begins when the Company obtains control over the subsidiary and ceases when the Company loses control of the subsidiary. Specifically, income and expenses of a subsidiary acquired or disposed of during the year are included in the consolidated statement of profit or loss and other comprehensive income from the date the Company gains control until the date when the Company ceases to control the subsidiary.

Profit or loss and each component of other comprehensive income are attributed to the owners of the Company and to the non-controlling interests. Total comprehensive income of subsidiaries is attributed to the owners of the Company and to the non-controlling interests even if this results in the non-controlling interests having a deficit balance.

When necessary, adjustments are made to the financial statements of subsidiaries to bring their accounting policies into line with the Group's accounting policies.

All intragroup assets and liabilities, equity, income, expenses and cash flows relating to transactions between members of the Group are eliminated in full on consolidation.

Changes in the Group's interest in a subsidiary that do not result in a loss of control are accounted for as equity transactions. The carrying amounts of the Group's interests and the non-controlling interests are adjusted to reflect the changes in their relative interests in the subsidiary. Any difference between the amount by which the non-controlling interests are adjusted and the fair value of the consideration paid or received is recognized directly in equity and attributed to owners of the Company.

When the Group loses control of a subsidiary, the profit or loss on disposal is calculated as the difference between (i) the aggregate of the fair value of the consideration received and the fair value of any retained interest and (ii) the previous carrying amount of the assets (including goodwill), and liabilities of the subsidiary and any non-controlling interests. Amounts previously recognized in other comprehensive income in relation to the subsidiary are accounted for (i.e. reclassified to profit or loss or transferred directly to retained earnings) in the same manner as would be required if the relevant assets or liabilities were disposed of. The fair value of any investment retained in the former subsidiary at the date when control is lost is regarded as the fair value on initial recognition for subsequent accounting under IAS 39 *Financial Instruments: Recognition and Measurement* or, when applicable, the cost on initial recognition of an investment in an associate or joint venture.

BUSINESS COMBINATIONS

Acquisitions of businesses (including joint operations which are assessed to be businesses) are accounted for using the acquisition method. The consideration for each acquisition is measured as the aggregate of the acquisition date fair values of assets given, liabilities incurred by the Group to the former owners of the acquiree, and equity interests issued by the Group in exchange for control of the acquiree. Acquisition-related costs are recognized in profit or loss as incurred.

Where applicable, the consideration for the acquisition includes any asset or liability resulting from a contingent consideration arrangement, measured at its acquisition-date fair value. Subsequent changes in such fair values are adjusted against the cost of acquisition where they qualify as measurement period adjustments (see below). The subsequent accounting for changes in the fair value of the contingent consideration that do not qualify as measurement period adjustments depends on how the contingent consideration is classified. Contingent consideration that is classified as equity is not re-measured at subsequent reporting dates and its subsequent settlement is accounted for within equity. Contingent consideration that is classified as an asset or a liability is remeasured at subsequent reporting dates in accordance with IAS 39 *Financial Instruments: Recognition and Measurement*, or IAS 37 *Provisions, Contingent Liabilities and Contingent Assets*, as appropriate, with the corresponding gain or loss being recognised in profit or loss.

At the acquisition date, the identifiable assets acquired and the liabilities assumed are recognized at their fair value, at the acquisition date, except that:

- Deferred tax assets or liabilities and liabilities or assets related to employee benefit arrangements are recognized and measured in accordance with IAS 12 Income Taxes and IAS 19 Employee Benefits respectively;

- Liabilities or equity instruments related to share-based payment transactions of the acquiree or the replacement of an acquiree's share-based payment awards transactions with share-based payment awards transactions of the acquirer, in accordance with the method in IFRS 2 Share-based Payment at the acquisition date; and

- Assets (or disposal groups) that are classified as held for sale in accordance with IFRS 5 *Non-current Assets Held for Sale and Discontinued Operations*.

If the initial accounting for a business combination is incomplete by the end of the reporting period in which the combination occurs, the Group reports provisional amounts for the items for which the accounting is incomplete. Those provisional amounts are adjusted during the measurement period (see below), or additional assets or liabilities are recognised, to reflect new information obtained about facts and circumstances that existed as of the acquisition date that, if known, would have affected the amounts recognised as of that date.

The measurement period is the period from the date of acquisition to the date the Group obtains complete information about facts and circumstances that existed as of the acquisition date and is subject to a maximum of one year from acquisition date.

Where an interest in a Production Sharing Contract ("PSC") is acquired by way of a corporate acquisition, the interest in the PSC is treated as an asset purchase unless the acquisition of the corporate vehicle meets the requirements to be treated as a business combination and definition of a business.

GOODWILL

Goodwill arising in a business combination is recognised as an asset at the date that control is acquired (the acquisition date). Goodwill is measured as the excess of the sum of the consideration transferred, the amount of any non-controlling interest in the acquiree and the fair value of the acquirer's previously held equity interest (if any) in the entity over net of the acquisition-date amounts of the identifiable assets acquired and the liabilities assumed.

If, after reassessment, the Group's interest in the fair value of the acquiree's identifiable net assets exceeds the sum of the consideration transferred, the amount of any non-controlling interest in the acquiree and the fair value of the acquirer's previously held equity interest in the acquiree (if any), the excess is recognised immediately in profit or loss as a purchase discount gain.

FOREIGN CURRENCY TRANSACTIONS

The individual financial statements of each Group entity are measured and presented in the currency of the primary economic environment in which the entity operates (its functional currency).

In preparing the financial statements of each individual Group entity, transactions in currencies other than the entity's functional currency are recorded at the rates of exchange prevailing on the dates of the transactions. At the end of each reporting period, monetary items denominated in foreign currencies are retranslated at the rates prevailing at the end of the reporting period. Non-monetary items carried at fair value that are denominated in foreign currencies are retranslated at the rates prevailing on the date when the fair value was determined. Non-monetary items that are measured in terms of historical cost in a foreign currency are not retranslated.

Exchange differences arising on the settlement of monetary items, and on retranslation of monetary items are included in profit or loss for the period. Exchange differences arising on the retranslation of non-monetary items carried at fair value are included in profit or loss for the period except for differences arising on the retranslation of non-monetary items in respect of which gains or losses are recognized in other comprehensive income. For such non-monetary items, any exchange component of that gain or loss is also recognized in other comprehensive income.

JOINT OPERATIONS

A joint operation is a joint arrangement whereby the parties that have joint control of the arrangement have rights to the assets, and obligations for the liabilities, relating to the arrangement. Joint control is the contractually agreed sharing of control of an arrangement, which exists only when decisions about the relevant activities require unanimous consent of the parties sharing control.

When a Group entity undertakes its activities under joint operations, the Group as a joint operator recognizes in relation to its interest in a joint operation:

- Its assets, including its share of any assets held jointly;
- Its liabilities, including its share of any liabilities incurred jointly;
- Its revenue from the sale of its share of the output arising from the joint operation; and
- Its expenses, including its share of any expenses incurred jointly.

The Group accounts for the assets, liabilities, revenue and expenses relating to its interest in a joint operation in accordance with the IFRSs applicable to the particular assets, liabilities, revenues and expenses.

When a Group entity transacts with a joint operation in which a Group entity is a joint operator (such as a sale or contribution of assets), the Group is considered to be conducting the transaction with the other parties to the joint operation, and gains and losses resulting from the transactions are recognized in the Group's consolidated financial statements only to the extent of other parties' interests in the joint operation.

When a Group entity transacts with a joint operation in which a Group entity is a joint operator (such as a purchase of assets), the Group does not recognize its share of the gains and losses until it resells those assets to a third party.

Changes to the Group's interest in PSCs usually require the approval of the appropriate regulatory authority. A change in interest is recognized when:

a) Approval is considered highly likely; and

b) All affected parties are effectively operating under the revised arrangement.

Where this is not the case, no change in interest is recognized and any funds received or paid are included in the statement of financial position as Contractual deposits.

Reimbursement of Joint Operator's costs

The Company's subsidiaries, when acting as operator, incur certain general overhead expenses in carrying out activities on behalf of the joint operation. As these costs are often not specifically identified, the PSCs allow the operator to recover the general overhead expenses incurred by charging an overhead fee that is based on a fixed percentage of the total costs incurred during a period. Such overhead fees have been disclosed as Joint Operator Overhead Charge. Although the purpose of this recharge is similar to the reimbursement of direct costs, the subsidiaries are not acting as agent in this case. Therefore, the general overhead expenses and the overhead fee are recognized as an expense and income respectively.

PRE-LICENCE AWARD COSTS

Costs incurred prior to the effective award of oil and gas licences, concessions and other exploration rights are expensed in the statement of profit and loss and other comprehensive income.

EXPLORATION AND EVALUATION COSTS

The costs of exploring for and evaluating oil and gas properties, including the costs of acquiring rights to explore, geological and geophysical studies, exploratory drilling and directly related overheads such as directly attributable employee remuneration, materials, fuel used, rig costs and payments made to contractors are capitalized and classified as intangible exploration assets (E&E assets).

If no potentially commercial hydrocarbons are discovered, the exploration asset is written off through profit or loss as a dry hole. If extractable hydrocarbons are found and, subject to further appraisal activity (e.g. the drilling of additional wells), it is probable they can be commercially developed, the costs continue to be carried as intangible exploration costs while sufficient/continued progress is made in assessing the commerciality of the hydrocarbons. Costs directly associated with appraisal activity undertaken to determine the size, characteristics and commercial potential of a reservoir following the initial discovery of hydrocarbons, including the costs of appraisal wells where hydrocarbons were not found, are initially capitalized as intangible exploration assets.

All such capitalized costs are subject to technical, commercial and management review, as well as review for indicators of impairment at the end of each reporting period. This is to confirm the continued intent to develop or otherwise extract value from the discovery. When such intent no longer exists or if there is a change in circumstances signifying an adverse change in initial judgment, the costs are written off.

When commercial reserves of hydrocarbons are determined and development is approved by management, the relevant expenditure is transferred to property, plant and equipment. The technical feasibility and commercial viability of extracting a mineral resource is considered to be determinable when proved or probable reserves are determined to exist. The determination of proved or probable reserves is dependent on reserve evaluations which are subject to significant judgments and estimates.

Costs related to geological and geophysical studies that relate to blocks that have not yet been acquired, and costs related to blocks for which no commercially viable hydrocarbons are expected, are taken direct to the profit or loss and have been disclosed as expensed exploration costs.

FARM-OUTS IN THE EXPLORATION AND EVALUATION PHASE

The Group does not record any expenditure made by the farmee on its account. It also does not recognize any gain or loss on its exploration and evaluation farm-out arrangements, but redesignates any costs previously capitalized in relation to the whole interest as relating to the partial interest retained. Any cash consideration received directly from the farmee is credited against costs previously capitalized in relation to the whole interest with any excess accounted for by the farmor as a gain on disposal.

OIL AND GAS PROPERTIES

Producing assets

The Group recognises oil and gas properties at cost less accumulated depletion, depreciation and impairment losses. Directly attributable costs incurred for the drilling of development wells and for the construction of production facilities are capitalised together with the discounted value of estimated future costs of decommissioning obligations. Workover expenses are recognised in profit or loss in the period in which they are incurred. When components of oil and gas properties are replaced, disposed of, or no longer in use, they are derecognised.

Depletion and amortisation expense

Depletion of oil and gas properties is calculated using the units of production method for an asset or group of assets from the date in which they are available for use. The cost of those assets are depleted based on proved and probable reserves. Costs subject to depletion include expenditures to date, together with approved estimated future expenditure to be incurred in developing proved and probable reserves. Costs of major development projects are excluded from the costs subject to depletion until they are available for use.

The impact of changes in estimated reserves is dealt with prospectively by depreciating the remaining carrying value of the asset over the expected future production. If reserves estimates are revised downwards, earnings could be affected by higher depreciation expense or an immediate write-down of the property's carrying value.

Asset restoration obligations

The Group estimates the future removal and restoration costs of oil production facilities, wells, pipelines and related assets at the time of installation or acquisition of the assets and based on prevailing legal requirements and industry practice. In most instances, the removal of these assets will occur many years in the future. The estimates of future removal costs are made considering relevant legislation and industry practice and require management to make judgments regarding the removal date, the extent of restoration activities required and future removal technologies.

Site restoration costs are capitalised within the cost of the associated assets and the provision is stated in the statement of financial position at total estimated present value. These costs are based on judgements and assumptions regarding removal dates, technologies, and industry practice. This estimate is evaluated on a periodic basis and any adjustment to the estimate is applied prospectively. Changes in the estimated liability resulting from revisions to estimated timing, amount of cash flows, or changes in the discount rate are recognised as a change in the asset restoration liability and related capitalised asset restoration cost.

The change in net present value of the future obligations due to passage of time is expensed as accretion expense within financing charges. Actual restoration obligations settled during the period reduce the decommissioning liability.

The asset restoration costs are depleted using the units of production method (see above accounting policy).

BORROWING COSTS

Borrowing costs directly attributable to the acquisition, construction or production of qualifying assets, which are assets that necessarily take a substantial period of time to get ready for their intended use or sale, are added to the cost of those assets, until such time as the assets are substantially ready for their intended use or sale.

Investment income earned on the temporary investment of specific borrowings pending their expenditure on qualifying assets is deducted from the borrowing costs eligible for capitalization. All other borrowing costs are recognized in profit or loss in the period in which they are incurred and this includes borrowing costs in relation to exploration activities which are capitalized in intangible exploration assets as management is of the view that these do not meet the definition of a qualifying asset.

PLANT AND EQUIPMENT

Plant and equipment is stated at cost less accumulated depreciation and any recognized impairment loss.

Depreciation is charged so as to write off the cost of assets evenly over their estimated useful lives, on the following basis:

Computer equipment	3 years
Fixtures and equipment	3 years
Motor vehicles	3 years

The estimated useful lives, residual values and depreciation method are reviewed at each year end, with the effect of any changes in estimate accounted for on a prospective basis.

An item of plant and equipment is derecognized upon disposal or when no future economic benefits are expected to arise from the continued use of asset. Any gain or loss arising on the disposal or retirement of an item of plant and equipment is determined as the difference between the sales proceeds and the carrying amount of the asset and is recognized in profit or loss.

IMPAIRMENT OF TANGIBLE ASSETS AND INTANGIBLE ASSETS EXCLUDING GOODWILL

At the end of each reporting period, the Group reviews the carrying amounts of its assets to determine whether there is any indication that those assets have suffered an impairment loss. If any such indication exists, the recoverable amount of the asset is estimated in order to determine the extent of the impairment loss (if any). Where it is not possible to estimate the recoverable amount of an individual asset, the Group estimates the recoverable amount of the cash-generating unit to which the asset belongs. When a reasonable and consistent basis of allocation can be identified, corporate assets are also allocated to individual cash-generating units, or otherwise they are allocated to the smallest group of cash-generating units for which a reasonable and consistent allocation basis can be identified.

Intangible assets with indefinite useful lives and intangible assets not yet available for use, are tested for impairment annually, and whenever there is an indication that the asset may be impaired.

Recoverable amount is the higher of fair value less costs to sell and value in use. In assessing value in use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset for which estimates of future cash flows have not been adjusted.

If the recoverable amount of an asset (or cash-generating unit) is estimated to be less than its carrying amount, the carrying amount of the asset (or cash-generating unit) is reduced to its recoverable amount. An impairment loss is recognized immediately in profit or loss.

Where an impairment loss subsequently reverses, the carrying amount of the asset (cash-generating unit) is increased to the revised estimate of its recoverable amount, but so that the increased carrying amount does not exceed the carrying amount that would have been determined had no impairment loss been recognized for the asset (cash-generating unit) in prior years. A reversal of an impairment loss is recognized immediately in profit or loss.

INVENTORY

Inventories are valued at the lower of cost and net realisable value. Cost is determined as follows:

- Petroleum products, comprising primarily of extracted crude oil stored in tanks, pipeline systems and aboard vessels, and natural gas, are valued using all costs of production inclusive of amortisation and depreciation; and

- Materials, which include drilling and maintenance stocks, are valued at the cost of acquisition.

Net realisable value represents the estimated selling price less applicable selling expenses. If the carrying value exceeds net realizable value, a write-down is recognized. The write-down may be reversed in a subsequent period if the inventory is still on hand but the circumstances which caused the write-down no longer exist.

FINANCIAL INSTRUMENTS

Financial assets and financial liabilities are recognized when the Group has become a party to the contractual provisions of the instrument.

Effective interest method

The effective interest method is a method of calculating the amortized cost of a financial instrument and of allocating interest income or expense over the relevant period. The effective interest rate is the rate that exactly discounts estimated future cash receipts or payments (including all fees paid, or received, that form an integral part of the effective interest rate, transaction costs, and other premiums or discounts) through the expected life of the financial instrument, or where appropriate, a shorter period to the net carrying amount of initial recognition.

Financial assets

The Group has classified all its financial assets as loans and receivables. Loans and receivables are non-derivative financial assets that are not quoted in an active market. They are included in current assets except for those maturing later than 12 months after the reporting date which are classified as non-current assets. Loans and receivables include trade and other receivables and cash at bank as shown on the statement of financial position.

Other receivables

Other receivables are initially recognized at fair value. They are subsequently measured at amortized cost using the effective interest method less any provision for impairment.

Impairment of financial assets

Financial assets are assessed for indicators of impairment at the end of each reporting period. Financial assets are impaired where there is objective evidence that, as a result of one or more events that occurred after the initial recognition of the financial asset, the estimated future cash flows of the financial asset have been impacted. Significant financial difficulties of the debtor, probability that the debtor will enter bankruptcy or financial reorganisation, and default or significant delay in payments, are objective evidence that these financial assets are impaired.

For financial assets carried at amortized cost, the amount of the impairment is the difference between the asset's carrying amount and the present value of estimated future cash flows, discounted at the original effective interest rate. The amount of allowance of the impairment is recognized in profit or loss.

For financial assets that are carried at cost, the amount of the impairment loss is measured as the difference between the asset's carrying amount and the present value of the estimated future cash flows discounted at the current market rate of return for a similar financial asset. Such impairment loss will not be reversed in subsequent periods.

The carrying amount of the financial asset is reduced by the impairment loss directly, for all financial assets with the exception of trade receivables where the carrying amount is reduced through the use of an allowance account. When a trade receivable is uncollectible, it is written off against the allowance account. Subsequent recoveries of amounts previously written off are credited against the allowance account. Changes in the carrying amount of the allowance account are recognized in profit or loss.

For financial assets measured at amortized cost, if, in a subsequent period, the amount of the impairment loss decreases and the decrease can be related objectively to an event occurring after the impairment was recognized, the previously recognized impairment loss is reversed through profit or loss to the extent that the carrying amount of the financial asset at the date the impairment is reversed, does not exceed what the amortized cost would have been had the impairment not been recognized.

Derecognition of financial assets

The Group derecognizes a financial asset only when the contractual rights to the cash flows from the asset expire, or it transfers the financial asset and substantially all the risks and rewards of ownership of the asset to another entity. If the Group neither transfers nor retains substantially all the risks and rewards of ownership, and continues to control the transferred asset, the Group recognizes its retained interest in the asset and an associated liability for amounts it may have to pay. If the Group retains substantially all the risks and rewards of ownership of a transferred financial asset, the Group continues to recognize the financial asset and also recognizes a collateralised borrowing for the proceeds received.

Financial liabilities and equity instruments

Financial liabilities and equity instruments are classified according to the substance of the contractual arrangements entered into. An equity instrument is any contract that evidences a residual interest in the assets of the Group after deducting all of its liabilities.

Other payables

Other payables are initially recognized at fair value, net of transaction costs, and subsequently at amortized cost using the effective interest method, with interest expense recognized on an effective yield basis.

Equity instruments

Equity instruments issued by the Company are recorded at the fair value of the proceeds received, net of direct issue costs, except where the accounting treatment is defined by a separate accounting standard, as in the case of share based payments and warrants.

Convertible bonds

Convertible bonds are regarded as compound instruments, consisting of a debt host component and an equity conversion option, which are classified separately as financial liabilities and equity in accordance with the substance of the contractual arrangement on initial recognition. Conversion options that will be settled by the exchange of a fixed amount of cash or another financial asset for a variable number of the Company's own equity instruments, is classified as a derivative financial liability. Conversion options that will be settled by the exchange of a fixed amount of cash or another financial asset for a fixed number of the Company's own equity instruments, is classified as an equity instrument.

On initial recognition, the fair value of the liability host component is determined using the prevailing market interest rate of similar non-convertible debts. The difference between the gross proceeds of the issue of the convertible loans and the fair value assigned to the liability host component, representing the conversion option for the holder to convert the loans into equity, is recognized separately as a derivative financial liability.

In subsequent periods, the derivative financial liability which represents the equity conversion option is measured at its fair value and with fair value changes recognized in the profit or loss. The liability host component is carried at amortized cost using the effective interest method until the liability is extinguished on conversion or redemption.

Upon conversion, the derivative financial liability and the carrying amount of the liability host component will be transferred to share capital.

Transaction costs

Transaction costs that relate to the issue of the convertible loans are allocated to the liability host and equity or derivative liability components in proportion to the allocation of the gross proceeds. Transaction costs relating to the equity components are charged directly to equity. Transaction costs relating to the liability components are included in the carrying amount of the liability and amortized over the period of the convertible loans using the effective interest method.

Transaction costs incurred prior to any issue of the convertible loans are capitalised as prepayments and assessed for indications for impairment at the end of each reporting period. The amount of the impairment is recognised in profit or loss.

Derecognition of financial liabilities

The Group derecognizes financial liabilities when, and only when, the Group's obligations are discharged, cancelled or they expire. The difference between the carrying amount of the financial liability derecognized, and the consideration paid and payable, is recognized in profit or loss.

Derivative financial instruments

A derivative financial instrument is initially recognized at its fair value on the date the contract is entered into, and is subsequent carried at its fair value. Fair value changes for derivative financial instruments are included in profit or loss in the financial year when the changes arise.

FAIR VALUE ESTIMATION OF FINANCIAL ASSETS AND LIABILITIES

The fair value of current financial assets and liabilities carried at amortized cost, approximate their carrying amounts, as the effect of discounting is immaterial.

SHARE-BASED PAYMENTS

Share based incentive arrangements are provided to employees which allow them to acquire shares of the Company. The fair value of options granted is recognized as an employee expense with a corresponding increase in equity.

Share options are valued at the date of grant using the Black-Scholes pricing model, and are charged to operating costs over the vesting period of the award. The charge is modified to take account of options granted to employees who leave the Company during the vesting period and forfeit their rights to the share options, and in the case of non-market related performance conditions, where it becomes unlikely they will vest. At the end of the reporting period, the Group revises its estimates of the number of equity instruments expected to vest. The impact of the original estimates, if any, is recognized in profit or loss such that the cumulative expense reflects the revised estimate, with a corresponding adjustment to the share options reserve.

Equity-settled share-based payment transactions with parties other than employees are measured at the fair value of goods or services received, except where that fair value cannot be estimated reliably, in which case they are measured at the fair value of the equity instruments granted, measured at the date at which the entity obtains the goods or the counterparty renders the service.

For cash-settled share-based payments, a liability is recognized for the goods and services acquired, measured initially at the fair value of the liability. At the end of each reporting period until the liability is settled, and at the date of settlement, the fair value of the liability is re-measured, with any changes in fair value recognized in profit or loss for the year. The Company does not issue cash-settled options.

When the share-based payment awards held by the employees of an acquirer (acquirer awards) are replaced by the Group's share-based payment awards (replacement awards), both the acquirer awards and the replacement awards are measured in accordance with IFRS 2 ("market-based measure") at the acquisition date. The portion of the replacement award that is included in measuring the consideration transferred in a business combination, equals the market-based measure of the acquirer awards multiplied by the ratio of the portion of the vesting period completed to the greater of the total vesting period or the original vesting period of the acquirer awards. The excess of the market-based measure of the replacement awards over the market-based measure of the acquirer awards included in measuring the consideration transferred, is recognized in profit or loss.

WARRANTS

The warrants enable shares of the Company to be acquired in the future at fixed rates, granted to shareholders as an incentive to invest in the shares of the Company, or to brokers to facilitate that investment. Such warrants not issued in exchange for goods or services are generally within the scope of IAS 32 and IAS 39.

To determine the appropriate accounting under IAS 32, the Group carefully reviews the terms and conditions of the warrants to understand whether the warrants have characteristics of:

- A derivative financial liability that is measured at fair value, with changes in value recorded in profit or loss; or
- An equity instrument.

Under IAS 32, equity classification applies to instruments where a fixed amount of cash (or liability), denominated in the issuer's functional currency, is exchanged for a fixed number of shares (often referred to as the "fixed for fixed" criteria). The Group has evaluated all warrants issued in the prior years as none was issued in the current period and evaluated that the warrants have characteristics of an equity instrument, as the exercise price of the warrant is fixed, the price is denominated in the same functional currency of the Company, and the number of shares to be issued upon exercise of the warrant is fixed.

Consideration received on the sale of a share and share purchase warrant classified as equity is allocated, within equity, to their respective equity accounts on a reasonable basis. Two commonly accepted allocation approaches are the residual method and the relative fair value method. Under the residual method, one component is measured first and the residual amount is allocated to the remaining component. In contrast, under the relative fair value method the total proceeds of the instrument is allocated to the components in proportion to their relative fair values.

The Group uses the residual method for the warrants and have been valued at the date of the grant, using the Black-Scholes pricing model, and are charged to equity immediately where there are no vesting conditions to be met.

LEASES

Leases are classified as finance leases whenever the terms of the lease transfer substantially all the risks and rewards of ownership to the lessee. All other leases are classified as operating leases.

The Group as lessee

Rentals payable under operating leases are charged to profit or loss on a straight-line basis over the term of the relevant lease unless another systematic basis is more representative of the time pattern in which economic benefits from the leased asset are consumed. Contingent rentals arising under operating leases are recognized as an expense in the period in which they are incurred.

In the event that lease incentives are received to enter into operating leases, such incentives are recognized as a liability. The aggregate benefit of incentives is recognized as a reduction of rental expense on a straight-line basis, except where another systematic basis is more representative of the time pattern in which economic benefits from the leased assets are consumed.

PROVISIONS

Provisions are recognized when the Group has a present obligation (legal or constructive) as a result of a past event, it is probable that the Group will be required to settle the obligation, and a reliable estimate can be made of the amount of the obligation.

The amount recognized as a provision is the best estimate of the consideration required to settle the present obligation at the end of the reporting period, taking into account the risks and uncertainties surrounding the obligation. Where a provision is measured using the cash flows estimated to settle the present obligation, its carrying amount is the present value of those cash flows (when the effect of the time value of money is material).

When some or all of the economic benefits required to settle a provision are expected to be recovered from a third party, the receivable is recognized as an asset if it is virtually certain that reimbursement will be received and the amount of the receivable can be measured reliably.

RETIREMENT BENEFIT OBLIGATIONS

Payments to defined contribution retirement benefit plans are charged as an expense as and when employees have tendered the services entitling them to the contributions. Payments made to state-managed retirement benefit schemes, such as the Malaysia's Employees Provident Fund, are dealt with as payments to defined contribution plans where the Group's obligations under the plans are equivalent to those arising in a defined contribution retirement benefit plan. The Group does not have any defined benefit plans.

REVENUE

Revenue is recognised to the extent that it is probable that the economic benefits will flow to the Group and the revenue can be reliably measured. Revenue is measured at the fair value of consideration received or receivable, taking into account contractually defined terms of payment and excluding taxes or duty.

Revenue from the sale of oil and gas is recognised when the significant risks and rewards of ownership have been transferred, which is considered to occur when title passes to the customer. This generally occurs when the product is physically transferred into a vessel, pipe or other delivery mechanism.

Revenue from the production of oil and gas, in which the Group has an interest with other producers, is recognised based on the Group's working interest and the terms of the relevant production sharing contracts. Differences between oil lifted and sold and the Group's share of production are not significant.

ROYALTIES

Royalty arrangements that are based on production are recognised by reference to the underlying arrangement.

The Group's oil and gas operations are reflected in the profit or loss, based on the Group's working interest in such production. All government stakes, other than income taxes, and including government's share of production, are considered to be royalties. Royalties to government on production from these joint operations represent the entitlement of the respective governments to a portion of the Group's share of oil and gas and are recorded using rates in effect under the terms of contracts at the time of production.

INCOME TAX

Income tax expense represents the sum of the tax currently payable and deferred tax.

The tax currently payable is based on taxable profit for the year. Taxable profit differs from profit as reported in the statement of profit or loss and other comprehensive income, because it excludes items of income or expense that are taxable or deductible in other years and it further excludes items that are not taxable or tax deductible. The Group's liability for current tax (and tax laws) is calculated using tax rates that have been enacted or substantively enacted, in countries where the Company and its subsidiaries operate, by the end of the reporting period.

Deferred tax is recognized on temporary differences between the carrying amounts of assets and liabilities in the financial statements and the corresponding tax bases used in the computation of taxable profit. Deferred tax liabilities are generally recognized for all taxable temporary differences and deferred tax assets are recognized to the extent that it is probable that taxable profits will be available, against which deductible temporary differences can be utilised.

Deferred tax liabilities are recognized for taxable temporary differences arising on investments in subsidiaries, except where the Group is able to control the reversal of the temporary difference and it is probable that the temporary difference will not reverse in the foreseeable future. Deferred tax assets arising from deductible temporary differences associated with such investments and interests, are only recognized to the extent that it is probable that there will be sufficient taxable profits against which to utilise the benefits of the temporary differences and they are expected to reverse in the foreseeable future.

The carrying amount of deferred tax assets is reviewed at the end of each reporting period and reduced to the extent that it is no longer probable that sufficient taxable profits will be available to allow all or part of the asset to be recovered.

Deferred tax is calculated at the tax rates that are expected to apply in the period when the liability is settled or the asset realised based on the tax rates (and tax laws) that have been enacted or substantively enacted, by the end of the reporting period.

Deferred tax assets and liabilities are offset when there is a legally enforceable right to set off current tax assets against current tax liabilities and when they relate to income taxes levied by the same taxation authority and the Group intends to settle its current tax assets and liabilities on a net basis.

Current and deferred tax are recognized as an expense or income in profit or loss, except when they relate to items credited or debited outside profit or loss (either in other comprehensive income or directly in equity), in which case the tax is also recognized outside profit or loss (either in other comprehensive income or directly in equity, respectively).

CASH AND CASH EQUIVALENTS IN THE STATEMENT OF CASH FLOWS

Cash and cash equivalents comprise cash in hand and at bank and other short term deposits held by the Group with maturities of less than 3 months.

3. CRITICAL ACCOUNTING JUDGMENTS AND KEY SOURCES OF ESTIMATION UNCERTAINTY

In the application of the Group's accounting policies, management is required to make judgments, estimates and assumptions about the carrying amounts of assets and liabilities that are not readily apparent from other sources. The estimates and associated assumptions are based on historical experience and other factors that are considered to be relevant. Actual results may differ from these estimates.

The estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which the estimate is revised, if the revision affects only that period, or in the period of the revision and future periods if the revision affects both current and future periods.

In particular, the Group has identified the following areas where significant judgments, estimates and assumptions are required. Changes in these assumptions may materially affect the financial position or financial results reported in future periods. Further information on each of these areas and how they impact the various accounting policies are described below, and also in the relevant notes to the financial statements.

a) Acquisitions, divestitures, farm-in arrangements and/or assignment of interests

The Group accounts for acquisitions, divestitures, and farm-in arrangements by considering if the acquired or transferred interest relates to that of an asset, or of a business as defined in IFRS 3 *Business Combinations*. Accordingly, the Group considers if there is the existence of business elements (e.g., inputs, processes and outputs) or a group of assets that includes inputs, outputs and processes that are capable of being managed together for providing a return to investors or other economic benefits. The Group is of the view that the acquisitions of the Stag Oilfield (Note 9) and the Ogan Komering PSC (Note 10) meet the definition of a business. Accordingly, they have been accounted for as business combinations.

The Group considers farm-in arrangements that pertain to exploration interests, with no production license, and no proved reserves, to be assets, rather than of a business, and would account for such farm-ins based on the consideration paid, which would be capitalized as an intangible exploration asset and subject to impairment reviews.

b) Carrying value of oil and gas properties

Oil and gas properties are depreciated using the units of production method.

The calculation of the units of production rate of amortisation could be impacted to the extent that actual production in the future is different from current forecast production based on proved and probable reserves. This would generally result from significant changes in any of the factors or assumptions used in estimating reserves.

These factors could include:

- Changes in proved and probable reserves;
- The effect on proved and probable reserves of differences between actual commodity prices and commodity price assumptions;
- Future estimates of capital expenditure requirements; and
- Unforeseen operational issues.

The carrying amount of oil and gas properties at December 31, 2017 and at March 31, 2017, is shown in Note 19.

c) Share-based payments

The Group measures the cost of equity-settled transactions by reference to the fair value of the share options at the date on which they are granted. Judgment is required in determining the most appropriate valuation model for the share options granted, depending on the terms and conditions of the grant. Management is also required to use judgment in determining the most appropriate inputs to the valuation model, including expected life of the option, volatility and dividend yield.

d) Intangible exploration assets

The application of the Group's accounting policy for intangible exploration assets requires judgment to determine whether future economic benefits are likely, either from future exploitation or sale, or whether activities have not reached a stage which permits a reasonable assessment of the existence of reserves. The determination of reserves and resources is itself an estimation process that requires varying degrees of uncertainty, depending on how the resources are classified. These estimates directly impact when the Group defers intangible exploration assets. The deferral policy requires management to make certain estimates and assumptions as to future events and circumstances, in particular, whether an economical viable extraction can be established. Any such estimates and assumptions may change as new information becomes available. If after expenditure is capitalized, information becomes available suggesting that the recovery of the expenditure is unlikely, the relevant capitalized amount is written off in profit or loss in the period when the new information becomes available. The carrying amounts of intangible exploration assets are disclosed in Note 18 to the financial statements.

On November 8, 2017, Mitra Energy (Philippines SC-56) Ltd, a wholly owned subsidiary of the Group, commenced an arbitration action against Total E&P Philippines BV ("Total") with the Singapore International Arbitration Centre claiming Total's failure or refusal to proceed with the planning and drilling of the Halcon well within Block SC56, as set out in their farm out agreement dated August 12, 2012, as well as resultant damages. Management is confident that the outcome will be favourable to the Group based on facts known to date.

e) Taxes

The Group recognises the net future economic benefit to deferred tax assets to the extent that it is probable that the deductible temporary differences will reverse in the foreseeable future and the carry forward of unused tax credits and unused tax losses can be utilized accordingly. Assessing the recoverability of deferred income tax assets requires the Group to make significant estimates related to expectations of future taxable income. Estimates of future taxable income are based on forecast cash flows from operations and the application of existing tax laws in each jurisdiction. To the extent that future cash flows and taxable income differ significantly from estimates, the ability of the Group to realise the net deferred tax assets as recorded in the statement of financial position, could be impacted. The carrying amounts of the Group's deferred tax assets are disclosed in Note 20 to the financial statements.

f) Reserve estimates

The estimated reserves are management assessments, and take into consideration reviews by an independent third party, under the Group's reserves audit programme, as well as other assumptions, interpretations and assessments. These include assumptions regarding commodity prices, exchange rates, discount rates, future production and transportation costs, and interpretations of geological and geophysical models to make assessments of the quality of reservoirs and their anticipated recoveries. Changes in reported reserves can impact asset carrying values, the provision for restoration and the recognition of deferred tax assets, due to changes in expected future cash flows. Reserves are integral to the amount of depreciation, depletion and amortisation charged to the statement of comprehensive income, and the calculation of inventory.

g) Impairment of assets

The Group undertakes a regular review of asset carrying values to determine whether there is any indication of impairment. For oil and gas properties, expected future cash flow estimation is based on reserves, future production profiles, commodity prices and costs. The carrying amounts of intangible exploration assets and oil and gas properties are disclosed in Notes 18 and 19 respectively.

h) Asset restoration obligations

The Group estimates the future removal and restoration costs of oil production facilities, wells, pipelines and related assets at the time of installation of the assets. In most instances the removal of these assets will occur many years in the future. The estimate of future removal costs is made considering relevant legislation and industry practice and requires management to make judgments regarding the removal date, the extent of restoration activities required and future removal technologies. The carrying amounts of the Group's asset restoration obligations is disclosed in Note 28 to the financial statements.

4. RECLASSIFICATION OF PRESENTATION OF STATEMENT OF PROFIT OR LOSS AND OTHER COMPREHENSIVE INCOME

During the period, the management has improved the presentation of statement of profit or loss and other comprehensive income to be more relevant and useful for the user of financial statements. Accordingly, the group has reclassified certain items on the statement of profit or loss and other comprehensive income. The reclassifications of each of the affected financial line items for the previous financial year ended March 31, 2017 are as follows:

	As previously reported March 31, 2017 US$000		As restated March 31, 2017 US$000
Statement of profit or loss and other comprehensive income:			
Cost of sales	(40,830)	Royalties	(725)
Depreciation	(58)	Production cost	(25,486)
		Floating storage and offloading ("FSO") vessel expenses	(10,781)
		Depletion, depreciation and amortisation	(3,896)
	(40,888)		(40,888)

Staff costs	(10,702)		
Share-based compensation	(103)		
Staff costs	(10,805)	Staff costs	(10,805)
Finance costs	(1,695)		
Interest income	5		
Foreign exchange loss	(339)		
Finance costs	2,029	Finance costs	2,029

5. COMPARATIVE FIGURES

The Ogan Komering PSC purchase price discount reported in the financial year ended March 31, 2017 has been revised from US$2.2 million to US$0.8 million arising from new information obtained with respect to fair values of certain identifiable assets and liabilities as at the time of the acquisition (Note 10). The restatement of each of the affected financial line items for the previous financial year ended March 31, 2017 are as follows:

	March 31, 2017	
	As previously reported US$000	As restated US$000
Statement of financial position		
Inventories	10,803	10,801
Receivables and prepayments	8,953	7,045
Trade & other payables, accruals and provisions	(12,530)	(12,046)
Accumulated losses	(261,767)	(263,193)

6. GROSS REVENUE

	Nine months ended December 31, 2017 US$000	Year ended March 31, 2017 US$000
Liquids revenue		
- Stag Oilfield	42,203	33,135
- Ogan Komering	12,782	1,416
Gas revenue		
- Ogan Komering	5,458	591
Total revenue	60,443	35,142

Average realised price:		
Crude oil – Stag (US$/bbl)	53.73	51.67
Crude oil – Ogan Komering (US$/bbl)	49.53	47.07
Gas – Ogan Komering (US$/mmbtu)	6.65	6.30
Average production:		
Crude oil – Stag (bbl/d) [1]	2,810	2,520
Crude oil and condensate – Ogan Komering (bbl/d)	942	970
Gas – Ogan Komering (mmbtu/day)	2,985	3,025

[1] Production relates to crude oil produced and stored into the floating storage and offloading ("FSO") vessel. Revenue derives from the sale to a third party of the produced and stored oil. This results in timing differences between produced oil at Stag, and sales of oil from the FSO.

7. PRODUCTION COST

	Nine months ended December 31, 2017 US$000	Year ended March 31, 2017 US$000
Stag Oilfield:		
FSO vessel expenses	14,592	10,781
Workovers	9,430	5,272
Repair & maintenance	1,558	2,458
Air, marine and onshore support	2,653	(56)
Operating expenses	9,720	17,116
	37,953	35,571
Ogan Komering:		
Operating expenses	5,567	696
	43,520	36,267

8. DEPLETION, DEPRECIATION AND AMORTISATION

	Nine months ended December 31, 2017 US$000	Year ended March 31, 2017 US$000
Depletion and amortisation (Note 19)		
Stag Oilfield	6,699	3,838
Ogan Komering	3,088	-
	9,787	3,838
Depreciation for plant and equipment	199	58
	9,986	3,896

9. ACQUISITION OF STAG OILFIELD

On November 11, 2016, Jadestone Energy (Australia) Pty Ltd, as buyer, and Jadestone as guarantor, satisfied the conditions precedent to closing the Stag Oilfield acquisition, resulting in the purchase of the Stag Oilfield. The fair value of the net assets acquired was identified, after a purchase price allocation exercise had been performed.

During the current financial period, the purchase price allocation in relation to the acquisition made and provisionally accounted for in the financial year ended March 31, 2017, was finalized, and there were no changes to the fair value of identifiable assets acquired and liabilities. The final price allocation, as at the date of acquisition, is presented in the following table:

	Fair value recognised on acquisition US$000
Assets	
Current Assets	
Cash and cash equivalents	1,372
Other receivables	419
Inventory – materials	4,668
Inventory - crude oil on hand	17,962
	24,421
Non-Current Assets	
Oil and gas properties	66,880
Deferred petroleum resource rent tax ("PRRT") tax asset	19,086
	85,966
Total Assets	110,387
Liabilities	
Current Liabilities	
Trade and other payables	(3,046)
Provisions	(1,328)
	(4,374)
Non-Current Liabilities	
Asset restoration obligations	(79,207)
Other provisions	(6,940)
	(86,147)
Total Liabilities	90.521
Net identifiable assets acquired	19,866
Total consideration	**19,866**
Consideration transferred:	
Purchase consideration	10,000
Working capital adjustments	9,866
Total consideration	**19,866**
Cash acquired	(1,372)
Net cash flows	18,494

10. ACQUISITION OF OGAN KOMERING PRODUCTION SHARING CONTRACT

On March 9, 2017, Jadestone Energy International Holdings Inc., a wholly-owned subsidiary of the Company, closed the acquisition of a fifty percent (50%) interest in the Ogan Komering Production Sharing Contract, Sumatra, Indonesia ("OK PSC"). For the financial year ended March 31, 2017, the initial purchase price allocation for the OK PSC acquisition was estimated based on the information known at that time and a purchase discount of US$2.2 million was recognised on a provisional basis in the audited financial statements for the year ended March 31, 2017.

Subsequently, the Group reviewed the purchase price allocation and adjusted the provisional amounts recognised at the acquisition date of the fair value of certain identifiable assets and liabilities, pursuant to IFRS 3, to reflect new information obtained about facts and circumstances that existed as of the acquisition date. The adjusted fair values of the identifiable assets and liabilities, as at the date of acquisition are presented in the following table:

	Provisional fair value March 9, 2017 US$000	**Fair value adjustments US$000**	**Adjusted provisional amount US$000**
Assets			
Current Assets			
Inventory – materials	154	(2)	152
Other receivables and prepayments	4,507	(1,908)	2,599
	4,661	(1,910)	2,751
Non-Current Assets			
Oil and gas properties	3,705	-	3,705
Restricted cash	669	-	669
	4,374	-	4,374
Total Assets	9,035	(1,910)	7,125
Liabilities			
Current Liabilities			
Deferred tax liabilities	(1,200)	-	(1,200)
Other payables and accruals	(3,979)	484	(3,495)
Total Liabilities	(5,179)	484	(4,695)
Net identifiable assets acquired	3,856	(1,426)	2,430
Total consideration	**1,641**		**1,641**
Consideration transferred:			
Base purchase consideration	5,800	-	5,800
Working capital/adjustments	(1,944)	(1,426)	(3,370)
Purchase discount	(2,215)	1,426	(789)
Total consideration	**1,641**	-	**1,641**

Accordingly, the purchase discount of US$2,215,000 (previously reported for the year ended March 31, 2017) was adjusted to US$789,000 (Note 5).

11. STAFF COSTS

	Nine months ended December 31, 2017 US$000	Year ended March 31, 2017 US$000
Wages, salaries and fees	7,201	6,767
Staff benefits-in-kind	1,071	842
Termination payments	311	3,093
Share-based compensation	436	103
	9,019	10,805

The Group has capitalized US$173,400 (March 31, 2017: US$1,537,500) in respect of staff costs as part of intangible exploration assets as these relate to time costs that are directly attributable to the active blocks.

12. OTHER EXPENSES

	Nine months ended December 31, 2017 US$000	Year ended March 31, 2017 US$000
Professional fees/consultancies	3,776	4,810
Office costs	2,281	1,793
Travel & subsistence	366	493
Time costs – recovery	(231)	(2,049)
Operator G&A	29	176
Other overhead	-	759
Others	109	534
Participating interest tax and branch profit tax	-	333
	6,330	6,849

13. IMPAIRMENT OF ASSETS

	Nine months ended December 31, 2017 US$000	Year ended March 31, 2017 US$000
Impairment of intangible exploration assets	-	8,512
Impairment of material and spare parts	-	1,717
	-	10.229

14. OTHER INCOME

	Nine months ended December 31, 2017 US$000	Year ended March 31, 2017 US$000
Gain on disposal of intangible exploration asset	400	-
Gain on disposal of motor vehicle	12	-
Others	341	239
	753	239

15. FINANCE COSTS

	Nine months ended December 31, 2017 US$000	Year ended March 31, 2017 US$000
Accretion expense (Note 28)	1,589	680
Transaction cost on convertible bonds facility	913	115
Fair value loss on derivative liability	677	-
Interest on convertible bonds (Note 32)	563	-
Professional fees	153	893
Foreign exchange loss	114	339
Interest income	(57)	(5)
Others	352	7
	4,304	2,029

16. TAXATION CREDIT/(EXPENSE)

	Nine months ended December 31, 2017 US$000	Year ended March 31, 2017 US$000
Deferred tax income relating to carry forward tax losses (Note 20)	3,548	-
Deferred tax income relating to PRRT (Note 20)	2,524	(1,650)
Corporate income tax – current	(1,526)	(217)
Corporate income tax – prior year	(84)	-
Deferred tax liabilities	1,000	-
Tax credit/(expense)	5,462	(1,867)

The Australian corporate income tax rate is applied at 30% and PRRT at 40% of sales revenue less certain permitted deductions and is tax deductible for Australian income tax purposes. The above movement in deferred tax balances relates to temporary differences between the tax base of an asset or liability, and its carrying amount in the statement of financial position.

The Indonesian corporate income tax rate is applied at 35%. Branch profit tax is applied at 20%.

The Company is resident in the Province of British Columbia and pays no tax on account of its losses. Subsidiary companies are resident for tax purposes in the territories in which they operate. No tax arises in the current period or in the previous year from any of the subsidiaries' operations in view of the losses incurred.

The tax credit/(expense) on Group losses differs from the amount that would arise using the standard rate of income tax applicable in the countries of operation of the various Group companies as explained below:

	Nine months ended December 31, 2017 US$000	Year ended March 31, 2017 US$000
Loss before tax	(20,392)	(34,630)
Tax calculated at domestic tax rates applicable to loss in the respective countries	4,697	5,917
Effects of non-deductible expenses	(2,699)	(5,646)
Effects of non-taxable income	-	600
Effects of tax losses not recognized	-	(2,738)
Effects of previously unrecognized and unused tax losses and now recognized as deferred tax assets	2,604	-
Effects of unused tax losses recognized as deferred tax assets	860	-
Tax credit/(expense)	5,462	(1,867)

As at December 31, 2017, Jadestone Energy (Australia) Pty Ltd has carried forward losses of US$8.5 million and other timing differences of US$3.6 million, totalling US$12.1 million. The Group has recognized deferred tax assets of US$3.5 million as at December 31, 2017, as management is confident that there will be sufficient taxable income in the foreseeable future.

17. LOSS PER ORDINARY SHARE

The calculation of the basic and diluted loss per share is based on the following data:

	Nine months ended December 31, 2017 US$000	Year ended March 31, 2017 US$000 Restated
Loss for the purpose of basic and diluted per share, being the net loss for the period/year attributable to equity holders of the parent	14,930	36,497
Number of shares	No.	No.
Weighted average number of ordinary shares for the purposes of basic loss per share	221,298,004	140,941,566

Diluted loss per share is calculated based on the weighted average number of ordinary shares outstanding during the period/year plus the weighted number of shares that would be issued on the conversion of all potentially dilutive shares to ordinary shares. Where the impact of converted shares would be anti-dilutive, these are excluded from the calculation.

Since the conversion of potential ordinary shares to ordinary shares from share options (Note 27) would decrease the loss per share, they are not dilutive. Accordingly, diluted loss per share is the same as basic loss per share.

18. INTANGIBLE EXPLORATION ASSETS

	Total US$000
Cost:	
At April 1, 2016	194,812
Additions	3,688
At March 31, 2017	198,500
Additions	744
Disposal of exploration asset	(5,950)
At December 31, 2017	193,294
Impairment:	
At April 1, 2016	85,059
Charged to profit or loss	8,512
At March 31, 2017	93,571
Charged to profit or loss	-
Disposal of exploration asset	(5,950)
At December 31, 2017	87,621
Net book value:	
At December 31, 2017	105,673
At March 31, 2017	104,929

For the purpose of statement of cash flows, intangible exploration assets of US$452,182 remained unpaid as at December 31, 2017 (March 31, 2017: US$327,862).

19. OIL AND GAS PROPERTIES

	Total US$000
Cost:	
At April 1, 2016	-
Arising from acquisition of businesses	70,585
Changes in asset restoration obligation	(2,701)
Additions	288
At March 31, 2017	68,172
Changes in asset restoration obligation (Note 28)	5,919
Additions	1,772
At December 31, 2017	75,863
Accumulated depletion and amortisation:	
At April 1, 2016	-
Depletion and amortisation for the year	(3,838)
At March 31, 2017	(3,838)
Depletion and amortisation for the period	(9,787)
At December 31, 2017	(13,625)
Net book value:	
At December 31, 2017	62,238
At March 31, 2017	64,334

20. DEFERRED TAX ASSETS

	December 31, 2017 US$000	March 31, 2017 US$000
PRRT Tax:		
Beginning balance	17,541	-
PRRT - deferred tax arising from business acquisition	-	19,086
PRRT credit/(expense) (Note 16)	2,524	(1,650)
Foreign currency effect	208	105
	20,273	17,541
Corporate Income Tax:		
Beginning balance	-	-
Income tax loss carried forward (Note 16)	3,548	-
	3,548	-
Total deferred tax assets	23,821	17,541

21. PLANT AND EQUIPMENT

	Computer equipment US$000	Fixtures and equipment US$000	Motor vehicles US$000	Total US$000
Cost:				
At April 1, 2016	545	860	56	1,461
Additions	561	71	-	632
At March 31, 2017	1,106	931	56	2,093
Additions	74	93	-	167
Disposal	-	-	(56)	(56)
At December 31, 2017	1,180	1,024	-	2,204
Accumulated depreciation:				
At April 1, 2016	439	860	56	1,355
Charge for the year	53	5	-	58
At March 31, 2017	492	865	56	1,413
Charge for the period	173	26	-	199
Disposal	-	-	(56)	(56)
At December 31, 2017	665	891	-	1,556
Net book value:				
At December 31, 2017	515	133	-	648
At March 31, 2017	614	66	-	680

22. INVESTMENT IN SUBSIDIARIES AND INTEREST IN JOINT OPERATIONS

The succeeding sections present the details of the subsidiaries and joint operations of the Group.

A. Details of the investments in which the Group holds 20% or more of the nominal value of any class of share capital are as follows:

Name of company:	**Place of Incorporation**	**% voting rights and shares held** As at Dec 31, 2017 %	As at Mar 31, 2017 %	**Nature of business**
Jadestone Energy (Australia) Pty Ltd	Australia	100	100	Production of oil
Jadestone Energy International Holdings Inc.	Canada	100	100	Investment holdings
Jadestone Energy (Ogan Komering) Ltd	Canada	100	100	Production of oil and gas
Jadestone Energy Limited	Bermuda	100	100	Investment holdings
Mitra Energy Biliton Pte. Ltd.	Singapore	100	100	Exploration
Mitra Energy (Philippines SC-56) Ltd.	Bermuda	100	100	Exploration
Mitra Energy (Philippines SC-57) Ltd.	British Virgin Islands ("BVI")	100	100	Exploration
Mitra Energy (Indonesia Sibaru) Ltd.	Bermuda	100	100	Exploration
Jadestone Energy (Holdings) Ltd.	BVI	100	100	Dormant
Mitra Energy (Services) Ltd.	BVI	100	100	Dormant
Mitra Energy (Indonesia Bone) Limited	BVI	100	100	Exploration
Mitra Energy (Vietnam Con Son) Ltd.	Bermuda	100	100	Exploration
Titan Resources (Natuna) Indonesia Limited	Bermuda	100	100	Exploration
Jadestone Energy (Singapore) Pte Ltd.	Singapore	100	100	Investment holdings
Mitra Energy (Vietnam Phu Quy) Pte Ltd.	Singapore	100	100	Exploration
Mitra Energy (Vietnam Rang Dong) Pte Ltd.	Singapore	100	100	Exploration
Mitra Energy (Vietnam Nam Du) Pte Ltd.	Singapore	100	100	Exploration
Mitra Energy (Vietnam Tho Chu) Pte Ltd.	Singapore	100	100	Exploration
Mitra Energy (Vietnam Minh Hai) Pte Ltd.	Singapore	100	100	Exploration
Titan Resources (Natuna) Indonesia Ltd.	Barbados	100	100	Exploration
Mitra Energy (Vietnam Song Tu) Pte Ltd.	Singapore	100	100	Dormant
Mitra Energy (Indonesia North Madura) Pte Ltd.	Bermuda	100	100	Exploration
Mitra Energy (Indonesia Titan) Pte Ltd.	Bermuda	100	100	Exploration
Mitra Energy (Indonesia Spermonde) Ltd.	Bermuda	100	100	Exploration
Mitra Energy (Indonesia NV) Ltd.	Bermuda	100	100	Exploration
Mitra Energy (Vietnam Thanh Long) Pte Ltd.	Singapore	100	100	Exploration
Mitra Energy (Vietnam Phu Khanh) Pte Ltd.	Singapore	100	100	Exploration
Jadestone Energy Sdn Bhd	Malaysia	100	100	Administration
Mitra Energy (Vietnam Song Hong) Pte Ltd.	Singapore	100	100	Exploration
Mitra Energy (Indonesia Rombebai) Limited	Bermuda	100	100	Exploration

B. Details of the operations of which all are in exploration stage, except for Stag Oilfield and Ogan Komering which are in production stage, are as follows:

Contract area	Date of Expiry	Held by	Place of Operation	Group Effective Working Interest	
				As at Dec 31, 2017 %	As at Mar 31, 2017 %
Stag Oilfield	Aug 25, 2018[1]	Jadestone Energy (Australia) Pty Ltd	Australia	100	100
Ogan Komering	Feb 28, 2018[2]	Jadestone Energy (Ogan Komering) Ltd	Indonesia	50	50
SC56	Aug 4, 2055	Mitra Energy (Philippines SC-56) Ltd	Philippines	25	25
SC57	Sep 14, 2055	Mitra Energy (Philippines SC-57) Ltd	Philippines	21	21
51	Jun 10, 2040	Mitra Energy (Vietnam Tho Chu) Pte Ltd	Vietnam	100	70[3]
46/07	Jun 29, 2035	Mitra Energy (Vietnam Nam Du) Pte Ltd	Vietnam	100	70[3]
45	Dec 26, 2041	Mitra Energy (Vietnam Minh Hai) Pte Ltd	Vietnam	-	70
127[4]	May 24, 2042	Mitra Energy (Vietnam Phu Khanh) Pte Ltd	Vietnam	100	100
MVHN/12KS[5]	Feb 19, 2043	Mitra Energy (Vietnam Song Hong) Pte Ltd	Vietnam	-	100
Bone[6]	Nov 25, 2040	Mitra Energy (Indonesia Bone) Ltd	Indonesia	-	60[6]

(1) Management has assessed and considered the renewal process of the license perfunctory in nature as long as the management complies with the terms of the license. As at the date of this report, the renewal process is still in progress

(2) On February 28, 2018, Jadestone, along with Pertamina Hulu Energi, has been appointed to temporarily manage the Ogan Komering working area for up to six months from March 1, 2018 to September 1, 2018, or until the new gross split PSC of Ogan Komering working area is signed, whichever occurs first

(3) Before back-in arrangements. Mitra has an agreement with an introducing party that gives them the right to acquire at cost from Mitra a 3% interest in any commercial discovery on Vietnam Block 51 PSC and Vietnam Block PSC 46/07. Effective May 1, 2017, Petrovietnam Exploration Production Corporation (PVEP) relinquished its 30% working interest in Block 46/07 and 51 leaving Jadestone as operator with a 100% working interest in the Blocks

(4) A one year extension of exploration phase one to May 2018 was approved by the Prime Minister of Vietnam in May 2017. Subsequent to period end, the Group performed a review of its asset base and as a result of that review, informed Vietnam Oil and Gas (PVN) on April 4, 2018 of its decision to relinquish the block at the end of the current exploration phase one

(5) The Vietnamese Government's approval for Mitra's relinquishment was received on June 30, 2017. The Group no longer has an interest in Block MVHN/12KS PSC

(6) On May 4, 2017, Mitra signed a Withdrawal Agreement with Azimuth Indonesia Ltd. ("Azimuth") to transfer Mitra's 60% working interest and operatorship of Bone PSC to Azimuth. The transfer was effective from April 15, 2017, but remains subject to final government approval

23. INVENTORIES

	December 31, 2017 US$000	March 31, 2017 US$000 Restated
Materials and spare parts: Southeast Asia ("SEA") portfolio	-	202
Materials and spare parts: Stag operation	4,194	5,402
Crude oil on hand: Stag	5,416	5,197
	9,610	10,801

The cost of inventories recognized in cost of sales includes US$Nil (March 31, 2017: US$713,000) in respect of write-downs of crude oil on hand to net realizable value. In the prior year an impairment of US$1,717,000 was recognised during the year against materials and spare parts, to reduce the balance to net realisable value.

24. RECEIVABLES AND PREPAYMENTS

	December 31, 2017 US$000	March 31, 2017 US$000
Share of joint venture receivables (trade)	1,987	1,191
Other prepayments	1,271	424
Other receivables and deposits	285	469
Accrued cash call receivables	-	2,403
GST/value added tax receivables	681	737
Amount due from Partners [1]	-	736
Prepaid facility expense	495	560
Prepaid asset insurance	-	519
	4,719	7,039

[1] Partners is a party to a contractual agreement under a PSC or petroleum concession with relevant Government Authorities in Philippines, Vietnam and Indonesia.

25. CASH AND CASH EQUIVALENTS

	December 31, 2017 US$000	March 31, 2017 US$000
Current asset		
Cash at bank	10,450	14,478
Non-current asset		
Restricted cash: Stag	10,000	-
Restricted cash: Ogan Komering	729	669
	10,729	669

Restricted cash at December 31, 2017 comprises Stag's cash deposit of US$10.0 million placed by the Company in support of a bank guarantee to a key contractor with respect to the Company's obligations under a long term contract, and Ogan Komering PSC's asset and site restoration fund of US$0.7 million.

Cash at bank earns interest at floating rates based on daily bank deposit rates.

26. SHARE CAPITAL

Authorised ordinary shares:

Unlimited number of common voting shares with no par value.

Allotted and outstanding:

	No. Shares	US$000
At December 31, 2017	221,298,004	364,466
At March 31, 2017	221,298,004	364,466

he holders of ordinary shares are entitled to receive dividends as and when declared by the Company. Fully paid ordinary shares carry one vote per share without restriction, and carry a right to dividends as and when declared by the Company.

27. SHARE-BASED PAYMENT AND WARRANTS

The total expense arising from share-based payments recognized for the period ended December 31, 2017 was US$435,614 (March 31, 2017: US$102,906).

On August 19, 2015, the Company adopted, as approved by shareholders, a stock incentive plan (the "Plan") which establishes a rolling number of shares issuable under the plan in the amount of 10% of the Company's issued shares at the date of grant. Under the terms of the Plan, the exercise price of each option granted cannot be less than the market price at the date of grant, or such other price as may be required by TSX-V. Options under the plan can have a term of up to 10 years, with vesting provisions determined by the directors in accordance with TSX-V policies for Tier 2 Issuers.

The Black-Scholes option-pricing model, with the following assumptions, was used to estimate the fair value of the options at the date of grant:

	Options granted on			
	December 10, 2017	March 28, 2017	June 8, 2017	April 21, 2015
Risk-free interest rate	1.11% to 1.21%	1.11% to 1.21%	0.70% to 0.83%	0.89%
Expected life	5.5 to 6.5 years	5.5 to 6.5 years	5.5 to 6.5 years	5 years
Expected volatility	41.6% to 42.8%	41.6% to 42.8%	42.1% to 42.7%	37.70%
Share price	C$0.42	C$0.45	C$0.49	C$1.25
Exercise price	C$0.45	C$0.47	C$0.49	C$1.82
Expected dividends	Nil	Nil	Nil	Nil

The following table summarizes the share options outstanding and exercisable as at December 31, 2017:

	Share options			
	Number of options	Weighted average exercise price C$	Weighted average remaining contract life	Number of options exercisable
As at April 1, 2016	7,400,891	2.34	7.36	7,399,588
New share options issued	7,250,000	0.47	9.92	-
Cancelled during the year	(4,223,070)	2.72	-	(4,221,767)
As at March 31, 2017	10,427,821	0.88	7.62	3,177,821
New share options issued	175,000	0.45	9.95	-
Cancelled during the year	(2,500,000)	1.82	-	(2,249,999)
As at December 31, 2017	8,102,821	0.58	9.03	927,822

The following table summarizes the share warrants outstanding and exercisable as at December 31, 2017:

	Share warrants			
	Number of warrants	Weighted average exercise price C$	Weighted average remaining contract life	Number of warrants exercisable
As at April 1, 2016 and March 31, 2017	234,641	3.24	0.08	234,641
Expired during the period	(234,641)	3.24	-	(234,641)
As at December 31, 2017	-	-	-	-

28. PROVISION FOR ASSET RESTORATION OBLIGATIONS

	December 31, 2017 US$000	March 31, 2017 US$000
Non-Current:		
Opening balance	77,186	-
Acquisition of Stag Oilfield (Note 9)	-	79,207
Accretion expense (Note 15)	1,589	680
Changes in assumptions discount rate and foreign exchange rate (Note 19)	5,919	(2,701)
Others	34	-
	84,728	77,186

The Group's asset restoration obligations ("ARO") result from the future costs of decommissioning the Stag Oilfield facilities which are expected to be incurred up to 2033. The balance of the provision is the discounted present value of the estimated future cost. The present value of the ARO has been calculated based on the blended estimated Australian and United States risk free rate of 2.52% after allowing for an inflation rate of 2.27% as at 31 December, 2017 (Australian risk free rate 2.70% as at March 31, 2017).

29. OTHER PAYABLES

Other payables comprises long-term liabilities associated with the Stag leased FSO vessel. The present value of the liabilities has been calculated based on the estimated Australian risk free rate of 2.63% as at December 31, 2017 (2.70% as at March 31, 2017).

30. BORROWINGS

	December 31, 2017 US$000	March 31, 2017 US$000
Insurance premium funding	829	435

The borrowing has an effective interest rate of 7.08% as at December 31, 2017 (5.56% as at March 31, 2017). No security or charges over property are in place for this arrangement.

31. TRADE & OTHER PAYABLES, ACCRUALS AND PROVISIONS

	December 31, 2017 US$000	March 31, 2017 US$000 Restated
Trade payables	1,098	2,135
Other payables	8,591	7,869
Provision for long service leave	668	815
Other provisions	480	328
Accruals – finance costs	-	893
	10,837	12,040

These amounts are non-interest bearing and repayable on demand. Payables are normally settled on 30 (March 31, 2017: 30) days terms.

32. SECURED CONVERTIBLE BONDS

Pursuant to the establishment of the convertible bond facility (the "Facility") with Tyrus Capital Event S.à r.l. ("Tyrus") on November 8, 2016, Jadestone paid a structuring fee equal to 2% of the total amount of the Facility. Jadestone is also required to pay a standby fee equal to 1% per annum on all undrawn amounts until maturity. The Facility will mature on October 31, 2019, at which time Tyrus will have the option to convert the full amount of any principal owing under the Facility into common shares of the Company at a conversion price of C$0.50. Tyrus also has the option to convert any principal owing under the Facility at any time prior to maturity, and the option to require the Company to draw down all undrawn amounts at any time prior to 15 days from maturity.

As at December 31, 2017, the Company had drawn down US$15 million from the Facility, to fund capital expenditures and for related corporate purposes. The interest on the convertible bonds for the period ended December 31, 2017 amounted to US$563,014 (March 31, 2017: US$Nil). In addition to this, the Company has capitalized bond accretion expenses of US$538,457 (March 31, 2017: US$Nil). The structuring fee of US$560,000 was initially capitalized in the financial statements as a prepaid expense in the prior period (Note 24). Following the drawdown, the Company has commenced amortization of the structuring fee over the remaining period of the bond.

The standby fees accrued by the Company amounted to US$238,816 (March 31, 2017: US$114,943) for the period ended December 31, 2017, and have been included in Finance Costs (Note 15).

The 3% issue discount on the issuance of the convertible bonds amounted to US$450,000 (March 31, 2017: US$Nil). The portion of the discount fee attributable to the bond of US$378,302 (March 31, 2017: US$Nil) has been included in the carrying value of convertible bonds, and the remaining attributable to the options embedded in the bonds of US$71,698 (March 31, 2017: US$Nil) has been charged to the profit and loss during the period ended December 31, 2017 (Note 15).

The fair value of the options as at December 31, 2017 amounting to US$3,067,000 (March 31, 2017: US$Nil) embedded in the bonds as a derivative financial instrument in the consolidated financial statement as a liability.

	December 31, 2017 US$000	March 31, 2017 US$000
Nominal value of convertible bonds issued	15,000	-
Derivative financial instruments at date of issuance	2,390	-
Liability component at date of issuance	12,610	-
Less: Convertible bonds issuance cost	(378)	-
Liability recognized at inception, net of costs	12,232	-
Cumulative accretion expense	538	-
	12,770	-

Reconciliation of liabilities arising from financing activities

The table overleaf details changes in the Group's liabilities arising from financing activities, including both cash and non-cash changes. Liabilities arising from financing activities are those for which cash flows were, or future cash flows will be, classified in the Group's consolidated statement of cash flows, as cash flows from financing activities.

The cash flows represent the drawdown from convertible bonds, drawdown on borrowings and repayment of borrowing in the statement of cash flows.

	April 1, 2017	Financing cash flows	Derivative liability component	Other changes	December 31, 2017
	US$'000	US$'000	US$'000	US$'000	US$'000
Group					
Convertible bonds (Note 32)	-	14,550	(2,390)	610[1]	12,770
Borrowings (Note 30)	435	383	-	11[2]	829

[1] Other changes on convertible bonds includes issuance discount, issuance cost and cumulative accretion expenses
[2] Other changes on borrowings includes foreign exchange movement

33. FINANCIAL INSTRUMENTS, FINANCIAL RISKS AND CAPITAL MANAGEMENTS

Categories of financial instruments

	December 31, 2017	March 31, 2017
	US$000	US$000
Financial assets		
Loans and receivables (including cash and cash equivalents)	12,722	19,283
Financial liabilities		
At amortised cost:		
Borrowings, provisions and payables	103,653	96,579
At fair value:		
Convertible bonds & derivative financial instruments	15,837	-
	119,490	96,579

Financial instruments

The Group's financial instruments that are not measured at fair value, comprise cash and bank balances, other receivables, other payables and accruals. As at December 31, 2017 and March 31, 2017 management considers that the carrying amounts of financial assets and financial liabilities in the financial statements approximate their fair value.

The Group drew down US$15 million from the US$28 million convertible bond facility in June and July 2017. As at December 31, 2017, the carrying value of the convertible bonds was US$12.8 million and the carrying value of the derivative liability component amounted to US$3.1 million.

Fair values are based on management's best estimates after consideration of current market conditions. The estimates are subjective and involve judgment and as such are not necessarily indicative of the amount that the Group may incur in actual market transactions.

Commodity price risk

The Group's earnings are affected by changes in oil and gas prices. The Group manages this risk by monitoring the oil and gas prices and entering into commodity hedges against fluctuations in oil and bunker price if considered appropriate. As at December 31, 2017 and March 31, 2017, the Group has no outstanding oil and gas price hedging contracts.

Commodity price sensitivity

The results of operations and cash flows of oil and gas production can vary significantly with fluctuations in the market prices of oil and/or natural gas. These are affected by factors outside the Group's control, including the market forces of supply and demand, regulatory and political actions of governments, and attempts of international cartels to control or influence prices, among a range of other factors.

At the end of reporting period, if the oil and gas price changes by 10% and all other variables were held constant, the Group's loss for the year will change by US$6,044,300 (March 31, 2017: US$$3,514,200).

Foreign currency risk

Foreign currency risk is the risk that a variation in exchange rates between United States Dollars ("US Dollar") and foreign currencies will affect the fair value or future cash flows of the Company's financial assets or liabilities.

Cash and bank balances are generally held in the currency of likely future expenditures to minimize the impact of currency fluctuations. It is the Group's normal practice to hold the majority of funds in US Dollars in order to match the Group's revenue and expenditures. The Company's US$28.0 million convertible debt facility is a US Dollar denominated instrument.

In addition to United States Dollars, the Group transacts in various currencies, including Canadian Dollars, Singapore Dollars, Australian Dollars, Indonesian Rupiah, Vietnamese Dong, and Malaysian Ringgit. No sensitivity analysis has been prepared for carrying amounts of monetary assets and liabilities denominated in these foreign currencies as the Group does not expect any material effect arising from the effects of reasonably possible changes to the exchange rate for these foreign currencies.

Foreign denominated balances were as follows:

	December 31, 2017 US$000	March 31, 2017 US$000
Cash and bank balances:		
Malaysian Ringgit	105	57
Indonesian Rupiah	8	24
Singapore Dollars	38	102
Vietnamese Dong	74	153
Canadian Dollars	8	554
Australian Dollars	2,070	695

	December 31, 2017 US$000	March 31, 2017 US$000
Trade and other receivables:		
Malaysian Ringgit	106	80
Indonesian Rupiah	188	309
Singapore Dollars	143	103
Vietnamese Dong	242	356
Canadian Dollars	12	12
Australian Dollars	1,434	578

	December 31, 2017 US$000	March 31, 2017 US$000
Trade and other payables:		
Malaysian Ringgit	376	30
Indonesian Rupiah	1,705	649
Singapore Dollars	812	169
Vietnamese Dong	410	207
Canadian Dollars	-	893
Australian Dollars	5,769	6,007

Interest rate risk

The Group's interest rate exposure arises from some of its cash and bank balances and short-term borrowings. The Group's other financial instruments are non-interest bearing or fixed rate, and are therefore not subject to interest rate risk.

Jadestone holds some of its cash in interest bearing accounts and short-term deposits. Interest rates currently received are at historically relatively low levels. Accordingly, a downward interest rate movement would not cause significant exposure to the Group.

The balance of short term borrowings as at December 31, 2017 amounts to US$828,621 (March 31, 2017: US$435,000). The 7.5% coupon on the Company's US$15.0 million convertible bond facility, drawn down as at December 31, 2017, is a fixed rate coupon (Note 32).

Any interest rate movement would not cause significant exposure to the Group.

Credit risk

Credit risk represents the financial loss that the Company would suffer if a counterparty in a transaction fails to meet its obligations in accordance with the agreed terms.

The Group's trade and other receivables are primarily with (i) counterparties to oil and gas sales, (ii) governments for recoverable amounts of value added taxes, and with (iii) joint venture partners in the oil and gas industry.

The Company actively manages its exposure to credit risk, granting credit limits consistent with the financial strength of the Group's counterparties and customers, requiring financial assurances as deemed necessary, reducing the amount and duration of credit exposures, and close monitoring of relevant accounts.

The Group trades only with recognised, creditworthy third parties. Where Jadestone operates joint ventures on behalf of partners it seeks to recover the appropriate share of costs from these partners. The majority of the partners in these ventures are well established oil and gas companies.

In the event of non-payment, Jadestone has recourse to increase its venture share under the operating agreements.

Stag Oilfield production, our largest credit risk exposure, is currently sold to an investment grade customer in the energy sector, subject to customary industry credit risk.

The maximum credit risk exposure relating to financial assets is represented by their carrying value as at the balance sheet date.

Liquidity risk

Liquidity risk is the risk that the Company will not be able to meet all of its financial obligations as they become due. This includes the risk that the Company cannot generate sufficient cash flow from producing assets or is unable to raise further capital in order to meet its obligations.

The Company manages it liquidity risk by optimising the positive free cash flow from its producting assets (with full legal ownership of Stag effective from July 10, 2017), on-going cost reduction initiatives, drawing down on the convertible bond facility to meet necessary capital expenditure needs, merger and acquisition strategies, and bank balance on hand.

The Group has reduced the loss for the nine-months ended December 31, 2017 by US$21.6 million to US$14.9 million compared to twelve-months ended March 31, 2017. Net cash used in operations for the nine-months ended December 2017, was reduced by US$3.3 million to US$5.0 million compared to twelve-months ended March 31, 2017. The Group's net current assets remained positive at US$13.1 million (March 31, 2017: net current asset of US$19.8 million).

During the nine-month period ended December 31, 2017, the Company drew down US$10 million on June 27, 2017 and a further US$5 million on July 13, 2017, totalling US$15 million from the convertible bond facility, to fund capital expenditures and for related corporate purposes. The remaining undrawn amount of the convertible bond facility as at December 31, 2017 is US$13.0 million.

The Company believes it has sufficient liquidity to meet all reasonable scenarios of operating and financial performance for the next 12 months.

The table below analyses the Group's financial liabilities into relevant maturity groupings at the reporting date, based on the remaining period to the contractual maturity date. The amounts disclosed in the table are the contractual undiscounted cash flows. Balances due are equal to their carrying balances as the impact of discounting is not significant. The maturity profile is:

	December 31, 2017 US$000	March 31, 2017 US$000
<u>*Less than 1 year*</u>		
Trade & other payables, accruals and provisions (Note 31)	10,837	12,040
Borrowings (Note 30))	829	435
	11,666	12,475
<u>Within 2 years</u>		
Secured Convertible Bond (Note 32)	12,770	-
	12,770	-

The Company's derivative financial instruments comprise the convertible bond amounting to US$12.8 million (March 31, 2017: US$Nil).

Capital management

The Company manages its capital structure and makes adjustments to it, based on the funds available to the Company, in order to support the acquisition, exploration and development of resource properties and the ongoing operations of its producing assets. Given the nature of the Company's activities, the Board of Directors does not establish quantitative return on capital criteria for management, but rather works with management to ensure that capital is managed effectively and the business has a sustainable future.

To carry-out planned assets acquisition, exploration and development, and to pay for administrative costs, the Company may spend excess cash generated from its ongoing operations and may spend its existing working capital, and will work to raise additional funds if needed.

Management reviews its capital management approach on an ongoing basis and believes that this approach, given the relative size of the Company, is reasonable. There were no changes in the Company's approach to capital management during the financial period ended December 31, 2017. The Company is not subject to externally imposed capital requirements.

Fair value measurements

The Group discloses fair value measurements by level of the following fair value measurement hierarchy:

(i) Quoted prices (unadjusted) in active markets for identical assets or liabilities (Level 1);

(ii) Inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly (Level 2); and

(iii) Inputs for the asset or liability that are not based on observable market data (unobservable inputs) (Level 3).

The Group only measures its derivative financial instruments at fair value and these have been classified as Level 3. If one or more of the significant inputs is not based on observable market data, the instrument is included in Level 3. The financial instruments that are recorded in the Level 3 category comprise of unquoted equity investments/ liabilities. The fair values of these financial instruments are measured using valuation techniques that incorporate assumptions that are not evidenced by prices from observable current market transactions. Instead, they are based on unobservable inputs reflecting management's own assumptions about the way assets would be priced.

34. SEGMENT INFORMATION

For management purposes, the Group operates in two business segments, namely exploration and production of oil and gas. The geographic focus of the business is on SEA and Australia.

Revenue and non-current assets information based on the geographical location of assets respectively are as follows:

	Revenue		Non-current assets	
	Nine-months ended December 31, 2017	Twelve-months ended March 31, 2017	December 31, 2017	March 31, 2017
	US$000	US$000	US$000	US$000 Restated
Producing Assets				
Australia	42,203	33,135	95,898	78,781
SEA - Indonesia	18,240	2,007	1,346	4,374
Exploration and Evaluation Assets				
SEA – Vietnam	-	-	55,258	54,560
SEA - Philippines	-	-	50,415	50,369
Others	-	-	192	69
	60,443	35,142	203,109	188,153

	Nine-months ended December 31, 2017				Twelve-months ended March 31, 2017			
	Production Assets	Exploration Assets	Corporate	Total	Production Assets	Exploration Assets	Corporate Restated	Total Restated
Gross revenue	60,443	-	-	60,443[1]	35,142	-	-	35,142
Royalties	(8,429)	-	-	(8,429)	(725)	-	-	(725)
Net revenue	52,014	-	-	52,014	34,417	-	-	34,417
Production cost	(28,928)	-	-	(28,928)	(25,486)	-	-	(25,486)
FSO expenses	(14,592)	-	-	(14,592)	(10,781)	-	-	(10,781)
Depletion, depreciation and amortisation	(9,986)	-	-	(9,986)	(3,850)	-	(46)	(3,896)
Staff costs	(1,276)	(736)	(7,007)	(9,019)	(3,675)	(2,001)	(5,026)	(10,805)
Other expenses	(1,425)	(750)	(4,155)	(6,330)	(3,974)	(1,736)	(1,139)	(6,849)
Impairment of asset	-	-	-	-	-	(10,229)	-	(10,229)
Gain on disposal of assets	-	400	12	412	-	-	-	-
Exploration credit	-	341	-	341	-	239	-	239
Purchase discount	-	-	-	-	-	-	789	789
Finance costs	(3,888)	-	(416)	(4,304)	(687)	-	(1,342)	(2,029)
LOSS BEFORE TAX	(8,081)	(745)	(11,566)	(20,392)	(14,036)	(13,727)	(6,764)	(34,630)

[1] As at December 31, 2017, revenue from one (March 31, 2017: one) customer, domiciled in Singapore, contributed to 70% (March 31, 2017: 89%) of the Group's total revenue.

35. FINANCIAL COMMITMENTS

COMMITMENTS UNDER OPERATING LEASES AND EXPENSES FOR THE PERIOD/ YEAR

The Group has recognized the following expense during the period/ year related to operating leases:

	Nine months ended December 31, 2017 US$000	Year ended March 31, 2017 US$000
Operating lease rental:		
- Land and buildings	495	644
- Other	82	55
	577	699

The Group has entered into commercial leases as a lessee in respect of the rental of office premises, office equipment and cars. Future minimum rentals payable under non-cancellable operating leases as at period ended are as follows:

	December 31, 2017 US$000	March 31, 2017 US$000
Amount to be paid:		
Not later than one year	614	886
After one year but not more than five years	568	699
	1,182	1,585

SEA Portfolio PSC Operational Commitments

Certain PSC's and Service Concessions' have firm capital commitments where we are required to participate in minimum exploration activities. The Group has the following outstanding minimum exploration commitments:

	December 31, 2017 US$000	March 31, 2017 US$000
Not later than one year	10,000	10,000

The SEA portfolio PSC operational commitments as at December 31, 2017 amounting to US$10,000,000 (March 31, 2017: US$ 10,000,000), relates to the minimum work commitment outstanding in exploration phase two of the Block 46/07 PSC for the drilling of a further well.

Drilling of this well has been delayed as a result of Petrovietnam Exploration Production Corporation's ODP deliberations. The Group is seeking a further extension to exploration phase two of the Block 46/07 PSC, in order to maintain the alignment of appraisal and development drilling.

Stag Oilfield Operational Commitments

The treated oil from the Stag Oilfield is pumped 2 kilometres to a leased FSO vessel permanently moored to a catenary anchor leg mooring buoy. The following commitments relate to the FSO facility service agreement:

	December 31, 2017 US$000	March 31, 2017 US$000
Not later than one year	17,714	17,424
After one year but not more than five years	93,975	91,843
After five years	6,853	21,328

36. CONTINGENT LIABILITES

Stag Oilfield Contingent Liabilities

The Group may be responsible for certain contingent payments after 2017 of up to US$15 million which are linked to future expansion of the oilfield and oil price appreciation above agreed price levels. At this stage the Group's management does not consider it probable that the conditions necessary to trigger the contingent payments will occur. Accordingly, as at December 31, 2017, no provision has been recognised in these financial statements.

37. RELATED PARTY TRANSACTIONS

During the year, the Group entities did not enter into any transactions with related parties other than the following:

Compensation of directors and key management personnel

The remuneration of directors and other members of key management during the year were as follows:

	December 31, 2017 US$000	March 31, 2017 US$000
Short-term benefits	2,732	3,024
Other benefits	657	574
Termination payments	-	1,425
Share-based payments	318	94
	3,707	5,117

38. EVENTS AFTER THE REPORTING PERIOD

Commodity hedge
On January 3, 2018 Jadestone entered into a commodity hedge to hedge 350,000 bbls of crude oil production, over the period January 2, 2018 to June 30, 2018 at Brent ICE crude fixed at US$64.60/bbl. On January 22, 2018 Jadestone entered into another 350,000 bbls oil hedge, over the period July 1, 2018 to December 31, 2018, at Brent ICE crude fixed at US$65.00/bbl.

Block 05-1b&c
On February 22, 2018, Teikoku Oil (Con Son) Co. Ltd ("Teikoku"), a wholly owned subsidiary of Inpex Corporation, delivered to Jadestone, a purported notice of termination of the signed sale and purchase agreement ("SPA"), that had previously been agreed between Teikoku and a wholly owned subsidiary of Jadestone, on August 9, 2016, for the acquisition by Jadestone, from Teikoku, of a 30% working interest in the Blocks 05-1b and 05-1c. The purported termination was delivered despite Teikoku having just received, on February 9, 2018, the written waiver, by Vietnam Oil and Gas ("PVN"), of PVN's statutory pre-emption rights held under Vietnamese Law. Jadestone has not accepted Inpex's alleged termination and views the obligations of both parties under the SPA as continuing. Jadestone maintains its rights under the SPA and is assessing its options, including remedies available through legal action.

Ogan Komering
On February 28, 2018 Jadestone, along with Pertamina Hulu Energy, has been appointed to temporarily manage the Ogan Komering working area for up to six months from March 1, 2018 to September 1, 2018 or until the new Gross Split PSC of Ogan Komering working area is signed, whichever occurs first.

Stocks options
On March 29, 2018 Jadestone issued 3,000,000 incentive stock options to employees, officers and directors, and a consultant engaged in investor relations activities on behalf of the Company, exercisable for a period of ten years, at an exercisable price of C$0.50 per share. The stock options will vest over a period of three years and were granted in accordance with the terms of the Company's stock option plan, which has been approved by the Company's shareholders and the TSX Venture Exchange.

Block 127 PSC
Jadestone operates Block 127 PSC, a predominantly deepwater exploration block at the southern end of the Phu Khanh basin, with a 100% working interest. Subsequent to year end, the Company performed a review of its asset base and as a result of that review, the Company has decided to relinquish Vietnam PSC MEVPK/127 at the end of the PSC's exploration phase one, and having met all minimum work commitments. Jadestone informed PVN of its relinquishment decision on April 4, 2018 and will proceed with the relinquishment process in accordance with all applicable Vietnamese laws.

Jadestone Energy Inc.

(Formerly Mitra Energy Inc.)

CONSOLIDATED FINANCIAL STATEMENTS

for the year ended

March 31, 2017

Company Registration No. BC0350583 (Canada)

Jadestone Energy Inc. (Formerly Mitra Energy Inc.)

MANAGEMENT'S REPORT

The accompanying consolidated financial statements are the responsibility of management. The consolidated financial statements were prepared by management in accordance with International Financial Reporting Standards outlined in the notes to the consolidated financial statements.

Management maintains appropriate systems of internal controls. Policies and procedures are designed to give reasonable assurance that transactions are appropriately authorized, assets are safeguarded and financial records properly maintained to provide reliable information for the presentation of consolidated financial statements.

Deloitte & Touche LLP, an independent firm of chartered accountants, was appointed by the shareholders to audit the consolidated financial statements and to provide an independent professional opinion.

The Audit Committee reviewed the consolidated financial statements with management. The Board of Directors has approved the consolidated financial statements on the recommendation of the Audit Committee.

A. Paul Blakeley
Director

Daniel Young
Chief Financial Officer

July 28, 2017

INDEPENDENT AUDITOR'S REPORT TO THE MEMBERS OF

JADESTONE ENERGY INC. (FORMERLY MITRA ENERGY INC.)

We have audited the accompanying consolidated financial statements of Jadestone Energy Inc. (formerly Mitra Energy Inc.) (the "Company") and its subsidiaries (the "Group"), which comprise the consolidated statement of financial position as at March 31, 2017 and 2016, and the consolidated statement of profit or loss and other comprehensive income, consolidated statement of changes in equity and consolidated statement of cash flows for the years then ended, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

INDEPENDENT AUDITOR'S REPORT TO THE MEMBERS OF

JADESTONE ENERGY INC. (FORMERLY MITRA ENERGY INC.)

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial positions of the Group as at March 31, 2017 and 2016, and of its financial performance and its cash flows for the years then ended in accordance with International Financial Reporting Standards.

Deloitte & Touche LLP

Public Accountants and
Chartered Accountants
Singapore

July 28, 2017

Jadestone Energy Inc. (Formerly Mitra Energy Inc.)
CONSOLIDATED STATEMENT OF FINANCIAL POSITION
March 31, 2017

	Notes	2017 US$000	2016 US$000
ASSETS			
Non-current assets:			
Intangible exploration assets	15	104,929	109,753
Oil and gas properties	16	64,334	-
Deferred tax assets	17	17,541	-
Plant and equipment	18	680	106
Restricted cash	22	669	-
		188,153	109,859
Current assets:			
Inventories	20	10,803	1,907
Receivables and prepayments	21	8,953	959
Cash and cash equivalents	22	14,478	9,117
		34,234	11,983
TOTAL ASSETS		222,387	121,842
EQUITY AND LIABILITIES			
Equity:			
Share capital	23	364,466	324,748
Share-based payment and warrants	24	21,419	21,316
Accumulated losses		(261,767)	(226,696)
		124,118	119,368
Non-current liabilities:			
Provision for asset restoration obligations	25	77,186	-
Other provisions	26	6,918	-
Deferred tax liabilities	8	1,200	-
		85,304	-
Current liabilities:			
Borrowings	27	435	-
Trade & other payables, accruals and provisions	28	12,530	2,474
		12,965	2,474
TOTAL EQUITY AND LIABILITIES		222,387	121,842

The accompanying notes are an integral part of the consolidated financial statements

Jadestone Energy Inc. (Formerly Mitra Energy Inc.)

CONSOLIDATED STATEMENT OF PROFIT OR LOSS AND
OTHER COMPREHENSIVE INCOME
for the year ended March 31, 2017

	Notes	2017 US$000	2016 US$000
Revenue	5	35,142	-
Cost of sales	6	(40,830)	-
GROSS LOSS		(5,688)	-
Staff costs	10	(10,702)	(6,110)
Share-based compensation	10, 24	(103)	(1,478)
Other operating expenses	11	(6,849)	(2,647)
Depreciation	18	(58)	(26)
Impairment of materials and spare parts	20	(1,717)	-
Expensed exploration costs		(541)	(216)
Joint operator overhead charge recovered		780	810
Impairment of intangible exploration assets	15	(8,512)	-
Gain on disposal of intangible exploration asset		-	125
Fair value loss on derivative financial instruments	29	-	(548)
Gain on acquisition of unsecured convertible bonds	29	-	9,439
Non-cash loss on completion of Transaction	9	-	(17,515)
Receivables written off		-	(51)
Foreign exchange loss		(339)	(383)
OPERATING LOSS BEFORE INTEREST, TAXATION AND OTHER INCOME		(33,729)	(18,600)
Interest income		5	1
Finance costs	12	(1,695)	(608)
Purchase discount	8	2,215	-
LOSS BEFORE TAX		(33,204)	(19,207)
Taxation	13	(1,867)	-
LOSS FOR THE YEAR, REPRESENTING TOTAL COMPREHENSIVE LOSS FOR THE YEAR		(35,071)	(19,207)
Loss per ordinary share:			
Basic and diluted (US$)	14	(0.25)	(0.23)

The accompanying notes are an integral part of the consolidated financial statements

	Share capital[(1)] US$000	Share-based payment reserves US$000	Accumulated losses US$000	Total US$000
At April 1, 2016	324,748	21,316	(226,696)	119,368
Total comprehensive loss for the year				
Loss for the year	-	-	(35,071)	(35,071)
Transactions with owners, recognized directly in equity				
Share capital issued (private placement)	39,805	-	-	39,805
Recognition of share-based compensation	-	103	-	103
Share issue costs (private placement)	(87)	-	-	(87)
Total transactions with owners	39,718	103	-	39,821
At March 31, 2017	364,466	21,419	(261,767)	124,118
At April 1, 2015	223,856	19,838	(207,489)	36,205
Total comprehensive loss for the year				
Loss for the year	-	-	(19,207)	(19,207)
Transactions with owners, recognized directly in equity				
Acquisition of unsecured convertible bonds	51,360	-	-	51,360
Deemed shares issued in Transaction (Note 2)	25,000	-	-	25,000
Share issue costs	(468)	-	-	(468)
Share capital issued	25,000	-	-	25,000
Recognition of share-based compensation	-	1,478	-	1,478
Total transactions with owners	100,892	1,478	-	102,370
At March 31, 2016	324,748	21,316	(226,696)	119,368

(1) Share capital as at April 1, 2015 consists of share capital of Mitra Energy Limited of US$11,142,511 and share premium of US$212,713,221 which has been reclassified as share capital.

Jadestone Energy Inc. (Formerly Mitra Energy Inc.)
CONSOLIDATED STATEMENT OF CASH FLOWS
for the year ended March 31, 2017

	Notes	2017 US$000	2016 US$000
OPERATING ACTIVITIES			
Loss before tax		(33,204)	(19,207)
Adjustments for:			
Depreciation	18	58	26
Share-based compensation	10, 24	103	1,478
Impairment of intangible exploration assets	15	8,512	-
Impairment of materials and spare parts	20	1,717	-
Inventories written down	20	713	-
Depletion and amortization	16	3,838	-
Purchase discount	8	(2,215)	-
Gain on acquisition of unsecured convertible bonds	29	-	(9,439)
Non-cash loss on completion of Transaction	9	-	17,515
Receivables written off		-	51
Gain on disposal of intangible exploration asset		-	(125)
Interest income		(5)	(1)
Finance costs	12	1,695	608
Fair value loss of derivative financial instrument	29	-	548
Unrealized foreign exchange loss		339	383
Operating cash flows before movements in working capital		(18,449)	(8,163)
Changes in working capital:			
Decrease in inventories		11,304	-
(Increase)/decrease in receivables and prepayments		(2,354)	1,037
Increase/(decrease) in trade & other payables, accruals and provisions		1,116	(4,728)
NET CASH USED IN OPERATING ACTIVITIES		(8,383)	(11,854)

Jadestone Energy Inc. (Formerly Mitra Energy Inc.)
CONSOLIDATED STATEMENT OF CASH FLOWS
for the year ended March 31, 2017

	Notes	2017 US$000	2016 US$000
INVESTING ACTIVITIES			
Acquisition of Stag Oilfield, net of cash acquired	7	(18,494)	-
Acquisition of Ogan Komering, net of cash acquired	8	(1,641)	-
Oil and gas properties	16	(288)	-
Payment for intangible exploration assets	15	(4,234)	(7,817)
Payment for plant and equipment	18	(632)	(127)
Interest received		5	1
NET CASH USED IN INVESTING ACTIVITIES		(25,284)	(7,943)
FINANCING ACTIVITIES			
Proceeds from share issuance	2a, 2d	39,805	25,000
Net drawdown on borrowings	27	428	-
Payments of convertible bonds facility expenses	21, 30	(560)	-
Payments of bonds facility standby fees	12, 29	(115)	-
Cash acquired in Transaction	9	-	2,558
Share issue costs		(87)	(468)
NET CASH FROM FINANCING ACTIVITIES		39,471	27,090
Effect of translation on foreign currency cash and cash equivalents		(443)	(383)
NET INCREASE IN CASH AND CASH EQUIVALENTS		5,361	6,910
CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR		9,117	2,207
CASH AND CASH EQUIVALENTS AT END OF YEAR		14,478	9,117

1. CORPORATE INFORMATION

Jadestone Energy Inc. (the "Company" or "Jadestone") (formerly Mitra Energy Inc.) is an oil and gas company incorporated in Canada. The Company's common shares are listed on the TSX Ventures Exchange ("TSX-V"). On December 6, 2016, the Company changed its name to Jadestone Energy Inc. and changed its symbol on the TSX-V to JSE (formerly under the symbol MTE). The financial statements are expressed in United States Dollars ("US$").

On June 8, 2016, the Company announced changes to its Board of Directors and senior management. A. Paul Blakeley, Cedric Fontenit and David Neuhauser joined the board, while Jerry Korpan (formerly Non-Executive Chairman) and Paul Ebdale (formerly Chief Executive Officer) resigned as directors. A. Paul Blakeley was appointed as Executive Chairman and Michael Horn was appointed Interim CEO. On January 18, 2017, the Company announced the appointment of Daniel Young as Chief Financial Officer, replacing William Mathers, who resigned as an officer of the Company. On June 27, 2017, A. Paul Blakeley took on the role of Chief Executive Officer while remaining as Chairman and Michael Horn became Executive Vice President Corporate and Business Development.

The Company and its subsidiaries (the "Group") are engaged in exploration, appraisal and pre-development activities in Southeast Asia (Philippines, Vietnam and Indonesia), production activity in the Carnarvon Basin, Australia, following the completion of the Stag Oilfield acquisition on November 11, 2016 and production activity in Sumatra, Indonesia, following the completion of the acquisition of a fifty percent (50%) working interest in the Ogan Komering Production Sharing Contract ("PSC").

The Company's head office is located at Keppel Towers, #15-05/06, 10 Hoe Chiang Road, Singapore 089315. The registered office of the Company is 2600 Oceanic Plaza, 1066 West Hastings Street, Vancouver, British Columbia, V6E 3X1 Canada.

2a. GOING CONCERN ASSUMPTION

The Group recorded a loss before tax of US$33.2 million for the financial year ended March 31, 2017 (March 31, 2016: US$19.2 million), and as at March 31, 2017, the Group's current assets exceeded its current liabilities by US$21.3 million (March 31, 2016: net current asset of US$9.5 million). The ability of the Company and the Group to continue as going concerns remains dependent on developing future profitable operations and raising adequate capital to support operations.

On November 8, 2016 Jadestone completed a non-brokered private placement (the "Private Placement") of 132,500,000 common shares (each, a "Share") at a price per Share of C$0.40 for gross proceeds of C$53,000,000 (US$39.5 million). In conjunction with the Private Placement, on November 8, 2016 Jadestone also entered into a US$28 million convertible debt facility (the "Facility") with Tyrus Capital Event S.à.r.l. ("Tyrus"). Under the terms of the Facility, Jadestone will have the ability to drawdown tranches of US$5 million, subject to Tyrus' approval, and any amounts drawn down will bear interest at the rate of 7.5% per annum payable quarterly in cash and a 3% issue discount. The Facility will mature after three years, at which time Tyrus will have the option to convert the full amount of any principal owing under the Facility into common shares of the Company at a conversion price of C$0.50. Tyrus also has the option to convert any principal owing under the Facility at any time prior to maturity and the option to require the Company to draw down all undrawn amounts at any time prior to 15 days from maturity.

Subsequent to year end, the Company applied for draw down of US$15 million from the Facility (Note 29) to fund capital expenditures and for related corporate purposes. By July 13, 2017 the Company had received the proceeds of this drawdown (Note 35).

Accordingly, the Company has sufficient working capital to meet its financial obligations for the next 12 months. As such, the accompanying financial statements are presented on a going concern basis.

2b. ACQUISITION OF STAG OILFIELD (NOTE 7)

On November 11, 2016, the Company announced that Jadestone Energy (Australia) Pty Ltd (formerly named Mitra Energy (Australia) Pty Ltd), as buyer, and Jadestone, as guarantor, had satisfied the conditions precedent to closing the Stag Oilfield acquisition and the acquisition had closed. At closing, a cash consideration of US$10 million was paid by Jadestone to Quadrant Northwest Pty Ltd ("Quadrant Energy") and Santos Offshore Pty Ltd. The payment was funded from the proceeds of the Private Placement completed on November 8, 2016 (Note 23).

In addition to the purchase consideration, a further US$9.9 million was paid in connection with the settlement of working capital adjustments. On July 10, 2017 Jadestone has provided a bank guarantee of US$10 million to a key contractor to the Stag Oilfield to support Jadestone's obligations under a long term contract. Jadestone may also be responsible for certain contingent payments after 2017, of up to US$15 million, which are linked to future expansion of the oilfield and oil price appreciation above agreed price levels.

Following the closing of the transaction, Quadrant Energy continued to perform their duty as operator of the Stag Oilfield on behalf of Jadestone under a transitional services agreement until July 10, 2017, after which the full legal ownership was transferred to Jadestone.

Further details on the acquisition are disclosed in Note 7.

2c. ACQUISITION OF OGAN KOMERING PRODUCTION SHARING CONTRACT (NOTE 8)

On March 9, 2017, Jadestone Energy International Holdings Inc. ("JEIH"), a wholly-owned subsidiary of the Company, closed the acquisition of a fifty percent (50%) interest in the Ogan Komering Production Sharing Contract, Sumatra, Indonesia ("OK PSC").

JEIH, as buyer, and Jadestone Energy Limited ("JEL"), as guarantor, have signed a definitive Sale & Purchase Agreement ("SPA") with Repsol Oil & Gas Canada Inc. ("Repsol"), as seller, for the acquisition of all issued and outstanding shares in Talisman (Ogan Komering) Ltd. ("TOKL").

TOKL holds a fifty percent (50%) interest in the PSC. The SPA was signed and the acquisition closed concurrently. The PSC's corresponding block is located in South Sumatra, Indonesia. The remaining fifty percent (50%) in the PSC is held by PT Pertamina Hulu Energi Ogan Komering ("Pertamina Ogan Komering"), an affiliate of PT Pertamina Persero, Indonesia's national oil company. TOKL, together with Pertamina Ogan Komering, operates the PSC through a joint operated body.

Further details on the acquisition are disclosed in Note 8.

2d. REVERSE TAKEOVER TRANSACTION (THE "TRANSACTION") (NOTE 9)

In the prior year, the Company's Shareholders consented to a business combination between Petra Petroleum Inc. ("Petra") and Mitra Energy Limited ("MEL") a private Bermuda incorporated entity, pursuant to an Arrangement Agreement dated March 13, 2015 (the "Transaction").

On April 8, 2015, the Company closed the financing of the arrangement (the "Financing") and a total of C$31,722,500 (US$25,000,000) was deposited into escrow with Computershare Trust Company of Canada. In connection with the closing of the Financing, the Company issued 17,429,945 subscription receipts at a price of C$1.82 (US$1.43) per subscription receipt.

On April 21, 2015, Petra closed the acquisition of all of the outstanding shares of MEL. Prior to completing the acquisition, the Company changed its name from Petra Petroleum Inc. to Mitra Energy Inc. and consolidated its share capital on a four (old) for one (new) basis. Following the consolidation and in accordance with a Scheme of Arrangement duly approved by MEL's shareholders and the Bermuda Supreme Court, the Company issued a total of 17,429,962 common shares to the shareholders of MEL in exchange for all of the outstanding shares of MEL based on a share exchange ratio of 0.62571 of a Company share for each MEL share.

Upon completion of the Transaction, the subscription receipts converted on a one-for-one basis into a total of 17,429,945 post consolidation common shares of the Company and the proceeds of the Financing were released from escrow.

Concurrent with the closing of the Transaction, the Company acquired all of the outstanding Senior Unsecured Convertible Bonds of MEL. As at closing there was a total of US$51,360,072 in outstanding principal and accrued interest on the bonds. In consideration for the purchase of these bonds, the Company issued a total of 35,808,126 common shares at a deemed price of C$1.82 (US$1.43) per share.

As part of the closing of the Transaction, the Company issued 234,641 warrants with an exercise price of C$3.24 in exchange for the cancellation of 375,000 post consolidation warrants in MEL and agreed to assume 135,570 share options in exchange for 216,667 post-consolidation share options previously issued by MEL. In addition to this, 1,082,000 post-consolidation share options of MEL, held by directors and employees of MEL, were cancelled and replaced with an award of 6,377,821 new options in the Company, exercisable at C$1.82 (US$1.43) for a period of ten years.

Following the completion of the Transaction, MEL became a wholly-owned subsidiary of the Company. The Transaction constituted a reverse takeover transaction of Petra by MEL pursuant to TSX-V Policy 5.2, Change of Business and Reverse Takeovers.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

BASIS OF PREPARATION

The financial statements are prepared in accordance with the historical cost basis, except as disclosed in the accounting policies below, and are drawn up in accordance with the provisions of International Financial Reporting Standards ("IFRS").

Historical cost is generally based on the fair value of the consideration given in exchange for goods and services.

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date, regardless of whether that price is directly observable or estimated using another valuation technique. In estimating the fair value of an asset or a liability, the Group takes into account the characteristics of the asset or liability which market participants would take into account when pricing the asset or liability at the measurement date. Fair value for measurement and/or disclosure purposes in these consolidated financial statements is determined on such a basis, except for share-based payment transactions that are within the scope of IFRS 2 *Share-based Payment*, leasing transactions that are within the scope of IAS 17 *Leases*, and measurements that have some similarities to fair value but are not fair value, such as net realisable value in IAS 2 *Inventories* or value in use in IAS 36 *Impairment of Assets.*

In addition, for financial reporting purposes, fair value adjustments are categorised into Level 1, 2 or 3 based on the degree to which the inputs to the fair value adjustments are observable and the significance of the inputs to the fair value measurement in its entirety which are described as follows:

- Level 1 inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities that the entity can access at the measurement date;
- Level 2 inputs are inputs, other than quoted prices included within Level 1, that are observable for the asset or liability, either directly or indirectly; and
- Level 3 inputs are unobservable inputs for the asset or liability.

APPLICATION OF NEW AND REVISED INTERNATIONAL FINANCIAL REPORTING STANDARDS (IFRSs)

Amendments to IFRSs that are mandatorily effective for the current year

In the current year, the Group adopted a number of amendments to IFRSs issued by the International Accounting Standards Board ("IASB") that were mandatorily effective for an accounting period that began on or after April 1, 2016.

The application of these amendments to IFRSs had no material impact on the Group's consolidated financial statements.

New and revised IFRSs in issue but not yet effective

The Group has not applied the following new and revised IFRSs that are relevant to the Group were issued but not effective:

IFRS 9	Financial Instruments (2)
IFRS 15	Revenue from Contract with Customers (with clarifications issued) (2)
IFRS 16	Leases (3)
Amendments to IAS 7	Statement of Cash Flows: Disclosure Initiative (1)
Amendments to IAS 12	Income Taxes: Recognition of Deferred Tax Assets for Unrealised Losses (1)
Amendments to IFRS 2	Share-based payment: Classification and Measurement of Share-based Payment transactions (2)
IFRIC 22	Foreign Currency Transactions and Advance Consideration (2)
Amendments to IFRSs	Annual Improvements to IFRS 2014-2016 Cycle

(1) Applies to annual periods beginning on or after January 1, 2017, with earlier application permitted.
(2) Applies to annual periods beginning on or after January 1, 2018, with early application permitted.
(3) Applies to annual periods beginning on or after January 1, 2019, with early application permitted if IFRS 15 is also applied.

Management anticipates that the adoption of the above IFRSs, IFRIC and amendments to IASs and IFRSs in future periods will not have a material impact on the financial statements of the Group in the period of their initial adoption except for the following:

IFRS 16 *Leases*

IFRS 16 was issued in June 2016 and it will supersede IAS 17 *Leases* and its associated interpretative guidance.

The Standard provides a comprehensive model for the identification of lease arrangements and their treatment in the financial statements of both lessees and lessors. The identification of leases, distinguishing between leases and service contracts are determined on the basis of whether there is an identified asset controlled by the customer.

Significant changes to lessee accounting are introduced, with the distinction between operating and finance leases removed and assets and liabilities recognised in respect of all leases (subject to limited exceptions for short-term leases and leases of low value assets). The Standard maintains substantially the lessor accounting approach under the predecessor IAS 17.

IAS 17 does not require the recognition of any right-of-use asset or liability for future payments for these lease; instead certain information is disclosed as operating lease commitments. A preliminary assessment indicates that these arrangements, other short term leases and low value asset leases, will meet the definition of a lease under IFRS 16 and hence the Group will recognise a right-of-use asset and a corresponding liability of all these leases. Management is currently working on a detailed assessment on the potential impact of the changes in the period of initial adoption.

BASIS OF CONSOLIDATION

The consolidated financial statements incorporate the financial statements of the Company and enterprises controlled by the Company and its subsidiaries. Control is achieved where the Company:

- has power over the investee;
- is exposed, or has rights, to variable returns from its involvement with the investee; and
- has the ability to use its power to affect its returns.

The Company reassesses whether or not it controls an investee if facts and circumstances indicate that there are changes to one or more of the three elements of control listed above.

When the Company has less than a majority of the voting rights of an investee, it has power over the investee when the voting rights are sufficient to give it the practical ability to direct the relevant activities of the investee unilaterally. The Company considers all relevant facts and circumstances in assessing whether or not the Company's voting rights in an investee are sufficient to give it power, including:

- the size of the Company's holding of voting rights relative to the size and dispersion of holdings of the other vote holders;

- potential voting rights held by the Company, other vote holders or other parties;
- rights arising from other contractual arrangements; and
- any additional facts and circumstances that indicate that the Company has, or does not have, the current ability to direct the relevant activities at the time that decisions need to be made, including voting patterns at previous shareholders' meetings.

Consolidation of a subsidiary begins when the Company obtains control over the subsidiary and ceases when the Company loses control of the subsidiary. Specifically, income and expenses of a subsidiary acquired or disposed of during the year are included in the consolidated statement of profit or loss and other comprehensive income from the date the Company gains control until the date when the Company ceases to control the subsidiary.

Profit or loss and each component of other comprehensive income are attributed to the owners of the Company and to the non-controlling interests. Total comprehensive income of subsidiaries is attributed to the owners of the Company and to the non-controlling interests even if this results in the non-controlling interests having a deficit balance.

When necessary, adjustments are made to the financial statements of subsidiaries to bring their accounting policies into line with the Group's accounting policies.

All intragroup assets and liabilities, equity, income, expenses and cash flows relating to transactions between members of the Group are eliminated in full on consolidation.

Changes in the Group's interest in a subsidiary that do not result in a loss of control are accounted for as equity transactions. The carrying amounts of the Group's interests and the non-controlling interests are adjusted to reflect the changes in their relative interests in the subsidiary. Any difference between the amount by which the non-controlling interests are adjusted and the fair value of the consideration paid or received is recognized directly in equity and attributed to owners of the Company.

When the Group loses control of a subsidiary, the profit or loss on disposal is calculated as the difference between (i) the aggregate of the fair value of the consideration received and the fair value of any retained interest and (ii) the previous carrying amount of the assets (including goodwill), and liabilities of the subsidiary and any non-controlling interests. Amounts previously recognized in other comprehensive income in relation to the subsidiary are accounted for (i.e. reclassified to profit or loss or transferred directly to retained earnings) in the same manner as would be required if the relevant assets or liabilities were disposed of. The fair value of any investment retained in the former subsidiary at the date when control is lost is regarded as the fair value on initial recognition for subsequent accounting under IAS 39 *Financial Instruments: Recognition and Measurement* or, when applicable, the cost on initial recognition of an investment in an associate or joint venture.

BUSINESS COMBINATIONS

Acquisitions of businesses (including joint operations which are assessed to be businesses) are accounted for using the acquisition method. The consideration for each acquisition is measured at the aggregate of the acquisition date fair values of assets given, liabilities incurred by the Group to the former owners of the acquiree, and equity interests issued by the Group in exchange for control of the acquiree. Acquisition-related costs are recognized in profit or loss as incurred.

Where applicable, the consideration for the acquisition includes any asset or liability resulting from a contingent consideration arrangement, measured at its acquisition-date fair value. Subsequent changes in such fair values are adjusted against the cost of acquisition where they qualify as measurement period adjustments (see below). The subsequent accounting for changes in the fair value of the contingent consideration that do not qualify as measurement period adjustments depends on how the contingent consideration is classified. Contingent consideration that is classified as equity is not re-measured at subsequent reporting dates and its subsequent settlement is accounted for within equity. Contingent consideration that is classified as an asset or a liability is remeasured at subsequent reporting dates in accordance with IAS 39 *Financial Instruments: Recognition and Measurement*, or IAS 37 *Provisions, Contingent Liabilities and Contingent Assets*, as appropriate, with the corresponding gain or loss being recognised in profit or loss.

The acquiree's identifiable assets, liabilities and contingent liabilities that meet the conditions for recognition under the FRS are recognized at their fair value at the acquisition date, except that:

- Deferred tax assets or liabilities and liabilities or assets related to employee benefit arrangements are recognized and measured in accordance with IAS 12 *Income Taxes* and IAS 19 *Employee Benefits* respectively;
- Liabilities or equity instruments related to share-based payment transactions of the acquiree or the replacement of an acquiree's share-based payment awards transactions with share-based payment awards transactions of the acquirer in accordance with the method in IFRS 2 *Share-based Payment* at the acquisition date; and
- Assets (or disposal groups) that are classified as held for sale in accordance with IFRS 5 *Non-current Assets Held for Sale and Discontinued Operations*

Where a business combination is achieved in stages, the Group's previously held interests in the acquired entity are re-measured to fair value at the acquisition date (i.e. the date the Group attains control) and the resulting gain or loss, if any, is recognized in profit or loss. Amounts arising from interests in the acquiree prior to the acquisition date that have previously been recognized in other comprehensive income are reclassified to profit or loss, where such treatment would be appropriate if that interest were disposed of.

If the initial accounting for a business combination is incomplete by the end of the reporting period in which the combination occurs, the Group reports provisional amounts for the items for which the accounting is incomplete. Those provisional amounts are adjusted during the measurement period (see below), or additional assets or liabilities are recognised, to reflect new information obtained about facts and circumstances that existed as of the acquisition date that, if known, would have affected the amounts recognised as of that date.

The measurement period is the period from the date of acquisition to the date the Group obtains complete information about facts and circumstances that existed as of the acquisition date and is subject to a maximum of one year from acquisition date.

Where an interest in a Production Sharing Contract ("PSC") is acquired by way of a corporate acquisition, the interest in the PSC is treated as an asset purchase unless the acquisition of the corporate vehicle meets the requirements to be treated as a business combination and definition of a business.

GOODWILL

Goodwill arising in a business combination is recognised as an asset at the date that control is acquired (the acquisition date). Goodwill is measured as the excess of the sum of the consideration transferred, the amount of any non-controlling interest in the acquiree and the fair value of the acquirer's previously held equity interest (if any) in the entity over net of the acquisition-date amounts of the identifiable assets acquired and the liabilities assumed.

If, after reassessment, the Group's interest in the fair value of the acquiree's identifiable net assets exceeds the sum of the consideration transferred, the amount of any non-controlling interest in the acquiree and the fair value of the acquirer's previously held equity interest in the acquiree (if any), the excess is recognised immediately in profit or loss as a purchase discount gain.

FOREIGN CURRENCY TRANSACTIONS

The individual financial statements of each Group entity are measured and presented in the currency of the primary economic environment in which the entity operates (its functional currency).

In preparing the financial statements of each individual Group entity, transactions in currencies other than the entity's functional currency are recorded at the rates of exchange prevailing on the dates of the transactions. At the end of each reporting period, monetary items denominated in foreign currencies are retranslated at the rates prevailing at the end of the reporting period. Non-monetary items carried at fair value that are denominated in foreign currencies are retranslated at the rates prevailing on the date when the fair value was determined. Non-monetary items that are measured in terms of historical cost in a foreign currency are not retranslated.

Exchange differences arising on the settlement of monetary items, and on retranslation of monetary items are included in profit or loss for the period. Exchange differences arising on the retranslation of non-monetary items carried at fair value are included in profit or loss for the period except for differences arising on the retranslation of non-monetary items in respect of which gains or losses are recognized in other comprehensive income. For such non-monetary items, any exchange component of that gain or loss is also recognized in other comprehensive income.

JOINT OPERATIONS

A joint operation is a joint arrangement whereby the parties that have joint control of the arrangement have rights to the assets, and obligations for the liabilities, relating to the arrangement. Joint control is the contractually agreed sharing of control of an arrangement, which exists only when decisions about the relevant activities require unanimous consent of the parties sharing control.

When a Group entity undertakes its activities under joint operations, the Group as a joint operator recognizes in relation to its interest in a joint operation:

- Its assets, including its share of any assets held jointly;
- Its liabilities, including its share of any liabilities incurred jointly;
- Its revenue from the sale of its share of the output arising from the joint operation; and
- Its expenses, including its share of any expenses incurred jointly.

The Group accounts for the assets, liabilities, revenue and expenses relating to its interest in a joint operation in accordance with the IFRSs applicable to the particular assets, liabilities, revenues and expenses.

When a Group entity transacts with a joint operation in which a Group entity is a joint operator (such as a sale or contribution of assets), the Group is considered to be conducting the transaction with the other parties to the joint operation, and gains and losses resulting from the transactions are recognized in the Group's consolidated financial statements only to the extent of other parties' interests in the joint operation.

When a Group entity transacts with a joint operation in which a Group entity is a joint operator (such as a purchase of assets), the Group does not recognize its share of the gains and losses until it resells those assets to a third party.

Changes to the Group's interest in PSCs usually require the approval of the appropriate regulatory authority. A change in interest is recognized when:

a) Approval is considered highly likely; and

b) All affected parties are effectively operating under the revised arrangement.

Where this is not the case, no change in interest is recognized and any funds received or paid are included in the statement of financial position as Contractual deposits.

Reimbursement of Joint Operator's costs

The Company's subsidiaries, when acting as operator, incur certain general overhead expenses in carrying out activities on behalf of the joint operation. As these costs are often not specifically identified, the PSCs allow the operator to recover the general overhead expenses incurred by charging an overhead fee that is based on a fixed percentage of the total costs incurred during a period. Such overhead fees have been disclosed as Joint Operator Overhead Charge. Although the purpose of this recharge is similar to the reimbursement of direct costs, the subsidiaries are not acting as agent in this case. Therefore, the general overhead expenses and the overhead fee are recognized as an expense and income respectively.

PRE-LICENCE AWARD COSTS

Costs incurred prior to the effective award of oil and gas licences, concessions and other exploration rights are expensed in the statement of profit and loss and other comprehensive income.

EXPLORATION AND EVALUATION COSTS

The costs of exploring for and evaluating oil and gas properties, including the costs of acquiring rights to explore, geological and geophysical studies, exploratory drilling and directly related overheads such as directly attributable employee remuneration, materials, fuel used, rig costs and payments made to contractors are capitalized and classified as intangible exploration assets (E&E assets).

If no potentially commercial hydrocarbons are discovered, the exploration asset is written off through profit or loss as a dry hole. If extractable hydrocarbons are found and, subject to further appraisal activity (e.g. the drilling of additional wells), it is probable they can be commercially developed, the costs continue to be carried as intangible exploration costs while sufficient/continued progress is made in assessing the commerciality of the hydrocarbons. Costs directly associated with appraisal activity undertaken to determine the size, characteristics and commercial potential of a reservoir following the initial discovery of hydrocarbons, including the costs of appraisal wells where hydrocarbons were not found, are initially capitalized as intangible exploration assets.

All such capitalized costs are subject to technical, commercial and management review, as well as review for indicators of impairment at the end of each reporting period. This is to confirm the continued intent to develop or otherwise extract value from the discovery. When such intent no longer exists or if there is a change in circumstances signifying an adverse change in initial judgment, the costs are written off.

When commercial reserves of hydrocarbons are determined and development is approved by management, the relevant expenditure is transferred to property, plant and equipment. The technical feasibility and commercial viability of extracting a mineral resource is considered to be determinable when proved or probable reserves are determined to exist. The determination of proved or probable reserves is dependent on reserve evaluations which are subject to significant judgments and estimates.

Costs related to geological and geophysical studies that relate to blocks that have not yet been acquired and costs related to blocks for which no commercially viable hydrocarbons are expected are taken direct to the profit or loss and have been disclosed as expensed exploration costs.

FARM-OUTS IN THE EXPLORATION AND EVALUATION PHASE

The Group does not record any expenditure made by the farmee on its account. It also does not recognize any gain or loss on its exploration and evaluation farm-out arrangements, but redesignates any costs previously capitalized in relation to the whole interest as relating to the partial interest retained. Any cash consideration received directly from the farmee is credited against costs previously capitalized in relation to the whole interest with any excess accounted for by the farmor as a gain on disposal.

OIL AND GAS PROPERTIES

Producing Assets

The Group recognises oil and gas properties at cost less accumulated depletion, depreciation and impairment losses. Directly attributable costs incurred for the drilling of development wells and for the construction of production facilities are capitalised together with the discounted value of estimated future costs of decommissioning obligations. When components of oil and gas properties are replaced, disposed of, or no longer in use, they are derecognised.

Depletion and Amortisation Expense

Depletion of oil and gas properties is calculated using the units of production method for an asset or group of assets from the date in which they are available for use. The cost of those assets are depleted based on proved and probable reserves. Costs subject to depletion include expenditures to date, together with approved estimated future expenditure to be incurred in developing proved and probable reserves. Costs of major development projects are excluded from the costs subject to depletion until they are available for use.

The impact of changes in estimated reserves is dealt with prospectively by depreciating the remaining carrying value of the asset over the expected future production. If reserves estimates are revised downwards, earnings could be affected by higher depreciation expense or an immediate write-down of the property’s carrying value.

Asset Restoration Obligations

The Group estimates the future removal and restoration costs of oil production facilities, wells, pipelines and related assets at the time of installation or acquisition of the assets and based on prevailing legal requirements and industry practice. In most instance the removal of these assets will occur many years in the future. The estimates of future removal costs are made considering relevant legislation and industry practice and require management to make judgments regarding the removal date, the extent of restoration activities required and future removal technologies.

Site restoration costs are capitalised within the cost of the associated assets and the provision is stated in the statement of financial position at total estimated present value. These costs are based on judgements and assumptions regarding removal dates, technologies, and industry practice. This estimate is evaluated on a periodic basis and any adjustment to the estimate is applied prospectively. Changes in the estimated liability resulting from revisions to estimated timing, amount of cash flows, or changes in the discount rate are recognised as a change in the asset restoration liability and related capitalised asset restoration cost.

The change in net present value of the future obligations due to passage of time is expensed as accretion expense within financing charges. Actual restoration obligations settled during the period reduce the decommissioning liability.

The asset restoration costs are depleted using the units of production method (see above accounting policy).

BORROWING COSTS

Borrowing costs directly attributable to the acquisition, construction or production of qualifying assets, which are assets that necessarily take a substantial period of time to get ready for their intended use or sale, are added to the cost of those assets, until such time as the assets are substantially ready for their intended use or sale.

Investment income earned on the temporary investment of specific borrowings pending their expenditure on qualifying assets is deducted from the borrowing costs eligible for capitalization. All other borrowing costs are recognized in profit or loss in the period in which they are incurred and this includes borrowing costs in relation to exploration activities which are capitalized in intangible exploration assets as management is of the view that these do not meet the definition of a qualifying asset.

PLANT AND EQUIPMENT

Plant and equipment is stated at cost less accumulated depreciation and any recognized impairment loss.

Depreciation is charged so as to write off the cost of assets evenly over their estimated useful lives, on the following basis:

Computer equipment	3 years
Fixtures and equipment	3 years
Motor vehicles	3 years

The estimated useful lives, residual values and depreciation method are reviewed at each year end, with the effect of any changes in estimate accounted for on a prospective basis.

An item of plant and equipment is derecognized upon disposal or when no future economic benefits are expected to arise from the continued use of asset. Any gain or loss arising on the disposal or retirement of an item of plant and equipment is determined as the difference between the sales proceeds and the carrying amount of the asset and is recognized in profit or loss.

IMPAIRMENT OF TANGIBLE ASSETS AND INTANGIBLE ASSETS EXCLUDING GOODWILL

At the end of each reporting period, the Group reviews the carrying amounts of its assets to determine whether there is any indication that those assets have suffered an impairment loss. If any such indication exists, the recoverable amount of the asset is estimated in order to determine the extent of the impairment loss (if any). Where it is not possible to estimate the recoverable amount of an individual asset, the Group estimates the recoverable amount of the cash-generating unit to which the asset belongs. When a reasonable and consistent basis of allocation can be identified, corporate assets are also allocated to individual cash-generating units, or otherwise they are allocated to the smallest group of cash-generating units for which a reasonable and consistent allocation basis can be identified.

Intangible assets with indefinite useful lives and intangible assets not yet available for use are tested for impairment annually, and whenever there is an indication that the asset may be impaired.

Recoverable amount is the higher of fair value less costs to sell and value in use. In assessing value in use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset for which estimates of future cash flows have not been adjusted.

If the recoverable amount of an asset (or cash-generating unit) is estimated to be less than its carrying amount, the carrying amount of the asset (or cash-generating unit) is reduced to its recoverable amount. An impairment loss is recognized immediately in profit or loss.

Where an impairment loss subsequently reverses, the carrying amount of the asset (cash-generating unit) is increased to the revised estimate of its recoverable amount, but so that the increased carrying amount does not exceed the carrying amount that would have been determined had no impairment loss been recognized for the asset (cash-generating unit) in prior years. A reversal of an impairment loss is recognized immediately in profit or loss.

INVENTORY

Inventories are valued at the lower of cost and net realisable value. Cost is determined as follows:

- Petroleum products, comprising primarily of extracted crude oil stored in tanks, pipeline systems and aboard vessels, and natural gas, are valued using all costs of production inclusive of amortisation and depreciation; and
- Materials, which include drilling and maintenance stocks, are valued at the cost of acquisition.

Net realisable value represents the estimated selling price less applicable selling expenses. If the carrying value exceeds net realizable value, a write-down is recognized. The write-down may be reversed in a subsequent period if the inventory is still on hand but the circumstances which caused the write-down no longer exist.

FINANCIAL INSTRUMENTS

Financial assets and financial liabilities are recognized when the Group has become a party to the contractual provisions of the instrument.

Effective interest method

The effective interest method is a method of calculating the amortized cost of a financial instrument and of allocating interest income or expense over the relevant period. The effective interest rate is the rate that exactly discounts estimated future cash receipts or payments (including all fees on points paid or received that form an integral part of the effective interest rate, transaction costs and other premiums or discounts) through the expected life of the financial instrument, or where appropriate, a shorter period. Income and expense recognized on an effective basis for debt instruments.

Financial assets

The Group has classified all its financial assets as loans and receivables. Loans and receivables are non-derivative financial assets that are not quoted in an active market. They are included in current assets except for those maturing later than 12 months after the reporting date which are classified as non-current assets. Loans and receivables include trade and other receivables and cash at bank as shown on the statement of financial position.

Other receivables

Other receivables are initially recognized at fair value. They are subsequently measured at amortized cost using the effective interest method less any provision for impairment.

Impairment of financial assets

Financial assets are assessed for indicators of impairment at the end of each reporting period. Financial assets are impaired where there is objective evidence that, as a result of one or more events that occurred after the initial recognition of the financial asset, the estimated future cash flows of the financial asset have been impacted. Significant financial difficulties of the debtor, probability that the debtor will enter bankruptcy or financial reorganisation, and default or significant delay in payments are objective evidence that these financial assets are impaired.

For financial assets carried at amortized cost, the amount of the impairment is the difference between the asset's carrying amount and the present value of estimated future cash flows, discounted at the original effective interest rate. The amount of allowance of the impairment is recognized in profit or loss.

For financial assets that are carried at cost, the amount of the impairment loss is measured as the difference between the asset's carrying amount and the present value of the estimated future cash flows discounted at the current market rate of return for a similar financial asset. Such impairment loss will not be reversed in subsequent periods.

The carrying amount of the financial asset is reduced by the impairment loss directly for all financial assets with the exception of trade receivables where the carrying amount is reduced through the use of an allowance account. When a trade receivable is uncollectible, it is written off against the allowance account. Subsequent recoveries of amounts previously written off are credited against the allowance account. Changes in the carrying amount of the allowance account are recognized in profit or loss.

For financial assets measured at amortized cost, if, in a subsequent period, the amount of the impairment loss decreases and the decrease can be related objectively to an event occurring after the impairment was recognized, the previously recognized impairment loss is reversed through profit or loss to the extent that the carrying amount of the financial asset at the date the impairment is reversed does not exceed what the amortized cost would have been had the impairment not been recognized.

Derecognition of financial assets

The Group derecognizes a financial asset only when the contractual rights to the cash flows from the asset expire, or it transfers the financial asset and substantially all the risks and rewards of ownership of the asset to another entity. If the Group neither transfers nor retains substantially all the risks and rewards of ownership and continues to control the transferred asset, the Group recognizes its retained interest in the asset and an associated liability for amounts it may have to pay. If the Group retains substantially all the risks and rewards of ownership of a transferred financial asset, the Group continues to recognize the financial asset and also recognizes a collateralised borrowing for the proceeds received.

Financial liabilities and equity instruments

Financial liabilities and equity instruments are classified according to the substance of the contractual arrangements entered into. An equity instrument is any contract that evidences a residual interest in the assets of the Group after deducting all of its liabilities.

Other payables

Other payables are initially recognized at fair value, net of transaction costs, and subsequently at amortized cost using the effective interest method, with interest expense recognized on an effective yield basis.

Equity instruments

Equity instruments issued by the Company are recorded at the fair value of the proceeds received, net of direct issue costs, except where the accounting treatment is defined by a separate accounting standard, as in the case of share based payments and warrants.

Convertible bonds

Convertible bonds are regarded as compound instruments, consisting of a debt host component and an equity conversion option which are classified separately as financial liabilities and equity in accordance with the substance of the contractual arrangement on initial recognition. Conversion option that will be settled by the exchange of a fixed amount of cash or another financial asset for a variable number of the Company's own equity instruments is classified as a derivative financial liability. Conversion option that will be settled by the exchange of a fixed amount of cash or another financial asset for a fixed number of the Company's own equity instruments is classified as an equity instrument.

Where conversion option will be settled by the exchange of a fixed amount of cash or another financial asset for a variable number of the Company's own equity instruments.

On initial recognition, the fair value of the liability host component is determined using the prevailing market interest of similar non-convertible debts. The difference between the gross proceeds of the issue of the convertible loans and the fair value assigned to the liability host component, representing the conversion option for the holder to convert the loans into equity, is recognized separately as derivative financial liability.

In subsequent period, the derivative financial liability which represents the equity conversion option is measured at its fair value and with fair value changes recognized in the profit or loss. The liability host component is carried at amortized cost using the effective interest method until the liability is extinguished on conversion or redemption.

Upon conversion, the derivative financial liability and the carrying amount of the liability host component will be transferred to share capital.

Transaction Costs

Transaction costs that relate to the issue of the convertible loans are allocated to the liability host and equity or derivative liability components in proportion to the allocation of the gross proceeds. Transaction costs relating to the equity components are charged directly to equity. Transaction costs relating to the liability components are included in the carrying amount of the liability and amortized over the period of the convertible loans using the effective interest method.

Transaction costs incurred prior to any issue of the convertible loans are capitalised as prepayments and assessed for indications for impairment at the end of each reporting period. The amount of the impairment is recognised in profit or loss.

Derecognition of financial liabilities

The Group derecognizes financial liabilities when, and only when, the Group’s obligations are discharged, cancelled or they expire. The difference between the carrying amount of the financial liability derecognized and the consideration paid and payable is recognized in profit or loss.

Derivative financial instruments

A derivative financial instrument is initially recognized at its fair value on the date the contract is entered into and is subsequent carried at its fair value. Fair value changes for derivative financial instruments are included in profit or loss in the financial year when the changes arise.

FAIR VALUE ESTIMATION OF FINANCIAL ASSETS AND LIABILITIES

The fair value of current financial assets and liabilities carried at amortized cost approximate their carrying amounts, as the effect of discounting is immaterial.

SHARE-BASED PAYMENTS

Share based incentive arrangements are provided to employees which allow them to acquire shares of the Company. The fair value of options granted is recognized as an employee expense with a corresponding increase in equity.

Share options are valued at the date of grant using the Black-Scholes pricing model, and are charged to operating costs over the vesting period of the award. The charge is modified to take account of options granted to employees who leave the Company during the vesting period and forfeit their rights to the share options and in the case of non-market related performance conditions, where it becomes unlikely they will vest. At the end of the reporting period, the Group revises its estimates of the number of equity instruments expected to vest. The impact of the original estimates, if any is recognized in profit or loss such that the cumulative expense reflects the revised estimate, with a corresponding adjustment to the share options reserve.

Equity-settled share-based payment transactions with parties other than employees are measured at the fair value of goods or services received, except where that fair value cannot be estimated reliably, in which case they are measured at the fair value of the equity instruments granted, measured at the date at which the entity obtains the goods or the counterparty renders the service.

For cash-settled share-based payments, a liability is recognized for the goods and services acquired, measured initially at the fair value of the liability. At the end of each reporting period until the liability is settled, and at the date of settlement, the fair value of the liability is re-measured, with any changes in fair value recognized in profit or loss for the year. The Company does not issue cash-settled options.

When the share-based payment awards held by the employees of an acquirer (acquirer awards) are replaced by the Group's share-based payment awards (replacement awards), both the acquirer awards and the replacement awards are measured in accordance with IFRS 2 ("market-based measure") at the acquisition date. The portion of the replacement award that is included in measuring the consideration transferred in a business combination equals the market-based measure of the acquire awards multiplied by the ratio of the portion of the vesting period completed to the greater of the total vesting period or the original vesting period of the acquirer awards. The excess of the market-based measure of the replacement awards over the market-based measure of the acquirer awards included in measuring the consideration transferred is recognized in profit or loss.

WARRANTS

The warrants enable shares of the Company to be acquired in the future at fixed rates, granted to shareholders as an incentive to invest in the shares of the Company, or to brokers to facilitate that investment. Such warrants not issued in exchange for goods or services are generally within the scope of IAS 32 and IAS 39.

To determine the appropriate accounting under IAS 32, the Group carefully reviews the terms and conditions of the warrants to understand whether the warrants have characteristics of:

- a derivative financial liability that is measured at fair value, with changes in value recorded in profit or loss; or
- an equity instrument.

Under IAS 32, equity classification applies to instruments where a fixed amount of cash (or liability), denominated in the issuer's functional currency, is exchanged for a fixed number of shares (often referred to as the "fixed for fixed" criteria). The Group has evaluated all warrants issued in the prior years as none was issued in the current year and evaluated that the warrant have characteristics of an equity instrument as the exercise price of the warrant is fixed, the price is denominated in the same functional currency of the Company and the number of shares to be issued upon exercise of the warrant is fixed.

Consideration received on the sale of a share and share purchase warrant classified as equity is allocated, within equity, to their respective equity accounts on a reasonable basis. Two commonly accepted allocation approaches are the residual method and the relative fair value method. Under the residual method, one component is measured first and the residual amount is allocated to the remaining component. In contrast, under the relative fair value method the total proceeds of the instrument is allocated to the components in proportion to their relative fair values.

The Group uses the residual method for the warrant and, have been valued at the date of the grant, using the Black-Scholes pricing model, and are charged to equity immediately where there are no vesting conditions to be met.

LEASES

Leases are classified as finance lease whenever the terms of the lease transfer substantially all the risks and rewards of ownership to the lessee. All other leases are classified as operating leases.

The Group as lessee

Rentals payable under operating leases are charged to the profit or loss on a straight-line basis over the term of the relevant lease unless another systematic basis is more representative of the time pattern in which economic benefits from the leased asset are consumed. Contingent rentals arising under operating leases are recognized as an expense in the period in which they are incurred.

In the event that lease incentives are received to enter into operating leases, such incentives are recognized as liability. The aggregate benefit of incentives is recognized as a reduction of rental expense on a straight-line basis, except where another systematic basis is more representative of the time pattern in which economic benefits from the leased assets are consumed.

PROVISIONS

Provisions are recognized when the Group has a present obligation (legal or constructive) as a result of a past event, it is probable that the Group will be required to settle the obligation, and a reliable estimate can be made of the amount of the obligation.

The amount recognized as a provision is the best estimate of the consideration required to settle the present obligation at the end of the reporting period, taking into account the risks and uncertainties surrounding the obligation. Where a provision is measured using the cash flows estimated to settle the present obligation, its carrying amount is the present value of those cash flows (when the effect of the time value of money is material).

When some or all of the economic benefits required to settle a provision are expected to be recovered from a third party, the receivable is recognized as an asset if it is virtually certain that reimbursement will be received and the amount of the receivable can be measured reliably.

RETIREMENT BENEFIT OBLIGATIONS

Payments to defined contribution retirement benefit plans are charged as an expense as when employees have tendered the services entitling them to the contributions. Payments made to state-managed retirement benefit schemes, such as the Malaysia’s Employees Provident Fund, are dealt with as payments to defined contribution plans where the Group’s obligations under the plans are equivalent to those arising in a defined contribution retirement benefit plan. The Group does not have any defined benefit plans.

REVENUE

Revenue is recognised to the extent that it is probable that the economic benefits will flow to the Group and the revenue can be reliably measured. Revenue is measured at the fair value of consideration received or receivable, taking into account contractually defined terms of payment and excluding taxes or duty.

Revenue from the sale of oil and gas is recognised when the significant risks and rewards of ownership have been transferred, which is considered to occur when title passes to the customer. This generally occurs when the product is physically transferred into a vessel, pipe or other delivery mechanism.

Revenue from the production of oil and gas, in which the Group has an interest with other producers, is recognised based on the Group's working interest and the terms of the relevant production sharing contracts. Differences between oil lifted and sold and the Group's share of production are not significant.

ROYALTIES

Royalty arrangements that are based on production are recognised by reference to the underlying arrangement.

The Group's production of oil and gas are conducted jointly with the respective national oil companies. These operations are reflected in the Group's profit or loss based on the Group's working interest in such production. All government stakes, other than income taxes, are considered to be royalties. Royalties to government on production from these joint operations represent the entitlement of the respective governments to a portion of the Group's share of oil and gas and are recorded using rates in effect under the terms of contracts at the time of production.

INCOME TAX

Income tax expense represents the sum of the tax currently payable and deferred tax.

The tax currently payable is based on taxable profit for the year. Taxable profit differs from profit as reported in the statement of profit or loss and other comprehensive income because it excludes items of income or expense that are taxable or deductible in other years and it further excludes items that are not taxable or tax deductible. The Group's liability for current tax (and tax laws) is calculated using tax rates that have been enacted or substantively enacted in countries where the Company and its subsidiaries operate by the end of the reporting period.

Deferred tax is recognized on temporary differences between the carrying amounts of assets and liabilities in the financial statements and the corresponding tax bases used in the computation of taxable profit. Deferred tax liabilities are generally recognized for all taxable temporary differences and deferred tax assets are recognized to the extent that it is probable that taxable profits will be available against which deductible temporary differences can be utilised.

Deferred tax liabilities are recognized for taxable temporary differences arising on investments in subsidiaries, except where the Group is able to control the reversal of the temporary difference and it is probable that the temporary difference will not reverse in the foreseeable future. Deferred tax assets arising from deductible temporary differences associated with such investments and interests are only recognized to the extent that it is probable that there will be sufficient taxable profits against which to utilise the benefits of the temporary differences and they are expected to reverse in the foreseeable future.

The carrying amount of deferred tax assets is reviewed at the end of each reporting period and reduced to the extent that it is no longer probable that sufficient taxable profits will be available to allow all or part of the asset to be recovered.

Deferred tax is calculated at the tax rates that are expected to apply in the period when the liability is settled or the asset realised based on the tax rates (and tax laws) that have been enacted or substantively enacted by the end of the reporting period.

Deferred tax assets and liabilities are offset when there is a legally enforceable right to set off current tax assets against current tax liabilities and when they relate to income taxes levied by the same taxation authority and the Group intends to settle its current tax assets and liabilities on a net basis.

Current and deferred tax are recognized as an expense or income in profit or loss, except when they relate to items credited or debited outside profit or loss (either in other comprehensive income or directly in equity), in which case the tax is also recognized outside profit or loss (either in other comprehensive income or directly in equity, respectively).

CASH AND CASH EQUIVALENTS IN THE STATEMENT OF CASH FLOWS

Cash and cash equivalents comprise cash in hand and at bank and other short term deposits held by the Group with maturities of less than 3 months.

4. CRITICAL ACCOUNTING JUDGMENTS AND KEY SOURCES OF ESTIMATION UNCERTAINTY

In the application of the Group's accounting policies, management is required to make judgments, estimates and assumptions about the carrying amounts of assets and liabilities that are not readily apparent from other sources. The estimates and associated assumptions are based on historical experience and other factors that are considered to be relevant. Actual results may differ from these estimates.

The estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which the estimate is revised if the revision affects only that period, or in the period of the revision and future periods if the revision affects both current and future periods.

In particular the Group has identified the following areas where significant judgments, estimates and assumptions are required. Changes in these assumptions may materially affect the financial position or financial results reported in future periods. Further information on each of these areas and how they impact the various accounting policies are described below and also in the relevant notes to the financial statements.

a) Farm-in arrangements and/or assignment of interests

The Group accounts for farm-in arrangements by considering if the acquired or transferred interest relates to that of an asset or of a business as defined in IFRS 3 *Business Combinations.* Accordingly, the Group would consider if there is existence of business elements (e.g., inputs, processes and outputs) or a group of assets that includes inputs, outputs and processes that are capable of being managed together for providing a return to investors or other economic benefits. The Group is of the view that the acquisitions of Stag Oilfield (Note 7) and Ogan Komering PSC (Note 8) during the year meet the definition of a business. Accordingly, they have been accounted for as business combinations.

The Group considers farm-in arrangements that pertain to exploration interests with no production license and no proved reserves to be assets rather than of a business and would account for such farm-ins based on the consideration paid which would be capitalized as an intangible exploration asset and subject to impairment reviews.

b) Carrying value of oil and gas properties

Oil and gas properties are depreciated using the unit of production.

The calculation of the unit of production rate of amortisation could be impacted to the extent that actual production in the future is different from current forecast production based on proved and probable reserves. This would generally result from significant changes in any of the factors or assumptions used in estimating reserves.

These factors could include:

- changes in proved and probable reserves;
- the effect on proved and probable reserves of differences between actual commodity prices and commodity price assumptions;
- future estimates of capital expenditure requirements; and
- unforeseen operational issues.

The carrying amount of oil and gas properties at March 31, 2017 is shown in Note 16.

c) Share-based payments

The Group measures the cost of equity-settled transactions by reference to the fair value of the share options at the date on which they are granted. Judgment is required in determining the most appropriate valuation model for the share options granted, depending on the terms and conditions of the grant. Management is also required to use judgment in determining the most appropriate inputs to the valuation model including expected life of the option, volatility and dividend yield.

d) Intangible exploration assets

The application of the Group's accounting policy for intangible exploration assets requires judgment to determine whether it is likely that future economic benefits are likely, either from future exploitation or sale, or whether activities have not reached a stage which permits a reasonable assessment of the existence of reserves. The determination of reserves and resources is itself an estimation process that requires varying degrees of uncertainty depending on how the resources are classified. These estimates directly impact when the Group defers intangible exploration assets. The deferral policy requires management to make certain estimates and assumptions as to future events and circumstances, in particular, whether an economical viable extraction can be established. Any such estimates and assumptions may change as new information becomes available. If after expenditure is capitalized, information becomes available suggesting that the recovery of the expenditure is unlikely, the relevant capitalized amount is written off in profit or loss in the period when the new information becomes available. The carrying amounts of intangible exploration assets are disclosed in Note 15 to the financial statements.

e) Taxes

The Group recognises the net future economic benefit to deferred tax assets to the extent that it is probable that the deductible temporary differences will reverse in the foreseeable future. Assessing the recoverability of deferred income tax assets requires the Group to make significant estimates related to expectations of future taxable income. Estimates of future taxable income are based on forecast cash flows from operations and the application of existing tax laws in each jurisdiction. To the extent that future cash flows and taxable income differ significantly from estimates, the ability of the Group to realise the net deferred tax assets as recorded in the statement of financial position could be impacted. The carrying amounts of Group's deferred tax assets are disclosed in Note 17 to the financial statements.

f) Reserve Estimates

The estimated reserves are management assessments and take into consideration reviews by an independent third party, under the Group's reserves audit programme, as well as other assumptions, interpretations and assessments.

These include assumptions regarding commodity prices, exchange rates, discount rates, future production and transportation costs, and interpretations of geological and geophysical models to make assessments of the quality of reservoirs and their anticipated recoveries. Changes in reported reserves can impact asset carrying values, the provision for restoration and the recognition of deferred tax assets, due to changes in expected future cash flows. Reserves are integral to the amount of depreciation, depletion and amortisation charged to the statement of comprehensive income and the calculation of inventory.

g) Impairment of Assets

The Group undertakes a regular review of asset carrying values to determine whether there is any indication of impairment. For oil and gas properties, expected future cash flow estimation is based on reserves, future production profiles, commodity prices and costs. The carrying amounts of intangible exploration assets and oil and gas properties are disclosed in Notes 15 and 16 respectively.

h) Asset Restoration Obligations

The Group estimates the future removal and restoration costs of oil production facilities, wells, pipelines and related assets at the time of installation of the assets. In most instances the removal of these assets will occur many years in the future. The estimate of future removal costs are made considering relevant legislation and industry practice and require management to make judgments regarding the removal date, the extent of restoration activities required and future removal technologies. The carrying amounts of Group's asset restoration obligations is disclosed in Note 25 to the financial statements.

5. REVENUE

	2017 US$000	2016 US$000
Oil Revenue		
- Stag Oilfield	33,135	-
- Ogan Komering	1,416	-
Gas Revenue		
- Ogan Komering	591	-
Total Revenue	35,142	-
Average realised price:		
Crude Oil– Stag (US$/bbl)	51.67	-
Crude Oil– Ogan Komering (US$/bbl)	47.07	-
Gas – Ogan Komering (US$/mmbtu)	6.30	-
Average production:		
Crude Oil and condensate – Stag (bopd)	2,520	-
Crude Oil and condensate – Ogan Komering (bopd)	970	-
Gas – Ogan Komering (mmbtu/day)	3,025	-

6. COST OF SALES

	2017 US$000	2016 US$000
Cost of operations – Stag	35,571	-
Depletion and amortisation (Note 16)	3,838	-
	39,409	-
Cost of operations – Ogan Komering	1,421	-
	40,830	-

7. ACQUISITION OF STAG OILFIELD

As detailed in Note 2b to the Financial Statements, on November 11, 2016, Jadestone Energy (Australia) Pty Ltd, as buyer, and Jadestone as guarantor, satisfied the conditions precedent to closing the Stag Oilfield acquisition, resulting in the purchase of the Stag Oilfield. As the Stag Oilfield meets the definition of a business under *IFRS3 Business Combinations* ("IFRS 3"), the acquisition has been accounted for as a business combination. In accordance with the requirement of IFRS 3, the transaction has been accounted for using the acquisition method that requires the net assets acquired to be recorded at fair value.

The following table summarises the net assets acquired and the consideration paid pursuant to the acquisition. The amounts are estimates made by management at the time of preparation of these financial statements. Amendments may be made to these amounts as values subject to estimate are finalised.

	Provisional fair value November 11, 2016 US$000
Assets	
Current Assets	
Cash and cash equivalents	1,372
Other receivables	419
Inventory - materials	4,668
Inventory - crude oil on hand	17,962
	24,421
Non-Current Assets	
Oil and Gas properties	66,880
Deferred PRRT Tax Asset	19,086
	85,966
Total Assets	110,387
Liabilities	
Current Liabilities	
Trade and other payables	(3,046)
Provisions	(1,328)
	(4,374)
Non-Current Liabilities	
Asset Restoration Obligations	(79,207)
Other provisions	(6,940)
	(86,147)
Total Liabilities	90,521
Net identifiable assets acquired	19,866
Total consideration	**19,866**
Consideration transferred:	
Purchase consideration	10,000
Working capital adjustments	9,866
Total consideration	**19,866**
Cash acquired	(1,372)
Net cash flows	18,494

The results of operations from the Stag Oilfield have been included in the Group's consolidated statement of profit and loss and other comprehensive income effective November 11, 2016.

With regards to the impact of the acquisition on the results of the Group as though it was acquired on April 1, 2016, it is impracticable to disclose the pro-forma information as the data was not collected in the relevant period in a way that was consistent with the Group's accounting policies.

8. ACQUISITION OF OGAN KOMERING PRODUCTION SHARING CONTRACT ("OK PSC")

As detailed in Note 2c to the Financial Statements, on March 9, 2017, Jadestone Energy International Holdings Inc., as buyer, and Jadestone Energy Limited as guarantor, have signed a definitive SPA with Repsol, as seller, for the acquisition of all issued and outstanding shares in Talisman (Ogan Komering) Ltd, resulting in the purchase of the OK PSC. As the OK PSC meets the definition of a business under *IFRS3 Business Combinations* ("IFRS 3"), the acquisition has been accounted for as a business combination. In accordance with the requirement of IFRS 3, the transaction has been accounted for using the acquisition method that requires the net assets acquired to be recorded at fair value. The following table summarises the net assets acquired and the consideration paid pursuant to the acquisition.

	Provisional fair value March 9, 2017 US$000
Assets	
Current Assets	
Inventory - materials	154
Other receivables and prepayments	4,507
	4,661
Non-Current Assets	
Oil and gas properties	3,705
Restricted cash	669
	4,374
Total Assets	9,035
Liabilities	
Current Liabilities	
Deferred tax liabilities	(1,200)
Other payables and accruals	(3,979)
Total Liabilities	(5,179)
Net identifiable assets acquired	3,856
Total consideration	**1,641**
Consideration transferred:	
Base purchase consideration	5,800
Working capital adjustments	(1,944)
Purchase discount	(2,215)
Total consideration	**1,641**

The purchase discount of $2,215,000 arose after taking into account the positive working capital movement favouring the Company, under the locked box mechanism embedded in the SPA. Under the locked box mechanism, the valuation of the target business is based on historic reference accounts and is fixed as at an historic reference date. All subsequent economic upside (and downside) in the business since that reference date to the time of financial closure of the transaction is for the account of the buyer.

The results of operations from the Ogan Komering have been included in the Group's consolidated statement of profit and loss and other comprehensive income effective March 9, 2017.

With regards to the impact of the acquisition on the results of the Group as though it was acquired on April 1, 2016, it is impracticable to disclose the pro-forma information as the data was not collected in the relevant period in a way that was consistent with the Group's accounting policies.

9. NON-CASH LOSS ON COMPLETION OF TRANSACTION

Pursuant to the Transaction (see Note 2d), the Company acquired all of the outstanding shares of MEL based on the exchange ratio set out in the Scheme of Arrangement. Following the completion of the Transaction, MEL became a fully owned subsidiary of the Company. The Transaction constituted a reverse takeover transaction of Petra by MEL pursuant to TSX-V Policy 5.2, Change of Business and Reverse Takeovers.

As Petra did not meet the definition of a business under IFRS, accordingly the Transaction was outside the scope of IFRS 3 *Business Combinations* and has been accounted for as a capital transaction under IFRS 2 *Share-based Payment*. Under this basis of accounting, the consolidated entity is considered to be a continuation of MEL, with the net identifiable assets of Petra deemed to have been acquired by MEL.

The deemed purchase price paid for the acquisition of Petra by MEL is the fair value of the 17,429,962 Post-Consolidation Petra Shares on issue valued at C$1.82 (US$1.43) per share, being US$25,000,000.

The fair value of the shares was allocated to the fair value of the net assets acquired as follows, resulting in a non-cash accounting loss on completion of the transaction of US$17,514,590 in the current period:

	US$000
Cash and cash equivalents	2,558
Bridge loan receivables	5,344
Other receivables	78
Other payables	(495)
Net assets acquired	7,485
Fair value of consideration paid	(25,000)
Non-cash loss on completion of the Transaction	(17,515)

In addition, Transaction costs of US$468,000 comprising legal fees were incurred and recorded in share capital as Transaction costs.

10. STAFF COSTS

	2017 US$000	2016 US$000
The aggregate remuneration for the above persons comprised:		
Staff costs for the above persons:		
Wages, salaries and fees	6,767	5,816
Termination payments	3,093	294
Others	842	-
	10,702	6,110
Share-based compensation (Note 24)	103	1,478
	10,805	7,588

The Group has capitalized US$1,537,500 (2016: US$1,906,148) in respect of staff costs as part of intangible exploration assets as these relate to time costs that are directly attributable to the active blocks for the year ended March 31, 2017.

Share-based payment expense (related to share options) in respect of the directors for the year ended March 31, 2017 amounted to US$81,846 (2016: US$483,821).

11. OTHER OPERATING EXPENSES

	2017 US$000	2016 US$000
Office costs	1,793	2,453
Professional fees / consultancies	4,810	1,716
Participating interest tax and branch profit tax	333	-
Operator G&A	176	-
Travel & subsistence	493	444
Time costs – recovery	(2,049)	(2,696)
Administrative overhead	759	730
Others	534	-
	6,849	2,647

12. FINANCE COSTS

	2017 US$000	2016 US$000
Accretion expense (Note 25)	680	-
Standby fee on undrawn convertible bonds (Note 29)	115	-
Professional fees	893	-
Interest on premium funding	7	-
Interest on convertible bonds	-	608
	1,695	608

13. TAXATION

	2017 US$000	2016 US$000
PRRT tax - deferred	1,650	-
Corporate income tax - current	217	-
	1,867	-

The Australian corporate income tax rate is applied at 30% and PRRT at 40%. The above movement in deferred tax balances relates to temporary differences between the tax base of an asset or liability and its carrying amount in the statement of financial position.

The Indonesian corporate income tax rate is applied at 35%. Branch profit tax is applied at 20%.

The Company is resident in the Province of British Columbia and pays no tax on its losses. Subsidiary companies are resident for tax purposes in the territories in which they operate. No tax arises in the current or previous year from any of the subsidiaries' operations in view of the losses incurred.

The tax expense on loss differs from the amount that would arise using the standard rate of income tax applicable in the countries of operation of the various Group companies as explained below:

	2017 US$000	2016 US$000
Loss before tax	(33,204)	(19,207)
Tax calculated at domestic tax rates applicable to loss in the respective countries	(5,917)	(3,951)
Effects of non-deductible expenses	5,646	4,931
Effects of non-taxable income	(600)	(2,454)
Effects of tax losses not recognized	2,738	1,474
Tax expense	1,867	-

No deferred tax asset has been recognized in respect of tax losses arising in any of the countries in which the Group is active due to the uncertainty of the timing of its potential recovery.

14. LOSS PER ORDINARY SHARE

The calculation of the basic and diluted loss per share is based on the following data:

	2017 US$000	2016 US$000
Loss for the purpose of basic and diluted per share, being the net loss for the year attributable to equity holders of the parent	(35,071)	(19,207)
Number of shares	No.	No.
Weighted average number of ordinary shares for the purposes of basic loss per share	140,941,566	84,043,280

Diluted loss per share is calculated based on the weighted average number of ordinary shares outstanding during the year plus the weighted number of shares that would be issued on the conversion of all potentially dilutive shares to ordinary shares. Where the impact of converted shares would be anti-dilutive, these are excluded from the calculation.

Since the conversion of potential ordinary shares to ordinary shares from share options (see Note 24) would decrease the loss per share, they are not dilutive. Accordingly, diluted loss per share is the same as basic loss per share.

15. INTANGIBLE EXPLORATION ASSETS

	Total US$000
Cost:	
At April 1, 2015	186,121
Additions	8,691
At March 31, 2016	194,812
Additions	3,688
At March 31, 2017	198,500
Impairment:	
At March 31, 2015 and March 31, 2016	85,059
Charged to profit or loss	8,512
At March 31, 2017	93,571
Net book value:	
At March 31, 2017	104,929
At March 31, 2016	109,753

For the purpose of statement of cash flows, intangible exploration assets of US$327,862 (2016: US$874,753) remained unpaid as at March 31, 2017.

During the year, as part of implementing the Group's formulated new strategy, the Group performed reviews of its exploration assets. As a result of the reviews, the Group had decided to relinquish Vietnam PSC MVHN/12KS and Bone PSC (Note 35). Accordingly, the Group has fully impaired the Blocks, resulted in an impairment charge of US$2,561,611 and US$5,950,484 respectively.

16. OIL AND GAS PROPERTIES

	Total US$000
Cost:	
At April 1, 2016/2015	-
Arising from acquisition of businesses	70,585
Additions	288
At March 31, 2017	70,873
Accumulated depletion and amortisation:	
At April 1, 2016/2015	-
Depletion and amortisation for the year	3,838
At March 31, 2017	3,838
Accumulated provision for asset restoration obligations (Note 25):	
At April 1, 2016/2015	-
Additions	2,701
At March 31, 2017	2,701
Net book value:	
At March 31, 2017	64,334
At March 31, 2016	-

17. DEFERRED TAX ASSETS

	Total US$000
PRRT Tax:	
At April 1, 2016/2015	-
Acquisition of Stag Oilfield (Note 7)	19,086
Credit during the year	(1,650)
Foreign currency translation	105
At March 31, 2017	17,541

18. PLANT AND EQUIPMENT

	Computer equipment US$000	Fixtures and equipment US$000	Motor vehicles US$000	Total US$000
Cost:				
At April 1, 2015	418	860	56	1,334
Additions	127	-	-	127
At March 31, 2016	545	860	56	1,461
Additions	561	71	-	632
At March 31, 2017	1,106	931	56	2,093
Accumulated depreciation:				
At April 1, 2015	413	860	56	1,329
Charge for the year	26	-	-	26
At March 31, 2016	439	860	56	1,355
Charge for the year	53	5	-	58
At March 31, 2017	492	865	56	1,413
Net book value:				
At March 31, 2017	614	66	-	680
At March 31, 2016	106	-	-	106

19. INVESTMENT IN SUBSIDIARIES AND INTEREST IN JOINT OPERATIONS

The succeeding sections present the details of the subsidiaries and joint operations of the Group.

A. Details of the investments in which the Group holds 20% or more of the nominal value of any class of share capital at March 31, 2017 are as follows:

Name of company:	Place of Incorporation	% voting rights and shares held		Nature of business
		As at Mar 31, 2017 %	As at Mar 31, 2016 %	
Jadestone Energy (Australia) Pty Ltd	Australia	100	-	Production of oil
Jadestone Energy International Holdings Inc.	Canada	100	-	Investment holdings
Jadestone Energy (Ogan Komering) Ltd	Canada	100	-	Production of oil and gas
Jadestone Energy Limited (formerly Mitra Energy Limited)	Bermuda	100	100	Investment Holdings
Mitra Energy Biliton Pte. Ltd.	Singapore	100	100	Exploration
Mitra Energy (Philippines SC-56) Ltd.	Bermuda	100	100	Exploration
Mitra Energy (Philippines SC-57) Ltd.	British Virgin Islands (“BVI”)	100	100	Exploration
Mitra Energy (Indonesia Sibaru) Ltd.	Bermuda	100	100	Exploration
Jadestone Energy (Holdings) Ltd. (Formerly Mitra Energy (Holdings) Ltd.)	BVI	100	100	Dormant
Mitra Energy (Services) Ltd.	BVI	100	100	Dormant
Mitra Energy (Indonesia Bone) Limited	BVI	100	100	Exploration
Mitra Energy (Vietnam Con Son) Ltd.	Bermuda	100	100	Exploration
Titan Resources (Natuna) Indonesia Limited	Bermuda	100	100	Exploration
Jadestone Energy (Singapore) Pte Ltd. (formerly Mitra Energy (Singapore) Pte Ltd.)	Singapore	100	100	Investment holdings
Mitra Energy (Vietnam Phu Quy) Pte Ltd.	Singapore	100	100	Exploration
Mitra Energy (Vietnam Rang Dong) Pte Ltd.	Singapore	100	100	Exploration
Mitra Energy (Vietnam Nam Du) Pte Ltd.	Singapore	100	100	Exploration
Mitra Energy (Vietnam Tho Chu) Pte Ltd.	Singapore	100	100	Exploration
Mitra Energy (Vietnam Minh Hai) Pte Ltd.	Singapore	100	100	Exploration
Titan Resources (Natuna) Indonesia Ltd.	Barbados	100	100	Exploration
Mitra Energy (Vietnam Song Tu) Pte Ltd.	Singapore	100	100	Dormant
Mitra Energy (Indonesia North Madura) Pte Ltd.	Bermuda	100	100	Exploration
Mitra Energy (Indonesia Titan) Pte Ltd.	Bermuda	100	100	Exploration
Mitra Energy (Indonesia Spermonde) Ltd.	Bermuda	100	100	Exploration
Mitra Energy (Indonesia NV) Ltd. (formerly Mitra Energy (Indonesia Salayar) Ltd.)	Bermuda	100	100	Exploration
Mitra Energy (Vietnam Thanh Long) Pte Ltd.	Singapore	100	100	Exploration
Mitra Energy (Vietnam Phu Khanh) Pte Ltd.	Singapore	100	100	Exploration
Jadestone Energy Sdn Bhd (formerly Mitra Energy Sdn Bhd)	Malaysia	100	100	Administration
Mitra Energy (Vietnam Song Hong) Pte Ltd.	Singapore	100	100	Exploration
Mitra Energy (Indonesia Rombebai) Limited	Bermuda	100	100	Exploration

B. Details of the joint operations, of which all are in exploration stage except for Stag Oilfield and Ogan Komering which are in production stage, as at March 31, 2017 are as follows:

Contract area	Date of Expiry	Held by	Place of Operation	Group Effective Working Interest As at Mar 31, 2017 %	Group Effective Working Interest As at Mar 31, 2016 %
Stag Oilfield	Aug 25, 2018[9]	Jadestone Energy (Australia) Pty Ltd	Australia	100	-
Ogan Komering	Feb 28, 2018	Jadestone Energy (Ogan Komering) Ltd	Indonesia	50	-
SC56	Aug 4, 2055	Mitra Energy (Philippines SC-56) Ltd	Philippines	25	25
SC57	Sep 14, 2055	Mitra Energy (Philippines SC-57) Ltd	Philippines	21	21
51	Jun 10, 2040	Mitra Energy (Vietnam Tho Chu) Pte Ltd	Vietnam	70[1][2]	70[1][2]
46/07	Jun 29, 2035	Mitra Energy (Vietnam Nam Du) Pte Ltd	Vietnam	70[1]	70[1]
45	Dec 26, 2041	Mitra Energy (Vietnam Minh Hai) Pte Ltd	Vietnam	70	70
127[7]	May 24, 2042	Mitra Energy (Vietnam Phu Khanh) Pte Ltd	Vietnam	100	100
MVHN/12KS[8]	Feb 19, 2043	Mitra Energy (Vietnam Song Hong) Pte Ltd	Vietnam	100	100
Bone[3]	Nov 25, 2040	Mitra Energy (Indonesia Bone) Ltd	Indonesia	60[3]	60
Titan	N/a	Mitra Energy (Indonesia Titan) Limited	Indonesia	-[5]	25[4]
Sibaru	N/a	Mitra Energy (Indonesia Sibaru) Ltd	Indonesia	-[6]	100

(1) Before back-in arrangements. Mitra has an agreement with an introducing party that gives them the right to acquire at cost from Mitra a 3% interest in any commercial discovery on Vietnam Block 51 PSC and Vietnam Block PSC 46/07. Effective May 1, 2017, Petrovietnam Exploration Production Corporation ("PVEP") relinquished its 30% working interest in Block 46/07 and 51 leaving Jadestone as operator with a 100% working interest in the Blocks.

(2) On November 10, 2015, Kuwait Foreign Petroleum Exploration Company ("KUFPEC") informed the Block 51 PSC Joint Venture of their intention to withdraw from the PSC. Agreement has been subsequently reached for Mitra to be assigned KUFPEC's full 35% working interest, taking Mitra's net working interest in Block 51 to 70%. The assignment was effective from December 31, 2015. Final government approval was received on July 21, 2016, followed by an amended Investment Certificate issued and approved by Vietnam Ministry of Industry and Trade on August 3, 2016.

(3) On May 4, 2017, Mitra signed a Withdrawal Agreement with Azimuth Indonesia Ltd. ("Azimuth") to transfer Mitra's 60% working interest and operatorship of Bone PSC to Azimuth. The transfer was effective from April 15, 2017, but remains subject to final government approval (Note 35).

(4) On October 23, 2015 Mitra (Indonesia – Titan) Ltd. signed an agreement with AWE (Titan) NZ Limited that releases the company from any future liabilities under the PSC up to the point of final relinquishment.

(5) On August 1, 2016, the relinquishment was approved by SKKMIGAS. Consequently, Jadestone no longer has an interest in the Titan PSC.

(6) Notice of relinquishment submitted to SKKMIGAS April 24, 2015. The final relinquishment of PSC was approved on December 29, 2016. Consequently, Jadestone no longer has an interest in the Sibaru PSC.

(7) A one year extension of Exploration Phase 1 to May 2018 was approved by the Prime Minister of Vietnam in May 2017.

(8) The approval for relinquishment by the Government was received on June 30, 2017.

(9) Management has assessed and considered the renewal process of the license perfunctory in nature as long as the management comply with the terms of the license.

20. INVENTORIES

	2017 US$000	2016 US$000
Materials and spare parts: SEA portfolio	204	1,907
Materials and spare parts: Stag operation	5,402	-
Crude oil on hand: Stag operation	5,197	-
At March 31	10,803	1,907

The cost of inventories recognized in cost of sales includes $713,000 (2016: US$Nil) in respect of write-downs of inventory to net realizable value. An impairment of US$1,717,000 (2016: US$Nil) was recognised during the year against materials and spare parts: SEA portfolio, to lower the balance to net realisable value.

21. RECEIVABLES AND PREPAYMENTS

	2017 US$000	2016 US$000
Due within one year:		
Amount due from Partners [1]	742	57
Share of joint venture receivables (trade)	3,101	-
Accrued cash call receivables	2,403	-
Prepaid facility expenses (Note 29)	560	-
Prepaid asset insurance	519	-
GST/value added tax receivables	737	381
Other receivables	85	182
Oher deposits	382	-
Other prepayments	424	339
At March 31	8,953	959

(1) “Partners” is a party to a contractual agreement under the Production Sharing Contract (“PSC”) and petroleum concession with relevant Government Authorities in Philippines, Vietnam and Indonesia.

22. CASH AND CASH EQUIVALENTS

	2017 US$000	2016 US$000
Cash at bank	14,478	9,117
Restricted cash:		
- Decommissioning sinking funds	669	-
Total	15,147	9,117
Less: Restricted cash	(669)	-
	14,478	9,117

The restricted cash as at March 31, 2017 is a result of the acquisition of Ogan Komering (Note 8).

Cash at bank earns interest at floating rates based on daily bank deposit rates.

23. SHARE CAPITAL

Authorised ordinary shares:

Unlimited number of common voting shares with no par value.

Allotted and outstanding:

	No. Shares	US$000
At April 1, 2016	88,098,004	324,748
New equity shares (private placement)	133,200,000	39,805
Share issue costs	-	(87)
	221,298,004	364,466

The holders of ordinary shares are entitled to receive dividends as and when declared by the Company. Fully paid ordinary shares carry one vote per share without restriction and carry a right to dividends as and when declared by the Company.

Upon their appointment, A. Paul Blakeley and Michael Horn participated in a private placement for a total of 700,000 common shares at a price of C$0.49 per common share, totalling gross proceeds of C$343,000 (US$262,574).

On November 8, 2016, Jadestone completed the non-brokered Private Placement of 132,500,000 common shares (each, a “Share”) at a price per Share of C$0.40 for gross proceeds of C$53,000,000 (US$39,542,228), which included C$550,000 (US$410,344) being subscribed by A. Paul Blakeley, Michael Horn, Eric Schwitzer and Robert Lambert for a total of 1,375,000 common shares at a price of C$0.40 per common share.

24. SHARE-BASED PAYMENT AND WARRANTS

On June 7, 2016, the Company granted 500,000 stock options to A. Paul Blakeley and 250,000 stock options to Michael Horn with an exercise price of C$0.49, which are exercisable for 10 years.

On March 28, 2017, the Company granted an aggregate of 6,500,000 incentive stock options to a number of employees, Officers and Directors exercisable for a period of ten years at an exercise price of C$0.47 per share.

The total expense arising from share-based payment recognized for the year ended March 31, 2017 was US$102,906 (2016: US$1,478,392).

In the previous financial year, as part of the closing of the Transaction (see Note 2d) on April 21, 2015, the Company issued 234,641 warrants with an exercise price of C$3.24 in exchange for the cancellation of 375,000 post-consolidation warrants in MEL and has agreed to assume 135,570 share options in exchange for 216,666 post-consolidation share options in MEL. In addition to this, 1,082,000 post-consolidation share options of MEL, held by directors and employees, have been cancelled and replaced with an award of 6,377,821 new options in the Company, which vest immediately and are exercisable at C$1.82 for a period of ten years.

On August 19, 2015, the Company adopted, as approved by shareholders, a stock incentive plan (the “Plan”) which establishes a rolling number of shares issuable under the plan in the amount of 10% of the Company’s issued shares at the date of grant. Under the terms of the Plan, the exercise price of each option granted cannot be less than the market price of at the date of grant, or such other price as may be required by TSX-V. Options under the plan can have a term of up to 10 years with vesting provisions determined by the directors in accordance with TSX-V policies for Tier 2 Issuers.

The Black-Scholes option-pricing model, with the following assumptions, was used to estimate the fair value of the options at the date of grant:

	Options Granted on March 28, 2017	Options Granted on June 8, 2016	Options Granted on April 21, 2015
Risk-free interest rate	1.11% to 1.21%	0.70% to 0.83%	0.89%
Expected life	5.5 to 6.5 years	5.5 to 6.5 years	5 years
Expected volatility	41.6% to 42.8%	42.1% to 42.7%	37.7%
Share price	C$0.45	C$0.49	C$1.25
Exercise price	C$0.47	C$0.49	C$1.82
Expected dividends	Nil	Nil	Nil

The following table summarizes the share options outstanding and exercisable as at March 31, 2017:

	Share options			
	Number of options	Weighted average exercise price C$/US$	Weighted average remaining contract life	Number of options exercisable
As at April 1, 2015	1,298,666	14.98(1)	6.66	981,499
Cancellation of options held by MEL Directors and employees	(1,082,000)	14.98(1)	6.45	(948,830)
Continuing options as at April 21, 2015	216,666	14.99(1)	7.39	214,583
Continuing share options assumed by the Company	135,570	29.47(2)	0.06	134,267
Petra share options	972,500(3)	1.89(2)	0.37	972,500
New share options issued	6,377,821	1.82(2)	8.52	6,377,821
Cancelled during the year	(85,000)	1.32(2)	-	(85,000)
As at March 31, 2016	7,400,891	2.34(2)	7.36	7,399,588
New share options issued	7,250,000	0.47(2)	9.92	-
Cancelled during the year	(4,223,070)	2.72(2)	-	(4,221,767)
As at March 31, 2017	10,427,821	0.88(2)	7.62	3,177,821

(1) US$
(2) C$
(3) Being 3,890,000 Petra shares options post 1 for 4 share consolidation.

The following table summarizes the share warrants outstanding and exercisable as at March 31, 2017:

	Share warrants			
	Number of warrants	Weighted average exercise price C$/US$	Weighted average remaining contract life	Number of warrants exercisable
As at April 1, 2015	375,000	1.60 (3)	n/a (2)	375,000
Cancellation of MEL's warrants	(375,000)	1.60 (3)	n/a (2)	(375,000)
Issue of warrants	234,641 (1)	3.24 (4)	1.08	234,641
As at March 31, 2016	234,641	3.24 (4)	1.08	234,641
As at March 31, 2017	234,641	3.24 (4)	0.08	234,641

(1) Being 375,000 warrants multiplied by 0.62571, the share exchange ratio of a company share for each MEL share per the terms of the Arrangement (see Note 2).
(2) Expiry of warrants was scheduled to be on the second anniversary of admission to an approved stock exchange.
(3) US$
(4) C$

25. PROVISION FOR ASSET RESTORATION OBLIGATIONS

	Total US$000
Non-Current:	
At April 1, 2016/2015	-
Acquisition of Stag Oilfield (Note 7)	79,207
Accretion expenses (Note 12)	680
Changes in discount rate and foreign exchange rate as at 31 March 2017	(2,701)
At March 31, 2017	77,186

The Group's Asset Restoration Obligations ("ARO") result from the future costs of decommissioning the Stag Oilfield facilities which are expected to be incurred up to 2033. The balance of the provision is the discounted present value of the estimated future cost, which has been assessed by an independent third party at the time of the acquisition. The present value of the Australian ARO has been calculated based on the estimated Australian risk free rate of 2.7% as at March 31, 2017.

26. OTHER PROVISIONS

	Total US$000
Non-Current:	
At April 1, 2016/2015	-
Acquisition of Stag Oilfield (Note 7)	6,940
Changes in discount rate and foreign exchange rate as at 31 March 2017	(22)
At March 31, 2017	6,918

This provision relates to long-term liabilities associated with the Stag leased floating storage and offloading ("FSO") vessel. The present value of the provisions have been calculated based on the estimated Australian risk free rate of 2.7% as at March 31, 2017.

27. BORROWINGS

	2017 US$000	2016 US$000
Current:		
Insurance premium funding	435	-

During the period Jadestone Energy (Australia) Pty Ltd entered into a borrowing arrangement related to insurance premium funding. The borrowing has an effective interest rate of 5.56%. No security or charges over property are in place for this arrangement.

28. TRADE & OTHER PAYABLES, ACCRUALS AND PROVISIONS

	2017 US$000	2016 US$000
Current:		
Trade payables	2,619	-
Amount due to Partners[1]	6	245
Other payables	704	928
Accruals – finance costs	893	-
Accruals – others	7,165	1,301
Provision for long service leave	815	-
Other provisions	328	-
	12,530	2,474

(1) "Partners" is a party to a contractual agreement under the PSC and petroleum concession with relevant Government Authorities in Philippines, Vietnam and Indonesia.

These amounts are non-interest bearing and repayable on demand. Payables are normally settled on 30 days terms.

29. SECURED AND UNSECURED CONVERTIBLE BONDS

In conjunction with the Private Placement, on November 8, 2016, Jadestone entered into a US$28 million convertible debt facility (the "Facility") with Tyrus Capital Event S.à.r.l. ("Tyrus"). Under the terms of the Facility, Jadestone will have the ability to drawdown tranches of US$5 million, subject to Tyrus' approval, and any amounts drawn down will bear interest at the rate of 7.5% per annum, payable quarterly in cash, and a 3% issue discount.

Pursuant to the establishment of the Facility, Jadestone paid a structuring fee equal to 2% of the total amount of the Facility. In addition to this charge, Jadestone is required to pay a standby fee equal to 1% per annum on all undrawn amounts to be paid quarterly in cash until maturity. The Facility will mature after three years, at which time Tyrus will have the option to convert the full amount of any principal owing under the Facility into common shares of the Company at a conversion price of C$0.50. Tyrus also has the option to convert any principal owing under the Facility at any time prior to maturity and the option to require the Company to draw down all undrawn amounts at any time prior to 15 days from maturity.

As at March 31, 2017, the Company has not drawn down on the Facility and as such no liabilities are recognised in the financial statements as at March 31, 2017, relating to the Facility. The structuring fee of US$560,000 has been capitalized in the financial statements as a prepaid expense (see Note 21 to the Financial Statements). The standby fees paid by the Company amounting US$114,943 as at March 31, 2017 have been included as Finance Costs (see Note 12 to the Financial Statements).

Subsequent to year end, the Company applied to draw down US$15 million from the Facility to fund capital expenditures and for related corporate purposes. By July 13, 2017 the Company had received the proceeds of this drawdown (Note 35).

30. FINANCIAL INSTRUMENTS, FINANCIAL RISKS AND CAPITAL MANAGEMENTS

Categories of financial instruments

	2017 US$000	2016 US$000
Financial assets		
Loans and receivables (including cash and cash equivalents)	21,191	9,356
Financial liabilities		
Amortised cost	97,069	2,474

Financial Instruments

The Group's financial instruments that are not measured at fair value of comprise cash and bank balances, other receivables, other payables and accruals. As at March 31, 2017 management considers that the carrying amounts of financial assets and financial liabilities in the financial statements approximate their fair value.

Fair values are based on management's best estimates after consideration of current market conditions. The estimates are subjective and involve judgment and as such are not necessarily indicative of the amount that the Group may incur in actual market transactions.

Commodity Price Risk

The Group has exposure to price risk in its exploration and production of oil and gas business. Jadestone does not currently have in place any hedging arrangements, however the Group may consider the use of derivative financial instruments to hedge the exposure to oil and/or gas price fluctuation at any time in the future.

Commodity price sensitivity

The results of operations and cash flows of oil and gas production can vary significantly with fluctuations in the market prices of oil and/or natural gas. These are affected by factors outside the Group's control, including the market forces of supply and demand; regulatory and political actions of governments; and attempts of international cartels to control or influence prices.

At the end of reporting period, if the oil and gas price increases by 10% and all other variables were held constant, the Group's loss for the year will decrease by US$3,514,200 (2016 : US$Nil).

Foreign Currency Risk

Foreign currency risk is the risk that a variation in exchange rates between United States Dollars ("US Dollar") and foreign currencies will affect the fair value or future cash flows of the Company's financial assets or liabilities.

Cash and bank balances are generally held in the currency of likely future expenditures to minimize the impact of currency fluctuations. It is the Group's normal practice to hold the majority of funds in US Dollars in order to match the Group's revenue and expenditures. The Company's US$28.0 million convertible debt facility is a US Dollar denominated instrument.

In addition to United States Dollars, the Group transacts in various currencies, including Canadian Dollars, Singapore Dollars, Australian Dollars, Indonesian Rupiah, Vietnamese Dong, and Malaysian Ringgit. No sensitivity analysis has been prepared for carrying amounts of monetary assets and liabilities denominated in these foreign currencies as the Group does not expect any material effect arising from the effects of reasonably possible changes to the exchange rate for these foreign currencies.

Foreign denominated balances, subject to exchange rate fluctuations, at of reporting period were as follows:

	2017 US$000	2016 US$000
Cash and bank balances:		
Great Britain Pound	2	30
Malaysian Ringgit	57	259
Indonesian Rupiah	24	33
Singapore Dollar	102	45
Thailand Baht	-	6
Vietnamese Dong	153	273
Canadian Dollars	554	674

Trade and other receivables:		
Malaysian Ringgit	80	55
Indonesian Rupiah	309	128
Singapore Dollar	103	-
Vietnamese Dong	356	472
Canadian Dollars	12	12
Australian Dollars	578	-
Trade and other payables:		
Malaysian Ringgit	30	69
Indonesian Rupiah	649	46
Singapore Dollar	169	12
Vietnamese Dong	207	175
Thailand Baht	-	7
Canadian Dollars	893	-
Australian Dollars	6,007	-

Interest Rate Risk

The Group's interest rate exposure arises from some of its cash and bank balances and short-term borrowings. The Group's other financial instruments are non-interest bearing or fixed rate, and are therefore not subject to interest rate risk.

Jadestone holds some of its cash in interest bearing accounts and short-term deposits. Interest rates currently received are at historical lows. Accordingly, a downward interest rate movement would not cause significant exposure to the Group.

The balance of short term borrowings as at March 31, 2017 amounts to US$435,000 (2016: US$Nil). The 7.5% coupon on the Company's US$28 million convertible bond facility, undrawn as at March 31, 2017, is a fixed rate coupon (Note 29).

Any interest rate movement would not cause significant exposure to the Group.

Credit Risk

Credit risk represents the financial loss that the Company would suffer if a counterparty in a transaction fails to meet its obligations in accordance with the agreed terms. The Company actively manages its exposure to credit risk granting credit limits consistent with the financial strength of the counterparties and customers, requiring financial assurances as deemed necessary, reducing the amount and duration of credit exposures and close monitoring of relevant accounts. Stag Oilfield production, our largest credit risk exposure, is currently sold to an investment grade customer in the energy sector, subject to customary industry credit risk. The Group's other trade and other receivables are primarily with (i) governments for recoverable amounts of value added taxes, and with (ii) joint venture partners in the oil and gas industry.

The Group's trade receivables pertain to proceeds from oil and gas sales. The Group trades only with recognised, creditworthy third parties. Where Jadestone operates joint ventures on behalf of partners it seeks to recover the appropriate share of costs from these partners. The majority of the partners in these ventures are well established oil and gas companies. In the event of non-payment, Jadestone has recourse to increase its venture share under the operating agreements.

The maximum credit risk exposure relating to financial assets is represented by their carrying value as at the balance sheet date.

Liquidity Risk

Liquidity risk is the risk that the Company will not be able to meet all of its financial obligations as they become due. This includes the risk that the Company cannot generate sufficient cash flow from producing assets or is unable to raise further capital in order to meet its obligations. The Company manages its liquidity risk by lowering the production cost of Stag's operation significantly (with full legal ownership effective from July 10, 2017), positive cash flow from Ogan Komering, on-going cost reduction initiatives, drawing on the convertible bond facility to meet necessary capital expenditure needs, mergers and acquisition strategies, and bank balance at hand. The Company believes it has sufficient liquidity to meet all reasonable scenarios of operating and financial performance for the next 12 months.

The table below analyses the Group's financial liabilities into relevant maturity groupings at the reporting date based on the remaining period to the contractual maturity date. The amounts disclosed in the table are the contractual undiscounted cash flows. Balances due within 12 months equal their carrying balances as the impact of discounting is not significant. The maturity profile is:

	2017 US$000	2016 US$000
Less than 1 year		
Trade & other payables, accruals and provisions (Note 28)	12,530	2,474
Borrowings (Note 27)	435	-
	12,965	2,474

Upon the closing of the Transaction (see Note 2) on April 21, 2015, the Company acquired all of the outstanding Senior Unsecured Convertible Bonds of MEL. Concurrently the principal and accrued interest of the Bridge Loan became an intercompany balance between the Company and MEL.

Capital Management

The Company manages its capital structure and makes adjustments to it, based on the funds available to the Company, in order to support the acquisition, exploration and development of resource properties. Given the nature of the Company's activities, the Board of Directors does not establish quantitative return on capital criteria for management, but rather works with management to ensure that capital is managed effectively and the business has a sustainable future.

To carry-out planned assets acquisition, exploration and development, and to pay for administrative costs, the Company will spend its existing working capital and will work to raise additional funds as needed.

Management reviews its capital management approach on an ongoing basis and believes that this approach, given the relative size of the Company, is reasonable. There were no changes in the Company's approach to capital management during the financial year ended March 31, 2017. The Company is not subject to externally imposed capital requirements.

Fair value measurements

The Group discloses fair value measurements by level of the following fair value measurement hierarchy:

(i) Quoted prices (unadjusted) in active markets for identical assets or liabilities (Level 1);

(ii) Inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly (Level 2); and

(iii) Inputs for the asset or liability that are not based on observable market data (unobservable inputs) (Level 3).

The Group only measures its derivative financial instruments at fair value and that has been classified as Level 3. If one or more of the significant inputs is not based on observable market data, the instrument is included in Level 3. The financial instruments that are recorded in the Level 3 category comprise of unquoted equity investments/ liabilities. The fair values of these financial instruments are measured using valuation techniques that incorporate assumptions that are not evidenced by prices from observable current market transactions. Instead, they are based on "unobservable" inputs reflecting management's "own assumptions" about the way assets would be priced.

31. SEGMENT INFORMATION

For management purposes, the Group operates in two business segments, namely exploration and production of oil and gas. The geographic focus of the business is on SEA and Australia.

Revenue and non-current assets information based on the geographical location of assets respectively are as follows:

	Revenue		**Non-current assets**	
	Year ended March 31, 2017 US$000	Year ended March 31, 2016 US$000	As at March 31, 2017 US$000	As at March 31, 2016 US$000
Producing Assets				
Australia	33,135	-	78,781	-
SEA - Indonesia	2,007	-	4,374	5,451
Exploration and Evaluation Assets				
SEA – Vietnam	-	-	54,560	54,937
SEA - Philippines	-	-	50,369	49,365
Others	-	-	69	106
	35,142	-	188,153	109,859

	---------------Year ended March 31, 2017 ---------------				--------- Year ended March 31, 2016 -------		
	Production Assets	**Exploration Assets**	**Corporate**	**Total**	**Exploration Assets**	**Corporate**	**Total**
Revenue	35,142	-	-	35,142	-	-	-
Cost of Sales	(36,992)	-	-	(36,992)	-	-	-
Depletion and amortisation	(3,838)	-	-	(3,838)	-	-	-
GROSS LOSS	(5,688)	-	-	(5,688)	-	-	-
Staff costs	(3,675)	(2,001)	(5,026)	(10,702)	(1,161)	(4,949)	(6,110)
Other operating expenses	(3,974)	(1,736)	(1,139)	(6,849)	(1,218)	(1,429)	(2,647)
Share-based payments	(103)	-	-	(103)	-	(1,478)	(1,478)
Depreciation	(12)	-	(46)	(58)	-	(26)	(26)
Expensed exploration costs	-	(541)	-	(541)	(216)	-	(216)
Joint operator overhead charge recovered	-	780	-	780	810	-	810
Impairment of Asset	-	(8,512)	-	(8,512)	-	-	-
Impairment of Inventories	-	(1,717)	-	(1,717)	-	-	-
Gain on disposal of intangible exploration asset	-	-	-	-	125	-	125
Fair value loss on derivative financial instruments	-	-	-	-	-	(548)	(548)
Gain on acquisition of unsecured convertible bonds	-	-	-	-	-	9,439	9,439
Non-cash loss on completion of Transactions	-	-	-	-	-	(17,515)	(17,515)
Receivables written off	-	-	-	-	(51)	-	(51)
Foreign exchange loss	-	-	(339)	(339)	-	(383)	(383)
Interest income	-	-	5	5	-	1	1
Finance costs	(687)	-	(1,008)	(1,695)	-	(608)	(608)
Purchase discount	-	-	2,215	2,215	-	-	-
LOSS BEFORE TAX	(14,139)	(13,727)	(5,338)	(33,204)	(1,711)	(17,496)	(19,207)

As at March 31, 2017, revenue from one (2016: Nil) customer who domiciled in Singapore contributed to 89% (2016: Nil) of the Group's total revenue.

32. FINANCIAL COMMITMENTS

COMMITMENTS UNDER OPERATING LEASES AND EXPENSES FOR THE YEAR

The Group has recognized the following expense during the year related to operating leases:

	2017 US$000	2016 US$000
Operating lease rental:		
- Land and buildings	644	898
- Other	55	57
	699	955

The Group has entered into commercial leases as a lessee in respect of the rental of office premises, office equipment and cars. Future minimum rentals payable under non-cancellable operating leases as at year ended are as follows:

	2017 US$000	2016 US$000
Amount to be paid:		
Not later than one year	886	534
After one year but not more than five years	699	144
	1,585	678

SEA PORTFOLIO PSC OPERATIONAL COMMITMENTS

Certain PSC's and Service Concessions' have firm capital commitments where we are required to participate in minimum exploration activities. The Group has the following outstanding minimum exploration commitments:

	As at March 31, 2017 US$000	As at March 31, 2016 US$000
Not later than one year	10,000	250
After one year but not more than five years	-	10,300
	10,000	10,550

The Southeast Asia portfolio PSC operational commitments as at March 31, 2017 amounting US$10,000,000 relates to the minimum work commitment outstanding in Exploration Phase Two of the Block 46/07 PSC for the drilling of a further well.

Drilling of this well has been delayed as a result of a result of Petrovietnam Exploration Production Corporation's ODP deliberations. The Group will now seek a further extension to Exploration Phase Two of the Block 46/07 PSC in order to maintain the alignment of appraisal and development drilling.

Stag Oilfield Operational Commitments

The treated oil from the Stag Oilfield is pumped 2 kilometres to a leased FSO vessel permanently moored to a catenary anchor leg mooring buoy. The following commitments relate to the FSO facility service agreement:

	As at March 31, 2017 US$000
Not later than one year	17,424
After one year but not more than five years	91,843
After five years	21,328
	130,595

33. CONTINGENT LIABILITES

Stag Oilfield Contingent Liabilities

The Group may be responsible for certain contingent payments after 2017 of up to US$15 million which are linked to future expansion of the oilfield and oil price appreciation above agreed price levels. At this stage the Group's management does not consider it probable that the conditions necessary to trigger the contingent payments will occur. Accordingly, as at March 31, 2017, no provision has been recognised in these financial statements.

34. RELATED PARTY TRANSACTIONS

During the year, the Group entities did not enter into any transactions with related parties other than the following:

Compensation of directors and key management personnel

The remuneration of directors and other members of key management during the year was as follows:

	As at March 31, 2017 US$000	As at March 31, 2016 US$000
Short-term benefits	3,024	2,580
Other benefits	574	-
Termination payments	1,425	294
Share-based payments	94	933
	5,117	3,807

35. EVENTS AFTER THE REPORTING PERIOD

Intangible Exploration Assets

Vietnam (Malay-Tho Chu Basin)

The Company operates three PSCs (Blocks 51, 46/07 and 45) and has three gas and condensate discoveries in the area known as the Malay-Tho Chu Basin. Prior to May 1, 2017, the Company operated these three Blocks with its partner Petrovietnam Exploration Production Corporation ("PVEP") with working interests as shown in the following table:

Vietnam Malay Tho Chu Basin Assets and Working Interests as at March 31, 2017:

	Jadestone	PVEP
Block 45 PSC	70% and operator	30%
Block 46/07 PSC	70% and operator	30%
Block 51 PSC	70% and operator	30%

Effective May 1, 2017, PVEP relinquished its 30% working interest in Block 46/07 and 51 leaving the Company as operator with a 100% working interest in the Blocks.

Block 46/07 PSC

There is one remaining commitment well for Block 46/07 which is planned to be drilled as an appraisal well on the Nam Du Field to facilitate the transition of 3C to 2C resources. The well is being designed to be suspended as a potential future production well.

With the ongoing delays in the ODP approval, development drilling has been further delayed. Accordingly, Jadestone requested a further one-year extension to Exploration Phase Two on May 31, 2017. Assuming this request is accepted, Jadestone would receive a one-year further extension to June 29, 2018. Jadestone has also indicated that it intends to request an additional one-year extension prior to this latest proposed extension expiring in June 2018, so as to maintain the alignment of appraisal and development drilling.

Block 127 PSC

The Company operates Block 127 PSC with a 100% working interest. The block covers an area of over 9,000 km^2 and is located at the southern end of the Phu Khanh Basin, off the east coast of Vietnam. Jadestone made the decision in Q1 2017 to request a further one-year extension to Exploration Phase One, with no further work commitment, in order to continue farm-out efforts, or to relinquish the PSC in May 2018. Approval for this one-year extension to May 2018 was given by the Prime Minister of Vietnam in May 2017.

Block MVHN/12KS PSC

The Company operates onshore Block MVHN/12KS PSC with a 100% working interest. The block covers an onshore extension of the producing Song Hong Basin and was signed as a shale gas PSC in 2013.

In June 2016, the Company performed a review of its asset base. As a result of that review, the Company decided to relinquish Vietnam PSC MVHN/12KS at the end of Exploration Phase One, upon completion of the minimum commitment work programme. The Company informed Vietnam Oil and Gas Group (“PVN”) of its relinquishment decision on January 23, 2017 and final government approval for this relinquishment was received on June 30, 2017. Accordingly, the Company has fully impaired the Block, resulting in an impairment charge of US$2.6 million during the year.

Bone PSC

On May 4, 2017, a wholly-owned subsidiary of the Group, Mitra Energy (Indonesia Bone) Ltd, signed a Withdrawal Agreement with Azimuth Indonesia Ltd for the transfer of its 60% working interest and operatorship of Bone PSC to Azimuth (Note 19). The transfer was effective from April 15, 2017, but remains subject to final government approval.

Other Matters

On June 27, 2017, A. Paul Blakeley took on the role of Chief Executive Officer while remaining as Chairman and Michael Horn became Executive Vice President Corporate and Business Development.

During June 2017 the Company entered into discussions with Tyrus Capital Event S.à.r.l to draw down US$15 million from the convertible bond facility (Note 29), to fund capital expenditures and for related corporate purposes. By July 13, 2017 the Company had received the proceeds of this drawdown.

Appendix 3

MITRA ENERGY INC. (FORMERLY PETRA PETROLEUM INC.) AUDITED CONSOLIDATED FINANCIAL STATEMENTS FOR THE YEARS ENDED MARCH 31, 2016 AND MARCH 31, 2015

Mitra Energy Inc.

(Formerly Petra Petroleum Inc.)

CONSOLIDATED FINANCIAL STATEMENTS

for the year ended

March 31, 2016

Company Registration No. BC0350583 (Canada)

Mitra Energy Inc.

MANAGEMENT'S REPORT

The accompanying consolidated financial statements are the responsibility of management. The consolidated financial statements were prepared by management in accordance with International Financial Reporting Standards outlined in the notes to the consolidated financial statements.

Management maintains appropriate systems of internal controls. Policies and procedures are designed to give reasonable assurance that transactions are appropriately authorized, assets are safeguarded and financial records properly maintained to provide reliable information for the presentation of consolidated financial statements.

Deloitte & Touche LLP, an independent firm of chartered accountants, was appointed by the shareholders, to audit the consolidated financial statements and to provide an independent professional opinion.

The Audit Committee reviewed the consolidated financial statements with management. The Board of Directors has approved the consolidated financial statements on the recommendation of the Audit Committee.

A. Paul Blakeley
Director

W.A. Mathers

William Mathers
Chief Financial Officer

July 29, 2016

Deloitte.

Deloitte & Touche LLP
Unique Entity No. T08LL0721A
6 Shenton Way, OUE Downtown 2
#33-00
Singapore 068809

Tel: +65 6224 8288
Fax: +65 6538 6166
www.deloitte.com/sg

INDEPENDENT AUDITORS' REPORT TO THE MEMBERS OF

MITRA ENERGY INC. (FORMERLY PETRA PETROLEUM INC.)

We have audited the accompanying consolidated financial statements of Mitra Energy Inc. (formerly Petra Petroleum Inc.) (the "Company") and its subsidiaries (the "Group"), which comprise the consolidated statements of financial position as at March 31, 2016 and 2015, and the consolidated statements of profit or loss and other comprehensive income, consolidated statements of changes in equity and consolidated statements of cash flows for the years then ended, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Mitra Energy Inc. and its subsidiaries as at March 31, 2016 and 2015, and its financial performance and its cash flows for the years then ended in accordance with International Financial Reporting Standards.

Deloitte.

INDEPENDENT AUDITORS' REPORT TO THE MEMBERS OF

MITRA ENERGY INC. (FORMERLY PETRA PETROLEUM INC.)

Emphasis of Matter

We draw attention to Note 2a in the accompanying consolidated financial statements which indicates that as at March 31, 2016, the Group only has funds to finance its working capital requirements till end September 2016. The ability of the Company and the Group to continue as going concerns is dependent on the successful execution and completion of equity raising to support operations. Certain major shareholders have expressly indicated their intention to participate in the equity raising. These conditions, along with other matters as set forth in Note 2a, indicate the existence of a material uncertainty which may cast significant doubt on the Company's and the Group's ability to continue as going concerns. Our opinion is not modified in respect of this matter.

Deloitte & Touche LLP
Public Accountants and
Chartered Accountants
Singapore

July 29, 2016

Mitra Energy Inc.

CONSOLIDATED STATEMENT OF FINANCIAL POSITION
March 31, 2016

	Notes	2016	2015
		US$000	US$000
ASSETS			
Non-current assets:			
Intangible exploration assets	10	109,753	101,062
Plant and equipment	11	106	5
		109,859	101,067
Current assets:			
Inventories	13	1,907	1,907
Other receivables and prepayments	14	959	1,844
Cash at bank	15	9,117	2,207
		11,983	5,958
TOTAL ASSETS		121,842	107,025
EQUITY AND LIABILITIES			
Equity:			
Share capital	16	324,748	223,856
Share-based payment reserve		21,316	19,838
Accumulated losses		(226,696)	(207,489)
		119,368	36,205
Current liabilities:			
Other payables and accruals	18	2,474	5,833
Unsecured convertible bonds	19	-	50,695
Derivative financial instruments	19	-	8,994
Bridge loan payable	20	-	5,298
		2,474	70,820
TOTAL EQUITY AND LIABILITIES		121,842	107,025

The accompanying notes are an integral part of the consolidated financial statements

Mitra Energy Inc.
CONSOLIDATED STATEMENT OF PROFIT OR LOSS AND OTHER COMPREHENSIVE INCOME
for the year ended March 31, 2016

	Notes	2016 US$000	2015 US$000
REVENUE		-	-
Staff costs	6	(7,588)	(7,370)
Other operating expenses	7	(2,647)	(4,680)
Depreciation	11	(26)	(47)
Impairment of inventories		-	(203)
Provision for performance bonds	15	-	(429)
Expensed exploration costs		(216)	(1,309)
Joint operator overhead charge recovered		810	884
Gain on farm-in/ farm-out arrangements - net		125	221
Fair value loss on derivative financial instruments	19	(548)	(5,559)
Gain on acquisition of unsecured convertible bonds	19	9,439	-
Non-cash loss on completion of Transaction	5	(17,515)	-
Receivables written off		(51)	-
Foreign exchange loss		(383)	(67)
OPERATING LOSS BEFORE INTEREST AND TAXATION		(18,600)	(18,559)
Interest income		1	12
Finance costs		(608)	(8,522)
LOSS BEFORE TAX		(19,207)	(27,069)
Taxation	8	-	-
LOSS FOR THE YEAR, REPRESENTING TOTAL COMPREHENSIVE LOSS FOR THE YEAR		(19,207)	(27,069)
Loss per ordinary share: Basic and diluted (US$)	9	(0.23)	(1.55)

The accompanying notes are an integral part of the consolidated financial statements

Mitra Energy Inc.

CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

for the year ended March 31, 2016

	Share capital[1] US$000	Share-based payment reserve US$000	Accumulated losses US$000	Total US$000
At April 1, 2015	223,856	19,838	(207,489)	36,205
Comprehensive loss				
Loss for the year	-	-	(19,207)	(19,207)
Transactions with owners				
Acquisition of unsecured convertible bonds	51,360	-	-	51,360
Deemed shares issued in Transaction (Note 2)	25,000	-	-	25,000
Share issue costs (Private placement)	(468)	-	-	(468)
Share capital issued (Private placement)	25,000	-	-	25,000
Share-based payments	-	1,478	-	1,478
Total transactions with owners	100,892	1,478	-	102,370
At March 31, 2016	324,748	21,316	(226,696)	119,368
At April 1, 2014	223,856	19,272	(180,420)	62,708
Comprehensive loss				
Loss for the year	-	-	(27,069)	(27,069)
Transaction with owners				
Share-based payments	-	566	-	566
At March 31, 2015	223,856	19,838	(207,489)	36,205

(1) Share capital as at April 1, 2015 consists of share capital of Mitra Energy Limited of US$11,142,511 and share premium of US$212,713,221 which has been reclassified as share capital.

Mitra Energy Inc.
CONSOLIDATED STATEMENT OF CASH FLOWS
for the year ended March 31, 2016

	2016 US$000	2015 US$000
OPERATING ACTIVITIES		
Loss before tax	(19,207)	(27,069)
Adjustments for:		
Depreciation	26	47
Provision for performance bonds	-	429
Impairment of inventories	-	203
Gain on acquisition of unsecured convertible bonds (Note 19)	(9,439)	-
Non-cash loss on completion of Transaction (Note 5)	17,515	-
Gain on farm-in/ farm-out arrangements - net	(125)	(373)
Loss on reversal of farm down arrangement	-	152
Receivables written off	51	-
Share-based payments	1,478	566
Interest income	(1)	(12)
Finance costs	608	8,522
Fair value loss of derivative financial instrument	548	5,559
Unrealized foreign exchange loss	383	-
Operating cash flows before movements in working capital	(8,163)	(11,976)
Changes in working capital:		
Decrease in inventories	-	141
Decrease in other receivables and prepayments	1,037	15,959
Decrease in other payables and accruals	(4,728)	(30,003)
NET CASH USED IN OPERATING ACTIVITIES	(11,854)	(25,879)
INVESTING ACTIVITIES		
Interest received	1	12
Payment for plant and equipment	(127)	-
Payment for intangible exploration assets	(7,817)	(6,215)
Restricted cash	-	1,900
NET CASH USED IN INVESTING ACTIVITIES	(7,943)	(4,303)
FINANCING ACTIVITIES		
Proceeds from share issuance	25,000	-
Cash acquired in Transaction (Note 5)	2,558	-
Share issue costs	(468)	-
Bridge loan received	-	5,000
NET CASH FROM FINANCING ACTIVITIES	27,090	5,000
Effect of translation on foreign currency cash and cash equivalents	(383)	-
NET INCREASE/(DECREASE) IN CASH AND CASH EQUIVALENTS	6,910	(25,182)
CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR	2,207	27,389
CASH AND CASH EQUIVALENTS AT END OF YEAR	9,117	2,207

1. CORPORATE INFORMATION

Mitra Energy Inc. (the "Company" or "Mitra", formerly Petra Petroleum Inc.) is an oil and gas company incorporated in Canada. The Company's common shares are listed on the TSX Venture Exchange ("TSX-V") under the symbol "MTE". The financial statements are expressed in United States Dollars ("US$").

Mitra is engaged in exploration, appraisal and pre-development activities in South East Asia (Philippines, Vietnam and Indonesia), with a portfolio of 10 exploration and pre-development assets. The current asset portfolio comprises approximately 12.8 million acres of awarded acreage and consists of two Service Contracts in the Philippines (Service Contract 56 ("SC 56") and Service Contract 57 ("SC-57"), five Production Sharing Contracts ("PSCs") in Vietnam (Block 51, Block 46-07 and Block 45, Block 127, Block MVHN/12KS) and three PSCs in Indonesia (Bone, Sibaru and Titan blocks).

The Company's head office is located at Suite 24.3, Level 24, Menara IMC, No.8 Jalan Sultan Ismail, 50250 Kuala Lumpur, Malaysia. The registered office of the Company is 2600 Oceanic Plaza, 1066 West Hastings Street, Vancouver, British Columbia, V6E 3X1 Canada.

2a. GOING CONCERN ASSUMPTION

(i) The Group recorded a loss before tax of US$19.2 million for the financial year ended March 31, 2016 (March 31, 2015: loss of US$27.1 million), and as at March 31, 2016, the Group's current assets exceeded its current liabilities by US$9.5 million (March 31, 2015: net current liability position of US$64.9 million). Management has prepared a cash flows forecast which indicates that the Group has funds to finance its working capital requirements till end September 2016. In the absence of revenue, the ability of the Company and the Group to continue as going concerns remains dependent on developing future profitable operations and raising adequate capital to support operations.

(ii) On June 8, 2016, the Company announced changes to its Board of Directors and senior management. A. Paul Blakeley, Cedric Fontenit and David Neuhauser have joined the board, while Jerry Korpan (formerly Non-Executive Chairman) and Paul Ebdale (formerly Chief Executive Officer) resigned as directors. A. Paul Blakeley has been appointed as Executive Chairman and Michael Horn has been appointed Interim CEO. The new management team's mandate is to review and execute new strategic directions, and guide the Group through the current challenges faced by the Group.

(iii) On July 26, 2016, the Company announced that Mitra Energy (Australia) Pty Ltd, a wholly owned subsidiary of the Company, as buyer, and the Company, as guarantor, have signed a definitive Sale & Purchase Agreement ("SPA") with Quadrant Northwest Pty Ltd and Santos Offshore Pty Ltd, as sellers, for the acquisition (the "Acquisition") of a 100% interest in the Stag Oilfield situated in Australia. The purchase consideration for the Acquisition is US$10 million and Mitra will also be required to provide a bank guarantee or letter of credit (the "Guarantee") in the amount of US$10 million to a key contractor to the Stag Oilfield to support Mitra Energy (Australia) Pty Ltd's obligations under a long term contract. Mitra may also be responsible for certain contingent payments after 2017 of up to US$15 million which are linked to future expansion of the oilfield and oil price appreciation above agreed price levels. The completion of the Acquisition is subject to certain conditions precedent which require approvals from various regulatory authorities in both Australia and Canada (including TSX Venture Exchange approval, Australian Foreign Investment Review Board approval and National Offshore Petroleum Titles Administrator approval and registration of the SPA). Management is confident that the condition precedents will be completed.

(iv) In order to finance the Acquisition and for Mitra's working capital requirements, the Company had obtained letters of equity raising commitment/ financial support from certain major shareholders ("Potential Subscribers") and a vote in favour from the majority shareholders for a private placement ("Private Placement") of up to C$65 million (approximately US$50 million). In the various letters of equity raising commitment/ financial support from the Potential Subscribers, they have indicated that in the event Mitra enters into the Acquisition and elects to seek financing, they would participate in the Private Placement in an amount pro-rata to their respective interests in Mitra. One of the Potential Subscribers has also indicated that its intention would be to subscribe for its pro rata entitlement in the Private Placement and, to the extent any Mitra shareholders did not take up their entitlement, it would subscribe for those shares.

As at the date of this report, management is in the process of appointing an agent to commence the private placement exercise.

The availability of such financing continues to be influenced by macroeconomic events, including the oil price and the prevailing capital market conditions, both of which remain outside the control of the Company.

(v) The matter set out in (iv) above represents a material uncertainty that may cast significant doubt on the Group's ability to continue as a going concern, and therefore, the Group may be unable to realize their assets and discharge their liabilities in the normal course of business. However, based on the expressed intention from certain of the key shareholders, the Board and Management of the Company are confident the Private Placement will be completed successfully. Accordingly, the accompanying financial statements have been prepared on going concern basis.

(vi) The accompanying financial statements did not include any adjustments relating to the realization and classification of asset and liability amounts that may be necessary if the Group was unable to continue as a going concern. Should the going concern assumption be inappropriate, adjustments may have to be made to (a) reflect the situation that assets may need to be realized other than their carrying amounts; (b) provide for further liabilities that might arise; and (c) reclassify non-current assets and non-current liabilities as current. No adjustments have been made in the accompanying financial statements in respect of these.

2b. REVERSE TAKEOVER TRANSACTION (THE "TRANSACTION")

In prior year, the Company's Shareholders consented to a business combination between Petra Petroleum Inc. ("Petra") and Mitra Energy Limited ("MEL") a private Bermuda incorporated entity, pursuant to an Arrangement Agreement dated March 13, 2015 (the "Transaction").

On April 8, 2015, the Company closed the financing of the arrangement (the "Financing") and a total of C$31,722,500 (US$25,000,000) was deposited into escrow with Computershare Trust Company of Canada. In connection with the closing of the Financing, the Company issued 17,429,945 subscription receipts at a price of C$1.82 (US$1.43) per subscription receipt.

On April 21, 2015, Petra closed the acquisition of all of the outstanding shares of MEL. Prior to completing the acquisition, the Company changed its name from Petra Petroleum Inc. to Mitra Energy Inc. and consolidated its share capital on a four (old) for one (new) basis. Following the consolidation and in accordance with a Scheme of Arrangement duly approved by MEL's shareholders and the Bermuda Supreme Court, the Company issued a total of 17,429,962 common shares to the shareholders of MEL in exchange for all of the outstanding shares of MEL based on a share exchange ratio of 0.62571 of a Company share for each MEL share.

Upon completion of the Transaction, the subscription receipts converted on a one-for-one basis into a total of 17,429,945 post consolidation common shares of the Company and the proceeds of the Financing were released from escrow.

Concurrent with the closing of the Transaction, the Company acquired all of the outstanding Senior Unsecured Convertible Bonds of MEL. As at closing there was a total of US$51,360,072 in outstanding principal and accrued interest on the bonds. In consideration for the purchase of these bonds, the Company issued a total of 35,808,126 common shares at a deemed price of C$1.82 (US$1.43) per share.

As part of the closing of the Transaction, the Company issued 234,641 warrants with an exercise price of C$3.24 in exchange for the cancellation of 375,000 post consolidation warrants in MEL and agreed to assume 135,570 share options in exchange for 216,667 post-consolidation share options previously issued by MEL. In addition to this, 1,082,000 post-consolidation share options of MEL, held by directors and employees of MEL, were cancelled and replaced with an award of 6,377,821 new options in the Company, exercisable at C$1.82 (US$1.43) for a period of ten years.

Following the completion of the Transaction, MEL became a wholly-owned subsidiary of the Company. The Transaction constituted a reverse takeover transaction of Petra by MEL pursuant to TSX-V Policy 5.2, Change of Business and Reverse Takeovers.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

BASIS OF PREPARATION

The financial statements are prepared in accordance with the historical cost basis, except as disclosed in the accounting policies below, and are drawn up in accordance with the provisions of International Financial Reporting Standards ("IFRS").

Historical cost is generally based on the fair value of the consideration given in exchange for goods and services.

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date, regardless of whether that price is directly observable or estimated using another valuation technique. In estimating the fair value of an asset or a liability, the Group takes into account the characteristics of the asset or liability which market participants would take into account when pricing the asset or liability at the measurement date. Fair value for measurement and/or disclosure purposes in these consolidated financial statements is determined on such a basis, except for share-based payment transactions that are within the scope of IFRS 2 *Share-based Payment*, leasing transactions that are within the scope of IAS 17 *Leases*, and measurements that have some similarities to fair value but are not fair value, such as net realisable value in IAS 2 *Inventories* or value in use in IAS 36 *Impairment of Assets*.

In addition, for financial reporting purposes, fair value adjustments are categorised into Level 1, 2 or 3 based on the degree to which the inputs to the fair value adjustments are observable and the significance of the inputs to the fair value measurement in its entirety which are described as follows:

- Level 1 inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities that the entity can access at the measurement date;
- Level 2 inputs are inputs, other than quoted prices included within Level 1, that are observable for the asset or liability, either directly or indirectly; and
- Level 3 inputs are observable inputs for the asset or liability.

APPLICATION OF NEW AND REVISED INTERNATIONAL FINANCIAL REPORTING STANDARDS (IFRSs)

Amendments to IFRSs that are mandatorily effective for the current year

In the current year, the Group has applied a number of amendments to IFRSs issued by the International Accounting Standards Board (IASB) that are mandatorily effective for an accounting period that begins on or after April 1, 2015.

The application of these amendments to IFRSs had no material impact on the Group's consolidated financial statements.

New and revised IFRSs in issue but not yet effective

The Group has not applied the following new and revised IFRSs that have been issued but are not yet effective:

IFRS 9	Financial Instruments (2)
IFRS 15	Revenue from Contract with Customers (2)
IFRS 16	Leases (5)
Amendments to IFRS 11	Accounting for Acquisitions of Interests in Joint Operations (1)
Amendments to IAS 1	Disclosure Initiative (1)
Amendments to IAS 7	Statement of Cash Flows: Disclosure Initiative (3)
Amendments to IAS 12	Income Taxes: Recognition of Deferred Tax Assets for Unrealised Losses (4)
Amendments to IFRSs	Annual Improvements to IFRSs 2012-2014 Cycle (1)

(1) Effective for annual periods beginning on or after January 1, 2016, with earlier application permitted.
(2) Effective for annual periods beginning on or after January 1, 2018, with earlier application permitted.
(3) Effective prospectively for annual periods beginning on or after January 1, 2017, with early application permitted.
(4) Effective for annual periods beginning on or after January 1, 2017, with early application permitted.
(5) Effective for annual periods beginning on or after January 1, 2019, with earlier application permitted.

IFRS 9 *Financial Instruments*

IFRS 9 issued in November 2009 introduced new requirements for the classification and measurement of financial assets. IFRS 9 was subsequently amended in October 2010 to include requirements for the classification and measurement of financial liabilities and for derecognition, and in November 2013 to include the new requirements for general hedge accounting. Another revised version of IFRS 9 was issued in July 2014 mainly to include a) impairment requirements for financial assets and b) limited amendments to the classification and measurement requirements by introducing a 'fair value through other comprehensive income' (FVTOCI) measurement category for certain simple debt instruments.

Key requirements of IFRS 9:

- all recognized financial assets that are within the scope of IAS 39 *Financial Instruments: Recognition and Measurement* are required to be subsequently measured at amortized cost or fair value. Specifically, debt investments that are held within a business model whose objective is to collect the contractual cash flows, and that have contractual cash flows that are solely payments of principal and interest on the principal outstanding are generally measured at amortized cost at the end of subsequent accounting periods. Debt instruments that are held within a business model whose objective is achieved both by collecting contractual cash flows and selling financial assets, and that have contractual terms of the financial asset give rise on specified dates to cash flows that are solely payments of principal and interest on the principal amount outstanding, are measured at FVTOCI. All other debt investments and equity investments are measured at their fair value at the end of subsequent accounting periods. In addition, under IFRS 9, entities may make an irrevocable election to present subsequent changes in the fair value of an equity investment (that is not held for trading) in other comprehensive income, with only dividend income generally recognized in profit or loss.

- with regard to the measurement of financial liabilities designated as at fair value through profit or loss, IFRS 9 requires that the amount of change in the fair value of the financial liability that is attributable to changes in the credit risk of that liability is presented in other comprehensive income, unless the recognition of the effects of changes in the liability's credit risk in other comprehensive income would create or enlarge an accounting mismatch in profit or loss. Changes in fair value attributable to a financial liability's credit risk are not subsequently reclassified to profit or loss. Under IAS 39, the entire amount of the change in the fair value of the financial liability designated as fair value through profit or loss is presented in profit or loss.

- in relation to the impairment of financial assets, IFRS 9 requires an expected credit loss model, as opposed to an incurred credit loss model under IAS 39. The expected credit loss model requires an entity to account for expected credit losses and changes in those expected credit losses at each reporting date to reflect changes in credit risk since initial recognition. In other words, it is no longer necessary for a credit event to have occurred before credit losses are recognized.

- the new general hedge accounting requirements retain the three types of hedge accounting mechanisms currently available in IAS 39. Under IFRS 9 greater flexibility has been introduced to the types of transactions eligible for hedge accounting, specifically broadening the types of instruments that qualify for hedging instruments and the types of risk components of non-financial items that are eligible for hedge accounting. In addition, the effectiveness test has been overhauled and replaced with the principle of an 'economic relationship'. Retrospective assessment of hedge effectiveness is also no longer required. Enhanced disclosure requirements about an entity's risk management activities have also been introduced.

The management anticipates that the application of IFRS 9 in the future may have a material impact of the amounts reported in respect of the Group's financial assets and liabilities. However, it is not practicable to provide a reasonable estimate of the effect of IFRS 9 until the Group undertakes a detailed review.

IFRS 15 *Revenue from Contracts with Customers*

In May 2014, IFRS 15 was issued which establishes a single comprehensive model for entities to use in accounting for revenue arising from contracts with customers. IFRS 15 will supersede the current revenue recognition guidance including IAS 18 *Revenue*, IAS 11 *Construction Contracts* and related Interpretations when it becomes effective.

The core principle of IFRS 15 is that an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. Specifically, the Standard introduces a 5-step approach to revenue recognition:

- Step 1 : Identify the contract(s) with customer
- Step 2 : Identify the performance obligations in the contract.
- Step 3 : Determine the transaction price.
- Step 4 : Allocate the transaction price to the performance obligations in the contract.
- Step 5 : Recognize revenue when (or as) the entity satisfies a performance obligation.

Under IFRS 15, an entity recognizes revenue when (or as) a performance obligation is satisfied, i.e. when "control" of the goods or services underlying the particular performance obligation is transferred to the customer. Far more prescriptive guidance has been added in IFRS 15 to deal with specific scenarios. Furthermore, extensive disclosures are required by IFRS 15.

In April 2016, amendments to IFRS 15 was issued to provide clarifications on (i) identifying performance obligations, (ii) principal versus agent considerations and (iii) licensing application guidance. The amendments also included two additional transition reliefs on contract modifications and completed contracts.

The management anticipates that the application of IFRS 15 in the future may have a material impact on the amounts reported and disclosures made in the Group's financial statements. However, it is not practicable to provide a reasonable estimate of the effect of IFRS 15 until the Group undertakes a detailed review.

IFRS 16 *Leases*

IFRS 16 was issued in January 2016 and it will supersede IAS 17 *Leases* and its associated interpretative guidance.

The Standard provides a comprehensive model for the identification of lease arrangements and their treatment in the financial statements of both lessees and lessors. The identification of leases, distinguishing between leases and service contracts are determined on the basis of whether there is an identified asset controlled by the customer.

Significant changes to lessee accounting are introduced, with the distinction between operating and finance leases removed and assets and liabilities recognised in respect of all leases (subject to limited exceptions for short-term leases and leases of low value assets). The Standard maintains substantially the lessor accounting approach under the predecessor IAS 17.

The management anticipates that the application of IFRS 16 in the future may have a material impact of the amounts reported in respect of the Group's financial assets and liabilities. However, it is not practicable to provide a reasonable estimate of the effect of IFRS 16 until the Group undertakes a detailed review.

Amendments to IFRS 11 ***Accounting for Acquisitions of Interests in Joint Operations***

The amendments to IFRS 11 provide guidance on how to account for the acquisition of a joint operation that constitutes a business as defined in IFRS 3 *Business Combinations*. Specifically, the amendments states the relevant principles on accounting for business combinations in IFRS 3 and other standards (e.g. IAS 36 *Impairment of Assets* regarding impairment testing of a cash-generating unit to which goodwill on acquisition of a joint operation has been allocated) should be applied. The same requirements should be applied to the formation of a joint operation if and only if an existing business is contributed to the joint operation by one of the parties that participate in the joint operation.

A joint operator is also required to disclose the relevant information required by IFRS 3 and other standards for business combination.

The management is currently evaluating the impact of the above amendments to IFRS 11.

Amendments to IAS 1 ***Disclosure Initiative***

The amendments to IAS 1 give some guidance on how to apply the concept of materiality in practice. The management does not anticipate that the application of these amendments to IAS 1 will have a material impact on the Group's consolidated financial statements.

Amendments to IAS 7 ***Statement of Cash Flows: Disclosure Initiative***

The amendments required an entity to provide disclosures that enable users of financial statements to evaluate changes in liabilities arising from financing activities, including both changes arising from cash flows and non-cash changes.

Management is currently evaluating the impact of IAS 7 on the financial statements of the Group.

Amendments to IAS 12 ***Income Taxes: Recognition of Deferred Tax Assets for Unrealised Losses***

The amendments clarify that unrealised losses on debt instruments measured at fair value in the financial statements but at cost for tax purposes can give rise to deductible temporary differences.

The amendments also clarify that the carrying amount of an asset does not limit the estimation of probable future taxable profits, and that when comparing deductible temporary differences with future taxable profits, the future taxable profits excludes tax deductions resulting from the reversal of those deductible temporary differences.

Management is currently evaluating the impact of IAS 12 on the financial statements of the Group.

Annual Improvements to IFRSs 2012-2014 Cycle

The *Annual Improvements to IFRSs 2012-2014 Cycle* include a number of amendments to various IFRSs, which are summarised below.

The amendments to IFRS 5 introduce specific guidance in IFRS 5 for when an entity reclassifies an asset (or disposal group) from held for sale to held for distribution to owners (or vice versa). The amendments clarify that such a change should be considered as a continuation of the original plan of disposal and hence requirements as set out in IFRS 5 regarding the change of sale plan do not apply. The amendments also clarifies that guidance for when held-for-distribution accounting is discontinued.

The amendments to IFRS 7 provide additional guidance to clarify whether a servicing contract is continuing involvement in a transferred asset for the purpose of the disclosures required in relation to transferred assets.

The amendments to IAS 19 clarify that the rate used to discount post-employment benefit obligations should be determined by reference to market yields at the end of the reporting period on high quality corporate bonds. The assessment of the depth of a market for high quality corporate bonds should be at the currency level (i.e. the same currency as the benefits are to be paid). For currencies for which there is no deep market in such high quality corporate bonds, the market yields at the end of the reporting period on government bonds denominated in that currency should be used instead.

The management does not anticipate that the application of these amendments will have a significant impact on the Group's consolidated financial statements.

BASIS OF CONSOLIDATION

The consolidated financial statements incorporate the financial statements of Mitra Energy Inc. (the "Company") and enterprises controlled by the Company ("its subsidiaries") made up to 31 March each year. Control is achieved where the Company:

- has power over the investee;
- is exposed, or has rights, to variable returns from its involvement with the investee; and
- has the ability to use its power to affect its returns.

The Company reassesses whether or not it controls an investee if facts and circumstances indicate that there are changes to one or more of the three elements of control listed above.

When the Company has less than a majority of the voting rights of an investee, it has power over the investee when the voting rights are sufficient to give it the practical ability to direct the relevant activities of the investee unilaterally. The Company considers all relevant facts and circumstances in assessing whether or not the Company's voting rights in an investee are sufficient to give it power, including:

- the size of the Company's holding of voting rights relative to the size and dispersion of holdings of the other vote holders;
- potential voting rights held by the Company, other vote holders or other parties;
- rights arising from other contractual arrangements; and
- any additional facts and circumstances that indicate that the Company has, or does not have, the current ability to direct the relevant activities at the time that decisions need to be made, including voting patterns at previous shareholders' meetings.

Consolidation of a subsidiary begins when the Company obtains control over the subsidiary and ceases when the Company loses control of the subsidiary. Specifically, income and expenses of a subsidiary acquired or disposed of during the year are included in the consolidated statement of profit or loss and other comprehensive income from the date the Company gains control until the date when the Company ceases to control the subsidiary.

Profit or loss and each component of other comprehensive income are attributed to the owners of the Company and to the non-controlling interests. Total comprehensive income of subsidiaries is attributed to the owners of the Company and to the non-controlling interests even if this results in the non-controlling interests having a deficit balance.

When necessary, adjustments are made to the financial statements of subsidiaries to bring their accounting policies into line with the Group's accounting policies.

All intragroup assets and liabilities, equity, income, expenses and cash flows relating to transactions between members of the Group are eliminated in full on consolidation.

Changes in the Group's interest in a subsidiary that do not result in a loss of control are accounted for as equity transactions. The carrying amounts of the Group's interests and the non-controlling interests are adjusted to reflect the changes in their relative interests in the subsidiary. Any difference between the amount by which the non-controlling interests are adjusted and the fair value of the consideration paid or received is recognized directly in equity and attributed to owners of the Company.

When the Group loses control of a subsidiary, the profit or loss on disposal is calculated as the difference between (i) the aggregate of the fair value of the consideration received and the fair value of any retained interest and (ii) the previous carrying amount of the assets (including goodwill), and liabilities of the subsidiary and any non-controlling interests. Amounts previously recognized in other comprehensive income in relation to the subsidiary are accounted for (i.e. reclassified to profit or loss or transferred directly to retained earnings) in the same manner as would be required if the relevant assets or liabilities were disposed of. The fair value of any investment retained in the former subsidiary at the date when control is lost is regarded as the fair value on initial recognition for subsequent accounting under IAS 39 *Financial Instruments: Recognition and Measurement* or, when applicable, the cost on initial recognition of an investment in an associate or joint venture.

BUSINESS COMBINATIONS

Acquisitions of subsidiaries and businesses are accounted for using the acquisition method. The consideration for each acquisition is measured at the aggregate of the acquisition date fair values of assets given, liabilities incurred by the Group to the former owners of the acquiree, and equity interests issued by the Group in exchange for control of the acquiree. Acquisition-related costs are recognized in profit or loss as incurred.

Where applicable, the consideration for the acquisition includes any asset or liability resulting from a contingent consideration arrangement, measured at its acquisition-date fair value. Subsequent changes in such fair values are adjusted against the cost of acquisition where they qualify as measurement period adjustments (see below). The subsequent accounting for changes in the fair value of the contingent consideration that do not qualify as measurement period adjustments depends on how the contingent consideration is classified. Contingent consideration that is classified as equity is not re-measured at subsequent reporting dates and its subsequent settlement is accounted for within equity. Contingent consideration that is classified as an asset or a liability is re-measured at subsequent reporting dates at fair value, with changes in fair value recognized in profit or loss.

The acquiree's identifiable assets, liabilities and contingent liabilities that meet the conditions for recognition under the FRS are recognized at their fair value at the acquisition date, except that:

- Deferred tax assets or liabilities and liabilities or assets related to employee benefit arrangements are recognized and measured in accordance with IAS 12 *Income Taxes* and IAS 19 *Employee Benefits* respectively;

- Liabilities or equity instruments related to share-based payment transactions of the acquiree or the replacement of an acquiree's share-based payment awards transactions with share-based payment awards transactions of the acquirer in accordance with the method in IFRS 2 *Share-based Payment* at the acquisition date; and

- Assets (or disposal groups) that are classified as held for sale in accordance with IFRS 5 *Non-current Assets Held for Sale and Discontinued Operations*

Where a business combination is achieved in stages, the Group's previously held interests in the acquired entity are re-measured to fair value at the acquisition date (i.e. the date the Group attains control) and the resulting gain or loss, if any, is recognized in profit or loss. Amounts arising from interests in the acquiree prior to the acquisition date that have previously been recognized in other comprehensive income are reclassified to profit or loss, where such treatment would be appropriate if that interest were disposed of.

The measurement period is the period from the date of acquisition to the date the Group obtains complete information about facts and circumstances that existed as of the acquisition date and is subject to a maximum of one year from acquisition date.

Where an interest in a Production Sharing Contract ("PSC") is acquired by way of a corporate acquisition, the interest in the PSC is treated as an asset purchase unless the acquisition of the corporate vehicle meets the requirements to be treated as a business combination and definition of a business.

FOREIGN CURRENCY TRANSACTIONS AND TRANSLATION

The individual financial statements of each Group entity are measured and presented in the currency of the primary economic environment in which the entity operates (its functional currency).

In preparing the financial statements of each individual Group entity, transactions in currencies other than the entity's functional currency are recorded at the rates of exchange prevailing on the dates of the transactions. At the end of each reporting period, monetary items denominated in foreign currencies are retranslated at the rates prevailing at the end of the reporting period. Non-monetary items carried at fair value that are denominated in foreign currencies are retranslated at the rates prevailing on the date when the fair value was determined. Non-monetary items that are measured in terms of historical cost in a foreign currency are not retranslated.

Exchange differences arising on the settlement of monetary items, and on retranslation of monetary items are included in profit or loss for the period. Exchange differences arising on the retranslation of non-monetary items carried at fair value are included in profit or loss for the period except for differences arising on the retranslation of non-monetary items in respect of which gains or losses are recognized in other comprehensive income. For such non-monetary items, any exchange component of that gain or loss is also recognized in other comprehensive income.

JOINT OPERATIONS

A joint operation is a joint arrangement whereby the parties that have joint control of the arrangement have rights to the assets, and obligations for the liabilities, relating to the arrangement. Joint control is the contractually agreed sharing of control of an arrangement, which exists only when decisions about the relevant activities require unanimous consent of the parties sharing control.

When a Group entity undertakes its activities under joint operations, the Group as a joint operator recognizes in relation to its interest in a joint operation:

- Its assets, including its share of any assets held jointly;
- Its liabilities, including its share of any liabilities incurred jointly;
- Its revenue from the sale of its share of the output arising from the joint operation; and
- Its expenses, including its share of any expenses incurred jointly.

The Group accounts for the assets, liabilities, revenue and expenses relating to its interest in a joint operation in accordance with the IFRSs applicable to the particular assets, liabilities, revenues and expenses.

When a Group entity transacts with a joint operation in which a Group entity is a joint operator (such as a sale or contribution of assets), the Group is considered to be conducting the transaction with the other parties to the joint operation, and gains and losses resulting from the transactions are recognized in the Group's consolidated financial statements only to the extent of other parties' interests in the joint operation.

When a Group entity transacts with a joint operation in which a Group entity is a joint operator (such as a purchase of assets), the Group does not recognize its share of the gains and losses until it resells those assets to a third party.

Changes to the Group's interest in PSCs usually require the approval of the appropriate regulatory authority. A change in interest is recognized when:

a) Approval is considered highly likely; and
b) All affected parties are effectively operating under the revised arrangement.

Where this is not the case, no change in interest is recognized and any funds received or paid are included in the statement of financial position as Contractual deposits.

Reimbursement of Joint Operator's costs

The Company's subsidiaries, when acting as operator, incur certain general overhead expenses in carrying out activities on behalf of the joint operation. As these costs are often not specifically identified, the PSCs allow the operator to recover the general overhead expenses incurred by charging an overhead fee that is based on a fixed percentage of the total costs incurred during a period. Such overhead fees have been disclosed as Joint Operator Overhead Charge. Although the purpose of this recharge is similar to the reimbursement of direct costs, the subsidiaries are not acting as agent in this case. Therefore, the general overhead expenses and the overhead fee are recognized as an expense and income respectively.

PRE-LICENCE AWARD COSTS

Costs incurred prior to the effective award of oil and gas licences, concessions and other exploration rights are expensed in the statement of profit and loss and other comprehensive income.

EXPLORATION AND EVALUATION COSTS

The costs of exploring for and evaluating oil and gas properties, including the costs of acquiring rights to explore, geological and geophysical studies, exploratory drilling and directly related overheads such as directly attributable employee remuneration, materials, fuel used, rig costs and payments made to contractors are capitalized and classified as intangible exploration assets (E&E assets).

If no potentially commercial hydrocarbons are discovered, the exploration asset is written off through profit or loss as a dry hole. If extractable hydrocarbons are found and, subject to further appraisal activity (e.g. the drilling of additional wells), it is probable they can be commercially developed, the costs continue to be carried as intangible exploration costs while sufficient/continued progress is made in assessing the commerciality of the hydrocarbons. Costs directly associated with appraisal activity undertaken to determine the size, characteristics and commercial potential of a reservoir following the initial discovery of hydrocarbons, including the costs of appraisal wells where hydrocarbons were not found, are initially capitalized as intangible exploration assets.

All such capitalized costs are subject to technical, commercial and management review, as well as review for indicators of impairment at the end of each reporting period. This is to confirm the continued intent to develop or otherwise extract value from the discovery. When such intent no longer exists or if there is a change in circumstances signifying an adverse change in initial judgment, the costs are written off.

When commercial reserves of hydrocarbons are determined and development is approved by management, the relevant expenditure is transferred to property, plant and equipment.

Costs related to geological and geophysical studies that relate to blocks that have not yet been acquired and costs related to blocks for which no commercially viable hydrocarbons are expected are taken direct to the profit or loss and have been disclosed as expensed exploration costs.

FARM-OUTS IN THE EXPLORATION AND EVALUATION PHASE

The Group does not record any expenditure made by the farmee on its account. It also does not recognize any gain or loss on its exploration and evaluation farm-out arrangements, but redesignates any costs previously capitalized in relation to the whole interest as relating to the partial interest retained. Any cash consideration received directly from the farmee is credited against costs previously capitalized in relation to the whole interest with any excess accounted for by the farmor as a gain on disposal.

BORROWING COSTS

Borrowing costs directly attributable to the acquisition, construction or production of qualifying assets, which are assets that necessarily take a substantial period of time to get ready for their intended use or sale, are added to the cost of those assets, until such time as the assets are substantially ready for their intended use or sale.

Investment income earned on the temporary investment of specific borrowings pending their expenditure on qualifying assets is deducted from the borrowing costs eligible for capitalization.

All other borrowing costs are recognized in profit or loss in the period in which they are incurred and this includes borrowing costs in relation to exploration activities which are capitalized an intangible exploration assets as management is of the view that these do not meet the definition of a qualifying asset.

PLANT AND EQUIPMENT

Plant and equipment is stated at cost less accumulated depreciation and any recognized impairment loss.

Depreciation is charged so as to write off the cost of assets evenly over their estimated useful lives, on the following basis:

Computer equipment	3 years
Fixtures and equipment	3 years
Motor vehicles	3 years

An item of plant and equipment is derecognized upon disposal or when no future economic benefits are expected to arise from the continued use of asset. Any gain or loss arising on the disposal or retirement of an item of plant and equipment is determined as the difference between the sales proceeds and the carrying amount of the asset and is recognized in profit or loss.

IMPAIRMENT OF TANGIBLE ASSETS AND INTANGIBLE ASSETS EXCLUDING GOODWILL

At the end of each reporting period, the Group reviews the carrying amounts of its assets to determine whether there is any indication that those assets have suffered an impairment loss. If any such indication exists, the recoverable amount of the asset is estimated in order to determine the extent of the impairment loss (if any). Where it is not possible to estimate the recoverable amount of an individual asset, the Group estimates the recoverable amount of the cash-generating unit to which the asset belongs. When a reasonable and consistent basis of allocation can be identified, corporate assets are also allocated to individual cash-generating units, or otherwise they are allocated to the smallest group of cash-generating units for which a reasonable and consistent allocation basis can be identified.

Intangible assets with indefinite useful lives and intangible assets not yet available for use are tested for impairment annually, and whenever there is an indication that the asset may be impaired.

Recoverable amount is the higher of fair value less costs to sell and value in use. In assessing value in use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset for which estimates of future cash flows have not been adjusted.

If the recoverable amount of an asset (or cash-generating unit) is estimated to be less than its carrying amount, the carrying amount of the asset (or cash-generating unit) is reduced to its recoverable amount. An impairment loss is recognized immediately in profit or loss.

Where an impairment loss subsequently reverses, the carrying amount of the asset (cash-generating unit) is increased to the revised estimate of its recoverable amount, but so that the increased carrying amount does not exceed the carrying amount that would have been determined had no impairment loss been recognized for the asset (cash-generating unit) in prior years. A reversal of an impairment loss is recognized immediately in profit or loss.

INVENTORY

Inventory is stated at the lower of cost and net realizable value. Cost is determined using the weighted average method and comprises direct purchase costs and transportation expenses. Net realizable value represents the estimated selling price less all estimated costs of completion and costs to be incurred in marketing, selling and distribution.

FINANCIAL INSTRUMENTS

Financial assets and financial liabilities are recognized when the Group has become a party to the contractual provisions of the instrument.

Effective interest method

The effective interest method is a method of calculating the amortized cost of a financial instrument and of allocating interest income or expense over the relevant period. The effective interest rate is the rate that exactly discounts estimated future cash receipts or payments (including all fees on points paid or received that form an integral part of the effective interest rate, transaction costs and other premiums or discounts) through the expected life of the financial instrument, or where appropriate, a shorter period. Income and expense recognized on an effective basis for debt instruments.

Financial assets

The Group has classified all its financial assets as loans and receivables. Loans and receivables are non-derivative financial assets that are not quoted in an active market. They are included in current assets except for those maturing later than 12 months after the reporting date which are classified as non-current assets. Loans and receivables include trade and other receivables and cash at bank as shown on the statement of financial position.

Other receivables

Other receivables are initially recognized at fair value. They are subsequently measured at amortized cost using the effective interest method less any provision for impairment.

Impairment of financial assets

Financial assets are assessed for indicators of impairment at the end of each reporting period. Financial assets are impaired where there is objective evidence that, as a result of one or more events that occurred after the initial recognition of the financial asset, the estimated future cash flows of the financial asset have been impacted. Significant financial difficulties of the debtor, probability that the debtor will enter bankruptcy or financial reorganisation, and default or significant delay in payments are objective evidence that these financial assets are impaired.

For financial assets carried at amortized cost, the amount of the impairment is the difference between the asset's carrying amount and the present value of estimated future cash flows, discounted at the original effective interest rate. The amount of allowance of the impairment is recognized in profit or loss.

For financial assets that are carried at cost, the amount of the impairment loss is measured as the difference between the asset's carrying amount and the present value of the estimated future cash flows discounted at the current market rate of return for a similar financial asset. Such impairment loss will not be reversed in subsequent periods.

The carrying amount of the financial asset is reduced by the impairment loss directly for all financial assets with the exception of trade receivables where the carrying amount is reduced through the use of an allowance account. When a trade receivable is uncollectible, it is written off against the allowance account. Subsequent recoveries of amounts previously written off are credited against the allowance account. Changes in the carrying amount of the allowance account are recognized in profit or loss.

For financial assets measured at amortized cost, if, in a subsequent period, the amount of the impairment loss decreases and the decrease can be related objectively to an event occurring after the impairment was recognized, the previously recognized impairment loss is reversed through profit or loss to the extent that the carrying amount of the financial asset at the date the impairment is reversed does not exceed what the amortized cost would have been had the impairment not been recognized.

Derecognition of financial assets

The Group derecognizes a financial asset only when the contractual rights to the cash flows from the asset expire, or it transfers the financial asset and substantially all the risks and rewards of ownership of the asset to another entity. If the Group neither transfers nor retains substantially all the risks and rewards of ownership and continues to control the transferred asset, the Group recognizes its retained interest in the asset and an associated liability for amounts it may have to pay. If the Group retains substantially all the risks and rewards of ownership of a transferred financial asset, the Group continues to recognize the financial asset and also recognizes a collateralised borrowing for the proceeds received.

Financial liabilities and equity instruments

Financial liabilities and equity instruments are classified according to the substance of the contractual arrangements entered into. An equity instrument is any contract that evidences a residual interest in the assets of the Group after deducting all of its liabilities.

Other payables

Other payables are initially recognized at fair value, net of transaction costs, and subsequently at amortized cost using the effective interest method, with interest expense recognized on an effective yield basis.

Equity instruments

Equity instruments issued by the Company are recorded at the fair value of the proceeds received, net of direct issue costs, except where the accounting treatment is defined by a separate accounting standard, as in the case of share based payments and warrants.

Convertible bonds

Convertible bonds are regarded as compound instruments, consisting of a debt host component and an equity conversion option which are classified separately as financial liabilities and equity in accordance with the substance of the contractual arrangement on initial recognition. Conversion option that will be settled by the exchange of a fixed amount of cash or another financial asset for a variable number of the Company's own equity instruments is classified as a derivative financial liability. Conversion option that will be settled by the exchange of a fixed amount of cash or another financial asset for a fixed number of the Company's own equity instruments is classified as an equity instrument.

Where conversion option will be settled by the exchange of a fixed amount of cash or another financial asset for a variable number of the Company's own equity instruments.

On initial recognition, the fair value of the liability host component is determined using the prevailing market interest of similar non-convertible debts. The difference between the gross proceeds of the issue of the convertible loans and the fair value assigned to the liability host component, representing the conversion option for the holder to convert the loans into equity, is recognized separately as derivative financial liability.

In subsequent period, the derivative financial liability which represents the equity conversion option is measured at its fair value and with fair value changes recognized in the profit or loss. The liability host component is carried at amortized cost using the effective interest method until the liability is extinguished on conversion or redemption.

Upon conversion, the derivative financial liability and the carrying amount of the liability host component will be transferred to share capital.

Transaction Costs

Transaction costs that relate to the issue of the convertible loans are allocated to the liability host and equity or derivative liability components in proportion to the allocation of the gross proceeds. Transaction costs relating to the equity components are charged directly to equity. Transaction costs relating to the liability components are included in the carrying amount of the liability and amortized over the period of the convertible loans using the effective interest method.

Derecognition of financial liabilities

The Group derecognizes financial liabilities when, and only when, the Group's obligations are discharged, cancelled or they expire. The difference between the carrying amount of the financial liability derecognized and the consideration paid and payable is recognized in profit or loss.

Derivative financial instruments

A derivative financial instrument is initially recognized at its fair value on the date the contract is entered into and is subsequent carried at its fair value. Fair value changes for derivative financial instruments are included in profit or loss in the financial year when the changes arise.

FAIR VALUE ESTIMATION OF FINANCIAL ASSETS AND LIABILITIES

The fair value of current financial assets and liabilities carried at amortized cost approximate their carrying amounts, as the effect of discounting is immaterial.

SHARE-BASED PAYMENTS

Share based incentive arrangements are provided to employees which allow them to acquire shares of the Company. The fair value of options granted is recognized as an employee expense with a corresponding increase in equity.

Share options are valued at the date of grant using the Black-Scholes pricing model, and are charged to operating costs over the vesting period of the award. The charge is modified to take account of options granted to employees who leave the Company during the vesting period and forfeit their rights to the share options and in the case of non-market related performance conditions, where it becomes unlikely they will vest. At the end of the reporting period, the Group revises its estimates of the number of equity instruments expected to vest. The impact of the original estimates, if any is recognized in profit or loss such that the cumulative expense reflects the revised estimate, with a corresponding adjustment to the share options reserve.

Equity-settled share-based payment transactions with parties other than employees are measured at the fair value of goods or services received, except where that fair value cannot be estimated reliably, in which case they are measured at the fair value of the equity instruments granted, measured at the date at which the entity obtains the goods or the counterparty renders the service.

For cash-settled share-based payments, a liability is recognized for the goods and services acquired, measured initially at the fair value of the liability. At the end of each reporting period until the liability is settled, and at the date of settlement, the fair value of the liability is re-measured, with any changes in fair value recognized in profit or loss for the year. The Company does not issue cash-settled options.

When the share-based payment awards held by the employees of an acquirer (acquirer awards) are replaced by the Group's share-based payment awards (replacement awards), both the acquirer awards and the replacement awards are measured in accordance with IFRS 2 ("market-based measure") at the acquisition date. The portion of the replacement award that is included in measuring the consideration transferred in a business combination equals the market-based measure of the acquire awards multiplied by the ratio of the portion of the vesting period completed to the greater of the total vesting period or the original vesting period of the acquirer awards. The excess of the market-based measure of the replacement awards over the market-based measure of the acquirer awards included in measuring the consideration transferred is recognized in profit or loss.

WARRANTS

The warrants enable shares of the Company to be acquired in the future at fixed rates, granted to shareholders as an incentive to invest in the shares of the Company, or to brokers to facilitate that investment. Such warrants not issued in exchange for goods or services are generally within the scope of IAS 32 and IAS 39.

To determine the appropriate accounting under IAS 32, the Group carefully reviews the terms and conditions of the warrants to understand whether the warrants have characteristics of:

- a derivative financial liability that is measured at fair value, with changes in value recorded in profit or loss; or
- an equity instrument.

Under IAS 32, equity classification applies to instruments where a fixed amount of cash (or liability), denominated in the issuer's functional currency, is exchanged for a fixed number of shares (often referred to as the "fixed for fixed" criteria). The Group has evaluated all warrants issued in the prior years as none was issued in the current year and evaluated that the warrant have characteristics of an equity instrument as the exercise price of the warrant is fixed, the price is denominated in the same functional currency of the Company and the number of shares to be issued upon exercise of the warrant is fixed.

Consideration received on the sale of a share and share purchase warrant classified as equity is allocated, within equity, to their respective equity accounts on a reasonable basis. Two commonly accepted allocation approaches are the residual method and the relative fair value method. Under the residual method, one component is measured first and the residual amount is allocated to the remaining component. In contrast, under the relative fair value method the total proceeds of the instrument is allocated to the components in proportion to their relative fair values.

The Group uses the residual method for the warrant and, have been valued at the date of the grant, using the Black-Scholes pricing model, and are charged to equity immediately where there are no vesting conditions to be met.

LEASES

Leases are classified as finance lease whenever the terms of the lease transfer substantially all the risks and rewards of ownership to the lessee. All other leases are classified as operating leases.

The Group as lessee

Assets held under finance lease are recognized as assets of the Group at their fair value at the inception of the lease or, if lower, at the present value of the minimum lease payments. The corresponding liability to the lessor is included in the statement of financial position as a finance lease obligation.

Lease payments are apportioned between finance charges and reduction of the lease obligation so as to achieve a constant rate of interest on the remaining balance of the liability. Finance charges are charged directly to profit or loss, unless they are directly attributable to qualifying assets, in which case they are capitalized in accordance with the Group's general policy on borrowing costs.

Rentals payable under operating leases are charged to the profit or loss on a straight-line basis over the term of the relevant lease unless another systematic basis is more representative of the time pattern in which economic benefits from the leased asset are consumed. Contingent rentals arising under operating leases are recognized as an expense in the period in which they are incurred.

In the event that lease incentives are received to enter into operating leases, such incentives are recognized as liability. The aggregate benefit of incentives is recognized as a reduction of rental expense on a straight-line basis, except where another systematic basis is more representative of the time pattern in which economic benefits from the leased assets are consumed.

PROVISIONS

Provisions are recognized when the Group has a present obligation (legal or constructive) as a result of a past event, it is probable that the Group will be required to settle the obligation, and a reliable estimate can be made of the amount of the obligation.

The amount recognized as a provision is the best estimate of the consideration required to settle the present obligation at the end of the reporting period, taking into account the risks and uncertainties surrounding the obligation. Where a provision is measured using the cash flows estimated to settle the present obligation, its carrying amount is the present value of those cash flows (when the effect of the time value of money is material).

When some or all of the economic benefits required to settle a provision are expected to be recovered from a third party, the receivable is recognized as an asset if it is virtually certain that reimbursement will be received and the amount of the receivable can be measured reliably.

RETIREMENT BENEFIT OBLIGATIONS

Payments to defined contribution retirement benefit plans are charged as an expense as when employees have tendered the services entitling them to the contributions. Payments made to state- managed retirement benefit schemes, such as the Malaysia's Employees Provident Fund, are dealt with as payments to defined contribution plans where the Group's obligations under the plans are equivalent to those arising in a defined contribution retirement benefit plan. The Group does not have any defined benefit plans.

INCOME TAX

Income tax expense represents the sum of the tax currently payable and deferred tax.

The tax currently payable is based on taxable profit for the year. Taxable profit differs from profit as reported in the statement of profit or loss and other comprehensive income because it excludes items of income or expense that are taxable or deductible in other years and it further excludes items that are not taxable or tax deductible. The Group's liability for current tax (and tax laws) is calculated using tax rates that have been enacted or substantively enacted in countries where the Company and its subsidiaries operate by the end of the reporting period.

Deferred tax is recognized on temporary differences between the carrying amounts of assets and liabilities in the financial statements and the corresponding tax bases used in the computation of taxable profit. Deferred tax liabilities are generally recognized for all taxable temporary differences and deferred tax assets are recognized to the extent that it is probable that taxable profits will be available against which deductible temporary differences can be utilised.

Deferred tax liabilities are recognized for taxable temporary differences arising on investments in subsidiaries, except where the Group is able to control the reversal of the temporary difference and it is probable that the temporary difference will not reverse in the foreseeable future. Deferred tax assets arising from deductible temporary differences associated with such investments and interests are only recognized to the extent that it is probable that there will be sufficient taxable profits against which to utilise the benefits of the temporary differences and they are expected to reverse in the foreseeable future.

The carrying amount of deferred tax assets is reviewed at the end of each reporting period and reduced to the extent that it is no longer probable that sufficient taxable profits will be available to allow all or part of the asset to be recovered.

Deferred tax is calculated at the tax rates that are expected to apply in the period when the liability is settled or the asset realised based on the tax rates (and tax laws) that have been enacted or substantively enacted by the end of the reporting period.

Deferred tax assets and liabilities are offset when there is a legally enforceable right to set off current tax assets against current tax liabilities and when they relate to income taxes levied by the same taxation authority and the Group intends to settle its current tax assets and liabilities on a net basis.

Current and deferred tax are recognized as an expense or income in profit or loss, except when they relate to items credited or debited outside profit or loss (either in other comprehensive income or directly in equity), in which case the tax is also recognized outside profit or loss (either in other comprehensive income or directly in equity, respectively).

CASH AND CASH EQUIVALENTS IN THE STATEMENT OF CASH FLOWS

Cash and cash equivalents comprise cash in hand and at bank and other short term deposits held by the Group with maturities of less than 3 months.

4. CRITICAL ACCOUNTING JUDGMENTS AND KEY SOURCES OF ESTIMATION UNCERTAINTY

In the application of the Group's accounting policies, management is required to make judgments, estimates and assumptions about the carrying amounts of assets and liabilities that are not readily apparent from other sources. The estimates and associated assumptions are based on historical experience and other factors that are considered to be relevant. Actual results may differ from these estimates.

The estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which the estimate is revised if the revision affects only that period, or in the period of the revision and future periods if the revision affects both current and future periods.

In particular the Group has identified the following areas where significant judgments, estimates and assumptions are required. Changes in these assumptions may materially affect the financial position or financial results reported in future periods. Further information on each of these areas and how they impact the various accounting policies are described below and also in the relevant notes to the financial statements.

a) Farm-in arrangements and/or assignment of interests

The Group accounts for farm-in arrangements by considering if the acquired or transferred interest relates to that of an asset or of a business as defined in IFRS 3 *Business Combinations*. Accordingly, the Group would consider if there is existence of business elements (e.g., inputs, processes and outputs) or a group of assets that includes inputs, outputs and processes that are capable of being managed together for providing a return to investors or other economic benefits. The Group considers farm-in arrangements that pertain to exploration interests with no production license and no proved reserves to be assets rather than of a business and would account for such farm-ins based on the consideration paid which would be capitalized as an intangible exploration asset and subject to impairment reviews.

b) Share-based payments

The Group measures the cost of equity-settled transactions by reference to the fair value of the share options at the date on which they are granted. Judgment is required in determining the most appropriate valuation model for the share options granted, depending on the terms and conditions of the grant. Management is also required to use judgment in determining the most appropriate inputs to the valuation model including expected life of the option, volatility and dividend yield.

c) Intangible exploration assets

The application of the Group's accounting policy for intangible exploration assets requires judgment to determine whether it is likely that future economic benefits are likely, either from future exploitation or sale, or whether activities have not reached a stage which permits a reasonable assessment of the existence of reserves. The determination of reserves and resources is itself an estimation process that requires varying degrees of uncertainty depending on how the resources are classified. These estimates directly impact when the Group defers intangible exploration assets. The deferral policy requires management to make certain estimates and assumptions as to future events and circumstances, in particular, whether an economical viable extraction can be established. Any such estimates and assumptions may change as new information becomes available. If after expenditure is capitalized, information becomes available suggesting that the recovery of the expenditure is unlikely, the relevant capitalized amount is written off in profit or loss in the period when the new information becomes available. The carrying amounts of intangible exploration assets are disclosed in Note 10 to the financial statements.

d) Taxes

Uncertainties exist with respect to the interpretation of complex tax regulations, changes in tax laws and the amount and timing of future taxable income in the jurisdictions in which the Group operates. As the Group does not have any revenue from any of its operations and foreseeable taxable income as at March 31, 2016 the Group has determined that no deferred tax asset should be recognized.

5. NON-CASH LOSS ON COMPLETION OF TRANSACTION

Pursuant to the Transaction (see Note 2), the Company acquired all of the outstanding shares of MEL based on the exchange ratio set out in the Scheme of Arrangement. Following the completion of the Transaction, MEL became a fully owned subsidiary of the Company. The Transaction constituted a reverse takeover transaction of Petra by MEL pursuant to TSX-V Policy 5.2, Change of Business and Reverse Takeovers.

As Petra did not meet the definition of a business under IFRS, accordingly the Transaction was outside the scope of IFRS 3 *Business Combinations* and has been accounted for as a capital transaction under IFRS 2 *Share-based Payment*. Under this basis of accounting, the consolidated entity is considered to be a continuation of MEL, with the net identifiable assets of Petra deemed to have been acquired by MEL.

The deemed purchase price paid for the acquisition of Petra by MEL is the fair value of the 17,429,962 Post-Consolidation Petra Shares on issue valued at C$1.82 (US$1.43) per share, being US$25,000,000.

The fair value of the shares was allocated to the fair value of the net assets acquired as follows, resulting in a non-cash accounting loss on completion of the transaction of US$17,514,590 in the current period:

	US$000
Cash and cash equivalents	2,558
Bridge loan receivables	5,344
Other receivables	78
Other payables	(495)
Net assets acquired	7,485
Fair value of consideration paid	(25,000)
Non-cash loss on completion of the Transaction	(17,515)

In addition, Transaction costs of US$468,000 comprising legal fees were incurred and recorded in share capital as Transaction costs (Note 16).

6. STAFF COSTS

	2016 No.	2015 No.
The average monthly number of persons (including directors) employed by the Group during the year was:		
Management	4	4
Technical	20	22
Administration	30	30
	54	56

	2016 US$000	2015 US$000
The aggregate remuneration for the above persons comprised:		
Staff costs for the above persons:		
Wages, salaries and fees	5,816	6,804
Termination payments	294	-
Share-based payments (Note 17)	1,478	566
	7,588	7,370

The Group has capitalized US$1,906,148 (2015 : US$1,587,039) in respect of staff costs as part of intangible exploration assets as these relate to time costs that are directly attributable to the active blocks for the year ended March 31, 2016.

Share-based payment expense (related to share options) in respect of the directors for the year ended March 31, 2016 amounted to US$483,821 (2015 : US$176,105).

Following the completion of the Transaction, the Company paid termination payments of US$267,055 to Robert Lambert (former CEO, Petra Petroleum Inc.) and US$26,706 to Andrew Boetius (former CFO, Petra Petroleum Inc.).

7. OTHER OPERATING EXPENSES

	2016 US$000	2015 US$000
Office costs	2,453	3,460
Professional fees	1,716	3,191
Travel & Subsistence	444	445
Time costs – recovery	(2,696)	(3,097)
Administrative overhead	730	681
	2,647	4,680

8. TAXATION

The Company is resident in the Province of British Columbia and pays no tax on its losses. Subsidiary companies are resident for tax purposes in the territories in which they operate. No tax arises in the current or previous year from any of the subsidiaries' operations in view of the losses incurred.

The tax expense on loss differs from the amount that would arise using the standard rate of income tax applicable in the countries of operation of the various Group companies as explained below:

	2016 US$000	2015 US$000
Loss before tax	(19,207)	(27,069)
Tax calculated at domestic tax rates applicable to loss in the respective countries	3,951	1,388
Effects of non-deductible expenses	(4,931)	-
Effects of non-taxable income	2,454	-
Effects of tax losses not recognized	(1,474)	(1,388)
Tax expense	-	-

No deferred tax asset has been recognized in respect of tax losses arising in any of the countries in which Mitra is active due to the uncertainty of the timing of its potential recovery.

9. LOSS PER ORDINARY SHARE

The calculation of the basic and diluted loss per share is based on the following data:

	2016 US$000	2015 US$000
Loss for the purpose of basic and diluted per share, being the net loss for the year attributable to equity holders of the parent	(19,207)	(27,069)
Number of shares	No.	No.
Weighted average number of ordinary shares for the purposes of basic loss per share	84,043,280	17,429,962

Diluted loss per share is calculated based on the weighted average number of ordinary shares outstanding during the year plus the weighted number of shares that would be issued on the conversion of all potentially dilutive shares to ordinary shares. Where the impact of converted shares would be anti-dilutive, these are excluded from the calculation.

Since the conversion of potential ordinary shares to ordinary shares from share options (see Note 17) would decrease the loss per share, they are not dilutive. Accordingly, diluted loss per share is the same as basic loss per share.

10. INTANGIBLE EXPLORATION ASSETS

	Total
	US$000
Cost:	
At April 1, 2014	177,848
Additions	6,704
Reversal of disposal	1,569
At March 31, 2015	186,121
Additions	8,691
At March 31, 2016	194,812
Impairment:	
At April 1, 2014, March 31, 2015 and March 31, 2016	85,059
Net book value:	
At March 31, 2016	109,753
At March 31, 2015	101,062

For the purpose of statement of cash flows, intangible exploration assets of US$874,753 (2015: US$488,177) remained unpaid as at March 31, 2016.

In January 2015, Azimuth Vietnam Limited terminated the Farmout Agreement signed on February 24, 2014, relating to Block 127 PSC. The Group recognized a reversal of the gain in profit or loss and a reversal of disposal of intangible exploration assets amounting to US$1,569,896 for the year ended March 31, 2015. The Group had also recognized a liability of US$1,861,322 for the refund of consideration received as at March 31, 2015 (Note 18).

11. PLANT AND EQUIPMENT

	Computer Equipment US$000	Fixtures & Equipment US$000	Motor Vehicles US$000	Total US$000
Cost:				
At April 1, 2014 and April 1, 2015	418	860	56	1,334
Additions	127	-	-	127
At March 31, 2016	545	860	56	1,461
Accumulated depreciation:				
At April 1, 2014	408	835	39	1,282
Charge for the year	5	25	17	47
At March 31, 2015	413	860	56	1,329
Charge for the year	26	-	-	26
At March 31, 2016	439	860	56	1,355
Net book value:				
At March 31, 2016	106	-	-	106
At March 31, 2015	5	-	-	5

12. INVESTMENT IN SUBSIDIARIES AND INTEREST IN JOINT OPERATIONS

The succeeding sections present the details of the subsidiaries and joint operations of the Group.

A. Details of the investments in which the Group holds 20% or more of the nominal value of any class of share capital at March 31, 2016 are as follows:

Name of company:	**Place of Incorporation**	**% voting rights and shares held**		**Nature of business**
		As at Mar 31, 2016 %	As at Mar 31, 2015 %	
Mitra Energy Limited	Bermuda	100	N/A	Investment Holdings
Mitra Energy Biliton Pte. Ltd.	Singapore	100	100	Exploration
Mitra Energy (Philippines SC-56) Ltd.	Bermuda	100	100	Exploration
Mitra Energy (Philippines SC-57) Ltd.	British Virgin Islands ("BVI")	100	100	Exploration
Mitra Energy (Indonesia Sibaru) Ltd.	Bermuda	100	100	Exploration
Mitra Energy (Holdings) Ltd.	BVI	100	100	Dormant
Mitra Energy (Services) Ltd.	BVI	100	100	Dormant
Mitra Energy (Indonesia Bone) Limited	BVI	100	100	Exploration
Mitra Energy (Vietnam Con Son) Ltd.	Bermuda	100	100	Exploration
Titan Resources (Natuna) Indonesia Limited	Bermuda	100	100	Exploration
Mitra Energy (Singapore) Pte Ltd.	Singapore	100	100	Investment Holdings
Mitra Energy (Vietnam Phu Quy) Pte Ltd.	Singapore	100	100	Exploration
Mitra Energy (Vietnam Rang Dong) Pte Ltd.	Singapore	100	100	Exploration
Mitra Energy (Vietnam Nam Du) Pte Ltd.	Singapore	100	100	Exploration
Mitra Energy (Vietnam Tho Chu) Pte Ltd.	Singapore	100	100	Exploration
Mitra Energy (Vietnam Minh Hai) Pte Ltd.	Singapore	100	100	Exploration
Titan Resources (Natuna) Indonesia Ltd.	Barbados	100	100	Exploration
Mitra Energy (Vietnam Song Tu) Pte Ltd.	Singapore	100	100	Dormant
Mitra Energy (Indonesia North Madura) Pte Ltd.	Bermuda	100	100	Exploration
Mitra Energy (Indonesia Titan) Pte Ltd.	Bermuda	100	100	Exploration
Mitra Energy (Indonesia Spermonde) Ltd.	Bermuda	100	100	Exploration
Mitra Energy (Indonesia Salayar) Ltd.	Bermuda	100	100	Exploration
Mitra Energy (Vietnam Thanh Long) Pte Ltd.	Singapore	100	100	Exploration
Mitra Energy (Vietnam Phu Khanh) Pte Ltd.	Singapore	100	100	Exploration
Mitra Energy Sdn Bhd	Malaysia	100	100	Administration
Mitra Energy (Vietnam Song Hong) Pte Ltd.	Singapore	100	100	Exploration
Mitra Energy (Indonesia Rombebai) Limited	Bermuda	100	100	Exploration

Subsequent to the end of the financial period, the Company incorporated a wholly-owned subsidiary, Mitra Energy (Australia) Pty Ltd, domiciled in Australia.

B. Details of the joint operations, of which all are in exploration stage, as at March 31, 2016 are as follows:

Contract area	Date of Expiry	Held by	Place of Operation	Group Effective Working Interest	
				As at Mar 31, 2016 %	As at Mar 31, 2015 %
SC56	Aug 31, 2055	Mitra Energy (Philippines SC-56) Ltd	Philippines	25	25
SC57	Sep 14, 2055	Mitra Energy (Philippines SC-57) Ltd	Philippines	21	21
51	Jun 10, 2035	Mitra Energy (Vietnam Tho Chu) Pte Ltd	Vietnam	70(1)(2)	35(1)
46/07	Dec 29, 2035	Mitra Energy (Vietnam Nam Du) Pte Ltd	Vietnam	70(1)	70(1)(3)
45	Dec 26, 2041	Mitra Energy (Vietnam Minh Hai) Pte Ltd	Vietnam	70	70(4)
127	May 24, 2042	Mitra Energy (Vietnam Phu Khanh) Pte Ltd	Vietnam	100	100
MVHN/12KS	Feb 19, 2043	Mitra Energy (Vietnam Song Hong) Pte Ltd	Vietnam	100	100
Biliton	Dec 29, 2013	Mitra Energy Biliton Pte Ltd	Indonesia	- (5)	47.5(5)
NE Natuna	Jul 14, 2015	Titan Resources (Natuna) Indonesia Limited	Indonesia	-(6)	90
Bone	Nov 25, 2040	Mitra Energy (Indonesia Bone) Ltd	Indonesia	60(7)	60(7)
Titan(10)	Nov 25, 2040	Mitra Energy (Indonesia Titan) Limited	Indonesia	25(8)	25
N. Madura	May 17, 2040	Mitra Energy (Indonesia N. Madura) Limited	Indonesia	-(9)	25(9)
Sibaru(10)	Jan 15, 2037	Mitra Energy (Indonesia Sibaru) Ltd	Indonesia	100	100

(1) Before back-in arrangements. Mitra has an agreement with an introducing party that gives them the right to acquire at cost from Mitra a 3% interest in any commercial discovery on Vietnam Block 51 PSC and Vietnam Block PSC 46/07.

(2) On November 10, 2015, Kuwait Foreign Petroleum Exploration Company ("KUFPEC") informed the Block 51 PSC Joint Venture of their intention to withdraw from the PSC. Agreement has subsequently been reached for Mitra to be assigned KUFPEC's full 35% working interest, taking Mitra's net working interest in Block 51 to 70%. The assignment was effective from December 31, 2015, but remains subject to final governmental approval.

(3) On October 17, 2014, Talisman announced their intention to withdraw from Block 46/07 PSC. The withdrawal took effect on November 30, 2014. On December 2, 2014, the Company signed an assignment agreement with Talisman Vietnam 46-07 B.V to transfer Talisman's 35% title in PSC Block 46-07 to the Company for nil consideration. Petrovietnam Exploration Production Corporation's (PVEP's) consent for the assignment to Mitra was received on December 1, 2014 and Government approval was received on May 28, 2015. As a consequence of Talisman's withdrawal, Mitra's interest in the PSC is 70%.

(4) On October 17, 2014, Talisman announced their intention to withdraw from Block 45 PSC. The withdrawal took effect on November 30, 2014. On December 2, 2014, the Company signed an assignment agreement with Talisman Vietnam 45 B.V to transfer Talisman's 35% title in PSC Block 45 to the Company for nil consideration. PVEP's consent for the assignment to Mitra was received on December 1, 2014 and Government approval was received on May 28, 2015. As a consequence of Talisman's withdrawal Mitra's interest in the PSC is 70%.

(5) The Biliton PSC expired on December 29, 2013. The relinquishment process commenced immediately thereafter and Government of Indonesia approval for the relinquishment of PSC working area was received February 26, 2016. Consequently, Mitra no longer has an interest in the Biliton PSC.

(6) Mitra held a 90% operated interest in the NE Natuna PSC Block, offshore Natuna Sea. The commitment well Durian Besar Deep-1 (DBD-1) was drilled in September / October 2012. The PSC terms required the partners to re-enter DBD-1 and also drill another well in the block before the expiry of the PSC on July 14, 2015, or relinquish the block. Efforts to farm-out the block were not successful and accordingly, a notice of relinquishment was submitted to SKKMIGAS (Government of Indonesia) on May 29, 2015. As of the expiry of the PSC, Mitra no longer has an interest in the NE Natuna PSC.

(7) A Farmdown Agreement relating to the Bone PSC was signed with Azimuth Indonesia Ltd on March 28, 2014. Government of Indonesia approval of the transfer was obtained on January 16, 2015.

(8) On October 23, 2015, Mitra (Indonesia – Titan) Ltd. signed an agreement with AWE (Titan) NZ Limited that releases the company from any future liabilities under the PSC up to the point of final relinquishment.

(9) On December 15, 2014, Mitra Energy (Indonesia N. Madura) Ltd. signed a Transfer Agreement with Azipac Limited for the transfer of its 25%. The farm-in was approved by SKKMIGAS and the Government of Indonesia on October 12, 2015. Consequently, Mitra no longer has an interest in the North Madura PSC.

(10) In the process of being relinquished.

13. INVENTORIES

	2016 US$000	2015 US$000
Materials and spare parts		
Costs:		
At April 1, 2015/2014	3,627	3,768
Movements	-	(141)
At March 31, 2016/2015	3,627	3,627
Impairment:		
At April 1, 2015/2014	1,720	1,517
Additions	-	203
At March 31, 2016/2015	1,720	1,720
Carrying value:		
At March 31, 2016/2015	1,907	1,907

14. OTHER RECEIVABLES AND PREPAYMENTS

	2016 US$000	2015 US$000
Due within one year:		
Amount due from Partners [1]	57	977
Other receivables	182	188
Value added tax receivables	381	293
Deposits & Prepayments	339	386
	959	1,844

(1) "Partners" is a party to a contractual agreement under the Production Sharing Contract ("PSC") and petroleum concession with relevant Government Authorities in Philippines, Vietnam and Indonesia.

15. CASH AT BANK

	2016 US$000	2015 US$000
Cash and cash equivalents	9,117	2,207
Restricted cash - performance bonds[1]	-	429
	9,117	2,636
Less: Provision for performance bonds[1]	-	(429)
	9,117	2,207

[1] The funds held in restricted accounts amounting to US$429,217 as at March 31, 2015 related to the Group's share of performance bonds placed by Partners. As a result of the decision to withdraw from the Titan PSC and North Madura PSC, it was likely that the amounts of US$54,217 and US$375,000 respectively held as performance bonds would be forfeited. Accordingly, management had provided for the performance bonds in full for the year ended March 31, 2015,

On October 23, 2015, Mitra (Indonesia – Titan) Ltd signed an agreement with AWE (Titan) NZ Limited that released Mitra from any future liabilities under the Titan PSC up to the point of final relinquishment. As a consequence of that agreement, US$54,217 held as a performance bond was forfeited.

On September 15, 2015, Mitra (Indonesia – North Madura) Ltd received approval from the Government of Indonesia confirming its withdrawal from the North Madura PSC. As a consequence of this, US$375,000 held as a performance bonds was forfeited.

Cash at bank earns interest at floating rates based on daily bank deposit rates.

16. EQUITY SHARE CAPITAL

Authorised ordinary shares:

Unlimited number of common voting shares with no par value.

Allotted and outstanding:

	No. Shares	US$000
MEL's share capital as at April 1, 2014 and April 21, 2015 (adjusted)	17,429,971	223,856
Reverse acquisition of Petra's net assets	17,429,962	25,000
New equity shares (Private placement)	17,429,945	25,000
Acquisition of unsecured convertible bonds	35,808,126	51,360
Transaction costs (Private placement)	-	(468)
Share capital of resulting issuer – Mitra Energy Inc.	88,098,004	324,748

The holders of ordinary shares are entitled to receive dividends as and when declared by the Company. Fully paid ordinary shares carry one vote per share without restriction and carry a right to dividends as and when declared by the Company.

17. SHARE-BASED PAYMENT AND WARRANTS

As part of the closing of the Transaction (see Note 2) on April 21, 2015, the Company issued 234,641 warrants with an exercise price of C$3.24 in exchange for the cancellation of 375,000 post-consolidation warrants in MEL and has agreed to assume 135,570 share options in exchange for 216,666 post-consolidation share options in MEL. In addition to this, 1,082,000 post-consolidation share options of MEL, held by directors and employees, have been cancelled and replaced with an award of 6,377,821 new options in the Company, which vest immediately and are exercisable at C$1.82 for a period of ten years.

The total expense arising from share-based payment recognized for the year ended March 31, 2016 was US$1,478,392 (2015: US$565,523), of which US$1,451,442 relates to the 6,377,821 replacement options issued upon the completion of the Transaction. The replacement was accounted in accordance with IFRS 2, in which the incremental fair value of the pre- and post-modification options was recorded as an expense in profit or loss. In addition, the unamortized balance of US$26,950 relating to options cancelled was expensed during the year.

On August 19, 2015, the Company adopted, as approved by shareholders, a stock incentive plan (the "Plan") which establishes a rolling number of shares issuable under the plan in the amount of 10% of the Company's issued shares at the date of grant. Under the terms of the Plan, the exercise price of each option granted cannot be less than the market price of at the date of grant, or such other price as may be required by TSX-V. Options under the plan can have a term of up to 10 years with vesting provisions determined by the directors in accordance with TSX-V policies for Tier 2 Issuers.

The Black-Scholes option-pricing model, with the following assumptions, was used to estimate the fair value of the options at the date of grant:

	2016
Risk-free interest rate	0.89%
Expected life	5 years
Expected volatility	37.72%
Share price	C$1.25
Exercise price	C$1.82
Expected dividends	Nil

The following table summarizes the share options outstanding and exercisable as at March 31, 2016:-

	Number of options	Share options Weighted average exercise price C$/US$	Weighted average remaining contract life	Number of options exercisable
As at April 1, 2014	1,649,000[(1)]	15.02[(1)]	6.66	712,833
Cancelled during the year	(350,334)[(1)]	15.16[(1)]	n/a	n/a
As at March 31, 2015	1,298,666	14.98[(1)]	6.66	981,499
Cancellation of options held by MEL Directors and employees	(1,082,000)	14.98[(1)]	6.45	(948,830)
Continuing options as at April 21, 2015	216,666	14.99[(1)]	7.39	214,583
Continuing share options assumed by the Company	135,570[(2)]	29.47[(2)]	0.06	134,267
Petra share options	972,500[(4)]	1.89[(2)]	0.37	972,500
New share options issued	6,377,821	1.82[(2)]	8.52	6,377,821
Cancelled during the year	(85,000)	1.32[(2)]	n/a	n/a
As at March 31, 2016	7,400,891	2.34[(2)]	7.36	7,399,588

(1) US$
(2) C$

The following table summarizes the share warrants outstanding and exercisable as at March 31, 2016:

	Number of warrants	Share warrants Weighted average exercise price C$/US$	Weighted average remaining contract life	Number of warrants exercisable
As at April 1, 2014	1,750,000[1]	16.04[6]	n/a[5]	1,750,000
Cancelled during the year	(1,375,000)[1]	20.00[6]	n/a[5]	(1,375,000)
As at March 31, 2015	375,000	1.60[6]	n/a[5]	375,000
Cancellation of MEL's warrants	(375,000)	1.60[6]	n/a[5]	(375,000)
Issue of warrants	234,641[3]	3.24[7]	1.08	234,641
As at March 31, 2016	234,641	3.24[7]	1.08	234,641

The outstanding share purchase warrants have an exercise price of C$3.24 (US$2.47) and a remaining contractual life of 1.08 years as at March 31, 2016.

(1) Being MEL's share options and warrants adjusted for post 1 for 4 share consolidation.
(2) Being 216,666 share options multiplied by 0.62571, the share exchange ratio of a company share for each MEL share per the terms of the Arrangement (see Note 2).
(3) Being 375,000 warrants multiplied by 0.62571, the share exchange ratio of a company share for each MEL share per the terms of the Arrangement (see Note 2).
(4) Being 3,890,000 Petra shares options post 1 for 4 share consolidation.
(5) Expiry of warrants was scheduled to be on the second anniversary of admission to an approved stock exchange.
(6) US$
(7) C$

18. OTHER PAYABLES AND ACCRUALS

	2016 US$000	2015 US$000
Current:		
Other payables	928	1,188
Amount due to Partners (1)	245	602
Amount due to a third party for reversal of farm out (Note 10)	-	1,861
Accruals	1,301	2,182
	2,474	5,833

(1) "Partners" is a party to a contractual agreement under the Production Sharing Contract ("PSC") and petroleum concession with relevant Government Authorities in Philippines, Vietnam and Indonesia.

These amounts are non-interest bearing and repayable on demand, and other payables and accruals relate to costs related to exploration activities of the Group. Other payables are normally settled on 30 days (2015 : 30 days) terms.

19. UNSECURED CONVERTIBLE BONDS

	2016 US$000	2015 US$000
Current:		
Unsecured convertible bonds	-	37,086
Accrued Interest Expense	-	13,609
	-	50,695

On May 8, 2013 ("Issue Date"), the Company raised proceeds of US$40,900,000 by issuing Senior Unsecured Pre-Initial Public Offering ("IPO") Convertible Bonds ("Bonds"), maturing on May 10, 2015.

Interest on the Bonds accrued at a rate of 10.0% per annum, increasing to 12.5% per annum 12 months after Issue Date and then to 16.0% per annum 18 months after Issue Date if there has not been an issue of securities via a Qualifying Public Offer ("QPO").

Under the terms of the Bond Instrument in the event of a QPO the principal amount together with all interest accrued to the date of conversion is converted into Shares of the Public Issuer. The conversion price was as follows:

Timing of Qualifying Public Offering (QPO)	Conversion Price
Within 12 months of Issue Date	90.0% of share issue price
Between 12-18 months of Issue Date	87.5% of share issue price
After 18 months of Issue Date	85.0% of share issue price

The key features of the unsecured convertible bonds were as follows:

(i) The bonds are a hybrid financial instrument with three components - financial liability, embedded conversion option and embedded redemption option.

(ii) The holder has the right to interest and principal payments only at the redemption date.

(iii) The bonds are automatically convertible into ordinary shares when there is a QPO or relevant change of control as defined in the bond agreement that are subject to determination of the conversion price which will result in variability in the number of ordinary shares that will be delivered upon conversion. The conversion is mandatory and the holder has no right to object or to require redemption in cash.

(iv) The bonds can be redeemed only on the occurrence of any of the following events: (1) Relevant redemption event as defined in the bond agreement; or (2) Bondholder acceptance of the issuer request to purchase the bonds; or (3) Event of default and (4) Maturity date.

The fair value of the options embedded in the bonds is recognized as a "derivative financial instruments" in the consolidated statement of financial position, while the residual amount is recognized as unsecured convertible bonds in the consolidated statement of financial position as liability.

The transactions costs incurred on the issuance of convertible bonds aggregated to US$1,017,461 had been netted with liability and this amount was amortized over the term of convertible bonds using the effective interest method.

On November 17, 2014 and pursuant to the signing of the arrangement agreement, MEL, Petra, OTPPB and Westface signed a Deed of Amendment to the Convertible Bonds which provided for the bonds to be redeemed and satisfied at a redemption price equal to the bondholders equivalent conversion amount and the bondholders shall receive, in lieu of cash payment, new common shares in the capital of Petra and the event be considered a QPO.

On March 13, 2015 and pursuant to the signing of the Arrangement Agreement (see Note 2), MEL, Petra, OTPPB and West Face signed a Second Deed of Amendment, replacing and superseding the Deed of Amendment dated November 17, 2014, where in the latest amendment, Petra agreed to purchase all of the outstanding Convertible Bonds plus accrued interest in exchange for Petra shares to be issued at a deemed price of C$1.82. Thereto the discount to the Conversion Price upon QPO would no longer be applicable upon the completion of the Transaction.

(a) Liability component of convertible bonds

	As at April 21, 2015 US$000	As at March 31, 2015 US$000
Proceeds from issue of unsecured convertible bonds, gross	40,900	40,900
Derivative financial instruments at inception	(2,797)	(2,797)
Liability component to be recognized at inception	38,103	38,103
Less: convertible bonds issuance costs, netted with liability	(1,017)	(1,017)
Liability recognized at inception, net of costs	37,086	37,086
Cumulative interest expense	14,170	13,609
Liability component of convertible bonds	51,256	50,695

(b) Derivative financial liabilities

	As at April 21, 2015 US$000	As at March 31, 2015 US$000
Derivative financial instruments at beginning/inception	2,796	2,796
Cumulative fair value loss on derivative charge to profit or loss	6,746	6,198
Derivative component on convertible bonds	9,542	8,994

Upon the closing of the Transaction (see Note 2) on April 21, 2015, the Liability component of the convertible bonds was US$51,256,280 and the Derivative component of the convertible bonds was US$9,542,554.

Concurrent with the closing of the Transaction, the Company acquired all of the outstanding Senior Unsecured Convertible Bonds of MEL, based on a value of US$51,360,072 (C$65,170,789). This resulted in a gain for accounting purposes of US$9,438,762 being recognized in the Consolidated Statement of Comprehensive Income upon the closing of the Transaction. In consideration for the purchase of these bonds the Company issued a total of 35,808,126 common shares at a deemed price of C$1.82 per share.

20. BRIDGE LOAN PAYABLE

	2016 US$000	2015 US$000
Current:		
Short term loan	-	5,000
Accrued Interest Expense	-	298
	-	5,298

Pursuant to the signing of the Deed of Amendment on November 17, 2014, Petra provided MEL with a bridge loan financing (unsecured) of US$5,000,000 (the "Bridge Loan"), ranking *pari passu* to the Senior Unsecured Convertible Bonds (Note 19). Interest accrued on the loan at 16% per annum, resulting in a charge during the period April 1, 2015 to April 21, 2015 (the Transaction date) of US$46,667.

Concurrent with the closing of the Transaction (see Note 2) on April 21, 2015, the principal and accrued interest of the Bridge Loan became an intercompany balance between the Company and MEL.

21. FINANCIAL INSTRUMENTS

The Group's financial instruments that are not measured at fair value of comprise cash and bank balances, other receivables, other payables and accruals. As at March 31, 2016 management considers that the carrying amounts of financial assets and financial liabilities in the financial statements approximate their fair value.

Fair values are based on management's best estimates after consideration of current market conditions. The estimates are subjective and involve judgment and as such are not necessarily indicative of the amount that the Group may incur in actual market transactions.

Foreign Currency Risk

Cash and bank balances are generally held in the currency of likely future expenditures to minimize the impact of currency fluctuations. It is the Group's normal practice to hold the majority of funds in United States Dollars in order to match the Group's exploration and appraisal commitments.

In addition to United States Dollar, the Group transacts in various currencies, including Canadian Dollar, Singapore Dollar, Great Britain Pound, Indonesian Rupiah, Vietnamese Dong, Thailand Baht and Malaysian Ringgit to support work commitments and local office requirements. No sensitivity analysis has been prepared for carrying amounts of monetary assets and liabilities denominated in these foreign currencies as the Group does not expect any material effect arising from the effects of reasonably possible changes to exchange rate for these foreign currencies.

Foreign denominated balances, subject to exchange rate fluctuations, at of reporting period were as follows:

	2016 US$000	2015 US$000
Cash and bank balances:		
Great Britain Pound	30	10
Malaysian Ringgit	259	215
Indonesian Rupiah	33	31
Singapore Dollar	45	66
Thailand Baht	6	15
Vietnam Dong	273	125
Canadian Dollar	674	-
Trade and other receivables:		
Malaysian Ringgit	55	1
Indonesian Rupiah	128	85
Singapore Dollar	-	1
Vietnam Dong	472	293
Canadian Dollar	12	-
Trade and other payables:		
Malaysian Ringgit	69	92
Indonesian Rupiah	46	297
Singapore Dollar	12	12
Vietnam Dong	175	127
Thailand Baht	7	-

Interest Rate Risk

The Group's interest rate exposure arises from its cash and bank balances. The Group's other financial instruments are non-interest bearing and are therefore not subject to interest rate risk.

Mitra holds its cash in interest bearing accounts and short term deposits. Interest rates currently received are at historical lows. Accordingly, a downward interest rate movement would not cause significant exposure to the Company.

Credit Risk

Where Mitra operates joint ventures on behalf of partners it seeks to recover the appropriate share of costs from these partners. The majority of the partners in these ventures are well established oil and gas companies. In the event of non-payment, Mitra has recourse to increase its venture share under the operating agreements. It is now considered normal business to place performance bonds with governments to cover work programmes. The risk of non-return of the performance bonds is mitigated by having clear performance scopes and expiry dates on the bonds.

The maximum credit risk exposure relating to financial assets is represented by their carrying value as at the balance sheet date.

Liquidity Risk

Mitra has raised equity to meet its commitments and where the financial exposure has been deemed significant it has farmed out its obligations to third parties in exchange for lowering its interest in the exploration concession or sought partners to share the cost of operations. Mitra manages its exposure to government delays in repayment of bonds by applying for reimbursement of the bond immediately once the commitment has been met.

The table below analyses the Group's financial liabilities into relevant maturity groupings at the reporting date based on the remaining period to the contractual maturity date. The amounts disclosed in the table are the contractual undiscounted cash flows. Balances due within 12 months equal their carrying balances as the impact of discounting is not significant. The maturity profile is:

	2016 US$000	2015 US$000
Less than 1 year		
Other payables and accruals	2,474	5,833
Bridge loan payable (Note 20)	-	5,298
Convertible bonds	-	51,743
	2,474	62,874

Upon the closing of the Transaction (see Note 2) on April 21, 2015, the Company acquired all of the outstanding Senior Unsecured Convertible Bonds of MEL. Concurrently the principal and accrued interest of the Bridge Loan became an intercompany balance between the Company and MEL.

Capital management

The Company manages its capital structure and makes adjustments to it, based on the funds available to the Company, in order to support the acquisition, exploration and development of resource properties. Given the nature of the Company's activities, the Board of Directors does not establish quantitative return on capital criteria for management, but rather works with management to ensure that capital is managed effectively and the business has a sustainable future.

To carry-out planned assets acquisition, exploration and development, and to pay for administrative costs, the Company will spend its existing working capital and will work to raise additional funds as needed.

Management reviews its capital management approach on an ongoing basis and believes that this approach, given the relative size of the Company, is reasonable. There were no changes in the Company's approach to capital management during the financial year ended March 31, 2016. The Company is not subject to externally imposed capital requirements.

Fair value measurements

The Group discloses fair value measurements by level of the following fair value measurement hierarchy:

(i) Quoted prices (unadjusted) in active markets for identical assets or liabilities (Level 1);

(ii) Inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly (Level 2); and

(iii) Inputs for the asset or liability that are not based on observable market data (unobservable inputs) (Level 3).

The Group only measures its derivative financial instruments at fair value and that has been classified as Level 3. If one or more of the significant inputs is not based on observable market data, the instrument is included in Level 3. The financial instruments that are recorded in the Level 3 category comprise of unquoted equity investments/ liabilities. The fair values of these financial instruments are measured using valuation techniques that incorporate assumptions that are not evidenced by prices from observable current market transactions. Instead, they are based on "unobservable" inputs reflecting management's "own assumptions" about the way assets would be priced.

The fair value of the derivative is disclosed in Note 19.

22. SEGMENT INFORMATION

For management purposes, the Group operates in one business segment that is exploration and evaluation of oil and gas primarily in South East Asia. Revenue and non-current assets information based on the geographical location of assets respectively are as follows:

	Revenue		**Non-current assets**	
	Year ended March 31, 2016 US$000	Year ended March 31, 2015 US$000	As at March 31, 2016 US$000	As at March 31 2015 US$000
Indonesia	-	-	5,451	4,375
Philippines	-	-	49,365	49,136
Vietnam	-	-	54,937	47,551
Others	-	-	106	5
	-	-	109,859	101,067

23. FINANCIAL COMMITMENTS

COMMITMENTS UNDER OPERATING LEASES AND EXPENSES FOR THE YEAR

The Group has recognized the following expense during the year related to operating leases:

	2016 US$000	2015 US$000
Operating lease rental:		
- land and buildings	898	664
- other	57	24
	955	688

The Group has entered into commercial leases as a lessee in respect of the rental of office premises, office equipment and cars. Future minimum rentals payable under non-cancellable operating leases as at quarter ended are as follows:

	2016 US$000	2015 US$000
Amount to be paid:		
Not later than one year	534	773
After one year but not more than five years	144	166
	678	939

PSC OPERATIONAL COMMITMENTS

Certain PSC's and Service Concessions' have firm capital commitments where we are required to participate in minimum exploration activities. The Group has the following outstanding minimum exploration commitments:

	As at March 31, 2016 US$000	As at March 31, 2015 US$000
Not later than one year	250	4,280
After one year but not more than five years	10,300	10,180
	10,550	14,460

The PSC operational commitments as at March 31, 2016 include an amount of US$10,000,000 related to the minimum work commitment outstanding in Exploration Phase Two of the Block 46/07 PSC, for the drilling of a further well.

Mitra has been in discussions with PetroVietnam on deferring the well to coincide with development drilling on the Nam Du discovery in 2017-18. To this end, on March 29, 2016 Mitra submitted a request for a further 1 year extension to Exploration Phase Two of Block 46/07 PSC. Petrovietnam advised Mitra of Vietnamese Prime Ministerial approval for the extension on July 19, 2016, extending the Exploration Phase Two to June 29, 2017. Accordingly, the remaining drilling commitment has been deferred and is recognized as being after one year as at March 31, 2016.

24. RELATED PARTY TRANSACTIONS

During the year, the Group entities did not enter into any transactions with related parties other than the following:

Compensation of directors and key management personnel

The remuneration of directors and other members of key management during the year was as follows:

	As at March 31, 2016 US$000	As at March 31, 2015 US$000
Short-term benefits	2,580	2,597
Termination payments	294	-
Share-based payments	933	342
	3,807	2,939

Upon the completion of the Transaction, 4,100,000 share options (of 6,377,821 share options issued as detailed in Note 2) were granted to key management personnel (directors and executive officers of the Company), resulting in an expense of US$933,063 for the financial year ended March 31, 2016.

25. EVENTS AFTER THE REPORTING PERIOD

On June 8, 2016, the Company announced changes to its Board of Directors and senior management. A. Paul Blakeley, Cedric Fontenit and David Neuhauser have joined the board, while Jerry Korpan (formerly Non-Executive Chairman) and Paul Ebdale (formerly Chief Executive Officer) resigned as directors.

A. Paul Blakeley has been appointed as Executive Chairman. Michael Horn has been appointed Interim CEO, in charge of supervising the transition towards a new strategy for the Company and focusing on M&A activity.

A. Paul Blakeley and Michael Horn participated in a small private placement by the Company for a total of 700,000 common shares at a price of C$0.49 per common share, totaling C$343,000 (US$262,574). The Company has also granted a total of 750,000 stock options with an exercise price of C$0.49 which are exercisable for 10 years. The options will vest in equal tranches over a period of three years.

Following the changes to the board, termination payments totaling US$686,786 were paid to Paul Ebdale (former CEO) and Jerry Korpan (former Non-Executive Chairman).

On July 26, 2016, the Company announced that Mitra Energy (Australia) Pty Ltd, a wholly owned subsidiary of the Company, as buyer, and the Company, as guarantor, have signed a definitive Sale & Purchase Agreement ("SPA") with Quadrant Northwest Pty Ltd and Santos Offshore Pty Ltd, as sellers, for the acquisition (the "Acquisition") of a 100% interest in the Stag Oilfield situated in Australia (see Note 2a for details).

Subsequent to year end, the Company has performed a further review of its asset base. As a result of that review the company is considering relinquishing Vietnam PSC MVHN/12KS. An asset carrying value of US$2,516,361 is included in the balance of Intangible Exploration Assets as at March 31, 2016.

Jadestone Energy Inc.

CONDENSED CONSOLIDATED INTERIM FINANCIAL STATEMENTS (UNAUDITED)

As at and for the three months ended

March 31, 2018

Company Registration No. BC0350583 (Canada)

ASSETS	Notes	**March 31, 2018** US$000	**December 31, 2017** US$000
Non-current assets:			
Intangible exploration assets	13	93,875	105,673
Oil and gas properties	14	56,897	62,238
Deferred tax assets	15	23,737	23,821
Plant and equipment	16	1,554	648
Restricted cash	19	10,729	10,729
		186,792	203,109
Current assets:			
Inventories	17	11,329	9,610
Receivables and prepayments	18	3,582	4,719
Cash and cash equivalents	20	9,662	10,450
		24,573	24,779
TOTAL ASSETS		211,365	227,888
EQUITY AND LIABILITIES			
Equity:			
Share capital	20	364,466	364,466
Share-based payment and warrants	21	22,001	21,855
Accumulated losses		(295,404)	(278,123)
		91,063	108,198
Non-current liabilities:			
Provision for asset restoration obligations	22	83,405	84,728
Other payables	23	6,915	7,259
Deferred tax liabilities		-	200
Secured convertible bonds	27	13,046	12,770
Derivative financial instruments	27	3,378	3,067
		106,744	108,024
Current liabilities:			
Borrowings	24	460	829
Trade & other payables, accruals and provisions	25	11,256	10,837
Other financial liabilities	26	1,842	-
		13,558	11,666
TOTAL EQUITY AND LIABILITIES		211,365	227,888

The accompanying notes are an integral part of the consolidated financial statements.

	Notes	Three months ended March 31, 2018 US$000	Three months ended March 31, 2017 US$000
Gross revenue	3	20,999	17,210
Royalties		(2,712)	(725)
Cash flow hedges		(235)	-
Net revenue		18,052	16,485
Production costs	4	(12,809)	(18,011)
Depletion, depreciation and amortization	5	(2,800)	(2,424)
Staff costs	7	(3,025)	(2,973)
Other expenses	8	(2,445)	(1,970)
Impairment of assets	9	(11,902)	(7,667)
Other income		12	118
Purchase discount	6	-	789
		(14,917)	(15,653)
Finance costs	10	(980)	(12)
LOSS BEFORE TAX		(15,897)	(15,665)
Taxation expense	11	(696)	(3,820)
LOSS FOR THE PERIOD		(16,593)	(19,485)
Loss per ordinary share:			
Basic and diluted (US$)	12	(0.07)	(0.09)
Loss for the period		(16,593)	(19,485)
Other comprehensive income, net of tax:			
Items to be reclassified to profit or loss in subsequent periods			
Loss on derivatives designated as cash flow hedges		(983)	-
Tax effect		295	-
Total comprehensive loss attributable to owners of the Company		(688)	-
		(17,281)	(19,485)

The accompanying notes are an integral part of the consolidated financial statements.

	Share capital US$000	Share-based payment reserves US$000	Cash flow hedging reserve US$000	Accumulated losses US$000	Total US$000
At January 1, 2017	364,466	21,357	-	(243,708)	142,115
Loss for the period	-	-	-	(19,485)	(19,485)
Transactions with owners, recognized directly in equity					
Recognition of share-based compensation	-	62	-	-	62
Total transactions with owners	-	62	-	-	62
At March 31, 2017	364,466	21,419	-	(263,193)	122,692
At January 1, 2018	364,466	21,855	-	(278,123)	108,198
Loss for the period	-	-		(16,593)	(16,593)
Other comprehensive loss for the period	-	-	(688)	-	(688)
Transactions with owners, recognized directly in equity					
Recognition of share-based compensation	-	146	-	-	146
Total transactions with owners	-	146	-	-	146
At March 31, 2018	364,466	22,001	(688)	(294,716)	91,063

The accompanying notes are an integral part of the consolidated financial statements.

	Notes	Three months ended March 31, 2018 US$000	Three months ended March 31, 2017 US$000
OPERATING ACTIVITIES			
Loss before tax		(15,897)	(15,665)
Adjustments for:			
Depletion, depreciation and amortization	5	2,800	2,424
Finance costs	10	795	442
Share-based payment	21	146	62
Unrealized foreign exchange loss/(gain)	10	(100)	(428)
Impairment of assets	9	11,902	7,667
Interest income	10	(34)	(2)
Purchase discount		-	(789)
Cash flow hedges		860	-
Inventories written down		-	(763)
Operating cash flows before movements in working capital		472	(7,052)
Changes in working capital:			
(Increase)/decrease in inventories		(1,719)	3,994
Decrease in receivables and prepayments		1,137	457
Increase/(decrease) in trade & other payables, accruals and provisions		705	(3,917)
Cash generated from/(used) in operations		595	(6,518)
Taxation paid		(518)	-
NET CASH GENERATED FROM/(USED) IN OPERATING ACTIVITIES		77	(6,518)
INVESTING ACTIVITIES			
Acquisition of Ogan Komering, net of cash acquired	6	-	(1,641)
Payment for oil and gas properties	14	(207)	(288)
Payment for intangible exploration assets	13	(289)	(2,000)
Payment for plant and equipment	16	(2)	(424)
Interest received		34	2
NET CASH (USED) IN INVESTING ACTIVITIES		(464)	(4,351)

FINANCING ACTIVITIES			
Payments for borrowings		(369)	(224)
Payments for bond facility standby fees	27	(32)	(115)
NET CASH (USED) FINANCING ACTIVITIES		(401)	(339)
Effect of translation on foreign currency cash and cash equivalents		-	(557)
NET DECREASE IN CASH AND CASH EQUIVALENTS		(788)	(11,765)
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD		10,450	26,243
CASH AND CASH EQUIVALENTS AT END OF PERIOD		9,662	14,478

The accompanying notes are an integral part of the consolidated financial statements

1. CORPORATE INFORMATION

Jadestone Energy Inc. (the "Company" or "Jadestone") is an oil and gas company incorporated in Canada. The Company's common shares are listed on the TSX Ventures Exchange ("TSX-V") under the symbol JSE. The financial statements are expressed in United States Dollars ("US$").

The Company and its subsidiaries (the "Group") are engaged in production, development, and exploration and appraisal activities in Australia, Indonesia, Vietnam and the Philippines. The Company's current two producing assets are in the Carnarvon Basin, offshore Western Australia and onshore Sumatra, Indonesia.

The Company's head office is located at Keppel Towers, #15-05/06, 10 Hoe Chiang Road, Singapore 089315. The registered office of the Company is 2600 Oceanic Plaza, 1066 West Hastings Street, Vancouver, British Columbia, V6E 3X1 Canada.

2. BASIS OF PREPARATION

Statement of Compliance

These unaudited condensed interim financial statements (the "Financial Statements") are prepared in accordance with International Accounting Standard IAS 34, Interim Financial Reporting, on a going concern basis under the historical cost convention. They do not contain all disclosures required by International Financial Reporting Standards for annual financial statements and accordingly, should be read in conjunction with JEI's audited consolidated financial statements for the period ended December 31, 2017.

These Financial Statements were approved for issuance by the Company's Board of Directors on May 30, 2018 on the recommendation of the Audit Committee.

Functional and Presentation Currency

These Financial Statements are presented in United States Dollars, which is the functional and reporting currency of the Company and its subsidiaries, based on the predominant currency of the Group's transactions and cash flows.

Basis of Consolidation

The Financial Statements incorporate the financial statements of the Company and enterprises controlled by the Company (its "subsidiaries") as at, and up to, March 31, 2018. Control is achieved where the Company has the power, directly or indirectly, to govern the financial and operating policies of an entity so as to obtain the benefits from its operations. The financial statements of the subsidiaries are prepared for the same reporting period as the parent company, using consistent accounting policies.

Basis of Measurement

These Financial Statements have been prepared on an historical cost basis, except for financial instruments classified as financial instruments at fair value, which are stated at their fair values. In addition, these financials have been prepared using the accrual basis of accounting.

The Company uses derivative financial instruments, such as commodity swaps, to hedge commodity price risks. Such derivative financial instruments are initially recognised at fair value, on the date on which a derivative contract is entered into, and are subsequently remeasured at fair value. The method of recognising any measurement gain or loss depends on the nature of the hedge.

Hedge accounting

For the purposes of hedge accounting, hedges are classified as either:

- Fair value hedges where they hedge the exposure to changes in the fair value of a recognised asset or liability; or
- Cash flow hedges where they hedge exposure to variability in cash flows that is either attributable to a particular risk associated with a recognised asset or liability, or a highly probable forecasted transaction.

At the inception of a hedge relationship, the Group formally designates and documents the hedge relationship to which it wishes to apply hedge accounting, along with the risk management objective and strategy for undertaking the hedge. The documentation includes identification of the hedging instrument, the hedged item or transaction, the nature of the risk being hedged, and how the entity will assess the effectiveness of changes in the hedging instrument's fair value in offsetting the exposure to changes in the hedged item's fair value or cash flows attributable to the hedged risk. To achieve hedge accounting, the relationships must be expected to be highly effective and are assessed on an ongoing basis, to determine that they continue to meet the risk management objective.

Hedge accounting is discontinued when the hedge instrument expires, is sold, terminates, is exercised, or no longer qualifies for hedge accounting. At that point in time, any cumulative gain or loss on the hedging instrument recognised in Other Comprehensive Income (OCI) remains in hedge reserve until the forecasted transaction occurs. If a hedged transaction is no longer expected to occur, the net cumulative gain or loss recognised in equity is transferred to profit or loss for the year.

Cash flow hedges

The effective portion of the gain or loss on hedging instruments that are classified as cash flow hedges, is recognised in OCI, while any ineffective portion is recognised immediately in the statement of profit or loss. The ineffective portion relating to commodity contracts is recognised in other operating income or expenses.

Amounts recognised as OCI are transferred to profit or loss when the hedged transaction affects profit or loss, such as when the hedged financial income or financial expense is recognised or when a forecast sale occurs.

3. GROSS REVENUE

	Three months ended March 31, 2018 US$000	Three months ended March 31, 2017 US$000
Liquids revenue:		
Stag Oilfield	14,085	15,203
Ogan Komering	5,154	1,416
Gas revenue		
Ogan Komering	1,760	591
Total revenue	20,999	17,210
Average realised price:		
Crude oil – Stag Oilfield (US$/bbl)	69.47	58.27
Liquids – Ogan Komering (US$/bbl)	61.30	47.07
Gas – Ogan Komering (US$/mmbtu)	6.35	6.30
Average production:		
Crude oil – Stag Oilfield (bbl/d) [1]	2,654	2,382
Liquids – Ogan Komering (bbl/d)	934	970
Gas – Ogan Komering (mmbtu/day)	3,079	3,025

[1] Production relates to crude oil produced and stored into the floating storage and offloading ("FSO") vessel. Revenue derives from the sale to a third party of the produced and stored oil. This results in timing differences between produced oil at Stag, and sales of oil from the FSO.

4. PRODUCTION COST

	Three months ended March 31, 2018 US$000	Three months ended March 31, 2017 US$000
Stag Oilfield:		
FSO vessel expenses	3,964	7,060
Workovers	3,430	2,919
Repairs & maintenance	765	1,274
Air, marine and onshore support	1,255	(56)
Other operating expenses	1,636	6,118
	11,050	17,315
Ogan Komering:		
Operating expenses	1,759	696
	12,809	18,011

5. DEPLETION, DEPRECIATION AND AMORTISATION

	Three months ended March 31, 2018 US$000	Three months ended March 31, 2017 US$000
Depletion and amortisation (Note 14):		
Stag Oilfield	2,044	2,399
Ogan Komering	657	-
	2,701	2,399
Depreciation for plant and equipment (Note 16)	99	25
	2,800	2,424

6. ACQUISITION OF OGAN KOMERING PRODUCTION SHARING CONTRACT

On March 9, 2017, Jadestone Energy International Holdings Inc., a wholly-owned subsidiary of the Company, closed the acquisition of a fifty percent (50%) interest in the Ogan Komering Production Sharing Contract, Sumatra, Indonesia ("OK PSC"). For the financial year ended March 31, 2017, the initial purchase price allocation for the OK PSC acquisition was estimated based on the information known at that time, and a purchase discount of US$2.2 million was recognised on a provisional basis, in the audited financial statements for the year ended March 31, 2017.

Subsequently, the Group reviewed the purchase price allocation and adjusted the provisional amounts recognised at the acquisition date of the fair value of certain identifiable assets and liabilities, pursuant to IFRS 3, to reflect new information obtained about facts and circumstances that existed as of the acquisition date. The adjusted fair values of the identifiable assets and liabilities, as at the date of acquisition are presented in the following table:

	Provisional fair value March 9, 2017 US$000	**Fair value adjustments US$000**	**Adjusted Provisional amount US$000**
Assets			
Current Assets			
Inventory – materials	154	(2)	152
Other receivables and prepayments	4,507	(1,908)	2,599
	4,661	(1,910)	2,751
Non-Current Assets			
Oil and gas properties	3,705	-	3,705
Restricted cash	669	-	669
	4,374	-	4,374
Total Assets	9,035	(1,910)	7,125

Liabilities			
Current Liabilities			
Deferred tax liabilities	(1,200)	-	(1,200)
Other payables and accruals	(3,979)	484	(3,495)
Total Liabilities	(5,179)	484	(4,695)
Net identifiable assets acquired	3,856	(1,426)	2,430
Total consideration	**1,641**		**1,641**
Consideration transferred:			
Base purchase consideration	5,800	-	5,800
Working capital/adjustments	(1,944)	(1,426)	(3,370)
Purchase discount	(2,215)	1,426	(789)
Total consideration	**1,641**	**-**	**1,641**

Accordingly, the purchase discount of US$2,215,000 (previously reported for the year ended March 31, 2017) was adjusted to US$789,000.

7. STAFF COSTS

	Three months ended March 31, 2018 US$000	Three months ended March 31, 2017 US$000
Wages, salaries and fees	2,550	2,069
Staff benefits-in-kind	329	842
Share-based compensation	146	62
	3,025	2,973

The Group has capitalized US$60,000 (March 31, 2017: US$420,000) in respect of staff costs as part of intangible exploration assets as these relate to time costs that are directly attributable to the active exploration blocks.

8. OTHER EXPENSES

	Three months ended March 31, 2018 US$000	Three months ended March 31, 2017 US$000
Professional fees/consultancies	898	722
Office costs	613	821
Cash flow hedges	625	-
Travel & subsistence	316	127
Time costs – recovery	(47)	(499)
Operator G&A	40	176
Other overhead	-	234
Others	-	56
Participating interest tax and branch profit tax	-	333
	2,445	1,970

9. IMPAIRMENT OF ASSETS

	Three months ended March 31, 2018 US$000	Three months ended March 31, 2017 US$000
Impairment of intangible exploration assets	11,902	5,950
Impairment of material and spare parts	-	1,717
	11,902	7,667

10. FINANCE COSTS

	Three months ended March 31, 2018 US$000	Three months ended March 31, 2017 US$000
Accretion expense (Note 22, 23, 27)	455	366
Fair value loss on derivative liability	311	-
Interest on convertible bonds (Note 27)	278	-
Foreign exchange gain	(100)	(428)
Interest income	(34)	(2)
Others	70	76
	980	12

11. TAXATION EXPENSE

	Three months ended March 31, 2018 US$000	Three months ended March 31, 2017 US$000
Deferred tax income relating to PRRT (Note 15)	272	3,092
Corporate income tax	882	728
Deferred tax on cash flow hedges	(258)	-
Deferred tax liabilities	(200)	-
Tax expense	696	3,820

The Australian corporate income tax rate is applied at 30%. Australian PRRT is applied at 40% of sales revenue less certain permitted deductions and is tax deductible for Australian corporate income tax purposes. The above movement in deferred tax balances relates to temporary differences between the tax base of an asset or liability, and its carrying amount in the statement of financial position.

The Indonesian corporate income tax rate is applied at 35%. Branch profit tax is applied at 20%.

The Company is resident in the Province of British Columbia and pays no Canadian tax on account of its tax losses. Subsidiary companies are resident for tax purposes in the territories in which they operate. No tax arises in the current period or in the previous year from any of the subsidiaries' operations in view of the tax losses incurred.

12. LOSS PER ORDINARY SHARE

The calculation of the basic and diluted loss per share is based on the following data:

	Three months ended March 31, 2018 US$000	Three months ended March 31, 2017 US$000
Loss for the purpose of basic and diluted per share, being the net loss for the quarter attributable to equity holders of the parent	16,593	19,485
Number of shares	No.	No.
Weighted average number of ordinary shares for the purposes of basic loss per share	221,298,004	221,298,004

Diluted loss per share is calculated based on the weighted average number of ordinary shares outstanding during the quarter plus the weighted number of shares that would be issued on the conversion of all potentially dilutive shares to ordinary shares. Where the impact of converted shares would be anti-dilutive, these are excluded from the calculation.

Since the conversion of potential ordinary shares to ordinary shares from share options (Note 21) and from secured convertible bonds (Note 27) would decrease the loss per share, they are not dilutive. Accordingly, diluted loss per share is the same as basic loss per share.

13. INTANGIBLE EXPLORATION ASSETS

	Total US$000
Cost:	
At January 1, 2018	193,294
Additions	104
	193,398
Exploration asset written off	(98,148)
At March 31, 2018	95,250
Impairment:	
At January 1, 2018	87,621
Charged to profit or loss	11,902
	99,523
Exploration asset written off	(98,148)
At March 31, 2018	1,375
Net book value:	
At March 31, 2018	93,875
At December 31, 2017	105,673

For the purpose of statement of cash flows, intangible exploration assets of US$267,433 remained unpaid as at March 31, 2018 (December 31, 2017: US$452,182).

During the three months ended March 2018, the Company performed reviews of its exploration assets and as a result of the reviews, the Group has decided to relinquish Vietnam PSC MEVPK/127. Accordingly, the Group has fully impaired the Block, resulting in an impairment charge of US$11.9 million (Note 9).

14. OIL AND GAS PROPERTIES

	Total US$000
Cost:	
At January 1, 2018	75,863
Changes in asset restoration obligation (Note 22)	(1,844)
Reclassification to Property plant and equipment	(1,003)
Addition	207
At March 31, 2018	73,223
Accumulated depletion and amortisation:	
At January 1, 2018	(13,625)
Depletion and amortisation for the period	(2,701)
At March 31, 2018	(16,326)
Net book value:	
At March 31, 2018	56,897
At December 31, 2017	62,238

15. DEFERRED TAX ASSETS

	March 31, 2018 US$000	December 31, 2017 US$000
PRRT Tax:		
Beginning balance	20,273	17,541
PRRT credit/(expense) (Note 11)	(272)	2,524
Foreign currency effect	-	208
	20,001	20,273
Corporate Income Tax:		
Beginning balance	3,548	-
Corporate income tax	188	3,548
	3,736	3,548
Total deferred tax assets	23,737	23,821

16. PLANT AND EQUIPMENT

	Computer equipment US$000	Fixtures and equipment US$000	Motor vehicles US$000	Total US$000
Cost:				
At January 1, 2018	1,180	1,024	-	2,204
Reclassification from oil and gas properties	1003	-	-	1003
Additions/(disposal)	3	(1)	-	2
At March 31, 2018	2,172	1,023	-	3,209
Accumulated depreciation:				
At January 1, 2018	665	891	-	1,556
Charge for the period	86	13	-	99
At March 31, 2018	751	904	-	1,655
Net book value:				
At March 31, 2018	1,421	119	-	1,554
At December 31, 2017	515	133	-	648

17. INVENTORIES

	March 31, 2018 US$000	December 31, 2017 US$000
Materials and spare parts: Stag	5,382	4,194
Crude oil on hand: Stag	5,947	5,416
	11,329	9,610

18. RECEIVABLES AND PREPAYMENTS

	March 31, 2018 US$000	December 31, 2017 US$000
Share of joint venture receivables (trade)	1,226	1,987
Other prepayments	1,009	1,271
Other receivables and deposits	215	285
GST/value added tax receivables	668	681
Prepaid facility expense	464	495
	3,582	4,719

19. CASH AND CASH EQUIVALENTS

	March 31, 2018 US$000	December 31, 2017 US$000
Current asset		
Cash at bank	9,662	10,450
Non-current asset		
Restricted cash: Stag	10,000	10,000
Restricted cash: Ogan Komering	729	729
	10,729	10,729

Restricted cash at March 31, 2018 comprises Stag's cash deposit of US$10.0 million placed by the Company in support of a bank guarantee to a key contractor with respect to the Company's obligations under a long term contract, and Ogan Komering PSC's asset and site restoration fund of US$0.7 million.

Cash at bank earns interest at floating rates based on daily bank deposit rates.

20. SHARE CAPITAL

Authorised ordinary shares:

Unlimited number of common voting shares with no par value.

Allotted and outstanding:

	No. Shares	US$000
At December 31, 2017	221,298,004	364,466
At March 31, 2018	221,298,004	364,466

The holders of ordinary shares are entitled to receive dividends as and when declared by the Company. Fully paid ordinary shares carry one vote per share without restriction, and carry a right to dividends as and when declared by the Company.

21. SHARE-BASED PAYMENT AND WARRANTS

The total expense arising from share-based payments recognized for the period ended March 31, 2018 was US$145,871 (March 31, 2017: US$62,287).

On August 19, 2015, the Company adopted, as approved by shareholders, a stock incentive plan (the "Plan") which establishes a rolling number of shares issuable under the plan in the amount of 10% of the Company's issued shares at the date of grant. Under the terms of the Plan, the exercise price of each option granted, cannot be less than the market price at the date of grant, or such other price as may be required by TSX-V. Options under the plan can have a term of up to 10 years, with vesting provisions determined by the directors in accordance with TSX-V policies for Tier 2 Issuers.

The Black-Scholes option-pricing model, with the following assumptions, was used to estimate the fair value of the options at the date of grant:

	Options granted on			
	March 29, 2018	December 10, 2017	March 28, 2017	June 8, 2017
Risk-free interest rate	1.11% to 1.21%	1.11% to 1.21%	1.11% to 1.21%	0.70% to 0.83%
Expected life	5.5 to 6.5 years	5.5 to 6.5 years	5.5 to 6.5 years	5.5 to 6.5 years
Expected volatility	41.6% to 42.8%	41.6% to 42.8%	41.6% to 42.8%	42.1% to 42.7%
Share price	C$0.51	C$0.42	C$0.45	C$0.49
Exercise price	C$0.50	C$0.45	C$0.47	C$0.49
Expected dividends	Nil	Nil	Nil	Nil

The following table summarizes the share options outstanding and exercisable as at March 31, 2018:

	Share options			
	Number of options	Weighted average exercise price C$	Weighted average remaining contract life	Number of options exercisable
As at January 1, 2018	8,102,821	0.58	9.03	927,822
New share options issued	3,000,000	0.50	10.00	-
Cancelled during the quarter	(170,000)	1.03	-	-
As at March 31, 2018	10,932,821	0.55	9.12	2,991,164

22. PROVISION FOR ASSET RESTORATION OBLIGATIONS

	March 31, 2018 US$000	December 31, 2017 US$000
Non-Current:		
Opening balance	84,728	77,186
Accretion expense (Note 10)	521	1,589
Changes in discount and forex rate assumptions (Note 14)	(1,844)	5,919
Others	-	34
	83,405	84,728

The Group's asset restoration obligations ("ARO") result from the future costs of decommissioning the Stag Oilfield facilities, which are expected to be incurred up to 2033. The balance of the provision is the discounted present value of the estimated future costs. The present value of the ARO has been calculated based on the blended estimated Australian and United States risk free rate of 2.67% after allowing for an inflation rate of 2.27%, both as at 31 March, 2018 (blended risk free rate of 2.52% and inflation rate of 2.27% as at December 31, 2017). The adjustments to the present value of the ARO arising from changes in discount rate and other economic estimates and assumptions for the quarter are included in oil and gas properties (Note 14).

23. OTHER PAYABLES

Other payables comprise long-term liabilities associated with the Stag leased FSO vessel. The present value of the liabilities has been calculated based on the estimated Australian risk free rate of 2.60% as at March 31, 2018 (2.63% as at December 31, 2017). Adjustments to the present value of the FSO vessel payable arising from changes in the discount rate and other economic and assumptions for the quarter are included in accretion expenses for the quarter (Note 10).

24. BORROWINGS

	March 31, 2018 US$000	December 31, 2017 US$000
Insurance premium funding	460	829

The borrowing has an effective interest rate of 7.08% as at March 31, 2018 (7.08% as at December 31, 2017). No security or charges over property are in place for this arrangement.

25. TRADE & OTHER PAYABLES, ACCRUALS AND PROVISIONS

	March 31, 2018 US$000	December 31, 2017 US$000
Trade payables	441	1,098
Other payables	9,791	8,591
Provision for long service leave	663	668
Other provisions	361	480
	11,256	10,837

These amounts are non-interest bearing and repayable on demand. Payables are normally settled on 30 (December 31, 2017: 30) days terms.

26. OTHER FINANCIAL LIABILITIES

	March 31, 2018 US$000	December 31, 2017 US$000
Cash flow hedges	1,842	-

During the three-month period ended March 31, 2018, the Company entered into two commodity hedges to hedge 350,000 bbls of crude oil production over the period January 2, 2018 to June 30, 2018 at Brent ICE crude fixed at US$64.60/bbl, and another 350,000 bbls over the period July 1, 2018 to December 31, 2018, at Brent ICE crude fixed at US$65.00/bbl. These have been designated as cash flow hedges and hence the fair value movements are recognised in other comprehensive income while the ineffective portion and the amount related to sales for the quarter are immediately recognised in the income statement.

27. SECURED CONVERTIBLE BONDS

Pursuant to the establishment of the convertible bond facility (the "Facility") with Tyrus Capital Event S.à r.l. ("Tyrus") on November 8, 2016, Jadestone paid a structuring fee equal to 2% of the total amount of the Facility. Jadestone is also required to pay a standby fee equal to 1% per annum on all undrawn amounts until maturity. The Facility will mature on October 31, 2019, at which time Tyrus will have the option to convert the full amount of any principal owing under the Facility into common shares of the Company at a conversion price of C$0.50. Tyrus also has the option to convert any principal owing under the Facility at any time prior to maturity, and the option to require the Company to draw down all undrawn amounts at any time prior to 15 days from maturity.

As at March 31, 2018, the drawn down amount of the convertible bond was US$15 million. The cost related to the convertible bonds is tabled below.

	Three months ended March 31, 2018 US$000	Three months ended March 31, 2017 US$000
Interest expense	277	-
Standby fee	32	69
Bond accretion	275	-
Fair value of associated financial derivative	311	-
Amortisation of prepaid structuring fee	32	-
	927	69

The fair value of the options as at March 31, 2018 amounting to US$3,377,506 (December 31, 2017: US$3,067,000), embedded in the bonds as a derivative financial instrument, is included in the consolidated financial statement as a liability.

	March 31, 2018 US$000	December 31, 2017 US$000
Nominal value of convertible bonds issued	15,000	15,000
Derivative financial instruments at date of issuance	2,390	2,390
Liability component at date of issuance	12,610	12,610
Less: Convertible bonds issuance cost	(378)	(378)
Liability recognized at inception, net of costs	12,232	12,232
Cumulative accretion expense	814	538
	13,046	12,770

Reconciliation of liabilities arising from financing activities

The table below details changes in the Group's liabilities arising from financing activities, including both cash and non-cash changes. Liabilities arising from financing activities are those for which cash flows were, or future cash flows will be, classified in the Group's consolidated statement of cash flows, as cash flows from financing activities.

The cash flows represent the drawdown from convertible bonds, drawdown on borrowings and repayment of borrowing in the statement of cash flows.

	Jan 1, 2018 US$'000	Financing cash flows US$'000	Other changes US$'000	Mar 31, 2018 US$'000
Group:				
Convertible bonds	12,770	-	276[1]	13,046
Borrowings (Note 24)	829	(369)	-	460

[1] Other changes in convertible bonds comprise accretion expense for the quarter.

28. FINANCIAL INSTRUMENTS, FINANCIAL RISKS AND CAPITAL MANAGEMENTS

Categories of financial instruments

	March 31, 2018 US$000	December 31, 2017 US$000
Financial assets		
Receivables (including cash and cash equivalents)	11,327	12,722
Financial liabilities		
At amortised cost:		
Borrowings, provisions and payables	101,803	103,653
At fair value:		
Convertible bonds & derivative financial instruments	16,424	15,837
	118,227	119,490

Financial instruments

The Group's financial instruments that are not measured at fair value, comprise cash and bank balances, other receivables, other payables and accruals. As at March 31, 2018 and December 31, 2017, management considers that the carrying amounts of financial assets and financial liabilities in the financial statements approximate their fair value.

The Group drew down US$15.0 million from the US$28.0 million convertible bond facility in June and July 2017. As at March 31, 2018, the carrying value of the convertible bonds was US$13.0 million and the carrying value of the derivative liability component amounted to US$3.3 million.

Fair values are based on management's best estimates after consideration of current market conditions. The estimates are subjective and involve judgment, and as such are not necessarily indicative of the amount that the Group may incur in actual market transactions.

Commodity price risk

The Group's earnings are affected by changes in oil and gas prices. The Group manages this risk by monitoring oil and gas prices and entering into commodity hedges against fluctuations in oil prices if considered appropriate. As at March 31, 2018, Jadestone had entered into two commodity hedges to hedge 350,000 bbls of crude oil production over the period January 2, 2018 to June 30, 2018 at Brent ICE crude fixed at US$64.60/bbl, and another 350,000 bbls over the period July 1, 2018 to December 31, 2018, at Brent ICE crude fixed at US$65.00/bbl.

During the three-months ended March 31, 2018, the loss on cash flow hedges recognised in the statement of other comprehensive income (OCI) amounted to US$688,236 net of tax (March 31, 2017: nil), and the loss on cash flow hedges recognised in the income statement amounted to US$601,606 net of tax (March 31, 2017: nil). As at March 31, 2018 the financial liability of the cash flow hedge amounted to US$1,842,631 (Note 26) (March 31, 2017: nil).

Commodity price sensitivity

The results of operations and cash flows of oil and gas production can vary significantly with fluctuations in the market prices of oil and/or natural gas. These are affected by factors outside the Group's control, including the market forces of supply and demand, regulatory and political actions of governments, and attempts of international cartels to control or influence prices, among a range of other factors.

The table below summarises the impact on profit/(loss) before tax, and on equity, from changes in commodity prices on the fair value of derivative financial instruments. The analysis is based on the assumption that the crude oil price moves 10%, with all other variables held constant. Reasonably possible movements in commodity prices were determined based on a review of recent historical prices and current economic forecasters' estimates.

Gain/(loss)	Effect on loss before tax for the quarter ended March 31, 2018 US$000	Effect on other comprehensive income for the quarter ended March 31, 2018 US$000	Effect on loss before tax for the quarter ended March 31, 2017 US$000	Effect on other comprehensive income for the quarter ended March 31, 2017 US$000
Increase by 10%	(393)	(3,109)	0	0
Decrease by 10%	866	2,635	0	0

Foreign currency risk

Foreign

Foreign currency risk

Foreign currency risk is the risk that a variation in exchange rates between United States Dollars ("US Dollar") and foreign currencies will affect the fair value or future cash flows of the Company's financial assets or liabilities.

Cash and bank balances are generally held in the currency of likely future expenditures, to minimize the impact of currency fluctuations. It is the Group's normal practice to hold the majority of funds

in US Dollars, in order to match the Group's revenue and expenditures. The Company's US$28.0 million convertible debt facility is a US Dollar denominated instrument.
In addition to United States Dollars, the Group transacts in various currencies, including Canadian Dollars, Singapore Dollars, Australian Dollars, Indonesian Rupiah, Vietnamese Dong, and Malaysian Ringgit. No sensitivity analysis has been prepared for carrying amounts of monetary assets and liabilities denominated in these foreign currencies, as the Group does not expect any material effect arising from the effects of reasonably possible changes to the exchange rate for these foreign currencies.

Interest rate risk

The Group's interest rate exposure arises from some of its cash and bank balances and short-term borrowings. The Group's other financial instruments are non-interest bearing or fixed rate, and are therefore not subject to interest rate risk.

Jadestone holds some of its cash in interest bearing accounts and short-term deposits. Interest rates currently received are at relatively low levels. Accordingly, a downward interest rate movement would not cause significant exposure to the Group.

The balance of short term borrowings as at March 31, 2018 amounts to US$460,345 (December 31, 2017: US$828,621). The 7.5% coupon on the Company's US$15.0 million convertible bond facility, drawn down as at March 31, 2018, is a fixed rate coupon (Note 27).

Any interest rate movement would not cause significant exposure to the Group.

Credit risk

Credit risk represents the financial loss that the Company would suffer if a counterparty in a transaction fails to meet its obligations in accordance with the agreed terms.

The Group's trade and other receivables are primarily with (i) counterparties to oil and gas sales, (ii) governments for recoverable amounts of value added taxes, and with (iii) joint venture partners in the oil and gas industry.

The Company actively manages its exposure to credit risk, granting credit limits consistent with the financial strength of the Group's counterparties and customers, requiring financial assurances as deemed necessary, reducing the amount and duration of credit exposures, and close monitoring of relevant accounts.

The Group trades only with recognised, creditworthy third parties. Where Jadestone operates joint ventures on behalf of partners it seeks to recover the appropriate share of costs from these partners. In the event of non-payment, Jadestone has recourse to increase its venture share under the operating agreements.

Revenue from Stag Oilfield production, our largest credit risk exposure, is currently sold to an investment grade customer in the energy sector, subject to customary industry credit risk.

The maximum credit risk exposure relating to financial assets is represented by their carrying value as at the balance sheet date.

Liquidity risk

Liquidity risk is the risk that the Company will not be able to meet all of its financial obligations as they become due. This includes the risk that the Company cannot generate sufficient cash flow from producing assets, or is unable to raise further capital in order to meet its obligations.

The Company manages it liquidity risk by optimising the positive free cash flow from its producing assets, on-going cost reduction initiatives, drawing down on the convertible bond facility to meet necessary capital expenditure needs, merger and acquisition strategies, and bank balance on hand.

The Group has reduced the loss for the three-month period ended March 31, 2018 by US$2.9 million compared to the three-months ended March 31, 2017. Net cash generated from operation for the three-month period ended March 31, 2018 was US$0.1 million compared to net cash used of US$6.5 million in the three-months ended March 31, 2017. The Group's net current assets, remains positive at US$11.0 million (December, 2017: US$13.1 million).

The Company believes it has sufficient liquidity to meet all reasonable scenarios of operating and financial performance for the next 12 months.

The table overleaf analyses the Group's financial liabilities into relevant maturity groupings at the reporting date, based on the remaining period to the contractual maturity date. The amounts disclosed in the table are the contractual undiscounted cash flows. Balances due are equal to their carrying balances, as the impact of discounting is not significant. The maturity profile is:

	March 31, 2018 US$000	December 31, 2017 US$000
Less than 1 year		
Trade & other payables, accruals and provisions (Note 25)	11,256	10,837
Other financial liabilities	1,842	-
Borrowings (Note 24)	460	829
	13,558	11,666

	March 31, 2018 US$000	December 31, 2017 US$000
Within 2 years		
Secured Convertible Bond (Note 27)	13,046	12,770
	13,046	12,770

Capital management

The Company manages its capital structure and makes adjustments to it, based on the funds available to the Company, in order to support the acquisition, exploration and development of resource properties and the ongoing operations of its producing assets. Given the nature of the Company's activities, the Board of Directors does not establish quantitative return on capital criteria for management, but rather works with management to ensure that capital is managed effectively and the business has a sustainable future.

To carry-out planned assets acquisition, exploration and development, and to pay for administrative costs, the Company may spend excess cash generated from its ongoing operations and may spend its existing working capital, and will work to raise additional funds if needed.

Management reviews its capital management approach on an ongoing basis and believes that this approach, given the relative size of the Company, is reasonable. There were no changes in the

Company's approach to capital management during the financial period ended March 31, 2018. The Company is not subject to externally imposed capital requirements.

Fair value measurements

The Group discloses fair value measurements by level of the following fair value measurement hierarchy:

(i) Quoted prices (unadjusted) in active markets for identical assets or liabilities (Level 1);

(ii) Inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly (Level 2); and

(iii) Inputs for the asset or liability that are not based on observable market data (unobservable inputs) (Level 3).

The Group measures its derivative financial instruments at fair value, and these have been classified as Level 3 in the hierarchy of fair value measurement. If one or more of the significant inputs is not based on observable market data, the instrument is included in Level 3. The financial instruments that are recorded in the Level 3 category comprise of unquoted equity investments/ liabilities. The fair values of these financial instruments are measured using valuation techniques that incorporate assumptions that are not evidenced by prices from observable current market transactions. Instead, they are based on unobservable inputs, reflecting management's own assumptions about the way assets would be priced.

29. SEGMENT INFORMATION

For management purposes, the Group operates in two business segments, namely exploration and production of oil and gas. The geographic focus of the business is on SEA and Australia.

Revenue and non-current assets information based on the geographical location of assets respectively are as follows:

	Revenue		**Non-current assets**	
	Three months ended March 31, 2018 US$000	Three months ended March 31, 2017 US$000	March 31, 2018 US$000	December 31, 2017 US$000
Producing Assets				
Australia	14,085	15,203	91,510	95,898
SEA - Indonesia	6,914	2,007	690	1,346
Exploration and Evaluation Assets				
SEA – Vietnam	-	-	43,407	55,258
SEA - Philippines	-	-	50,467	50,415
Others	-	-	166	192

20,999	17,210	186,240	203,109

	Three months ended March 31, 2018				Three months ended March 31, 2017			
	Production Assets	Exploration Assets	Corporate	Total	Production Assets	Exploration Assets	Corporate	Total
Gross revenue	20,999	-	-	20,999	17,210	-	-	17,210
Effective portion of cash flow hedge	(235)	-	-	(235)	-	-	-	-
Royalties	(2,712)	-	-	(2,712)	(725)	-	-	(725)
Net revenue	18,052	-	-	18,052	16,485	-	-	16,485
Production cost	(12,809)	-	-	(12,809)	(18,011)	-	-	(18,011)
Depletion, depreciation and amortisation	(2,775)	(25)	-	(2,800)	(2,411)	-	(13)	(2,424)
Staff costs	(606)	(172)	(2,247)	(3,025)	(3,581)	192	416	(2,973)
Other expenses	(1,031)	(1,016)	(398)	(2,445)	(1,668)	179	(481)	(1,970)
Impairment of asset	-	(11,902)	-	(11,902)	-	(7,667)	-	(7,667)
Gain on disposal of assets	-	-	-	-	-	-	-	-
Exploration credit	-	-	-	-	-	118	-	118
Purchase discount	-	-	-	-	-	-	789	789
Other income	-	12	-	12				
Finance costs	(72)	(12)	(896)	(980)	-	(12)	-	(12)
LOSS BEFORE TAX	759	(13,115)	(3,541)	(15,897)	(9,361)	(2,561)	(3,743)	(15,665)

[1] As at March 31, 2018, revenue from one (March 31, 2017: one) customer, domiciled in Singapore, contributed to 67% (March 31, 2017: 88%) of the Group's total revenue.

30. FINANCIAL COMMITMENTS

COMMITMENTS UNDER OPERATING LEASES AND EXPENSES FOR THE QUARTER

The Group has recognized the following expense during the quarter related to operating leases:

	As at March 31, 2018 US$000	As at March 31, 2017 US$000
Operating lease rental:		
- Land and buildings	181	308
- Other	21	20
	202	328

The Group has entered into commercial leases as a lessee in respect of the rental of office premises, office equipment and cars. Future minimum rentals payable under non-cancellable operating leases as at quarter ended are as follows:

	As at March 31, 2018 US$000	As at March 31, 2017 US$000
Amount to be paid:		
Not later than one year	562	699
After one year but not more than five years	481	886
	1,043	1,585

SEA Portfolio PSC Operational Commitments

Certain PSC's and Service Concessions' have firm capital commitments where we are required to participate in minimum exploration activities. The Group has the following outstanding minimum exploration commitments:

	As at March 31, 2018 US$000	As at March 31, 2017 US$000
Not later than one year	10,000	10,000

The SEA portfolio PSC operational commitments as at March 31, 2018 amounting to US$10,000,000 (December 31, 2017: US$ 10,000,000), relates to the minimum work commitment outstanding in exploration phase two of the Block 46/07 PSC for the drilling of a further well.

The Group is seeking a further extension to exploration phase two of the Block 46/07 PSC, in order to maintain the alignment of appraisal and development drilling.

Stag Oilfield Operational Commitments

The treated oil from the Stag Oilfield is pumped 2 kilometres to a leased FSO vessel permanently moored to a catenary anchor leg mooring buoy. The following commitments relate to the FSO facility service agreement:

	As at March 31, US$000	As at December 31, US$000
Not later than one year	17,605	17,714
After one year but not more than five years	93,738	93,975
After five years	1,965	6,853

31. CONTINGENT LIABILITES

Stag Oilfield Contingent Liabilities

The Group may be responsible for certain contingent payments after 2017 of up to US$12 million, which are linked to future expansion of the oilfield and oil price appreciation above agreed price levels. At this stage the Group's management does not consider it probable that the conditions necessary to trigger the contingent payments will occur. Accordingly, as at March 31, 2018, no provision has been recognised in these financial statements.

32. RELATED PARTY TRANSACTIONS

During the year, the Group entities did not enter into any transactions with related parties other than the following:

Compensation of directors and key management personnel

The remuneration of directors and other members of key management during the year were as follows:

	Three months ended March 31, 2018 US$000	Three months ended March 31, 2017 US$000
Short-term benefits	905	1,083
Other benefits	483	574
Termination payments	-	125
Share-based payments	106	53
	1,494	1,835

33. EVENTS AFTER THE REPORTING PERIOD

Ogan Komering

A new gross split PSC for the Ogan Komering working area has been signed between PT Pertamina Hulu Energi Ogan Komering ("Pertamina"), Indonesia's upstream regulator SKKMIGAS, and the Minister of Energy and Mineral Resources, effective May 20, 2018. Pursuant to Ministry of Energy and Mineral Resources decree 1793K/12/MEM/2018, a 100% participating interest is awarded to Pertamina. Jadestone, as the prior partner in the PSC with Pertamina, has been directed by SKKMIGAS to proceed with direct negotiations with Pertamina, for participation in the new PSC. Jadestone is progressing its discussions with Pertamina, for participation in the new gross split PSC, and expects to reach satisfactory binding terms by the end of July 2018, with participation to be back-dated to the commencement of the new PSC on May 20, 2018.