THIS DOCUMENT IS IMPORTANT AND REQUIRES YOUR IMMEDIATE ATTENTION. If you are in any doubt about the contents of this document, or as to what action you should take, you should consult your stockbroker, bank manager, solicitor, accountant or other independent financial adviser who (if you are resident and taking advice in the United Kingdom) is duly authorised under the Financial Services and Markets Act 2000 of the United Kingdom ("FSMA") or, (if you are resident in Ireland) is duly authorised under the European Communities (Markets in Financial Instruments) Regulations 2007 (Nos. 1 to 3) or the Investment Intermediaries Act 1995 (as amended) or, if you are not so resident, from another appropriately authorised independent professional adviser. The whole of the text of this document should be read.

This document, which comprises an AIM and ESM admission document drawn up in accordance with the AIM Rules and ESM Rules, has been issued in connection with the application for admission to trading on AIM and ESM of the Enlarged Issued Share Capital of Falcon. This document does not contain an offer or constitute any part of an offer to the public within the meaning of Sections 85 and 102B of FSMA or for the purposes of the Irish Prospectus Regulations or otherwise. This document is not an "approved prospectus" within the meaning of Section 85(7) of FSMA and a copy of it has not been, and will not be, delivered to the FSA or the Central Bank in accordance with the Prospectus Rules or the Irish Prospectus Rules respectively, or delivered to any other authority which could be a competent authority for the purpose of the Prospectus Directive. Its contents have not been examined or approved by the London Stock Exchange plc or the Irish Stock Exchange, nor has it been approved by an "authorised person" for the purposes of Section 21 of FSMA or the Irish Prospectus Regulations.

This document is only being, and may only be, circulated to and directed at persons in the United Kingdom and Ireland who are both (a) a "Qualified Investor" within the meaning of Section 86(7) of FSMA and the Irish Prospectus Regulations and (b) within the categories of persons referred to in Article 19(5) (Investment professionals) or Article 49(2)(a) to (d) (High net worth companies, unincorporated associations, etc.) of the Financial Services and Markets Act 2000 (Financial Promotions) Order 2005, or persons in the United Kingdom and Ireland to whom the offer of common shares in the capital of the Company pursuant to the Placing may otherwise be made or to whom the Placing may otherwise be directed in the United Kingdom and Ireland without an approved prospectus having been made available to the public in the United Kingdom before the Placing is made, and without making an unlawful financial promotion, all such persons together being referred to as "Relevant Persons". The securities being offered are only available to, and any invitation, offering or agreement to subscribe, purchase or otherwise acquire such securities will be engaged in only with, Relevant Persons. Any person who is not a Relevant Person should not act or rely on this document or any of its contents.

The Directors, whose names appear on Page 4 of this document, and the Company, accept full responsibility both individually and collectively for all of the information contained in this document, and for the Company's compliance with the AIM Rules and ESM Rules. To the best of the knowledge and belief of the Directors and the Company (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. To the extent that information has been sourced from a third party, this information has been accurately reproduced and, as far as the Directors and the Company are aware, no facts have been omitted which may render the reproduced information inaccurate or misleading. In connection with this document, no person is authorised to give any information or make any representation other than as contained in this document.

FALCON OIL & GAS

Falcon Oil & Gas Ltd.

Incorporated under the Business Corporations Act (British Columbia) with British Columbia incorporation number BC0203059

Placing of 120,381,973 new common shares at 14 pence per new common share
Admission to trading on AIM and ESM

Davy	GMP Securities Europe LLP
Nominated Adviser, ESM Adviser & Joint Broker	*Joint Broker*

Share capital immediately following Admission

Authorised Number		*Issued Number*
Unlimited	Common Shares of no par value	817,336,473

Your attention is drawn in particular to the "Risk Factors" set out in Part III of this document.

AIM and ESM are markets 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 and ESM securities are not admitted to the official list of the UKLA or to the official list of the Irish Stock Exchange. 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. Each ESM company is required pursuant to the ESM Rules to have an ESM adviser. The nominated adviser and ESM adviser are required to make declarations to the London Stock Exchange and the Irish Stock Exchange respectively on admission in the form set out in Schedule Two to the AIM Rules for Nominated Advisers and Schedule Two to the Rules for Enterprise Securities Market Advisers. Neither the London Stock Exchange nor the Irish Stock Exchange have themselves examined or approved the contents of this document.

The AIM Rules and ESM Rules are less demanding than those of the Official Lists. It is emphasised that no application is being made for admission of the Enlarged Issued Share Capital to the Official Lists or any regulated market or any other investment exchange.

Application will be made for the Enlarged Issued Share Capital to be admitted to trading on AIM and ESM. It is expected that Admission will become effective and dealings for normal settlement in the Enlarged Issued Share Capital will commence on AIM and ESM on 28 March 2013.

Davy, which is regulated in Ireland by the Central Banks, has been appointed as nominated adviser and ESM adviser (pursuant to the AIM Rules and ESM Rules respectively) and joint broker to the Company. Davy is acting exclusively for the Company in connection with arrangements described in this document and is not acting for any other person and will not be responsible to any person for providing the protections afforded to customers of Davy or for advising any other person in connection with the arrangements described in this document. In accordance with the AIM Rules and ESM Rules, Davy has confirmed to the London Stock Exchange and Irish Stock Exchange that it has satisfied itself that the Directors have received advice and guidance as to the nature of their responsibilities and obligations to ensure compliance by the Company with the AIM Rules and ESM Rules and that, in its opinion and to the best of its knowledge and belief, all relevant requirements of the AIM Rules and ESM Rules have been complied with.

GMP, which is authorised and regulated in the United Kingdom by the FSA, is acting exclusively for the Company and 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 GMP nor for providing advice in relation to the Placing or any matter referred to herein.

The New Common Shares being issued pursuant to the Placing will, on Admission, rank in full for all dividends and other distributions declared, made or paid on the New Common Shares after Admission and will otherwise rank *pari passu* in all respects with the then issued Common Shares.

This document does not constitute an offer to sell, or a solicitation of an offer to buy Common Shares in any jurisdiction in which such offer or solicitation is unlawful. In particular, this document is not for distribution in or into the United States, Canada, the Republic of South Africa or Japan except that the document may be provided in certain limited circumstances to persons in the United States in connection with a placing of Common Shares in private placements exempt from the registration requirements of the US Securities Act of 1933, as amended ("Securities Act"). The Common Shares have not been and will not be registered under the Securities Act, any state securities laws in the United States or any securities laws of Canada, the Republic of South Africa or Japan or in any country, territory or possession where to offer them without doing do so may contravene local securities laws or regulations. Accordingly, the Common Shares may not, subject to certain limited exceptions, be offered or sold, directly or indirectly, in the United States, Canada, the Republic of South Africa or Japan or to, or for the account limited or benefit of, any person in, or any national, citizen or resident of the United States, Canada, the Republic of South Africa or Japan. The distribution of this document outside the United Kingdom and Ireland may be restricted by law and therefore persons outside the United Kingdom and Ireland into whose possession this document comes should inform themselves about and observe any restrictions as to the Placing, the Common Shares or the distribution of this document.

Canada

The issuance of the New Common Shares will be exempt from the prospectus requirements of the securities legislation of the provinces and territories of Canada.

The New Common Shares have not been qualified for sale in the province of British Columbia, Canada, and may not be offered or sold in the province of British Columbia, Canada, directly or indirectly, on behalf of the Company.

This document has been provided to you on the basis that you are at the time of the offer and sale of the New Common Shares resident outside of the province of British Columbia, Canada and are acquiring the New Common Shares for investment purposes only, and not with a view to resale of the New Common Shares to a person resident in the province of British Columbia, Canada for a period of four months and one day from the time of the offer and sale of the New Common Shares. Persons who do not fall within the foregoing criteria should not rely on or act upon this document. If you are uncertain whether or not you fall within the above categories, you should consult a professional adviser for advice.

FORWARD-LOOKING STATEMENTS

This document includes "forward-looking statements" which include all statements other than statements of historical facts, including, without limitation, those regarding the group's financial position, business strategy, plans and objectives of management for future operations, or any statements preceded by, followed by or that include the words "targets", "believes", "expects", "aims", "intends", "will", "may", "anticipates", "would, "could" or similar expressions or negatives thereof.

Such forward-looking statements involve known and unknown risks, uncertainties and other important factors beyond the group's control that could cause the actual results, performance or achievements of the group to be materially different from future results, performance or achievements expressed or implied by such forward-looking statements. Such forward-looking statements are based on numerous assumptions regarding the group's present and future business strategies and the environment in which the group will operate in the future. These forward-looking statements speak only as at the date of this document. The Company expressly disclaims any obligation or undertaking to disseminate any updates or revisions to any forward-looking statements contained herein to reflect any change in the group's expectations with regard thereto or any change in events, conditions or circumstances on which any such statements are based unless required to do so by applicable law or the AIM Rules or ESM Rules.

TABLE OF CONTENTS

DIRECTORS, COMPANY SECRETARY AND ADVISERS

Directors	John Craven – *Non-Executive Chairman* Philip O'Quigley – *Chief Executive Officer* Dr. György Szabó – *Director* Daryl H. Gilbert – *Non-Executive Director* JoAchim Conrad – *Non-Executive Director* Gregory Smith – *Non-Executive Director* Igor Akhmerov – *Non-Executive Director* David Harris – *Non-Executive Director*
Company Secretary	Daniel Bloch Aird & Berlis LLP Brookfield Place 181 Bay Street, Suite 1800, Box 754 Toronto, Ontario M5J 2T9, Canada
Registered Office	810-675 Hastings Street West Vancouver, British Columbia V6B 1N2, Canada
Head Office	Styne House Upper Hatch Street Dublin 2 Ireland
Nominated Adviser, ESM Adviser & Joint Broker	Davy Davy House 49 Dawson Street Dublin 2 Ireland
Joint Broker	GMP Securities Europe LLP 5 Stratton Street London, W1J 8LA United Kingdom
Auditors	KPMG LLP 2700, 205 5th Avenue S. W. Calgary, Alberta, T2P 4B9, Canada
Reporting Accountants	PKF (UK) LLP Farringdon Place 20 Farringdon Road London, EC1M 3AP United Kingdom
UK Legal Advisers to the Company	Stikeman Elliot London Dauntsey House 4B Frederick's Place London, EC2R 8AB United Kingdom

Canadian Legal Advisers to the Company	Aird & Berlis LLP Brookfield Place 181 Bay Street, Suite 1800, Box 754 Toronto, Ontario, M5J 2T9 Canada
Hungarian Legal Advisers to the Company (and provider of Hungarian Legal Opinion)	Szűcs and Partners H-1138 Budapest Faludi u. 3., Budapest Hungary
Australian Legal Advisers to the Company (and provider of Australian Legal Opinion)	Gadens Lawyers Skygarden Building 77 Castlereagh Street Sydney, NSW, 2000 Australia
South African Legal Advisers to the Company (and provider of South African Legal Opinion)	Bowman Gilfillan Attorneys SA Reserve Bank Building 60 St. George's Mall Cape Town South Africa
Legal Advisers to the Nominated Adviser and Joint Brokers	McCarthy Tétrault 125 Old Broad Street, 26th Floor London, EC2N 1AR United Kingdom
Competent Person as to the Australian and Hungarian assets	RPS Energy 411 N. Sam Houston Parkway E Suite 400 Houston Texas, 77060-3545 USA
Registrar	Computershare Trust Company of Canada 3rd Floor, 510 Burrard Street Vancouver, British Columbia V6C 3B9, Canada
Depositary	Computershare Investor Services PLC The Pavilions Bridgewater Road Bristol, BS99 6ZZ United Kingdom
Company website	www.falconoilandgas.com

EXPECTED TIMETABLE OF PRINCIPAL EVENTS

All references to time in this document and in the expected timetable are to the time in London, United Kingdom, unless otherwise stated. Each of the times and dates in the table below are indicative only and may be subject to change.

Publication of this Admission Document	22 March 2013
CREST accounts credited with Depositary Interests in respect of the New Common Shares (where applicable)	28 March 2013
Admission effective and dealings commence on AIM and ESM	28 March 2013
Despatch of definitive share certificates in respect of New Common Shares (where applicable)	by 2 April 2013

STATISTICS RELATING TO THE PLACING

Existing Issued Share Capital	696,954,500
Number of New Common Shares to be issued	120,381,973
Enlarged Issued Share Capital following the Placing	817,336,473
Placing Price	14p per Common Share
Gross proceeds of the Placing	£16.9 million US$25 million
New Common Shares expressed as a percentage of the Enlarged Issued Share Capital	14.7%
AIM Symbol	FOG
ESM Symbol	FAC
TSX-V Symbol	FO.V
ISIN Code	CA3060711015
Conversion rates used in this document (unless otherwise indicated) are as follows:	£1 = US$1.494 £1 = C$1.535 US$1 = C$1.026

PART I

INFORMATION ON THE GROUP

1. INTRODUCTION

Falcon Oil & Gas Ltd. is an international oil and gas company engaged in the acquisition, exploration and development of conventional and unconventional oil and gas assets. Falcon's interests are located in internationally diversified countries that are characterised by a high regional demand for energy and are close to existing infrastructure allowing rapid delivery of oil and gas to market. In each territory, Falcon is partnered with a large, credible multinational energy company.

Falcon's strategy is to leverage the Group's expertise in the unconventional oil and gas industry to acquire interests in licences covering large acreages of land and to build on its internationally diversified portfolio of unconventional assets and interests, which are located in countries that the Board believes support the exploitation of unconventional oil and gas. Falcon seeks to add value to its assets by entering into farm-out arrangements with major oil and gas companies that will fully or partially carry Falcon through seismic and drilling work programmes. The Group's principal interests are located in two major underexplored basins in Australia and South Africa and in Hungary, covering approximately 14.75 million gross acres in total.

Falcon is incorporated in British Columbia, Canada and headquartered in Dublin, Ireland with a technical team based in Budapest, Hungary. On Admission, Falcon's Common Shares will be traded on AIM, the market operated by the London Stock Exchange (symbol: FOG), the TSX Venture Exchange (symbol: FO.V) and ESM, the market regulated by the Irish Stock Exchange (symbol: FAC).

Beetaloo Basin, Northern Territory, Australia

Falcon Australia, Falcon's 72.7 per cent. owned subsidiary, is the registered holder of four exploration permits covering approximately 7 million acres (approximately 28,000 km^2) in the Beetaloo Basin, a sparsely populated area of the Northern Territory. The Beetaloo Basin is a Proterozoic and Cambrian age tight oil and gas basin that the Board believes is well suited for unconventional oil and gas projects. RPS Energy, in its independent CPR dated 1 January 2013 (contained in Part IV of this document), estimates gross unrisked recoverable prospective resource (play level) potential of 162 Tcf of gas and 21,345 Mmbo of oil (P50) for Falcon Australia's Beetaloo Exploration Permits.

In its entirety, the Beetaloo Basin covers approximately 8.7 million acres (approximately 35,260 km^2) and, as far as the Company is aware, a total of 11 wells have been drilled in the Beetaloo Basin to date. This work was undertaken by a Rio Tinto Group subsidiary company exploring for conventional hydrocarbons and while not leading to a conventional development, the data from the cores demonstrated the presence of tight oil and gas and several horizons were shown to be prospective for unconventional oil and gas.

In April 2011, Falcon Australia entered into a joint venture with Hess, whereby Hess agreed to collect seismic data over an area covering three of the four Beetaloo Exploration Permits, excluding an area covering approximately 100,000 acres (approximately 405 km^2) surrounding the Shenandoah-1 well-bore. Since the date of this agreement, Hess has spent in excess of US$55 million acquiring 3,490 kilometres of 2D seismic data which is currently being interpreted. Hess has the option, valid until 30 June 2013, to acquire a 62.5 per cent. working interest in the Hess Area of Interest by committing to drill and evaluate five exploration wells at Hess' sole cost, one of which must be a horizontal well. Further details of the Hess Agreement are provided in Section 15.1.1 of Part VI of this document.

Karoo Basin, South Africa

Falcon holds a Technical Cooperation Permit covering an area of approximately 7.5 million acres (approximately 30,327 km^2) onshore Karoo Basin, South Africa. In geological terms the Karoo refers to a geological period lasting some 120 million years and the rocks laid down during that period of time. These rocks were deposited in a large regional basin and resulted in the build-up of extensive deposits, some of which have been identified as having potential for shale gas.

The TCP grants Falcon an exclusive right to apply for an exploration right over the underlying acreage. In February 2011, a moratorium on the processing of all new applications relating to the exploration and production of shale gas in the Karoo Basin was put in place, and in April 2011 the processing of all existing applications was suspended whilst the South African Department of Mineral Resources conducted an environmental study on the effects of hydraulic stimulation and developed a system to regulate onshore exploration activities. In September 2012, the South African Government announced a decision to lift the moratorium on the processing of existing shale gas exploration permit applications following the publication of regulations (expected in Q2 2013), and consequently the Board expects that the exploration right over the acreage will be awarded in the second half of 2013.

In December 2012, Falcon entered into an exclusive cooperation agreement with Chevron to jointly seek unconventional exploration opportunities in the Karoo Basin. The Chevron Agreement provides for Falcon to work exclusively with Chevron for a period of five years to jointly seek to obtain exploration rights in the Karoo Basin subject to the parties mutually agreeing participation terms applicable to each right. Further details of the Chevron Agreement are provided in Section 15.2.1 of Part VI of this document.

Makó Trough, Hungary

Falcon began operations in Hungary in 2005 and it is the most developed asset in its portfolio. Falcon's subsidiary, TXM, holds the 35-year Makó Production Licence covering an area of approximately 245,775 acres (approximately 1,000 km^2) located in the Makó Trough, part of the greater Pannonian Basin of central Europe. The Makó Licence is located approximately ten kilometres from the MOL Group owned and operated Algyö field, which has produced approximately 2.5 Tcf and 220 Mmbo to date. The Makó Licence area is transected by existing gas pipelines, including a 12 kilometre gas pipeline built by Falcon in 2007, which together offer potential access to local and international markets.

The Makó Trough contains two distinct plays;

- a play targeting gas prospects in the Algyö Play at depths between 2,300 metres and 3,500 metres; and
- a deeper unconventional play targeting significant contingent resources in the Deep Makó Trough.

RPS Energy estimates that eight prospects in the Algyö Play contain gross unrisked recoverable prospective gas resources of 568 Bcf (P50). In January 2013, Falcon agreed a three-well drilling exploration programme with NIS, owned 56 per cent. by Gazprom Group, to target the Algyö Play. NIS have made a cash payment of US$1.5 million to Falcon and agreed to drill three exploration wells by July 2014. NIS will earn 50 per cent. of net production from the first three wells, and has the option to participate in any future drilling on terms to be negotiated, after paying Falcon US$2.75 million. Falcon is to be fully carried on the drilling and testing of the three exploration wells. Further details of the NIS Agreement are contained in Section 15.3.1 of Part VI of this document.

Drilling preparations are already underway. NIS has informed the Company that it expects the first well to spud by the end of Q2 2013 and the three-well drilling programme to be completed before the end of 2013.

Between 2005 and 2007, Falcon acquired 1,100 km^2 of 3D seismic data and executed a six-well drilling programme on the Deep Makó Trough. Each of the six wells encountered thick sequences of hydrocarbon bearing rocks, and tests flowed hydrocarbons from each tested horizon. Early exploration efforts focused on proving hydrocarbon potential and delineation of the basin in order to secure the Makó Production Licence. Falcon may seek to partner with an industry player to re-enter and develop the Deep Makó Trough play.

RPS Energy in its independent CPR (contained in Part IV of this document) estimates gross recoverable contingent resources for the Makó Production Licence of 35.3 Tcf of gas and 76.7 Mmbo of oil (P50).

2. KEY INVESTMENT CONSIDERATIONS

The Directors believe that an investment in the Company should be attractive to potential investors for the following reasons:

- The Group has existing interests covering approximately 14.75 million acres in an internationally diversified portfolio and the Board believes that these are some of the most prospective unconventional oil and gas basins in the world;
- RPS Energy, in a report published 1 January 2013 (and reproduced in Part IV of this document), estimates gross unrisked recoverable prospective resources (play level) of 162 Tcf of gas and 21,345 Mmbo of oil (P50) in the Group's Beetaloo Exploration Permits in Australia, gross unrisked recoverable prospective gas resources of 568 Bcf (P50) (the Algyö Play), and gross recoverable contingent resources of 35.3 Tcf of gas and 76.7 Mmbo of oil (P50) (the Deep Makó Trough) in the Makó Production Licence in Hungary;
- The Group has significant, well established partners in place in each country, and in the case of Hess in Australia and NIS in Hungary, carrying the Company through the initial respective work programmes and providing technical skills and financial resources;
- The Group has interests located in countries close to existing energy infrastructure, in jurisdictions which the Directors believe have governments favourable towards unconventional oil and gas exploration; and
- The Company has an experienced board and management team, including individuals with established and successful track records in acquiring and developing oil and gas assets. Further details of the Company's Board and management are contained in Section 8 of this Part I.

3. GROUP STRATEGY

Falcon's strategy is to leverage the Group's expertise in the unconventional oil and gas industry to acquire interests in licences covering large acreages of land and to build on its internationally diversified portfolio of unconventional assets and interests, which are located in countries that the Board believes support the exploitation of unconventional oil and gas. Following acquisition, Falcon seeks to develop a deeper technical understanding of the potential of its acreage and establish good working relations with landowners, regulators and the local community. In parallel, Falcon seeks strategic joint ventures with technically capable and well-funded partners to participate in and advance their exploration efforts. The Board intends that Falcon will be fully or partially carried by its partners through seismic and drilling programmes by entering into farm-out arrangements in relation to its acreage positions, with the objective of retaining a material minority stake in the assets. It is the Board's intention to proactively manage its portfolio and monetise assets at a significant premium to the acquisition costs. Falcon may also seek to take advantage of opportunities as they arise to make strategic corporate acquisitions to expand its portfolio.

4. BACKGROUND AND HISTORY

Falcon was incorporated in British Columbia, Canada in 1980 as Sanfred Resources Ltd., which was listed on the TSX Venture Exchange in 1999. It subsequently changed its name to Falcon Oil & Gas Ltd. in 1999, and in 2002 it acquired an interest in four producing gas wells in Hackett, Alberta, Canada. In February 2005, Falcon acquired the entire issued share capital of Makó Energy Corporation, in a reverse takeover. Makó Energy Corporation held a number of exploration licences in Hungary. The Group conducted a six-well drilling programme in the Deep Makó Trough between 2005 and 2007.

In September 2008 Falcon, through Falcon Australia, acquired a 50 per cent. working interest in the Beetaloo Exploration Permits from PetroHunter Energy Corporation and its subsidiary, Sweetpea and in May 2009, the Group acquired a further 25 per cent. working interest in the Beetaloo Exploration Permits. In December 2009, Falcon Australia acquired the remaining 25 per cent. interest in the Beetaloo Exploration Permits from Sweetpea in consideration for, *inter alia*, the issuance to Sweetpea of 25 per cent. of Falcon Australia's shares. In April 2010, the Northern Territory's Department of Resources confirmed Falcon Australia's ownership of 100 per cent. of the Beetaloo Exploration Permits and in the course of 2010 Falcon Australia raised approximately US$6.1 million by way of a private placement of its ordinary shares.

In 2009, the Group was granted a TCP in the Karoo Basin in South Africa.

Between 2005 and 2011, the Group raised approximately US$341 million in a number of private placements of Common Shares. In addition, the Company issued Debentures worth C$10.7 million (approximately US$11 million) that mature in June 2013.

In September 2011, John Craven was appointed as Non-Executive Chairman and in May 2012 Philip O'Quigley was appointed Chief Executive Officer. In September 2012, the Company relocated its corporate headquarters from Denver, Colorado to Dublin, Ireland.

5. INFORMATION ON THE ASSETS

The following table summarises the principal oil and gas interests of the Group in Australia, South Africa and Hungary:

Assets (Country)	*Interest (%)*	*Operator*	*Status*	*Area (km^2)*	*Expiry*
Exploration Permit EP-76 (Beetaloo Basin, Northern Territory, Australia)	72.7%[1]	Hess	Exploration	4,976.3	31/12/2013
Exploration Permit EP-98 (Beetaloo Basin, Northern Territory, Australia)	72.7%[1]	Hess[2]	Exploration	11,412.1	31/12/2013
Exploration Permit EP-99 (Beetaloo Basin, Northern Territory, Australia)	72.7%[1]	Falcon Australia	Exploration	2,587.2	31/12/2013
Exploration Permit EP-117 (Beetaloo Basin, Northern Territory, Australia)	72.7%[1]	Hess	Exploration	9,218.3	31/12/2013
Technical Cooperation Permit, (Karoo Basin, South Africa)	100%	Falcon	TCP	30,326.9	In Force[3]
Makó Production Licence (Makó Trough, Hungary)	100%	TXM	Production	994.6	21/05/2042

Notes:

1 Falcon owns 72.7 per cent. of Falcon Australia, which holds a 100 per cent. interest in the Beetaloo Exploration Permits. Of the remaining 27.3 per cent. of Falcon Australia, 24.2 per cent. is owned by Sweetpea, a wholly owned Australian subsidiary of PetroHunter Energy Corp. and 3.1 per cent. interest is held by others.

2 Falcon Australia retains operatorship in the Shenandoah-1 well and approximately 405 km^2 (approximately 100,000 acres) land around the Shenandoah-1 well-bore in exploration permit EP-98.

3 In compliance with the terms of the TCP, Falcon submitted its application for an exploration permit in August 2010 prior to the moratorium being introduced in April 2011. Local counsel has confirmed that despite the TCP expiry date of October 2010 having passed, Falcon's interests remain valid and enforceable.

The CPR, which includes, *inter alia*, independent resource assessments in respect of the Group's Australian and Hungarian assets, is contained in Part IV of this document.

Beetaloo Basin, Northern Territory, Australia

Overview

Falcon Australia, Falcon's 72.7 per cent. owned subsidiary, is the registered holder of four exploration permits, comprising approximately 7 million acres (approximately 28,000 km^2) in the Beetaloo Basin, Northern Territory, Australia. The Beetaloo Basin is located 600 kilometres south of Darwin close to infrastructure including a highway, two pipelines and a railway, offering transport options to the Australian market and beyond via the existing and proposed LNG capacity in Darwin.

The Beetaloo Basin is a Proterozoic and Cambrian tight oil and gas basin. In its entirety, the Beetaloo Basin covers approximately 8.7 million acres (approximately 35,260 km^2) and is a relatively underexplored onshore exploration basin with, as far as the Company is aware, 11 exploration wells drilled in the Beetaloo Basin to date. The area is remote and sparsely populated and the Board believes that it is well suited for oil and gas projects. Australia has a developed resources industry with a stable political, legal and regulatory system.

RPS Energy, in its independent CPR dated 1 January 2013 (contained in Part IV of this document), estimates gross unrisked recoverable prospective resource (play level) potential of 162 Tcf of gas and 21,345 Mmbo of oil (P50) for Falcon Australia's Beetaloo Exploration Permits.

Exploration Permits

A summary of Falcon Australia's Beetaloo Exploration Permits is contained in the table above. The acreage interests covered by the Beetaloo Exploration Permits cover the majority of the Beetaloo Basin and are held 100 per cent. in the name of Falcon Australia.

In April 2011, Falcon Australia agreed a joint venture with Hess whereby Hess agreed to collect seismic data over an area made up of three of the four Beetaloo Exploration Permits, excluding exploration permit EP-99 and area within exploration permit EP-98 (the Shenandoah-1 well and approximately 100,000 acres (approximately 405 km^2) of land around the well-bore), referred to as the Hess Area of Interest. Falcon Australia is the operator of exploration permit EP-99 and Hess is the operator of exploration permits EP-76, EP-98 and EP-117. Falcon Australia also retained operatorship in the Shenandoah-1 well and approximately 100,000 acres (approximately 405 km^2) of land around the Shenandoah-1 well-bore within exploration permit EP-98. The work commitments for the Beetaloo Exploration Permits held by Falcon Australia have been met for previous years, with the exception of exploration permit EP-99, on which an extension was granted to 31 December 2013. In September 2012, Falcon Australia obtained Northern Territory Department of Resources approval for a 12 month extension of the Beetaloo Exploration Permits until 31 December 2013.

In accordance with local law and regulations, all Falcon Australia's acreage interests are subject to royalties on production values of up to approximately 12 per cent. to government and native title holders/claimants and up to approximately 13 per cent. to other parties. In addition, Falcon Australia is subject to Commonwealth Government corporation tax of 30 per cent., and to the Commonwealth Government's Petroleum Resource Rent Tax ("PRRT") levied at the rate of 40 per cent. on the taxable profits derived from the petroleum project in a year of tax.

Discoveries and Prospectivity

The Board believes that the Beetaloo Basin is relatively under-explored and has shale oil, shale gas and BCGA potential. As far as the Company is aware, 11 wells have been drilled in the Beetaloo Basin to date. This work was undertaken by a Rio Tinto Group subsidiary company exploring for conventional hydrocarbons and while not leading to a conventional development, the data from the cores demonstrated the presence of tight oil and gas and several horizons were shown to be prospective for unconventional oil and gas.

There are no existing fields but there are numerous mudlog and core oil and gas shows throughout the Beetaloo Basin in prospective formations. The Shenandoah-1 was a vertical hole well drilled by Sweetpea in 2007. The well was deepened by Falcon Australia in 2009 to finish at 2,714 metres. It was re-entered in Q3 2011 and five short tests were conducted including several fraccing operations. Gas was recovered from three zones with some liquids. One gas zone flowed gas at rates between 50 to 100 Mcfpd.

Current activity

Hess paid Falcon Australia an initial sum of US$17.5 million on signing the Hess Agreement and since then Hess has acquired 3,490 kilometres of 2D seismic data at an estimated cost in excess of US$55 million. The 2D seismic data is currently being processed and interpreted. Hess has the option, valid until 30 June 2013, to acquire a 62.5 per cent. working interest in the Hess Area of Interest by committing to drill and evaluate five exploration wells at Hess' sole cost, one of which must be a horizontal well. All costs to plug and abandon the five exploration wells will also be borne solely by Hess. The Board estimates that the gross costs associated with the five-well programme will be approximately US$75 million. Hess has agreed, subject to proceeding to the development phase, to carry Falcon Australia, on the first development well, up to a gross cost of US$10 million, which the Board believes will be the total gross cost of this well. Costs to drill wells after the five exploration wells and the first development well (and after the initial US$10 million) will be borne 62.5 per cent. by Hess and 37.5 per cent. by Falcon Australia. Further details of the Hess Agreement are provided in Section 15.1.1 of Part VI of this document.

Under the minimum work commitments for exploration permit EP-99, Falcon Australia must spend a minimum of US$1.5 million by 31 December 2013 in collecting 2D seismic data on the underlying acreage within exploration permit EP-99. Falcon Australia is currently finalising a 2D seismic acquisition programme for exploration permit EP-99 in order to meet this requirement in 2013. This 2D seismic data is expected to provide the necessary information to plan a potential well programme in the coming years. Falcon Australia intends to meet this commitment either through a farm-out arrangement or through its own resources. Falcon Australia has received expressions of interest from a number of third parties regarding a possible farm-out arrangement on the combined area outside of the Hess Area of Interest comprising exploration permit EP-99 and approximately 100,000 (approximately 405 km^2) acres around the Shenandoah-1 well, measuring approximately 739,388 acres (approximately 2,992 km^2) in total. The Board estimates that the gross costs associated with the initial drilling programme on the combined area outside of the Hess Area of Interest will be between US$25-US$50 million.

Karoo Basin, South Africa

Overview

Falcon holds a TCP covering an area of approximately 7.5 million acres (approximately 30,327 km^2), in the southwest Karoo Basin, South Africa, which grants Falcon exclusive rights to apply for an exploration right over the underlying acreage. In August 2010, Falcon submitted an application to the Petroleum Agency of South Africa for an exploration right over the acreage covered by the TCP and, as part of the application process, Falcon submitted an environmental management plan in January 2011.

On 1 February 2011, the Minister of Mineral Resources (the "Minister") published a notice in the Government Gazette declaring a moratorium on the processing of all new applications relating to the exploration and production of shale gas in the Karoo Basin. This moratorium did not extend to existing applications, such as Falcon's, that were submitted prior to 1 February 2011. In April 2011, the Minister announced a further moratorium, which was not officially declared in terms of a notice in the Government Gazette, prohibiting all new applications and suspending the processing of all pending application whilst the South African Department of Mineral Resources conducted an environmental feasibility study on the effects of hydraulic stimulation and developed a system to regulate onshore exploration activities (the "Undeclared Moratorium"). The Undeclared Moratorium has no legal effect since it is a requirement of the South African petroleum legislation that all such moratoriums be published in the Government Gazette. In September 2012, the South African Government announced a decision to lift the Undeclared Moratorium on shale gas exploration. The Minister has indicated that although the Undeclared Moratorium has been "lifted", pending exploration right applications will not be processed and awarded until the regulations regarding hydraulic fracturing have published. These regulations are expected to be published in Q2 2013. Consequently, the Board expects that the exploration right over the acreage will be awarded in the second half of 2013.

The South African Government is entitled to a royalty on the sale of mineral resources of up to seven per cent. of gross sales (in the case of unrefined resources) and five per cent. of gross sales (in the case of refined resources, such as oil and gas). The Liquid Fuels Charter provides that an oil and gas company must reserve not less than nine per cent. for Historically Disadvantaged South Africans ("HDSA") to buy-in to any offshore production right granted. On the advice of South African counsel, the Board believes that the HDSA buy-in will also apply to onshore production rights in South Africa, including any right granted pursuant to the TCP. Similarly, the State has an option to acquire an interest of up to ten per cent. in any production right granted. However, it is not required to pay any consideration for its ten per cent. interest or contribute to past costs, but must contribute *pro rata* in accordance with its interest towards production costs going forward.

Corporation tax in South Africa is imposed at a rate of 28 per cent. of taxable income. Dividends tax is imposed on the shareholder at a rate of 15 per cent.

Discoveries and Prospectivity

In its entirety, the Karoo Basin is approximately 173 million acres (approximately 700,000 km^2) in size located in central and southern South Africa and contains thick, organic rich shales such as the Permian Whitehill Formation. The Karoo describes a geological period lasting some 120 million years and the rocks laid down during that period of time, covering the late Paleozoic to early Mesozoic interval. These were deposited in a large regional basin and resulted in the build-up of extensive deposits.

Until recently, the Karoo Basin was not considered prospective for commercial hydrocarbons resulting in very limited modern hydrocarbon exploration onshore in South Africa. In an independent report dated April 2011, the U.S. Energy Information Administration ("EIA") estimated that there are 485 Tcf technically recoverable resources in the Karoo Basin which would rank it fifth in the world after China, USA, Argentina and Mexico for shale gas potential. In particular the Permian Ecca group contains three potential shales identified as having potential for shale gas. The shale in the Whitehall Formation, in particular, is ubiquitous, has a high organic content and is thermally mature for gas.

Current activity

In December 2012, Falcon entered into an exclusive cooperation agreement with Chevron to jointly seek unconventional exploration opportunities in the Karoo Basin. The Chevron Agreement provides for Falcon to work exclusively with Chevron for a period of five years to jointly seek to obtain exploration rights in the Karoo Basin subject to the parties mutually agreeing participation terms applicable to each right. As part of the Chevron Agreement, Chevron made a cash payment to Falcon of US$1 million in February 2013 as a contribution to past costs. Further details of the Chevron Agreement are provided in Section 15.2.1 of Part VI of this document.

Makó Trough, Hungary

Overview

Falcon has been active in the Makó Trough since 2005 when it acquired two exploration licences, the Makó and the Tisza exploration licences. Between 2005 and 2007, Falcon pursued a work programme consisting of the acquisition of 1,100 km^2 of 3D seismic data and a six-well drilling programme. Each of the six wells encountered thick sequences of hydrocarbon bearing rocks, and tests flowed hydrocarbons from each tested horizon. In 2007, Falcon's subsidiary, TXM, was awarded the 35-year Makó Production Licence which covers some of the acreage originally covered by the Makó and the Tisza exploration licences.

Hungary is an established oil and gas producing country and the Makó Production Licence is in the vicinity of the largest producing field in Hungary, the MOL Group owned and operated Algyö field, which has produced approximately 2.5 Tcf and 220 Mmbo to date, and is located approximately ten kilometres to the west of the Makó Production Licence boundary. The Makó Production Licence area is transected by existing gas pipelines and infrastructure, including a 12 kilometre gas pipeline built by Falcon in 2007, together offering transport and potential access to local markets and larger distribution centres for international markets.

Makó Production Licence

The Makó Production Licence was granted by the Hungarian Mining Authority over a gas exploration project in the Makó Trough, located in south-eastern Hungary. The lands within the Makó Production Licence were formerly part of the Group's two hydrocarbon exploration licences – the Tisza exploration licence and the Makó exploration licence.

The Makó Production License covers approximately 245,775 acres (approximately 1,000 km^2) and is held 100 per cent. by TXM, a wholly owned subsidiary of the Group. Under the terms of the Makó Production Licence, the Group is obliged to pay a 12 per cent. royalty to the Hungarian Government on any unconventional production and has a further five per cent. royalty payable under an agreement with Prospect Resources Inc., the previous owners of the acreage covered by the Makó Production Licence. Corporate profits are taxed at 19 per cent. In 2009, an additional profit based energy industry tax, levied on energy supplying companies, was introduced. The rate was originally set at eight per cent. but, as part of Hungary's third package of austerity measures, the rate has increased to 31 per cent. from 2013, with deductions allowable for certain capital expenditures. TXM is the operator and there are no outstanding work commitments on the Makó Production Licence.

Discoveries and Prospectivity

The Makó Trough contains two plays;

- a play targeting gas prospects in the Algyö Play at depths between 2,300 metres and 3,500 metres; and
- a deeper unconventional play targeting significant contingent resources in the Deep Makó Trough.

The Algyö Play

The Algyö Play is a relatively shallow play of between 2,300 and 3,500 metres. A number of Falcon wells have been drilled through the Algyö Play in recent years, some of which encountered gas shows, but to date none of these wells tested the shallow play concept at an optimal location, as these wells targeted the Deep Makó Trough, at intervals of up to 6,000 metres. Multiple Algyö prospects have subsequently been identified by the Group through extensive AVO analysis, and 3D seismic data has shown the presence of possible gas zones above the Szolnok formation (part of the Deep Makó Trough). In total, ten prospects have been identified within the Algyö Play from which RPS Energy, in its independent CPR (contained in Part IV of this document), estimates eight prospects contain gross unrisked recoverable prospective gas resources of 568 Bcf (P50).

In January 2013, Falcon agreed a three-well drilling exploration programme with NIS to target the Algyö Play, whereby NIS made a cash payment of US$1.5 million to Falcon in February 2013, and agreed to drill three exploration wells by July 2014. NIS will earn, after undertaking the three-well drilling obligation, 50 per cent. of the net production revenues from the three wells drilled. The Board estimates that the gross costs of the three-well drilling programme will be approximately US$21 million. In addition, NIS will have an option to acquire a right of first negotiation for future drilling operations in the Algyö Play, sharing any potential future costs and revenue with the Group, on terms to be negotiated, after paying Falcon US$2.75 million. Falcon will be fully carried on the drilling and testing of three exploration wells and will retain 100 per cent. interest in the Deep Makó Trough. Further details of the NIS Agreement are contained in Section 15.3.1 of Part VI of this document.

The Deep Makó Trough

This is a deeper unconventional play targeting gas, and to a lesser extent oil, in the low permeability and low porosity rocks in the deeper horizons of the basin. RPS Energy in its independent CPR (contained in Part IV of this document) estimates gross recoverable contingent resources for the Deep Makó Trough of 35.3 Tcf of gas and 76.7 Mmbo of oil (P50).

Between 2005 and 2007, Falcon acquired 1,100 km^2 of 3D seismic data and executed a six-well drilling programme on the Deep Makó Trough. Early exploration efforts focused on proving hydrocarbon potential and delineation of the basin in order to secure the Makó Production Licence. Each of the six wells encountered thick sequences of hydrocarbon bearing rocks, and tests flowed hydrocarbons from each tested horizon. Several wells flowed gas on test and one well, the Magyarcsanád-1, tested light oil. The deepest well was the Makó-7 which, along with the Makó-4, was not tested. The Makó-7 results demonstrated the presence of a very large column of hydrocarbons in the well-bore. In 2007, Falcon constructed a 12 kilometre gas pipeline which connected the Makó-6 and Makó-7 wells with a MOL operated pipeline, offering potential access to local and international markets. The Company plans to re-enter the untested Makó-7 and Makó-4 wells and will seek a technically and financially capable partner to test and produce the shale gas and tight gas formations in the Deep Makó Trough. The Board estimates that the gross costs of re-entering and testing the Makó-7 and Makó-4 wells will be approximately US$25 million.

Current Activity

Drilling preparations are already underway in the Algyö Play. NIS has informed the Company that it expects the first well to spud by the end of Q2 2013 and the three-well drilling programme to be completed before the end of 2013.

Alberta, Canada

For the 12 months ended 31 December 2011, Falcon had revenue of US$33,000 (2010: US$28,000) which was earned from non-operating working interests in three producing, and one recently shut-in, natural gas wells located in Alberta, Canada. Falcon does not anticipate any further exploration or development of these wells and no further material revenue is expected to be generated or material costs incurred.

6. REASONS FOR THE PLACING AND ADMISSION

The Board believes that a listing on AIM and ESM will give the Company access to additional sources of finance not currently available to it, providing the Company with further opportunities to fund growth in the future. A listing on AIM and ESM is also closer to the new corporate headquarters in Dublin, Ireland and is intended to establish a broad institutional shareholder base in London and increase liquidity.

7. CURRENT TRADING, TRENDS AND PROSPECTS

The unaudited results for the Group for the nine months to 30 September 2012 are set out in Part V of this document. The Group currently has no material revenue generating operations. Cash and cash equivalents as at 30 September 2012 were US$5.6 million. In Q3 2012, the Company relocated its corporate headquarters from Denver, Colorado to Dublin, Ireland. As a result, the Company recorded an estimate of the expenses related to this restructuring, including severance and employee related benefits and certain other expenses, totalling approximately US$1.9 million.

On 12 December 2012, Falcon entered into an exclusive cooperation agreement with Chevron to jointly seek unconventional exploration opportunities in the Karoo Basin. The Chevron Agreement provides for Falcon to work exclusively with Chevron for a period of five years to jointly seek to obtain exploration rights in the Karoo Basin subject to the parties mutually agreeing participation terms applicable to each right. As part of the Chevron Agreement, Chevron made a cash payment to Falcon of US$1 million in February 2013 as a contribution to past costs.

On 21 January 2013, the Group announced the completion of the acquisition of 2D seismic data by Hess over the Hess Area of Interest in the Beetaloo Basin, Northern Territory, Australia. During 2011 and 2012, Hess acquired 3,490 km of 2D seismic data at an estimated cost in excess of US$55 million, which is currently being interpreted.

On 22 January 2013, Falcon agreed a three-well drilling exploration programme with NIS to target the Algyö Play. NIS has made a cash payment of US$1.5 million to Falcon and agreed to drill three exploration wells by July 2014. NIS will earn 50 per cent. of net production from the first three wells, and has the option to participate in any future drilling on terms to be negotiated, after paying Falcon US$2.75 million. Falcon is to be fully carried on the drilling and testing of the three exploration wells.

On 24 January 2013, the Group announced that an independent CPR carried out by RPS Energy estimates gross recoverable prospective resources for the Group's Beetaloo Exploration Permits in Australia of 162 Tcf of gas and 21,345 Mmbo of oil (P50), gross recoverable prospective gas resources in the Algyö Play of 568 Bcf (P50) and gross recoverable contingent resources in the Deep Makó Trough of 35.3 Tcf of gas and 76.7 Mmbo of oil (P50), both in Hungary.

In Q2 2013, the Company intends to repay approximately C$10.7 million (approximately US$11 million) relating to outstanding Debentures which have a maturity date of 30 June 2013.

Under the terms of Falcon Australia's exploration permit EP-99, which is not covered by the Hess Agreement, Falcon Australia must spend a minimum of US$1.5 million by 31 December 2013 in collecting 2D seismic data on acreage within exploration permit EP-99. Falcon Australia intends to meet this commitment either through a farm-out arrangement or through its own resources.

On receipt of an approved exploration right in South Africa, the Group will be required to make a payment to the South African government of approximately US$0.7 million as part of the process to obtain an approved work programme and an exploration permit. The Group is not planning any independent technical operations in Hungary other than joint operations with NIS, and as such no material capital expenditures are expected.

The prospects for Falcon are dependent on, *inter alia*, the decision by Hess to exercise its option to acquire a 62.5 per cent. working interest in the Hess Area of Interest, the outcome of the drilling of the initial three wells by NIS in the Algyö Play, the award of an exploration right over the Group's acreage interest in South Africa and the success of the Company in implementing its strategy as set out in Section 3 of this Part I.

8. DIRECTORS AND SENIOR MANAGEMENT

The Board, as at the date of this document, comprises two executive directors and six non-executive directors. Biographies on the Directors and senior management are provided below.

John Craven: *Non-Executive Chairman (63)*

Mr. Craven has been Non-Executive Chairman of the Board since September 2011 and has over 35 years of experience in technical, commercial, financial and leadership roles at major international upstream oil companies and junior independents. John is currently CEO of Discover EXploration and his career has been noted for a series of successful new venture negotiations, the exploration of which led to major discoveries in Mozambique, Algeria, Colombia, offshore Ghana and Indonesia. Along with his co-directors, he led Ardmore Petroleum, Dana Petroleum, Petroceltic International and recently Cove Energy through the acquisition of major upstream assets and key exploration and developmental milestones. During this time Mr. Craven has been actively involved in corporate finance and was responsible for raising initial capital through private sources and floating Petroceltic International on the Irish Stock Exchange and Cove Energy on AIM. Mr. Craven holds an MSc in Petroleum Geology from the Royal School of Mines in London and an MBA from Queen's University in Belfast.

Philip O'Quigley: *Chief Executive Officer (49)*

Mr. O'Quigley has been a member of the Board since September 2012 and has been Chief Executive Officer of Falcon since May 2012. Mr. O'Quigley brings 20 years' experience in senior management positions in the oil and gas industry. His career, which spans a number of London and Dublin listed exploration and production companies, includes experience working in countries such as Argentina, the United States, Algeria, the UK and Ireland. Most recently, he served as Finance Director for Providence Resources, an Irish oil and gas exploration and production company and he remains on the board of Providence Resources as a non-executive director. Mr. O'Quigley is a Fellow of the Institute of Chartered Accountants in Ireland and qualified as a Chartered Accountant with Ernst & Young in Dublin.

Dr. György Szabó: *Director (72)*

Dr. Szabó has been a Director of Falcon since 2006. He has also previously served as Consultant and Mining Bureau Registered Technical Responsible Person for Falcon's wholly-owned subsidiary TXM. Dr. Szabó is a widely recognized authority in the Hungarian and international petroleum industry. In addition to being a university professor, Dr. Szabó has overseen the design and implementation of the deepest HP-HT well ever drilled in Hungary. In 1991 he was in charge of successful fire control and well abandonment operations by Hungarian teams in Kuwait. He was instrumental in the privatisation and the strategy related to the capitalisation and structure of Hungary's former national oil company (presently MOL Group), as well as the landmark listing of the company on domestic and international securities exchanges in 1995. Dr. Szabó graduated from Miskolc University and received a degree in petroleum engineering in 1963. He received his Ph.D. in 1975.

Daryl H. Gilbert: *Non-Executive Director (61)*

Mr. Gilbert has been a member of the Board since September 2007 and is a Professional Petroleum Engineer with over 35 years experience in both the Canadian and international oil and gas industries. Mr. Gilbert serves as a director of several energy related public entities in addition to Falcon including AltaGas Ltd. and

Penn West Petroleum Ltd. He is also currently a Managing Director of JOG Capital Inc. a private equity oil and gas investment firm located in Calgary Alberta. The greater part of Mr. Gilbert's career was spent in the independent energy evaluation consulting sector. In 1979, he joined the predecessor oil and gas engineering and geological firm which became Gilbert Laustsen Jung Associates Ltd. ("GLJ") where he served as a Principal Officer beginning in 1988 and as President and Chief Executive Officer from 1994 through to his retirement from consulting in 2005. Mr. Gilbert has a BSc from the University of Manitoba in Civil Engineering and is a member of the Association of Petroleum Engineers, and Geoscientists of Alberta, the Society of Petroleum Engineers and the Society of Petroleum Evaluation Engineers.

JoAchim Conrad: *Non-Executive Director (48)*

Mr. Conrad has been a member of the Board since October 2008 and is currently a Senior Advisor at Gazprom Germania GmbH and Managing Director of BosphorusGaz Corporation, Turkey, Istanbul (a 71 per cent. Gazprom owned company). With a strong track record in the European natural gas industry, he was formerly serving in the position as Managing Director of Gazprom Marketing and Trading GmbH (100 per cent. Gazprom owned) and as member of the group executive board of Elektrizitätsgesellschaft Laufenburg AG ("EGL"), a European energy trading company with its own energy producing assets listed on the Swiss stock exchange, where he was responsible for EGL's gas division. At the same time, Mr. Conrad was member of the supervisory board of certain of EGL's foreign subsidiaries including the Trans Adriatic Pipeline AG, a joint venture of EGL and StatoilHydro. Prior to joining EGL, Mr. Conrad was Head of Trading at WINGAS GmbH, Germany, a joint venture of Wintershall and Gazprom. He served in various management functions for 10 years in the German oil and gas corporation Wintershall. Mr. Conrad graduated with an Economics degree from Georg-August Universität, Germany, in 1992 focusing on Economics and Information Technology, Graduation in Artificial Intelligence.

Gregory Smith: *Non-Executive Director (65)*

Mr. Smith has been a member of the Board and Chairman of the Audit Committee since December 2009 and is a Chartered Accountant and President of Oakridge Financial Management Inc., a provider of financial and management consulting services to private and public companies. He is also the CFO and a director of Maglin Site Furniture Inc., a corporation that manufacturers and distributes public site furniture primarily in Canada and the United States. He is currently a director and chairman of the audit committee of Armistice Resources Corp and a director of a number of private corporations. He is a past director and audit committee chairman of a number of public and private resource corporations, including director and chairman of the audit committees of TriWestern Energy Inc., Manson Creek Resources Ltd., CDG Investments Inc. and Tyler Resources Inc. Mr. Smith was admitted to the Institute of Chartered Accountants of Alberta in 1975 and holds a Bachelor of Commerce degree from the University of Calgary.

Igor Akhmerov: *Non-Executive Director (47)*

Mr. Akhmerov has been a member of the Board since December 2010. He was also on the Board from September 2007 until May 2008. Mr. Ahkmerov graduated from the Moscow Institute of Management in 1989, Wharton Business School in 1995, and Lauder Institute of Business and International Relations, also in 1995. From 1989 through 1993 Mr. Akhmerov worked at the Moscow office of Bain & Company, specialised in privatisation and banking. After graduation from Wharton Business School, Mr. Akhmerov joined the Boston office of Bain & Company. In 1998 Mr. Akhmerov returned to Russia and joined Sputnik Group, the largest Russian private equity investment group, as a partner. In 2001 he moved to TNK as First Vice President for planning, budgeting, investment governance, taxes, and reporting. From 2004 until 2006 he served as chief financial officer of Renova Group. He has served as Chief Executive Officer of Avelar Energy Group since 2007. Mr. Igor Akhmerov is also a non-executive member of the board of directors of Aión Renewables SpA, a leading player in the Italian solar market, since 24 September 2008.

David Harris: *Non-Executive Director (53)*

Mr. Harris has been a member of the Board since September 2012. Since 2010 Mr. Harris has operated as the sole proprietor of DGH International GeoConsulting ("DGH"). DGH has been involved in a wide variety of projects, ranging from brief opinion letters on investment opportunities to the assessment of the unconventional potential of various countries, to detailed technical assessments of farm-in opportunities and acquisitions. These have been done for Investment Banks, Energy Research Firms, private equity firms, boards of directors and management teams. Prior to this, Mr. Harris spent 22 years at GLJ Petroleum Consultants, where he held the roles of Senior Vice President, Senior Partner and director of the firm. His responsibility was oversight of the GeoSciences Group, which included 13 geologists, geophysicists and support staff. Mr. Harris holds a B.Sc. in Geology (with Honours) from University of Calgary (1981).

Senior Management Team

Eoin Grindley: *Chief Financial Officer (43)*

Eoin Grindley was appointed Chief Financial Officer of Falcon in July 2012. Eoin has over 20 years of financial management experience and has worked in senior management positions at Sandvik Mining and GE Energy. Eoin is a member of the Chartered Institute of Management Accountants since 1996, having graduated from Trinity College Dublin with a B.Sc (Management) in 1991.

Dr. Gábor Bada: *Technical Operations (43)*

Dr. Gábor Bada is a geologist with 15 years of experience in oil and gas exploration, research and assessment. Over the last six years, Dr. Bada has primarily focussed on exploring unconventional resources, including tight gas, shale gas and shale oil plays in various basins in Africa, Australia, the US and Central and Eastern Europe. Dr. Bada has published more than 150 scientific and technical papers. He obtained his geology degree at the Eötvös L. University in Budapest, Hungary and his Ph.D. at the Vrije Aniversiteit Amsterdam, the Netherlands. He is a member of the American Association of Petroleum Geologists, the European Association of Geoscientists & Engineers and the Society of Petroleum Engineers.

9. DETAILS OF THE PLACING AND USE OF PROCEEDS

The Company is proposing to raise £16.9 million, (US$25 million), (before expenses) by the issue of 120,381,973 new Common Shares at 14 pence per new Common Share. The New Common Shares will represent approximately 14.7 per cent. of the Enlarged Issued Share Capital. The New Common Shares will rank *pari passu* in all respects with the Existing Issued Share Capital including the rights to all dividends and other distributions declared, made or paid following Admission and will be issued fully paid. The Placing has not been underwritten.

The Board intends to use the proceeds of the Placing to repay the Company's outstanding Debentures (approximately US$11 million), to finance the Group's work commitments in Australia and South Africa (approximately US$5 million), to enable the Company to make strategic acquisitions (approximately US$5 million), and for general corporate purposes (approximately US$10 million).

The Placing is conditional, *inter alia*, on:

- the Placing Agreement becoming unconditional and not having terminated in accordance with its terms prior to Admission; and
- Admission occurring by no later than 28 March 2013 (or such later date as Davy, GMP and the Company may agree, not being later than 30 April 2013).

Further details of the Placing Agreement are set out in Section 15.4.1 of Part VI of this document.

10. STOCK OPTIONS AND WARRANTS

The Company has established a Stock Option Plan and may grant stock options to directors, officers, employees and consultants, to acquire up to ten per cent. of the Company's issued and outstanding common stock. Further details of the Stock Option Plan are set out in Section 11 of Part VI of this document. The exercise price of all stock options granted is based on the market price of the Company's Common Shares at the date of grant, and no stock options have been granted at a discount to the market price. The stock options can be granted for a maximum term of five years. The Company has in issue stock options over, in aggregate 32,837,000 Common Shares representing 4.0 per cent. of the Enlarged Issued Share Capital.

Further details of the Company's outstanding stock options are provided in Section 5 of Part VI of this document.

There are warrants to purchase 75,287,500 Common Shares in issue, representing 9.2 per cent. of the Enlarged Issued Share Capital. Warrants to purchase 65,287,500 Common Shares at a price of C$0.18 per Common Share were issued to Shareholders in 2011 in connection with the private placement at that time. These warrants expire in February 2014 and April 2014. Warrants to purchase 10,000,000 Common Shares at a price of C$0.19 per Common Share were issued to Hess in July 2011 in connection with the Hess Agreement and expire on 13 January 2015.

11. DIVIDEND POLICY

Falcon has not declared any dividends on the Common Shares. Given the Group's current exploration and appraisal stage, the Board does not anticipate paying any dividends in the foreseeable future. Any future determination to pay dividends will be at the discretion of the Board and will depend upon Falcon's financial condition, results of operations, capital requirements and such other factors as the Board deems relevant.

12. CORPORATE GOVERNANCE

The Company is subject, among other laws and regulations, to instruments published by relevant Canadian securities regulators. One such instrument, National Instrument 58-101 Disclosure of Corporate Governance Practices ("NI 58-101"), prescribes certain disclosure by the Company of its corporate governance practices and National Policy 58-201, Corporate Governance Guidelines ("NP 58-201"), 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 Venture Exchange and being a reporting issuer in British Columbia, Canada, the Company has already established corporate governance practices and procedures, and complies with Canadian corporate governance standards appropriate for a publicly listed company.

The Directors have also adopted a Code of Business Conduct (the "Code") applicable to all employees and officers of the Company and all Directors to highlight key issues and identify resources available to them in order to assist them in reaching appropriate decisions. A copy of the Code may be obtained on written request addressed to the Chief Financial Officer. The Board monitors compliance with the Code and management provides an annual report to the Board regarding issues, if any, arising under the Code.

In particular, the Company has established an Audit Committee, which meets regularly, and a Corporate Governance Committee, a Compensation Committee, a Nomination Committee and a Reserves Committee, each of which is convened as necessary.

The Company currently operates an insider trading and confidential information policy in respect of its listing on the TSX-V which applies to the Directors and certain employees 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 or ESM (particularly relating to dealing during close periods in accordance with Rule 21 of the AIM Rules and ESM Rules) and the Company will take all reasonable steps to ensure compliance by the Directors and any relevant employees with such policy.

As the Common Shares will be admitted to trading on AIM and ESM, the Board intends, where practical for a company of its size and stage of development, to comply with the main provisions of the QCA Guidelines.

13. FINANCIAL INFORMATION

The unaudited interim financial information relating to the Group for the nine month period ended 30 September 2012 and the audited consolidated financial information relating to the Group for the 12 month period ended 31 December 2011, 31 December 2010 and 31 December 2009 can be found in Part V of this document.

The audited consolidated financial information for the Group for the 12 month period ended 31 December 2011, together with restated audited consolidated financial information for 12 month period ended 31 December 2010, and the unaudited interim financial information relating to the Group for the nine month period ended 30 September 2012 have been prepared in accordance with International Financial Reporting Standards ("IFRS"). The audited consolidated financial information for the Group for the 12 month period ended 31 December 2010 and 31 December 2009 was prepared under Canadian Generally Accepted Accounting Principles ("GAAP") and, in relation to the 12 month period ended 31 December 2009, has not been restated.

14. TAXATION

Information regarding UK, Irish and Canadian taxation which may be relevant to holding or dealing in Common Shares is set out in Section 14 of Part VI of this document. That information is intended only as a general guide to the current tax position under UK, Irish and Canadian law. **If you are in any doubt as to your tax position you should consult your own independent financial adviser immediately.**

15. ADMISSION, SETTLEMENT AND DEALINGS

The Common Shares are listed, and in the immediate future will continue to be listed, on the TSX Venture Exchange. Application has been made to the London Stock Exchange and the Irish Stock Exchange for the Company's Enlarged Issued Share Capital to be admitted to trading on AIM and ESM. It is expected that Admission will be effective and that dealings in the Common Shares on AIM and ESM will commence on 28 March 2013.

CREST is a computerised paperless share transfer and settlement system which allows securities to be transferred by electronic means, without the need for a written instrument of transfer. Securities issued by non-UK companies cannot be held or traded in the CREST system. To enable investors to settle such securities through the CREST system, a depositary or custodian can hold the relevant foreign securities and issue dematerialised Depositary Interests representing the underlying securities. With effect from Admission, it will be possible for CREST members to hold and transfer interests in Common Shares of the Company within CREST pursuant to a depositary interest arrangement established by the Company with the Depositary. CREST is a voluntary system and holders of Common Shares who wish to remain outside CREST may do so and will have their details recorded on the Company's share register.

The Depositary will issue Depositary Interests in respect of the underlying Common Shares pursuant to the terms of a deed poll executed by the Depositary. Under the terms of the deed poll, the Depositary will hold as bare trustee all of the rights pertaining to the relevant underlying securities for the benefit of, and on behalf of, the Depositary Interest holder. Any rights or entitlements to cash distributions, to information to make choices and elections, and to attend and vote at general meetings shall be passed to the Depositary Interest holder by the Depositary. Under the deed poll, a Depositary Interest holder can cancel or transfer its Depositary Interests by giving instructions to the Depositary.

The Depositary Interests will be independent securities constituted under English law and will be held on a register maintained by the Depositary. Depositary Interests will have the same ISIN as the underlying Common Shares and do not require a separate admission to AIM or ESM.

Each Depositary Interest will be treated as one Common Share for the purposes of, for example, determining eligibility for dividend payments. Any payments received by the Depositary, as holder of the Common Shares, will be passed on to each Depositary Interest holder noted on the Depositary Interest register as the beneficial owner of the relevant Common Shares.

All Common Shares will remain admitted to trading on the TSX Venture Exchange. Shareholders wishing to migrate their holdings of Common Shares between the TSX Venture Exchange and AIM or ESM and *vice versa* can do so by contacting the Depositary.

Application has been made by the Depositary for Depositary Interests, which represent the underlying Common Shares, to be admitted to CREST on Admission.

16. LOCK IN ARRANGEMENTS

The Directors have each agreed with the Company, Davy and GMP the terms of lock in arrangements in respect of their shareholdings in the Company on Admission. Pursuant to the lock in agreements, each of the Director Shareholders have agreed not to dispose of their interests in the Common Shares held immediately prior to the Placing (excluding stock options and warrants), amounting to 39,920,000 Common Shares in aggregate, or 4.9 per cent. of the Company's Enlarged Issued Share Capital for 12 months after Admission, save in certain circumstances.

Further details of the lock-in agreements are set out in Section 15.4.3 of Part VI of this document.

17. THE BCA AND OTHER CANADIAN LEGISLATION

A summary of certain Canadian corporate legislation that is applicable to the Company is set out below. This summary is not a complete or extensive analysis of all Canadian law that applies to the Company and persons seeking a detailed explanation of Canadian law that will apply to the Company or to them as a consequence of their holding, acquiring or disposing of Common Shares and/or interests in Common Shares in the Company should seek specific independent advice without delay. The Company is obliged to comply with the BCA and also with specific obligations arising from other laws that relate to its activities.

Takeovers

The Company exists under the laws of the province of British Columbia, Canada, and has its registered office in British Columbia and is managed and controlled outside the United Kingdom. Accordingly, transactions in the Common Shares will not be subject to the provisions of the City Code or the Irish Takeover Rules. It is emphasised that, although the Common Shares will be traded on AIM and ESM, the Company will not be subject to takeover regulation in the United Kingdom or Ireland. It follows that Shareholders are not entitled to the protection afforded by the City Code or the Irish Takeover Rules. Instead, the Company is regulated by the relevant Canadian law.

In Canada, securities laws are generally a matter of provincial/territorial jurisdiction and as a result, takeover bids are governed by the securities legislation in each province or territory.

In British Columbia, a takeover bid is generally defined as an offer to acquire outstanding voting or equity securities of a class made to any holder in British Columbia of securities subject to the offer to acquire, if the securities subject to the offer to acquire, together with securities held by the offeror and any person acting in concert with the offeror, constitute in aggregate 20 per cent. or more of the outstanding securities of that class of securities at the date of the offer to acquire. 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 35 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 fifteen 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 administrators 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.

Under British Columbia corporate law, where an offeror has successfully acquired 90 per cent. 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.

Foreign Investment

In Canada, foreign investment in, and ownership of, companies and property is regulated by the Investment Canada Act ("ICA"). Pursuant to the ICA, the Canadian government may review the direct acquisition of control of a Canadian business by a World Trade Organisation ("WTO") investor (or a Canadian business owned by a WTO investor) where the Canadian business has assets with a book value of more than C$344 million (the "threshold") and by a non-WTO investor where the Canadian business has assets with a book value of more than C$5 million. However, following recent amendments to the ICA, the Canadian government is now permitted to review any investment by non-Canadians on the basis of national security concerns. No financial threshold applies and the Canadian government has up to 50 days, following either notification or the filing of an application for review, to issue notice of a potential national security review. In the absence of national security concerns an acquisition of control by a foreign investor of a Canadian business that falls below the threshold will simply require a notification.

Notification of Interests in Common Shares

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 acquiror's securities of that class, would constitute ten 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 a press release announcing the acquisition. Further early warning reports and press releases are required to be prepared and filed each time a person acquires beneficial ownership of, or the power to exercise directions or control over, an additional two per cent. or more of the outstanding securities of the class to which the first early warning report relates. They also require the Company to disclose, in its proxy circular sent out for a general meeting, the names of holders known to the Company to beneficially own more than ten per cent. of the Company's issued and outstanding shares.

The AIM Rules and ESM Rules require an AIM or ESM company (as the case may be) to issue a notification without delay of any relevant changes, being changes to the legal or beneficial interest, whether direct or indirect (insofar as it is aware of such changes), to the holding of a significant shareholder, a significant shareholder being three per cent. or more of any class of an AIM security and five per cent. or more of any class of an ESM security respectively, which increase or decrease such holding through any single percentage.

There are no requirements under the articles or Canadian Securities laws for the Directors or Shareholders who hold three per cent. or more of the Company's share capital to notify the Company of their interests in the Company's share capital or changes in such interests. The UK Disclosure and Transparency Rules do not apply to Falcon, as it is not a UK incorporated company. The Company has requested that the registrar notify it of significant Shareholders and relevant changes to significant Shareholders but this may not reveal all interests in Common Shares that require notification by the Company. Therefore, where a Shareholder acquires between three per cent. and ten per cent. of the Company's shares (or increases or decreases their shareholding within this range) the Company may not be aware of changes to these shareholdings and may not be able to announce these in accordance with the AIM Rules and ESM Rules.

In accordance with applicable Canadian Securities laws, insiders of the Company are required to prepare and file insider reports in the required form on the System for Electronic Disclosure of Insiders at any time when securities of the Company are either acquired or disposed of, over which they exercise direction or control, including the conversion or exchange of any securities of the Company which are exchangeable or convertible into other securities of the Company.

18. RISK FACTORS

AIM and ESM are markets designed primarily for emerging or smaller companies to which a higher investment risk than that associated with larger or more established companies tends to be attached. A prospective investor should be aware of the potential risks of investing in such companies and should make the decision to invest only after careful consideration and, if appropriate, consultation with your stockbroker, bank manager, solicitor, accountant or other independent financial adviser who (if you are resident and taking advice in the United Kingdom) is duly authorised under the FSMA of the United Kingdom or, (if you are resident in Ireland) is duly authorised under the European Communities (Markets in Financial Instruments) Regulations 2007 (Nos. 1 to 3) or the Investment Intermediaries Act 1995 (as amended) or, if you are not so resident, from another appropriately authorised independent professional adviser.

19. FURTHER INFORMATION

Prospective investors should read the whole of this document which provides additional information on the Company and should not rely on summaries or individual parts only. In particular, the attention of prospective investors is drawn to Part III of this document which contains certain risk factors relating to any investment in the Common Shares and Part IV of this document which contains a copy of the CPR.

PART II

INDUSTRY OVERVIEW

The information in the following section has been provided for background purposes. The information has been extracted from a variety of sources released by public and private organisations. The primary sources for information in this section are the Australian Government Bureau of Resources and Energy Economics "Energy in Australia" report (2012), "Energy White Paper 2011" published by the Commonwealth of Australia, PwC analysis of South African gas industry (June 2012), International Energy Agency ("IEA") report on Hungary (2012), KPMG Central and Eastern European Shale Gas Outlook, American Association of Petroleum Geologists European Region Newsletter (June 2012) the Hungarian Energy Office Annual report to the European Commission (August 2011) and the European Bank for Reconstruction and Development Profile on Hungary.

1. INTRODUCTION TO SHALE GAS

(a) Shale Gas versus Conventional Gas

Natural gas resources are typically divided into two categories: conventional and unconventional. Conventional gas typically is found in reservoirs with permeabilities greater than 1 mD and can be extracted via traditional techniques. A large proportion of the gas produced globally to date is conventional, and is relatively easy and inexpensive to extract. In contrast, unconventional gas is found in reservoirs with relatively low permeabilities (less than 1 mD) and hence cannot be extracted via conventional methods. There are several types of unconventional gas resources that are produced today but the three most common types are tight gas, coal bed methane and shale gas. Given the low permeability of these reservoirs, the gas must be developed via special techniques including hydraulic fracture stimulation, or fraccing, in order to be produced commercially.

(b) The Rise of Shale Gas in the US

Shale gas technology has been largely pioneered in the US and the emergence of US shale gas plays has fundamentally altered the US natural gas supply picture. The first shale gas well in the US commenced production in 1821 from a well near Fredonia, New York. Low level shale gas production occurred between this period and the year 2000, however the shale gas industry in the US started to gain significant momentum from 2006. The US domestic gas price has declined dramatically in recent years due to the excess of supply over demand. Since early 2009, prices for natural gas and crude oil have decoupled due to the increase in production of gas from domestic shales but at the same time, the shale gas and shale oil segment of the US oil and gas industry has continued to attract significant investor interest from both trade and financial investors.

(c) Key Shale Gas Production Techniques

Shales typically have low permeability. As a result of this, many wells are required to deplete the reservoir and special well design and well stimulation techniques are required to deliver production rates of sufficient levels to make a development economic. Horizontal drilling and hydraulic fracture stimulation have both been crucial in the development of the shale gas industry.

Horizontal Drilling

Horizontal drilling is a technique which allows the wellbore to come into contact with significantly larger areas of hydrocarbon bearing rock than a vertical well. As a result of this increased contact, production rates and recovery factors can be increased. As the technology for horizontal drilling and fraccing has improved, the use of horizontal drilling has increased significantly.

Hydraulic Fracture Stimulation

Hydraulic fracture stimulation, or fraccing, is a process through which a large number of fractures are created hydraulically in the rock through the application of high pressure, thus allowing the natural gas and/or crude oil trapped in subsurface formations to move through those fractures to the wellbore from where it can then flow to the surface. Fraccing can both increase production rates and increase the total amount of gas that can be recovered from a given volume of shale. Pump pressure causes the rock to fracture, and water carries sand into the hydraulic fracture to prop it open allowing the flow of gas. Whilst water and sand are the main components of hydraulic fracture fluid, chemical additives are often added in small concentrations to improve fracturing performance.

(d) **Benefits of Technology Improvements**

Decline in Drilling Costs

Due to the extensive reliance on horizontal drilling and hydraulic fracturing, the costs associated with the development of shale resources can be significantly higher than for conventional oil and gas. However, these costs have reduced over the past decade in North America due to efficiency improvements resulting from large scale drilling programmes.

Decline Mitigation and Increased Recovery

A combination of improved technology and shale-specific experience has also led to improvements in recovery factors and reductions in decline rates. Each shale play requires its own specific completion techniques, which can be determined through careful analysis of rock properties and trial and error of the drilling and completion parameters. The correct selection of well orientation, stimulation equipment, fracture size and fraccing fluids can all affect the final performance of a well. For developed shales in North America the combined benefits of improved technology and increased experience have resulted in the upward shift of well type-curves (expected well production curves) over time. Both the expected ultimate recovery per well and the peak production per well have been seen to increase as plays have matured.

(e) **Environmental Considerations**

Water Usage and Recycling

A large volume of water is needed for the development of shale gas plays. Water is used for drilling, where it is mixed with clays to form drilling mud. This mud is used to cool and lubricate the drill-bit, provide well-bore stability and also carry rock cuttings to the surface. Water is also used in significant volumes in fraccing. In addition to water and sand, a small concentration of other additives is combined with fluid to improve fraccing efficiency. This significant volume of water needs a plentiful source.

A typical fraccing fluid is more than 98 per cent. water and sand. The other 2 per cent. is made up of a number of additives which may vary depending on the particular well and operator. Typically additives include many substances that are commonly found in small measure in various household products.

During a typical hydraulic fracturing process the frac fluid is transmitted down cased well-bores through perforations to the target zones and then forced deep into the targeted shale gas formations. In some quarters, there is a concern that the fraccing fluid may contaminate drinking water in the area. In order to minimise the risk of any groundwater contamination, good drilling practice requires that one or more strings of steel casing are inserted into the well and cemented into place so as to ensure that the entire well-bore, other than the production zone, is completely isolated from the surrounding formations including aquifers. Most oil-bearing or gas-bearing shales tend to be at least 1,500 metres below the surface, whereas aquifers are generally no more than 500 metres below the surface. Given (i) the thickness of rock separating target shale formations from overlying aquifers, and (ii) the extremely low permeability of shale formations themselves, and assuming the implementation of good oilfield completion practices (such as casing and cementing), it is considered by the industry that, while it cannot be excluded altogether, the risk of contamination of overlying aquifers as a result of fraccing operations is remote. Instances where contamination of aquifers has been alleged are generally believed to have involved poor drilling practices, in particular poor casing and cementing of a well or poor construction of surface storage facilities. Technology improvements have led to significant enhancements in the environmental performance of fraccing fluids and there are a number of products on the market which offer advancement in this area including, for example, a fraccing fluid developed by Halliburton using products from the food industry. In addition, companies are exploring technology which will facilitate the recycling of water used in the fraccing process. Although the recycled water cannot yet be filtered enough for drinking or for agricultural use, it aims to allow companies to reuse this water in other wells and thus equate to significant savings over the lifetime of a typical well.

Disturbance

The disturbance of the land surrounding the drilling location is another environmental factor that may be considered. While the space required for a shale well location is frequently larger than that required for equivalent conventional plays multiple wells may be drilled from a single location.

2. AUSTRALIA

(a) Overview

Australia is the world's ninth largest energy producer, accounting for around 2.5 per cent. of world energy production and five per cent. of world energy exports. In 2011, Australia was the third-largest energy producer in the world and one of only three OECD net energy exporting countries. Exports accounted for around 80 per cent. of Australia's total energy production (in energy content terms) in 2010/2011. Fossil fuels accounted for around 96 per cent. of Australia's primary energy consumption and 90 per cent. of electricity generation in 2010/2011. With around A$290 billion of energy resource projects in planning or under development, Australia is well placed to supply its domestic energy needs and service global energy markets over the coming decade.

(b) Oil and Gas Production

Australia has diverse energy sources and has approximately 33 per cent. of the world's uranium resources, approximately ten per cent. of world black coal resources, and approximately 2 per cent. of world conventional gas resources. Australia has a relatively small proportion of world resources of crude oil and is a net importer of oil. At current rates of production, Australia's energy resources are expected to last for several decades.

Australia's primary energy production is dominated by coal which, in 2009/2010, accounted for approximately 61 per cent. of total energy production, followed by uranium (approximately 19 per cent.) and gas (approximately 12 per cent.). Crude oil and LPG combined represented approximately six per cent. of total energy production, and renewables approximately two per cent.

Gas (conventional and unconventional) is becoming increasingly important for Australia, both as a domestic energy source and as a source of export income. Australia is a significant exporter of LNG, with around half of all gas production exported. In 2010/2011, the value of Australian LNG exports was A$10.4 billion. Since 1999/2000, domestic gas consumption has increased at an average annual rate of 4 per cent. Gas accounted for 23 per cent. of Australian energy consumption, and 15 per cent. of electricity generation in 2009/2010.

Australia's conventional gas production is almost entirely sourced from three basins, with the Carnarvon (north-west Western Australia), Cooper/Eromanga (central Australia) and Gippsland (Victoria) basins accounting for 98 per cent. of production in 2010/2011. The Northern Territory is the smallest gas market in Australia, with supply historically sourced from the onshore Amadeus Basin. Gas production in the Northern Territory totalled 19 Bcf (20 Petajoules) in 2010/2011. Until 2005/2006, all of the gas produced in the Northern Territory gas market was consumed locally. The development of the offshore Bayu Undan field in 2005/2006 saw Darwin selected as the site for Australia's second LNG facility. In 2009, the offshore Blacktip gas field in the Bonaparte Basin started production with gas being piped onshore to supplement the declining Amadeus Basin supply. A second LNG plant for Darwin to process gas from the Ichthys field was announced by Inpex and Total (equity owners of Ichthys) in January 2012.

(c) **Gas Infrastructure**

The geographical distance between population centres in Australia as well as its key export markets limits trade by conventional pipeline transport. Instead, cooling the gas to –161ºC allows the volume to be reduced to enable it to be shipped as LNG.

Australia's annual LNG export capacity at the end of 2011 was 974 Bcf (20 million tonnes), more than three quarters of this is located in Western Australia with the remainder in the Northern Territory near Darwin. Production of LNG is exported, with the major trading partners being Japan, China and the Republic of Korea. There are seven additional LNG projects either under construction or at an advanced stage of development.

The Northern Territory represents a sixth of the Australian land mass and has a population of approximately 232,000 people. For a sparsely populated and remote jurisdiction it is well-served with infrastructure. Darwin, the capital city of the Northern Territory, has a deep water port which is connected to the Darwin to Adelaide railway line.

Taking advantage of its location and capacity, there is a number of major projects currently being developed for the Darwin area, including:

- A$34 billion Ichthys LNG project on Blaydin Point.
- A$110 million Marine Supply Base at East Arm Wharf, which will service oil and gas ships such as rig tenders.
- A$55 million Darwin Industry Fuel Terminal – a common user facility adjacent to the East Arm Wharf that provides tank storage and related logistics for the oil and chemical industries.
- A$50 million Helium Plant – the plant exports two thirds of its production to South-East Asia.

(d) **Unconventional Oil and Gas in Australia**

In recent years increasing attention has been given to the potential of unconventional oil and gas in Australia. This interest extends to the Northern Territory with a large portion of available land either covered by exploration permits or under application. A coal seam gas industry has developed rapidly over the last ten years. The industry is primarily based in Queensland and is intended to provide feedstock to three LNG plants currently under construction there.

Exploration for tight shale oil and gas is currently being undertaken across Australia over large areas in Western Australia, South Australia and the Northern Territory. Major oil companies have invested in exploration in the Northern Territory including Hess Corporation in Falcon's Beetaloo project, Statoil in PetroFrontier's Southern Georgina Basin permits and Santos in Tamboran's McArthur Basin play. Technical support is not as advanced as in the United States but with increasing exploration and potential production, capacity is increasing and appropriate equipment and skilled personnel are becoming more readily available.

The Northern Territory Geological Survey has developed initial estimates that there is potentially 200 Tcf of unconventional gas in the Northern Territory. On 21 September 2012, the Minister for Mines and Energy, the Hon Willem Westra van Holthe MLA, announced that "the Country Liberals Government supports the development of the unconventional shale oil and gas industry in the Territory".

While exploration is generally at the first stage, the first Australian commercial unconventional gas was produced by Santos in South Australia's Cooper Basin in October 2012.

(e) **Regulation and Pricing**

Government policies play an important role in shaping the energy market, and can affect both the pace of energy demand growth and the type of energy used.

Oil and gas exploration in the Northern Territory is regulated by the Northern Territory Government through the Petroleum Act (NT). The legislation is administered by the NT Department of Mines and Energy. Exploration permits and production licences are issued and controlled by the department. The Northern Territory Government is currently reviewing the legislation regulating the industry to ensure that it reflects current technological capability, industry best practice and the needs of the community.

The Australian domestic gas market consists of three distinct regional markets: the eastern market (Australian Capital Territory, New South Wales, Victoria, Queensland, South Australia and Tasmania); the western market (Western Australia); and the northern market (Northern Territory). The geographical isolation of these markets makes interconnection costly and currently uneconomic. Until recently, and with the exception of Victoria, wholesale gas was sold under confidential long term contracts between producers, pipeline operators, major users and retailers. The Victorian Wholesale Gas Market was established in 1999 to increase the flexibility of market participants in buying and selling gas. In September 2010, the Sydney and Adelaide hubs of the Short Term Trading Market ("STTM") commenced operation. The STTM is a day-ahead wholesale spot market for gas that aims to increase price transparency and improve efficiency and competition within the gas sector.

LNG contract prices are generally indexed to world oil prices, with higher world oil prices leading to higher LNG contract prices.

(f) **Fiscal Conditions**

Companies are subject to Commonwealth taxes including the Goods and Services Tax ("GST") of ten per cent. From 1 July 2012 the Commonwealth Government's Petroleum Resource Rent Tax ("PRRT") has been extended to onshore petroleum projects and is currently levied at the rate of 40 per cent. on the taxable profits derived from the petroleum project in a year of tax. A year of tax is the first financial year in which assessable petroleum receipts are derived by a taxpayer and any subsequent financial year.

During exploration the Northern Territory Government has an annual fee for the permits. There is a royalty of ten per cent. on all production. Commonwealth Government corporation tax is set at 30 per cent.

3. SOUTH AFRICA

(a) **Overview**

South Africa is Africa's biggest economy with an estimated GDP of US$524 billion. The main contributor to GDP is the services sector at approximately 67 per cent., followed by industry at approximately 31 per cent. with agriculture making up just three per cent. Of the country's 50 million people, an estimated 25 per cent. are unemployed resulting from modest economic growth, which has averaged approximately three per cent. per annum since 1995.

The 2009/2010 figures from the South African Department of Energy confirm that South Africa's primary energy source is coal. Coal constitutes approximately 66 per cent. of the energy supply followed by crude oil at approximately 22 per cent., renewables and waste at approximately 8 per cent. and gas at approximately 3 per cent. While coal is largely used to generate electricity, a significant amount is channelled to synthetic fuel and petrochemical operations. Sasol, an integrated energy and chemical company, is the largest coal-to-chemicals producer in the world and beneficiates coal, oil and gas into liquid fuels, fuel components and chemicals with the help of its proprietary Fischer-Tropsch processes. Because of its dependence on coal, South Africa is the 14th highest emitter of greenhouse gases.

Natural gas accounts for a small portion of the energy mix in South Africa (three per cent.) but this is expected to grow to around ten per cent. over the next decade. The South African Government has stated its objective to reduce emission levels and to increase the use of natural gas as a substitute for coal is seen as one way of achieving this. The availability of natural gas in neighbouring countries, such as Mozambique and Namibia, and the discovery of offshore gas reserves in South Africa are expected to change the gas industry in South Africa.

(b) **Oil and Gas Production**

The history of South Africa's oil industry dates to 1884, when the first oil company was established in Cape Town to import refined products. The first organised search for hydrocarbons was undertaken by the Geological Survey of South Africa during the 1940s. In 1965, Soekor (Pty) Ltd was established by government with the strategic imperative of finding domestic oil and gas. Oil exploration has been conducted primarily offshore. The Bredasdorp Basin, which contains South Africa's only oil and gas production facilities, has been the focus area for oil and gas exploration in South Africa. By comparison with more developed oil and gas regions, South Africa is relatively underexplored. Since 1965 approximately 300 wells have been drilled with approximately 233,000 kilometres of 2D seismic data and 10,200 km^2 of 3D seismic data being acquired.

South Africa has four conventional refineries and three synfuel plants with a total refining capacity of approximately 700 Mbopd. Of the refined product, 513 Mbopd is produced from crude oil, 150 Mbopd from coal to liquids and 45 Mbopd from gas to liquids.

(c) **Gas Infrastructure**

The South African energy landscape is dominated by coal and South Africa does not have any significant proven reserves of indigenous natural gas or production. According to Business Monitor International, South Africa had proven natural gas reserves of 0.7 Tcf in 2011.

Current demand for natural gas in South Africa is mainly for the gas to liquids and chemicals industries, where PetroSA, Sasol and some industrial users are the major players.

(d) **Unconventional Oil and Gas in South Africa**

The Karoo Basin extending to approximately 173 million acres (approximately 700,000 km^2) in size located in central and southern South Africa and contains thick, organic rich shales. Until recently, the Karoo Basin was not considered prospective for commercial hydrocarbons resulting in very limited modern hydrocarbon exploration onshore in South Africa. In an independent report dated April 2011, the U.S. Energy Information Administration ("EIA") estimated that there are 485 Tcf technically recoverable resources in the Karoo Basin which would rank it fifth in the world after China, USA, Argentina and Mexico for shale gas potential.

On 1 February 2011, a moratorium on shale gas exploration in South Africa was put in place and from 29 April 2011 all permit applications were suspended whilst the South African Department of Mineral Resources conducted, *inter alia*, an environmental study on the effects of hydraulic stimulation. In September 2012, the South African Government announced that the moratorium on shale gas exploration in South Africa would be lifted which should increase activities in the region.

(e) **Regulation and Pricing**

South Africa has a network of key laws and regulations which provides the general legal framework for oil activities. The Constitution of the Republic of South Africa requires the government of South Africa to implement legislative measures to ensure the ecologically sustainable development and use of South Africa's natural resources. In 2002, the Mineral and Petroleum Resources Development Act 28 of 2002 (the "MPRDA") repealed the 1991 Minerals Act to give legislative effect to the constitutional imperatives. The MPRDA declares petroleum resources (which include oil) the common heritage of the people of South Africa and the state the custodian thereof. Petroleum Agency SA (Pasa) is the official agency responsible for the promotion and regulation of South Africa's petroleum resources. The agency regulates and monitors exploration and production activities and is the custodian of the South African exploration and production database for petroleum.

South Africa is dependent on imported crude oil and is accordingly exposed to increased input prices. Upward increases in international crude oil prices partly account for escalation in domestic inflation, with the impact of this depending on the strength of the South Africa Rand. The price-setting regime for crude oil products is mandated by the Petroleum Products Act and maximum retail prices are set out in the regulations thereto.

(f) **Fiscal Conditions**

The South African Government is entitled to a royalty on the sale of mineral resources of up to seven per cent. of gross sales (in the case of unrefined resources) and five per cent. of gross sales (in the case of refined resources, such as oil and gas).

The Liquid Fuels Charter provides that an oil and gas company must reserve not less than nine per cent. for Historically Disadvantaged South Africans ("HDSA") to buy-in to any offshore production right granted. The HDSA buy-in is also expected to apply to onshore production rights in South Africa. Similarly, the State has an option to acquire an interest of up to ten per cent. in any production right granted. However, it is not required to pay any consideration for its ten per cent. interest or contribute to past costs, but must contribute *pro rata* in accordance with its interest towards production costs going forward.

Corporation tax in South Africa is imposed at a rate of 28 per cent. of taxable income. Dividends tax is imposed on the shareholder at a rate of 15 per cent.

4. HUNGARY

(a) **Overview**

Hungary has been a petroleum producer since the early 20th century. The Pannonian Basin covers most of Hungary and marine to lacustrine sediments deposited in this basin during the Miocene period are believed to be the source for most of Hungary's hydrocarbons.

Hungary relies on natural gas for the largest portion of its total primary energy supply ("TPES"), accounting for 39 per cent. of the total supply in 2010. Renewable energies have grown progressively, but they nevertheless remain limited in TPES share, at eight per cent. in 2010. In 2009, the parliament gave its preliminary permission to begin preparations for the setup of new nuclear units at the site of the existing Paks nuclear power plant.

(b) **Oil and Gas Production**

Hungary has oil reserves, primarily in the south-east of the country. Domestic crude oil production peaked in 1985, at 64 Mbopd and is in decline. In 2010 domestic production, including crude oil and condensate, amounted to 25 Mbopd, or 13 per cent. of total oil supply. In 2010, Hungary's oil demand was 147 Mbopd. Approximately 87 per cent. of Hungary's crude oil supply in 2010 was imported, with most of this coming from Russia via the Druzhba pipeline system. Because of the declining domestic production, import dependency is expected to grow further.

Hungary is also highly dependent on imported natural gas which in 2010 amounted to approximately 336 Bcf. Domestic gas production had been relatively stable from 2007, at around 88-92 Bcf. The country has proven gas reserves of 3 Tcf, according to Cedigaz, providing 38 years of supply at 2010 production levels. Gas production comes mostly from mature fields, and the government believes that production can be maintained at close to these volumes until around 2020. Thereafter, production is expected to decline considerably if no new resources are developed. The main consumers of natural gas are the residential sector (approximately 35 per cent.), power generation (approximately 30 per cent.), and the commercial sector (approximately 17 per cent.).

(c) **Gas Infrastructure**

Hungary's gas transmission network consists of some 5,632 kilometres of high-pressure pipelines, with 402 gas delivery points. The network includes five compressor stations with a total installed capacity of 135 mega watts. Hungary imports most of its gas from Russia via Ukraine at Beregdaróc (2 Mmcfpd), but also small amounts via Austria at Mosonmagyaróvár (427 Mcfpd). Hungary is planning to enhance its import capacity as well as diversifying import routes and sources. The planned Nabucco Gas Pipeline is expected to provide access to the gas resources of the Caspian and the Middle East. Hungary is also a key transit country for Russian gas to south-east Europe, and is looking at expanding its general role as a transit country. The gas transmission system is owned and operated by Földgázszállító Zrt ("FGSZ"), part of MOL Group.

(d) **Unconventional Oil and Gas in Hungary**

According to the US Energy Information Administration, the joint technically recoverable shale gas resources for Romania, Bulgaria and Hungary is around 19 Tcf. The government is encouraging unconventional gas production with lower royalty rates (12 per cent.) than conventional gas production (up to 30 per cent.).

One of the more promising exploration areas is considered to be the Makó Trough, which is located in the southern part of Hungary. The licences of the mining properties of the Makó Trough belong to MOL Group and Falcon. Falcon and NIS have agreed a three-well drilling program beginning in 2013 targeting gas in the Makó Trough. MOL is exploring the Derecske basin. There are a number of other companies involved in shale gas exploration in Hungary, such as RAG Hungary Kft. and Cuadrilla Resources Ltd, which are actively seeking reserves in various parts of the country. WildHorse Energy has been working on an underground coal gasification ("UCG") pilot using their CBM exploration licence in the Mecsek Hills, in southern Hungary.

Near the borders of Hungary, several other unconventional operations have been taking place. Ascent Resources, a UK company, announced that it had discovered 413 Bcf of unconventional gas near the Slovenian-Hungarian border. INA/MOL's pilot in the Drava trough in Croatia and NIS's Majdan project in northern Serbia all target Lower to Upper Miocene high TOC shales and adjoining tight sediments.

(e) **Regulation and Pricing**

The Hungarian Ministry of Transportation, Telecommunication and Energy (the "Ministry") is charged with primary responsibility for the energy sector and regulatory implementation is the responsibility of the Hungarian Energy Office ("HEO"). The HEO is a legally autonomous body regulating electricity, gas and district heating, under the supervision of the Ministry. While the HEO does not have the power to set either tariff rates or methodologies, the regulator plays an important role in pricing through the imposition of performance standards and through its licensing regime and through the issuance of guidelines to calculate electricity grid charges, wielding important authority in the implementation of the tariff regime within the final pricing issued by the Ministry. The HEO issues licences (for generation/production, transmission, distribution and supply/trade) and authorisations for new generation capacity.

Hungary is highly dependent on Russian natural gas, with imports from Russia covering nearly 80 per cent. of domestic consumption. Hungary's 20-year contract with the largest gas importer, Panrusgáz, a Gazprom subsidiary, is set to expire in the coming years, and will be subject to renegotiation in 2015. Russian gas is based on a "take or pay" contract indexed to oil prices. This is expected to be slowly replaced by spot gas prices in the long run due to the increased differential between Russian indexed and European natural gas spot prices.

The specific costs of natural gas is based on the price set in the long term purchase agreements indexed to petroleum products; the future market prices on the Endex TTF Gas (Dutch Gas Exchange) and the prices at the Central European Gas Hub, Vienna ("CEGH"). The so called 'mixed' specific natural gas prices consist of long term import contract prices with a weight of 60 per cent., and the natural gas price established on the markets referred to above with a weight factor of 40 per cent. Average spot prices for gas on the CEGH over the last three months equate to approximately US$ 8.48 per Mcf[1].

Mining and Exploration & Production activities are governed by the Act No. XLVIII on mining. The regulatory body of mining activities is the Hungarian Office for Mining and Geology.

(f) **Fiscal Conditions**

The fiscal regime in Hungary is tax and royalty based. There is a special royalty rate for the production of unconventional gas reserves. The exploration of non-renewable natural resources is subject to royalty, which varies, depending on the type of natural resource and the quantity exploited, between 0 per cent. and 30 per cent. If the natural gas is coming from unconventional sources and extractable by special procedures such as fracturing, the royalty rate is fixed at 12 per cent.

The corporate income tax rate is ten per cent. on taxable income up to HUF 500 million (approximately US$ 2.5 million), and 19 per cent. on the remaining portion of the taxable income. In 2009, an additional profit based energy industry tax, levied on energy supplying companies, was introduced. The rate was originally set at eight per cent. but, as part of Hungary's third package of austerity measures, the rate has increased to 31 per cent. from 2013, with deductions allowable for certain capital expenditures.

1 Prices on the CEGH Gas Exchange are quoted in Euro per megawatt hour. Price shown equates to 3 month average spot price as at 22 February 2013, assuming an average heating value of 850 megajoules per Mcf, which equates to 0.24 megawatts per hour. Exchange rate used is average 3 month €/US$ rate as at 22 February 2013 being US$1.32.

PART III

RISK FACTORS

An investment in the New Common Shares is subject to a number of risks. In addition to the other information set out in this document, the following specific risk factors should be considered carefully prior to making an investment decision regarding the Common Shares. The risks associated with holding Common Shares include the following identifiable risks which, individually or in aggregate, would have a material adverse effect on the Group, its business, prospects, financial condition and results of operations, and the Shareholders. The value of New Common Shares may decrease as well as increase.

An investment in the Common Shares is suitable only for investors who are capable of evaluating the risks and merits of such an investment and who have sufficient resources to bear any loss which might result from such an investment. If you are in any doubt about the contents of this document and what course of action you should take, you should consult your stockbroker, bank manager, solicitor, accountant or other independent financial adviser who (if you are resident and taking advice in the United Kingdom) is duly authorised under the FSMA of the United Kingdom or, (if you are resident in Ireland) is duly authorised under the European Communities (Markets in Financial Instruments) Regulations 2007 (Nos. 1 to 3) or the Investment Intermediaries Act 1995 (as amended) or, if you are not so resident, from another appropriately authorised independent professional adviser.

The risks identified below are those which the Directors believe to be material in relation to the Group but these risks may not be the only risks faced by the Group. Additional risks, including those that the Directors are unaware of or those that are currently deemed not to be material, may also result in decreased income, increased expenses or could result in a decline in the value of Common Shares.

1. RISKS RELATING TO THE GROUP AND ITS BUSINESS

A decision by Hess not to exercise its option to acquire a 62.5 per cent. working interest in the Hess Area of Interest would have a material adverse effect on the Group's business, prospects, financial condition and results of operations.

Under the terms of the Hess Agreement, Hess has the option until 30 June 2013 to acquire a 62.5 per cent. working interest in the Hess Area of Interest, by committing to drill and evaluate five exploration wells at Hess' sole cost, one of which must be a horizontal well. In the event that Hess decides not to drill and evaluate five wells, its obligations under the Hess Agreement will cease and Falcon Australia will become responsible for 100 per cent. of any exploration and development costs of the Hess Area of Interest. If Falcon Australia were unable to secure participation by a new farm-in or joint venture partner for the development of the Hess Area of Interest by 31 December 2013, its ability to develop and realise its investment in the asset could be significantly curtailed. A decision by Hess not to exercise its option would have a material adverse effect on the Group's business, prospects, financial condition and results of operations.

The Group may not be able to get the necessary approvals to operate its business

The Group might not be able to obtain necessary approvals from one or more Australian, South African or Hungarian government agencies, surface owners, or other third parties, for one or more of the following: surface use for seismic surveys; surface use for drilling activities; surface use for gathering lines, pipelines, or surface equipment; or commencing one or more wells.

Australia

Australian government agencies have discretion in interpreting various laws, regulations and policies, which govern operations in the Beetaloo Basin. Actions by Australian government agencies may affect the Company's operations including obtaining necessary approvals, land access, sovereign risk, regulatory risk, taxation and royalties which may be payable on the proceeds of the sale of any successful exploration. Further, the approval of contractual arrangements in relation to exploration permits as well as the renewal of exploration permits are also matters of governmental discretion and no guarantee can be given in this regard.

In Australia, Aboriginal native title to land ("Native Title") has survived the Crown's acquisition of sovereignty. The Native Title Act 1993 (Commonwealth) and the complementary state Native Title legislation, regulates the recognition and protection of Native Title in Australia and, amongst other things, sets out the procedures to be followed in relation to certain "future acts" including the grant of petroleum tenements. The Company is required to obtain clearances, consents and approvals in relation to Native Title in connection with the Beetaloo Exploration Permits. Access may be restricted or subject to suitable arrangements being agreed and entered into (for example, compensation and access arrangements) in respect of areas the subject of Native Title. If the requisite approvals and consents are not obtained in respect of the Beetaloo Exploration Permits, there may be a material adverse effect on the Group's business, prospects, financial condition and results of operations.

South Africa

The processing of Falcon's South African application for an exploration right over the TCP acreage has been subject to delay as a result of a moratorium on shale gas exploration introduced in April 2011 by the South African Department of Mineral Resources. In September 2012, following the conclusion of a study on the effects of hydraulic stimulation and the development of a system to regulate onshore exploration activities, the moratorium as far as it relates to pending applications such as Falcon's application was "lifted". However, it is expected that Falcon's exploration right application will only be finalised once regulations relating to hydraulic fracturing are published. These regulations are expected to be published in Q2 2013. Should the publication of these regulations be delayed, the decision to award Falcon an exploration right over the acreage may be delayed or, Falcon may be required to resubmit an application or risk losing its exclusive right to obtain an exploration right over the TCP acreage. This could have a material adverse effect on the Group's business, prospects, financial condition and results of operations.

Hungary

Hungarian government agencies have discretion in interpreting various laws, regulations, and policies governing operations under the Makó Production Licence. Further, the Group must enter into agreements with private surface owners to obtain access and agreements for the location of surface facilities. In addition, because Hungary enacted a new set of mining laws (which also govern oil and gas operations) in 1993, which have since been amended, there is only a relatively short history of the government agencies' handling and interpreting those laws, including the various regulations and policies relating to those laws. This short history does not provide extensive precedents or the level of certainty that allows the Group to predict whether such agencies will act favourably toward the Group.

Neither the Makó Production Licence nor Hungarian mining laws grant reasonable use of the surface across the geographical area covered by the Makó Production Licence. Instead, the licencee must obtain rights-of-way from surface owners, including private landowners, for access and other purposes. The land owner must ensure that those engaging in mining operations make observations and measurements, lay cables, put up adequate signage, and take any other actions necessary. If the land owner and licencee cannot establish operations that meet their mutual agreement, a licencee may request and pay for an easement from the Hungarian government. The Hungarian government has discretion to interpret various requirements for the issuance of drilling permits, and there is no assurance that the Group will be able to meet all such requirements. Any inability of the Group to meet any such requirements could have a material adverse effect on the Group's business, prospects, financial condition and results of operations.

A decision by NIS, following the completion of the initial three well drilling programme in the Algyö Play, not to participate in any further drilling operations, would have a material adverse effect on the Group's business, prospects, financial condition and results of operations.

Under the terms of the NIS Agreement, NIS will earn 50 per cent. of the net production revenues from the initial three wells being drilled in the Algyö Play, and will have an option to acquire a right of first negotiation for future drilling operations in the Algyö Play, sharing any potential future costs and revenue with the Group, on terms to be negotiated. In the event that NIS decide not participate in any further drilling operations in the Algyö Play, Falcon will become responsible for 100 per cent. of any exploration and development costs in the Algyö Play under the Makó Production Licence. If the Group were unable to secure participation by a new farm-in or joint venture partner for the development of the Algyö Play, its ability to develop and realise its investment in the asset could be significantly curtailed. This could have a material adverse effect on the Group's business, prospects, financial condition and results of operations.

There is no guarantee that the Company has or will continue to have good title to assets.

Although title reviews have been and will continue to be performed according to standard industry practice prior to the acquisition of all oil and gas assets or rights to acquire leases in prospects and assets or the commencement of drilling wells, such reviews do not guarantee or preclude that an unidentified or latent defect in the chain of title will not exist, or that a third party claim will not arise that burdens, diminishes or defeats the claim of the Company which could impact the Company's ability to realise its investment in a particular asset and could have a material adverse effect on the Group's business, prospects, financial condition and results of operations.

The Group cannot be certain that it will continue to meet all requirements to maintain its permits and licences

Falcon Australia is required to perform work programmes in order to maintain the Beetaloo Exploration Permits. In particular, under the minimum work commitments for exploration permit EP-99, Falcon Australia must spend a minimum of US$1.5 million by 31 December 2013 in collecting 2D seismic data within exploration permit EP-99. To the extent that the Group cannot fulfil its requirements under exploration permit EP-99, it may have to request an extension and/or may be at risk of losing this exploration permit.

Hungarian Mining Law requires that the Group file annual plans of development ("Plans") with regards to the Makó Production Licence. To the extent that the Group cannot fulfil the requirements, it might have to request extensions for filing a Plan or it may be at risk of losing rights under the Makó Production Licence. Alternatively, the Group may disagree with the government's interpretation of the legal requirements, in which case the Group may commence a legal proceeding, which could delay development of the Makó Production Licence.

Failure to carry out any commitments within the currently required timeframes, or to successfully negotiate extensions to the time permitted to carry out these work plan commitments, could result in the Group losing those relevant interests and the associated resource potential therein and also restrict the ability to obtain new licences in the relevant jurisdictions. The Group's rights to exploit many of their oil and gas interests are limited in time. There is no guarantee or assurance that such rights can be extended or that new rights can be obtained to replace any rights that expire. Furthermore, as licence terms and commitments are typically set by governments, unexpected and significant changes to licence terms and commitments could significantly impact the value of those licences to the Group, which may have a material adverse effect on the Group's business, prospects, financial condition and results of operations.

The Group is exposed to general business risks associated with its joint venture and other partners, in addition to their ability to perform their contractual obligations.

Like other companies of its size, the development of the Group's business is substantially reliant on forming strategic relationships with other, larger companies in the oil and gas industry, such as it has with Hess (Australia), Chevron (South Africa) and NIS (Hungary). The Group has sought and is likely to continue to seek to involve both the financial resources and the technical expertise and experience of farm-out or joint venture partners to explore and develop some or all of its interests. However, these relationships involve surrendering certain economic and operational rights to such partners. As a result, the Company's return on assets operated by others depends upon a number of factors that may be outside of the Group'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.

The Group will be exposed to the general risks associated with the businesses, operations and financial condition of its joint venture and other partners including, among other things, the risks of bankruptcy, insolvency, management changes, adverse change of control and natural disasters. There is also a risk that the Group may have disputes with these parties, including disputes regarding the quality and/or timelines of work performed by these parties. A failure by one or more of the Group's partners to satisfactorily meet on a timely basis the agreed-upon commitments may materially and adversely impact the Group's business, prospects, financial condition and results of operations.

The Group may have substantial capital requirements that, if not met, may hinder its growth and operations.

The Group's future growth depends on its and its partners' ability to make large capital expenditures for the exploration and development of oil and gas interests. Future cash flows and the availability of financing will be subject to a number of variables, such as:

- the success of the Group's exploration and development programme in Australia, South Africa and Hungary;
- success in locating new resources; and
- prevailing prices of oil and gas.

Additional financing sources may be required in the future to fund developmental and exploratory drilling. Issuing equity securities to satisfy the Group's financial requirements could cause substantial dilution to its existing Shareholders. Financing might not be available in the future or the Group might not be able to obtain necessary financing on acceptable terms. If sufficient capital resources are not available, the Group might be forced to curtail its activities or be forced to sell some of its interests on an untimely or unfavourable basis, which would have a material adverse effect on the Group's business, prospects, financial condition and results of operations.

The success of the Company's acquisition strategy is not guaranteed.

Falcon's strategy is to leverage the Group's knowledge of and expertise in the unconventional oil and gas industry to acquire interests in licences covering large acreages of land, to build on its internationally diversified portfolio of unconventional interests. Returns ultimately achieved by investors in the Company will be reliant upon the quality and performance of the assets being acquired directly or indirectly by the Company. The success of the Company's strategy also depends on the Directors' and management's ability to identify suitable assets, and their acquisition on favourable terms in order to generate value from those assets. No assurance is given that the strategy to be used will be successful under all or any market conditions or that the Company will be able to invest its capital directly or indirectly to acquire assets on attractive terms and to generate returns for investors. This could have a material adverse effect on the Group's business, prospects, financial condition and results of operations.

The Company might not be able to identify liabilities associated with its licences which could cause the Group to incur losses.

Although the Company believes it has reviewed and evaluated its assets in Australia and Hungary in a manner consistent with industry practices, such review and evaluation might not necessarily reveal all existing or potential problems. Inspections may not always be performed on every well, and environmental problems, such as groundwater contamination, are not necessarily observable even when an inspection is undertaken.

Resource estimates depend on many assumptions that may be inconclusive, subject to varying interpretations, or inaccurate.

Although the Company believes that the CPR prepared by RPS Energy was in accordance with industry standards, the Company cannot be sure that that the actual results will be as estimated. The CPR represents RPS Energy's best professional judgement and should not be considered a guarantee or prediction of results. Further drilling and production testing of horizontal wells will be necessary before the Group is able to make an estimate of recoverable volumes in any of its assets and it is possible that such further drilling and production testing may not yield positive results.

Drilling for and producing oil and gas are high-risk activities with many uncertainties that could adversely affect the Group's business, prospects, financial condition or results of operations.

The Group's future success depends primarily on the outcome of its exploration activities. These activities are subject to numerous risks beyond the Group's control, including the risk that it will not find any commercially productive oil or gas reservoirs. This is particularly true with respect to the exploration and development of oil and gas from unconventional reservoirs, such as shale gas, which relies on innovative and relatively expensive techniques and often involves exploration in areas where no proven reserves exist. The Group's decisions to purchase, explore, develop or otherwise exploit its interests will depend in part on the evaluation of data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations. The cost of drilling, completing and operating wells is often uncertain before drilling commences. Overruns in budgeted expenditures are common risks that can make a particular project uneconomical. Further, many factors may curtail, delay or prevent drilling operations, including:

- unexpected drilling conditions;
- pressure or irregularities in geological formations;
- equipment failures or accidents;
- pipeline and processing interruptions or unavailability;
- adverse weather conditions;
- lack of market demand for oil and gas;
- delays imposed by or resulting from compliance with environmental and other regulatory requirements;
- shortage of or delays in the availability of drilling rigs and the delivery of equipment; or
- reductions in oil and gas prices.

The Group's future drilling activities might not be successful, and drilling success rate overall or within a particular area could decline. The Group could incur losses by drilling unproductive wells. Shut-in wells, curtailed production and other production interruptions may materially and adversely impact the Group's business, prospects, financial condition and results of operations.

Market conditions or operation impediments may hinder the Group's access to oil and gas markets or delay any production in the future.

The marketability of any future production from the Group's interests will depend in part upon the availability, proximity and capacity of pipelines, oil and gas gathering systems and processing facilities. This dependence is heightened where this infrastructure is less developed. The Group may also be required to shut-in wells, at least temporarily, for lack of a market or because of the inadequacy or unavailability of transportation facilities. If that were to occur, the Group would be unable to realise revenue from those wells until arrangements were made to deliver production to market. The Group's ability to produce and market oil and gas is affected and also may be harmed by:

- the lack of pipeline transmission facilities or carrying capacity;
- the proximity and capacity of processing equipment;
- the availability of open access transportation infrastructure;
- government regulation of oil and gas production including environmental protection, royalties, allowable production, pricing, importing and exporting of oil and gas;
- government transportation, tax and energy policies;
- changes in supply and demand for oil and gas; and
- general economic conditions.

Any change in such factors may materially and adversely impact the Group's business, prospects, financial condition and results of operations.

Shortages of rigs, equipment, supplies and personnel could delay or otherwise adversely affect the Group's cost of operations or its ability to operate according to its business plans.

From time to time, shortages of drilling and completion rigs, field equipment and qualified personnel could occur, resulting in sharp increases in costs. The demand for wage rates of qualified drilling rig crews generally rise in response to the increased number of active rigs in service and could increase sharply in the event of a shortage. Shortages of drilling and completion rigs, field equipment or qualified personnel could delay, restrict or curtail the Group's exploration and development operations, which may materially and adversely impact the Group's business, prospects, financial condition and results of operations.

The loss of the Group's key management, technical personnel and Directors or its inability to attract and retain experienced technical personnel could adversely affect the Group's ability to operate.

Falcon depends to a large extent on the efforts and continued employment of the members of the Group's management team and certain board members. The loss of such services could adversely affect the Group's business operations. The success of the Group's operations depends on the Group's ability to attract and retain experienced petroleum engineers, geologists and other key personnel. From time to time, competition for experienced engineers and geologists is intense. If the Group cannot retain these personnel or attract additional experienced personnel, its ability to compete in the geographic regions in which the Group conducts operations could be harmed and as a result it may materially and adversely impact the Group's business, prospects, financial condition and results of operations.

The Group is subject to complex laws and regulations, including environmental regulations, which can have a material adverse effect on the cost, manner or feasibility of doing business.

Exploration for and exploitation, production and sale of oil and gas in Australia, South Africa and Hungary are subject to extensive national and local laws and regulations, including complex tax laws and environmental laws and regulations, and requires various permits and approvals from various governmental agencies. If these permits are not issued or unfavourable restrictions or conditions are imposed on the Group, it might not be able to conduct its operations as planned, or at all. Alternatively, failure to comply with these laws and regulations, including the requirements of any permits, might result in the suspension or termination of operations and subject the Group to penalties. Compliance costs may be significant. Further, these laws and regulations could change in ways that substantially increase the Group's costs and associated liabilities. The Group cannot be certain that existing laws or regulations, as currently interpreted or reinterpreted in the future, or future laws or regulations will not materially and adversely impact the Group's business, prospects, financial condition and results of operations.

The Company does not insure against all potential operating risks. It might incur substantial losses and be subject to substantial liability claims of its oil and gas operations.

The Company does not insure against all risks. It maintains insurance against various losses and liabilities arising from operations in accordance with customary industry practices and in amounts that Board believes to be prudent. Losses and liabilities arising from uninsured and underinsured events or in amounts in excess of existing insurance coverage could have a material adverse effect on the Group's business, prospects financial condition or results of operations. The Group's oil and gas exploration and production activities will be subject to hazards and risks associated with drilling for, producing and transporting oil and gas, and any of these risks can cause substantial losses resulting from:

- environmental hazards, such as uncontrollable flows of oil, gas, brine, well fluids, toxic gas or other pollution into the environment, including groundwater and shoreline contamination;
- abnormally pressured formations;
- fires and explosions;
- personal injuries and death;

- regulatory investigations and penalties; and
- natural disasters.

Any of these risks could have a material adverse effect on the Group's ability to conduct operations or result in substantial losses. The Company might elect not to obtain insurance if it believes that the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. If a significant accident or other event occurs and is not fully covered by insurance, this may materially and adversely impact the Group's business, prospects, financial condition and results of operations.

2. RISKS RELATING TO THE GROUP'S INDUSTRY

Competition in the oil and gas industry is intense, and many of the Group's competitors have greater financial, technological and other resources than the Group does, which may adversely affect its ability to compete.

The Group operates in the highly competitive areas of oil and gas exploration, development and acquisition with a number of other companies doing business in Australia, South Africa and Hungary. The Group faces intense competition from both major and other independent oil and gas companies in the locations where the Group operates. Many of the Group's competitors have substantially greater financial, managerial, technological and other resources. These companies might be able to pay more for exploratory prospects than the Group's financial resources permit. To the extent competitors are able to pay more for assets than the Group is willing to pay, it will be at a competitive disadvantage. Further, many competitors may enjoy technological advantages and may be able to implement new technologies more rapidly. The Group's ability to explore for oil and gas prospects and to acquire additional assets in the future will depend upon its ability to successfully conduct operations, implement advanced technologies, evaluate and select suitable assets and consummate transactions in this highly competitive environment. This may have a material adverse effect on the Group's business, prospects, financial condition and results of operations.

The Group has been an early entrant into new or emerging shale plays. As a result, its expectations regarding future drilling results in these areas are uncertain, and the value of its undeveloped acreage will decline if future drilling results are unsuccessful.

The Group has been an early entrant into new or emerging shale plays in the areas in which it operates, particularly in Australia and South Africa. Although the Group believes that its early entry has provided it with certain competitive advantages, including having had a wider selection of available concessions to choose from, there is no guarantee that such competitive advantages can be maintained in the future as more competitors, many of whom are larger than the Group in size and operation, enter into these regions. Additionally, the Group's prospects and expectations regarding future drilling results in these emerging shale plays are more uncertain than they would be in areas that are developed and producing substantial quantities of oil or gas already. Since new or emerging shale plays have limited or no production history, the Group is unable to use past drilling results in those areas to help predict its future drilling results. As a result, the Group's risk on the costs of drilling, completing and operating wells in these areas may be higher and the value of the Group's undeveloped acreage will decline if future drilling results are unsuccessful, all of which may materially and adversely impact the Group's business, prospects, financial condition and results of operations.

The environmental implications of certain technologies used in shale gas exploration activities are under scrutiny.

The Group's activities involve exploring for shale gas utilising drilling and completion techniques, such as horizontal drilling and hydraulic fracturing, the environmental implications of which have been, and continue to be, subject to significant controversy and public debate. Given that these technologies are relatively new, their environmental implications may not be fully understood at present, and research into their effects is still ongoing. There has been speculation about, amongst other things, the possible effects of hydraulic fracturing on water aquifers (due to either the chemicals used in fraccing fluids or gases released from the shales), contribution to seismic activity and disruption to local ecosystems. The controversy surrounding the environmental implications of shale gas exploration has led to opposition from significant sections of the public as well as certain legislative and regulatory initiatives aimed at restricting these activities. Further to the South African moratorium on shale gas exploration as announced in February 2011, similar initiatives have been introduced in a number of European countries (Bulgaria, France, Romania and the UK) and also in various regions of Canada and the United States. Any further restrictions on these activities in South Africa, or the introduction of such restrictions in any of the locations in which the Group operates (including a prohibition on hydraulic fracture stimulation), which make shale gas exploration and production currently unviable due to a lack of presently-existing alternative technologies, could prevent the Group from being able to profitably develop its interests. Furthermore, if any of the Group's activities were found to have caused environmental damage in any of the locations in which it operates, it could be subject to significant liabilities and reputational damage. Even if no environmental damage were tied directly to the Group's activities, to the extent operations by other companies in the shale gas industry were found to have caused environmental damage or to the extent further research provides evidence of negative environmental implications of fraccing or other aspects of shale gas exploration, public and political opposition to shale gas exploration may be further intensified and the Group's business could come under increasing legal and regulatory restrictions, all of which may materially and adversely impact the Group's business, prospects, financial condition and results of operations.

A substantial or extended decline in oil and gas prices may adversely impact the Group's business, prospects, financial condition and results of operations.

The Group's future revenues, operating results and rate of growth are substantially dependent upon the prevailing prices of, and demand for, oil and gas. Declines in the prices of, or demand for, oil and gas may adversely affect the Group's business, prospects, financial condition and results of operations. Lower oil and gas prices may also reduce the amount of oil and gas that the Group can produce economically. Historically, oil and gas prices and markets have been volatile and they are likely to continue to be volatile in the future. Oil and gas prices are subject to wide fluctuations in response to relatively minor changes in the supply of, and demand for, oil and gas, market uncertainty and a variety of additional factors that are beyond the Group's control. Among the factors that could cause this fluctuation are:

- change in global supply and demand for oil and gas;
- levels of production and other activities of the OPEC, and other oil and gas producing nations;
- weather conditions;
- the availability of transportation infrastructure;
- market expectations about future prices;
- the level of global oil and gas exploration,
- production activity and inventories; the overall level of energy demand;
- the effect of worldwide environmental and/or energy conservation measures;
- currency exchange rates;
- government regulations and taxes;
- the overall economic environment;
- political conditions, including embargoes, in or affecting other oil producing activity; and
- the price and availability of alternative fuels.

A substantial or extended decline in oil or gas prices may materially and adversely impact the Group's business, prospects, financial condition and results of operations.

Political instability or fundamental changes in the leadership or in the structure of the governments in the jurisdictions in which the Group operates could have a material negative impact on the Group's business, prospects, financial condition and results of operations.

The Group's interests may be affected by political and economic upheavals. Although the Group currently operates in jurisdictions that welcome foreign investment and are generally stable, there is no assurance that the current economic and political situation in these jurisdictions will not change significantly in the future. Local, regional and world events could result in changes to the oil and gas, mining, tax or foreign investment laws, or revisions to government policies in a manner that renders the Group's current and future interests uneconomic could have a material adverse affect on the Group's business, prospects, financial condition and results of operations. Furthermore, there is also the risk of resource nationalisation, or the imposition of restrictions and penalties on foreign-owned entities which may materially impact the Group's business, prospects, financial condition and results of operations.

3. RISKS RELATING TO THE COMMON SHARES

The Company's share price might be affected by matters not related to the Group's own operating performance for reasons that include the following:

- general political and economic conditions in Australia, South Africa, Hungary, and globally;
- industry conditions, including fluctuations in the price of oil and gas;
- governmental regulation of the oil and gas industry, including environmental regulation;
- fluctuation in foreign exchange or interest rates;
- liabilities inherent in oil and gas operations;
- geological, technical, drilling and processing problems;
- competition for, among other things, capital, undeveloped land and skilled personnel;
- the need to obtain required approvals from regulatory authorities;
- investor perception of the oil and gas industry in general and of unconventional oil and gas exploration in particular;
- limited trading volume of the Common Shares; and
- announcements relating to the Company's business or the business of its competitors.

In the past, companies that have experienced volatility in their value have been the subject of securities class action litigation. The Company might become involved in securities class action litigation in the future. Such litigation often results in substantial costs and diversion of management's attention and resources and could have a material adverse effect on the Group's business, prospects, financial condition and results of operations.

Volatility of Share Price

The market price of the Common Shares may be subject to fluctuations in response to many factors, including variations in the operating results of Falcon, divergence in financial results from market expectations, general economic conditions, legislative changes in the sector and other events and factors outside the Group's control. In addition, stock markets have from time to time experienced extreme price and volume fluctuations, which, as well as general economic and political conditions, could adversely affect the market price for the Common Shares. The value of Common Shares may go down as well as up. Investors may therefore realise less than or lose all their original investment.

Falcon is incorporated in British Columbia, Canada and, as such, is subject to Canadian company law.

Falcon is a company incorporated in the province of British Columbia, Canada and as such, its corporate structure, the rights and obligations of shareholders and its corporate bodies may be different from those of the home countries of international investors. Furthermore, non-Canadian residents may find it more difficult and costly to exercise shareholder rights. International investors may also find it costly and difficult to effect service of process and enforce their civil liabilities against the Company or some of its directors, controlling persons and officers.

Suitability of Common Shares as an investment

The Common Shares may not be suitable for all the recipients of this document. Before making any investment, prospective investors are advised to consult their stockbroker, bank manager, solicitor, accountant or other independent financial adviser who (if they are resident and taking advice in the United Kingdom) is duly authorised under the FSMA of the United Kingdom or, (if you are resident in Ireland) is duly authorised under the European Communities (Markets in Financial Instruments) Regulations 2007 (Nos. 1 to 3) or the Investment Intermediaries Act 1995 (as amended) or, if they are not so resident, from another appropriately authorised independent professional adviser.

The Company is not subject to the remit of the City Code or the Irish Takeover Rules

The Company exists under the laws of the province of British Columbia, Canada, and has its registered office in British Columbia and is managed and controlled outside the United Kingdom. Accordingly, transactions in the Common Shares will not be subject to the provisions of the City Code or the Irish Takeover Rules. It is emphasised that, although the Common Shares will be traded on AIM and ESM, the Company will not be subject to takeover regulation in the United Kingdom or Ireland. It follows that Shareholders are not entitled to the protection afforded by the City Code or the Irish Takeover Rules.

Liquidity of the Common Shares and realisation of investment in Common Shares

Following Admission, the Common Shares will be traded on AIM and ESM. Investors and potential investors should be aware that the value of the Common Shares and income from the Common Shares can go down as well as up and that Admission should not be taken as implying that there will be a liquid market in the Common Shares. AIM and ESM are markets designed primarily for emerging or smaller growing companies which carry a higher than normal financial risk and tend to experience lower levels of liquidity than larger companies. An investment in the Common Shares may thus be difficult to realise. The ability of an investor to sell Common Shares will depend on there being a willing buyer for them at an acceptable price. Consequently, it might be difficult for an investor to realise his/her investment in the Company and he/she may lose all his/her investment. In the event of a winding up of the Company, the Common Shares will rank behind any liabilities of the Company and therefore any return for Shareholders will depend on the Group's assets being sufficient to meet prior entitlements of creditors.

When the lock-in arrangements to which the Director Shareholders are subject expire, more Common Shares may become available on the market.

Subject to certain limited exceptions, the Director Shareholders will be prevented from selling Common Shares held by them (other than options and warrants) for a period of 12 months from Admission. On the expiry of these periods, the Director Shareholders will be free (subject to applicable laws) to sell the Common Shares held by them. The end of restrictions on the sale of Common Shares held by Director Shareholders and the issue of new Common Shares by the Company, will increase the number of Common Shares available for sale and may have a material adverse effect on the market price of the Common Shares. In addition, the exercise of warrants and conversions under the Trust Indenture may lead to a dilution of shareholdings of existing Shareholders and could adversely affect the price of the Common Shares.

A disposal of Common Shares by major Shareholders could adversely impact the market price of Common Shares

Sales of a substantial number of Common Shares in the market by major shareholders, or the perception that these sales might occur, could adversely impact the market price of the Common Shares.

Forward-Looking Statements

This document contains forward-looking statements that involve risks and uncertainties. The Group's results could differ materially from those anticipated in the forward-looking statements as a result of many factors, including the risks faced by the Group, which are described above and elsewhere in the document. Additional risks and uncertainties not currently known to the Board may also have an adverse effect on the Group's business.

Market information

The market price of the Common Shares may not reflect the underlying value of the Group. Potential investors should be aware that the value of Common Shares can rise or fall and that there may not be proper information available for determining the market value of an investment in the Company at all times.

PART IV

COMPETENT PERSON'S REPORT

411 N. Sam Houston Parkway E., Suite 400, Houston, Texas 77060-3545 USA
T +1 281 448 6188 **F** +1 281 488 6189 **W** www.rpsgroup.com

The Directors
Falcon Oil & Gas Ltd
Styne House
Upper Hatch Street
Dublin 2
Ireland

The Directors
J&E Davy
49, Dawson Street
Dublin 2
Ireland

22nd March 2013

Dear Sirs,

RE: EVALUATION OF THE HYDROCARBON RESOURCE POTENTIAL PERTAINING TO CERTAIN ACREAGE INTEREST IN THE BEETALOO BASIN, ONSHORE AUSTRALIA AND MAKO TROUGH, ONSHORE HUNGARY.

In accordance with the Work Orders dated 10 September 2012 and 25 September 2012 and subsequent Letter of Engagement (the "Agreement") dated 10 November 2012 with Falcon Oil & Gas Limited ("Falcon" or the "Company"), Cambrian Consultants America Inc., dba RPS ("RPS") has completed an independent evaluation of and produced a Competent Person's Report ("CPR") on the potential hydrocarbon resource potential pertaining to certain acreage interests of Falcon in the Makó Trough, onshore Hungary and Beetaloo Basin, onshore Australia (together "the Properties"), as at 01 January 2013.

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

This report is addressed to the Company and named Nominated Advisor and Third Parties as defined in the Agreement and is only capable of being relied on by the Company, the Nominated Advisor and any Third Parties under and pursuant to (and subject to the terms of) the Agreement.

The Company may disclose the signed and dated report to third parties as contemplated by the Purpose defined in the Agreement but in making any such disclosure the Company shall require the third party (including any Nominated Advisor and Third Parties) to accept it as confidential information only to be used or passed on to other persons as the Company is permitted to do under the Agreement.

This CPR has been prepared by RPS for inclusion in the admission document (the "Admission Document") to be published by the Company and its advisors in connection with the proposed admission (the "Admission") of the ordinary shares of the Company to trading on the AIM Market of the London Stock Exchange (the "Offer"). This CPR has been compiled in accordance with the requirements of the AIM Note for Mining, Oil and Gas Companies[1] dated June 2009 (the "AIM Note").

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

1. are professionally qualified and a member in good standing of a self-regulatory organisation of engineers and/or geoscientists including SPE, EI, AAPG and EAGE;
2. have at least five years' relevant experience in the estimation, assessment and evaluation of oil and gas assets;

---

[1] www.londonstockexchange.com/en-gb/products/companyservices/ourmarkets/aim_new/Publications

3. are independent of the Company, its directors, senior management and advisers;
4. will be remunerated by way of a time-based fee and not by way of a fee that is linked to the Admission or value of the Company;
5. are not a sole practitioner;
6. have the relevant and appropriate qualifications, experience and technical knowledge to appraise professionally and independently the assets, being all assets, licences, joint ventures or other arrangements owned by the Company and its subsidiary undertakings (the "Group") or proposed to be exploited or utilised by it ("Assets") and liabilities, being all liabilities, royalty payments, contractual agreements and minimum funding requirements relating to the Group's work programme and Assets ("Liabilities"); and
7. consider that the scope of this CPR is appropriate, given the Group's Assets and Liabilities and includes and discloses all information required to be included therein and was prepared to a standard expected in accordance with the AIM Note.

Neither RPS Energy, nor any of its directors, staff or sub-consultants who contributed to this report has any interest in:

1. the Company; or
2. any of the advisers to the Company; or
3. the Assets; or
4. the outcome of the Placing.

Standard applied

In compiling this report we have used the definitions and guidelines set out in the Petroleum Resources Management System ("PRMS") as set out by the SPE/SPEE/AAPG/WPC as the internationally recognised Standard required by the AIM Note (see Appendix B for more details).

Qualifications

RPS Energy is an independent consultancy specialising in petroleum reservoir evaluation and economic analysis. The provision of professional services has been solely on a fee basis. Mr. Andrew Kirchin, Executive VP, Consulting for RPS (Houston), has supervised the evaluation. Mr. Kirchin has over 25 years experience in upstream oil and gas.

Other RPS employees involved in this work hold at least a Masters degree in geology, geophysics, petroleum engineering or a related subject or have at least five years of relevant experience in the practice of geology, geophysics or petroleum engineering.

Effective Date and material change statement

The evaluation of the Properties is calculated as at 1st January 2013 (the "Effective Date"). We confirm that there has been no material change to the Properties between the Effective Date to the date hereof and we are not aware of any significant matters arising from our evaluation that are not covered by this CPR which might be of a material nature with respect to Admission.

Extraction of information

We confirm that we have reviewed information contained elsewhere in the Admission Document which relates to information contained in this CPR and confirm that the information presented therein has been extracted directly from this CPR in a manner which is not misleading, is accurate and provides a balanced and complete view which is not inconsistent with this CPR. This CPR is entitled "Evaluation Of The Hydrocarbon Resource Potential Pertaining To Certain Acreage Interest In The Beetaloo Basin, Onshore Australia And Makó Trough, Onshore Hungary." and is contained in this Part IV of the Admission Document.

Reliance on source data

The report is based on production data and information available up to November 30, 2012. An Effective Date of 1st January 2013 has been assumed for the valuation.

The Services have been performed by a RPS team of professional petroleum engineers, geoscientists and economists and is based on data and previous reports, supplied through Falcon.

Our approach has been to review the Operator's technical interpretation of their base case geoscience and engineering data for the field for reasonableness and to review the ranges of uncertainty for each parameter around this base case in order to estimate ranges of potential petroleum initially-in-place and recoverable.

RPS has been informed by Falcon that no new data exists since the date of the last report that would materially impact the results or conclusions of the Report.

Executive Summary

The Beetaloo Basin acreage interests are held 100% in the name of Falcon Oil and Gas Australia Pty. Ltd., ("Falcon Australia"), which is an Australian incorporated oil and gas exploration company. Falcon Oil & Gas Limited has a 73% interest in Falcon Australia. The remaining 24% interest is held by Sweetpea Petroleum Pty. Ltd, which is a wholly owned Australian subsidiary of PetroHunter Energy Corp., and 3% by others. According with local regulations, all Falcon Australia's acreage interests are subject to certain royalties payable to the Government of the Northern Territory, the Australian native stakeholders (Traditional owners), and certain other third parties. Falcon Australia is the operator of Exploration Permit EP 99 and Hess Australia (Beetaloo) Pty Ltd. is the operator of Exploration Permits EP 76, 98 and 117 comprising a total of approximately 28,200 square kilometres (7 million gross acres), covering the majority of the Beetaloo Basin and basin margin highs (see Figure 1-1). Falcon Australia Pty. retained operatorship in the Shenandoah-1 well and approximately 405 km^2 (100,000 acres) land around the Shenandoah-1 wellbore in EP98.

The Makó Trough acreage interest is held 100% in the name of TXM Oil & Gas Limited, ("TXM") a wholly owned subsidiary of Falcon Oil and Gas Limited. Under the terms of the Production Licence, Falcon is obliged to pay a 12% royalty to the Government of Hungary on any production and has a further 5% royalty agreement with Prospect Resources Inc., the previous owners of the licence. TXM is the operator of the production licence which covers 994.6 square kilometres (245,765 acres) following a 57.3% relinquishment as per the terms of the "Tisza" exploration permit in September 2010 and the "Makó" exploration permit in November 2010.

Reserves

No Reserves are assigned to the Properties described above.

Contingent Resources

The following potentially recoverable volumes have been assigned as Contingent Resources - Development Unclarified

Table A - Contingent Resources Summary for Makó Trough

Licence (WI=100%)	Gross				Net Attributable				Operator
	(1C)	(2C)	(3C)		(1C)	(2C)	(3C)	Risk Factor	
Gas (Tcf)									
Makó Trough Production Licence	**14.24**	**35.27**	**71.41**		**11.82**	**29.27**	**59.27**	≤ 25%	**TXM Oil and Gas Ltd.**
Oil (MMbo)									
Makó Trough Production Licence	**32.89**	**76.71**	**158.26**		**27.30**	**63.67**	**131.36**	≤ 25%	**TXM Oil and Gas Ltd.**

Source: - RPS Energy

Notes: "Gross" are the 100% Reserves that are attributable to the licence whilst "Net Attributable" are those estimated to be attributable to Falcon's 100% WI after royalties.

"Risk Factor" means the estimated chance, or probability, that the volumes will be commercially extracted. The volumes quoted above are classified as Contingent Resources – Development Unclarified. Oil and Gas have been discovered and may be present in large quantities but commercial flow-rates have yet to have been achieved (although Falcon does periodically produce oil and gas at low rates from certain wells).

Prospective Resources

Falcon's Prospective Resources in the Beetaloo Basin, Northern Territory, Australia, fall into two subdivisions – the Play level and Propsect level (see Figure B.1 in Appendix B). The Play level Prospective Resources represent the full Basin potential whilst the Prospect level Prospective Resources represent a number of identified individual areas which are centered around existing well penetrations. Table B, C and D show the Play level Prospective Resources and Table E and F show the Prospect level Prospective Resources.

Table B – Prospective Unconventional Oil Resources (Play level) Summary for Beetaloo Basin

Resource Play (WI=73%)	Gross				Net Attributable			
	Low Estimate	Best Estimate	High Estimate		Low Estimate	Best Estimate	High Estimate	Play risk
Unconventional Shale Oil (MMstb)								
Kyalla Upper	1,290	2,654	5,526		715.7	1,472.4	3,065.8	80%
Kyalla Lower	3,023	5,971	12,011		1,677.2	3,312.7	6,663.7	50%
Velkerri Middle	4,942	12,720	32,503		2,741.8	7,057.1	18,032.7	80%

Source: - RPS Energy

Table C – Prospective Unconventional Gas Resources (Play level) Summary for Beetaloo Basin

Resource Play (WI=73%)	Gross				Net Attributable			
	Low Estimate	Best Estimate	High Estimate		Low Estimate	Best Estimate	High Estimate	Play risk
Unconventional Shale Gas (Tcf)								
Kyalla Lower	21.83	37.29	63.81		12.11	20.69	35.40	90%
Velkerri Middle	45.09	74.50	122.78		25.02	41.33	68.12	100%

Source: - RPS Energy

Table D – Prospective BCGA Resources (Play level) Summary for Beetaloo Basin

Resource Play (WI=73%)	Gross				Net Attributable			
	Low Estimate	Best Estimate	High Estimate		Low Estimate	Best Estimate	High Estimate	Play risk
BCGA Gas (Tcf)								
Moroak Sst	0.95	5.90	36.72		0.53	3.27	20.37	50%
Bessie Creek Sst	24.58	44.31	78.48		13.64	24.58	43.54	50%

Source: - RPS Energy

Notes: "Gross" are the 100% Reserves that are attributable to the licence whilst "Net Attributable" are those estimated to be attributable to Falcon's 73% WI after royalties.

Play Risk is the chance that the licenced area within the basin will contain the range of calculated in-place and potentially recoverable volumes of hydrocarbons presented.

The nature of a basin-wide Resource Play means the Prospective Resources straddle multiple licences in each interval are not uniquely operated.

Table E - Prospective Unconventional Oil Resources (Prospect level) Summary for Beetaloo Basin

Prospect (WI=73%)	Gross				Net Attributable				Operator
	Low Estimate	Best Estimate	High Estimate		Low Estimate	Best Estimate	High Estimate	Risk Factor	
Unconventional Oil (MMstb)									
Shenandoah – Upper Kyalla	17.5	62.7	223.0		9.71	34.79	123.72	40%	**Falcon Oil & Gas Australia**
Elliot – Upper Kyalla	4.4	15.7	55.8		2.44	8.71	30.96	10%	**Hess Australia (Beetaloo) Pty Ltd.**
Burdo – Lower Kyalla	4.8	16.5	57.5		2.66	9.15	31.90	6.25%	
Ronald – Lower Kyalla	4.8	16.5	57.5		2.66	9.15	31.90	6.25%	
Chanin – Lower Kyalla	4.8	16.5	57.5		2.66	9.15	31.90	6.25%	
Walton-McManus – Middle Velkerri	12.2	49.6	198.0		6.77	27.52	109.85	40%	
Arithmetic Aggregation[1]	**48.5**	**177.5**	**649.3**		**26.91**	**98.48**	**360.23**	**<<1%**	
Stochastic Aggregation[2]	**130.0**	**245.0**	**497.0**		**72.12**	**135.93**	**275.74**	**<<1%**	
Stochastic Aggregation[3]	**14.2**	**69.4**	**253.0**		**7.88**	**38.50**	**140.36**	**73%**	

Source: - RPS Energy

Notes: “Gross” are the 100% Reserves that are attributable to the licence whilst “Net Attributable” are those estimated to be attributable to Falcon’s 73% WI after royalties.

“Risk Factor” means the estimated chance or probability of discovering gas in sufficient quantity for it to be tested to the surface (also referred to as GPoS). It should be noted that it will take a number of wells to confirm the volume range quoted.

1: although commonly done, it is statistically incorrect to arithmetically sum probabilistic estimates of P90, P50 and P10. To do so tends to under-estimate the true P90 and over-estimate the true P10 of the combined distribution as seen when compared to the Statistical Aggregation in the next row. This is exacerbated by the introduction of GPoS into the statistical aggregation (see below).

2: Statistical Aggregation assuming that all prospects are successful. The probability of this occurring is the product of each individual risk (GPoS) and is therefore very small.

3: Statistical Aggregation assuming at least one prospect is successful. This total takes into account all possible successful outcomes and the mean value for the resultant distribution (**62.14** MMstb Net) constitutes the true expectation of success.

Table F - Prospective Unconventional Gas Resources (Prospect level) Summary for Beetaloo Basin

Prospect (WI=73%)	Gross				Net Attributable				Operator
	Low Estimate	Best Estimate	High Estimate		Low Estimate	Best Estimate	High Estimate	Risk Factor	
Unconventional Gas (Bcf)									
Shenandoah – Lower Kyalla	95.1	299.0	958.0		52.76	165.89	531.50	45%	**Falcon Oil & Gas Australia**
Jamison – Lower Kyalla	95.1	299.0	958.0		52.76	165.89	531.50	45%	**Hess Australia (Beetaloo) Pty Ltd.**
Elliot – Lower Kyalla	95.1	299.0	958.0		52.76	165.89	531.50	11.25%	
Shenandoah – Middle Velkerri	90.5	281.0	889.0		50.21	155.90	493.22	50%	**Falcon Oil & Gas Australia**
Jamison – Middle Velkerri	90.5	281.0	889.0		50.21	155.90	493.22	32%	**Hess Australia (Beetaloo) Pty Ltd.**
Elliot –Middle Velkerri	90.5	281.0	889.0		50.21	155.90	493.22	12.5%	
Arithmetic Aggregation[1]	**556.8**	**1740.0**	**5541.0**		**308.91**	**965.35**	**3074.15**	**<<1%**	
Stochastic Aggregation[2]	**1400**	**2342**	**4015**		**776.72**	**1299.34**	**2227.52**	**<<1%**	
Stochastic Aggregation[3]	**184**	**703**	**1878**		**102.08**	**390.02**	**1041.91**	**92%**	

Source: - RPS Energy

Notes: “Gross” are the 100% Reserves that are attributable to the licence whilst “Net Attributable” are those estimated to be attributable to Falcon’s 73% WI after royalties.

“Risk Factor” means the estimated chance or probability of discovering gas in sufficient quantity for it to be tested to the surface (also referred to as GPoS). It should be noted that it will take a number of wells to confirm the volume range quoted.

1: Although commonly done, it is statistically incorrect to arithmetically sum probabilistic estimates of P90, P50 and P10. To do so tends to under-estimate the true P90 and over-estimate the true P10 of the combined distribution as seen when compared to the Statistical Aggregation in the next row. This is exacerbated by the introduction of GPoS into the statistical aggregation (see below).

2: Statistical Aggregation assuming that all prospects are successful. The probability of this occurring is the product of each individual risk (GPoS) and is therefore very small.

3: Statistical Aggregation assuming at least one prospect is successful. This total takes into account all possible successful outcomes and the mean value for the resultant distribution (**504.31** Bcf Net) constitutes the true expectation of success.

Falcon also has Prospective Resources associated with identified seismic features within the Algyo formation as detailed in Table G.

Table G - Prospective Resources Summary for Makó Trough

Prospect (WI=100%)	Gross				Net Attributable				Operator
	Low Estimate	Best Estimate	High Estimate		Low Estimate	Best Estimate	High Estimate	Risk Factor	
Gas (Bcf)									
Besa	26.8	65.0	125.0		22.2	54.0	103.8	10%	**TXM Oil and Gas Ltd.**
Hod, SE	32.3	103.0	219.0		26.8	85.5	181.8	10%	
Kiralyhegyes	3.7	12.1	26.0		3.1	10.0	21.6	10%	
Kodmonosdulo	11.0	36.3	78.6		9.1	30.1	65.2	10%	
Kovegy	2.0	6.7	14.5		1.7	5.6	12.0	10%	
Kutvolgy	47.1	144.0	304.0		39.1	119.5	252.3	10%	
Tompahat	39.8	135.0	296.0		33.0	112.1	245.7	10%	
Urmos	6.2	15.0	29.0		5.1	12.5	24.1	10%	
Arithmetic Aggregation[1]	**168.9**	**517.1**	**1092.1**		**140.2**	**429.2**	**906.4**	**<<1%**	
Stochastic Aggregation[2]	**378.0**	**568.0**	**820.0**		**313.7**	**471.4**	**680.6**	**<<1%**	
Stochastic Aggregation[3]	**8.0**	**64.0**	**251.0**		**6.6**	**53.1**	**208.3**	**57%**	

Source: - RPS Energy

Notes: "Gross" are the 100% Reserves that are attributable to the licence whilst "Net Attributable" are those estimated to be attributable to Falcon's 100% WI after royalties.

"Risk Factor" means the estimated chance or probability of discovering gas in sufficient quantity for it to be tested to the surface (also referred to as GPoS).

1: Although commonly done, it is statistically incorrect to arithmetically sum probabilistic estimates of P90, P50 and P10. To do so tends to under-estimate the true P90 and over-estimate the true P10 of the combined distribution as seen when compared to the Statistical Aggregation in the next row. This is exacerbated by the introduction of GPoS into the statistical aggregation (see below).

2: Statistical Aggregation assuming that all prospects are successful. The probability of this occurring is the product of each individual risk (GPoS) and is therefore very small.

3: Statistical Aggregation assuming at least one prospect is successful. This total takes into account all possible successful outcomes and the mean value for the resultant distribution (56.2 Bcf Net) constitutes the true expectation of success.

Basis of Opinion

The results presented herein reflects our informed judgement based on accepted standards of professional investigation, but is subject to generally recognised uncertainties associated with the interpretation of geological, geophysical and engineering data. The Services were conducted within our understanding of petroleum legislation, taxation and other regulations that currently apply to these interests. However, RPS is not in a position to attest to the property title, financial interest relationships or encumbrances related to the properties.

Our estimates of resources and value are based on the data set available to, and provided by Falcon. We have accepted, without independent verification, the accuracy and completeness of these data.

Site visits were not undertaken by RPS. Since no Reserves are being assigned a site visit to these assets was not considered necessary.

The report represents RPS' best professional judgement and should not be considered a guarantee or prediction of results. It should be understood that any evaluation, particularly one involving exploration and future petroleum developments, may be subject to significant variations over short periods of time as new information becomes available. As stated in the Agreement, RPS cannot and does not guarantee the accuracy or correctness of any interpretation made by it of any of the data, documentation and information provided by the Company or others in accordance with the

Agreement. The Consultant does not warrant or guarantee, through the Services, this report or otherwise, any geological or commercial outcome.

This report relates specifically and solely to the subject assets and is conditional upon various assumptions that are described herein. The report, of which this letter forms part, must therefore be read in its entirety. Except with permission from RPS, this report may only be used in accordance with the Agreement. It must not be reproduced or redistributed, in whole or in part, to any other person than the addressees or published, in whole or in part, for any purpose without the express written consent of RPS. The reproduction or publication of any excerpts, other than in relation to the Admission Document, is not permitted without the express written permission of RPS.

Consent

We hereby consent, and have not revoked such consent, to the issue by the Company of its Admission Document, the inclusion of this CPR in the Admission Document in its entirety and the inclusion in the Admission Document of the references to our reports and to our name in the form and context in which they appear in the Admission Document.

For the purposes of paragraph (a) of Schedule 2 of the AIM Rules, RPS accepts responsibility for the information contained in the CPR.

This CPR relates specifically and solely to the subject assets and is conditional upon various assumptions that are described herein. This CPR must therefore be read in its entirety.

Yours faithfully,

For and on behalf of RPS

Andrew J Kirchin

Executive Vice President, Consulting Business Unit (US)

411 N. Sam Houston Parkway E., Suite 400, Houston, Texas 77060-3545 USA
T +1 281 448 6188 **F** +1 281 488 6189 **W** www.rpsgroup.com

EVALUATION OF THE HYDROCARBON RESOURCE POTENTIAL PERTAINING TO CERTAIN ACREAGE INTEREST IN THE BEETALOO BASIN, ONSHORE AUSTRALIA AND MAKO TROUGH, ONSHORE HUNGARY.

Prepared for

FALCON OIL AND GAS LTD

1st January 2013

DISCLAIMER

The opinions and interpretations presented in this report represent our best technical interpretation of the data made available to us. However, due to the uncertainty inherent in the estimation of all sub-surface parameters, we cannot and do not guarantee the accuracy or correctness of any interpretation and we shall not, except in the case of gross or wilful negligence on our part, be liable or responsible for any loss, cost damages or expenses incurred or sustained by anyone resulting from any interpretation made by any of our officers, agents or employees.

Except for the provision of professional services on a fee basis, RPS does not have a commercial arrangement with any other person or company involved in the interests that are the subject of this report.

Table of Contents

List of Figures

List of Tables

1 INTRODUCTION AND BACKGROUND

1.1 LICENCE OVERVIEW

This Report has been prepared as a Competent Persons Report ("CPR") by RPS for Falcon Oil & Gas Limited ("Falcon" or "the Company"). The Report is an independent evaluation of the potential hydrocarbon resource potential pertaining to certain acreage interests of Falcon in the Makó Trough, onshore Hungary and Beetaloo Basin, onshore Australia (together "the Properties"), as at 01 January 2013, in which Falcon has an interest as per Table 1.1 below.

Table 1.1 – Licence Status Summary

Licence Concessions (Country)	Interest (%)	Operator	Status	Area (km^2)	Expiry	Comments
Makó Trough Production Licence (Onshore Hungary)	100.0%	TXM Oil and Gas Ltd.	Production	994.6	21/05/2042	Periodic limited production. Development Unclarified for BCGA unconventional resources. Exploration potential in shallower Algyo Formation
Exploration Permit EP-76, (Northern Territory - Onshore Australia)	73.0%[1]	Hess Australia (Beetaloo) Pty Ltd.	Exploration	4,976.3	31/12/2013[2]	Under evaluation
Exploration Permit EP-98 (Northern Territory - Onshore Australia)	73.0%[1]	Hess Australia (Beetaloo) Pty Ltd.[3]	Exploration	11,412.1	31/12/2013[4]	Under evaluation
Exploration Permit EP-99 (Northern Territory - Onshore Australia)	73.0%[1]	Falcon Oil & Gas Australia Pty.	Exploration	2,587.2	31/12/2013	Under evaluation
Exploration Permit EP-117 (Northern Territory - Onshore Australia)	73.0%[1]	Hess Australia (Beetaloo) Pty Ltd.	Exploration	9218.3	31/12/2013	Under evaluation

[1] Falcon Oil & Gas Limited owns 73% of Falcon Oil & Gas Australia which holds a 100% interest in the licences. The remaining 24% is owned by Sweetpea Petroleum Pty. Ltd, which is a wholly owned Australian subsidiary of PetroHunter Energy Corp., and 3% interest by others

[2] See Falcon's press release 0n 14/09/2012.

[3] Note: Falcon Oil and Gas Australia Pty. retains operatorship in the Shenandoah-1 well and approximately 405 km^2 (100,000 acres) land around the Shenandoah-1 wellbore.

[4] See Falcon's press release 0n 14/09/2012.

The licence contracts are standard tax and royalty contracts. The Makó Trough licence requires a 12% royalty to be paid to the Government of Hungary on any production and Falcon has a further 5% royalty agreement with Prospect Resources Inc., the previous owners of the licence. For the Northern Territory permits, a royalty of 10% will be payable to the Northern Territory government on any future production. In addition, there is a 1% royalty to the indigenous native stakeholders to pay-back of costs, rising to 2% after payback unless production has gone into decline. The Company will also pay royalties amounting to 13% to certain third parties.

RPS Energy has assigned Contingent Resources – Development Unclarified and Prospective Resources to Falcon's Makó Trough licence interests; and Prospective Resources to the Beetaloo Basin licence interests. These are summarised in Section 2.

2 SUMMARY OF ASSETS

2.1 MAKO TROUGH - Hungary

RPS has assigned **Contingent Resources – Development Unclarified** to the BCGA discoveries in the Szolnok, Endrod, Basal Conglomerate and Synrift Formations; and, Prospective Resources to a number of identified leads and prospects located in the overlying Algyo Formation.

The total estimated range of Contingent Resources is given in Table 2.1-1 below. Table 2.1-2 gives an estimated range of Prospective Resources. In each case they are arithmetic aggregation of the Resources calculated by zone.

Table 2.1-1 – Contingent Resources Summary

	Gross			Net Entitlement		
	1C	**2C**	**3C**	**1C**	**2C**	**3C**
Szolnok (Gas – Tcf)	12.13	30.96	63.60	10.07	25.70	52.79
Lower Endrod (Gas – Tcf)	0.61	1.11	1.87	0.51	0.92	1.55
Basal Conglomerate (Gas – Tcf)	1.41	3.00	5.53	1.17	2.49	4.59
Synrift Sequence (Gas – Tcf)	0.08	0.19	0.42	0.07	0.16	0.35
Arithmetic Aggregation[1]	**14.24**	**35.27**	**71.41**	**11.82**	**29.27**	**59.27**
Probabilistic Aggregation	**16.85**	**35.78**	**68.46**	**13.99**	**29.70**	**56.82**
Upper Endrod (Oil – MMstb)	32.89	76.71	158.26	27.30	63.67	131.36

1: It is statistically incorrect to arithmetically sum probabilistic estimates of P90, P50 and P10. To do so tends to under-estimate the true P90 and over-estimate the true P10 of the combined distribution as seen when compared to the Probabilistic Aggregation in the next row.

The volumes quoted above are classified as Contingent Resources – Development Unclarified. Oil and Gas have been discovered and may be present in large quantities but commercial flow-rates have yet to have be achieved (although Falcon does periodically produce oil and gas from certain wells). RPS currently estimates that there is a less than or equal to 25% chance that the Contingent Resources quoted above will be converted to Reserves.

Table 2.1-2 – Prospective Resources Summary

	Gross			Net Entitlement			GPoS
	Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate	
Besa (Gas – Bcf)	26.8	65.0	125.0	22.2	54.0	103.8	10%
Hod, SE (Gas – Bcf)	32.3	103.0	219.0	26.8	85.5	181.8	10%
Kiralyhegyes (Gas – Bcf)	3.7	12.1	26.0	3.1	10.0	21.6	10%
Kodmonosdulo (Gas – Bcf)	11.0	36.3	78.6	9.1	30.1	65.2	10%
Kovegy (Gas – Bcf)	2.0	6.7	14.5	1.7	5.6	12.0	10%
Kutvolgy (Gas – Bcf)	47.1	144.0	304.0	39.1	119.5	252.3	10%
Tompahat (Gas – Bcf)	39.8	135.0	296.0	33.0	112.1	245.7	10%
Urmos (Gas – Bcf)	6.2	15.0	29.0	5.1	12.5	24.1	10%
Arithmetic Aggregation[1]	**168.9**	**517.1**	**1092.1**	**140.2**	**429.2**	**906.4**	**<<1%**
Stochastic Aggregation[2]	**378.0**	**568.0**	**820.0**	**313.7**	**471.4**	**680.6**	**<<1%**
Stochastic Aggregation[3]	**8.0**	**64.0**	**251.0**	**6.6**	**53.1**	**208.3**	**57%**

1: It is statistically incorrect to arithmetically sum probabilistic estimates of P90, P50 and P10. To do so tends to under-estimate the true P90 and over-estimate the true P10 of the combined distribution as seen when compared to the Probabilistic Aggregation in the next row. This is exacerbated by the introduction of GPoS into the statistical aggregation (see below).

2: Statistical Aggregation assuming that all prospects are successful. The probability of this occurring is the product of each individual risk (GPoS) and is therefore very small.

3: Statistical Aggregation assuming at least one prospect is successful. This total takes into account all possible successful outcomes and the mean value for the resultant distribution (56.2 Bcf Net) constitutes the true expectation of success.

2.2 BEETALOO BASIN – Northern Territory, Australia

Basin Resource Potential – Prospective Resources (Play level)

Using the parameters described in Section 5.5.9.1 and the Play Risks described in Section 5.5.9.2, RPS has calculated the Prospective Resource potential for the Beetaloo Basin at the Play level as shown in Tables 2.2-1 to 2.2-3.

Table 2.2-1 – Prospective Unconventional Oil Resources (Play level) Summary for Beetaloo Basin

Resource Play	Potentially In-place				Potentially Recoverable			
	P90	P50	P10		P90	P50	P10	Play risk
Unconventional Shale Oil (MMstb)								
Kyalla Upper	49,663	70,985	100,700		1,290	2,654	5,526	80%
Kyalla Lower	121,327	159,658	209,528		3,023	5,971	12,011	50%
Velkerri Middle	168,927	337,982	673,176		4,942	12,720	32,503	80%

Table 2.2-2 – Prospective Unconventional Gas Resources (Play level) Summary for Beetaloo Basin

Resource Play	Potentially In-place				Potentially Recoverable			
	P90	P50	P10		P90	P50	P10	Play risk
Unconventional Shale Gas (Tcf)								
Kyalla Lower	31.47	52.26	86.97		21.83	37.29	63.81	90%
Velkerri Middle	65.012	104.22	166.77		45.09	74.50	122.78	100%

Table 2.2-3 – Prospective BCGA Resources (Play level) Summary for Beetaloo Basin

Resource Play	Potentially In-place				Potentially Recoverable			
	P90	P50	P10		P90	P50	P10	Play risk
BCGA Gas (Tcf)								
Moroak Sst	1.36	8.26	51.24		0.95	5.90	36.72	50%
Bessie Creek Sst	35.22	62.31	107.03		24.58	44.31	78.48	50%

Prospective Resources – Areas centered around well penetrations (Prospect level)

RPS has assigned Prospective Resources (Prospect level) to three shale plays within the Beetaloo Basin, namely Unconventional Shale Oil in the Kyalla and Middle Velkerri Formations (above 1500m TVDSRD), and Unconventional Shale Gas in the lower most Kyalla and Middle Velkerri. No wells have yet proved the viability of the Moroak and Bessie Creek sandstones and these remain as Propsective Resource (Play level) potential (possibly BCGA in type) but no Prospective Resources (Prospect level) have been assigned at this time. The Prospective Resources (Prospect level) are shown in Tables 2.2-4 and 2.2-5.

Table 2.2-4 – Prospective Unconventional Oil Resources (Prospect level) Summary for Beetaloo Basin

Prospect (WI=73%)	Gross				Net Attributable			
	Low Estimate	Best Estimate	High Estimate		Low Estimate	Best Estimate	High Estimate	GPoS
Unconventional Oil (MMstb)								
Shenandoah – Upper Kyalla	17.5	62.7	223.0		9.71	34.79	123.72	40%
Elliot – Upper Kyalla	4.4	15.7	55.8		2.44	8.71	30.96	10%
Burdo – Lower Kyalla	4.8	16.5	57.5		2.66	9.15	31.90	6.25%
Ronald – Lower Kyalla	4.8	16.5	57.5		2.66	9.15	31.90	6.25%
Chanin – Lower Kyalla	4.8	16.5	57.5		2.66	9.15	31.90	6.25%
Walton-McManus – Middle Velkerri	12.2	49.6	198.0		6.77	27.52	109.85	40%
Arithmetic Aggregation[1]	**48.5**	**177.5**	**649.3**		**26.91**	**98.48**	**360.23**	**<<1%**
Stochastic Aggregation[2]	**130.0**	**245.0**	**497.0**		**72.12**	**135.93**	**275.74**	**<<1%**
Stochastic Aggregation[3]	**14.2**	**69.4**	**253.0**		**7.88**	**38.50**	**140.36**	**73%**

1: Although commonly done, it is statistically incorrect to arithmetically sum probabilistic estimates of P90, P50 and P10. To do so tends to under-estimate the true P90 and over-estimate the true P10 of the combined distribution as seen when compared to the Statistical Aggregation in the next row. This is exacerbated by the introduction of GPoS into the statistical aggregation (see below).

2: Statistical Aggregation assuming that all prospects are successful. The probability of this occurring is the product of each individual risk (GPoS) and is therefore very small.

3: Statistical Aggregation assuming at least one prospect is successful. This total takes into account all possible successful outcomes and the mean value for the resultant distribution (**62.14** MMstb Net) constitutes the true expectation of success.

Table 2.2-5 – Prospective Unconventional Gas Resources (Prospect level) Summary for Beetaloo Basin

Prospect (WI=73%)	Gross				Net Attributable			
	Low Estimate	Best Estimate	High Estimate		Low Estimate	Best Estimate	High Estimate	Risk Factor
Unconventional Gas (Bcf)								
Shenandoah – Lower Kyalla	95.1	299.0	958.0		52.76	165.89	531.50	45%
Jamieson – Lower Kyalla	95.1	299.0	958.0		52.76	165.89	531.50	45%
Elliot – Lower Kyalla	95.1	299.0	958.0		52.76	165.89	531.50	11.25%
Shenandoah – Middle Velkerri	90.5	281.0	889.0		50.21	155.90	493.22	50%
Jamieson – Middle Velkerri	90.5	281.0	889.0		50.21	155.90	493.22	32%
Elliot –Middle Velkerri	90.5	281.0	889.0		50.21	155.90	493.22	12.5%
Arithmetic Aggregation[1]	**556.8**	**1740.0**	**5541.0**		**308.91**	**965.35**	**3074.15**	**<<1%**
Stochastic Aggregation[2]	**1400.0**	**2342.0**	**4015.0**		**776.72**	**1299.34**	**2227.52**	**<<1%**
Stochastic Aggregation[3]	**184.0**	**703.0**	**1878.0**		**102.08**	**390.02**	**1041.91**	**92%**

1: Although commonly done, it is statistically incorrect to arithmetically sum probabilistic estimates of P90, P50 and P10. To do so tends to under-estimate the true P90 and over-estimate the true P10 of the combined distribution as seen when compared to the Statistical Aggregation in the next row. This is exacerbated by the introduction of GPoS into the statistical aggregation (see below).

2: Statistical Aggregation assuming that all prospects are successful. The probability of this occurring is the product of each individual risk (GPoS) and is therefore very small.

3: Statistical Aggregation assuming at least one prospect is successful. This total takes into account all possible successful outcomes and the mean value for the resultant distribution (**504.31** Bcf Net) constitutes the true expectation of success.

3 METHODOLOGY USED IN THIS REPORT

The evaluation presented in this report has been conducted within our understanding of petroleum legislation, taxation and other regulations that currently apply to these interests. RPS Energy is not in a position to attest to the property title, financial interest relationships or encumbrances related to the property.

3.1 RESERVES AND RESOURCES CLASSIFICATION

All Reserves and Resources definitions and estimates, and also risk factors, shown in this report are based on the SPE/SPEE/AAPG/WPC Petroleum Resource Management System ("PRMS"). The key definitions of the PRMS are given in Appendix B.

In estimating Reserves and resources we have used standard petroleum engineering techniques. These techniques combine geological and production data with detailed information concerning fluid characteristics and reservoir pressure. RPS Energy has estimated the degree of uncertainty inherent in the measurements and interpretation of the data and has calculated a range of recoverable resources. RPS Energy has assumed that the working interest in the assets advised by Falcon is correct and RPS Energy has not investigated nor does it make any warranty as to the Falcon interest in these properties.

Hydrocarbon resource and reserve estimates are expressions of judgement based on knowledge, experience and industry practice and are restricted to the data made available. They are, therefore, imprecise and depend to some extent on interpretations, which may prove to be inaccurate. Estimates that were reasonable when made may change significantly when new information from additional exploration or appraisal activity becomes available.

3.2 RISK ASSESSMENT

For all prospects and appraisal assets estimates of the commercial chance of success for Contingent Resources, and estimates of geological chance of success for Prospective Resources, have been made. The former is called Chance of Development (CoD) and the latter Chance of Discovery (also CoD). To avoid confusion with acronyms we have used the term Geological Probability of Success (GPoS) in this document synonymously with Chance of Discovery.

3.2.1 Contingent Resources (Discovered Hydrocarbons)

The chance of success in this context means the estimated chance, or probability, that the volumes will be commercially extracted. A Contingent Resource includes both proved hydrocarbon accumulations for which there is currently no development plan or sales contract and proved hydrocarbon accumulations that are too small or are in reservoirs that are of insufficient quality to allow commercial flow rates and development at current prices. As a result, the estimation of the chance that the volumes will be commercially extracted may have to address both commercial (i.e. contractual or oil price considerations) and technical (i.e. technology to address low deliverability reservoirs) issues.

3.2.2 Prospective Resources (Exploration Prospects)

Unlike risk assessment for Contingent Resources, when dealing with undrilled prospects there is a more accepted industry approach to risk assessment for Prospective Resources. It is standard practice to assign a Geological Probability of Success (GPoS) which represents the likelihood of source rock, charge, reservoir, trap and seal combining to result in a present-day hydrocarbon accumulation. RPS assesses risk by considering both a play risk and a prospect risk. The chance of success for the play and prospect are multiplied together to give a Geological Probability of Success (GPoS). We consider three factors when assessing play risk: source, reservoir, seal and we consider four factors when assessing prospect risk: trap, seal, reservoir and charge. The result is the chance or probability of discovering hydrocarbon volumes within the range defined. As a check on the outcome of such exercises, RPS usually cross-checks the resulting GPoS against published benchmarks[2] that position the GPoS percentage relative to historical oil and gas play maturity.

Where the resources in question are unconventional (in particular "shale" plays and prospects), RPS has developed a methodology which is described in more detail in Section 5.5.9.2.

3.3 UNCERTAINTY ESTIMATION

The estimation of expected hydrocarbon volumes is an integral part of the evaluation process. It is normal practice to assign a range to the volume estimates because of the uncertainty over exactly how large the discovery or prospect will be. Estimating the range is normally undertaken in a probabilistic way (i.e. using Monte Carlo simulation), using a range for each input parameter to derive a range for the output volumes. Key contributing factors to the overall uncertainty are data uncertainty, interpretation uncertainty and model uncertainty.

Volumetric input parameters, gross rock volume (GRV), porosity, net-to-gross ratio (N:G), water saturation (Sw), fluid expansion factor (Bo or Bg) and recovery factor, are considered separately. RPS Energy has internal guidelines on the best practice in characterising appropriate input distributions for these parameters.

Systematic bias in volumetric assessment is a well-established phenomenon. There is a tendency to estimate parameters to a greater degree of precision than is warranted[3] and to bias pre-drill estimates to the high side[4]. Rose and Edwards observe the tendency towards assessing volumes in too narrow a range with overly large low-side and mean estimates. RPS Energy uses benchmarked P90/P10 ratios and known field size distributions to check the reasonableness of estimated volumes.

3.4 AUDIT METHOD

RPS Energy has performed the audit of Resources estimates in accordance with generally accepted petroleum engineering evaluation principles as set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers ("SPE Audit Standards").

Our approach in this instance has been to review the technical interpretation of the geoscience and engineering data for reasonableness. Where necessary, RPS Energy has undertaken independent re-interpretation to produce a technically reasonable base case interpretation. We have then reviewed the range of uncertainty for each parameter around this base case which have been used to estimate a range of petroleum initially in place and recoverable for each field.

---

[2] E.g. Otis, R.M. & Schneidermann, N. 1997. "A Process for Evaluating Exploration Prospects", AAPG Bulletin 81 (7) pp.1087-1109.

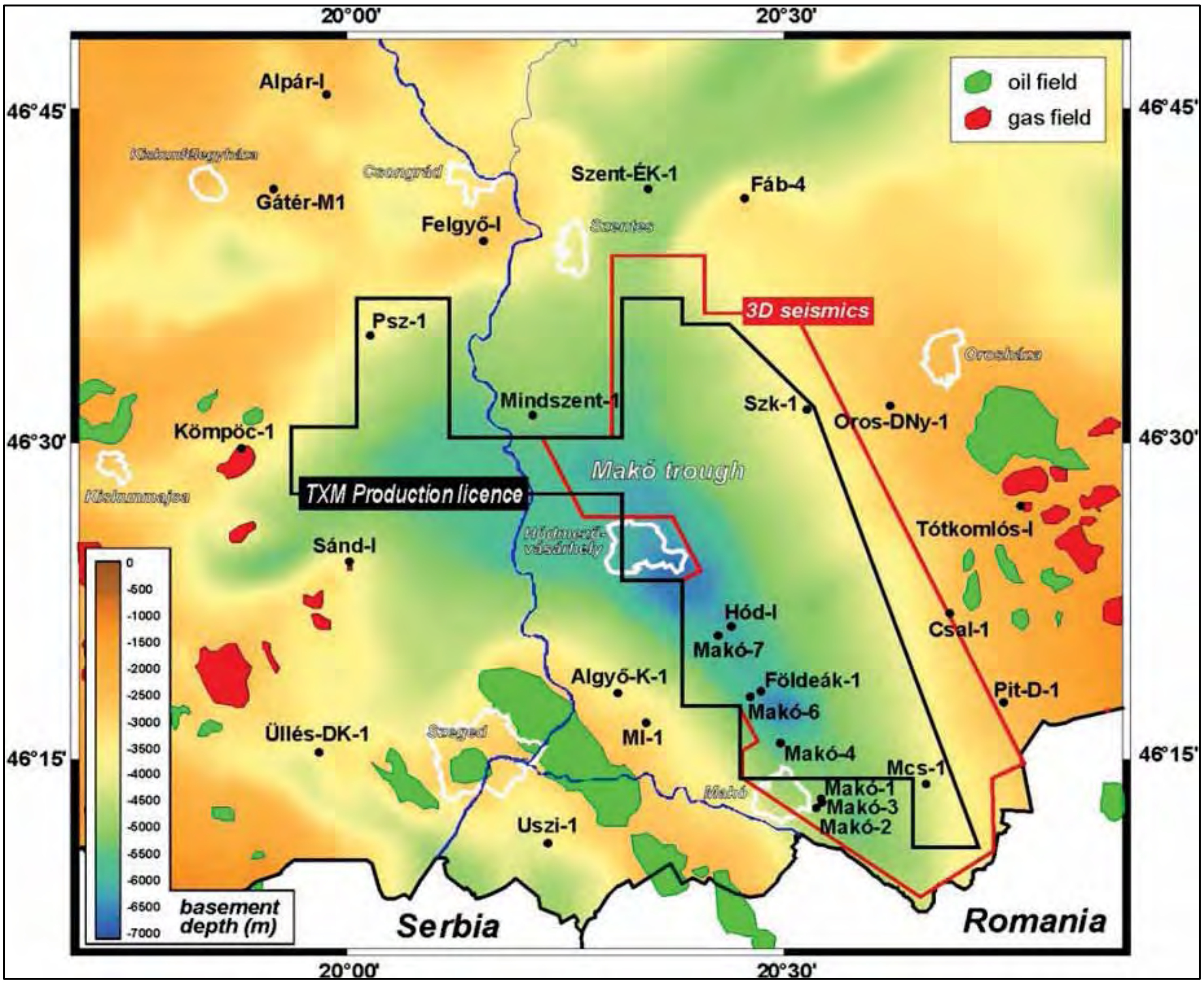
[3] Rose, P.R., 1987. Dealing with Risk and Uncertainty in Exploration: How Can We Improve? AAPG Bulletin, 71 (1), pp. 1-16.

[4] Rose, R.P. and Edwards, B., 2001. Could this prospect turn out to be a mediocre little one-well field? Abstract, AAPG Bulletin, 84(13)

4 MAKO TROUGH PRODUCTION LICENCE (Onshore Hungary)

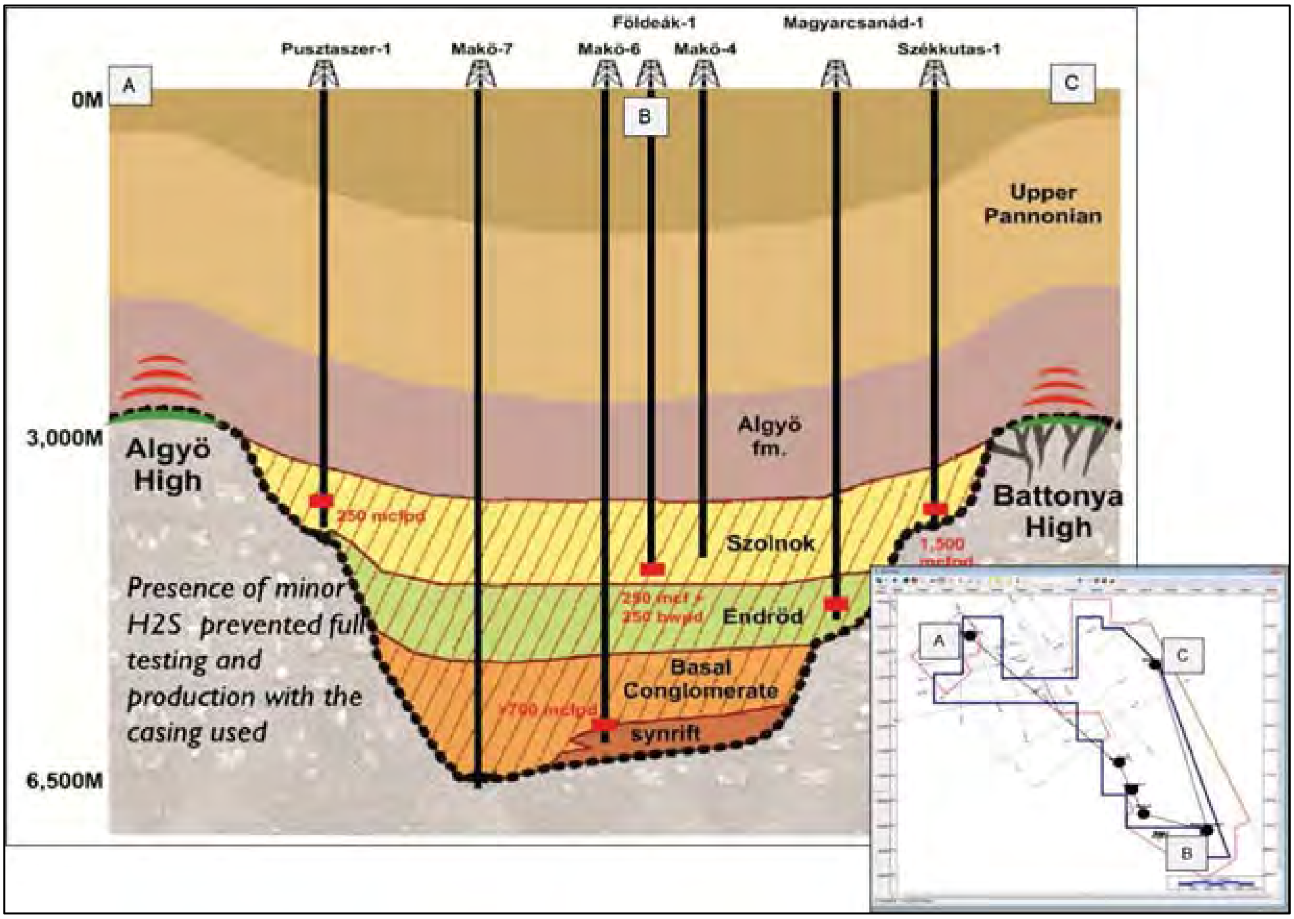
4.1 GEOLOGICAL OVERVIEW

The Makó Trough is a large structural sag or trough, which is located in southeastern Hungary near the Romanian border (see Figure 4.1-1). Hungary is an established oil and gas producing country and Falcons' licence is located some 5 km to the east of the largest field in Hungary, the Algyo field (2.5Tcf and 220 MMbo produced). The licence is transacted by existing gas pipeline infrastructure offering transport and access to local and other European markets.



Source: Falcon

Figure 4.1-1: Regional Location Map



Source: Falcon

Figure 4.1-2: Schematic Geological Section Across the Makó Trough

Figure 4.1-2 shows a schematic geological cross-section across the Makó Trough play. The play consists of a discovered Basin Centered Gas Accumulation ("BCGA") and several leads and prospects located within a conventional turbiditic sandstone play within the overlying Algyo Formation.

BCGA's are characterized by overpressured, gas-saturated, low-permeability reservoirs. In this case the principal potential reservoirs are divided into the Szolnok, Endrod, Basal Conglomerate and Synrift Formations. These formations are also the source rocks for the oil and gas fields found on structural highs which surround the Makó Trough depression.

The Algyo Formation is characterised as southeast prograding lacustrine slope deposits and are expected to vary between sandy slope aprons connected to shelf-margin deltas to turbidite systems fed by major channels. These stratigraphic intervals are distinctive on 3D seismic data as prograding clinoforms. Several leads and prospects have been identified within the toes of clinoforms or in slope detached positions within the fan sequences.

4.2 LICENCE STATUS AND WORK COMMITMENTS

The Makó Trough acreage interest is held 100% in the name of TXM Oil & Gas Limited, ("TXM") a wholly owned subsidiary of Falcon Oil and Gas Limited. Under the terms of the Production Licence, Falcon is obliged to pay a 12% royalty to the Government of Hungary on any production and has a further 5% royalty agreement with Prospect Resources Inc., the previous owners of the licence. TXM is the operator of the licence which covers 994.6 square kilometres (245,765 acres) following a 57.3% relinquishment as per the terms of the licence in "Tisza" exploration permit in September 2010 and the "Makó" exploration permit in November 2010.

Table 4.2-1 summarises the Makó Trough production licence status.

Table 4.2-1 - Licence Status Summary

Licence Concessions (Country)	Interest (%)	Operator	Status	Area (km^2)	Expiry	Comments
Makó Trough Production Licence **(Onshore Hungary)**	100.0%	TXM Oil and Gas Ltd.	Production	994.6	21/05/2042	Periodic limited production. Development Unclarified for BCGA unconventional resources. Exploration potential in shallower Algyo Formation

4.2.1 Required Minimum Work Program

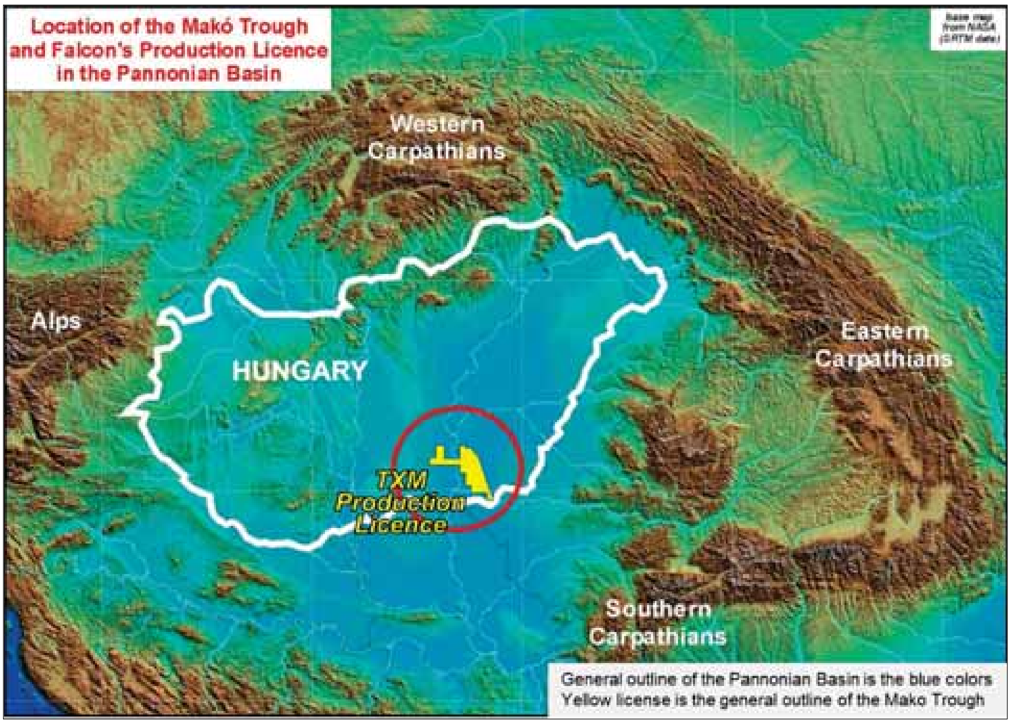
There are no remaining work commitments outstanding for the licence.

4.3 GEOLOGICAL SETTING AND PROSPECTIVTY

4.3.1 Tectonic Setting

The Makó Trough is a large structural sag or trough, which is located in southeastern Hungary near the Romanian border. The axis of the trough strikes in a NW-SE direction.

The greater Pannonian Basin encompasses most of Hungary (Figure 4.3.1). The Makó Trough is a large extensional feature lying within this basin.

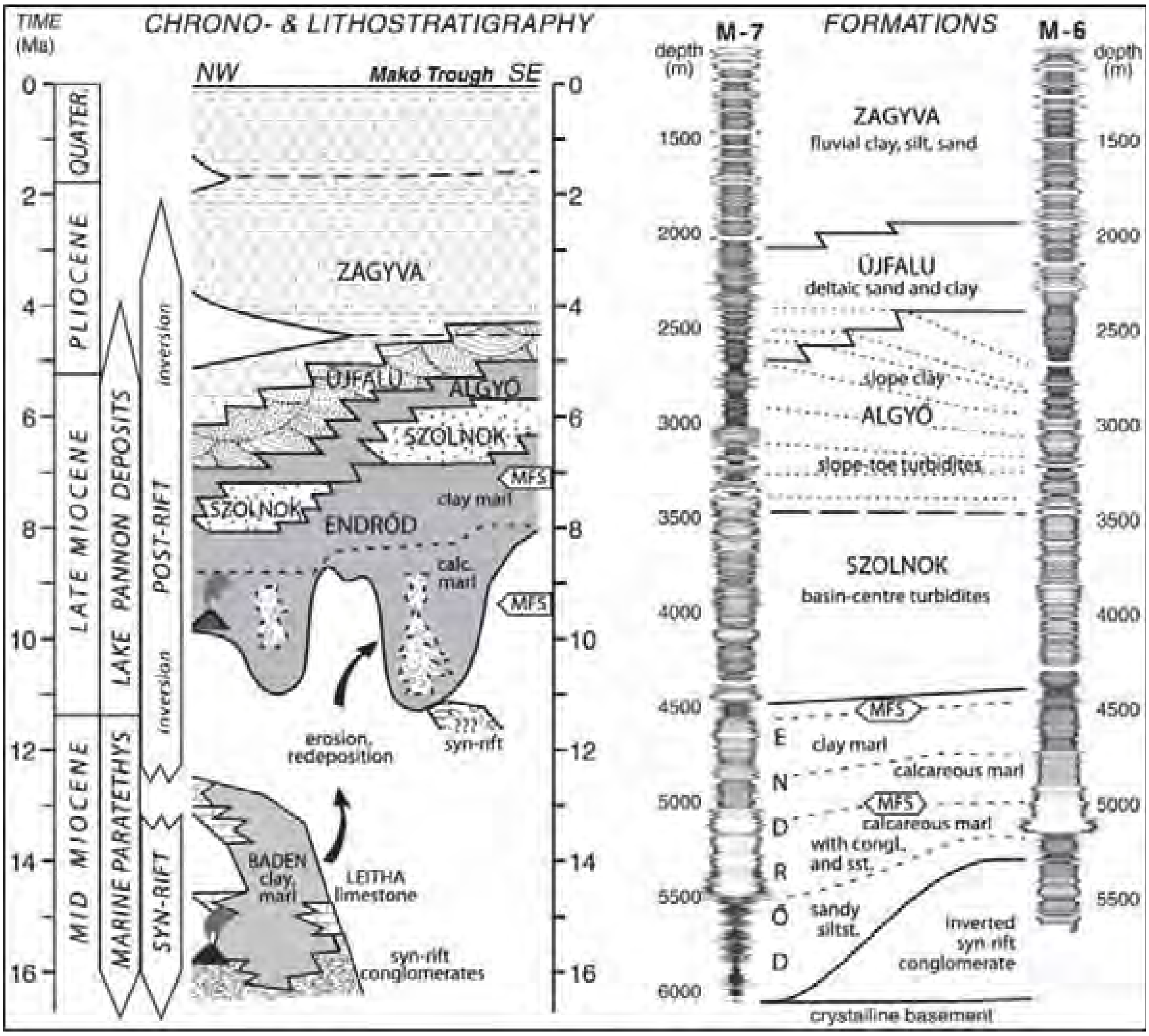


Source: Falcon

Figure 4.3-1: Location of the Pannonian Basin

The early Paleozoic and Mesozoic history of the area is complex and not completely constrained. In the Mesozoic compression caused by the northward movement of Africa and the Adriatic microplate initiated the closure of the Tethys Sea. During this process the smaller, Paratethys Sea formed with the deposition of marine sediments. In the Oligocene to early Miocene the seaway remained open despite continued northward African plate movement, compression, rotation, thrusting and folding.

In the Middle Miocene, rifting occurred due to the coeval extrusion of Alpine terranes and subduction roll-back and the large Pannonian Basin formed in central Europe (Figure 4.3-1). The greater Pannonian Basin is approximately 600 km from east to west and 500 km from north to south. Within this larger area, there are numerous sub-basins separated by horst blocks. The formation of these depressions was diachronous between the late Early Miocene and the early Late Miocene. One of these is the Makó Trough. It strikes northwest-southeast and is between the Algyo and Battonya basement highs. The connection to the Paratethys remained open during the deposition of the Synrift sediments (Figures 4.1-2 and 4.3-2).



Source: Falcon

Figure 4.3-2: Makó Trough Stratigraphic Chart

After the termination of the slab retreat, the soft collision of the extruded blocks with the East European Platform led to the build-up of the Carpathian orogen. This resulted in the isolation of the Pannonian Basin from the sea, the formation of Lake Pannon. The collision was accompanied by a short period of tectonic inversion and is marked by a widespread unconformity between the syn- and postrift deposits. It was followed by the phase of post-rift thermal subsidence and the formation and maintenance of deep basins with the deposition of the lacustrine and non-marine sediments of the Endrod, Szolnok, and Algyo formations. Due to the ongoing indentation of the Adriatic microplate and the cessation of the subduction beneath the contemporaneous Carpathians, the basin has been gradually inverted. The Pliocene and

Quaternary has had uplift along the basin edges and subsidence in the basin center. In the Makó Trough section of the Pannonian Basin there is currently in excess of 7,000 m of sediment.

The target zones are the entire accumulations of Szolnok and Endrod clastic sediments in the Makó Trough as well as the underlying Basal Conglomerate and Synrift Sequence (the BCGA dicoveries) and leads and prospects within the overlying Algyo formation.

4.3.1.1 Synrift Formation

The Synrift formation is poorly understood. In places it is composed of poorly sorted conglomerates interbedded with shales. The conglomerates are composed of metamorphic, granitic, quartz, and dolomite clasts. The deposition environment is also poorly known. It may have been deposited in alluvial fans into a fluvial or near shore environment.

4.3.1.2 Basal Conglomerates

These are also considered the lowermost part of the Endrod Formation. The Basal Conglomerate is dominantly black marls with a thin clast/matrix supporting a metamorphic and quartz conglomerate and sandstone intercalations. The coarse-grained sediments most probably have local source (neighboring basement highs) and their deposition is related to mass gravity flow processes. Upwards decreasing abundance of conglomeratic intercalations points to ongoing transgression of local shorelines.

4.3.1.3 Endrod

Deposition of the Endrod began with volcanic tuffs, limestones, and conglomerates. This was followed by alternating bands of sandstone, siltstone, and anoxic shales, and marls deposited in basin floor fans. The Endrod formation represents a transgressive phase of the basin fill. The formation is often subdivided into smaller units based on lithology. The changes in lithology correspond to major changes in deposition. The shales and marls are dark gray to brownish gray and the often grade into a siltstone/shale section with minor sandstone beds.

The Lower Endrod is generally a calcareous marl. The organic-rich calcareous marls contain brackish water microfossils indicating they were deposited in clear open lacustrine waters. The calcareous marls grade into very thin sandstones and siltstones. Condensed black marls reveal maximum flooding during the transgressive phase.

The Upper Endrod is composed mainly of a clayey marls and siltstones. They are characterized by upward decreasing carbonate and increasing silt content. A few centimeter scale very fine grained interbedded turbiditic sandstones are common. This reflects the gradual approach of the shelf-margin slope system. The uppermost 100 m of the Endrőd Marl is clay. The lack of silt and mass gravity flow deposits may indicate significant pause in sediment input.

4.3.1.4 Szolnok

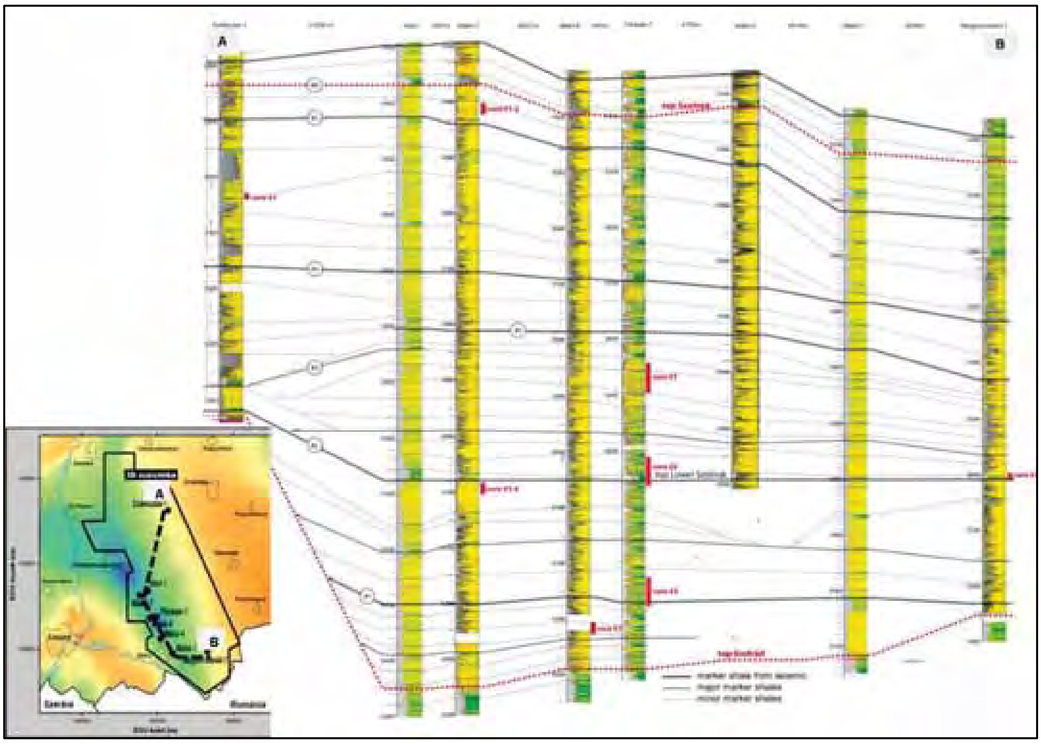
With the increased subsidence, came increased sedimentation. The Szolnok Formation has basal, deep water sediments of the turbidite deposition of the Pannonian Delta (Figure 4.3-3). The Szolnok in the center of the Makó Trough is composed of interbedded sandstone, siltstone and shale, which may be finely interbedded. Sandstones are light gray, hard, micaceous, very fine-grained, well sorted with calcareous cement and poor visual porosity. Siltstones are dark to medium gray, micaceous, occasionally fissile, splintery and sometimes sandy. Shales are brownish gray or light brownish gray, medium to hard and splintery. The entire sequence may be considered a series of shifting channel fans and lobes.

Four facies have been defined in the Szolnok:

1. Fully bioturbated clay, clayey siltstone,
2. Silty mudstones with mm-thick very fine sandstones to coarse siltstones,
3. Thin-bedded turbidites (mostly 5–10 cm thick, fine to very fine-grained sandstones) alternating with siltstones

4. Thick-bedded turbidites (0.3–2 m thick, fine- to medium-grained, commonly amalgamated sandstones) without any silt- or claystone.

These are alternating low density, low-volume suspension deposits and large volume high-density turbidity currents. The facies appear to be a typical turbiditic sequence with the silty mudstones deposited in between turbidite flows.



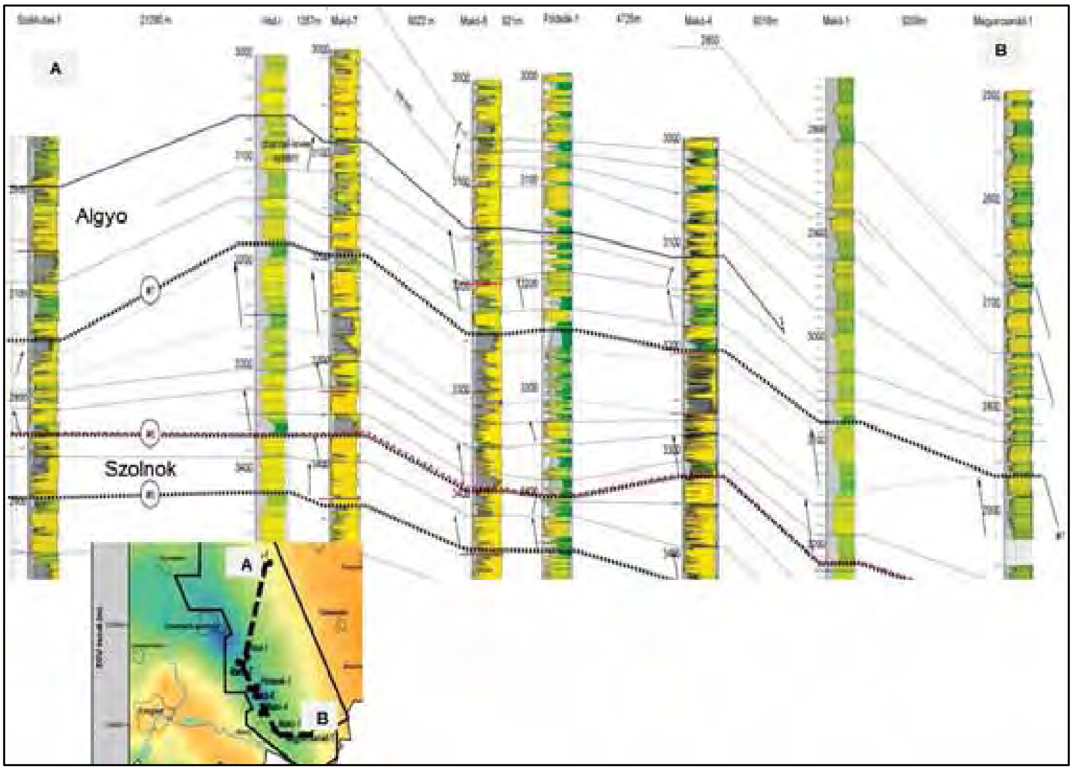
Source: Falcon

Figure 4.3-3: Szolnok Cross Section

The sand-dominated intervals are regarded as the center of the channels and fan lobe deposits while the thin-bedded sandstone association may be interpreted as overbank of distal fan deposits. Minor shales indicate fan/channel abandonment and quiet water deposition. Amalgamated channel and fan deposits occur and the sand bodies are stacked to form 50–150 m thick complexes, separated by major marker shales of 5–10 m thickness.

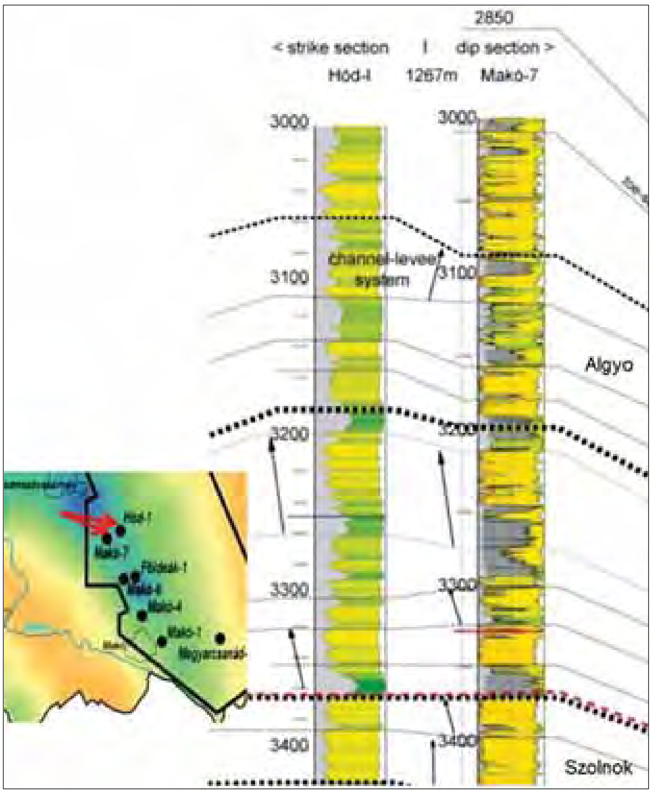
4.3.1.5 Algyo

The Algyo formation represents the slope deposits of the Pannonian Delta and is composed of prograding clinoforms. The Algyo is composed of dark gray siltstones, interbedded with thin to thicker sandstone beds (Figures 4.3-4 and 4.3-5). Thicker (20-50 m) coarsening upward sandstones separated by 5-10 m thick mudstone units are more abundant in the lower part of the formation. The clayey sediments represent the slope, while the sandy units were deposited from decelerating turbidity currents comprising channel-fed lobes near the slope-toe region.



Source: Falcon

Figure 4.3-4: Algyo Cross Section



Source: Falcon

Figure 4.3-5: Detailed Algyo Cross Section

Six wells were drilled and cased to test the Makó Trough BCGA during the years of 2006 and 2007. All of the wells confirmed the presence of BCGA in the Makó Trough but production characteristics were mixed.

In the most recent well, ExxonMobil's Foldeak-1 drilled and completed in 2009, a minor increase in background total gas readings was recorded while drilling the Algyo and Szolnok formations. After reaching total depth (TD), the Foldeak-1 completed and tested the Upper and Lower Szolnok. Each of the zones was perforated and fracture stimulated. Following the stimulation of each zone, the Foldeak-1 was production tested. The highest gas rate was recorded in the Lower Szolnok at 250 Mcfd and 370 bwpd. The upper Szolnok tested at a post-frac rate of 20 Mcfd. The well was plugged and abandoned following production testing of the Szolnok later in 2009. Figure 4.1-2 shows the seven well penetrations through the Makó Trough unconventional play with production test rates posted on each well.

The unconventional play is interpreted to exist within the Szolnok and Endrod formations from a depth of about 3,200 m (as encountered in the Makó-6 well) and to persist to the total depth of that well at 5,689 m (driller's depth), to include the underlying Basal Conglomerate and Synrift Sequence. This is based on an evaluation of available data for the deep section within the Makó Trough. The Algyo formation top for the exploration prospects is interpreted to be present at 2782 m in the ExxonMobil Foldeak-1 to a base of 3390 m in the Makó-4 well.

4.3.2 Overview Of Discoveries and Prospectivity

The initial wells (Szekkutas-1, Pusztaszer-1, Mako-4, Mako-6, Mako-7, Magyarcsanad-1 and Foldeak-1) have been drilled, cased and partially tested as of the Effective Date of this report. The Algyo was MDT tested in the Makó-4 and flowed water. The Szolnok tested burnable hydrocarbons, CO_2 and some H_2S in the Pusztaszer-1, Szekkutas-1 and Foldeak-1. The Makó-6, Magyarcsanad-1 and Szekkutas-1 tested burnable hydrocarbons in the Endrod and Basal Conglomerate. The Synrift flowed water in the Makó-6. The Magyarcsanad-1 produced some light oil and associated gas from the Endrod.

4.3.2.1 Pusztaszer-1

In late 2005, Falcon began its initial exploration drilling program with the Pusztaszer-1. The well was designed as a delineation well to test the northeastern extent of the Makó Trough. The well was drilled to a total vertical depth of 3,782 m and encountered Gneiss Basement, the Endrod and Szolnok formations. The Pusztaszer was then tested in the Basement and Szolnok formation following small fracture stimulation. The well tested approximately 200 Mcfd and 200 bwpd from the Szolnok formation.

4.3.2.2 Szekkutas-1

The next well to be drilled and tested in early 2006 was the Szekkutas-1. The well was designed to test the northwest extension of the Makó Trough and was drilled to a total depth of 3,585 m. The well encountered the Triassic Basement, Endrod and the Szolnok formations. The well tested 130 Mcfd and 549 bwpd from the Triassic Basement. The Endrod tested gas at an unstabilized rate of 1,577 Mcfd at 50 to 100 ppm hydrogen sulfide and 150 Mcfd at similar H_2S concentrations from the Szolnok. The presence of H_2S in these concentrations required Falcon to abort the test due to safety considerations.

4.3.2.3 Makó-6

The Makó-6 was drilled in 2006 to a total depth of 5,692 m and was the first deep test in the basin by Falcon. The well encountered the Synrift, Basal Conglomerate, Endrod and Szolnok formations. Petrophysical analysis of the log and core data indicated the possible presence of hydrocarbons in all formations, establishing a possible hydrocarbon column of 2 km. A test of the Synrift was attempted which proved tight. An interval at the base of the Basal Conglomerate was tested with initial rates of up to 700 Mcfd with associated H_2S of 400 ppm. The test was aborted when a suspected down-hole failure occurred.

4.3.2.4 Makó-7

The Makó-7, also drilled in 2006, was designed to be a second deep basin test. The well was drilled to a total depth of 6,085 m and encountered the Basal Conglomerate, Endrod and Szolnok formations. Petrophysical analysis indicates the possible presence of hydrocarbon in all formations encountered, but no testing has been accomplished to date. If the well tests hydrocarbons it may indicate the presence of a 2.5 km hydrocarbon column. The interval between 3370 and 3429 m MD shows density/neutron crossover, and increase in background total gas reading up to 2670 gas units. The well has produced/tested Basal Conglomerate gas intermittently between October 2011 and September 2012 (cumulative production of 1.5 MMcf) from the well, which has since been shut-in.

4.3.2.5 Magyarcsanad-1

The evaluation program continued in 2006 with the Magyarcsanad-1. This well was designed to test the southern end of the Makó Trough. The well was drilled to a total depth of 4,226 m and encountered the Endrod and Szolnok formations. The well tested oil and gas from the Endrod formation at unstabilized rates of 360 bopd and 1,100 Mcfd, declining to 65 bopd and 137 Mcfd without stimulation. The well has produced/tested gas and light oil intermittently from the Endrod between November 2009 and July 2012 (cumulative production of 2000 Mcf of gas and 850 Bbls of light oil).

This is very encouraging in that it establishes the presence of mobile high gravity oil in the Endrod formation. In addition, it indicates the Endrod in the area of the wellbore to be a naturally fractured reservoir capable of delivering hydrocarbon. If future analysis and testing establishes the Endrod to contain a pervasive natural fracture system, charged with hydrocarbon and capable of transmissibility of the hydrocarbon, this could significantly add to resources of the basin.

4.3.2.6 Makó-4

Makó-4, drilled in 2007, was designed to test the Szolnok formation in the southern portion of the basin. The well was drilled to a total depth of 4,011 m. An MDT test from 2368-3179 m yielded water. The well encountered low gas saturated sands in the Algyo Urmos lead and TD's in the Szolnok formation and is suspended pending completion of the current geologic and operational review.

4.3.2.7 Foldeak-1

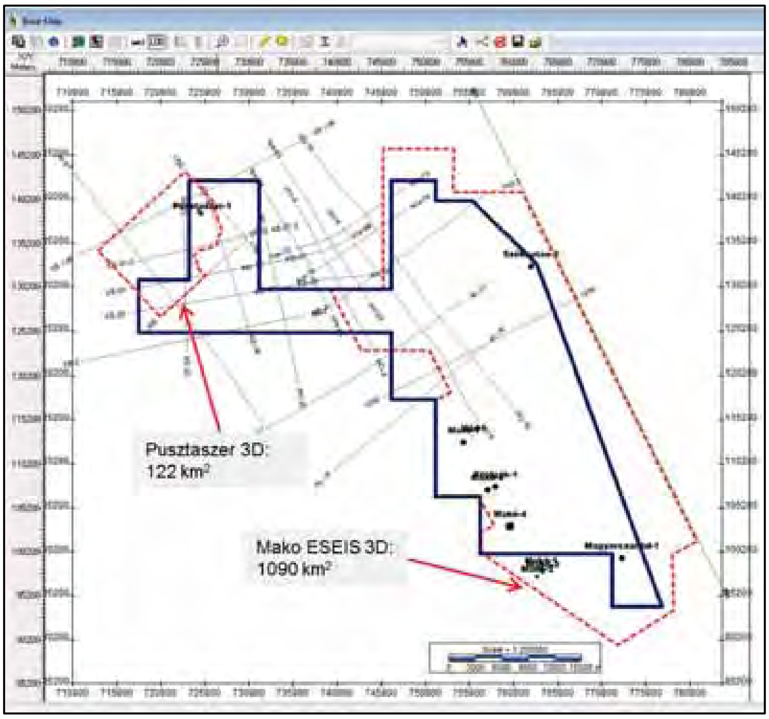
The ExxonMobil well was drilled in early 2009 to a total depth of 4,421 m in the top of the Endrod as a northeast offset to the Makó-6. After reaching total depth, the Foldeak #1 completed and tested the Upper and Lower Szolnok. Each of the zones was perforated and fracture stimulated. Following the stimulation of each zone, the Foldeak #1 was production tested. The Lower Szolnok was tested at 200 Mcfd on a 16/64"choke with a 300 ppm H_2S average concentration. This well confirms the distribution of gas in the deep basin from the shallower Szolnok test in the Szekkutas-1 on the eastern Makó Trough flank and the Pusztaszer-1 on the western flank. The well has since been suspended.

4.4 DATABASE

RPS was provided access to a comprehensive dataset including an interpreted SMT project, as well as well logs, well reports, deviation data, mudlogs, core data, well test and well completion reports.

4.4.1 Seismic Data

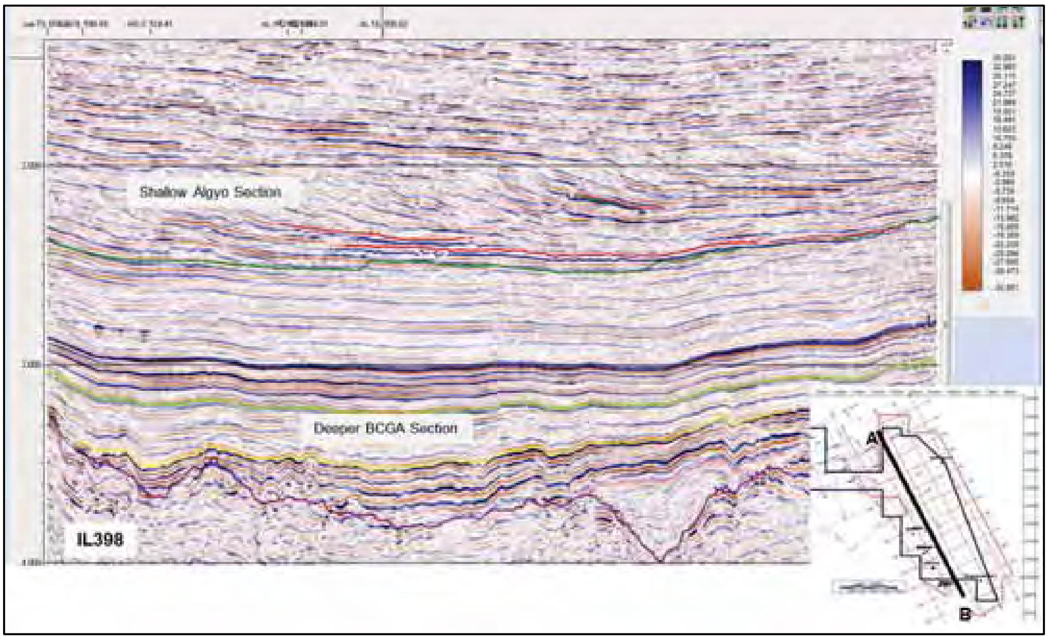
The SMT project included two 3D seismic surveys and older 2D data. Falcon also provided, in the SMT project, the well logs, well tops, horizons, key faults, grids and coonturs. Figure 4.4-1 shows the avaliable seismic data.



Source: Falcon

Figure 4.4-1: Makó Trough Seismic Data

The resources included in this report were covered by the Makó-ESEIS 3D. A number of seismic cubes were provided for the review including frequency, Hilbert, phase, and proprietary ESEIS processing attributes. Seismic data quality was fair to good and the time maps were completed on the 4thPrSTM processing. Figure 4.4-2 is a strike seismic line through the center of the Makó trough. The clinoforms of the shallower Algyo formation are well imaged, as is the deeper section.



Source: Falcon

Figure 4.4-2: Example of Seismic Data Quality

4.4.2 Well Data

RPS was provided access to a comprehensive dataset including an interpreted SMT project, as well as well logs, well reports, deviation data, mudlogs, core data, well test and well completion reports

4.4.3 Previous Reports

1. **"RESOURCE ESTIMATE , MAKO TROUGH, HUNGARY", Effective date August 15, 2006**. Scope of work: Preparation of report under the Canadian Oil & Gas Evaluation Handbook (COGEH) and Canadian securities instrument National Instrument 51-101 – Standards of Disclosure for Oil and Gas Issues (51-101) standards regarding the Client's Mining license in the Makó trough and Tisza license blocks in Hungary (each the Makó Mining License and Tisza License and together Licenses).
2. **"RESOURCE ESTIMATE , MAKO TROUGH, HUNGARY", Effective date March 31, 2008**. Scope of work: Preparation of report under the Canadian Oil & Gas Evaluation Handbook (COGEH) and Canadian securities instrument National Instrument 51-101 – Standards of Disclosure for Oil and Gas Issues (51-101) standards regarding the Client's Mining license in the Makó trough and Tisza license blocks in Hungary (each the Makó Mining License and Tisza License and together Licenses).
3. **"MAKÓ TROUGH GEOLOGICAL MODEL", January 7, 2009**. Main objective was to identify rock volumes having anomalous characteristics that might indicate prospectivity, using all available 3D data volumes. Nine (9) Petrel models containing data and geocellular models were developed and delivered as final products.

4.5 DISCOVERED BCGA AND ALGYO FORMATION LEADS AND PROSPECTS

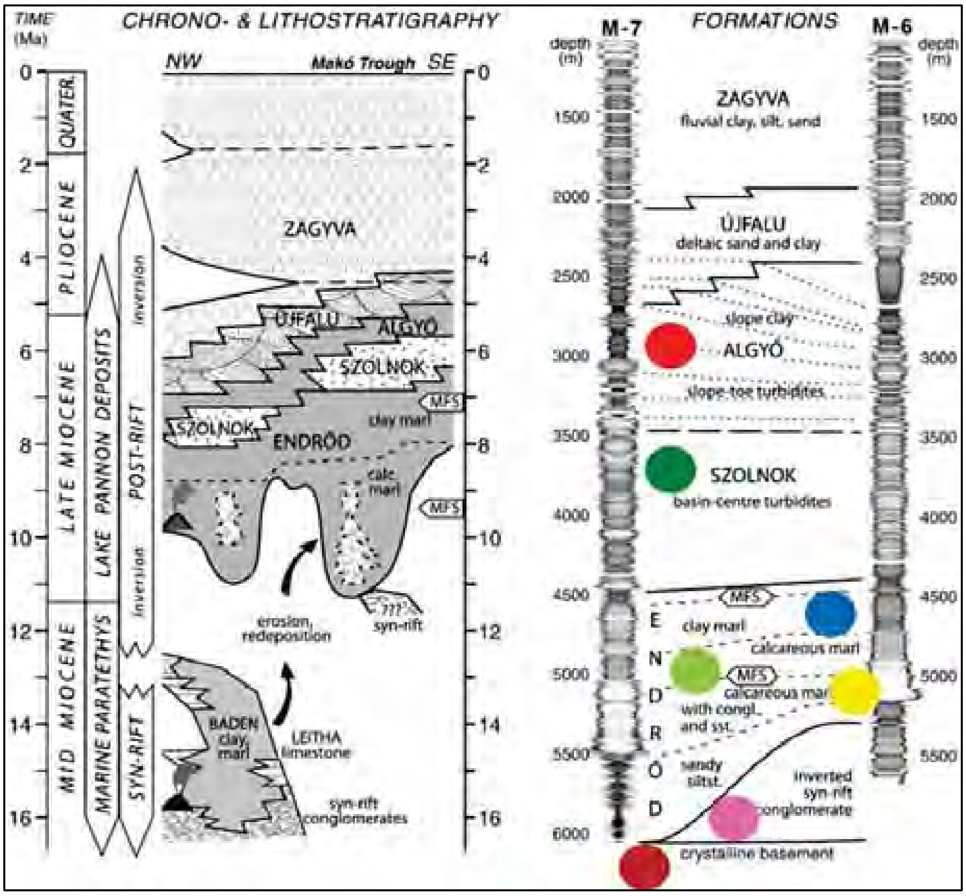
4.5.1 Overview

RPS evaluated several sources of information provided by Falcon (see Section 4.4) to assess the unconventional shale BCGA resource for the Szolnok, Endrod, Basal Conglomerate and Synrift Formations and the shallower conventional fan deposit leads and prospects for the Algyo Formation. The information used in the evaluation included seismic data and interpretation, depth maps, mudlogs, wireline logs, test data, and geochemical analysis.

4.5.2 Seismic Interpretation and Depth Maps

RPS has QC'd the seismic interpretation behind the current Falcon mapping of the Makó Trough and finds it to be broadly consistent with the underlying data. Since the BCGA is mapped as a resource play the seismic interpretation is used to confirm the general sequence stratigraphy and the presence or absence of the resource zones.

Figure 4.5-1 is a stratigraphic chart with the major formations and Figure 4.5-2 illustrates the seismic horizons interpreted by Falcon and reviewed by RPS.



Source: Falcon

Figure 4.5-1: Stratigraphic Chart with Seismic Horizons Annotated

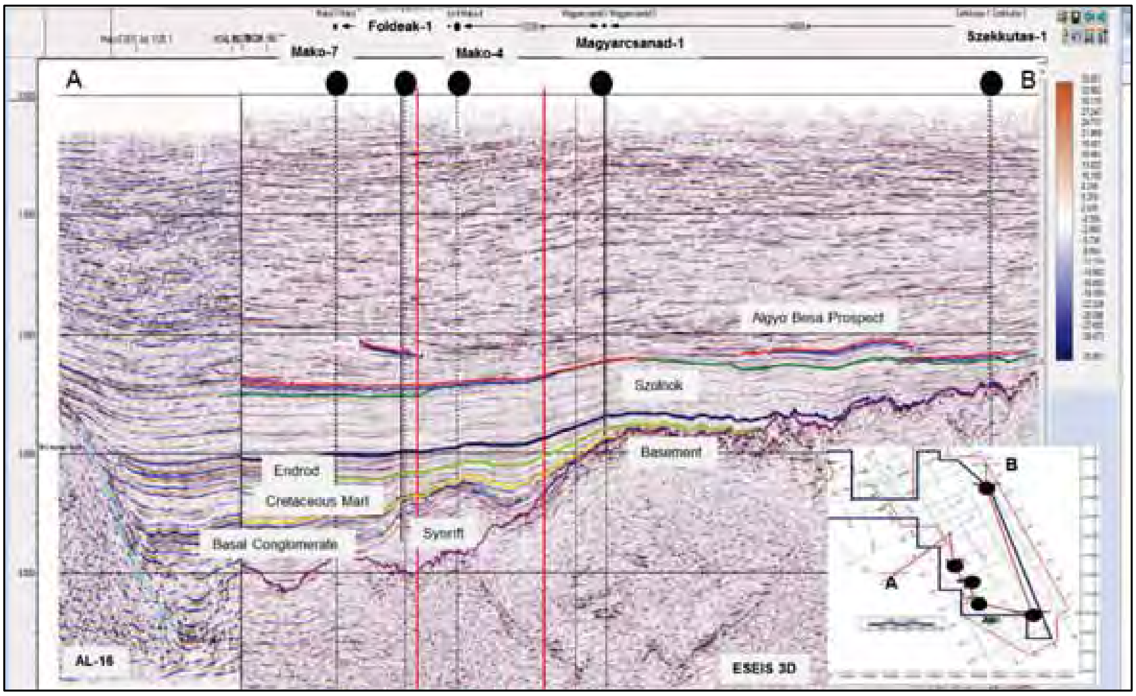
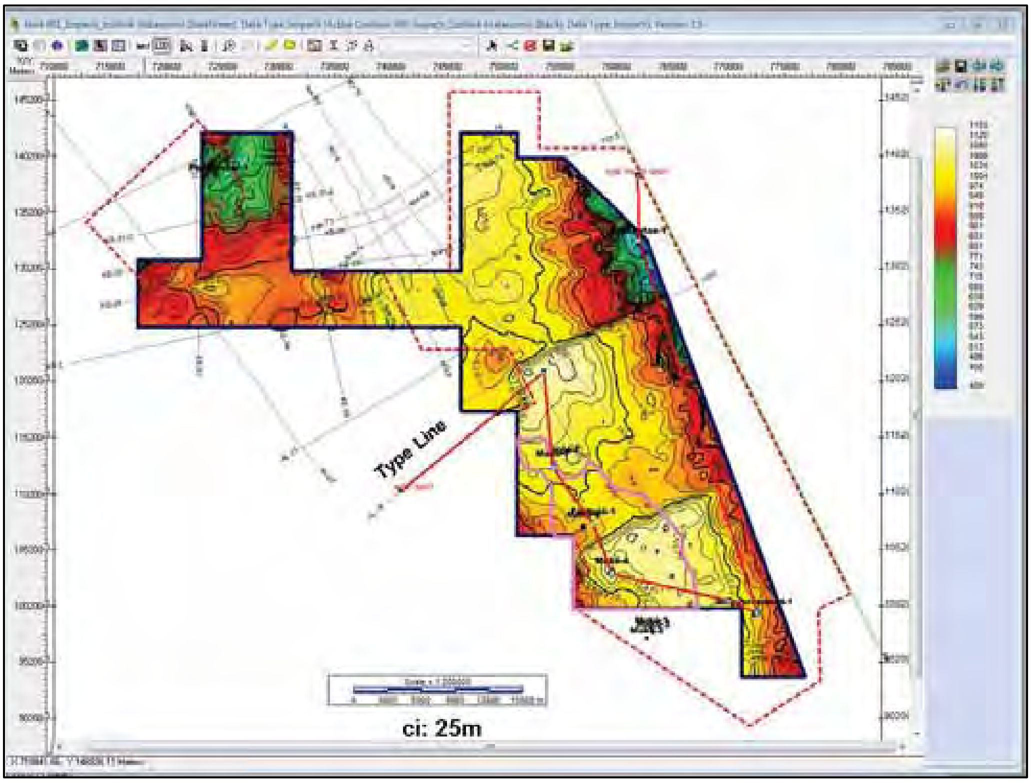


Figure 4.5-2: Type Seismic Line through the Key Wells

Falcon interpreted seven deeper horizons for use in the BCGA resource assessment:

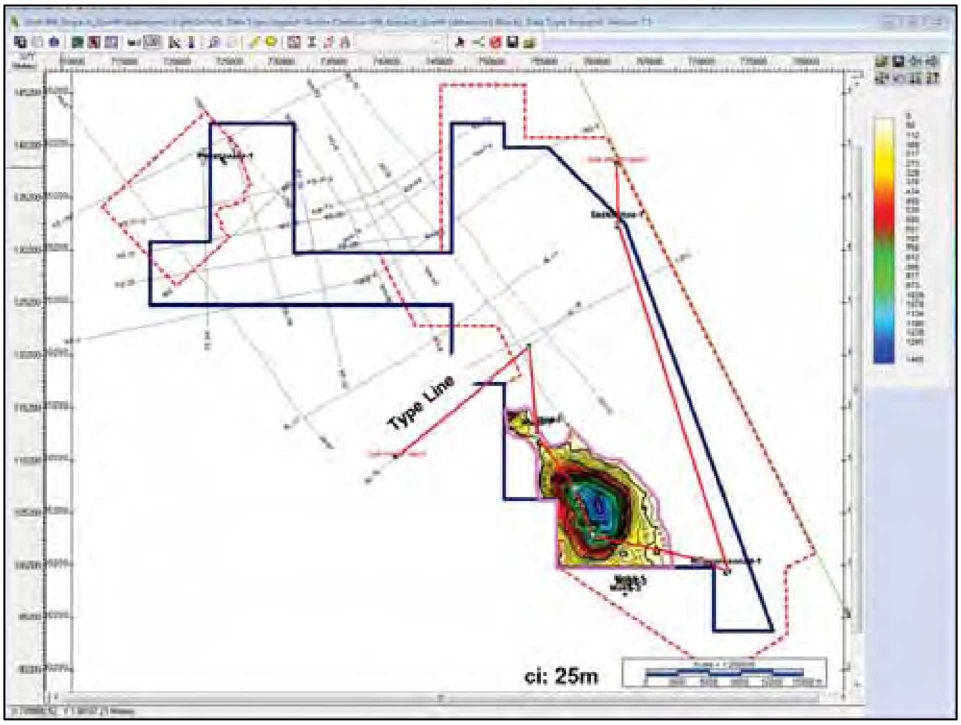
- Top Szolnok
- Top Endrod
- Top Calcareous marl
- Top Basal
- Top Synrift
- Top Basement

The gross rock volume used in the BCGA analysis was derived from the interval isopachs in SMT. The areas covered vary from the entire concession, Szolnok, to the areally restricted Synrift sequence. These gross rock volumes were placed into the Monte Carlo resource calculations. For example, Figure 4.5-3, the isopach for the Szolnok encompasses the entire Falcon concession and the gross rock volume used in the resource calculations is derived from the SMT volumetrics module in EarthPak™. Different from Szolnok, is the areally restricted Synrift sequence (see Figures 4.5-2 and 4.5-4). The resources for the BGCA for the synrift are found only in the south-western corner of the concession in the deepest part of the basin.



Source: Falcon

Figure 4.5-3: Szolnok Isopach used for Gross Rock Volume Calculations



Source: Falcon

Figure 4.5-4: Synrift Isopach used for Gross Rock Volume Calculations

For the conventional fan deposit sands in the Algyo, seismic amplitude anomalies are used to identify potential stratigraphically trapped sand-bodies. The prospects are identified by variations in calculated seismic attributes that have not yet been definitively calibrated to the well control. This lack of calibration is compounded by the fact that the seismic signal and seismic attributes are also impacted by constructive and destructive interference of the overlying and underlying turbidites and channels.

The time-to-depth conversion was reviewed and is considered correct. Depth conversion is not considered a key consideration for either play-type.

4.5.3 Well Test Information

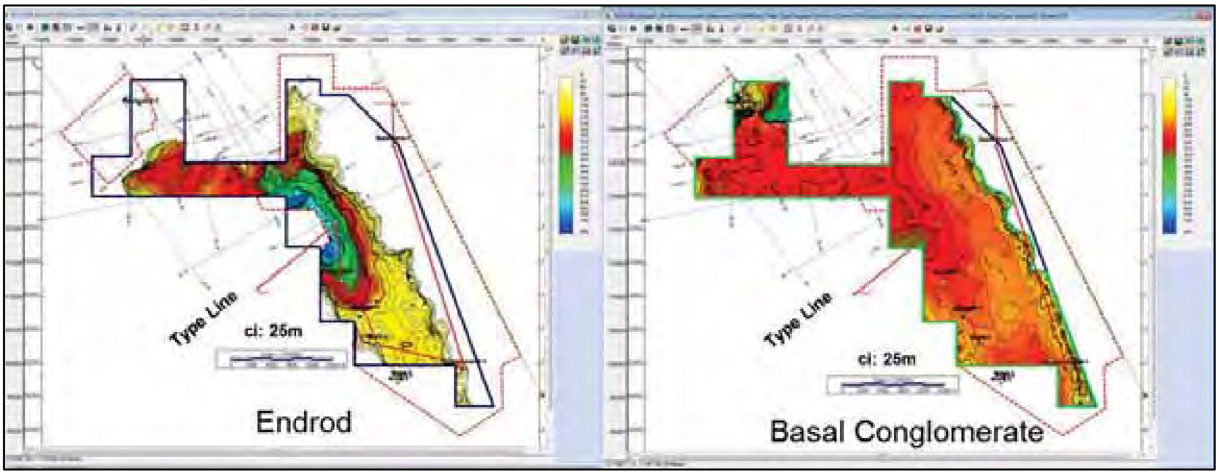
As described in Section 4.3.3, a number of well tests have been conducted within the BCGA play. All of the wells confirmed the presence of BCGA in the Makó Trough but the tests have yet to prove sustainable commercial flow rates of gas or oil, although Falcon does periodically produce oil and gas from certain wells.

4.5.4 BCGA Play

The exploration program in the Makó Trough is in the early-intermediate stages of evaluating the BCGA. BCGA plays are termed “unconventional” due to the low permeabilities that characterize such plays and the fact that thick, continuous, gas-charged sections are encountered across the play without the requirement for a conventional stratigraphic or structural trap. Due to the low permeability, commercially successful wells require the presence of a thick gas bearing section and successful implementation of hydraulic fracture treatments. Experience has shown that considerable experimentation is usually required to find the optimal completion technology. Given that even with successful completion technology, the productivity of low permeability gas wells is less than that of their conventional counterparts, the risks are primarily engineering and economic factors, rather than geological.

The deep drilling results to date have shown the presence of a thick sequence of hydrocarbon-bearing sediments. The presence of hydrocarbon is not in question, as drilling and testing results to date have confirmed its existence. The unknowns at present concern whether technology can be applied that will allow these hydrocarbon accumulations can be produced at commercial rates.

The gross rock volumes used in the four BGCA resource calculations were derived from the interval isopach maps. Figures 4.5-3 and 4.5-4 represent two of the four units in the BGCA resource assessment. The remaining two are the Endrod and Basal Conglomerate. As above, the gross rock volumes were calculated from the isopachs (Figure 4.5-5).



Source: Falcon

Figure 4.5-5: Endrod and Basal Conglomerate Isopachs used for Gross Rock Volume Calculations

4.5.5 Algyo Play

The shallow Algyo southeast prograding lacustrine slope deposits are expected to vary between sandy slope aprons connected to shelf-margin deltas to turbidite systems fed by major channels. The clinoforms prograded basinward from northwest to southeast over the Szolnok Formation. These stratigraphic intervals are distinctive on 3D seismic data as prograding clinoforms. The seismic characteristics of the amplitudes are variable. Eight (8) prospects have been considered in the newly defined Algyo play. Most prospects lie along the toes of the clinoforms or are in a slope detached position in the fan sequences. This new play is unproven and has risk in all play elements. The prospects are identified by variations in calculated seismic attributes that have not yet been definitively calibrated to the well control. This lack of calibration is compounded by the fact that the seismic signal and seismic attributes are also impacted by constructive and destructive interference of the overlying and underlying turbidites and channels.

Figure 4.5-6 shows the production license outline, key wells, and the Algyo prospect areas. One of the prospects, Urmos, has been penetrated by the Makó-4 well (See Section 4.3.3.6). This well encountered low gas saturated sands within the prospect outline at 3320-3367 m. There was no density/neutron gas cross-over, but an increase in background Total Gas readings up to 42 units recorded while drilling thus indicated low gas saturations. Another interval, 2368 m to 3179 m MD, had Total Gas readings for an up to 80 units, 38 units higher than the 3320-3367 m interval. The 3320 interval has no density/neutron cross-over and an MDT test yielded water. This indicates the Urmos prospect is likely water with low gas saturation. Thus, Makó-4 is illustrative of one of the risks with a new play, the inability to distinguish gas pay from low gas saturation. Sands in other wells penetrating the Algyo had inconsistent calibration of seismic attributes with gas pay.

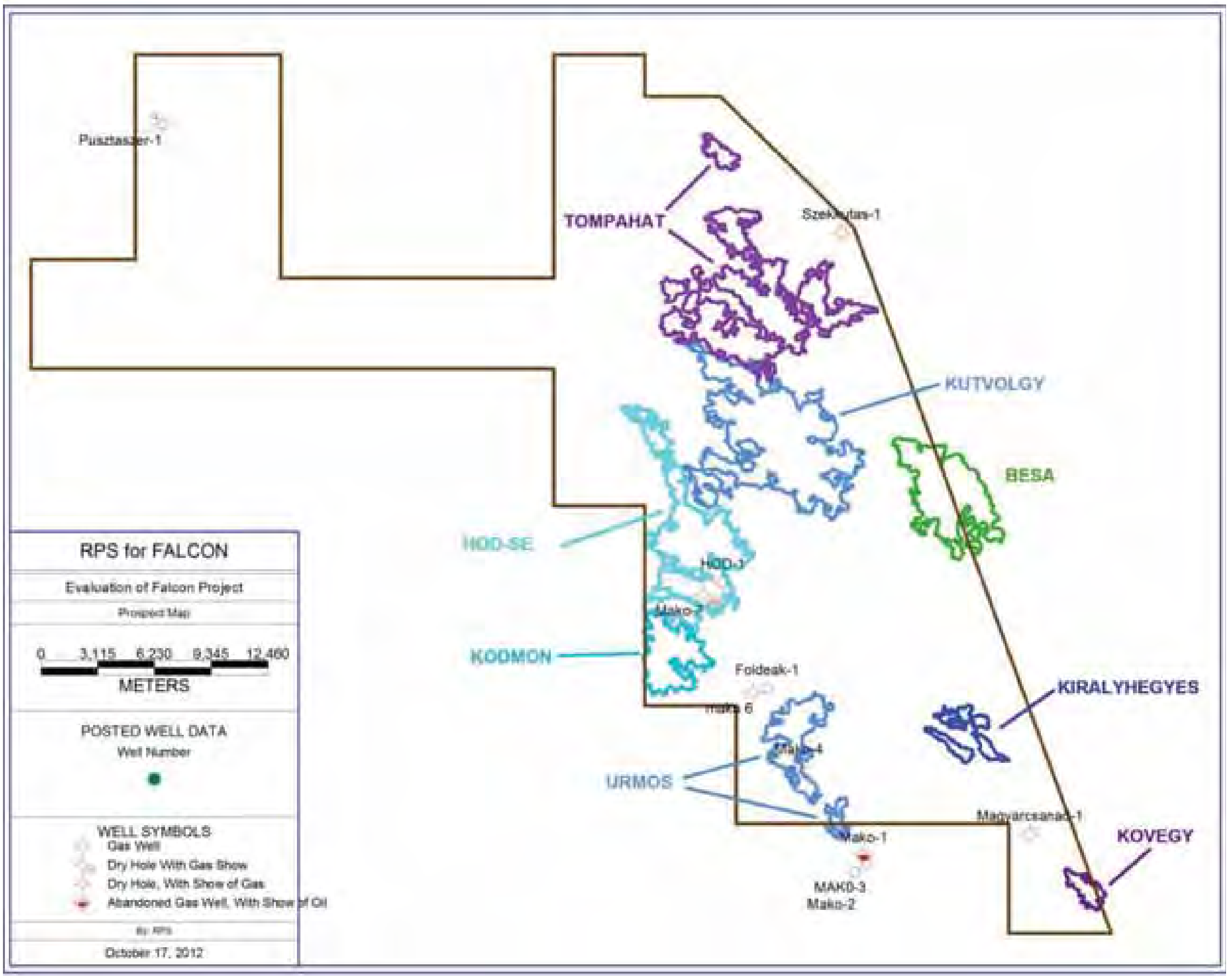


Figure 4.5-6: Algyo prospect location map

The traps are not structural, but are defined by the stratigraphic limits of the seismic attributes. Most of the Algyo anomalies are along the bases of the clinoforms. Figure 4.5-7 is a type seismic line across the Algyo Besa Prospect. The prograding clinoforms begin in the north and spread southward. Besa lies along the eastern edge of the concession and is located at the base of a clinoform. Figure 4.5-8 is an expanded view of Besa Prospect. The top of the Besa anomaly is the red horizon and the base is the blue horizon. The actual Besa prospect is the white zero crossing between the two horizons. Figure 4.5-9 is the same line from an inversion cube. The Besa anomaly is between the top and base seismic markers and is in bright red on the display. Figure 4.5-10 is the amplitude map from the inversion cube. The P10 is derived from the maximum extent of the blending of the seismic attributes and the P90 is from the areas with the strongest attribute strength.

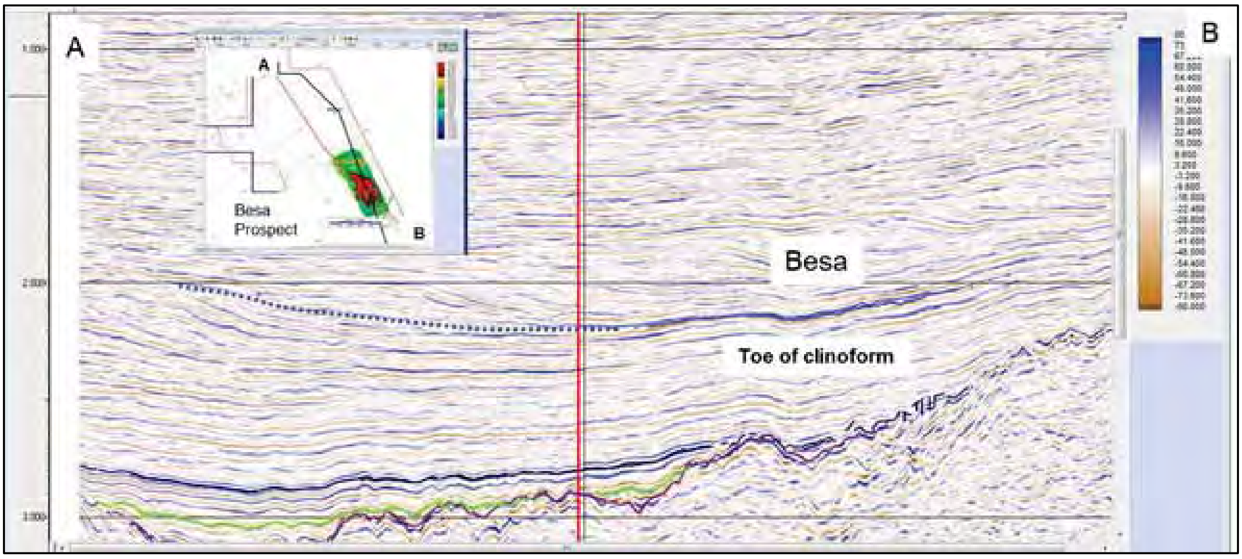


Figure 4.5-7: Besa Prospect Type Line

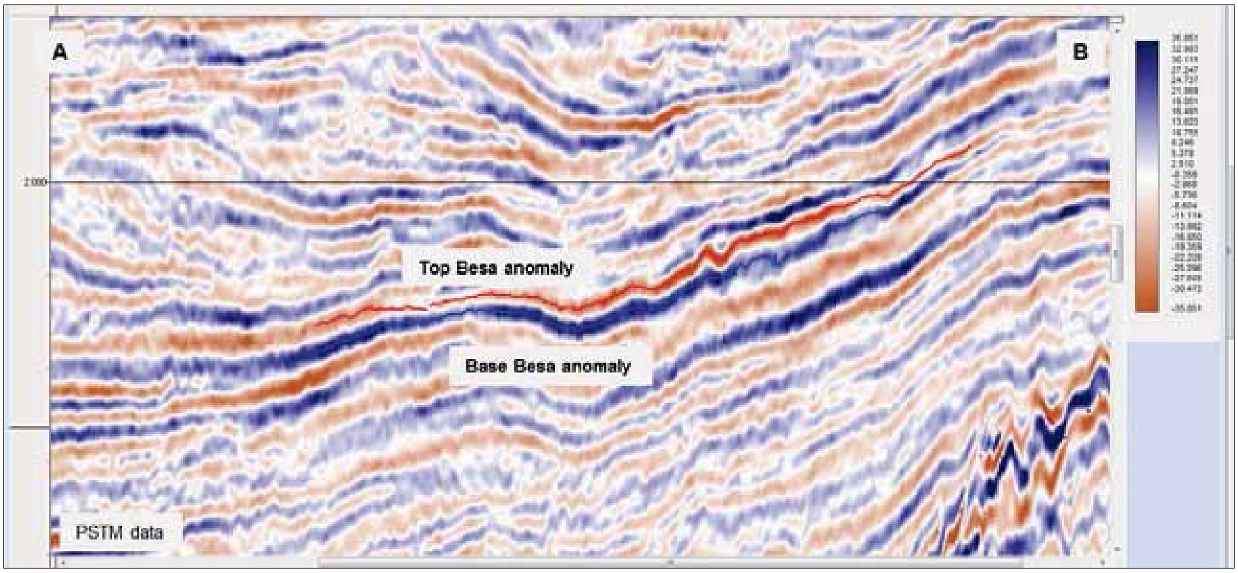


Figure 4.5-8: Besa Prospect: Detailed View on PSTM Seismic Data

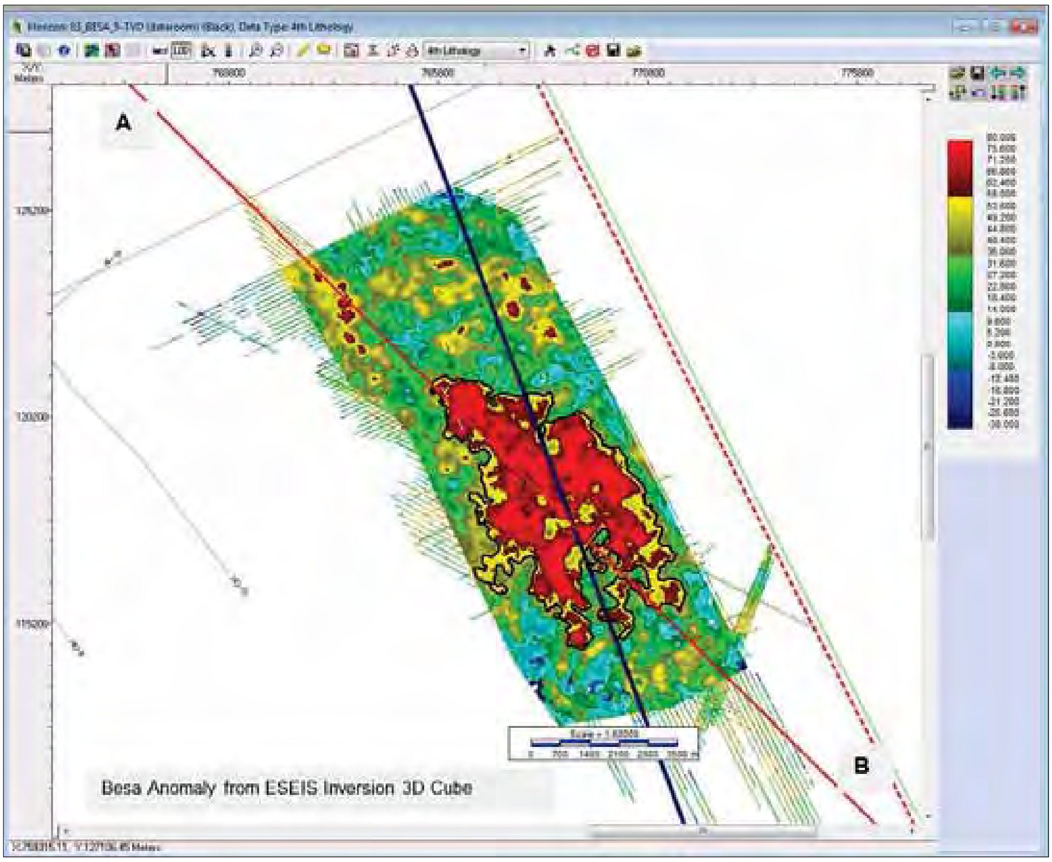


Figure 4.5-9: Besa Prospect ESEIS Inversion Map

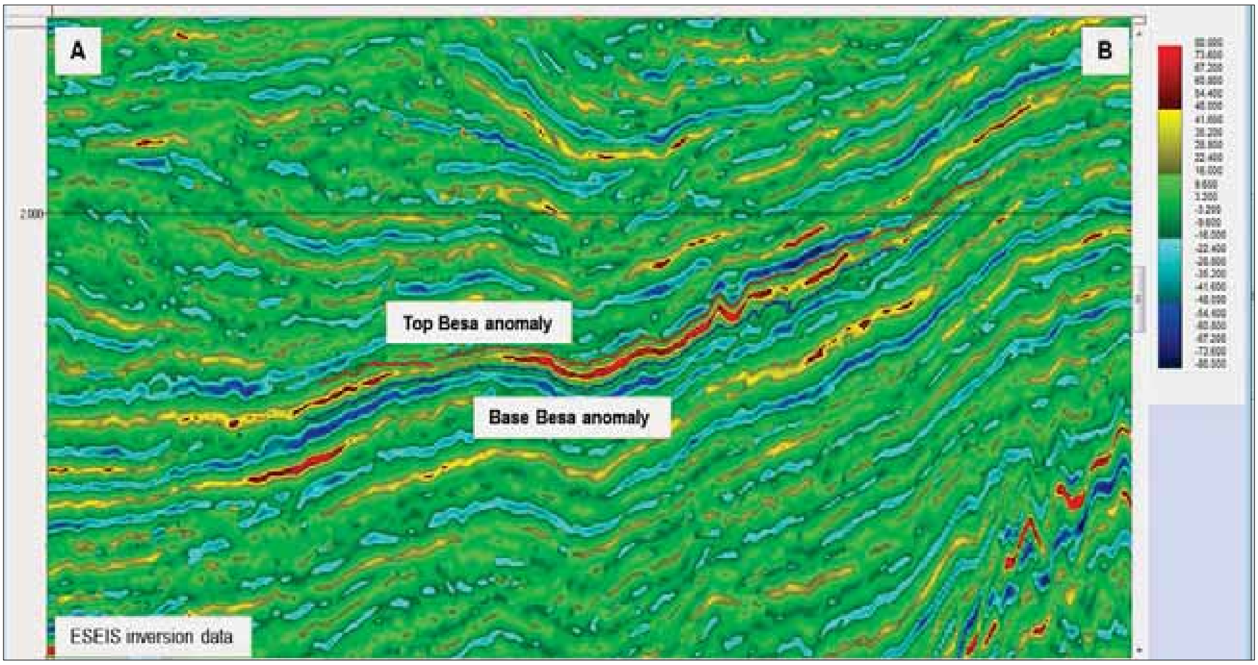


Figure 4.5-10: Besa Prospect Detailed View on ESEIS Inversion 3D Cube

The Algyo reservoir is composed of sands and shales. There is a good possibility of encountering sand and the reservoir presence risk is relatively low. The reservoir quality is fair as the risk of encountering good quality reservoir is low. The overall reservoir risk is low. Top seal is provided by the interbedded shales and seal risk is generally low.

The underlying Szolnok, Endrod, and Synrift formation are mature source rocks containing gas. The risk assigned to the presence of source is low. However, migration risk can be considerable and is somewhat dependent on vertical migration through the section or the presence of fractures connecting the Algyo clinoforms to the deeper source rocks.

4.5.6 Probabilistic Resource Estimates

The probabilistic Resource estimates were computed using the REP™ (Logicom E&P Ltd) software. This software allows for input of a variety of probability distributions for each uncertain parameter. The program then performs a large number of iterations randomly sampling each variable and honoring the dependencies that were input. The number of iterations was set at 100,000, which achieved the desired level of stability of the resulting answers. The results include a probability distribution for the output, sampled probability for the inputs, and sensitivity analysis showing which input parameters have the most effect on the uncertainty in each output parameter.

4.5.6.1 Input Parameters

The parameters required for this analysis consist of the inputs to the volumetric equation, and are described as follows, including a brief statement as to the source of information for each parameter in the BCGA discovered zones and Algyo leads and prospects.

Gross Rock Volume – For the BCGA reservoirs, the dependency between area and thickness in calculating gross rock volume from distributions is eliminated by starting with a gross rock volume estimate itself rather than area and thickness. Interpretation of new 3D seismic took place during 2009-2012, isopachs have been created by subtraction. For the present report, isopachs maps were provided by Falcon in a SMT™ project and gross rock volumes thus calculated, limiting the calculation to those volumes that are inside the License areas. (See Section 4.5.2)

The Algyo traps are not structural, but are defined by the stratigraphic limits based on mapping of seismic attributes (see Section 4.5.5). The P10 area is derived from the maximum extent of the blending of the seismic attributes and the P90 is from the areas with the strongest attribute strength. Thickness was determined by a petrophysical analsysis of the Algyo formation in the wells. The sand thickness in the key wells varied from 10 m to 20 m. Therefore, 10 m was used as the P90 and 20 m was used as the P10.

Porosity –For the BCGA reservoirs, these porosities were determined in a previous 2008 study by Falcon's petrophysicist D. Hoyer using Statmin, the statistical mineral analysis add-on module to Fugro-Jason's PowerLog™ that uses a probabilistic model to calculate the reservoir volumetric composition based on actual log responses and anticipated component log measurement endpoints. One such endpoint was the measured grain density from the core data. Adverse environmental effects required log measurement corrections and normalizations. The previously determined minimum porosity cut-off value of 6% was used to differentiate between reservoir and non-reservoir intervals. Using this value and a maximum clay volume cut-off of 40%, a net reservoir thickness for each well was determined. New core data measured in whole cores recovered from Upper and Lower Szolnok in well Foldeak-1 were used to adjust the porosity range in the probabilistic analysis of the recoverable resource estimated in the Szolnok interval. For the Algyo prospects, porosity was estimated by Falcon and considered reasonable by RPS.

Fluid Saturations – Estimations of the percentage of the rock pore volume that contain fluids, either water or hydrocarbons. This estimate, when calculated from logs, is highly dependent on knowledge of the resistivity or composition of the formation waters. For the BCGA reservoirs, the water saturations were determined in the previous 2008 study by Falcon's petrophysicist D. Hoyer using the Archie Water Saturation model within Fugro-Jason's PowerLog™ well log interpretation software.

The formation water resistivity value of 0.30 ohm-m at 75° F was verified through SP deflection analysis and was temperature-corrected to the value corresponding to the interval temperature based on a temperature gradient established for the Makó Trough. The other selected values of the saturation parameters of tortuosity (a), cementation (m), and saturation (n), were 1.0, 1.8, and 2.0. In the Monte Carlo simulation model, gas saturation was modeled as a direct function of porosity. For the Algyo prospects, the water saturation was estimated by Falcon and considered reasonable by RPS.

Net-to-Gross Ratio – The fraction of the gross rock volume that is estimated to contain gas pay. For the BCGA reservoir, the net reservoir thickness was calculated using the 6% minimum porosity and 40% maximum clay volume was divided by the gross thickness for each interval under consideration to yield the net-to-gross ratio for each layer. For the Algyo prospects, the Net-to-Gross Ratio was estimated by Falcon and considered reasonable by RPS

Percent Productive – An estimate of what fraction of the total play will be productive. As noted above, even though gas saturation is ubiquitous, commercial productivity is not. Percent productive is a key unknown, and was estimated by performing an analysis of five BCGA plays in the Rocky Mountain area of the US and using these plays as analogies. For the Algyo prospects this parameter does not apply.

Formation Volume Factor – The factor that represents the amount of expansion of gas from reservoir to surface conditions. Estimation of formation volume factor is dependent on knowledge of temperature, pressure and gas compositional variations. For the BCGA reservoirs, data from the existing well penetrations was used in calculating these factors, and is consistent with the original estimate performed by RPS in 2006 and 2008. For the Algyo prospects, the Formation Volume Factor was estimated by Falcon and considered reasonable by RPS.

Recovery Factor – The fraction of the calculated in-place resources that is considered typically recoverable. Note that the amounts estimated represent potentially recoverable Resources, not Reserves. Since there is insufficient information at this point in time on the potential productivity of each zone, no meaningful economic analysis is possible. However, knowledge of the performance of U.S. BCGA wells does provide information on the typical recovery and drainage areas. Since drainage areas are typically small, a large number of wells are required to achieve the optimal recovery factor. Although insufficient data exists to accurately well performance, it is reasonable to assume that the recovery factor will be critically dependant on the number of wells it is commercially viable to drill i.e. very high recovery factors are theoretically possible drilling to a very high density. However, in reality, the actual density achieved will be the result of the balance between the cost of the wells and the relative deliverability. At present proven deliverability is low and improved performance (via large frac programs or other stimulation techniques) will be required to improve recovery.

Table 4.5.6-1 summarizes the BCGA unconventional parameters used in the probabilistic analysis and Table 4.5.6-2 summarizes the Algyo parameters used in the probabilistic analysis

Table 4.5.6-1 – Summary of the BCGA unconventional parameters used in the probabilistic analysis.

Szolnok	Units	Minimum	Most Likely	Maximum
Bulk Rock Volume	MM ac.ft	670.9	745.4	819.9
Net:Gross Ratio	ratio	0.052	0.302	0.430
Fraction Productive	dec.fr	0.050	0.400	0.700
Porosity	dec.fr	0.040	0.100	0.138
Gas Saturation	dec.fr	0.400	0.545	0.700
Fmn Vol Factor	vol/vol	273.224	298.503	316.456
Overall Recovery factor	dec.fr	0.650	0.700	0.750
Upper Endröd	Units	Minimum	Most Likely	Maximum
Bulk Rock Volume	MM ac.ft	179.0	198.8	218.7
Net:Gross Ratio	ratio	0.044	0.250	0.649
Fraction Productive	dec.fr	0.050	0.150	0.300
Porosity	dec.fr	0.060	0.070	0.097
Oil Saturation	dec.fr	0.400	0.585	0.650
Oil Shrinkage	MMstb	0.428	0.457	0.485
Overall Recovery factor	dec.fr	0.040	0.060	0.080
Lower Endröd	Units	Minimum	Most Likely	Maximum
Bulk Rock Volume	MM ac.ft	184.5	205.0	225.5
Net:Gross Ratio	ratio	0.066	0.130	0.178
Fraction Productive	dec.fr	0.050	0.150	0.300
Porosity	dec.fr	0.060	0.070	0.108
Gas Saturation	dec.fr	0.400	0.499	0.550
Fmn Vol Factor	vol/vol	327.869	332.226	336.700
Overall Recovery factor	dec.fr	0.450	0.500	0.550
Basal Conglomerate	Units	Minimum	Most Likely	Maximum
Bulk Rock Volume	MM ac.ft	132.0	146.6	161.3
Net:Gross Ratio	ratio	0.070	0.400	0.521
Fraction Productive	dec.fr	0.050	0.150	0.300
Porosity	dec.fr	0.060	0.075	0.089
Gas Saturation	dec.fr	0.400	0.545	0.850
Fmn Vol Factor	vol/vol	273.224	300.000	316.456
Overall Recovery factor	dec.fr	0.650	0.700	0.750
Synrift Sequence	Units	Minimum	Most Likely	Maximum
Bulk Rock Volume	MM ac.ft	37.0	41.1	45.3
Net:Gross Ratio	ratio	0.060	0.065	0.069
Fraction Productive	dec.fr	0.050	0.150	0.300
Porosity	dec.fr	0.060	0.075	0.095
Gas Saturation	dec.fr	0.400	0.523	0.750
Fmn Vol Factor	vol/vol	341.297	343.643	347.222
Overall Recovery factor	dec.fr	0.350	0.400	0.450

Table 4.5.6-2 – Summary of the Algyo parameters used in the probabilistic analysis

BESA	Units	Distribution	P90	P10
Area	km^2	Normal	5.855	18.44
Thickness	m	Normal	10	20
Shape Factor	%	Single	100	100
Degree of Fill	%	Single	100	100
Net:Gross Ratio	dec.fr	Single	1	1
Porosity	dec.fr	Normal	0.1075	0.1728
Water Saturation	dec.fr	Normal	0.4	0.6
Fmn Vol Factor	vol/vol	Normal	215	235
Overall Recovery Factor	dec.fr	Single	0.6	0.8
HOD SE	**Units**	**Distribution**	**P90**	**P10**
Area	km^2	Normal	3.877	27.13
Thickness	m	Normal	10	20
Shape Factor	%	Single	100	100
Degree of Fill	%	Single	100	100
Net:Gross Ratio	dec.fr	Single	1	1
Porosity	dec.fr	Normal	0.1075	0.1728
Water Saturation	dec.fr	Normal	0.4	0.6
Fmn Vol Factor	vol/vol	Normal	265	285
Overall Recovery Factor	dec.fr	Single	0.6	0.8
KIRALYHEGYES	**Units**	**Distribution**	**P90**	**P10**
Area	km^2	Normal	0.513	4.026
Thickness	m	Normal	10	20
Shape Factor	%	Single	100	100
Degree of Fill	%	Single	100	100
Net:Gross Ratio	dec.fr	Single	1	1
Porosity	dec.fr	Normal	0.1075	0.1728
Water Saturation	dec.fr	Normal	0.4	0.6
Fmn Vol Factor	vol/vol	Normal	210	230
Overall Recovery Factor	dec.fr	Single	0.6	0.8
KODMONOSDULO	**Units**	**Distribution**	**P90**	**P10**
Area	km^2	Normal	1.094	9.88
Thickness	m	Normal	10	20
Shape Factor	%	Single	100	100
Degree of Fill	%	Single	100	100
Net:Gross Ratio	dec.fr	Single	1	1
Porosity	dec.fr	Normal	0.1075	0.1728
Water Saturation	dec.fr	Normal	0.4	0.6
Fmn Vol Factor	vol/vol	Normal	265	285
Overall Recovery Factor	dec.fr	Single	0.6	0.8

KOVEGY	Units	Distribution	P90	P10
Area	km^2	Normal	0.247	2.199
Thickness	m	Normal	10	20
Shape Factor	%	Single	100	100
Degree of Fill	%	Single	100	100
Net:Gross Ratio	dec.fr	Single	1	1
Porosity	dec.fr	Normal	0.1075	0.1728
Water Saturation	dec.fr	Normal	0.4	0.6
Fmn Vol Factor	vol/vol	Normal	215	235
Overall Recovery Factor	dec.fr	Single	0.6	0.8
KUTVOLGY	**Units**	**Distribution**	**P90**	**P10**
Area	km^2	Normal	6.832	41.18
Thickness	m	Normal	10	20
Shape Factor	%	Single	100	100
Degree of Fill	%	Single	100	100
Net:Gross Ratio	dec.fr	Single	1	1
Porosity	dec.fr	Normal	0.1075	0.1728
Water Saturation	dec.fr	Normal	0.4	0.6
Fmn Vol Factor	vol/vol	Normal	265	285
Overall Recovery Factor	dec.fr	Single	0.6	0.8
TOMPAHAT	**Units**	**Distribution**	**P90**	**P10**
Area	km^2	Normal	3.39	36.63
Thickness	m	Normal	10	20
Shape Factor	%	Single	100	100
Degree of Fill	%	Single	100	100
Net:Gross Ratio	dec.fr	Single	1	1
Porosity	dec.fr	Normal	0.1075	0.1728
Water Saturation	dec.fr	Normal	0.4	0.6
Fmn Vol Factor	vol/vol	Normal	210	230
Overall Recovery Factor	dec.fr	Single	0.6	0.8
URMOS	**Units**	**Distribution**	**P90**	**P10**
Area	km^2	Normal	1.1	3.5
Thickness	m	Normal	10	20
Shape Factor	%	Single	100	100
Degree of Fill	%	Single	100	100
Net:Gross Ratio	dec.fr	Single	1	1
Porosity	dec.fr	Normal	0.1075	0.1728
Water Saturation	dec.fr	Normal	0.4	0.6
Fmn Vol Factor	vol/vol	Normal	265	285
Overall Recovery Factor	dec.fr	Single	0.6	0.8

4.5.6.2 Risk and Uncertainty

As previously discussed, the BCGA in the deeper formations is discovered and therefore has a GPoS (see Section 3.2.2) of 100%. The elements impacting the remining commercial risks are discussed below and the calculated range of uncertainty, based on the geological uncertainties is discussed in Section 4.5.6.1 above.

For the Algyo leads and prospects, however, most are yet to be drilled and have an associated GPoS. The exploration of the Algyo stratigraphic leads and prospects is at an early stage and the calibration of seismic amplitude/attributes to the presence of high concentrations of hydrocarbons has yet to be proved. As an example the Makó-4 well, whilst reportedly drilled to target the underlying Szolnok, did drill through the edge of the Urmos lead as defined by the seismic amplitude/attribute mapping. The well did find low but variable saturations of gas at different depths which were not picked by density/neutron cross-over. The well is suspended awaiting testing (see Section 4.3.3.6).

There are many examples around the world where low concentrations of gas in water can lead to an apparent seismic "anomaly" and given the Makó-4 well results to date, this must be regarded as a risk to the seismically mapped stratigrapic traps currently proposed in the Algyo Formation. However, as discussed in Section 4.5.5, seismic response to fluid and thickness changes in reservoirs is a complex matter and insufficient calibration has been done to prove or disprove the potential at this point. In Section 4.5.5, RPS notes that reservoir presence and quality in the Algyo is considered relatively low risk and the Formation overlies known source rocks. Oil and gas has clearly migrated to surrounding fields, however, this migration path may rely on the basin edges rather than vertically into the prognosed fan deposits of the Algyo. The sands appear to be encased in shales (consistent with the seismic response noted regardless of fluid fill) making trap risk small. Therefore, many of the conventional risk elements that effect GPoS appear to be positive. Nonetheless, given the uncertainty on gas concentration, RPS has assigned a GPoS based on the maturity of this relatively recently recognised play and RPS assigns a risk between 1 in 12 (8.33%) to 1 in 8 to (12.5%) to the current likelihood of discovering a hydrocarbon accumulation in the Blue Creek concession. Otis and Schneidermann's 'Rule of Thumb' for Geological Risk Assessment[5] describes this range of risk as an appropriate level of risk for a new play in an emerging area. Accordingly, an average GPoS of 10% is assigned to the Algyo leads and prospects.

4.5.6.3 Summary of Resources

RPS has assigned **Contingent Resources – Development Unclarified** to the BCGA discoveries in the Szolnok, Endrod, Basal Conglomerate and Synrift Formations; and, Prospective Resources to a number of identified leads and prospects located the overlying Algyo Formation.

The total estimated range of Contingent Resources is given in Table 4.5.6-3 below. Table 4.5.6-4 gives an estimated range of Prospective Resources. In each case they are arithmetic aggregation of the Resources calculated by zone. **Actual recovery is likely to be less and may be substantially less or zero.**

Table 4.5.6-3 – Contingent Resources Summary

	Gross			**Net Entitlement**		
	1C	**2C**	**3C**	**1C**	**2C**	**3C**
Szolnok (Gas – Tcf)	12.13	30.96	63.60	10.07	25.70	52.79
Lower Endrod (Gas – Tcf)	0.61	1.11	1.87	0.51	0.92	1.55
Basal Conglomerate (Gas – Tcf)	1.41	3.00	5.53	1.17	2.49	4.59
Synrift Sequence (Gas – Tcf)	0.08	0.19	0.42	0.07	0.16	0.35
Arithmetic Aggregation[1]	**14.24**	**35.27**	**71.41**	**11.82**	**29.27**	**59.27**
Probabilistic Aggregation	**16.85**	**35.78**	**68.46**	**13.99**	**29.70**	**56.82**
Upper Endrod (Oil – MMstb)	32.89	76.71	158.26	27.30	63.67	131.36

1: It is statistically incorrect to arithmetically sum probabilistic estimates of P90, P50 and P10. To do so tends to under-estimate the true P90 and over-estimate the true P10 of the combined distribution as seen when compared to the Probabilistic Aggregation in the next row.

[5] Otis, R.M. & Schneidermann, N. 1997. "A Process for Evaluating Exploration Prospects", AAPG Bulletin 81 (7) pp.1087-1109.

The volumes quoted above are classified as Contingent Resources – Development Unclarified. Oil and Gas have been discovered and may be present in large quantities but commercial flow-rates have yet to be achieved (although Falcon does periodically produce oil and gas from certain wells). In addition to the currently low flow-rates, several of the well-tests to date have demonstrated quantities of H_2S sufficient to cause shut-ins for safety reasons. This is not an insurmountable problem by any means but will add to capex and Opex considerations since the H_2S will need to be collected and treated in special separation towers and the resulting sulphur disposed of (though this can be a useful by-product in certain parts of the world).

As a result of the current commercial uncertainties, RPS currently estimates that there is a less than or equal to 25% chance that the Contingent Resources quoted above will be converted to Reserves based on the data available at this time.

Table 4.5.6-4 – Prospective Resources Summary

	Gross			**Net Entitlement**			**GPoS**
	Low Estimate	**Best Estimate**	**High Estimate**	**Low Estimate**	**Best Estimate**	**High Estimate**	
Besa (Gas – Bcf)	26.8	65.0	125.0	22.2	54.0	103.8	10%
Hod, SE (Gas – Bcf)	32.3	103.0	219.0	26.8	85.5	181.8	10%
Kiralyhegyes (Gas – Bcf)	3.7	12.1	26.0	3.1	10.0	21.6	10%
Kodmonosdulo (Gas – Bcf)	11.0	36.3	78.6	9.1	30.1	65.2	10%
Kovegy (Gas – Bcf)	2.0	6.7	14.5	1.7	5.6	12.0	10%
Kutvolgy (Gas – Bcf)	47.1	144.0	304.0	39.1	119.5	252.3	10%
Tompahat (Gas – Bcf)	39.8	135.0	296.0	33.0	112.1	245.7	10%
Urmos (Gas – Bcf)	6.2	15.0	29.0	5.1	12.5	24.1	10%
Arithmetic Aggregation[1]	**168.9**	**517.1**	**1092.1**	**140.2**	**429.2**	**906.4**	**<<1%**
Stochastic Aggregation[2]	**378.0**	**568.0**	**820.0**	**313.7**	**471.4**	**680.6**	**<<1%**
Stochastic Aggregation[3]	**8.0**	**64.0**	**251.0**	**6.6**	**53.1**	**208.3**	**57%**

1: It is statistically incorrect to arithmetically sum probabilistic estimates of P90, P50 and P10. To do so tends to under-estimate the true P90 and over-estimate the true P10 of the combined distribution as seen when compared to the Probabilistic Aggregation in the next row. This is exacerbated by the introduction of GPoS into the statistical aggregation (see below).

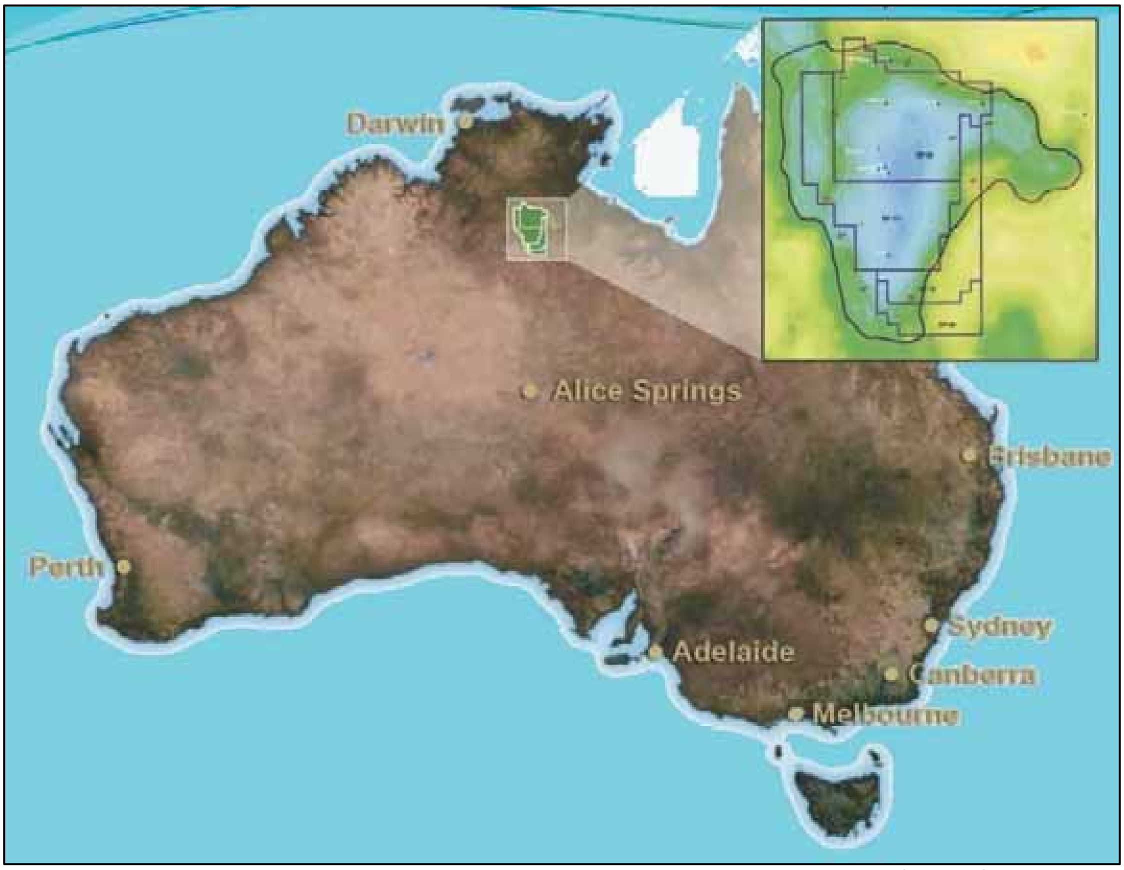
2: Statistical Aggregation assuming that all prospects are successful. The probability of this occurring is the product of each individual risk (GPoS) and is therefore very small.

3: Statistical Aggregation assuming at least one prospect is successful. This total takes into account all possible successful outcomes and the mean value for the resultant distribution (56.2 Bcf Net) constitutes the true expectation of success.

5 BEETALOO EXPLORATION PERMITS (Northern Territory, Australia)

5.1 GEOLOGICAL OVERVIEW

The EP-76, -98, -99 and -117 Beetaloo Exploration Permits (also known as Beetaloo Blocks) are located in the Beataloo Basin of the greater McArthur Basin in the Northern Territory, Australia (see Figure 5-1).



Source: Silverman

Figure 5-1: Regional Location Map

The Beetaloo Basin is a Proterozoic and Cambrian age tight oil and gas basin described by Silverman as a “crustal downwarp” and a separate depocenter within the greater McArthur Basin. The Beetaloo Basin represents one of the few remaining sparsely explored - 11 exploration wells in approximately 28,000 km^2 (7 million acres) - onshore exploration basins of the world located in a “western country” with political, legal and regulatory system stability. Figure 5-2 shows the Beetaloo Exploration Permits in relation to the Northern territory pipeline infrastructure.

Figure 5-3 shows a typical depth structure map and stratigraphic column. The historical wells are shown on the map and likely source and reservoir rocks within the stratigraphic column. Oil is thought to be likely within the Upper to Lower Kyalla Formation with gas likely to be the dominant phase in the lowest most Kyalla and the underlying Velkerri Shale and Moroak and Bessie Creek low porosity/permeability sandstones (“Tight Gas Sandstones”).

Beetaloo Basin (as defined by gravity, 2D seismic and previous wells) has undergone mild tectonism and is bounded on the north by the Walton High, on the northeast by the Arnold Arch, to the west by the Daly-Waters Arch and to the south by the Helen Springs High. Sediments are up to 3000 m thick in the basin center. Conventional tight sandstone reservoirs, pervasive tight sandstone gas in the basin center as well as unconventional shale source oil and gas have been identified in the basin from approximately 600 to 2500 m depth. Erosional thinning has occurred on the Walton High and Arnold Arch structural highs resulting in unconformities. No metamorphism has been reported for these sediments.

The stratigraphic section shown in Figure 5-3 demonstrates fluvial, deltaic and shallow marine deposition and at times a “starved basin” condition was present and is represented by organic rich source rock deposition of the Kyalla and Middle Velkerri formation shales. Organic matter in these formations consist primarily of bacteria, cyanobacteria and algae. Source rock of Proterozoic age are not common but have generated significant economic volumes of oil and gas in Eastern Siberia and Oman.

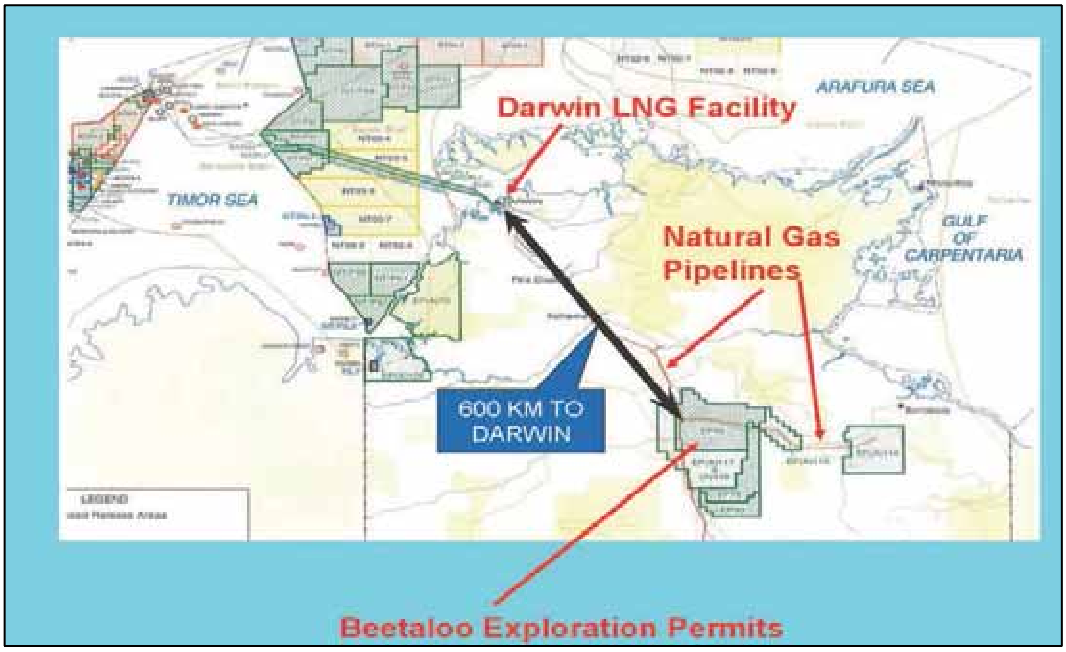
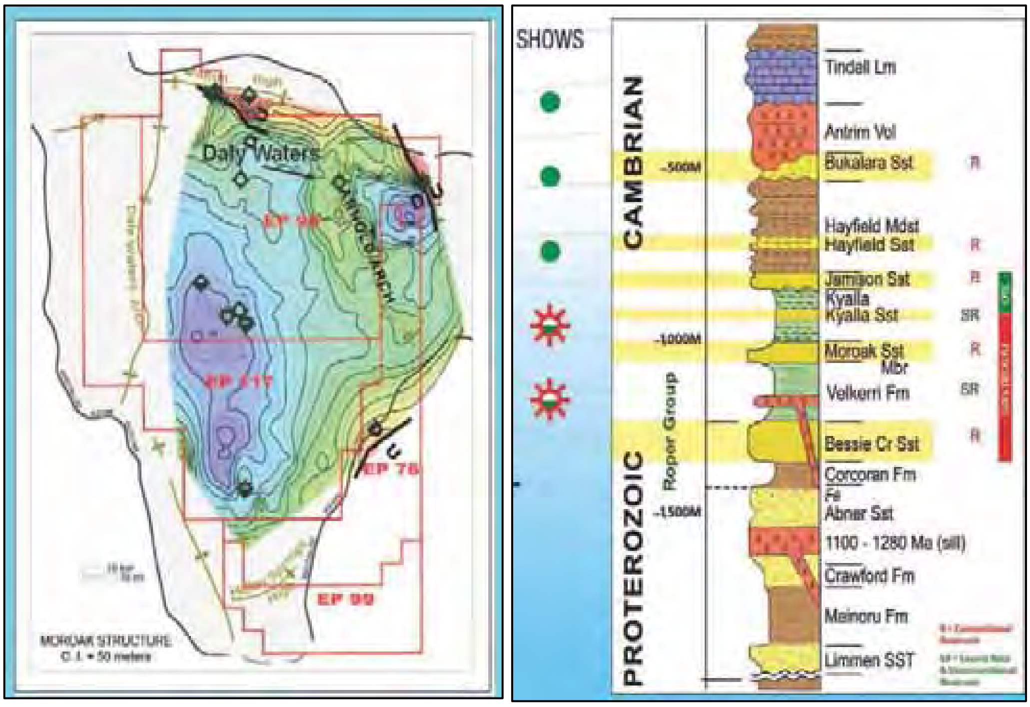


Figure 5-2: Beetaloo Basin Regional Facilities and Exploration Permits showing existing field areas



Source: Silverman

Figure 5-3: Beetaloo Moroak Sandstone Depth Structure and Stratigraphic Column

5.2 LICENCE STATUS AND WORK COMMITMENTS

The EP-76, EP-98, EP-99 and EP-117 Exploration Permits in the Beetaloo Basin (comprising 28,193 square kilometres or 6,966,860 acres) covering the majority of the Beetaloo Basin and basin margin highs (see Figure 5-3).

The subject acreage interests are held 100 per cent. in the name of Falcon Oil and Gas Australia Pty. Ltd., ("Falcon Australia"), which is an Australian incorporated oil and gas exploration company. Falcon has a 73 per cent. interest in Falcon Australia. Sweetpea Petroleum Pty. Ltd, which is a wholly owned Australian subsidiary of PetroHunter Energy Corp, owns 24 per cent and others the remaining 3 per cent interest in Falcon Australia. In accordance with local regulations, all Falcon Australia's acreage interests are subject to certain royalties payable to the Government of the Northern Territory, the Australian native stakeholders (Traditional owners), and the other third parties as detailed below. Falcon Australia is the operator of Exploration Permit EP 99 and Hess Australia (Beetaloo) Pty Ltd. is the operator of Exploration Permits EP 76, 98 and 117. Falcon Australia Pty. retained operatorship in the Shenandoah-1 well and aprroximately 405 km^2 (100,000 acres) land around the Shenandoah-1 wellbore in EP98.

- NT Government – 10% royalty on production revenues.
- Native Stakeholders – 1% royalty on production revenues form first production until Falcon Australia has recovered its costs and 2% thereafter unless the production has gone into decline, in which case, the royalty will return or remain at 1%.
- Other third parties – 13% royalty on production revenues.

The Minister for Mines and Energy, Northern Territory (NT), is responsible for the administration of the Petroleum Act which regulates hydrocarbon exploration. The Department of Mines and Energy administers the legislation and is responsible for overseeing the activities of Permit holders including the meeting of work commitments. The Northern Territory Government issues Exploration Permits under the Petroleum Act for a period of five years. In each year the minimum work commitments to be achieved by the titleholder are specified by the Department of Mines and Energy. These requirements can be reviewed and adjusted in light of changing circumstances. The Government has the power to suspend permits where the titleholder demonstrates a sufficiently strong case and has done so on a number of occasions for the Beetaloo Basin permits. These changes are formalised in a Determination by the Director of Energy, Department of Mines and Energy.

On June 17, 2011 the Director of Energy, Department of Resources ("DoR" - predecessor to Department of Mines and Energy), advised Falcon of approvals to vary the work programs for EP-76, EP-98 and EP-117 to undertake seismic work with Hess as the operator. On August 27, 2012 the Director of Energy advised Falcon of his approval to vary the work program for EP-99 by deferring the completion of the proposed seismic program for 12 months to December 31, 2013. The commitments for the permits held by Falcon have all been met for previous years. All the permits are in good standing and can be renewed.

Table 5.2-1 sumarizes the status of each of the four EPs.

Table 5.2-1 – Summary of Beetaloo Basin Exploration Permit status

Licence Concessions (Country)	Interest (%)	Operator	Status	Area (km^2)	Expiry	Comments
Exploration Permit EP-76, (Northern Territory - Onshore Australia)	73.0%[1]	Hess Australia (Beetaloo) Pty Ltd.	Exploration	4,976.3	31/12/2013[2]	Under evaluation
Exploration Permit EP-98 (Northern Territory - Onshore Australia)	73.0%[1]	Hess Australia (Beetaloo) Pty Ltd.[3]	Exploration	11,412.1	31/12/2013[4]	Under evaluation
Exploration Permit EP-99 (Northern Territory - Onshore Australia)	73.0%[1]	Falcon Oil & Gas Australia Pty.	Exploration	2,587.2	31/12/2013	Under evaluation
Exploration Permit EP-117 (Northern Territory - Onshore Australia)	73.0%[1]	Hess Australia (Beetaloo) Pty Ltd.	Exploration	9218.3	31/12/2013	Under evaluation

[1] Falcon Oil & Gas Limited owns 73% of Falcon Oil & Gas Australia which holds a 100% interest in the licences. The remaining 24% is owned by Sweetpea Petroleum Pty. Ltd, which is a wholly owned Australian subsidiary of PetroHunter Energy Corp., and 3% interest by others

[2] See Falcon's press release 0n 14/09/2012.

[3] Note: Falcon Oil and Gas Australia Pty. retains operatorship in the Shenandoah-1 well and approximately 405 km^2 (100,000 acres) land around the Shenandoah-1 wellbore.

[4] See Falcon's press release 0n 14/09/2012.

5.2.1 Required Minimum Work Program

Tables 5.2-1, 5.2-2, 5.2-3 and 5.2-4 summarize the required minimum work program for each of the 4 licences.

Table 5.2-1 – Summary of Licence Status and Minimum Work Commitments for EP-76

Permit Name	Licence Period	Start	End	Minimum Work Requirements	Status and Cost
EP-76	Phase 4	01-Jan-09	31-Dec-10	- G&G studies - Reservoir assessment	**AUS$ 200,000** Completed
EP-76	Phase 5	01-Jan-11	31-Dec-13	- Collect and analyse 485 km 2D seismic data	**AUS$ 3,500,000** 327 km 2D seismic data collected by Dec-2012. Program not yet completed.

Table 5.2-2 – Summary of Licence Status and Minimum Work Commitments for EP-98

Permit Name	Licence Period	Start	End	Minimum Work Requirements	Status and Cost
EP-98	Phase 4	01-Jan-09	31-Dec-10	- Complete Shenandoah-1 well	Well completion suspended with approval of DoR
EP-98	Phase 5	01-Jan-11	31-Dec-13	- Complete and test Shenandoah-1 well - Collect and analyse 1,945 km 2D seismic data	**AUS$ 11,000,000** Falcon Australia completed the Shenandoah-1 well in Nov-2012 at a total cost of AUS$ 14 million **AUS$ 14,000,000** 1,852 km 2D seismic data collected by Dec-2012. Program not yet completed.

Table 5.2-2 – Summary of Licence Status and Minimum Work Commitments for EP99

Permit Name	Licence Period	Start	End	Minimum Work Requirements	Status and Cost
EP-99	Phase 4	01-Jan-10	31-Dec-11	- G&G studies - Geophysical re-evaluation	**AUS$ 100,000** Completed
EP-99	Phase 5	01-Jan-12	31-Dec-13	- Collect and analyse 150 km 2D seismic data	**AUS$ 1,500,000** Seismic data collection on schedule for first half of 2013

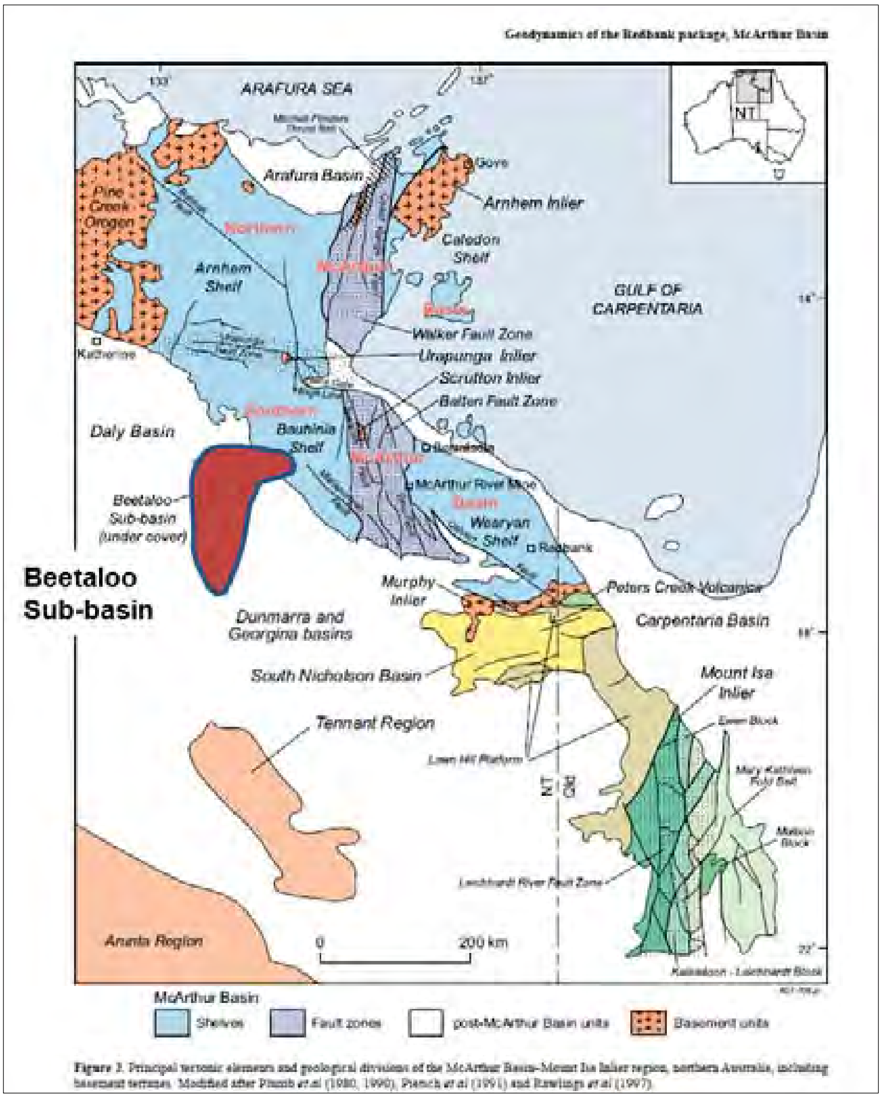
Table 5.2-2 – Summary of Licence Status and Minimum Work Commitments for EP-117

Permit Name	Licence Period	Start	End	Minimum Work Requirements	Status and Cost
EP-117	Phase 4	01-Jan-10	31-Dec-11	- Collect and analyse 280 km 2D seismic data	**AUS$ 2,000,000** Seismic program not completed because of regulatory delays and weather. Extended into Phase 5
EP-117	Phase 5	01-Jan-12	31-Dec-13	- Collect and analyse 890 km 2D seismic data	**AUS$ 6,400,000** 1,311 km 2D seismic data collected by Dec-2012. Program not yet completed.

5.3 GEOLOGICAL SETTING AND PROSPECTIVTY

5.3.1 Tectonic Setting

Central Australia is divided into separate and distinct basins, most of which, including the Beetaloo basin, have a Proterozoic origin. The 8.8 million acre Beetaloo Basin is a rift basin resting on Archean crust that formed during the Pre-Cambrian approximately 1.4 billion years ago. The Beetaloo Basin is considered a sub-basin of the larger McArthur Basin (Figure 5.3-1).



Source: Rawlings

Figure 5.3-1: Beetaloo Basin Tectonic Setting

There is some evidence of compression or transpression on the seismic data. The Beetaloo Basin appears to have undergone mild tectonism resulting in a set of northwest-southeast trending faults and two sub-basins separated by an intervening high. Although there is in excess of 3 km (perhaps as much as 10 km) of sediment in the center of the basin visible on the seismic data, the oldest sediments show no significant metamorphism. It is bounded on the north by the Walton High (Figure 5.3-2), and to the south by the Helen Springs High. It is less well defined on the east and west, but the Daly Waters Arch and Arnold Arch can be observed cutting through the basin. One result of this is the erosion of much of the section in the northern wells that are located on the Walton High. The deeper of the two sub-basins lies in the west beneath the Shenandoah-1 well

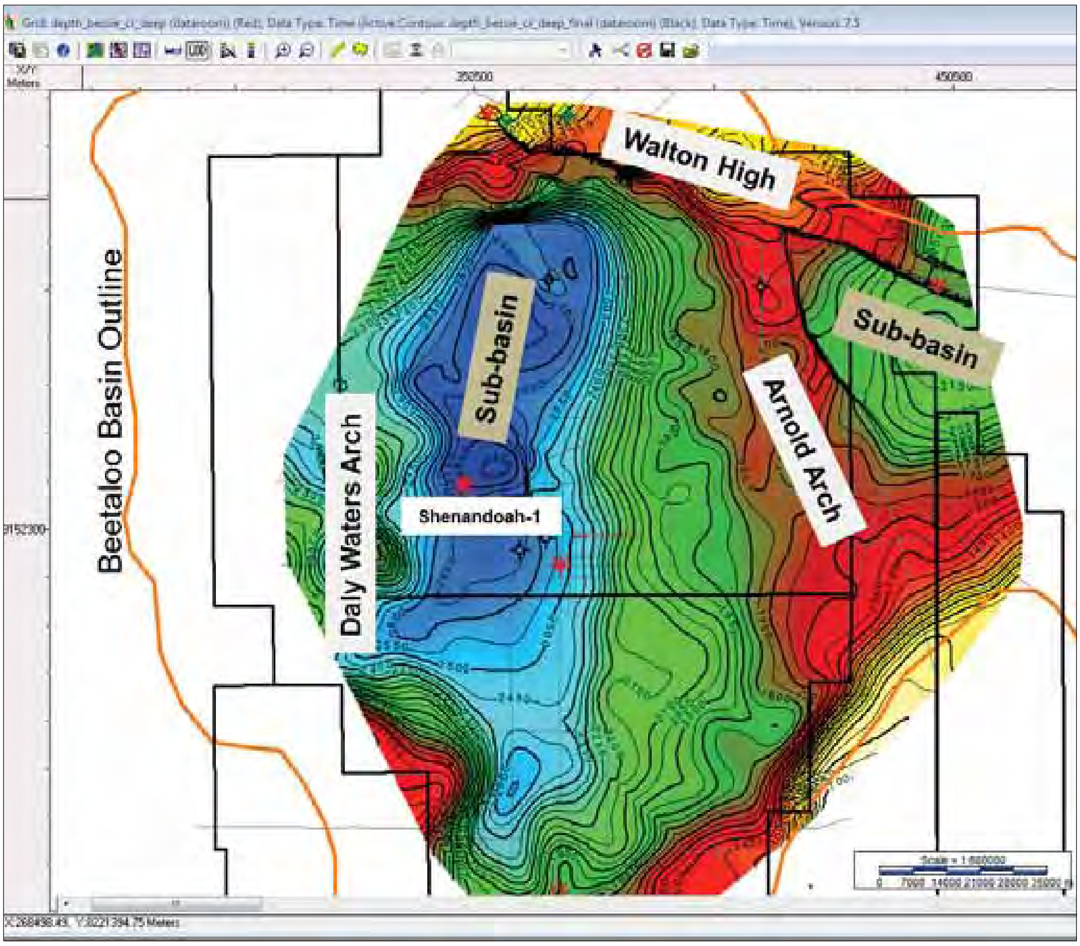


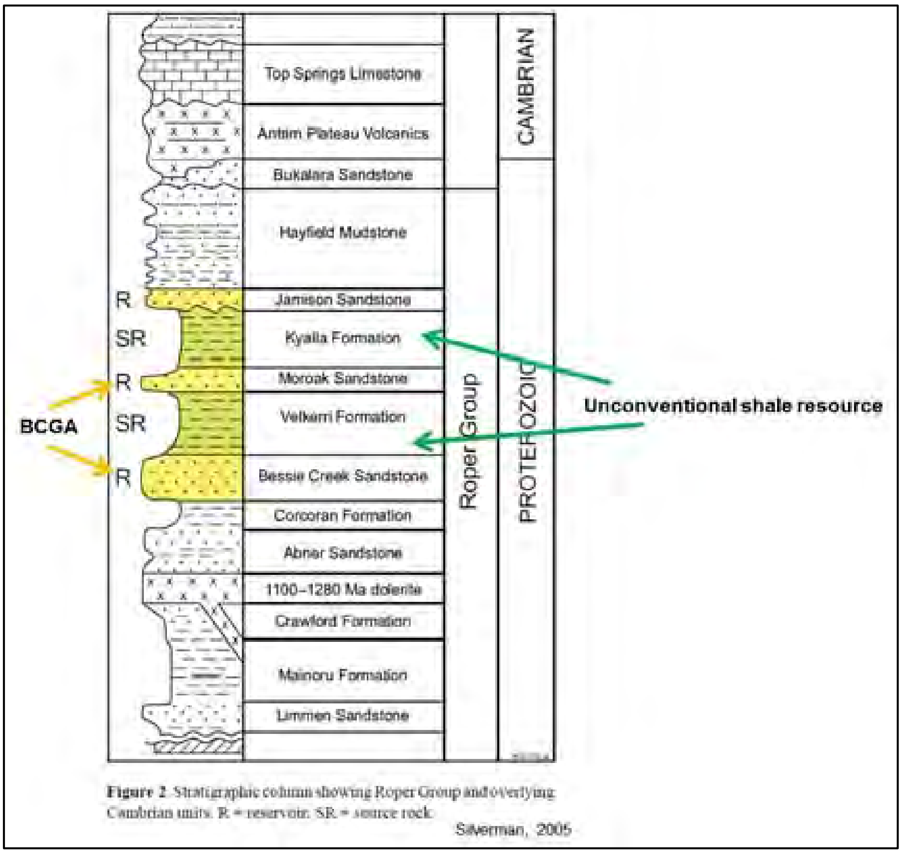
Figure 5.3-2: Beetaloo Principal Tectonic Elements on Bessie Creek Depth Map

5.3.2 Resource Stratigraphy

There is a shallow veneer of Paleozoic and recent sediments overlying a sequence of unmetamorphosed sedimentary rocks. The stratigraphy is in the Beetaloo basin is illustrated on Figures 5.3-3 and 5.3-4. All of the formations reviewed in this report are part of the Proterozoic Roper Group that extends across both the Beetaloo and McArthur basins. The Roper Group is generally a shallow marine sequence composed of shales and sands. It contains both petroleum source rocks and reservoir sands.

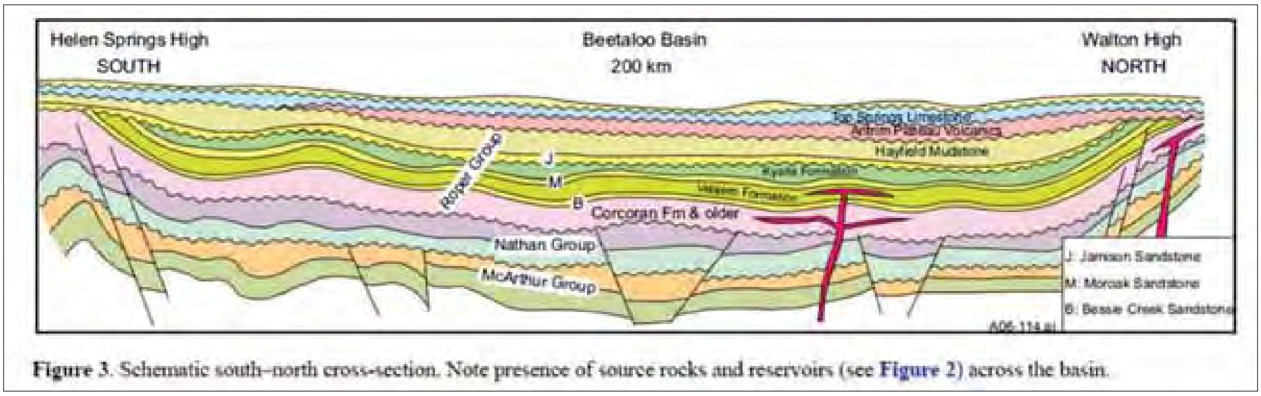
The Moroak Sandstone is situated between the Kyalla and Velkerri source rocks. It is a regional coarsening-upward quartz sandstone with anhydrite and silica cement. The Bessie Creek Sandstone is a fine-to-medium grained sandstone deposited and may have the best reservoir parameter in the Roper Group.

This Mesoproterozoic intercratonic basin is one of the oldest basins in the world known to contain live oil and hydrocarbons. The preservation of the oils is attributed to the mild tectonic activity experienced by the basin over the last 1.4 Ga.



Source: Silverman, 2005

Figure 5.3-3: Stratigraphic Column



Source: Silverman, 2005

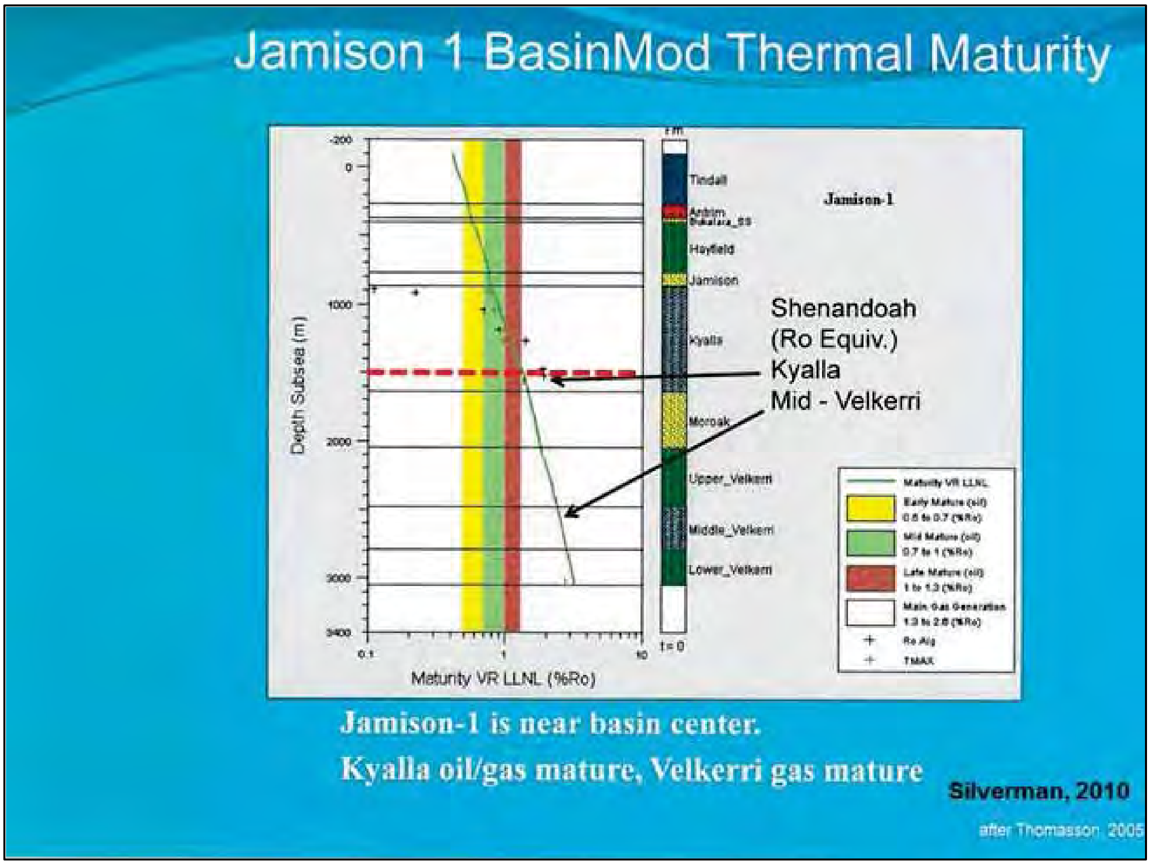
Figure 5.3-4: Schematic North-South Cross Section

The Kyalla and Velkerri formations are the two source rocks evaluated in this report and the Moroak and Bessie Creek Formations are considered to have BCGA (basin centered gas accumulation) potential.

Both source rock units are composed of primarily Type II kerogen. The Kyalla formation is a deep water unit with the highest organic content just above the underlying Moroak sandstone. The organic-rich Velkerri is the best source rock in the Beetaloo Basin and has the highest generation potential in the middle of the formation (Middle Velkerri). It was deposited in anoxic conditions, probably on the deep shelf. Both exhibit oil and gas shows in cores and mud logs. Geochemical analysis indicates that both the Kyalla and Velkerri source rocks are mature.

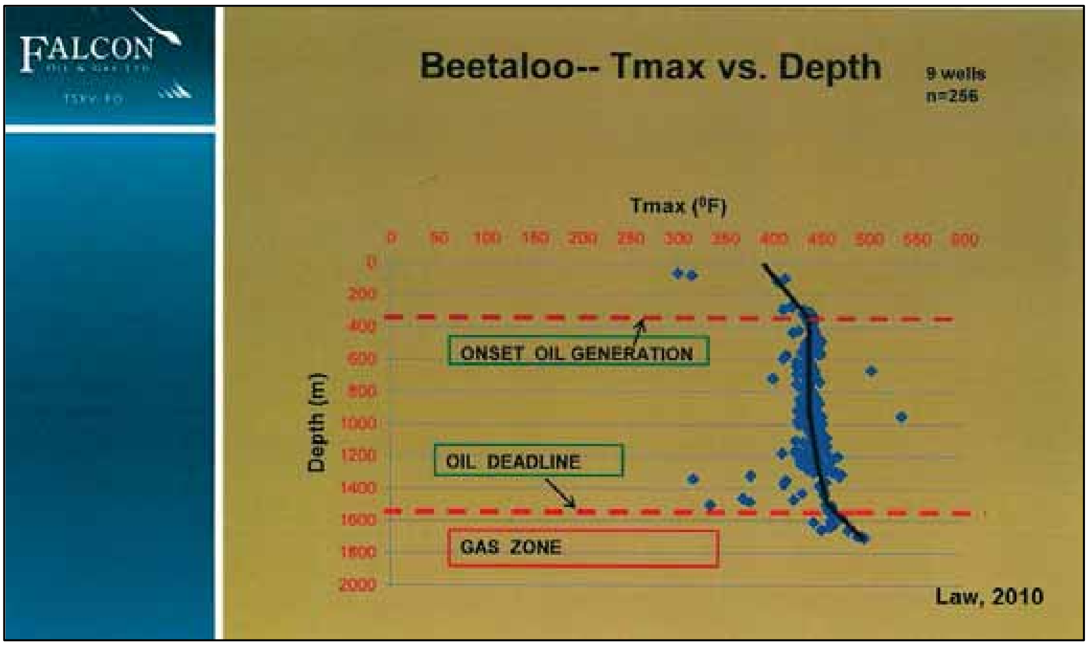
Although these formations are Proterozoic in age and there is some uncertainty in the maturation data and modelling, the Kyalla and Velkerri have had a relatively shallow burial history and subsequent uplift. Maturation modelling has been discussed by Silverman (2005), Law (2010), and Dutkiewicz (2005). Additional work was done by Thomasson Partners (2005) in a proprietary report that has been discussed, but was not available to RPS for review. The maximum burial depth and maturation may have occured shortly after the deposition of the Moroak sandstone (Dutkiewicz) with uplift shortly thereafter. This has preserved much of the section in the oil window and the deeper parts of the basin still remain in the gas generating window. Results indicate that the shales are mature to over-mature in the center of the basin and in the oil window along the shallower basin edges.

According to the 2010 Ryder Scott report and modelling completed by Law and Thomasson Partners, the source rocks are mature for oil above 1500 m TVD seismic and for gas below 1500 m. Both Figures 5.3-5 and 5.3-6 illustrate data from basin modelling of geochemical analyses and alganite Ro values. They indicate that the sediments may be mature for oil generation below 300-500 m TVDss and for gas generation below 1400 m to 1700 m. The report follows the convention used in the 2010 Ryder Scott report of the 1500 m TVD seismic contour as the boundary between the oil generation area and the gas generation area. The 1500m depth contour on the maps was used to distinguish the potential oil shale resources form the potential gas shale resources.



Source: Silverman, 2010

Figure 5.3-5: Jamison-1 BasinMod thermal Maturity



Source: Law

Figure 5-3.6: Beetaloo: Tmax vs. Depth

5.3.3 Overview Of Discoveries and Prospectivity

The Beetaloo Basin is relatively under-explored and has shale oil, shale gas and BCGA potential. The formations under evuation are the Upper Kyalla, Lower Kyalla and Middle Velkerri for shale oil and gas and the Moroak and Bessie Creek for BCGA. There are no existing fields in the basin, but the Shenandoah -1 has produced gas and condensate from the Middle Velkerri and gas from the Lower Kyalla on test. There are also numerous mudlog and core oil and gas shows throughout the basin in the prospective formations.

The drilling and suspension of the Shenandoah-1 wells at a 1555 m TD (vertical) occurred in 2007. The well was deepened to 2714 m TD in August 2009 as a vertical well and renamed as Shenandoah-1A. The Shenandoah-1A was a twin to an older Balmain-1 well which had significant oil and gas shows. Falcon re-entered the Shenandoah-1A on September 14, 2011, ran casing and tested the well. Five short-term production tests, including fracture treatments and conventional perforation tests were run in the deep section to test the potential of the Lower Kyalla shale, Moroak Sandstone and the Middle Velkerri shale formations. Summary of the well test is presented below.

Middle Velkerri

Test #1 (2529-2548 m MD): Interpreted to be a shale/siltstone rock with average TOC of approximately 2 wt%. Testing equipment was not properly suited for unconventional well testing and could not properly handle the high water rates in conjunction with low gas rates. There was enough gas to burn the flare without the pilot being on. Gas rate was insufficient to measure. Increasing CO_2 content ranged from 3% to 6%. Condensate with an API gravity of 43 degrees was collected in the mud pit. Modeling of the data and fracture treatment results indicated a very low permeability (0.000074 mD).

Test#2 (2481-2598.5 m MD): Interpreted to be a low porosity sands with shale laminations. Little to no TOC identified. Early flow initial gas rates were as high as 84 Mscf with 3,200 bbls of water per day. After performing a post-frac DFIT, the well flowed unasssisted with measureable rates of over 2,000 bbl/d water and ~60 Mscfd gas. Modeling of the data and fracture treatment results indicated a very low permeability (0.006 mD).

Moroak Sandstone

Test#3 (1837-1910 m MD): Interpreted to be a very low porosity sands with shale laminations. There is a subtle mud gas increase over this interval. The well did not flow as a result of very low permeability. Modeling of the data and fracture treatment results indicate a permeability of 0.000913 mD)

Test#4 (1728-1780 m MD): Interpreted to be a massive fluvial sandstone. There were modest mud gas shows over this interval. However, the test failed to flow any detectable gas. Modeling of the data and fracture treatment results indicated a very low permeability (0.0829 mD).

Lower Kyalla

Test#5 (1631-1649 m MD): Interpreted to be composed of shale/siltstone and sandstone layers with TOC of 2 wt%. Mudlog gas shows over this interval reaching 11% TGas. Burnable gas was observed. Modeling of the data and fracture treatment results indicated a very low permeability (0.002190 mD)

The well was plugged and abandoned on November 7, 2011.

Petrophysical evaluations done by Falcon and Darrell Hoyer (see Appendix C, Figure C-19 indicate pay in Upper and Lower Kyalla, Moroak Sandstone and Middle Velkerri formations.

Figure 5.3-7 shows the prospective shale oil resource areas for the Upper Kyalla, Lower Kyalla and the Middle Velkerri. Much of the basin has unconventional shale oil potential. Figure 5.3-8 has the Lower Kyalla and Middle Velkerri unconventional shale gas potential outlined. The shale gas areas are confined to the center of the basin. Figure 5.3-9 has the BCGA outlines for the Moroak and Bessie Creek. In accordance with the model, they are limited to the center of the basin where the source rocks are in the gas window.

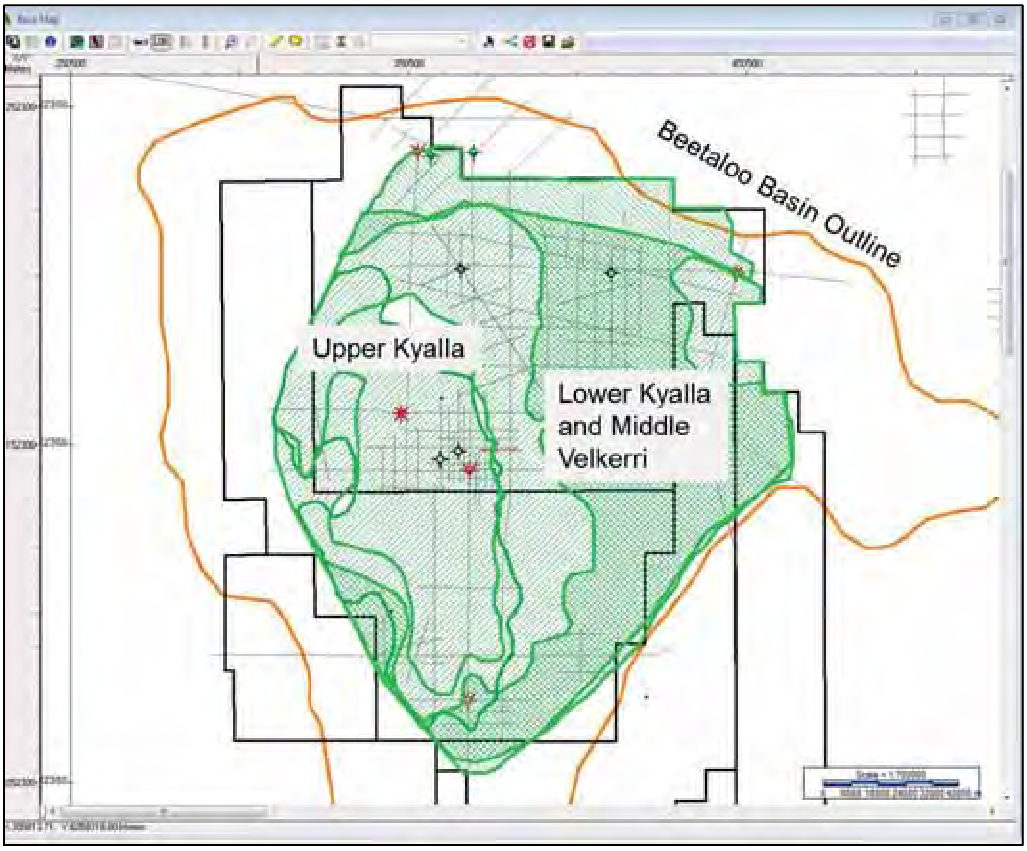


Figure 5.3-7: Potentially Prospective Upper Kyalla, Lower Kyalla, and Middle Velkerri Shale Oil Areas

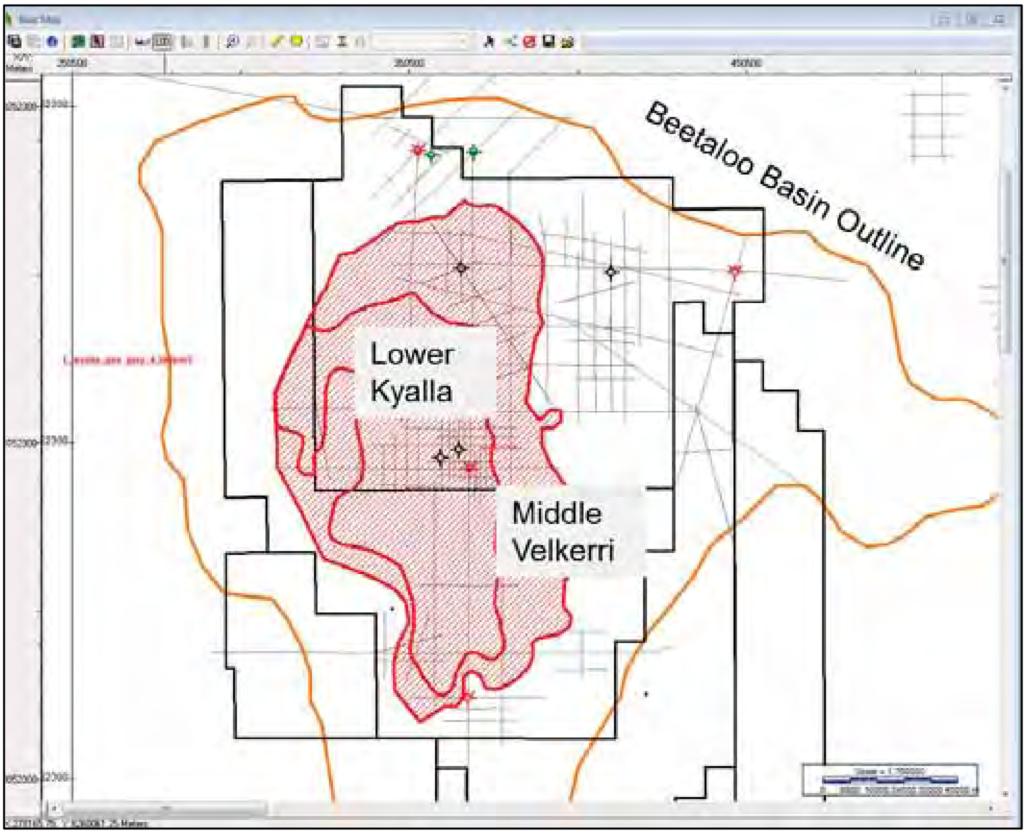


Figure 5.3-8: Potentially Prospective Lower Kyalla and Middle Velkerri Gas Areas

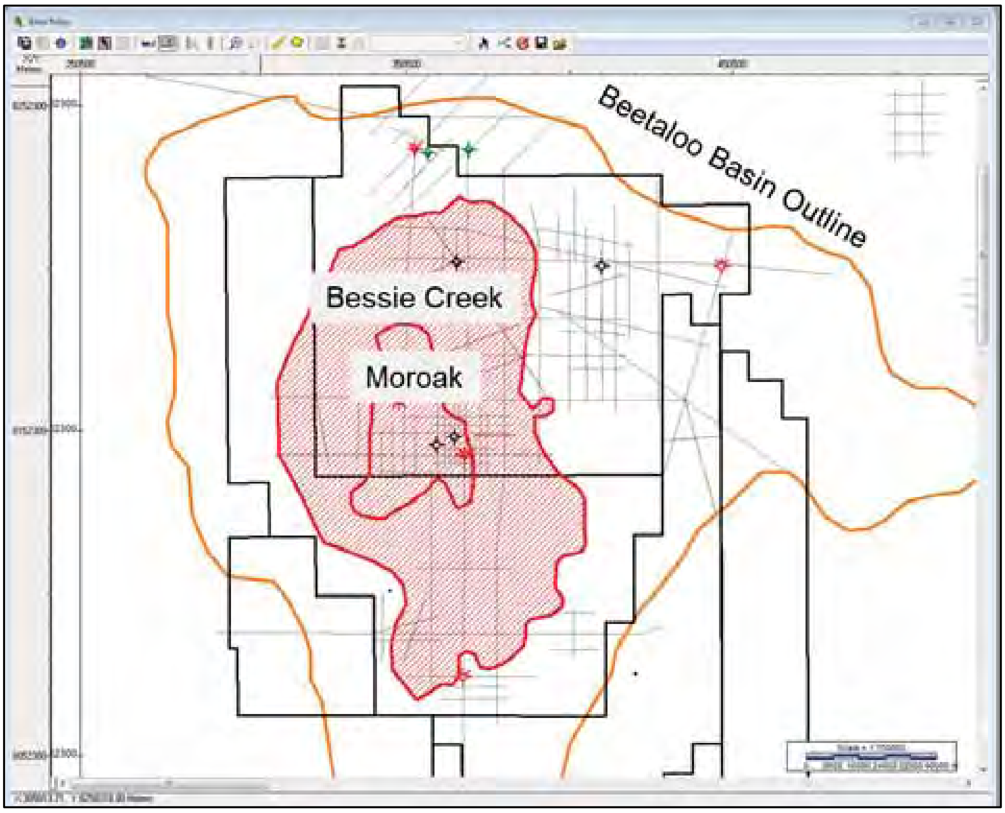


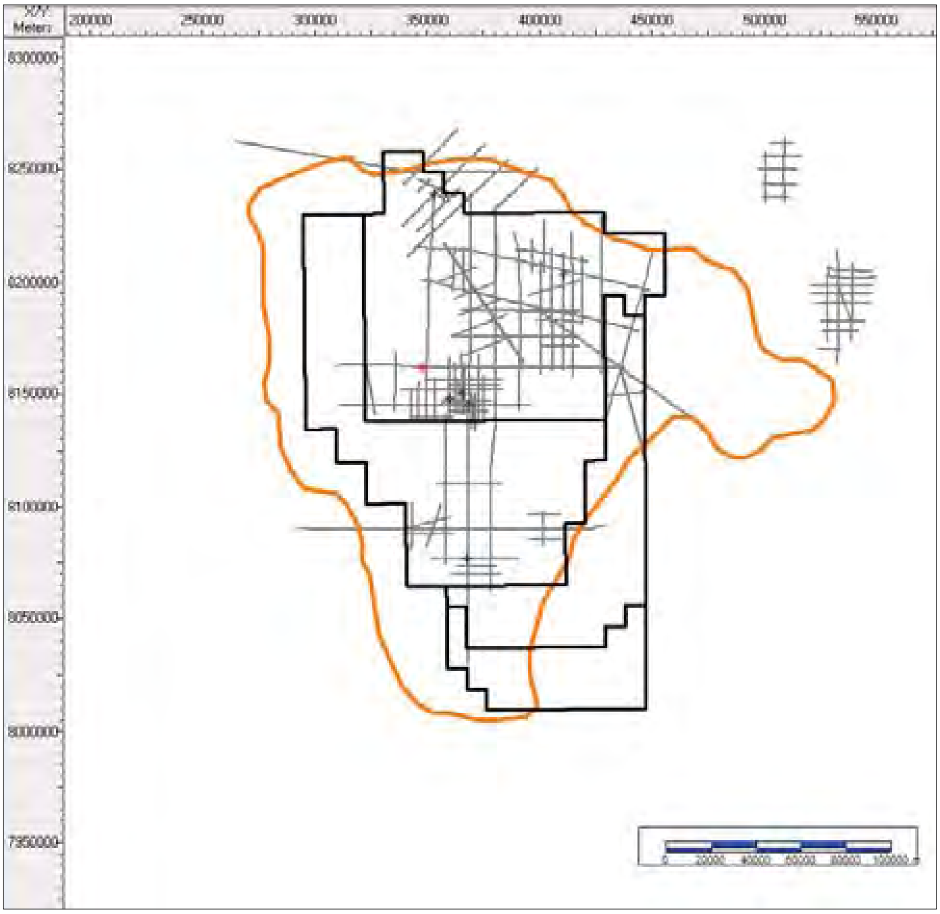
Figure 5.3-9: Potentially Prospective Moroak and Bessie Creek BCGA Areas

5.4 DATABASE

RPS was provided access to a comprehensive dataset including an interpreted SMT project, as well as well logs, well reports, deviation data, mudlogs, core data, well test and well completion reports.

5.4.1 Seismic Data

RPS was were provided with access to a SMT Kingdom™ project containing various vintages of 2D seismic data. The prospective area is covered by 2D seismic data. The seismic data and interpretation was loaded into an SMT project and provide to RPS for review. Approximately 2000 line km was acquired between 1984 and 1988 and 1988 and 1992 (Figure 5.4-1). As part of their farm-in agreement, Hess acquired 700 line km of 2D sesimic in 2006 and an additional 3,490 line km of new seismic data in 2011-2012 which is still in processing (Figure 5.4-2). Falcon Australia will collect an additional 150 km 2D seismic data in the EP99 permit in 2013. Under the terms of the current potential farm-in agreement, Hess has until 30 June 2013 to elect to undertake a five (5) well program in return for a 62.5% interest in the agreement area. Falcon will be carried though these five wells.

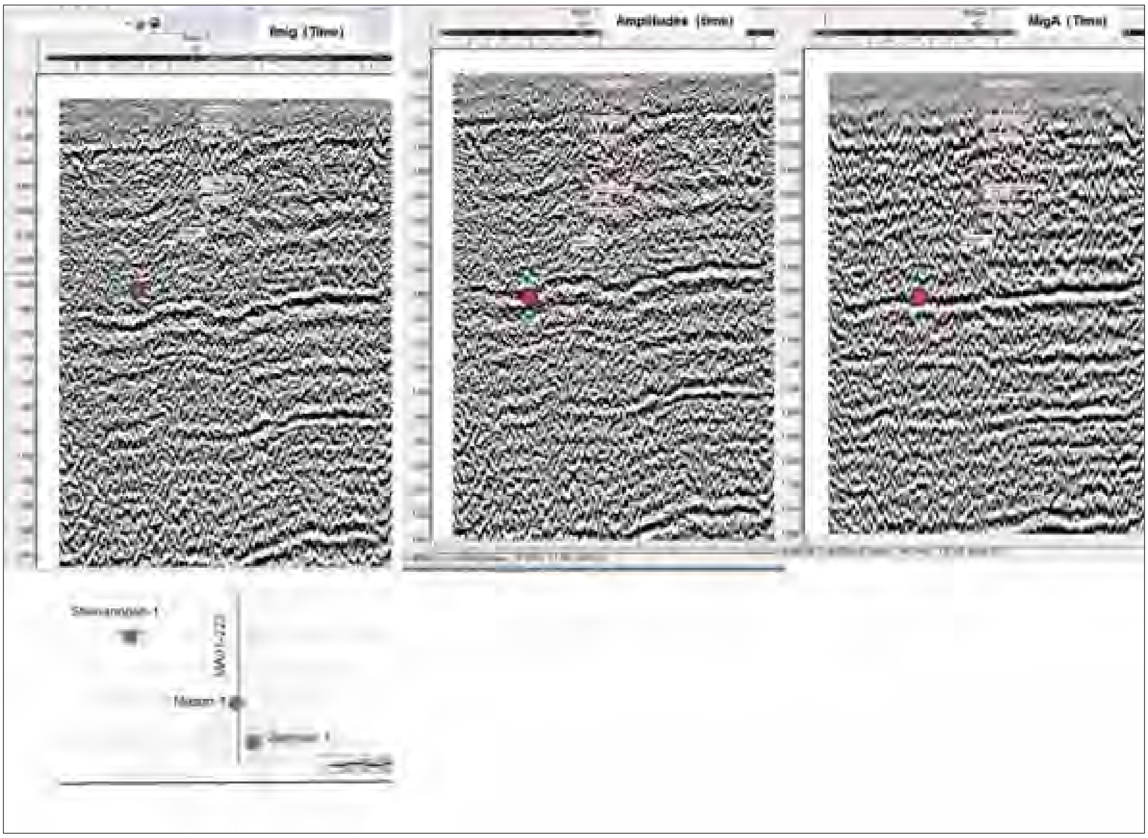


Source: Falcon

Figure 5.4-1: Existing 2D Seismic Data before Hess 2011-12 Seismic Acquisition

Seismic data quality is poor to fair. There are significant velocity issues resulting from a shallow karsted limestone (Tindall Formation), variable unconsolidated surface sediments, and the effects of volcanics (Antrim) injected into the near subsurface. Much of the seismic data is processed using different algorithms with the different statics and replacement velocities resulting in 2D time misties.

Multiple processing efforts have occurred and most of the data has been reprocessed several times. The effects of the different surface statics and shallow velocities can be observed in Figure 5.4-2.



Source: Falcon

Figure 5.4-2: Seismic Processing Issues

The three different sets of processing parameters are shown for Line MA91-223. The brown dot is located at the same X, Y, Z position on all three lines. The changes in these line versions clearly show the impact of the karsted carbonate surface topography, the shallow intrusions and dykes, and the different static corrections and replacement velocities. These issues result in a high degree of uncertainty in prospect mapping. However, the general basin configuration and general depth to the major sequence boundaries are broadly recognisable and the resulting interpretation and maps can be used for basin-wide unconventional analysis.

In 2007, 1000 line km of seismic were reprocessed with varying and unpredictable results. In some areas, the processing improved, but in others, the near surface problems limited the success of the results. Additional reprocessing in 2008 showed some improvement, but the velocity and statics problems remained. In 2009, approximately 2700 line km of the data were again reprocessed with some success. It is hoped that the new acquisition will include improvements in the source acquisition parameters, spacing, coupling of the geophones, and processing and will deliver a more consistent and usable dataset.

Working with the Falcon geoscientists, RPS is satisfied that the seismic interpretation has been carried out in an appropriate manner, incorporating all available geological information including well data.

5.4.2 Well Data

Data made available to RPS include CPI (Computer Processed Interpretation) in LAS (Log Ascii Standard) format for wells Altree-2, Balmain-1, Burdo-1, Chanin-1, Elliot-1, Jamison-1, Mason-1, McManus-1, Ronald-1, Shenandoah-1, Shortland-1 and Walton-1. Also, composite logs in PDF (Portable Document File) format. Digital mud log data was made available for all wells.

Available core data for the offset wells Altree-2, Balmain-1, Broadmere-1, Burdo-1, Chanin-1, Elliot-1, Jamison-1, Mason-1, McManus-1, Ronald-1, Sever-1, Walton-2, include Porosity, Permeability, grain density, Water Saturation, Oil Saturation and TOC.

Petrophysical evaluations had been previously made by Falcon and Darrell Hoyer, (Falcon's independent petrophysical consultant) and RPS concluded that previous petrophysical work was reasonable.

Well completion report for the Shenandoah-1 includes Diagnostic Fracture Injection Test (DFIT) results on 5 zones. The report also includes results of fracture stimulation treatments pumped in 3 of the 5 zones.

5.4.3 Previous Reports

Two previous reports were made available to RPS. These include but are not limited to:

- "Falcon Oil & Gas Ltd. Evaluation of the Hydrocarbon Resource Potential Pertaining to Certain Acreage Interest in the Beetaloo Basin, Northern Territory, Australia, as of July 1, 2009. By Ryder Scott Company".
- "Falcon Oil & Gas Ltd. Evaluation of the Unconventional Oil Resource Potential Pertaining to Certain Acreage Interest in the Beetaloo Basin, Northern Territory, Australia. As of May 1, 2010. By Ryder Scott Company".

5.5 BEETALOO BASIN UNCONVENTIONAL AND TIGHT GAS RESOURCES

5.5.1 Overview

RPS evaluated several sources of information provided by Falcon to assess the unconventional shale resource for the Upper Kyalla, the Lower Kyalla, and Middle Velkerri formations and BCGA potential for the Moroak and Bessie Creek sandstone in the Beetaloo Basin. The information used in the evaluation included seismic data and interpretation, depth maps, mudlogs, wireline logs, test data, and geochemical analysis.

5.5.2 Seismic Interpretation and Depth Maps

RPS has QC'd the seismic interpretation behind the current Falcon mapping of the Beetaloo Basin and finds it to be consistent with the underlying data. It is clear that much care has been taken to incorporate all the available geological information from both wells and surface geology.

RPS believes that the mapping, whilst subject to a large range of uncertainty as a result of the sparse, poor quality 2D seismic is a reasonable representation of the potential structures at this time.

Figure 5.5-1 is a stratigraphic chart with the major formations and Figure 5.5-2 illustrates the seismic horizons interpreted by Falcon and reviewed by RPS.

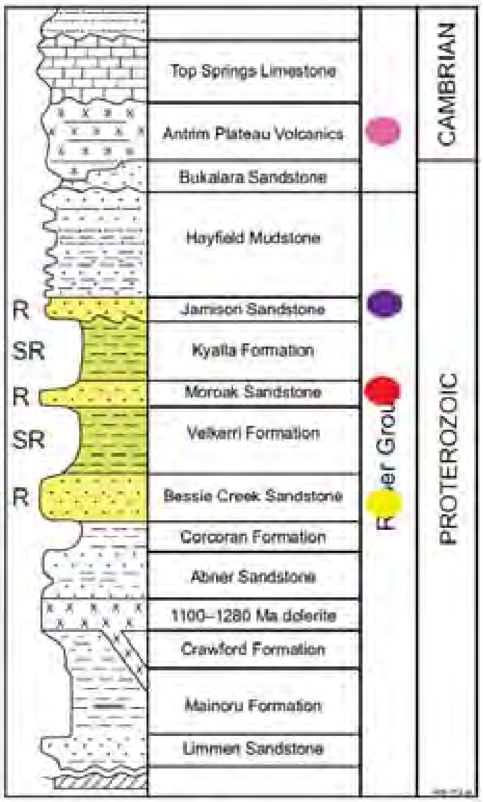


Figure 2. Stratigraphic column showing Roper Group and overlying Cambrian units. R = reservoir; SR = source rock.

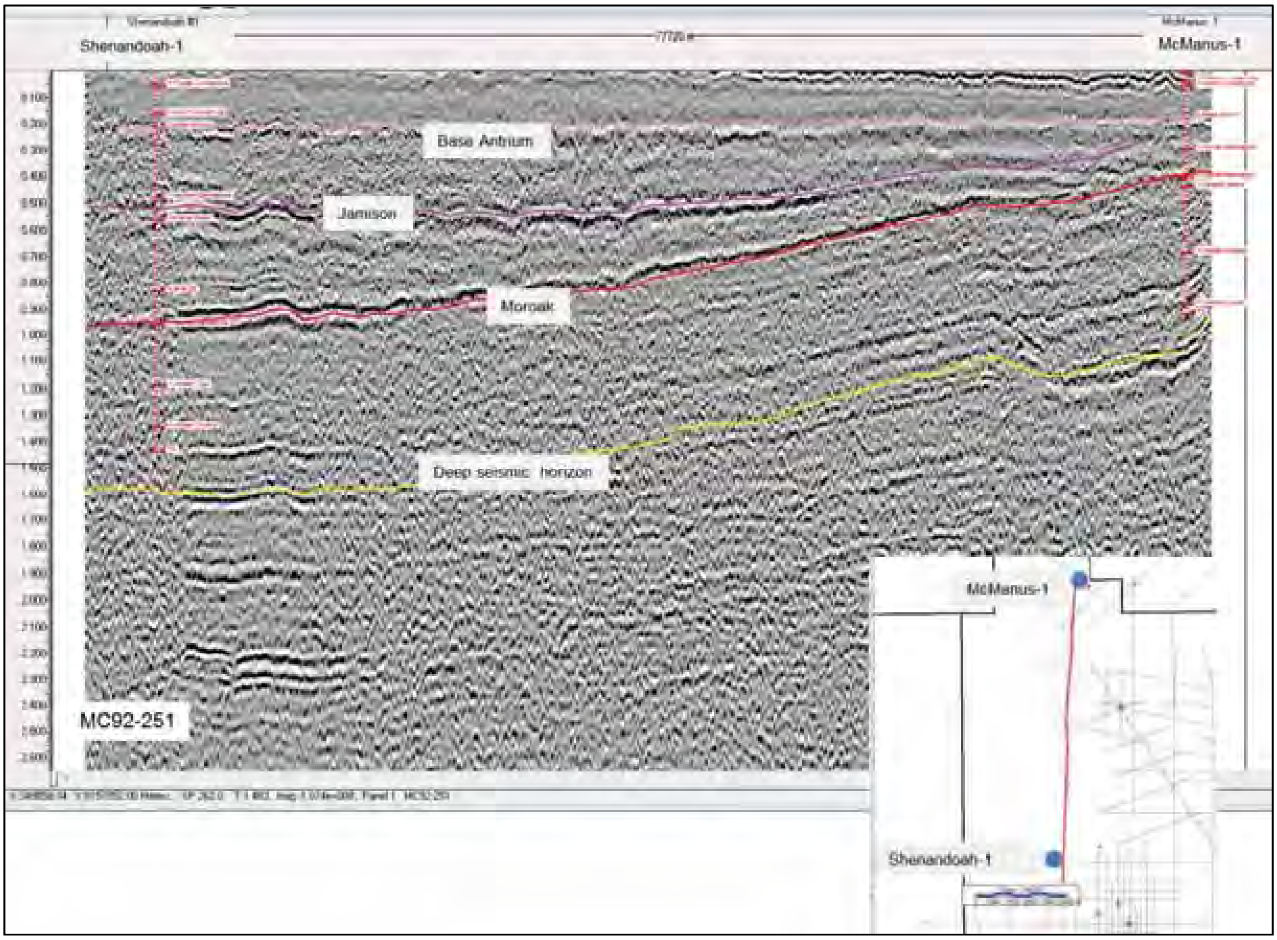
Source: Silverman

Figure 5.5-1: Stratigraphic Chart with Seismic Horizons Annotated

The four horizons interpreted were:

- Antrim and/or Base of Antrim
- Jamison Sandstone
- Moroak Sandstone
- Deep seismic horizon

These are represented by the strongest, most continuous reflectors on the seismic data. The Moroak and Jamison sandstones are good consistent seismic markers across the area and are the most widely interpreted. A synthetic generated in the Jamison well was tied to the seismic data to confirm the Jamison, Moroak, and Base Antrim volcanic seismic markers. The seismic interpretation and mapping is generally good and was accepted for use in the resource assessment.



Source: Falcon

Figure 5.5-2: Type Seismic Line

Depth grids were provided to RPS for use in the assessment. The depth maps are in TVD Seismic which is 200 m above mean sea level. The depth maps were tied to the well control except along the northern basin margin where both the well log correlations are uncertain and the seismic data is very poor quality.

The depth conversion was confirmed by generating time grids from the seismic interpretation and calculating average velocity grids from the time and depth maps. The Jamison and Moroak interpretation, mapping, and depth conversion appear to be reasonable.

The depth maps used in the resource assessment include:

- Upper Kyalla shale
- Lower Kyalla shale
- Moroak sandstone
- Middle Velkerri shale
- Bessie Creek sandstone

The Upper Kyalla depth map was derived from the Jamison interpretation and depth mapping. The Upper Kyalla is 75 - 90 m below the Jamison. The Jamison depth map was downward continued 80 m to generate the Upper Kyalla map. The Lower Kyalla depth map was generated from the Moroak depth map. The most prospective shaly part of the Lower Kyalla lies just above the Moroak sandstone and the Lower Kyalla depth map was upward continued 20 m to this shaly unit.

There are limited Middle Velkerri penetrations, Shenandoah-1 in the center of the basin and the Walton-2, Altree-2 and McManus-1 on the shallow northern basin edge. The Middle Velkerri does not have a strong, continuous seismic event and the Middle Velkerri depth map was generated from the Moroak depth map.

There are limited Middle Velkerri penetrations, Shenandoah-1 in the center of the basin and the Walton-2, Altree-2 and McManus-1 on the shallow northern basin edge. The Moroak depth map was downward continued to match the Middle Velkerri in the Shenandoah-1 well.

The Bessie Creek is reached in the Walton-2 and Altree-2. The Bessie Creek depth map was tied to the well control along the northern edge of the basin and downward continued to give a depth estimate to the Bessie Creek.

5.5.3 Well Test Information

Fourteen wells have penetrated the Beetaloo Basin from as shallow as 777m in the Balmain-1 to as deep as 2714m in the Shenandoah-1. All of the wells with the exception of the Shenandoah-1 were drilled to capture data and were not flow tested. The Shenandoah-1 was re-entered in September 2011 with the objective to complete and fracture stimulate unconventional zones in the vertical well to determine the hydrocarbon productivity potential in the Basin as well as fracture design parameters. High rates of production were not expected because the objective was a Diagnostic Fracture Injection Test (DFIT). The DFIT provided much needed hydraulic fracturing design parameters that will be helpful in optimizing future hydraulic frac designs.

Diagnostic Fracture Injection Tests were performed in five (5) stages in the Shenandoah-1. Stage 1 was in the Middle Velkerri LB sand and Stage 2 was in the Middle Velkerri B sand. Stages 3 and 4 were in the Moroak sandstone and Stage 5 was in the Lower Kyalla sand. Stages 1 and 2 were stimulated with 40/70 mesh proppant as well as Stage 5. Stages 3 and 4 were not stimulated with proppant due to extremely low porosity and permeability. See Table 5.4.1 provides a summary of perforation and stimulation data for the Shenandoah-1.

Summary of the well test is presented below.

Middle Velkerri

Test #1 (2529-2548 m MD): Interpreted to be a shale/siltstone rock with average TOC of approximately 2 wt%. Testing equipment was not properly suited for unconventional well testing and could not properly handle the high water rates in conjunction with low gas rates. There was enough gas to burn the flare without the pilot being on. Gas rate was insufficient to measure. Increasing CO_2 content ranged from 3% to 6%. Condensate with an API gravity of 43 degrees was collected in the mud pit. Modeling of the data and fracture treatment results indicated a very low permeability (0.000074 mD).

Test#2 (2481-2598.5 m MD): Interpreted to be a low porosity sands with shale laminations. Little to no TOC identified. Early flow initial gas rates were as high as 84 Mscf with 3,200 bbls of water per day. After performing a post-frac DFIT, the well flowed unasssisted with measureable rates of over 2,000 bbl/d water and ~60 Mscfd gas. Modeling of the data and fracture treatment results indicated a very low permeability (0.006 mD).

Moroak Sandstone

Test#3 (1837-1910 m MD): Interpreted to be a very low porosity sands with shale laminations. There is a subtle mud gas increase over this interval. The well did not flow as a result of very low permeability. Modeling of the data and fracture treatment results indicate a permeability of 0.000913 mD)

Test#4 (1728-1780 m MD): Interpreted to be a massive fluvial sandstone. There were modest mud gas shows over this interval. However, the test failed to flow any detectable gas. Modeling of the data and fracture treatment results indicated a very low permeability (0.0829 mD).

Lower Kyalla

Test#5 (1631-1649 m MD): Interpreted to be composed of shale/siltstone and sandstone layers with TOC of 2 wt%. Mudlog gas shows over this interval reaching 11% TGas. Burnable gas was observed. Modeling of the data and fracture treatment results indicated a very low permeability (0.002190 mD)

The well was plugged and abandoned on November 7, 2011.

Table 5.5-1: Summary of Perforation and Stimulation data for the Shanandoah-1 Well

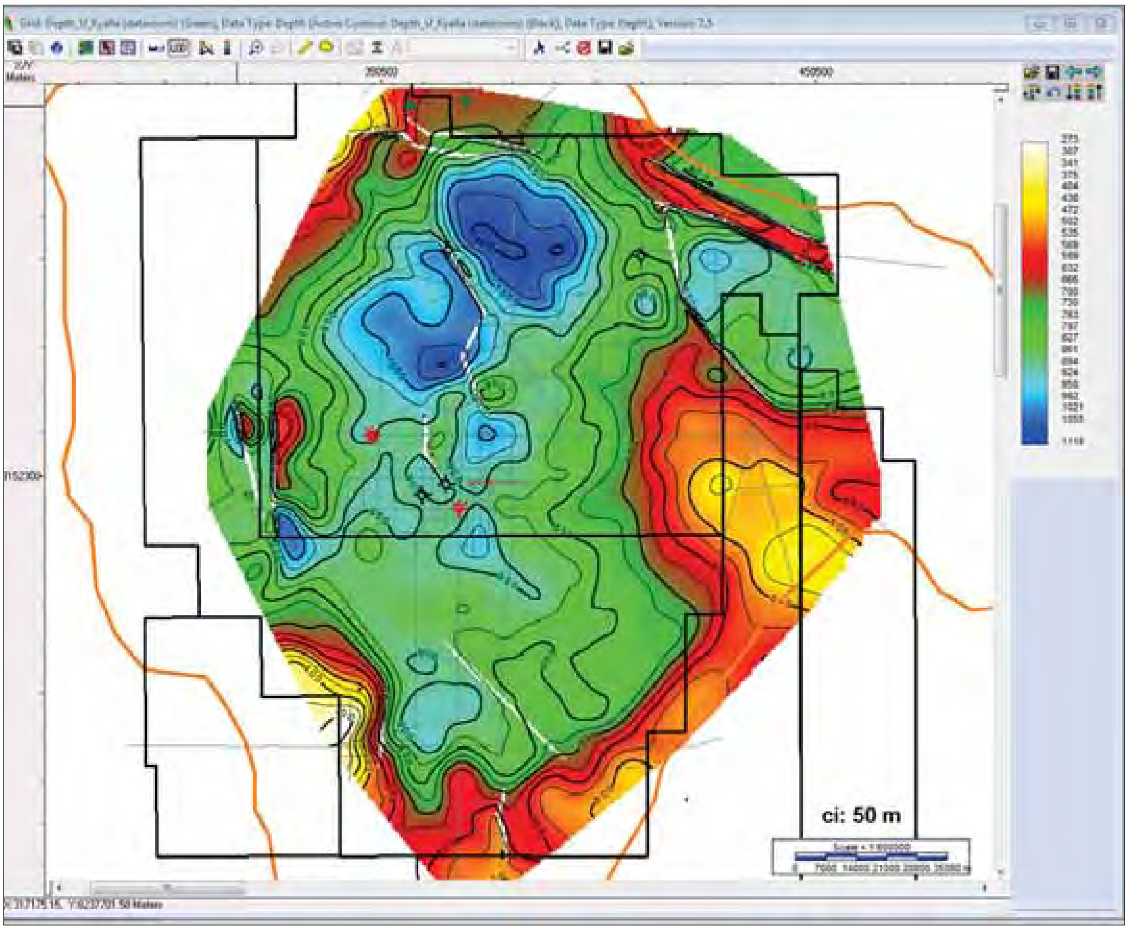
PERFORATION / STIMULATION SUMMARY

	Wireline Perforations (meter MDRT)					DFIT		Stimulation Treatment		
	Top (m)	Base (m)	Interval (m)	Type SDP	Density (shots/m)	Water (bbls)	HCL% (bbls)	Total Fluid (bbls)	Silica Sand 100 mesh	Silica Sand 40/70 mesh
Stage 1	2547	2548	1	3/3/8"	20	212	36 @15%	6,654	52,912 lbs	148,815 lbs
	2529	2530	1	3/3/8"	20					
CIBP 1	2522									
Stage 2	2497.5	2498.5	1	3/3/8"	20	320	47 @15%	7,575	76,061 lbs	125,666 lbs
	2481	2482	1	3/3/8"	20					
CIBP 2	1952									
Stage 3	1900	1910	10	2 3/4"	10	12.6	32 @13.5%	44.6	N.A.	N.A.
	1860	1870	10	2 3/4"	10					
	1850	1860	10	2 3/4"	10					
	1837	1843	6	2 3/4"	10					
CIBP 3	1815									
Stage 4	1774	1780	6	2 7/8"	10	No DFIT	28.2 @15%	135.2	N.A.	N.A.
	1755	1760	5	2 3/4"	5					
	1745	1755	10	2 7/8"	10					
	1728	1740	12	2 7/8"	10					
CIBP 4	1660									
Stage 5	1648	1649	1	3/3/8"	20	No DFIT	32 @15%	7,866	69,447 lbs	158,736 lbs
	1641	1642	1	3/3/8"	20					
	1631	1632	1	3/3/8"	20					
CIBP 5	1610									
CIBP 6	1575									

5.5.4 Upper Kyalla Formation

Shale plays have a wide range of TOC (Total Organic Carbon) and HI (Hydrogen Index) values. However, the better shale gas/oil plays have current average TOC values in excess of 2.0% and HI values above 400 mg/g (Jarvie). The best shale plays have TOC values above 3.0% and HI values in excess of 500 mg/g.

The Upper Kyalla depth map (Figure 5.5-3) shows the central syncline of the Beetaloo basin and the basin edges.



Source: Falcon

Figure 5.5-3: Upper Kyalla Depth Structure Map

The geochemical analysis of the northern wells did not show reasonable TOC or HI values, even though the section is in the oil window and should be at or below the peak oil generation. The Chanin-1 (average 0.47% TOC and HI of 243 mg/m) , Ronald-1 (average 0.61%TOC and HI of 274 mg/m), and Burdo-1 (average 0.66% TOC and 192 mg/m HI) all had TOC values <2.0% and HI values <400 mg/m. The source rock characteristics of the Elliot-1 and Jamison-1 were better. The Upper Kyalla interval in the Ellliott-1 is from 664 m to 1140 m MD. One interval, 1064 m to 1141 m, had the best shale potential. The best source rock samples were sent for source rock analysis (Appendix 5 of the well report) and the results indicate an average TOC of 1.88% and average HI of 235 mg/m. In Jamison-1 the Upper Kyalla is from 965 m to 1485 m MD. As with the Elliot-1, the darkest and finest-grained samples (Appendix 4 of the well report) were sent for geochemical analysis and yielded the best results from 1012 m to 1043 m MD with an average TOC of 2.16% and HI of 410 mg/m.

Since the source rock characteristics of the Upper Kyalla are so varied, it may be that paleo-topography and distance from the basin edges controlled the amount of and later preservation of the organic matter. The thickest and deepest part of the Upper Kyalla away from the sediment influx from the basin boundary should have had the most anoxic and reducing environment with the best source rock resource potential. Figure 5.5-4 is an isopach map with the geochemical results annotated. It confirms that the deeper part of the Beetaloo basin in Upper Kyalla time has the greatest potential for the development of shale resources, with much less potential outside the basin center.

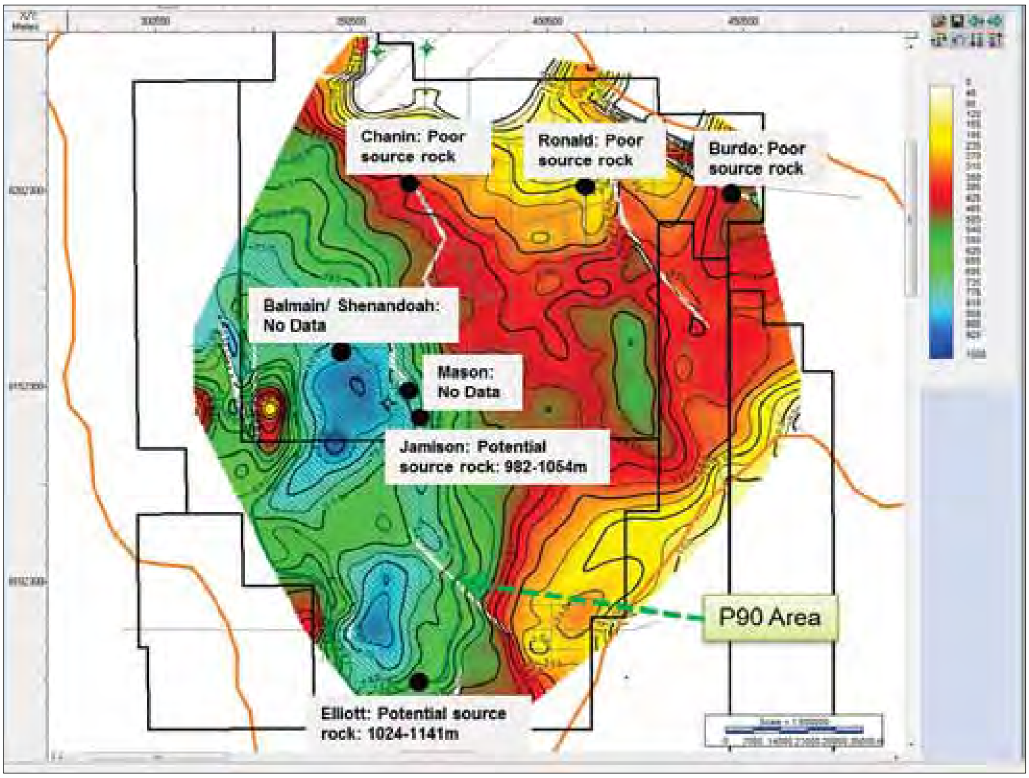


Figure 5.5-4: Upper Kyalla Isopach Map with Geochemical Analysis and P10 Area

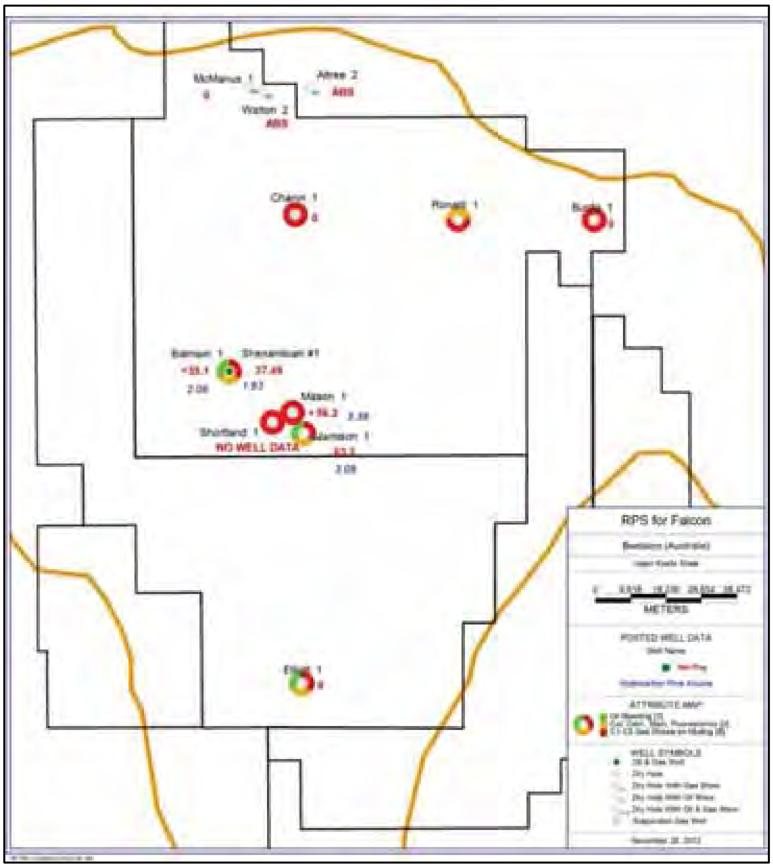


Figure 5.5-5: Upper Kyalla Show Map

Figure 5.5-5 is a map with the mudlog, test, show and calculated net pay annotated. While there are mudlog shows in the Chanin-1, Ronald-1 and Burdo-1, there is no calculated net shale resource pay. Also, the Elliot-1, along the southern edge of the basin center, did not have any calculated net pay. All of the wells in the center, thickest, most distal part of the basin had 35 m to 63 m of net pay (red numbers in Figure 5.5-5).

Therefore, the isopach was used to define both the Upper Kyalla shale P10 and P90 areas. The P90 includes the Shenandoah, Balmain, Mason and Jamison wells with calculated oil pay and covers 4421 km^2 (1,092,504 ac.). As the Elliot-1 had marginal geochemical characteristics and no calculated oil pay, but is reported to have had some oil in a well test and the P10 area (Figure 5.5-6) was extended to include this well and is 5576 km^2 (1,377,987 ac.).

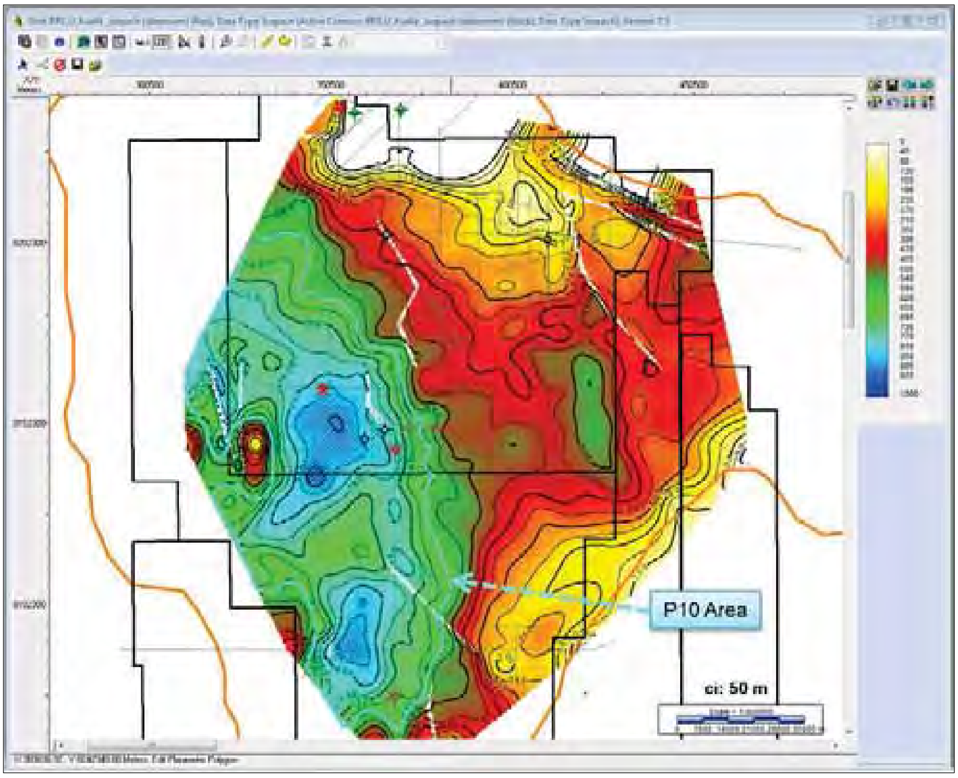
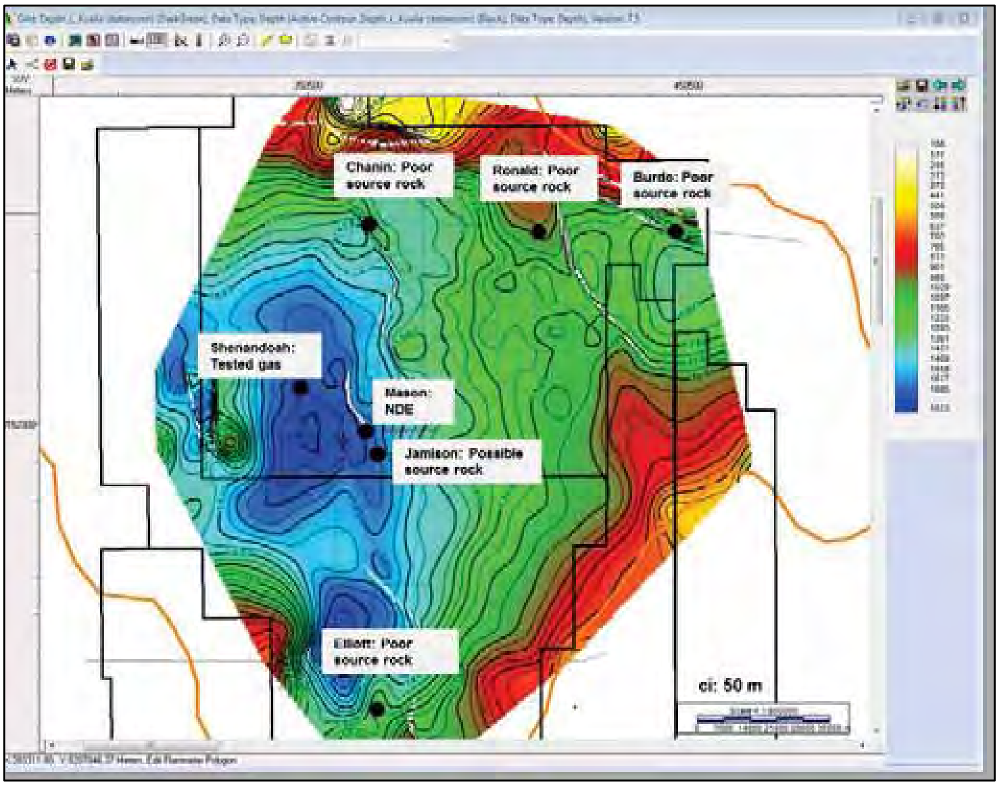


Figure 5.5-6: Upper Kyalla Isopach with P10 Area

5.5.5 Lower Kyalla Formation

The Lower Kyalla (Figure 5.5-7) reaches depths greater than 1500 m (see Section 5.3.2). Therefore, it is sub-divided into a gas resource play (<1500 m TVDSRD) and an oil resource play (>1500 m TVDSRD). As with the Upper Kyalla, the Lower Kyalla is eroded along the northern boundary of the basin in the McManus-1, Altree-2, and Walton-2 and may also be eroded along the high areas to the west and east.

There is limited TOC and HI data for the Lower Kyalla (Figure 5.5-7). The Burdo-1 has an average 0.82% TOC and 185 mg/m HI. The Chanin-1 has an average 1.0% TOC and 108 mg/m HI. The Ronald-1 average is 0.63% TOC and 120 mg/m HI. The Elliot-1, which is still in the oil window, has an average TOC of 1.18% with no values above 1.55% and an average HI of 136 mg/m. As these wells are in the oil window and not over mature, the source rock characteristics imply this may be a poor quality oil resource play. In the center of the basin, the Shenandoah-1 (gas window) tested gas from the Lower Kyalla. The Jamison-1 (gas window) had the best shale resource potential, 1492 m to TD, with an average TOC of 2.29% and numerous values over 2%. The average HI is low, 66 mg/m, but Jamison is in the gas window, most of the generation could have occurred earlier when in the oil window, the shale is now depleted in hydrogen, and is no longer able to generate hydrocarbons. The high remaining TOC values imply that this may have been an excellent source rock in the past and may have retained the gas it has generated.



Source: Falcon

Figure 5.5-7: Lower Kyalla Depth Structure Map

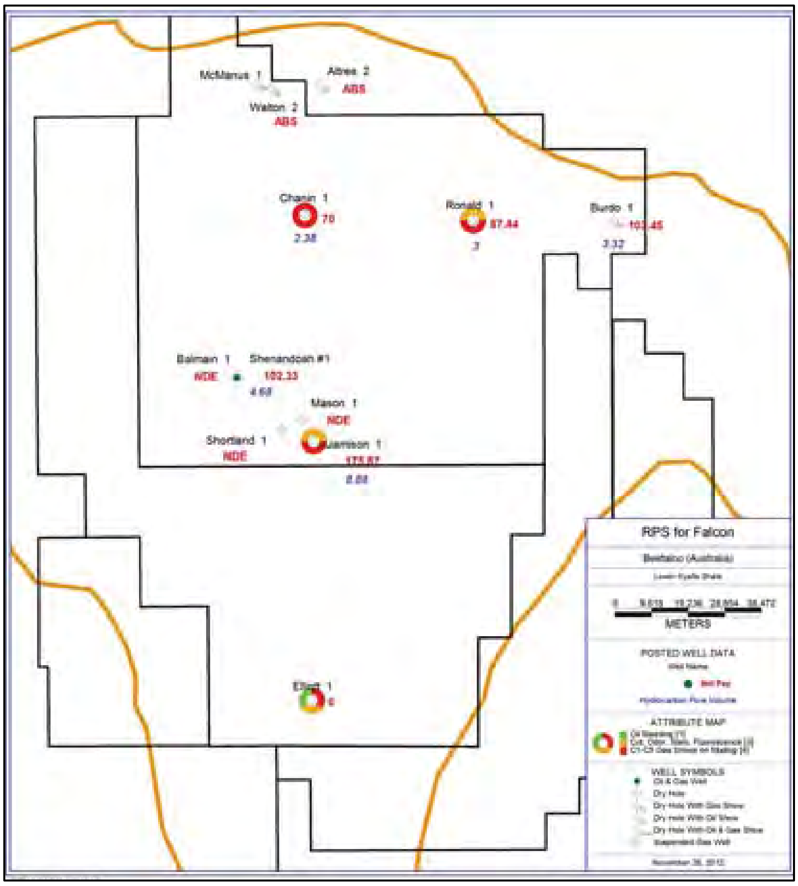
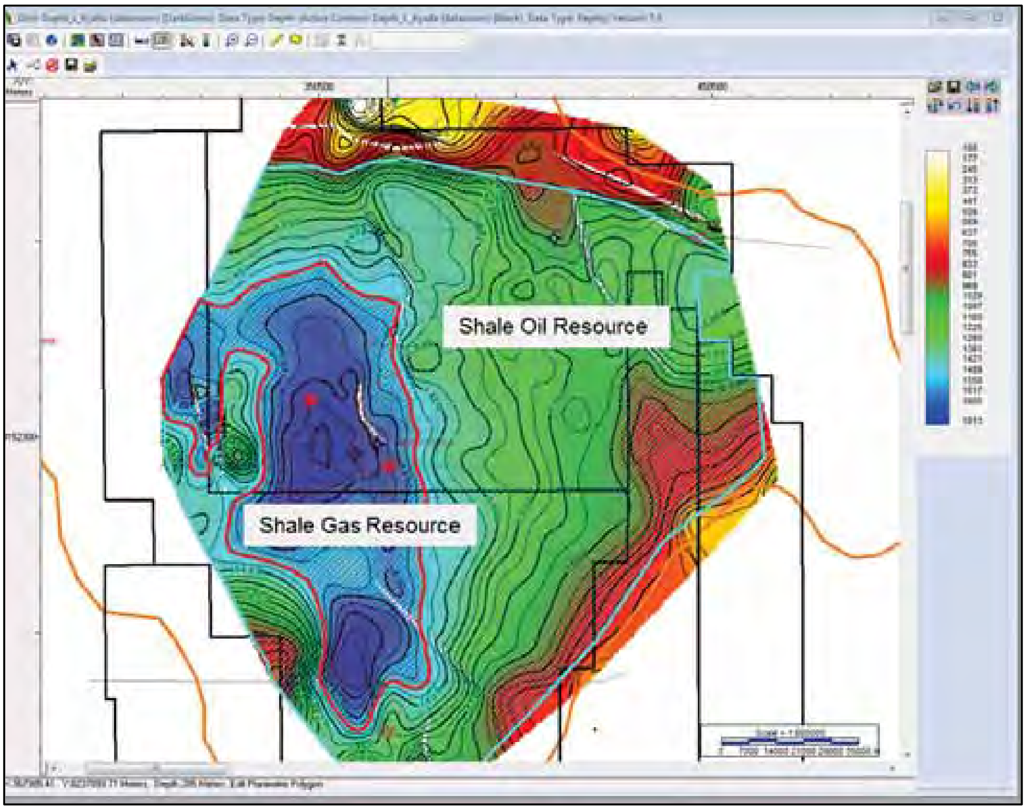


Figure 5.5-8: Lower Kyalla Show Map

Although the TOC and HI values were low, the wells had oil or gas shows (Figure 5.5-8), staining, fluorescence, and/or other indications of hydrocarbons. The Lower Kyalla had calculated net pay in all the wells except Elliot-1. The calculated net pay (red numbers in Figure 5.5-9) ranged from 70 m in the Chanin-1 to 175 m in the Jamison-1. Although the geochemical TOC and HI data indicates poor potential for Lower Kyalla shale resources, the net pay counts are good and the entire basin was included in the resource calculations.

The P10 shale oil area (Figure 5.5-9) encompasses the entire basin above the 1500 m line. This area (cyan outline) is 12,694 km^2 (3,136,820 ac.). The shale gas area (red outline) located in the deepest part of the basin, has a P10 area of 4382 km^2 or 1,082,942 ac. surrounding the Jamison-1 and Shenandoah-1. The P90 area for the Lower Kyalla oil resource was set at 70% of the P10 area i.e. 8,885 km^2 (2,195,776 ac.) The P90 for the Lower Kyalla gas resource was also set at 70% of the P10 area or 3068 km^2 (758,063 ac.).

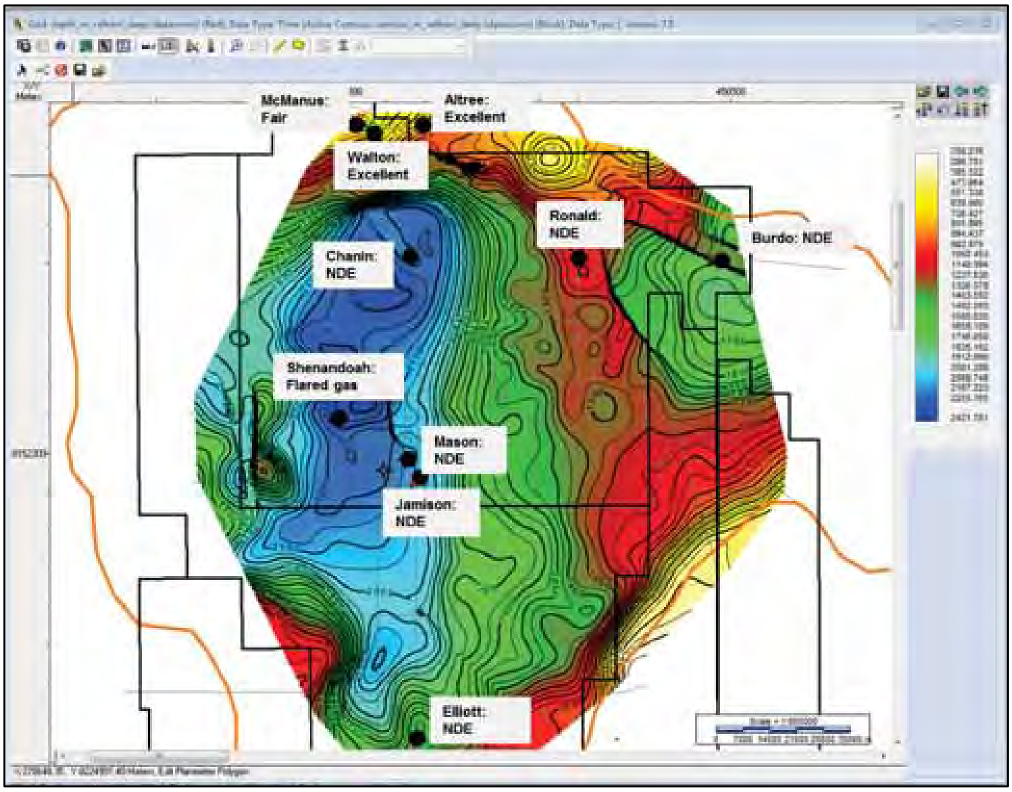


Source: Falcon

Figure 5.5-9: Lower Kyalla Depth Structure Map with P10 Gas and Oil Areas

5.5.6 Middle Velkerri Formation

The Middle Velkerri (Figure 5.5-10) is not penetrated in most of the wells. The only wells with Velkerri are the three wells along the basin edge, McManus-1, Altree-2, and Walton-2 and the Shenandoah-1 in the center of the basin. The Middle Velkerri appears to have excellent source rock characteristics and meets the criteria for a shale resource play. Biomarker data implies that the source rock is composed primarily of of prokaryotic cyanobacteria (Dutkiewicz). The Altree-2 is in the oil window and has excellent TOC (average 3.8%) and HI values (ranges from 200-460 mg/m). The McManus-1 has an average TOC of 2.32% and an HI range of <100 to 330 mg/m. The good oil shale in the McManus appears to be laminated with high TOC/HI values from 1130-1160 m, 1220-1280 m, 1360-1440 m and 1540-1550 m. Photomicrographs show that solid bitumen and oil-bearing inclusions in the McManus-1 are found in microfractures (Dutkiewicz, Figure 5). In the Walton-2, the Upper Velkerri has excellent source rock characteristics with TOC with most of the values are >3% TOC and >400 mg/m HI. According the Dutkiewicz, analysis of key wells in the Beetaloo and adjacent McArthur Basin indicates that a large portion of the generated hydrocarbons appear to remain in the Velkerri formation.



Source: Falcon

Figure 5.5-10: Middle Velkerri Depth Structure Map with Geochemical Analysis

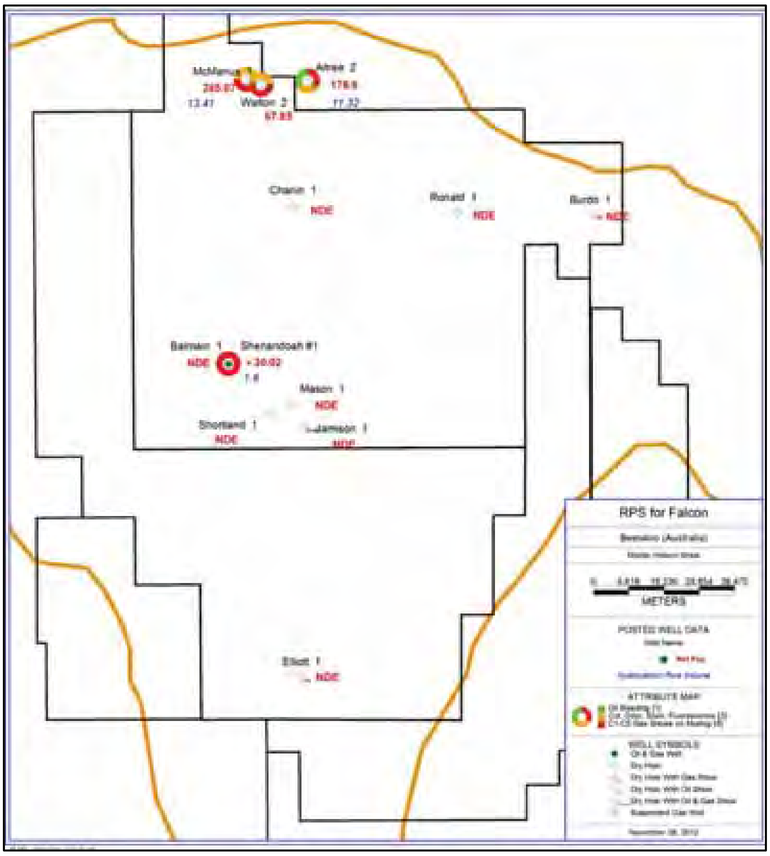
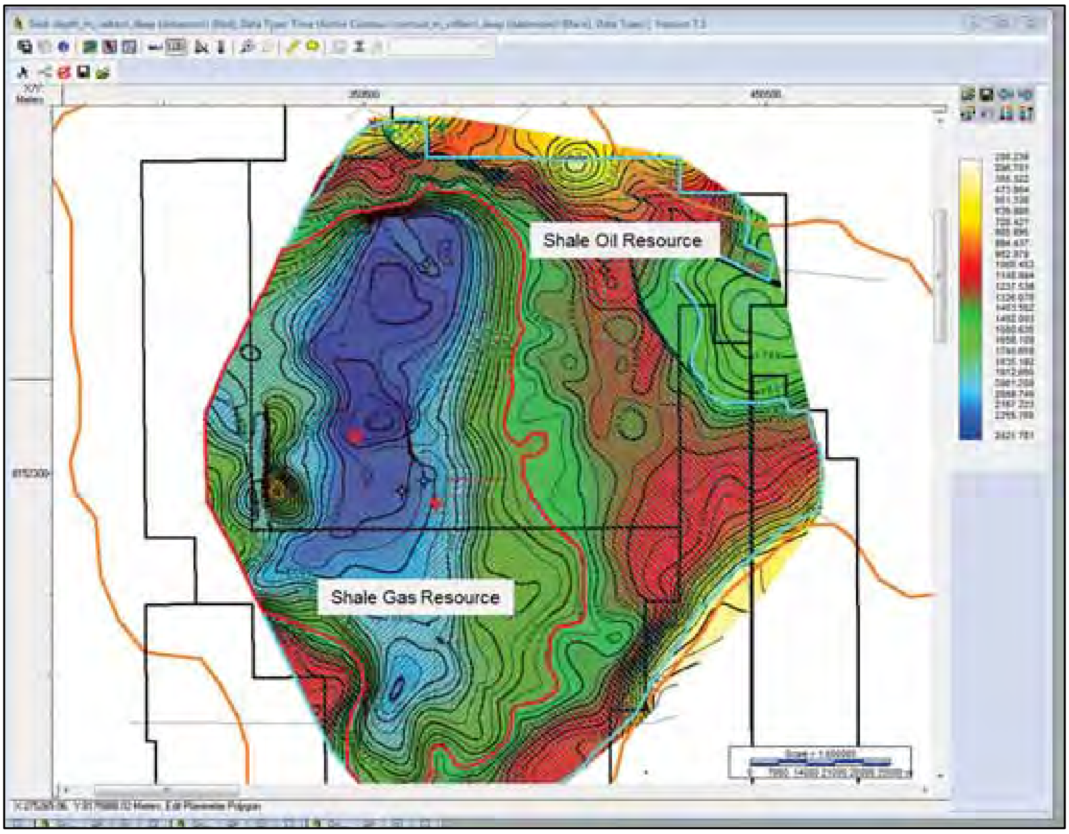


Figure 5.5-11: Middle Velkerri Show Map

On Figure 5.5-11 is the oil show information, the net pay (red numbers) and hydrocarbon pore volume data (blue numbers). The calculated net pay ranged from >30 m in the Shenandoah-1 well to 245 m in the McManus-1. The wells also had oil or gas shows, staining, fluorescence and/or other indications of hydrocarbons.

The P10 oil area (Figure 5.5-12) includes the Middle Velkerri from the 1500m gas/oil line to the edge of the block or 8,978 km^2 (2,218,598 ac.). The P10 for the gas window is 9,302 km^2 or 2,298,607 ac. The P90 areas are 70% of the P10 areas or 6284 km^2 for oil and 6511 km^2 for gas.



Source: Falcon

Figure 5.5-12: Middle Velkerri Depth Map with P10 Oil and Gas Areas

5.5.7 Moroak Formation

The Moroak Sandstone is a proposed BCGA (basin centered gas accumulation) play. Seven wells in the basin (Figure 5.5-13) did not have hydrocarbons, had no pay, and were wet (McManus-1, Walton-2, Altree-2, Chanin-1, Ronald-1, Burdo-1 and Elliot-1). The Jamison may have 1 m of pay. There was a significant amount of net pay in the Shenandoah-1, 144 m.

The Shenandoah-1 tested the Moroak sandstone (2 stages). Middle Moroak Deltaic interval 1837-1910 mMD, very low porosity and permeability with shale laminations, subtle log gas increase. After perforation test the well did not flow. Moroak Fluvial Sandstone interval 1728-1780 mMD, with indications of natural fractures from the STAR image log (Well completion report), modest mud log gas shows. After perforation test and Nitrogen circulation the well did not flow.Moroak was not fracked.

As petrophysical analysis indicated that most of the wells do not have any net pay, the P10 area was (Figure 5.5-14) set to exclude the wet wells, include the Shenandoah-1, and honor the possible 1 m of net pay in the Jamison well. This gave a P10 area of 1,372 km^2 or 339,071 ac. The P90 area is 70% of the P10 or 960 km^2.

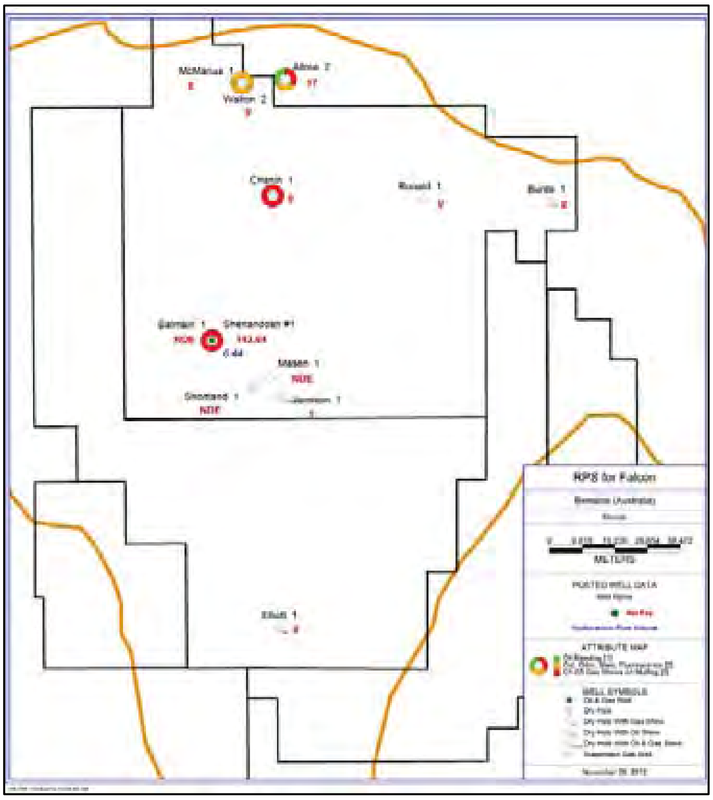


Figure 5.5-13: Moroak Show Map

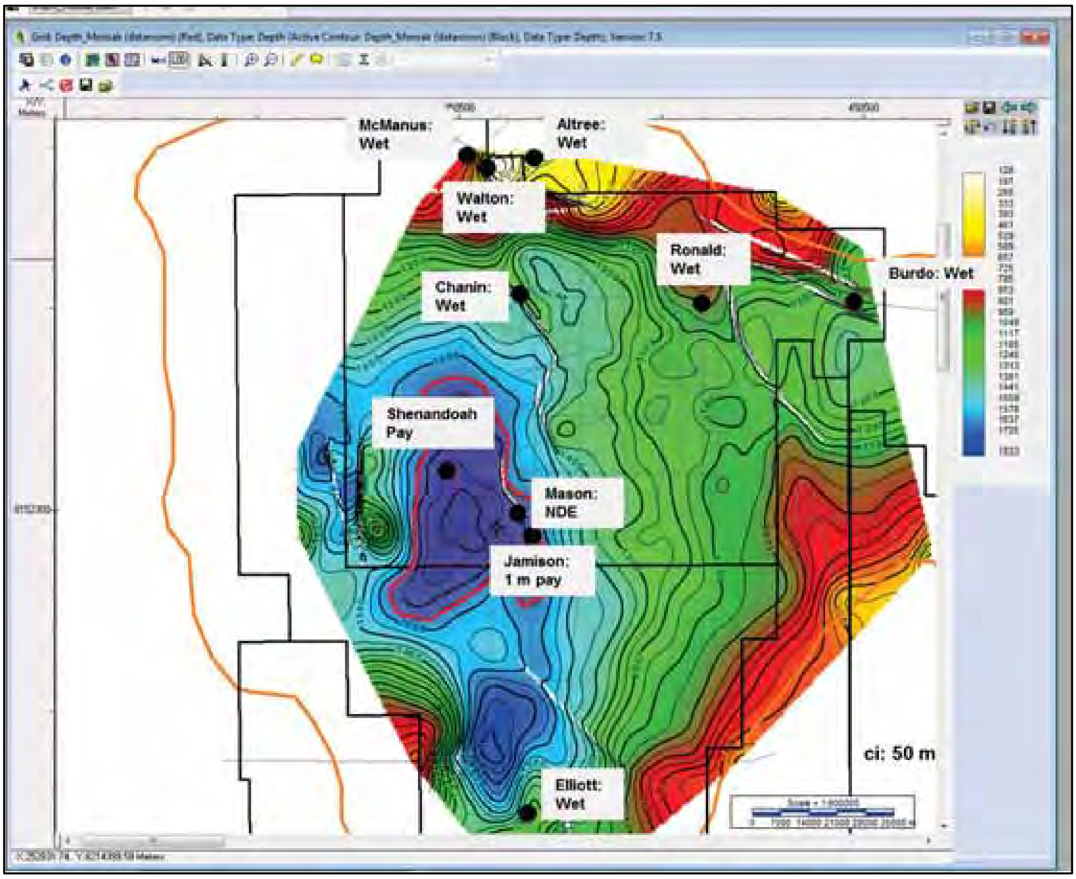


Figure 5.5-14: Moroak Depth Structure Map with BCGA Area

5.5.8 Bessie Creek Formation

The Bessie Creek is a deep sandstone unit penetrated only along the basin edge in the Altree-2 and Walton-2. Figure 5.5-15 has the show information for the Bessie Creek sandstone. Of the two wells penetrating the formation, the Walton-2 was wet, but the Altree-2 calculated 42 m of oil pay. These wells are on the flank of the basin leaving the center of the basin for a potential BCGA. As the BCGA may occur where the Middle Velkerri source rock in in the gas window, the P10 area (Figure 5.5-16) is coincident with the Middle Velkerri gas generation window and is 9,302 km^2 (2,298,607 ac.). The P90 is 70% of the P10 area or 6511 km^2.

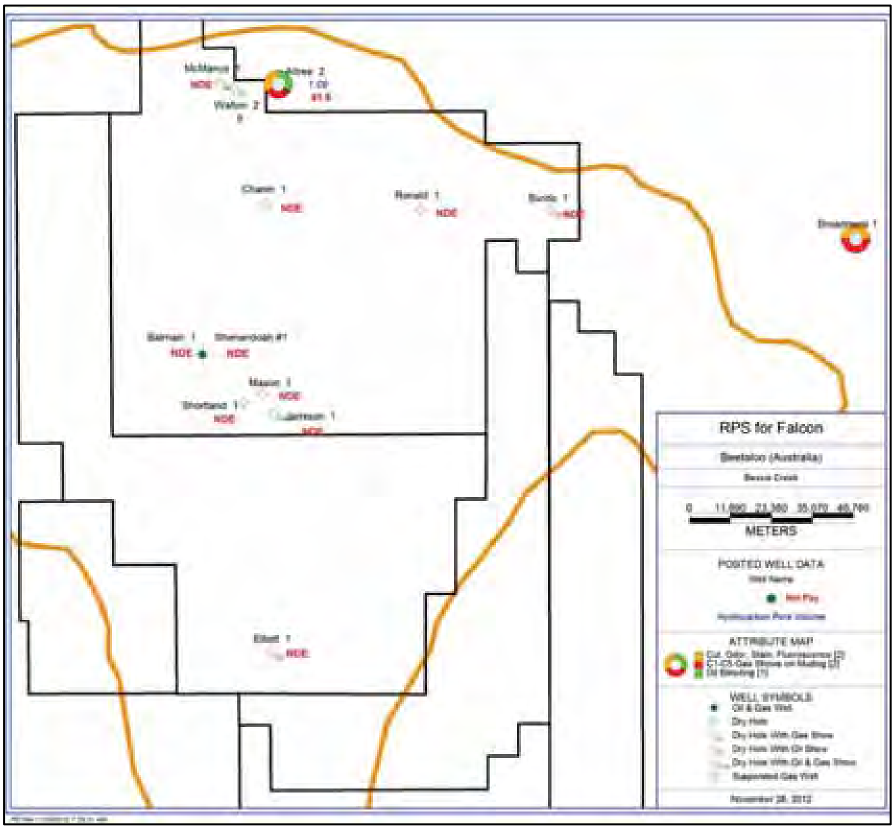


Figure 5.5-15: Bessie Creek Show Map

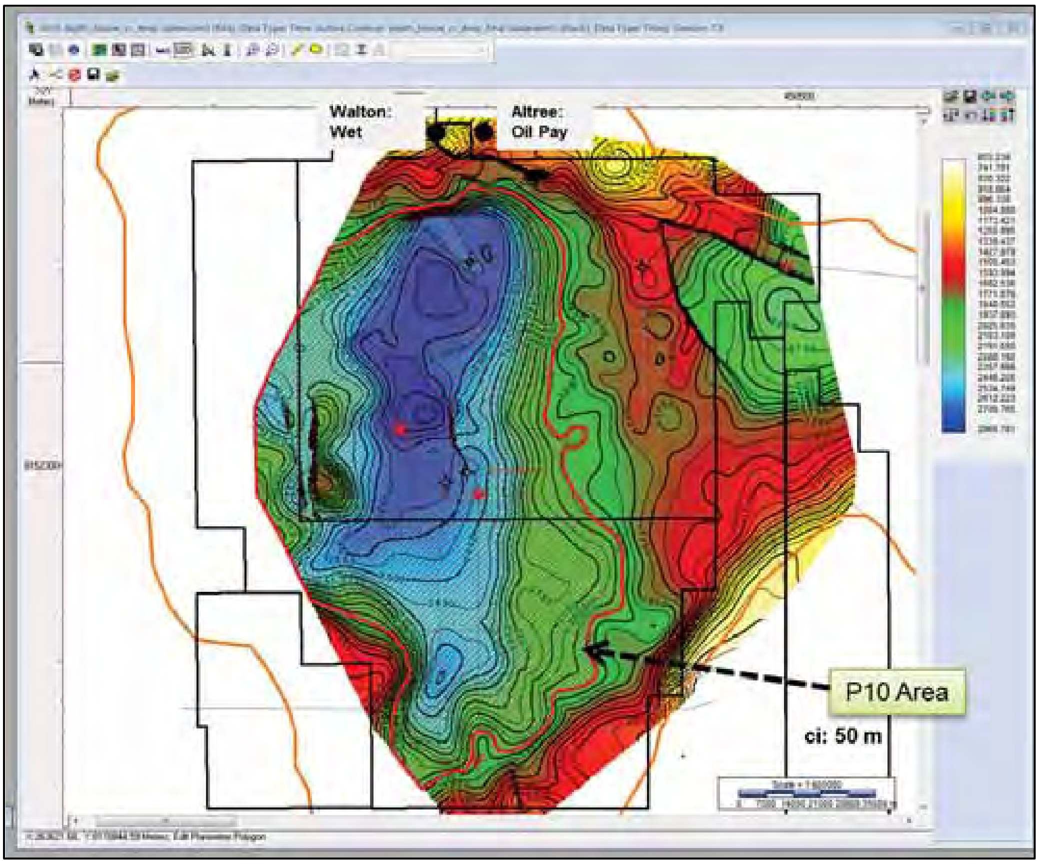


Figure 5.5-16: Bessie Creek Depth Structure Map with BCGA Area

5.5.9 Probabilistic Resource Estimates

Potentially recoverable Resources were estimated for five intervals; three in the unconventional shale for the Upper Kyalla, the Lower Kyalla (partitioned into oil and gas windows), and Middle Velkerri formations (also partitioned into the oil and gas window) and two with BCGA potential in the Moroak and Bessie Creek sandstone in the Beetaloo Basin:

- Kyalla Upper Oil
- Kyalla Lower Oil
- Velkerri Middle Oil
- Kyalla Lower Gas
- Velkerri Middle Gas
- Moroak Sandstone Gas
- Bessie Creek Sandstone Gas

The probabilistic Resource estimates were computed using the REP™ (Logicom E&P Ltd) software. This software allows for input of a variety of probability distributions for each uncertain parameter. The program then performs a large number of iterations randomly sampling each variable and honoring the dependencies that were input. The number of iterations was set at 100,000, which achieved the desired level of stability of the resulting answers. The results include a probability distribution for the output, sampled probability for the inputs, and sensitivity analysis showing which input parameters have the most effect on the uncertainty in each output parameter.

Once the Resource potential of each interval had been calculated for the basin, each interval was reviewed on a well by well basis to determine which wells might be assigned a more representative area to define the currently identified leads and prospects for the purposes of determining Prospective Resources at this stage of the basin's exploration.

Section 5.5.9.2 discusses the risking of each play (the resource potential for each interval and maturity window) and the further risking for each identified 'prospect' within the various intervals as currently sampled by the existing wells. As exploration (and subsequent appraisal) continues, RPS expects the number of prospects (or 'sweetspots') to increase and become better defined and prioritised.

5.5.9.1 Resource Potential Input Parameters for the Beetaloo Basin

The parameters required for the probabilistic analysis of the Resource potential of the Beetaloo Basin are summarized in Tables 5.5.9.1-1, 5.5.9.1-2 and 5.5.9.1-3 shown below.

Table 5.5.9.1-1: Input parameters for Kyalla Upper & Lower and Velkerri Middle shales

Kyalla Upper Oil	Units	P90	P50	P10
Area	acres	1,092,505	1,226,971	1,377,987
Thickness	m	35.05	47.24	63.40
Shape Factor	%	100	100	100
Porosity	%	8.3	8.97	9.7
Sw	%	34.60	39.20	44.40
FVF	rb/stb	1.01	1.13	1.26
GOR	scf/bbl	201	281	402
Oil Rec Fact	%	2.00	3.74	7.00
Kyalla Lower Oil	**Units**	**P90**	**P50**	**P10**
Area	acres	2,195,776	2,624,453	3,136,820
Thickness	m	70.00	85.10	103.00
Shape Factor	%	100	100	100
Porosity	%	6.6	6.7	6.8
Sw	%	49.7	50.6	51.5
FVF	rb/stb	1.10	1.18	1.26
GOR	scf/bbl	201	281	402
Oil Rec Fact	%	2.00	3.74	7.00
Velkerri Middle Oil	**Units**	**P90**	**P50**	**P10**
Area	acres	1,553,019	1,856,212	2,218,598
Thickness	m	67.8	129	245
Shape Factor	%	100	100	100
Porosity	%	8.8	10.2	11.8
Sw	%	37.2	38.8	40.4
FVF	rb/stb	1.01	1.13	1.26
GOR	scf/bbl	201	281	402
Oil Rec Fact	%	2.00	3.74	7.00

Table 5.5.9.1-2: Input parameters for Kyalla Lower and Velkerri Middle Shales

Kyalla Lower Gas	Units	P90	P50	P10
Area	acres	758,063	906,056	1,082,942
Thickness	m	31.09	40.84	53.64
Shape Factor	%	100	100	100
Porosity	%	7.60	8.36	9.20
Sw	%	40.10	42.40	44.90
FVF	vol/vol	140	205	300
Gas Rec Fact	%	60.00	71.40	85.00
Velkerri Middle Gas	**Units**	**P90**	**P50**	**P10**
Area	acre	1,609,026	1,923,153	2,298,607
Thickness	m	25	29.6	35
Shape Factor	%	100	100	100
Porosity	%	8.8	10.2	11.8
Sw	%	37.2	38.8	40.4
FVF	vol/vol	140	205	300
Gas Rec Fact	%	60.00	71.40	85.00

Table 5.5.9.1-3: Input parameters for Moroak and Bessie Creek Sandstones

Moroak SS Gas	Units	P90	P50	P10
Area	acres	237,350	283,687	339,071
Thickness	m	4.2	24.7	144
Shape Factor	%	100	100	100
Porosity	%	5.5	6.63	8
Sw	%	37.2	38.8	40.4
FVF	vol/vol	140	205	300
Gas Rec Fact	%	60.00	71.40	85.00
Bessie Creek SS Gas	**Units**	**P90**	**P50**	**P10**
Area	acres	1,609,026	1,923,153	2,298,607
Thickness	m	36.4	41.1	46.5
Shape Factor	%	100	100	100
Porosity	%	5.06	6.26	7.75
Sw	%	46	55.9	67.9
FVF	vol/vol	140	205	300
Gas Rec Fact	%	60.00	71.40	85.00

5.5.9.2 Risk and Uncertainty

Resource plays, particularly “shale” plays, are notoriously difficult to assign an appropriate level of risk in terms of assessing the likelihood of making a successful discovery (i.e flowing potentially commercial quantities of hydrocarbons to surface under test) within what is usually a regionally extensive (hundreds of thousands to millions of acres) layer of variable quality but generally low porosity, low permeability rock with internal hydrocarbon generation potential. Such discoveries and subsequent developments almost always occur in areas where many necessary components (i.e various geochemical, formation continuity and mechanical properties) all occur in the same place, usually a relatively restricted area or areas compared to the resource play, known as “Sweet Spots”. These “Sweet Spots” are the equivalent to the more tradtional ‘trap’ areas (or Prospects) associated with conventional hydrocarbon accumulations.

RPS’ methodology is similar to that used for conventional reservoirs (see Section 3.2.2) in that the risk is divided into a Play risk and an individual Prospect risk. However, the component parameters that make up the Play and Prospect risk have been adapted to capture the main elements that make up a working unconventional hydrocarbon play and prospects therein.

Play Risk

Three main components are considered in assessing the risk of a shale play, namely:

Basin – characteristics likely to promote the deposition of areally extensive clastic sequences under relatively stable conditions over periods of ‘geological time’ (hundreds of thousands to millions of years) such that the predicted shale sequence is present at a suitable depth and laterally continuous.

Burial history – evidence of sufficient burial characteristics (depth, thickness of over-burden, temperature gradient etc) likely to have resulted in hydrocarbon generation within organic rich source rocks.

Organic content – evidence that sufficient organic content exists to promote hydrocarbon generation. This can be assigned as likely from core sample measurements where established minima (see Jarvie, 2012) are exceeded by some degree or proved up by test data (preferably from within, but not necessarily limited to, the generating shale itself).

“Sweet Spot” or Prospect Risk

Individual “Sweet Spots” or prospects are risked based on three main component groupings:

Geochemical – the specific area in question (sampled by a well or wells) must demonstrate the correct kerogen type, acceptable TOC and hydrocarbon indices (HI), and thermal maturity. Each of these parameters are considered based on the well data and assigned a risk. The lowest chance of success from the three is passed through to the prospect risk matrix.

Mechanical – the specific area in question must have certain mechanical properties that will likely promote effective fracturing (necessary to create permeability near the well-bore and allow hydrocarbons to be produced). Such properties include brittleness, natural fractures, clay content, over-pressure and present-day stress regimes. The lowest chance of success from the three properties is passed to the prospect risk matrix.

Continuity – the specific area in question must favourably located such that the Geochemical and Mechanical parameters and shale thickness are likely to extend for sufficiently long distances from the well(s) to make the prospect large enough to drill a significant number of relative low EUR wells such that production will be commercially viable. Evidence that the seismic interpretation and depth conversion correctly define the “Sweet Spot”. Evidence such as position withn the basin structure and isopach mapping is considered and risked accordingly.

For each identified potential prospect (where rock has already been sampled by a well and possibly tested but at low rates over a short unsustained period or from an adjacent zone rather than the “shale” itself), the play risk and prospect risk are combined such that the product of the two becomes the individual prospect risk or geological probability of success (“GPoS”) as recognised by PRMS.

For the Beetaloo Basin, RPS has identified the following prospects based on the wells drilled to date:

- Upper Kyalla – The Elliot prospect and the Shenandoah prospect; both prognosed as potentially oil prospects.
- Lower Kyalla – The Burdo, Roanld and Chanin prospects in the oil window and the Shenandoah, Jamison and Elliot prospects in the gas window.
- Middle Velkerri – The Walton-McManus prospect in the oil window and the Shenandoah, Jamison and Elliot prospects in the gas window.

The Moroak and Bessie Creek tight sand plays are risked as basin centered gas accumulation (BCGA) plays but have no identified prospects at this time.

Tables 5.5.9.2-1 and 5.5.9.2-2 below show the Play and Prospect Risk derivation for the formations and prospects.

Table 5.5.9.2-1 – Play Risk Summary for Beetaloo Shales

Zone	Phase	Basin	Burial History	Organic Content	Play Risk	Comments
Upper Kyalla	Oil	100%	100%	80%	80%	No test from Upper Kyalla. Variable TOC/HI observed in wells.
Lower Kyalla	Oil	100%	100%	50%	50%	No test from Lower Kyalla and no insitu samples. Some shows.
	Gas	100%	100%	90%	90%	Gas tested in adjacent clayey-siltstone. Reasonable TOC/HI in most wells.
Middle Velkerri	Oil	100%	100%	80%	80%	No test from Middle Velkerri. Reasonable TOC/HI in one well at far north of basin area.
	Gas	100%	100%	100%	100%	Gas tested from Middle Velkerri.

Table 5.5.9.2-2 – Prospect Risk Summary for Beetaloo Shales

Prospect	Zone / Phase	Geochem	Mech.	Cont.	Prospect Risk	Play Risk	GPoS	Comments
Shenandoah (incl Jamison)	Upper Kyalla / Oil	100%	50%	100%	50%	80%	**40%**	No data on Mech. for all prospects below
Elliot		50%	50%	50%	12.5%		**10%**	Poor well up-dip of potentially good loc.
Burdo	Lower Kyalla / Oil	25%	50%	100%	12.5%	50%	**6.25%**	No TOCs etc in well
Ronald		25%	50%	100%	12.5%		**6.25%**	No TOCs etc in well
Chanin		25%	50%	100%	12.5%		**6.25%**	No TOCs etc in well
Shenandoah	Lower Kyalla / Gas	100%	50%	100%	50%	90%	**45%**	Reasonable TOCs etc
Jamison		100%	50%	100%	50%		**45%**	Reasonable TOCs etc
Elliot		50%	50%	50%	12.5%		**11.25%**	Poor well up-dip of potentially good loc.
Walton-McManus	Middle Velkerri / Oil	100%	50%	100%	50%	80%	**40%**	Reasonable TOCs etc
Shenandoah	Middle Velkerri / Gas	100%	50%	100%	50%	100%	**50%**	Reasonable TOCs etc
Jamison		80%	50%	80%	32%		**32%**	No data in M.V. but other zones good
Elliot		50%	50%	50%	12.5%		**12.5%**	Poor well up-dip of potentially good loc.

The Moroak and Bessie Creek sandstones are potential BCGA plays and have been risked using the more conventional approach of Source, Reservoir and Seal. Source and seal are more or less assured as they are inter-bedded with the Lower Kyalla and Middle Velkerri shales which have been assigned very high probabilities of being a working source rock for gas (see Table 5.5.9.1) and will also likely act as a seal relative to the sandstone porosity. The main remaining play risk is reservoir effectiveness since frac'ing is likely to be required and is untested. A natural flow test was attempted in the Moroak in the Shenandoah-1 well and was a failure. The presence of effective reservoir (even allowing for potential frac'ing success) is therefore no better than 50% which becomes the play risk for these potential BCGAs.

5.5.9.3 Summary of Resources

Basin Resource Potential – Prospective Resources (Play level)

Using the parameters described in Section 5.5.9.1 and the Play Risks described in Section 5.5.9.2, RPS has calculated the Prospective Resource potential for the Beetaloo Basin at the Play level as shown in Tables 5.5.9.3-1 to 5.5.9.3-3.

Table 5.5.9.3-1 – Prospective Shale Oil Resources (Play level) Summary for Beetaloo Basin

Resource Play	Potentially In-place				Potentially Recoverable			
	P90	P50	P10		Low Estimate	Best Estimate	High Estimate	Play risk
Unconventional Shale Oil (MMstb)								
Kyalla Upper	49,663	70,985	100,700		1,290	2,654	5,526	80%
Kyalla Lower	121,327	159,658	209,528		3,023	5,971	12,011	50%
Velkerri Middle	168,927	337,982	673,176		4,942	12,720	32,503	80%

Table 5.5.9.3-2 – Prospective Shale Gas Resources (Play level) Summary for Beetaloo Basin

Resource Play	Potentially In-place				Potentially Recoverable			
	P90	P50	P10		Low Estimate	Best Estimate	High Estimate	Play risk
Unconventional Shale Gas (Tcf)								
Kyalla Lower	31.47	52.26	86.97		21.83	37.29	63.81	90%
Velkerri Middle	65.012	104.22	166.77		45.09	74.50	122.78	100%

Table 5.5.9.3-3 – Prospective BCGA Resources (Play level) Summary for Beetaloo Basin

Resource Play	Potentially In-place				Potentially Recoverable			
	P90	P50	P10		Low Estimate	Best Estimate	High Estimate	Play risk
BCGA Gas (Tcf)								
Moroak Sst	1.36	8.26	51.24		0.95	5.90	36.72	50%
Bessie Creek Sst	35.22	62.31	107.03		24.58	44.31	78.48	50%

Prospective Resources – Areas centered around well penetrations (Prospect level)

RPS has assigned Prospective Resources (Prospect level) to three shale plays within the Beetaloo Basin, namely Unconventional Shale Oil in the Kyalla and Middle Velkerri Formations (above 1500m TVDSRD), and Unconventional Shale Gas in the lower most Kyalla and Middle Velkerri. No wells have yet proved the viability of the Moroak and Bessie Creek sandstones and these remain as Propsective Resource (Play level) potential (possibly BCGA in type) but no Prospective Resources (Prospect level) have been assigned at this time.

To calculate the potential volumes associated with the prospects, the same reservoir parameter ranges as were used for the regional Resource potential calculations (Section 5.5.9.1) with the exception of the area assigned to each prospect. As described above, each prospect is currently based on a single well with the exception of Upper Kyalla “Shenendoah” prospect which has been amalgamated with the three relatively close wells which all exhibit encouraging indications of potential prospectivity.

RPS has estimated, based on experience in similar types of play (mainly in the United States), an average Sweet Spot area of 10,240 acres (based on step-out increments of 640-1280 acres). To get a meaningful range of uncertainty, RPS has adopted a P90 area of 2560 acres and a P10 of 20,480 acres which gives an acceptable ratio between P10 and P90 for the stage of exploration that the Beetaloo Basin is at. This range is used for each prospect (single well data points) except the Upper Kyalla “Shenandoah” prospect as described above. This prospect is assessed as potentially having an area of 10,240 acres (P90) to 81,920 acres (P10). These areas were substituted into the REP™ runs prepared earlier for the Resource potential calculations and re-run to derive the potentially recoverable volumes of hydrocarbon associated with each prospect.

The total estimated range of Prospective Resources by play type is given in Tables 5.5.9.3-1 to 5.5.9.3-2 below. The Gross Prospective Resources are those allocated to each prospect on a 100% WI basis and the Net Attributable is the volume adjusted for WI and Royalties which would be attributable to Falcon in the event of success. The Prospective Resources are aggregated using RPS' standard presentation to show the statistically correct range of outcomes assuming all prospects are successfully discovered or assuming at least one prospect is successful taking into account the range of outcomes between the prospects and the appropriate chance of success (GPoS). It should be noted that it will take a number of wells to confirm the volume ranges quoted.

Table 5.5.9.3-1 – Prospective Shale Oil Resources (Prospect level) Summary for Beetaloo Basin

Prospect (WI=73%)	Gross				Net Attributable			
	Low Estimate	Best Estimate	High Estimate		Low Estimate	Best Estimate	High Estimate	GPoS
Unconventional Oil (MMstb)								
Shenandoah – Upper Kyalla	17.5	62.7	223.0		9.71	34.79	123.72	40%
Elliot – Upper Kyalla	4.4	15.7	55.8		2.44	8.71	30.96	10%
Burdo – Lower Kyalla	4.8	16.5	57.5		2.66	9.15	31.90	6.25%
Ronald – Lower Kyalla	4.8	16.5	57.5		2.66	9.15	31.90	6.25%
Chanin – Lower Kyalla	4.8	16.5	57.5		2.66	9.15	31.90	6.25%
Walton-McManus – Middle Velkerri	12.2	49.6	198.0		6.77	27.52	109.85	40%
Arithmetic Aggregation[1]	**48.5**	**177.5**	**649.3**		**26.91**	**98.48**	**360.23**	**<<1%**
Stochastic Aggregation[2]	**130.0**	**245.0**	**497.0**		**72.12**	**135.93**	**275.74**	**<<1%**
Stochastic Aggregation[3]	**14.2**	**69.4**	**253.0**		**7.88**	**38.50**	**140.36**	**73%**

1: Although commonly done, it is statistically incorrect to arithmetically sum probabilistic estimates of P90, P50 and P10. To do so tends to under-estimate the true P90 and over-estimate the true P10 of the combined distribution as seen when compared to the Statistical Aggregation in the next row. This is exacerbated by the introduction of GPoS into the statistical aggregation (see below).

2: Statistical Aggregation assuming that all prospects are successful. The probability of this occurring is the product of each individual risk (GPoS) and is therefore very small.

3: Statistical Aggregation assuming at least one prospect is successful. This total takes into account all possible successful outcomes and the mean value for the resultant distribution (**62.14** MMstb Net) constitutes the true expectation of success.

Table 5.5.9.3-2 – Prospective Shale Gas Resources (Prospect level) Summary for Beetaloo Basin

Prospect (WI=73%)	Gross				Net Attributable			
	Low Estimate	Best Estimate	High Estimate		Low Estimate	Best Estimate	High Estimate	Risk Factor
Unconventional Gas (Bcf)								
Shenandoah – Lower Kyalla	95.1	299.0	958.0		52.76	165.89	531.50	45%
Jamison – Lower Kyalla	95.1	299.0	958.0		52.76	165.89	531.50	45%
Elliot – Lower Kyalla	95.1	299.0	958.0		52.76	165.89	531.50	11.25%
Shenandoah – Middle Velkerri	90.5	281.0	889.0		50.21	155.90	493.22	50%
Jamison – Middle Velkerri	90.5	281.0	889.0		50.21	155.90	493.22	32%
Elliot –Middle Velkerri	90.5	281.0	889.0		50.21	155.90	493.22	12.5%
Arithmetic Aggregation[1]	**556.8**	**1740.0**	**5541.0**		**308.91**	**965.35**	**3074.15**	**<<1%**
Stochastic Aggregation[2]	**1400.0**	**2342.0**	**4015.0**		**776.72**	**1299.34**	**2227.52**	**<<1%**
Stochastic Aggregation[3]	**184.0**	**703.0**	**1878.0**		**102.08**	**390.02**	**1041.91**	**92%**

1: Although commonly done, it is statistically incorrect to arithmetically sum probabilistic estimates of P90, P50 and P10. To do so tends to under-estimate the true P90 and over-estimate the true P10 of the combined distribution as seen when compared to the Statistical Aggregation in the next row. This is exacerbated by the introduction of GPoS into the statistical aggregation (see below).

2: Statistical Aggregation assuming that all prospects are successful. The probability of this occurring is the product of each individual risk (GPoS) and is therefore very small.

3: Statistical Aggregation assuming at least one prospect is successful. This total takes into account all possible successful outcomes and the mean value for the resultant distribution (**504.31** Bcf Net) constitutes the true expectation of success.

References

1. Dutkiewicz, A., 2005, Precambrian Inclusion Oils in the Roper Group: a Review, Geodynamics of the Redbank package, McArthur Basin, Proceedings Central Australian Basins Symposium, p 326-348.
2. Law, B. et al, 2010, Source and Reservoir Rock Attributes of Mesoproterozoic Shale, Beetaloo Basin, Northern Territory, Australia, AAPG Annual Convention, New Orleans, La, April 11-14, 2010
3. Rawlings, D.J., 2005, Geodynamics of the Redbank package, McArthur Basin, Proceedings Central Australian Basins Symposium, p349-387.
4. Ryder-Scott, 2010,Evaluation of Unconventional Oil Resource Potential Pertaining ot Certain Acreage Interests in the Beetaloo Basin, Northern Territory, Australia
5. Silverman, M.R., et al; 2005, Proceedings Central Australian Basins Symposium, p. 201-215.

6. Silverman, M.R., 2010, Mesoproterozoic Unconventional Plays, Beetaloo Basin, Australia: The world's Oldest Petroleum Systems, AAPG International Conference, Calgary, September 14, 2010.

7. Thomasson Partner Associates, 2005, Hydrocarbon Potential of the Beetaloo Basin, Northern Territory, Australia; Proprietary Report for Sweetpea Corp, Ltd.Jarvie, D.M.; 2012, Components and Processes Affecting Producibility and Commerciality of Shale Oil Resource systems; HGS AGC Conference, 20-21 February 2012.

APPENDIX A - GLOSSARY OF TERMS AND ABBREVIATIONS

API	American Petroleum Institute
AUS$	Austrailian Dollar
B	Billion
bbl(s)	Barrels
bbls/d	barrels per day
Bcm	billion cubic metres
B_g	gas formation volume factor
B_o	oil formation volume factor
BTU	British Thermal Unit
Bscf	billions of standard cubic feet
Bwpd	barrels of water per day
CO_2	Carbon dioxide
DST	Drill stem test
EMV	Expected Monetary Value
EP	Exploration Permit
ft	Feet
ftSS	depth in feet below sea level
GDT	Gas Down To
GIP	Gas in Place
GIIP	Gas Initially in Place
GOR	gas/oil ratio
GRV	gross rock volume
GWC	gas water contact
H_2S	Hydrogen sulphide
HI	hydrogen index
IRR	internal rate of return
KB	Kelly Bushing
k	permeability
Km	Kilometres
Km^2	square kilometres
M	Thousand
MM	Million
M$	thousand US dollars
MM$	million US dollars
MD	measured depth
MDT	Modular (formation) dynamic tester
mD	permeability in millidarcies

m^3	cubic metres
m^3/d	cubic metres per day
MMscf/d	millions of standard cubic feet per day
m/s	metres per second
Msec	Milliseconds
NDE	No Deep Enough
NTG	net to gross ratio
NPV	Net Present Value
OWC	oil water contact
Petroleum	deposits of oil and/or gas
Phi	porosity fraction
PVT	pressure volume temperature
RFT	repeat formation tester
RKB	relative to kelly bushing
SCAL	Special Core Analysis
scf	standard cubic feet measured at 14.7 pounds per square inch and 60° F
sscf/d	standard cubic feet per day
sscf/stb	standard cubic feet per stock tank barrel
Sm^3	standard cubic metres
S_o	oil saturation
Stb	stock tank barrels measured at 14.7 pounds per square inch and 60° F
Stb/d	stock tank barrels per day
STOIIP	stock tank oil initially in place
S_w	water saturation
$	United States Dollars
Tcf	trillion cubic feet
TVDSRD	True vertical depth relative to seismic reference datum
TVDSS	true vertical depth (sub-sea)
TVT	true vertical thickness
TWT	two-way time
US$	United States Dollar
V_{sh}	shale volume
ϕ	porosity
μ	viscosity

APPENDIX B - SPE/WPC/AAPG/SPEE RESERVE/RESOURCE DEFINITIONS

The following is extracted from the SPE/WPC/AAPG/SPEE PRMS 2007 using the section numbering and spelling from PRMS.

1.0 Basic Principles and 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.

1.1 Petroleum Resources Classification Framework

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 B.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.

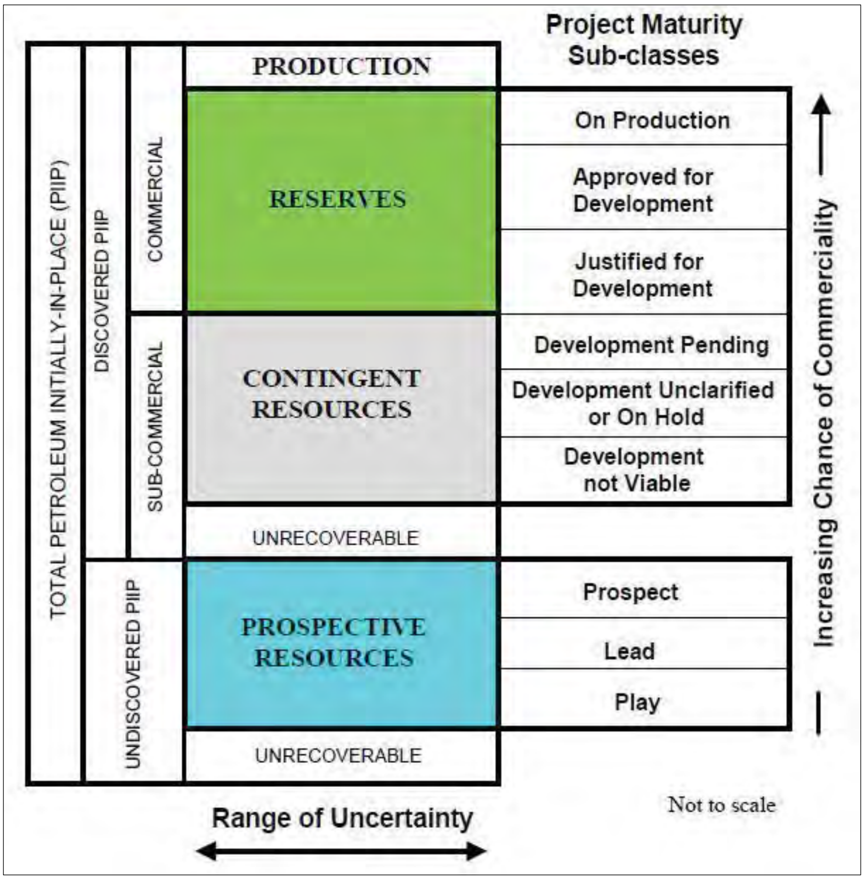


Figure B.1: Resources Classification Framework

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 Commerciality, that is, the chance that the project that will be developed and reach commercial producing status.

A further option for classification purposes is to subdivide Contingent Resource projects on the basis of economic status, into Marginal or Submarginal Contingent Resources. In addition, PRMS indicates that, where evaluations are incomplete such that it is premature to clearly define ultimate chance of commerciality, it is acceptable to note that project economic status is “undetermined.” As with the classification options for Reserves that are based on reserves status, this is an optional subdivision that may be used alone or in combination with project maturity subclasses. Broadly speaking, one might expect the following approximate relationships between the two optional approaches:

Project Maturity Subclass	Additional Sub-Classification	Economic Status
Development Pending	**Pending**	**Marginal Contingent Resources**
Development Unclarified or On Hold	**On Hold**	
	Unclarified	**Undetermined**
Development Not Viable	**Not Viable**	**Sub-marginal Contingent Resources**

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

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 is that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production.

PRODUCTION is the cumulative quantity of petroleum that has been recovered at a given date. While all recoverable resources are estimated and production is measured in terms of the sales product specifications, raw production (sales plus non-sales) quantities are also measured and required to support engineering analyses based on reservoir voidage.

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 are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must further satisfy four criteria: they must be discovered, recoverable, commercial, and remaining (as of the evaluation date) based on the development project(s) applied. Reserves are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by development and production status.

CONTINGENT RESOURCES are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, but the applied project(s) are not yet considered mature enough for commercial development due to one or more contingencies. Contingent Resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent Resources are further categorized in accordance with the level of certainty associated with the estimates and may be subclassified based on project maturity and/or characterized by their economic status.

UNDISCOVERED PETROLEUM INITIALLY-IN-PLACE is that quantity of petroleum estimated, as of a given date, to be contained within accumulations yet to be discovered.

PROSPECTIVE RESOURCES are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective Resources have both an associated chance of discovery and a chance of development. Prospective Resources are further subdivided in accordance with the level of certainty associated with recoverable estimates assuming their discovery and development and may be sub-classified based on project maturity.

UNRECOVERABLE is that portion of Discovered or Undiscovered Petroleum Initially-in-Place quantities which is estimated, as of a given date, not to be recoverable by future development projects. A portion of these quantities may become recoverable in the future as commercial circumstances change or technological developments occur; the remaining portion may never be recovered due to physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks.

Estimated Ultimate Recovery (EUR) is not a resources category, but a term that may be applied to any accumulation or group of accumulations (discovered or undiscovered) to define those quantities of petroleum estimated, as of a given date, to be potentially recoverable under defined technical and commercial conditions plus those quantities already produced (total of recoverable resources).

1.2 Project-Based Resources Evaluations

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

This concept of a project-based classification system is further clarified by examining the primary data sources contributing to an evaluation of net recoverable resources (see Figure A1-2) that may be described as follows:

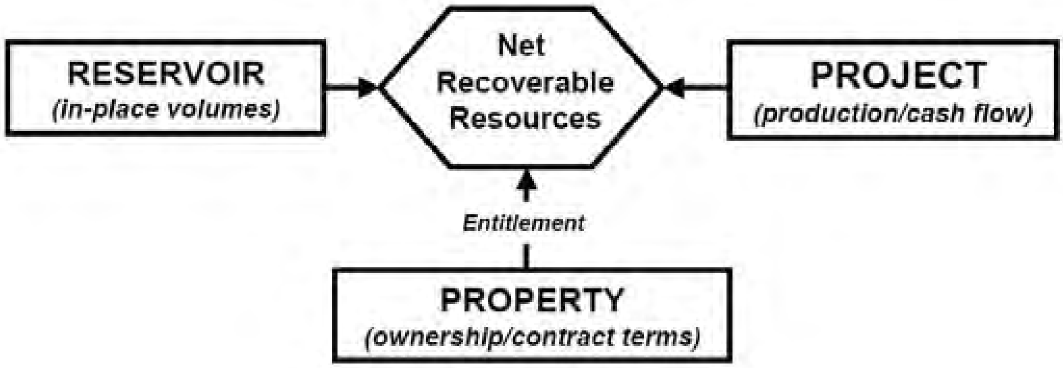


Figure B.2: Resources Evaluation Data Sources

- The Reservoir (accumulation): Key attributes include the types and quantities of Petroleum Initially-in-Place and the fluid and rock properties that affect petroleum recovery.
- The Project: Each project applied to a specific reservoir development generates a unique production and cash flow schedule. The time integration of these schedules taken to the project's technical, economic, or contractual limit defines the estimated recoverable resources and associated future net cash flow projections for each project. The ratio of EUR to Total Initially-in-Place quantities defines the ultimate recovery efficiency for the development project(s). A project may be defined at various levels and stages of maturity; it may include one or many wells and associated production and processing facilities. One project may develop many reservoirs, or many projects may be applied to one reservoir.

- The Property (lease or license area): Each property may have unique associated contractual rights and obligations including the fiscal terms. Such information allows definition of each participant's share of produced quantities (entitlement) and share of investments, expenses, and revenues for each recovery project and the reservoir to which it is applied. One property may encompass many reservoirs, or one reservoir may span several different properties. A property may contain both discovered and undiscovered accumulations.

In context of this data relationship, "project" is the primary element considered in this resources classification, and net recoverable resources are the incremental quantities derived from each project. Project represents the link between the petroleum accumulation and the decision-making process. A project may, for example, constitute the development of a single reservoir or field, or an incremental development for a producing field, or the integrated development of several fields and associated facilities with a common ownership. In general, an individual project will represent the level at which a decision is made whether or not to proceed (i.e., spend more money) and there should be an associated range of estimated recoverable quantities for that project.

An accumulation or potential accumulation of petroleum may be subject to several separate and distinct projects that are at different stages of exploration or development. Thus, an accumulation may have recoverable quantities in several resource classes simultaneously.

In order to assign recoverable resources of any class, a development plan needs to be defined consisting of one or more projects. Even for Prospective Resources, the estimates of recoverable quantities must be stated in terms of the sales products derived from a development program assuming successful discovery and commercial development. Given the major uncertainties involved at this early stage, the development program will not be of the detail expected in later stages of maturity. In most cases, recovery efficiency may be largely based on analogous projects. In-place quantities for which a feasible project cannot be defined using current, or reasonably forecast improvements in, technology are classified as Unrecoverable.

Not all technically feasible development plans will be commercial. The commercial viability of a development project is dependent on a forecast of the conditions that will exist during the time period encompassed by the project's activities. "Conditions" include technological, economic, legal, environmental, social, and governmental factors. While economic factors can be summarized as forecast costs and product prices, the underlying influences include, but are not limited to, market conditions, transportation and processing infrastructure, fiscal terms, and taxes.

The resource quantities being estimated are those volumes producible from a project as measured according to delivery specifications at the point of sale or custody transfer. The cumulative production from the evaluation date forward to cessation of production is the remaining recoverable quantity. The sum of the associated annual net cash flows yields the estimated future net revenue. When the cash flows are discounted according to a defined discount rate and time period, the summation of the discounted cash flows is termed net present value (NPV) of the project.

APPENDIX C – COMPUTER PROCESSED INTERPRETATIONS (CPI)

Figure C-1
Well ALTREE-2 – Velkerri Middle, CPI

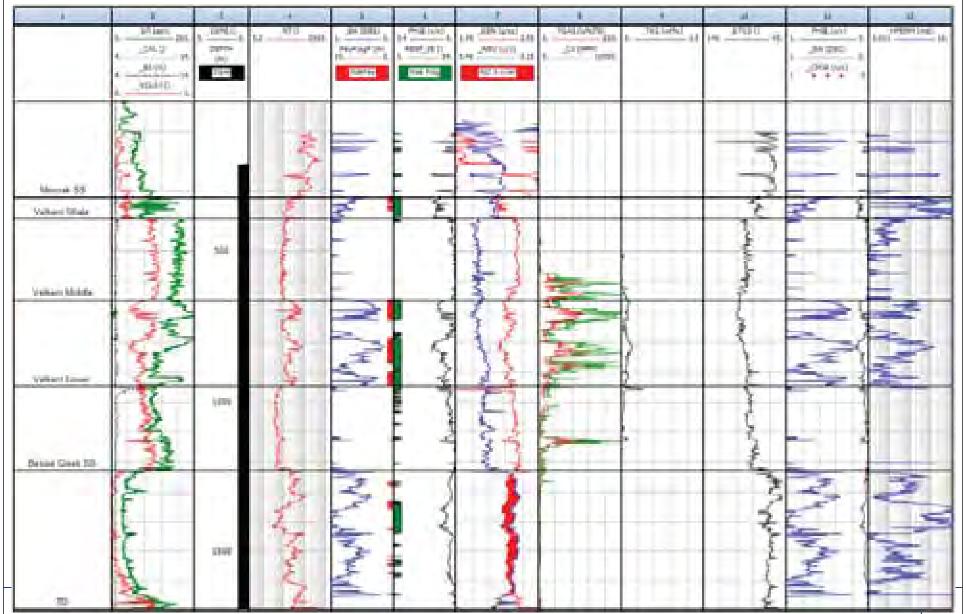


Figure C-2
Well ALTREE-2 – Velkerri Middle Summation

Petrophysical Zone Averages Report

Well : ALTREE 2
Date : 11/16/2012 10:15:10 AM

Reservoir Summary

Zn #	Zone Name	Top	Bottom	Gross	Net	N/G	Av Phi	Av Sw	Av Vcl Arl	Phi*H	PhiSo*H
1	Moroak SS	320.00	392.00	72.00	67.48	0.937	0.116	0.798	0.174	7.81	1.58
2	Velkerri Shale	392.00	662.00	270.00	11.48	0.043	0.060	0.846	0.411	0.69	0.11
3	Velkerri Middle	662.00	948.00	286.00	221.23	0.774	0.094	0.429	0.319	20.75	11.86
4	Velkerri Lower	948.00	1229.00	281.00	60.35	0.215	0.063	0.920	0.374	3.80	0.31
5	Bessie Creek SS	1229.00	1693.00	464.00	139.29	0.300	0.067	0.819	0.018	9.35	1.69
	All Zones	320.00	1693.00	1373.00	499.84	0.364	0.085	0.634	0.224	42.41	15.54

Pay Summary

Zn #	Zone Name	Top	Bottom	Gross	Net	N/G	Av Phi	Av Sw	Av Vcl Arl	Phi*H	PhiSo*H
1	Moroak SS	320.00	392.00	72.00	16.88	0.234	0.122	0.650	0.155	2.05	0.72
2	Velkerri Shale	392.00	662.00	270.00	1.37	0.005	0.070	0.638	0.342	0.10	0.03
3	Velkerri Middle	662.00	948.00	286.00	176.63	0.618	0.102	0.372	0.299	18.02	11.32
4	Velkerri Lower	948.00	1229.00	281.00	4.12	0.015	0.091	0.564	0.267	0.37	0.16
5	Bessie Creek SS	1229.00	1693.00	464.00	41.45	0.089	0.061	0.568	0.022	2.52	1.09
	All Zones	320.00	1693.00	1373.00	240.45	0.175	0.096	0.422	0.241	23.07	13.33

Cutoffs Used

Zn #	Zone Name	Top	Bottom	Min. Height	Phi _PHIE	Sw _Sw	Vcl _VCLAY
	Reservoir						
1	Moroak SS	320.00	392.00	0	>= 0.05		<= 0.5
2	Velkerri Shale	392.00	662.00	0	>= 0.05		<= 0.5
3	Velkerri Middle	662.00	948.00	0	>= 0.05		<= 0.5
4	Velkerri Lower	948.00	1229.00	0	>= 0.05		<= 0.5
5	Bessie Creek SS	1229.00	1693.00	0	>= 0.05		<= 0.5
	Pay						
1	Moroak SS	320.00	392.00	0	>= 0.05	<= 0.7	<= 0.5
2	Velkerri Shale	392.00	662.00	0	>= 0.05	<= 0.7	<= 0.5
3	Velkerri Middle	662.00	948.00	0	>= 0.05	<= 0.7	<= 0.5
4	Velkerri Lower	948.00	1229.00	0	>= 0.05	<= 0.7	<= 0.5
5	Bessie Creek SS	1229.00	1693.00	0	>= 0.05	<= 0.7	<= 0.5

Depth units : m

Figure C-2
Well BALMAIN-1 – Jamison SS & Kyalla Shale, CPI

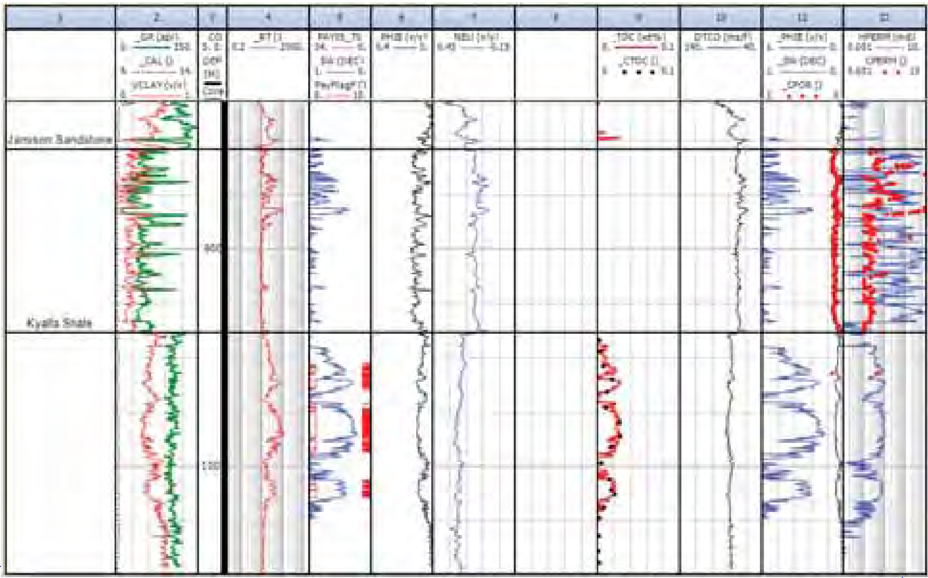


Figure C-4
Well BALMAIN-1 – Kyalla Shale Summation

Petrophysical Zone Averages Report

Well : BALMAIN 1
Date : 11/03/2012 21:26:02

Reservoir Summary

Zn #	Zone Name	Top	Bottom	Gross	Net	N/G	Av Phi	Av Sw	Av Vcl Ari	Phi*H	PhiSo*H
1	Kyalla Shale	938.50	1050.00	111.16	$$68.94	0.620	0.083	0.537	0.397	5.72	2.65
	All Zones	938.50	1050.00	111.15	$$68.94	0.620	0.083	0.537	0.397	5.72	2.65

Pay Summary

Zn #	Zone Name	Top	Bottom	Gross	Net	N/G	Av Phi	Av Sw	Av Vcl Ari	Phi*H	PhiSo*H
1	Kyalla Shale	938.50	1050.00	111.16	$$35.05	0.315	0.097	0.391	0.357	3.39	2.06
	All Zones	938.50	1050.00	111.15	$$35.05	0.315	0.097	0.391	0.357	3.39	2.06

Cutoffs used

Zn #	Zone Name	Top	Bottom	Min. Height	Phi _PHIE	Sw _SW	Vcl _VCLAY
	Reservoir						
1	Kyalla Shale	938.50	1050.00	0	>= 0.05		<= 0.5
	Pay						
1	Kyalla Shale	938.50	1050.00	0	>= 0.05	<= 0.55	<= 0.5

Depth Units : m
$$ indicates missing or null data in the zone.

Figure C-5
Well BURDO-1 – Kyalla SS and Kyalla Shale Lower CPI

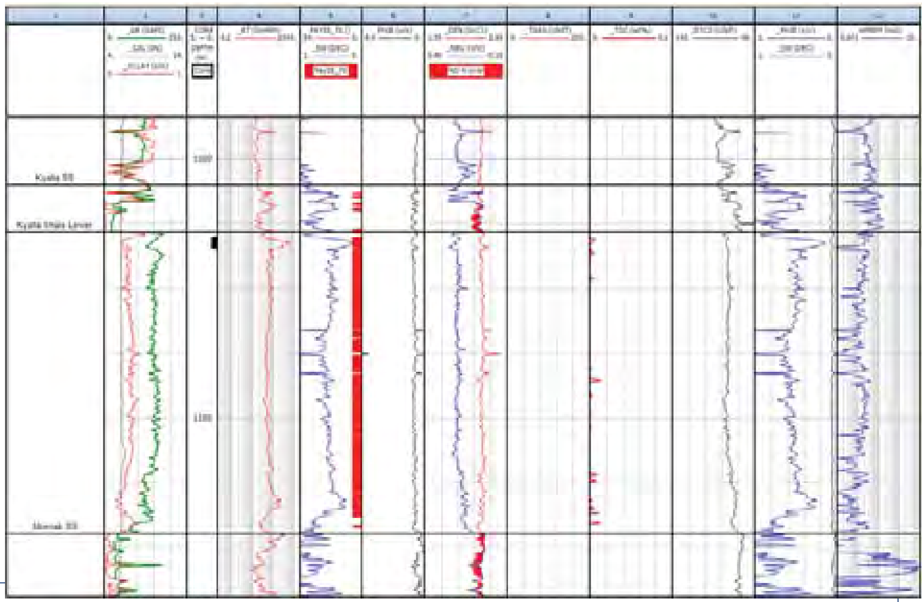


Figure C-6
Well BURDO-1 – Kyalla SS and Kyalla Shale Lower Summation

Petrophysical Zone Averages Report

Well : BURDO 1
Date : 11/7/2012 9:08:05 AM

Reservoir Summary

Zn #	Zone Name	Top	Bottom	Gross	Net	N/G	Av Phi	Av Sw	Av Vcl Arl	Phi*H	PhiSo*H
1	Kyalla SS	1010.10	1028.30	18.20	15.25	0.838	0.070	0.663	0.317	1.07	0.36
2	Kyalla Shale Lower	1028.30	1144.60	116.30	110.35	0.949	0.066	0.531	0.206	7.27	3.41
	All Zones	1010.10	1144.60	134.50	125.60	0.934	0.066	0.548	0.276	8.33	3.77

Pay Summary

Zn #	Zone Name	Top	Bottom	Gross	Net	N/G	Av Phi	Av Sw	Av Vcl Arl	Phi*H	PhiSo*H
1	Kyalla SS	1010.10	1028.30	18.20	8.35	0.459	0.068	0.339	0.338	0.57	0.26
2	Kyalla Shale Lower	1028.30	1144.60	116.30	103.45	0.890	0.066	0.515	0.295	6.85	3.32
	All Zones	1010.10	1144.60	134.50	111.80	0.831	0.066	0.517	0.285	7.43	3.58

Cutoffs Used

Zn #	Zone Name	Top	Bottom	Min. Height	Phi _PHIE	Sw _SW	Vcl _VCLAY
	Reservoir						
1	Kyalla SS	1010.10	1028.30	0	>= 0.05		<= 0.5
2	Kyalla Shale Lower	1028.30	1144.60	0	>= 0.05		<= 0.5
	Pay						
1	Kyalla SS	1010.10	1028.30	0	>= 0.05	<= 0.7	<= 0.5
2	Kyalla Shale Lower	1028.30	1144.60	0	>= 0.05	<= 0.7	<= 0.5

Depth Units : m

Figure C-7
Well CHANIN-1 – Kyalla Shale Lower SS CPI

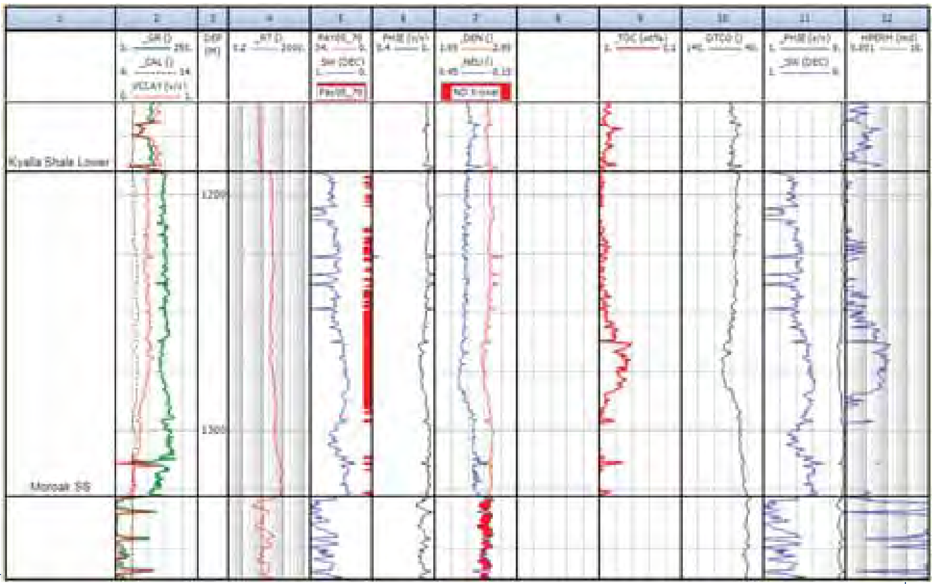


Figure C-8
Well CHANIN-1 – Kyalla Shale Lower Summation

Petrophysical Zone Averages Report

Well : CHANIN 1
Date : 11/03/2012 09:56:55

Reservoir Summary

Zn #	Zone Name	Top	Bottom	Gross	Net	N/G	Av Phi	Av Sw	Av Vcl Arl	Phi*H	PhiSo*H
1	Kyalla Shale Lower	1190.00	1328.00	138.00	70.00	0.507	0.068	0.497	0.363	4.74	2.38
	All Zones	1190.00	1328.00	138.00	70.00	0.507	0.068	0.497	0.363	4.74	2.38

Pay Summary

Zn #	Zone Name	Top	Bottom	Gross	Net	N/G	Av Phi	Av Sw	Av Vcl Arl	Phi*H	PhiSo*H
1	Kyalla Shale Lower	1190.00	1328.00	138.00	70.00	0.507	0.068	0.497	0.363	4.74	2.38
	All Zones	1190.00	1328.00	138.00	70.00	0.507	0.068	0.497	0.363	4.74	2.38

Cutoffs Used

Zn #	Zone Name	Top	Bottom	Min. Height	Phi _PHIE	Sw _SW	Vcl _VCLAY
	Reservoir						
1	Kyalla Shale Lower	1190.00	1328.00	0	>= 0.05		<= 0.5
	Pay						
1	Kyalla Shale Lower	1190.00	1328.00	0	>= 0.05	<= 0.7	<= 0.5

Depth Units : m

Figure C-9
Well ELLIOT-1 – Kyalla Shale Lower SS CPI

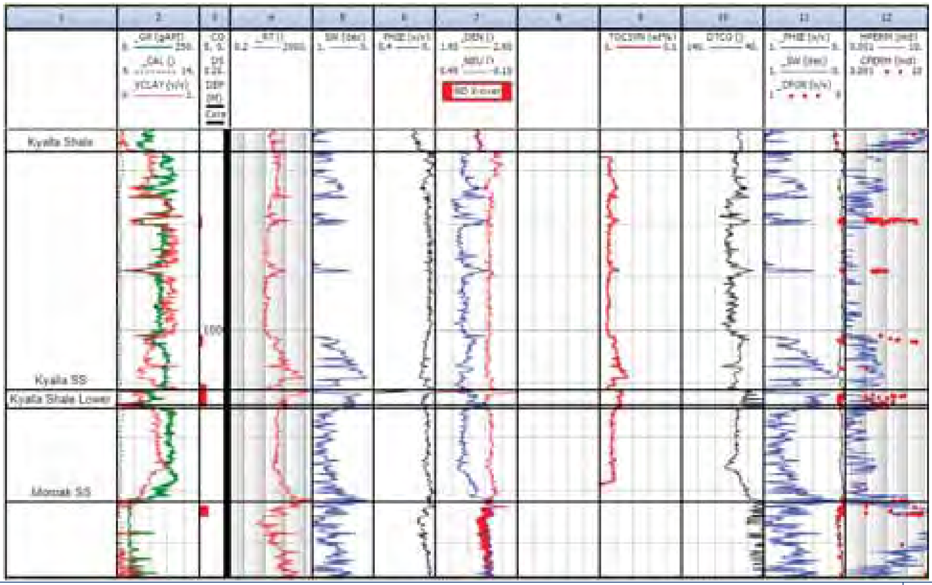


Figure C-10
Well JAMISON-1 – Kyalla Shale and Kyalla SS CPI

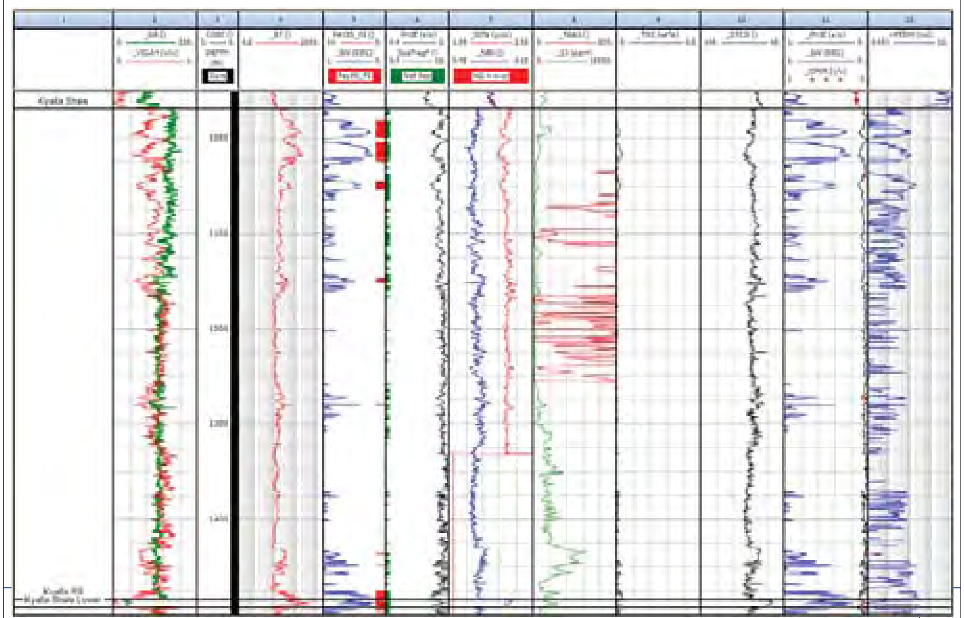


Figure C-11
Well JAMISON-1 – Kyalla Shale Lower CPI

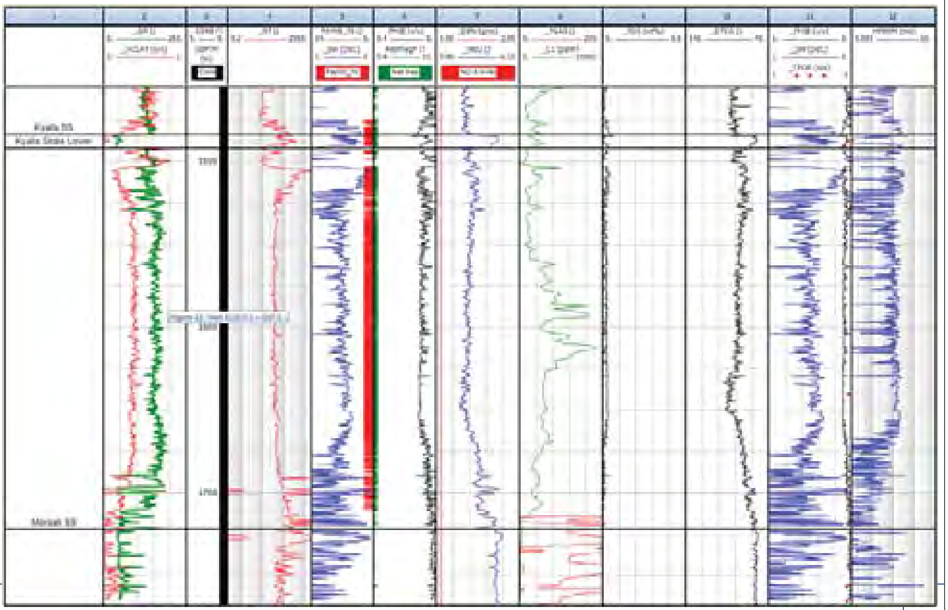


Figure C-12
Well JAMISON-1 – Kyalla Summation

Petrophysical Zone Averages Report

Well : JAMISON 1
Date : 11/15/2012 16:16:43

Reservoir Summary

Zn #	Zone Name	Top	Bottom	Gross	Net	N/G	Av Phi	Av Sw	Av Vcl Arl	Phi*H	PhiSo*H
1	Kyalla Shale	968.90	1483.90	515.00	150.48	0.292	0.075	0.675	0.391	11.35	3.69
2	Kyalla SS	1483.90	1492.10	8.20	6.80	0.829	0.087	0.494	0.012	0.59	0.31
3	Kyalla Shale Lower	1492.10	1722.00	229.90	182.12	0.792	0.091	0.457	0.329	16.49	8.96
4	Moroak SS	1722.00	1769.00	47.00	$$0.76	0.016	0.055	0.432	0.002	0.04	0.02
	All Zones	968.90	1769.00	800.10	$$340.16	0.425	0.084	0.544	0.349	28.48	12.98

Pay Summary

Zn #	Zone Name	Top	Bottom	Gross	Net	N/G	Av Phi	Av Sw	Av Vcl Arl	Phi*H	PhiSo*H
1	Kyalla Shale	968.90	1483.90	515.00	63.30	0.123	0.088	0.444	0.344	5.54	3.08
2	Kyalla SS	1483.90	1492.10	8.20	5.12	0.625	0.085	0.360	0.011	0.44	0.28
3	Kyalla Shale Lower	1492.10	1722.00	229.90	175.87	0.765	0.092	0.449	0.327	16.13	8.88
4	Moroak SS	1722.00	1769.00	47.00	$$0.76	0.016	0.055	0.432	0.002	0.04	0.02
	All Zones	968.90	1769.00	800.10	$$245.06	0.306	0.090	0.446	0.324	22.14	12.26

Cutoffs Used

Zn #	Zone Name	Top	Bottom	Min. Height	Phi _PHIE	Sw _SW	Vcl _VCLAY
	Reservoir						
1	Kyalla Shale	968.90	1483.90	0	>= 0.05		<= 0.5
2	Kyalla SS	1483.90	1492.10	0	>= 0.05		<= 0.5
3	Kyalla Shale Lower	1492.10	1722.00	0	>= 0.05		<= 0.5
4	Moroak SS	1722.00	1769.00	0	>= 0.05		<= 0.5
	Pay						
1	Kyalla Shale	968.90	1483.90	0	>= 0.05	<= 0.7	<= 0.5
2	Kyalla SS	1483.90	1492.10	0	>= 0.05	<= 0.7	<= 0.5
3	Kyalla Shale Lower	1492.10	1722.00	0	>= 0.05	<= 0.7	<= 0.5
4	Moroak SS	1722.00	1769.00	0	>= 0.05	<= 0.7	<= 0.5

Depth units : m
$$ indicates missing or null data in the zone.]

Figure C-13
Well MASON-1 – Kyalla Shale CPI

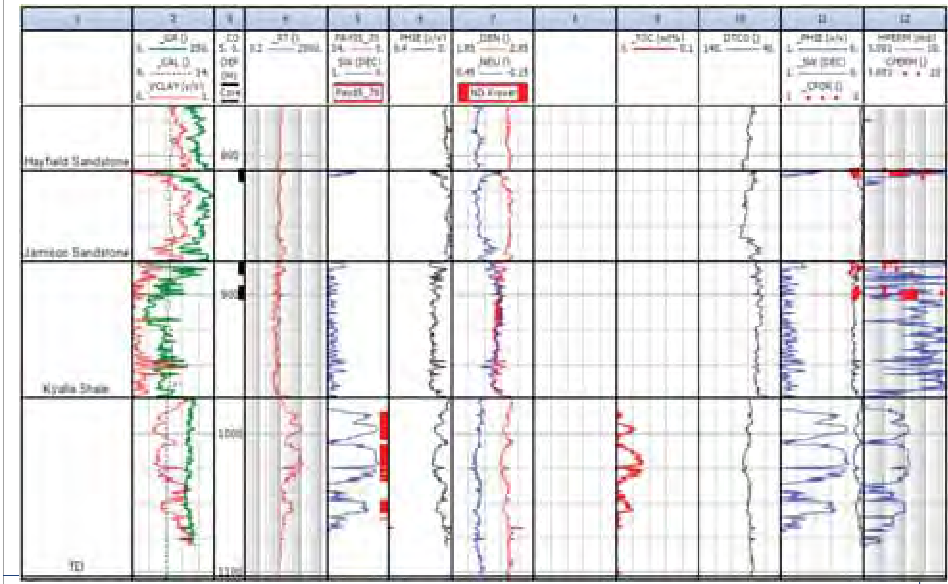


Figure C-14
Well MASON-1 – Kyalla Shale Summation

Petrophysical Zone Averages Report

Well : MASON 1
Date : 11/03/2012 13:23:03

Reservoir Summary

Zn #	Zone Name	Top	Bottom	Gross	Net	N/G	Av Phi	Av Sw	Av Vcl Ari	Phi*H	PhiSo*H
1	Kyalla Shale	974.00	1103.00	129.00	$$59.74	0.463	0.090	0.360	0.355	5.37	3.44
	All Zones	974.00	1103.00	129.00	$$59.74	0.463	0.090	0.360	0.355	5.37	3.44

Pay Summary

Zn #	Zone Name	Top	Bottom	Gross	Net	N/G	Av Phi	Av Sw	Av Vcl Ari	Phi*H	PhiSo*H
1	Kyalla Shale	974.00	1103.00	129.00	$$56.24	0.436	0.092	0.346	0.348	5.17	3.38
	All Zones	974.00	1103.00	129.00	$$56.24	0.436	0.092	0.346	0.348	5.17	3.38

Cutoffs Used

Zn #	Zone Name	Top	Bottom	Min. Height	Phi _PHIE	Sw _SW	Vcl _VCLAY
	Reservoir						
1	Kyalla Shale	974.00	1103.00	0	>= 0.05		<= 0.5
	Pay						
1	Kyalla Shale	974.00	1103.00	0	>= 0.05	<= 0.7	<= 0.5

Depth Units : m
$$ indicates missing or null data in the zone.

Figure C-15
Well MCMANUS-1 – Kyalla Shale CPI

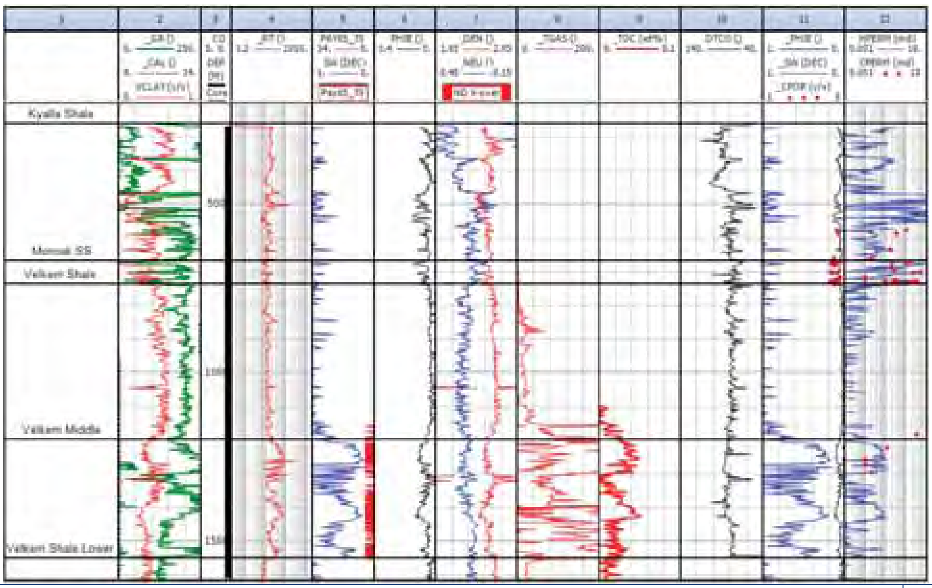


Figure C-16
Well MCMANUS-1 – Kyalla Shale Summation

Petrophysical Zone Averages Report

Well : MCMANUS 1
Date : 11/03/2012 18:50:00

Reservoir Summary

Zn #	Zone Name	Top	Bottom	Gross	Net	N/G	Av Phi	Av Sw	Av Vcl Ari	Phi*H	PhiSo*H
1	Velkerri Middle	1199.00	1550.00	351.00	268.54	0.765	0.085	0.399	0.336	22.81	13.72
	All Zones	1199.00	1550.00	351.00	268.54	0.765	0.085	0.399	0.336	22.81	13.72

Pay Summary

Zn #	Zone Name	Top	Bottom	Gross	Net	N/G	Av Phi	Av Sw	Av Vcl Ari	Phi*H	PhiSo*H
1	Velkerri Middle	1199.00	1550.00	351.00	245.08	0.698	0.088	0.375	0.331	21.44	13.41
	All Zones	1199.00	1550.00	351.00	245.07	0.698	0.088	0.375	0.331	21.44	13.41

Cutoffs Used

Zn #	Zone Name	Top	Bottom	Min. Height	Phi _PHIE	Sw _SW	Vcl _VCLAY
	Reservoir						
1	Velkerri Middle	1199.00	1550.00	0	>= 0.05		<= 0.5
	Pay						
1	Velkerri Middle	1199.00	1550.00	0	>= 0.05	<= 0.7	<= 0.5

Depth units : m

Figure C-17
Well RONALD-1 – Kyalla Shale Lower CPI

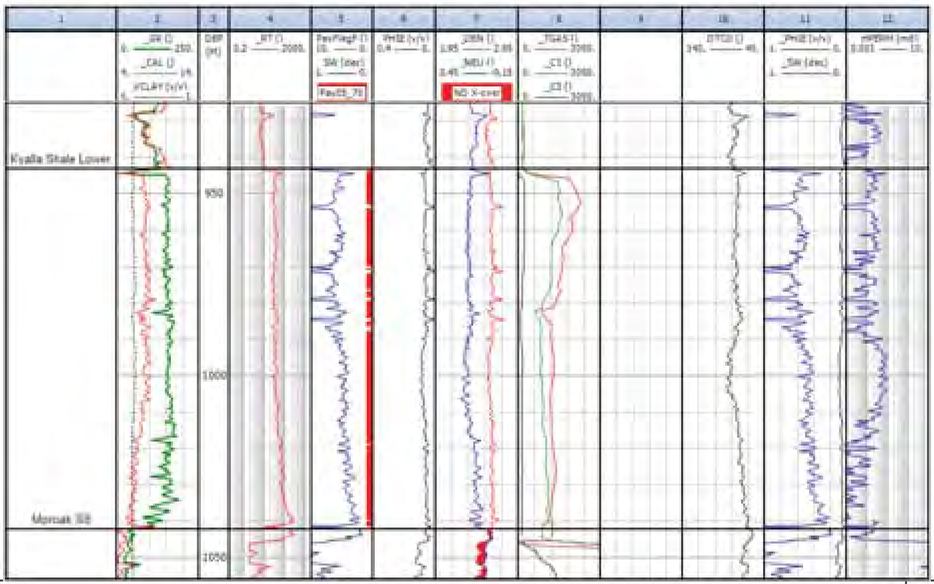


Figure C-18
Well RONALD-1 – Kyalla Shale Lower Summation

Petrophysical Zone Averages Report

Well : RONALD 1
Date : 11/03/2012 19:34:21

Reservoir Summary

Zn #	Zone Name	Top	Bottom	Gross	Net	N/G	Av Phi	Av Sw	Av Vcl Ari	Phi*H	PhiSo*H
1	Kyalla Shale Lower	943.20	1042.00	98.80	90.64	0.917	0.068	0.505	0.304	6.16	3.05
	All Zones	943.20	1042.00	98.80	90.64	0.917	0.068	0.505	0.304	6.16	3.05

Pay Summary

Zn #	Zone Name	Top	Bottom	Gross	Net	N/G	Av Phi	Av Sw	Av Vcl Ari	Phi*H	PhiSo*H
1	Kyalla Shale Lower	943.20	1042.00	98.80	87.44	0.885	0.068	0.498	0.301	5.99	3.00
	All Zones	943.20	1042.00	98.80	87.44	0.885	0.068	0.498	0.301	5.99	3.00

Cutoffs Used

Zn #	Zone Name	Top	Bottom	Min. Height	Phi _PHIE	Sw _Sw	Vcl _VCLAY
	Reservoir						
1	Kyalla Shale Lower	943.20	1042.00	0	>= 0.05		<= 0.5
	Pay						
1	Kyalla Shale Lower	943.20	1042.00	0	>= 0.05	<= 0.7	<= 0.5

Depth units : m

Figure C-19
Well SHENANDOAH-1 – CPI

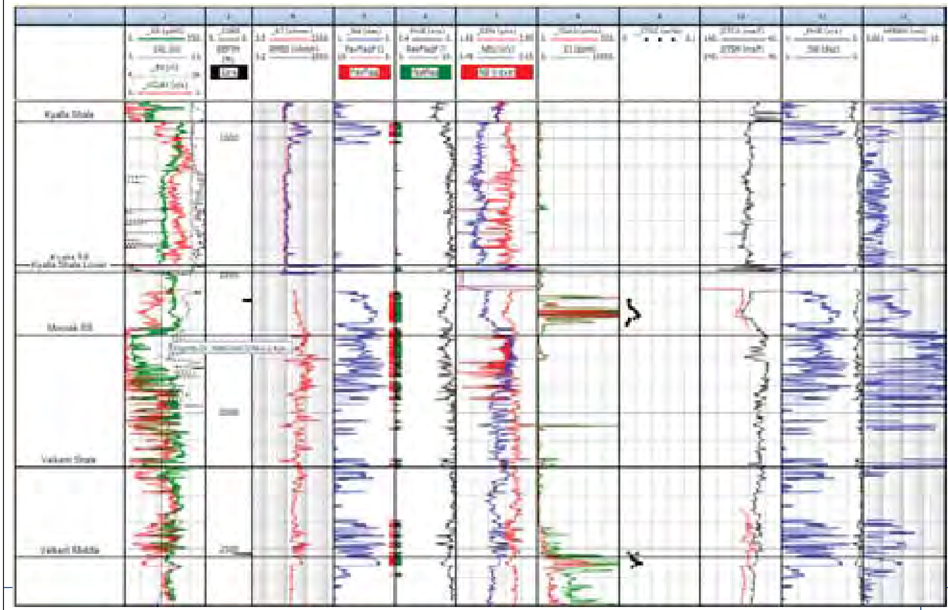


Figure C-20
Well RONALD-1 – SHENANDOAH-1 Summation

Petrophysical Zone Averages Report

Well : SHENANDOAH 1
Date : 11/16/2012 9:14:17 AM

Reservoir Summary

Zn #	Zone Name	Top	Bottom	Gross	Net	N/G	Av Phi	Av Sw	Av Vcl Arl	Phi*H	PhiSo*H
1	Kyalla Shale	938.00	1464.00	526.00	50.57	0.096	0.080	0.501	0.426	4.02	2.01
2	Kyalla SS	1464.00	1487.40	23.40	$$12.98	0.555	0.083	0.954	0.069	1.08	0.05
3	Kyalla Shale Lower	1487.40	1718.00	230.60	$$102.94	0.446	0.076	0.405	0.267	7.87	4.68
4	Moroak SS	1718.00	2200.00	482.00	186.16	0.386	0.079	0.532	0.057	14.68	6.87
5	Velkerri Shale	2200.00	2529.00	329.00	58.37	0.177	0.069	0.344	0.238	4.01	2.63
6	Velkerri Middle	2529.00	2714.00	185.00	$$33.99	0.184	0.074	0.345	0.296	2.53	1.65
	All Zones	938.00	2714.00	1776.00	$$445.01	0.251	0.077	0.476	0.190	34.19	17.90

Pay Summary

Zn #	Zone Name	Top	Bottom	Gross	Net	N/G	Av Phi	Av Sw	Av Vcl Arl	Phi*H	PhiSo*H
1	Kyalla Shale	938.00	1464.00	526.00	37.46	0.071	0.083	0.383	0.414	3.12	1.93
2	Kyalla SS	1464.00	1487.40	23.40	$$0.64	0.027	0.078	0.304	0.023	0.05	0.03
3	Kyalla Shale Lower	1487.40	1718.00	230.60	$$102.33	0.444	0.076	0.401	0.267	7.81	4.68
4	Moroak SS	1718.00	2200.00	482.00	143.68	0.298	0.080	0.442	0.041	11.55	6.44
5	Velkerri Shale	2200.00	2529.00	329.00	57.91	0.176	0.069	0.341	0.237	3.99	2.63
6	Velkerri Middle	2529.00	2714.00	185.00	$$30.02	0.162	0.077	0.308	0.271	2.32	1.60
	All Zones	938.00	2714.00	1776.00	$$372.01	0.209	0.078	0.400	0.190	28.84	17.31

Cutoffs Used

Zn #	Zone Name	Top	Bottom	Min. Height	Phi _PHIE	Sw _SW	Vcl _VCLAY
	Reservoir						
1	Kyalla Shale	938.00	1464.00	0	>= 0.05		<= 0.5
2	Kyalla SS	1464.00	1487.40	0	>= 0.05		<= 0.5
3	Kyalla Shale Lower	1487.40	1718.00	0	>= 0.05		<= 0.5
4	Moroak SS	1718.00	2200.00	0	>= 0.05		<= 0.5
5	Velkerri Shale	2200.00	2529.00	0	>= 0.05		<= 0.5
6	Velkerri Middle	2529.00	2714.00	0	>= 0.05		<= 0.5
	Pay						
1	Kyalla Shale	938.00	1464.00	0	>= 0.05	<= 0.7	<= 0.5
2	Kyalla SS	1464.00	1487.40	0	>= 0.05	<= 0.7	<= 0.5
3	Kyalla Shale Lower	1487.40	1718.00	0	>= 0.05	<= 0.7	<= 0.5
4	Moroak SS	1718.00	2200.00	0	>= 0.05	<= 0.7	<= 0.5
5	Velkerri Shale	2200.00	2529.00	0	>= 0.05	<= 0.7	<= 0.5
6	Velkerri Middle	2529.00	2714.00	0	>= 0.05	<= 0.7	<= 0.5

Depth units : m
$$ indicates missing or null data in the zone.

Figure C-21
Well WALTON-1 – Kyalla Shale CPI

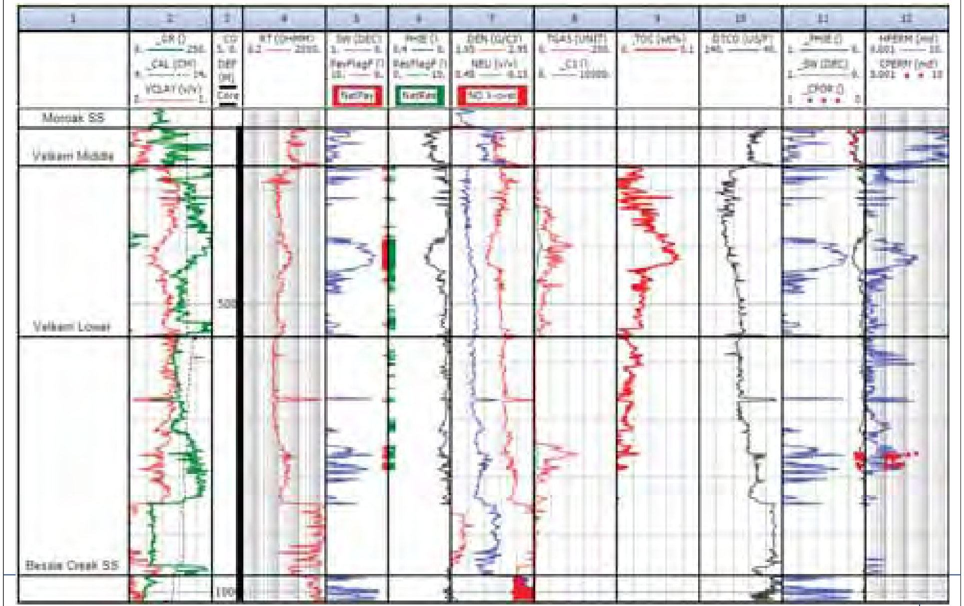


Figure C-22
Well WALTON-2 – Summation

Petrophysical Zone Averages Report

Well : WALTON 2
Date : 11/16/2012 11:54:34

Reservoir Summary

Zn #	Zone Name	Top	Bottom	Gross	Net	N/G	Av Phi	Av Sw	Av Vcl Arl	Phi*H	PhiSo*H
1	Velkerri Middle	260.00	556.00	296.00	98.10	0.331	0.103	0.503	0.359	10.13	5.04
2	Velkerri Lower	556.00	971.00	415.00	54.55	0.131	0.069	0.746	0.317	3.77	0.96
3	Bessie Creek SS	971.00	1033.00	46.95	$$0.40	0.009	0.061	0.104	0.053	0.02	0.02
	All Zones	260.00	1033.00	757.95	$$153.05	0.202	0.091	0.568	0.343	13.93	6.02

Pay Summary

Zn #	Zone Name	Top	Bottom	Gross	Net	N/G	Av Phi	Av Sw	Av Vcl Arl	Phi*H	PhiSo*H
1	Velkerri Middle	260.00	556.00	296.00	67.85	0.229	0.118	0.404	0.344	8.01	4.78
2	Velkerri Lower	556.00	971.00	415.00	22.15	0.053	0.075	0.489	0.258	1.66	0.85
3	Bessie Creek SS	971.00	1033.00	46.95	$$0.40	0.009	0.061	0.104	0.053	0.02	0.02
	All Zones	260.00	1033.00	757.95	$$90.40	0.119	0.107	0.418	0.321	9.70	5.65

Cutoffs Used

Zn #	Zone Name	Top	Bottom	Min. Height	Phi _PHIE	Sw _SW	Vcl _VCLAY
	Reservoir						
1	Velkerri Middle	260.00	556.00	0	>= 0.05		<= 0.5
2	Velkerri Lower	556.00	971.00	0	>= 0.05		<= 0.5
3	Bessie Creek SS	971.00	1033.00	0	>= 0.05		<= 0.5
	Pay						
1	Velkerri Middle	260.00	556.00	0	>= 0.05	<= 0.7	<= 0.5
2	Velkerri Lower	556.00	971.00	0	>= 0.05	<= 0.7	<= 0.5
3	Bessie Creek SS	971.00	1033.00	0	>= 0.05	<= 0.7	<= 0.5

Depth units : m
$$ indicates missing or null data in the zone.

APPENDIX D – RPS INPUT PARAMETERS FOR VOLUMETRICS

Beetaloo - RPS Input parameters for volumetrics

	Area (acres)			PAY	PHIE	SW	SoPHIEH	Comments
	P10	P50	P90	(m)	(v/v)	(v/v)	(m)	
Kyalla Upper (Oil)	1,377,987		1,092,505					650 m isopach contour to estimate P90. P10 to 600 m isopach contour to include Elliott Potential
Balmain-1				35.05	0.097	0.391	2.06	Partial penetration. Mayority of the Pay included
Jamison-1				63.3	0.088	0.444	3.08	
Mason-1				56.4	0.092	0.346	3.38	Partial penetration. Mayority of the Pay included
Shenandoah-1				37.46	0.083	0.383	1.93	
				48.05	**0.09**	**0.391**	**2.61**	
Kyalla Lower (Oil)	3,136,820		2,195,775					P90 1500 meter contourn shalower (CHECK). P90 = P10*0.7
Chenin-1				70	0.068	0.497	2.38	
Burdo-1				103.45	0.066	0.515	3.32	
Ronald-1				87.44	0.068	0.498	3	
				86.96333	**0.067333**	**0.503333**	**2.9**	
Velkerri Middle (Oil)	2,218,598		1,553,019					P90 = P10*0.7. Excludes area outside concession boundary
Altree-2				176.63	0.102	0.372	11.32	PAY concentrated in three bodies
McManus-1				245.08	0.088	0.375	13.41	PAY concentrated
Walton-2				67.85	0.118	0.404	4.78	PAY concentrated in lower half interval
				163.1867	**0.102667**	**0.383667**	**9.836667**	
Kyalla Lower (Gas)	1,082,942		758,063					P90 = P10*0.7
Jamison-1				175.8	0.092	0.449	8.88	
Shenandoah-1				102.33	0.076	0.401	4.68	PAY concentrated in lower 2/3
				139.065	**0.084**	**0.425**	**6.78**	
Velkerri Middle (Gas)	2,298,607		1,609,026					P90 = 800m isopach contour
Shenandoah-1				30.02	0.077	0.308	1.6	Partial penetration. PAY concentrated in top of the Velkerri Lower
				30.02	**0.077**	**0.308**	**1.6**	
Moroak SS (Tight Gas)	339,071		237,350					P90 = Jamison-1 and take 70%
Shenandoah-1				143.64	0.08	0.442	6.44	Tested 1728-1780m, 1837-1870m. No stimulated, no flow. Very low permeability.
Jamison-1				0				Partial penetration.
Chanin-1				0		High		High Sw
				143.64	**0.08**	**0.442**	**6.44**	
Bessie Creek SS (Tight Gas)	2,298,607		1,609,026					P90 = P10*0.7. P10 same as the Velkerri Middle
Altree-2				41.45	0.061	0.568	1.09	PAY concentrated mostly in the middle of the interval.In the oil window. No gas penetration
Walton-2				0				Partial penetration. PAY not observed. Very low porosity and permeability
				41.45	**0.061**	**0.568**	**1.09**	

Only wells with Pay observed are included in this table

APPENDIX E – QUALIFICATIONS

Andy Kirchin is the Executive Vice President in charge of RPS' Houston upstream consulting services. RPS has brought Andy over to Houston to help grow the U.S. consulting business and help facilitate an effective exchange of skill-sets between RPS' various international offices. Before moving to the U.S. Andy was the operational director in charge of RPS' City of London office which provides integrated geoscience, engineering and commercial analysis of oil and gas properties internationally. He has more than 25 years of industry experience and, as one of the Principal consultants at RPS Energy, Andy has conducted numerous Expert roles both in Unitisation / Redetermination disputes and in the Valuations / Certification area providing technical advice and Competent Person Reporting to the City of London, both on AIM and full LSE. Andy has worked on projects in most of the world's hydrocarbon provinces on both conventional and unconventional plays. He is a geophysicist by background but has a broad experience in dealing with the techno-commercial aspects of upstream sector.

PART V

FINANCIAL INFORMATION ON THE GROUP

Interim Financial Information

The interim financial information relating to the Group for the nine month period ended 30 September 2012 has been extracted without adjustment from the published unaudited interim condensed consolidated financial statements of the Group for the nine month period ended 30 September 2012. The interim financial information for the Group for nine month period ended 30 September 2012 has been prepared in accordance with IFRS.

Historical Annual Financial Information

The consolidated financial information relating to the Group for the 12 month period ended 31 December 2011, 31 December 2010, and 31 December 2009 has been extracted without adjustment from the published audited consolidated financial statements of the Group for the 12 month period ended 31 December 2011, 31 December 2010 and 31 December 2009.

The consolidated financial information for the Group for the 12 month period ended 31 December 2011 has been prepared in accordance with IFRS, and within the 2011 report the consolidated financial information for the Group for the 12 month period ended 31 December 2010 has been restated to show the Group's financial performance and its financial position as at that date, presented under IFRS.

The consolidated financial information for the Group for the 12 month period ended 31 December 2010 has been prepared in accordance with Canadian GAAP.

The consolidated financial information for the Group for the 12 month period ended 31 December 2009 has been prepared in accordance with Canadian GAAP.

The consolidated financial information relating to the Group has been reproduced in this document so as to provide the information required under the AIM Rules and ESM Rules and to ensure that Shareholders and others are aware of all information which, according to the particular nature of the Group and the Common Shares, is necessary to enable Shareholders and others to make an informed assessment of the assets and liabilities, financial position, profit and losses and prospects of the Group.

FALCON OIL & GAS LTD.

Interim Condensed Consolidated Financial Statements

Three and Nine Months Ended September 30, 2012 and 2011

(Presented in U.S. Dollars)

FALCON OIL & GAS LTD.
Interim Condensed Consolidated Statements of Financial Position
(Unaudited)

(thousands of US dollars)	September 30, 2012	December 31, 2011
Assets		
Current assets:		
Cash and cash equivalents	$ 5,554	$ 15,358
Restricted cash	319	51
Accounts receivable	516	1,602
Prepaid expenses and other	357	330
Inventory held for sale	483	628
Total current assets	7,229	17,969
Non-current assets:		
Exploration and evaluation costs (Note 6)	72,209	70,977
Property, plant and equipment	5,141	5,224
Other assets	934	731
Total non-current assets	78,284	76,932
Total assets	$ 85,513	$ 94,901
Liabilities		
Current liabilities:		
Accounts payable and accrued liabilities	$ 2,303	$ 3,836
Decommissioning provision (Note 12)	130	150
Convertible debentures (Note 9)	8,102	-
Derivative liabilities (Note 10)	253	-
Total current liabilities	10,788	3,986
Non-current liabilities:		
Convertible debentures (Note 9)	-	5,960
Derivative liabilities (Note 10)	7,229	3,314
Decommissioning provision (Note 12)	8,863	8,663
Total non-current liabilities	16,092	17,937
Total liabilities	26,880	21,923
Equity		
Share capital (Note 7)	339,171	339,006
Contributed surplus	41,785	39,654
Deficit	(333,291)	(316,838)
Equity attributable to common shareholders	47,665	61,822
Non-controlling interest	10,968	11,156
Total equity	58,633	72,978
Total liabilities and equity	$ 85,513	$ 94,901

The notes are an integral part of these condensed consolidated financial statements.

FALCON OIL & GAS LTD.
Interim Condensed Consolidated Statements of Operations and Comprehensive Loss
(Unaudited)

	Three Months Ended, September 30,		Nine Months Ended September 30,	
(thousands of US dollars)	2012	2011	2012	2011
Revenue:				
Oil and natural gas revenue	$ 1	$ 7	$ 12	$ 24
Other income	-	80	238	360
	1	87	250	384
Expenses:				
Exploration and evaluation expenses	447	240	1,561	938
Production and operating expenses	18	6	30	25
Depletion, depreciation and amortization	57	129	295	307
General and administrative expenses	1,670	2,394	4,917	5,974
Share based compensation (Note 11)	763	430	2,204	1,994
Restructuring expense (Note 14)	62	-	674	-
Other expense	40	-	40	-
Reversal of litigation expense	-	-	-	(1,654)
	3,057	3,199	9,721	7,584
Results from operating activities	(3,056)	(3,112)	(9,471)	(7,200)
Finance income (Note 4)	15	3,050	53	4,094
Finance expenses (Note 4)	(5,877)	(697)	(7,223)	(2,360)
Net finance (expenses) income	(5,862)	2,353	(7,170)	1,734
Net loss and comprehensive loss for the period	$ (8,918)	$ (759)	$(16,641)	$ (5,466)
Net loss and comprehensive loss attributable to:				
Common shareholders	$ (8,891)	$ (645)	$(16,453)	$ (5,253)
Non-controlling interest	(27)	(114)	(188)	(213)
Net loss and comprehensive loss for the period	$ (8,918)	$ (759)	$(16,641)	$ (5,466)
Net loss per share attributable to common shareholders:				
Basic and diluted (Note 8)	$ (0.013)	$ (0.001)	$ (0.024)	$ (0.008)

The notes are an integral part of these condensed consolidated financial statements.

FALCON OIL & GAS LTD.
Interim Condensed Consolidated Statements of Changes in Equity
(Unaudited)

(thousands of US dollars)	Share capital	Contributed surplus	Deficit	Equity attributable to common shareholders	Non-controlling interest	Total equity
Balance at January 1, 2011	$ 331,215	$ 37,874	$ (282,277)	$ 86,812	$ 11,422	$ 98,234
Private placement of stock	6,924	–	–	6,924	–	6,924
Issuance of stock	648	(648)	–	–	–	–
Options exercised	15	(7)	–	8	–	8
Share based compensation	–	1,994	–	1,994	–	1,994
Stock bonus	–	107	–	107	–	107
Net loss for the period	–	–	(5,253)	(5,253)	(213)	(5,466)
Balance at September 30, 2011	$ 338,802	$ 39,320	$ (287,530)	$ 90,592	$ 11,209	$ 101,801
Balance at January 1, 2012	$ 339,006	$ 39,654	$ (316,838)	$ 61,822	$ 11,156	$ 72,978
Options exercised	165	(73)	–	92	–	92
Share based compensation	–	2,204	–	2,204	–	2,204
Net loss for the period	–	–	(16,453)	(16,453)	(188)	(16,641)
Balance at September 30, 2012	$ 339,171	$ 41,785	$ (333,291)	$ 47,665	$ 10,968	$ 58,633

The notes are an integral part of these condensed consolidated financial statements.

FALCON OIL & GAS LTD.
Interim Condensed Consolidated Statements of Cash Flows
(Unaudited)

	Nine Months Ended September 30,	
(thousands of US dollars)	2012	2011
Cash flows from operating activities:		
Net loss for the period	$ (16,641)	$ (5,466)
Adjustments for:		
Share based compensation	2,204	1,994
Stock bonus	-	107
Depletion, depreciation and amortization	295	307
Net financing expense (income)	7,170	(1,734)
Other	(636)	51
Change in non-cash working capital (Note 5)	1,308	(4,215)
Interest paid	(579)	(593)
Interest received	53	62
Net cash used in operating activities	(6,826)	(9,487)
Cash flows from investing activities:		
Exploration and evaluation costs	(2,827)	(6,267)
Proceeds from farm-out transaction, net	-	17,709
Acquisition of furniture and equipment	(21)	(133)
Other assets	-	(600)
Net cash from investing activities	(2,848)	10,709
Cash flows from financing activities:		
Increase in restricted cash	(268)	-
Proceeds from private placement of units offering, net	-	13,480
Proceeds from private placement of warrants	-	945
Proceeds from exercise of share options	90	8
Net cash from financing activities	(178)	14,433
Change in cash and cash equivalents	(9,852)	15,655
Effect of exchange rates on cash and cash equivalents	48	(471)
Cash and cash equivalents, beginning of period	15,358	7,274
Cash and cash equivalents, end of period	$ 5,554	$ 22,458

The notes are an integral part of these condensed consolidated financial statements.

1. Reporting Entity

Falcon Oil & Gas Ltd. (the "Company" or "Falcon") was incorporated under the laws of British Columbia, and has producing petroleum and natural gas properties in Alberta, Canada and exploration projects in Hungary, Australia and South Africa.

The Company is in the business of acquiring, exploring and developing petroleum and natural gas properties which, by its nature, involves a high degree of risk, and there can be no assurance that current exploration programs will result in profitable operations. The recoverability of the carrying value of the petroleum and natural gas properties and the Company's continued existence is dependent upon the preservation of its interests in the underlying properties, the discovery of economically recoverable reserves, the achievement of profitable operations, or the ability of the Company to obtain financing or, alternatively, upon the Company's ability to economically dispose of its interests. Certain of the Company's petroleum and natural gas properties are subject to the risks associated with foreign investment, including increases in taxes and royalties, renegotiation of contracts, currency exchange fluctuations and political uncertainty.

2. Basis of Presentation and Preparation

(a) Statement of compliance:

These interim condensed consolidated financial statements are unaudited and have been prepared in accordance with IAS 34 'Interim Financial Reporting' ("IAS 34") using accounting policies consistent with the International Financial Reporting Standards ("IFRS") issued by the International Accounting Standards Board ("IASB") and Interpretations of the International Financial Reporting Interpretations Committee ("IFRIC"). The condensed consolidated interim financial statements do not, however, include all of the information required for full annual financial statements prepared under IFRS.

The condensed consolidated financial statements are presented in United States dollars and tabular amounts, except as otherwise indicated, are presented in thousands of dollars.

(b) Basis of measurement:

The condensed consolidated financial statements have been prepared on the historical cost basis except for derivative financial instruments which are measured at fair value (as discussed in Note 4) and the expensing of share options.

2. Basis of Presentation and Preparation (continued)

(c) Going Concern:

For the nine months ended September 30, 2012, the Company incurred a net loss of $16.6 million and operating cash outflows of $6.8 million and, as at September 30, 2012, had negative working capital of $3.6 million and a deficit of $333.3 million. The Company's ability to continue as a going concern in the short term is dependent upon its ability to raise additional capital from the sale of additional common shares or other debt or equity instruments and/or to secure an industry partner for its operations in Hungary and South Africa. There is no assurance that additional capital will be available to the Company on acceptable terms or at all, or that an industry partner will be secured.

The Company has worked on securing joint venture funding for its operations in the Makó Trough located in Hungary. On June 9, 2011, the Company entered into a Letter of Intent with Naftna Industrija Srbije, j.s.c. Novi Sad ("NIS") for the earning of an interest by NIS in producing the Algyö play within Falcon's Makó production license in Hungary. In July 2012, the Company and NIS concluded negotiations and have filed the proposed agreement with the Hungarian Ministry of Finance ("the Ministry") for a ruling on the tax and accounting treatment of the agreement. The Agreement between NIS and TXM was finalized, but not signed on the July 31, 2012, as the transaction remains subject to a favorable ruling of the negotiated tax and accounting treatment by the Hungarian Ministry of Finance. The company has now received the tax ruling, but has appealed one aspect of the tax treatment. The outcome of the appeal is not expected to affect the ability of TXM to sign the Agreement with NIS.

In the longer term, the recoverability of the carrying value of the Company's long-lived assets in Hungary and Australia is dependent upon the Company's ability to preserve its interest in the underlying petroleum and natural gas properties, the discovery of economically recoverable reserves, the achievement of profitable operations, and the ability of the Company to obtain financing to support its acquisition, exploration, development and production activities.

These consolidated financial statements are prepared in accordance with IFRS appropriate for a going concern. The going concern basis of accounting assumes the Company will continue to realize the value of its assets and discharge its liabilities and other obligations in the ordinary course of business. There is material uncertainty that may cast significant doubt as to whether the Company will be able to realize its assets and discharge its liabilities in the normal course of operations. Should the Company be required to realize the value of its assets in other than the ordinary course of business, the net realizable value of its assets may be materially less than the amounts shown in the consolidated financial statements. These consolidated financial statements do not include any adjustments to the amounts and classifications of assets and liabilities that may be necessary should the Company be unable to repay its liabilities and meet its other obligations in the ordinary course of business or continue operations, and those adjustments may be material.

(d) Use of estimates and judgments:

The preparation of financial statements in conformity with IFRS requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses. Actual results may differ from these estimates.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the year in which the estimates are revised and in any future years affected.

2. Basis of Presentation and Preparation (continued)

In preparing these condensed consolidated interim financial statements, the significant judgments made by management in applying the Group's accounting policies and the key sources of estimation uncertainty were the same as those applied to the consolidated financial statement as at and for the year ended December 31, 2011.

3. Significant Accounting Policies

The interim financial statements have been prepared following the same accounting policies and methods of computation as the audited financial statements of the Company for the year ended December 31, 2011. The interim financial statements and notes thereto should be read in conjunction with the 2011 annual financial statements.

4. Finance income and expenses

	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
Finance income:				
Interest income on bank deposits	$ 15	$ 25	$ 53	$ 62
Derivative gains – unrealized	-	2,992	-	4,032
Net foreign exchange gain	-	33	-	-
	15	3,050	53	4,094
Finance expenses:				
Interest on loans and borrowings	(1,015)	(628)	(2,689)	(1,723)
Accretion of provisions	(53)	(69)	(170)	(206)
Derivative losses – unrealized	(4,776)	-	(4,168)	-
Net foreign exchange loss	(33)	-	(196)	(431)
	(5,877)	(697)	(7,223)	(2,360)
Net finance (expenses) income	$ (5,862)	$ 2,353	$ (7,170)	$ 1,734

5. Supplemented cash flow information

Changes in non-cash working capital is comprised of:

	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
Source (use) of cash:		
Accounts receivable	$ 1,086	$ (747)
Prepaid expenses and other	(27)	30
Inventory held for sale	145	(1)
Accounts payable and accrued expenses	104	(3,497)
	1,308	(4,215)

6. Exploration and evaluation costs

	Hungary	Australia	South Africa	Total
Balance as at January 1, 2011	$ 46,497	$ 52,258	$ -	$ 98,755
Additions	2,259	15,572	-	17,831
Impairment	(26,000)	-	-	(26,000)
Proceeds from farm-out transaction, net of transaction costs	-	(19,609)	-	(19,609)
Balance as at December 31, 2011	22,756	48,221	-	70,977
Additions	-	1,201	-	1,201
Decommissioning provision	31	-	-	31
Balance as at September 30, 2012	$ 22,787	$ 49,422	$ -	$ 72,209

Exploration and evaluation ("E&E") assets consist of the Company's exploration projects which are pending the determination of proven or probable reserves. Additions represent the Company's costs incurred on E&E assets during the period.

7. Share capital

As at September 30, 2012 and December 31, 2011, the Company was authorized to issue an unlimited number of common shares, without par value.

The following is a reconciliation of issued and outstanding common shares:

	Number of shares	Share capital
Balance as at January 1, 2011	602,216,800	$ 331,215
Issuance of shares in a private placement, net of offering costs	87,050,000	6,924
Issuance of shares to two former officers	5,000,000	648
Options exercised	50,000	15
Shares issued to employees and consultants	676,800	107
Issuance of shares in a private placement to officers and a director	660,900	97
Balance as at December 31, 2011	695,654,500	339,006
Options exercised	600,000	165
Balance as at September 30, 2012	696,254,500	$ 339,171

8. Net loss per share

Net loss per share – basic was calculated as follows:

	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
Net loss for the period	$ (8,891)	$ (645)	$(16,453)	$ (5,253)
Weighted average number of common shares – basic (in thousand)				
Issued common shares as at beginning of period	695,654	602,217	695,654	602,217
Shares issued in a private placement	-	87,050	-	56,120
Shares issued to two former officers	-	5,000	-	2,604
Share options exercised	196	50	66	46
Weighted average number of common shares – basic	695,850	694,317	695,720	660,987

All outstanding convertible securities, options and warrants were excluded from the calculation of net loss per share as the effect of these assumed conversions and exercises was anti-dilutive.

9. Convertible debentures

The face value of the convertible debentures, due on maturity at June 30, 2013, is $10.8 million (CDN$10.7 million).

10. Derivative liabilities

Derivative liabilities consist of the fair value of the convertible debt conversion feature, the fair value of the private placement warrants and the fair value of the Hess warrants. Changes in the fair value of the derivative liabilities are recorded as part of net finance expenses. The composition of the derivative liabilities as at September 30, 2012 and December 31, 2011, and the changes therein for the nine months and the year then ended, respectively, are as follows:

Fair value of:	Convertible Debt Conversion Feature	Private Placement Warrants	Hess Warrants	Total
Balance as at January 1, 2011	$ 775	$ -	$ -	$ 775
Fair value of derivatives	-	6,541	945	7,486
Derivative gains - unrealized	(734)	(3,889)	(324)	(4,947)
Balance as at December 31, 2011	41	2,652	621	3,314
Derivative losses - unrealized	212	3,562	394	4,168
Balance as at September 30, 2012	$ 253	$ 6,214	$ 1,015	$ 7,482

10. Derivative liabilities (continued)

Fair value of:	Convertible Debt Conversion Feature	Private Placement Warrants	Hess Warrants	Total
Current	$ 253	$ –	$ –	$ 253
Long-term	–	6,214	1,015	7,229
Balance as at September 30, 2012	$ 253	$ 6,214	$ 1,015	$ 7,482

11. Share based compensation

The Company, in accordance with the policies of the TSX-V, may grant options to directors, officers, employees and consultants, to acquire up to 10% of the Company's issued and outstanding common stock. The exercise price of each option is based on the market price of the Company's stock at the date of grant, which may be less a discount in accordance with TSX-V policies. The exercise price of all options granted has been based on the market price of the Company's stock at the date of grant, and no options have been granted at a discount to the market price. The options can be granted for a maximum term of five years. The Company records compensation expense over the vesting period based on the fair value at the grant date of the options granted. These amounts are recorded as contributed surplus. Any consideration paid on the exercise of these options together with the related contributed surplus associated with the exercised options is recorded as share capital.

A summary of the Company's stock option plan as of September 30, 2012 and December 31, 2011 and changes during the nine months and the year then ended, is presented below:

	2012		2011	
	Number of options	Weighted average exercise price	Number of options	Weighted average exercise price
Outstanding as at beginning of period	29,764,500	$ 0.41	21,764,500	$ 1.81
Granted	6,000,000	0.10	17,810,000	0.15
Expired	(978,333)	0.73	(8,623,333)	1.28
Forfeited	(949,167)	1.10	(1,136,667)	0.46
Exercised	(600,000)	0.15	(50,000)	0.16
Outstanding as at end of period	33,237,000	$ 0.35	29,764,500	$ 0.41
Exercisable as at end of period	21,390,333	$ 0.48	15,021,000	$ 0.57

During the nine months ended September 30, 2012, the Company granted 6.0 million options at an exercise price of $0.10 (CDN$0.10) (2011 – 17.8 million at $0.15 (CDN $0.15)) per share. Of the options granted during the nine months ended September 30, 2012, all vest 1/3 ratably at the anniversary date over three years, and have an expiry date of May 1, 2017. Of the options granted during the year ended December 31, 2011, all vest 1/3 at the date of grant, with the remainder vesting ratably at the anniversary date over the two years thereafter.

The fair value of the granted options was estimated using a Black Scholes model with the following weighted average inputs:

	2012	2011
Fair value as at grant date	$ 0.08	$ 0.15
Share price	0.10	0.15
Exercise price	0.10	0.15
Volatility	104%	105% – 106%
Option life	5.00 years	5.00 years
Dividends	Nil	Nil
Risk-free interest rate	1.59%	2.23% – 2.44%

A forfeiture rate of 11% (2011 - 16%) is used when recording share based compensation. This estimate is adjusted based on the actual forfeiture rate.

12. Decommissioning Provision

A reconciliation of the decommissioning provision for the nine months ended September 30, 2012 and for the year ended December 31, 2011 is provided below:

	2012	2011
Balance as at beginning of period	$ 8,813	$ 6,310
Revision to provisions	30	2,236
Accretion	170	267
Liabilities settled	(20)	–
Balance as at end of period	$ 8,993	$ 8,813
Current	$ 130	$ 150
Long-term	8,863	8,663
Balance as at end of period	$ 8,993	$ 8,813

The Company’s decommissioning provision results from its ownership interest in oil and natural gas assets. The total decommissioning provision is estimated based on the Company’s net ownership interest in the wells, estimated costs to reclaim and abandon these wells and the estimated timing of the costs to be incurred in future years. The Company has estimated the net present value of the decommissioning provision to be $9 million as at September 30, 2012 (2011 – $8.8 million) based on an undiscounted total future liability of $13.1 million (2011 – $13.1 million). These payments are expected to be made over the next 20 years with the majority of costs to be incurred between 2027 and 2031. The discount factor, being the risk free rate related to the liability, was 2.42% as at September 30, 2012 (December 31, 2011 – 2.57%).

13. Segment Information

All of the Company's operations are in the petroleum and natural gas industry with its principal business activity being in the acquisition, exploration and development of petroleum and natural gas properties. The Company has producing petroleum and natural gas properties located in Canada and considers the results from its operations to relate to the petroleum and natural gas properties. The Company has unproven petroleum and natural gas properties in Hungary and Australia.

	Canada	United States	Hungary	Australia	Ireland	Total
Nine months ended September 30, 2012:						
Revenue	$ 6	$ -	$ 6	$ -	$ -	$ 12
Balance as at September 30, 2012:						
Capital assets	$ -	$ -	$ 27,921	$ 49,423	$ 6	77,350

	Canada	United States	Hungary	Australia	Ireland	Total
Nine months ended September 30, 2011:						
Revenue	$ 24	$ –	$ –	$ –	$ –	$ 24
Balance as at September 30, 2011:						
Capital assets	$ 37	$ 189	$ 53,309	$ 43,213	$ –	96,748

14. Corporate Headquarters Relocation

During the third quarter of 2012, the Company relocated its corporate headquarters from Denver, Colorado to Dublin, Ireland. In connection with that decision, all individuals and consultants in Denver were terminated. At September 30, 2012, the Company has recorded an estimate of the expenses related to this restructuring, including severance and employee related benefits, certain expenses, acceleration of the recognition of certain future expenses and acceleration of the depreciation of certain assets. The Denver office closed on September 28, 2012.

14. Corporate Headquarters Relocation (continued)

The following is a summary of restructuring expenses related to the relocation of the corporate headquarters including the line in the consolidated statement of operations and comprehensive loss in which the expense is recognized:

		2012
Restructuring expense:		
Severance and health benefits	$	510
Rent expense, net of sublease		118
Other		46
Total restructuring expense		674
Share based compensation		1,078
Depreciation		114
Total	$	1,866

The resulting liabilities of $0.6 million are reflected in accounts payable and accrued expenses in the consolidated balance sheet as at September 30, 2012.

FALCON OIL & GAS LTD.

Consolidated Financial Statements

Years Ended December 31, 2011 and 2010

(Presented in U.S. Dollars)

KPMG

INDEPENDENT AUDITORS' REPORT

To the Shareholders of Falcon Oil & Gas Ltd.

We have audited the accompanying consolidated financial statements of Falcon Oil & Gas Ltd. ("the Company"), which comprise the consolidated statements of financial position as at December 31, 2011, December 31, 2010 and January 1, 2010, the consolidated statements of operations and comprehensive loss, changes in equity and cash flows for the years ended December 31, 2011 and December 31, 2010, and notes, comprising 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 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 our 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, we consider 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 consolidated financial position of the Company as at December 31, 2011, December 31, 2010 and January 1, 2010, and its consolidated financial performance and its consolidated cash flows for the years ended December 31, 2011 and December 31, 2010 in accordance with International Financial Reporting Standards.

Emphasis of Matter

Without qualifying our opinion, we draw attention to Note 2(c) in the consolidated financial statements which indicates the Company incurred a loss of $34.8 million and operating cash outflows of $12.1 million during the year ended December 31, 2011 and that the Company's ability to continue as a going concern is dependent upon raising additional capital. This condition, along with other matters as set forth in Note 2(c), indicate the existence of a material uncertainty that may cast significant doubt about the Company's ability to continue as a going concern.

KPMG LLP

Chartered Accountants
Calgary, Canada
April 30, 2012

FALCON OIL & GAS LTD.
Consolidated Statements of Financial Position

(thousands of US dollars)	December 31, 2011	December 31, 2010	January 1, 2010
Assets			
Current assets:			
Cash and cash equivalents	$ 15,358	$ 7,274	$ 11,804
Restricted cash	51	51	1,184
Accounts receivable	1,602	1,025	2,955
Prepaid expenses	330	391	720
Inventory held for sale	628	1,678	4,196
Total current assets	17,969	10,419	20,859
Non-current assets:			
Exploration and evaluation assets (Note 8)	70,977	98,755	207,792
Property, plant and equipment (Note 7)	5,224	5,521	6,021
Other assets	731	714	8,277
Total non-current assets	76,932	104,990	222,090
Total assets	$ 94,901	$ 115,409	$ 242,949
Liabilities			
Current liabilities:			
Accounts payable and accrued expenses	$ 3,836	$ 1,871	$ 2,683
Decommissioning provision (Note 14)	150	–	–
Provision for legal matters (Note 14)	–	3,700	–
Total current liabilities	3,986	5,571	2,683
Non-current liabilities:			
Convertible debentures (Note 11)	5,960	4,519	3,266
Derivative liabilities (Note 12)	3,314	775	1,468
Decommissioning provision (Note 14)	8,663	6,310	5,673
Total non-current liabilities	17,937	11,604	10,407
Total liabilities	21,923	17,175	13,090
Equity			
Share capital (Note 9)	339,006	331,215	331,215
Contributed surplus	39,654	37,874	34,357
Deficit	(316,838)	(282,277)	(135,713)
Equity attributable to common shareholders	61,822	86,812	229,859
Non-controlling interest	11,156	11,422	–
Total equity	72,978	98,234	229,859
Total liabilities and equity	$ 94,901	$ 115,409	$ 242,949

On behalf of the Board:

"*Gregory Smith*", Director "*Robert Macaulay*", Director

The notes are an integral part of these consolidated financial statements.

FALCON OIL & GAS LTD.
Consolidated Statements of Operations and Comprehensive Loss

(thousands of US dollars)	Year Ended December 31, 2011	2010
Revenue:		
Oil and natural gas revenue	$ 33	$ 28
Expenses:		
Exploration and evaluation expenses	1,629	1,602
Production and operating expenses	34	26
Depletion and depreciation	368	434
Impairment of non-current assets (Notes 7 and 8)	26,035	122,111
General and administrative expenses	7,703	11,323
Share based compensation (Note 13)	2,435	3,516
Write-down of inventory available for sale	641	1,186
Write off of receivable	–	4,345
(Reversal of) litigation expense (Note 14)	(1,533)	3,700
Other (income) expense	(543)	386
	36,769	148,629
Results from operating activities	(36,736)	(148,601)
Finance income (Note 5)	5,029	737
Finance expenses (Note 5)	(3,120)	(2,920)
Net finance expenses	1,909	(2,183)
Net loss and comprehensive loss for the year	$ (34,827)	$ (150,784)
Net loss and comprehensive loss attributable to:		
Common shareholders	$ (34,561)	$ (150,247)
Non-controlling interest	(266)	(537)
Net loss and comprehensive loss for the year	$ (34,827)	$ (150,784)
Net loss per share attributable to common shareholders:		
Basic and diluted (Note 10)	$ (0.05)	$ (0.25)

The notes are an integral part of these consolidated financial statements.

FALCON OIL & GAS LTD.
Consolidated Statements of Changes in Equity

(thousands of US dollars)	Share capital	Contributed surplus	Deficit	Equity attributable to common shareholders	Non-controlling interest	Total equity
Balance as at January 1, 2010	$ 331,215	$ 34,357	$ (135,713)	$ 229,859	$ –	$ 229,859
Share based compensation	–	3,516	–	3,516	–	3,516
Issuance of shares of subsidiary	–	–	–	–	15,642	15,642
Non-controlling interest dilution gain (loss)	–	–	3,683	3,683	(3,683)	–
Net loss for the year	–	–	(150,247)	(150,247)	(537)	(150,784)
Balance as at December 31, 2010	331,215	37,874	(282,277)	86,812	11,422	98,234
Private placement of shares	6,924	–	–	6,924	–	6,924
Issuance of shares	648	(648)	–	–	–	–
Options exercised	15	(7)	–	8	–	8
Share based compensation	–	2,435	–	2,435	–	2,435
Share bonus to employees and consultants	107	–	–	107	–	107
Private placement of shares to officers and a director	97	–	–	97	–	97
Net loss for the year	–	–	(34,561)	(34,561)	(266)	(34,827)
Balance as at December 31, 2011	$ 339,006	$ 39,654	$ (316,838)	$ 61,822	$ 11,156	$ 72,978

The notes are an integral part of these consolidated financial statements.

FALCON OIL & GAS LTD.
Consolidated Statements of Cash Flows

	Year Ended December 31,	
(thousands of US dollars)	2011	2010
Cash flows from operating activities:		
Net loss for the year	$ (34,827)	$ (150,784)
Adjustments for:		
Share based compensation	2,435	3,516
Share bonus	204	–
Depletion and depreciation	368	434
Impairment of non-current assets	26,035	122,111
Write off of receivable	–	4,345
(Reversal of) litigation expense	(1,533)	3,700
Net financing (income) expenses	(1,909)	2,183
Other	20	89
Change in non-cash working capital (Note 6)	(1,845)	5,296
Interest paid	(1,170)	(1,028)
Interest received	83	45
Net cash used in operating activities	(12,139)	(10,093)
Cash flows from investing activities:		
Exploration and evaluation assets	(13,397)	(1,442)
Proceeds from farm-out transaction, net	19,609	–
Property, plant and equipment	(157)	(51)
Net cash used in investing activities	6,055	(1,493)
Cash flows from financing activities:		
Decrease in restricted cash	–	1,132
Proceeds from private placement of units offering, net	13,480	–
Proceeds from private placement of warrants	945	–
Proceeds from exercise of share options	8	–
Proceeds from unit offering by subsidiary, net	–	5,591
Net cash from financing activities	14,433	6,723
Change in cash and cash equivalents	8,349	(4,863)
Effect of exchange rates on cash and cash equivalents	(265)	333
Cash and cash equivalents, beginning of year	7,274	11,804
Cash and cash equivalents, end of year	$ 15,358	$ 7,274

The notes are an integral part of these consolidated financial statements.

1. Reporting Entity

Falcon Oil & Gas Ltd. (the "Company" or "Falcon") was incorporated under the laws of British Columbia, and has producing petroleum and natural gas properties in Alberta, Canada and exploration projects in Hungary, Australia and South Africa.

The Company is in the business of acquiring, exploring and developing petroleum and natural gas properties which, by its nature, involves a high degree of risk, and there can be no assurance that current exploration programs will result in profitable operations. The recoverability of the carrying value of the petroleum and natural gas properties and the Company's continued existence is dependent upon the preservation of its interests in the underlying properties, the discovery of economically recoverable reserves, the achievement of profitable operations, or the ability of the Company to obtain financing or, alternatively, upon the Company's ability to economically dispose of its interests. Certain of the Company's petroleum and natural gas properties are subject to the risks associated with foreign investment, including increases in taxes and royalties, renegotiation of contracts, currency exchange fluctuations and political uncertainty.

2. Basis of Presentation and Preparation

(a) Statement of compliance:

These consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") issued by the International Accounting Standards Board ("IASB") and Interpretations of the International Financial Reporting Interpretations Committee ("IFRIC"). This is the first year for which the Company has adopted IFRS. Previously, the Company prepared its annual consolidated financial statements in accordance with Canadian Generally Accepted Accounting Principles ("GAAP"). The disclosures concerning the transition from Canadian GAAP to IFRS are included in Note 22.

(b) Reporting and functional currency

The consolidated financial statements are presented in United States dollars, the functional currency of the Company and its subsidiaries. All amounts, except as otherwise indicated, are presented in thousands of dollars.

Basis of measurement: The consolidated financial statements have been prepared on the historical cost basis except for derivative financial instruments which are measured at fair value (as discussed in Note 4).

2. Basis of Presentation and Preparation (continued)

(c) Going Concern:

For the year ended December 31, 2011, the Company incurred a net loss of $34.827 million and operating cash outflows of $12.139 million and, as at December 31, 2011, had a deficit of $316.838 million. The Company's ability to continue as a going concern in the short term is dependent upon its ability to raise additional capital from the sale of additional common shares or other debt or equity instruments and/or to secure an industry partner for its operations in Hungary and South Africa. There is no assurance that additional capital will be available to the Company on acceptable terms or at all, or that an industry partner will be secured.

The Company has worked on securing joint venture funding for its operations in the Makó Trough located in Hungary. As discussed in Note 8, on June 9, 2011, the Company entered into a Letter of Intent with Naftna Industrija Srbije, j.s.c. Novi Sad ("NIS") for the earning of an interest by NIS in producing the Algyö play within Falcon's Makó production license in Hungary. The transaction is subject to the execution of a definitive agreement with NIS.In the longer term, the recoverability of the carrying value of the Company's long-lived assets is dependent upon the Company's ability to preserve its interest in the underlying petroleum and natural gas properties, the discovery of economically recoverable reserves, the achievement of profitable operations, and the ability of the Company to obtain financing to support its acquisition, exploration, development and production activities.

These consolidated financial statements are prepared in accordance with IFRS appropriate for a going concern. The going concern basis of accounting assumes the Company will continue to realize the value of its assets and discharge its liabilities and other obligations in the ordinary course of business. There is uncertainty as to whether the Company will be able to realize its assets and discharge its liabilities in the normal course of operations. Should the Company be required to realize the value of its assets in other than the ordinary course of business, the net realizable value of its assets may be materially less than the amounts shown in the consolidated financial statements. These consolidated financial statements do not include any adjustments to the amounts and classifications of assets and liabilities that may be necessary should the Company be unable to repay its liabilities and meet its other obligations in the ordinary course of business or continue operations, and those adjustments may be material.

(d) Use of estimates and judgments:

The preparation of financial statements in conformity with IFRS requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses. Actual results may differ from these estimates.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the year in which the estimates are revised and in any future years affected.

Information about significant areas of estimation uncertainty and critical judgments in applying accounting policies that have the most significant effect on the amounts recognized in the consolidated financial statements is included in Note 8 – valuation of intangible exploration assets, other intangible assets.

3. Significant Accounting Policies

The accounting policies set out below have been applied consistently to all years presented in these consolidated financial statements, and have been applied consistently by the Company and its subsidiaries.

(a) Basis of consolidation:

These consolidated financial statements include the accounts of the Company and the accounts of its subsidiaries. Control exists when the Company has the power, directly or indirectly, to govern the financial and operating policies of an entity so as to obtain benefits from its activities. The financial statements of subsidiaries are included in the consolidated financial statements from the date that control commences until the date that control ceases.

Non-controlling interest in the net assets of consolidated subsidiaries are identified separately from the Company's equity. Non-controlling interest consists of the non-controlling interest at the date of the change in ownership plus the non-controlling interest's share of changes in equity since that date.

All of the Company's subsidiaries are wholly owned except for Falcon Oil & Gas Australia Limited ("Falcon Australia") of which approximately 73% of the outstanding Common Shares are owned by Falcon. The consolidated financial statements include a non-controlling interest representing the 27% portion of Falcon Australia's assets and liabilities not owned by Falcon. The reporting dates of the Company and its subsidiaries are coterminous.

Intercompany balances and transactions, and any unrealized income and expenses arising from intercompany transactions, are eliminated in preparing the consolidated financial statements, except when losses realized on intercompany transactions are evidence of impairment.

(b) Foreign currency:

Transactions in foreign currencies are translated to United States dollars, the functional currency of all group entities, at exchange rates at the dates of the transactions. Monetary assets and liabilities denominated in foreign currencies are translated to United States dollars at the period end exchange rate. Non-monetary assets and liabilities denominated in foreign currencies that are measured at fair value are translated to the functional currency at the exchange rate at the date that the fair value was determined. Foreign currency differences arising on translation are recognized in profit or loss.

(c) Financial instruments:

(i) Non-derivative financial instruments:

Non-derivative financial instruments comprise accounts receivable, cash and cash equivalents, restricted cash, convertible debentures, and accounts payable and accrued expenses. Non-derivative financial instruments are recognized initially at fair value plus, for instruments not at fair value through profit or loss, any directly attributable transaction costs. Subsequent to initial recognition non-derivative financial instruments are measured as described below. Transaction costs for non-derivative financial instruments at fair value through profit or loss are recognized directly in profit or loss.

3. Significant accounting policies (continued)

(c) Financial instruments (continued):

(i) Non-derivative financial instruments (continued):

The Company classifies non-derivative financial assets into the following categories: financial assets at fair value through profit or loss, held-to-maturity loans and receivables and available for sale financial assets. Non-derivative liabilities are classified as financial liabilities at fair value through profit or loss or as other financial liabilities. As at December 31, 2011 and 2010 and as at January 1, 2010, the company did not have non-derivative financial instruments classified as available for sale financial assets or liabilities through profit or loss.

Cash and cash equivalents and restricted cash:

Cash and cash equivalents and restricted cash comprise cash on hand, term deposits held with banks, and other short-term highly liquid investments with original maturities of three months or less. Bank overdrafts that are repayable on demand and form an integral part of the Company's cash management, whereby management has the ability and intent to net bank overdrafts against cash, are included as a component of cash and cash equivalents and restricted cash for the purpose of the statement of cash flows.

Financial assets at fair value through profit or loss:

An instrument is classified at fair value through profit or loss if it is held for trading or is designated as such upon initial recognition. Financial instruments are designated at fair value through profit or loss if the Company manages such investments and makes purchase and sale decisions based on their fair value in accordance with the Company's risk management or investment strategy. Financial instruments at fair value through profit or loss are measured at fair value, and changes therein are recognized in profit or loss. The Company has designated cash and cash equivalents and restricted cash as financial assets at fair value through profit or loss.

Loans and receivables:

Accounts receivable are initially recognized on the date they originate and are measured at amortized cost using the effective interest method, less any impairment losses.

Other liabilities

Accounts payable and accrued expenses and convertible debentures are classified as other liabilities and are measured at amortized cost using the effective interest rate method.

3. Significant accounting policies (continued)

(ii) Derivative financial instruments:

Warrants:

Warrants which do not meet the criteria to be classified as an equity instrument are classified at fair value through profit or loss and are recorded on the statement of financial position at fair value. Transaction costs are recognized in profit or loss as incurred.

Embedded derivatives are separated from the host contract and accounted for separately if the economic characteristics and risks of the host contract and the embedded derivative are not closely related, a separate instrument with the same terms as the embedded derivative would meet the definition of a derivative, and the combined instrument is not measured at fair value through profit or loss. Changes in the fair value of separable embedded derivatives are recognized immediately in profit or loss.

(iii) Convertible financial instruments:

Convertible debentures, of which the exercise of the conversion feature does not result in a fixed number of shares being issued for a fixed amount in the functional currency of the Company, are separated into a host contract, the note, and embedded derivatives in accordance with the accounting policies for derivative financial instruments.

(iv) Share capital:

Common shares are classified as equity. Incremental costs directly attributable to the issue of common shares and share options are recognized as a deduction from equity, net of any tax effects.

(d) Property, plant and equipment and intangible exploration assets:

(i) Recognition and measurement:

Exploration and evaluation (“E&E”) expenditures:

Pre-license costs are recognized in the statement of operations as incurred.

Exploration and evaluation costs, including the costs of acquiring licenses and directly attributable general and administrative costs, initially are capitalized as either tangible or intangible exploration and evaluation assets according to the nature of the assets acquired, except for costs incurred in relation to projects for which exploration and evaluation activities have been temporarily suspended. The costs are accumulated in cost centers by well, field or exploration area pending determination of technical feasibility and commercial viability. No costs are charged to a cost center when operations in that cost center are suspended for more than 12 months.

Exploration and evaluation assets are assessed for impairment if (i) sufficient data exists to determine technical feasibility and commercial viability, or (ii) facts and circumstances suggest that the carrying amount exceeds the recoverable amount. For purposes of impairment testing, exploration and evaluation assets are allocated to cash-generating units.

3. Significant accounting policies (continued)

(d) Property, plant and equipment and intangible exploration assets (continued):

(i) Recognition and measurement (continued):

The technical feasibility and commercial viability of extracting a mineral resource is considered to be determinable when proven reserves are determined to exist. A review of each exploration license or field is carried out, at least annually, to ascertain whether proven reserves have been discovered. Upon determination of proven reserves, intangible exploration and evaluation assets attributable to those reserves are first tested for impairment and then reclassified from exploration and evaluation assets to a separate category within tangible assets referred to as oil and natural gas interests.

Proceeds from disposal or farm-out transactions of intangible exploration assets are used to reduce the carrying amount of the assets. When proceeds exceed the carrying amount, the difference is recognized as a gain. When the Company disposes of its' full interests, gains or losses are recognized in accordance with the policy for recognizing gains or losses on sale of plant, property and equipment.

Development and production costs:

Items of property, plant and equipment, which include oil and gas development and production assets, are measured at cost less accumulated depletion and depreciation and accumulated impairment losses. Development and production assets are grouped into CGU's for impairment testing. The cost of property, plant and equipment at January 1, 2010, the date of transition to IFRS, was determined by application of the deemed cost exemption for oil and gas companies of IFRS 1. When significant parts of an item of property, plant and equipment, including oil and natural gas interests, have different useful lives, they are accounted for as separate items (major components).

Gains and losses on disposal of an item of property, plant and equipment, including oil and natural gas interests, are determined by comparing the proceeds from disposal with the carrying amount of property, plant and equipment and are recognized net within "other income" or "other expenses" in profit or loss.

(ii) Subsequent costs:

Costs incurred subsequent to the determination of technical feasibility and commercial viability and the costs of replacing parts of property, plant and equipment are recognized as oil and natural gas interests only when they increase the future economic benefits embodied in the specific asset to which they relate. All other expenditures are recognized in profit or loss as incurred. Such capitalized oil and natural gas interests generally represent costs incurred in developing proved and/or probable reserves and bringing in or enhancing production from such reserves, and are accumulated on a field or geotechnical area basis. The carrying amount of any replaced or sold component is derecognized. The costs of the day-to-day servicing of property, plant and equipment are recognized in profit or loss as incurred.

3. Significant accounting policies (continued)

(d) Property, plant and equipment and intangible exploration assets (continued):

(iii) Depletion, depreciation and amortization:

The net carrying value of development or production assets is depleted using the unit of production method by reference to the ratio of production in the year to the related proven and probable reserves, taking into account estimated future development costs necessary to bring those reserves into production. Future development costs are estimated taking into account the level of development required to produce the reserves. These estimates are reviewed by independent reserve engineers at least annually.

Proven and probable reserves are estimated using independent reserve engineer reports and represent the estimated quantities of crude oil, natural gas and natural gas liquids which geological, geophysical and engineering data demonstrate with a specified degree of certainty to be recoverable in future years from known reservoirs and which are considered commercially producible. There should be a 50 percent statistical probability that the actual quantity of recoverable reserves will be more than the amount estimated as proven and probable and a 50 percent statistical probability that it will be less. The equivalent statistical probabilities for the proven component of proven and probable reserves are 90 percent and 10 percent, respectively.

Such reserves may be considered commercially producible if management has the intention of developing and producing them and such intention is based upon:

- a reasonable assessment of the future economics of such production;
- a reasonable expectation that there is a market for all or substantially all the expected oil and natural gas production; and
- evidence that the necessary production, transmission and transportation facilities are available or can be made available.

Reserves may only be considered proven and probable if the ability to produce is supported by either actual production or a conclusive formation test. The area of reservoir considered proven includes (a) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any, or both, and (b) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geophysical, geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of oil and natural gas controls the lower proved limit of the reservoir.

Reserves which can be produced economically through application of improved recovery techniques (such as fluid injection) are only included in the proven and probable classification when successful testing by a pilot project, the operation of an installed program in the reservoir, or other reasonable evidence (such as, experience of the same techniques on similar reservoirs or reservoir simulation studies) provides support for the engineering analysis on which the project or program was based.

For other assets, depreciation is recognized in profit or loss on a straight-line basis over the estimated useful lives of each part of an item of property, plant and equipment of two to seven years.

3. Significant accounting policies (continued)

(d) Property, plant and equipment and intangible exploration assets (continued):

(iii) Depletion, depreciation and amortization (continued):

Depreciation methods, useful lives and residual values are reviewed at each reporting date.

(e) Leased assets:

Leases where the Company assumes substantially all the risks and rewards of ownership are classified as finance leases. Upon initial recognition the leased asset is measured at an amount equal to the lower of its fair value and the present value of the minimum lease payments. Subsequent to initial recognition, the asset is accounted for in accordance with the accounting policy applicable to that asset.

Minimum lease payments made under finance leases are apportioned between the finance expenses and the reduction of the outstanding liability. The finance expenses are allocated to each year during the lease term so as to produce a constant periodic rate of interest on the remaining balance of the liability.

Other leases are operating leases, which are not recognized on the Company's statement of financial position.

Payments made under operating leases are recognized in profit or loss on a straight-line basis over the term of the lease. Lease incentives received are recognized as an integral part of the total lease expense, over the term of the lease.

(f) Impairment:

(i) Financial assets:

A financial asset is assessed at each reporting date to determine whether there is any objective evidence that it is impaired. A financial asset is considered to be impaired if objective evidence indicates that one or more events have had a negative effect on the estimated future cash flows of that asset.

An impairment loss in respect of a financial asset measured at amortized cost is calculated as the difference between its carrying amount and the present value of the estimated future cash flows discounted at the original effective interest rate.

Individually significant financial assets are tested for impairment on an individual basis. The remaining financial assets are assessed collectively in groups that share similar credit risk characteristics.

All impairment losses are recognized in profit or loss. An impairment loss is reversed if the reversal can be related objectively to an event occurring after the impairment loss was recognized. For financial assets measured at amortized cost the reversal is recognized in profit or loss.

3. Significant accounting policies (continued)

(ii) Non-financial assets:

The carrying amounts of the Company's non-financial assets, other than E&E assets and deferred tax assets, are reviewed at each reporting date to determine whether there is any indication of impairment. If any such indication exists, then the asset's recoverable amount is estimated. E&E assets are assessed for impairment when they are reclassified to property, plant and equipment, as oil and natural gas interests, and also if facts and circumstances suggest that the carrying amount exceeds the recoverable amount.

For the purpose of impairment testing, assets are grouped together into the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets (the "cash-generating unit" or "CGU"). The recoverable amount of an asset or a CGU is the greater of its value in use and its fair value less costs to sell.

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. Value in use is generally computed by reference to the present value of the future cash flows expected to be derived from production of proven and probable reserves.

E&E assets are allocated to related CGU's when they are assessed for impairment, both at the time of any triggering facts and circumstances as well as upon their eventual reclassification to producing assets (oil and natural gas interests in property, plant and equipment).

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses are recognized in profit or loss. Impairment losses recognized in respect of CGU's are allocated to reduce the carrying amounts of the other assets in the unit (group of units) on a pro rata basis.

Impairment losses recognized in prior years are assessed at each reporting date for any indications that the loss has decreased or no longer exists. An impairment loss is reversed if there has been a change in the estimates used to determine the recoverable amount. An impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depletion and depreciation or amortization, if no impairment loss had been recognized.

(g) Share based compensation:

Share based compensation is measured at fair value at the grant date and expensed over the vesting period with a corresponding increase to contributed surplus. The amount recognized as expense is adjusted for an estimated forfeiture rate for options that will not vest, which is adjusted as actual forfeitures occur, until the shares are fully vested. Consideration paid upon the exercise of stock options, together with corresponding amounts previously recognized in contributed surplus, is recorded as an increase to share capital.

3. Significant accounting policies (continued)

(h) Provisions:

A provision is recognized if, as a result of a past event, the Company has a present legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are determined by discounting the expected future cash flows at a pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the liability. Provisions are not recognized for future operating losses.

(i) Decommissioning provisions:

The Company's activities give rise to dismantling, decommissioning and site disturbance re-mediation activities. Provision is made for the estimated cost of site restoration and capitalized in the relevant asset category.

Decommissioning provisions are measured at the present value of management's best estimate of expenditure required to settle the present obligation at the statement of financial position date. Subsequent to initial measurement, the obligation is adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation. The increase in the provision due to the passage of time is recognized as finance costs whereas increases/decreases due to changes in the estimated future cash flows are recorded against the related asset. Actual costs incurred upon settlement of the decommissioning provisions are charged against the provision to the extent the provision was established.

(ii) Legal matters:

A provision for legal matters is recognized when legal action is threatened or initiated, and management considers it probable that the legal actions will result in an obligation for the Company. The provision is determined based on the expected cash flows, including legal expenses, and considering the time value of money. When the legal matter relates to exploration and evaluation activities, the recognition of the provision and subsequent change in the expected cash flows is recorded in exploration and evaluation assets.

(i) Revenue:

Revenue from the sale of oil and natural gas is recorded when the significant risks and rewards of ownership of the product is transferred to the buyer which is usually when legal title passes to the external party. Revenue is measured net of discounts, customs duties and royalties. Royalty income is recognized as it accrues in accordance with the terms of the overriding royalty agreements.

(j) Finance income and expenses:

Finance expense comprises interest expense on borrowings, accretion of the discount on provisions, changes in fair value of derivatives and impairment losses recognized on financial assets.

Borrowing costs incurred for the construction of qualifying assets are capitalized during the period of time that is required to complete and prepare the assets for their intended use or sale. All other borrowing costs are recognized in profit or loss using the effective interest method. The capitalization rate used to determine the amount of borrowing costs to be capitalized is the weighted average interest rate applicable to the Company's outstanding borrowings during the period.

3. Significant accounting policies (continued)

(j) Finance income and expenses (continued):

Interest income is recognized as it accrues in profit or loss, using the effective interest method.

Foreign currency gains and losses, reported under finance income and expenses, are reported on a net basis.

(k) Income tax:

Income tax expense comprises current and deferred tax. Income tax expense is recognized in profit or loss except to the extent that it relates to items recognized directly in equity, in which case it is recognized in equity.

Current tax is the expected tax payable on the taxable income for the year, using tax rates enacted or substantively enacted at the reporting date, and any adjustment to tax payable in respect of previous years.

Deferred tax is recognized using the statement of financial position method, providing for temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Deferred tax is not recognized on the initial recognition of assets or liabilities in a transaction that is not a business combination. In addition, deferred tax is not recognized for taxable temporary differences arising on the initial recognition of goodwill. Deferred tax is measured at the tax rates that are expected to be applied to temporary differences when they reverse, based on the laws that have been enacted or substantively enacted by the reporting date. Deferred tax assets and liabilities are offset if there is a legally enforceable right to offset, and they relate to income taxes levied by the same tax authority on the same taxable entity, or on different tax entities, but they intend to settle current tax liabilities and assets on a net basis or their tax assets and liabilities will be realized simultaneously.

A deferred tax asset is recognized to the extent that it is probable that future taxable profits will be available against which the temporary difference can be utilized. Deferred tax assets are reviewed at each reporting date and are reduced to the extent that it is no longer probable that the related tax benefit will be realized.

(l) Earnings per share:

Basic earnings per share is calculated by dividing the profit or loss attributable to common shareholders of the Company by the weighted average number of common shares outstanding during the period. Diluted earnings per share is determined by adjusting the profit or loss attributable to common shareholders and the weighted average number of common shares outstanding for the effects of dilutive instruments such as options granted to employees.

(m) New standards and interpretations not yet adopted:

Several new standards and amendments to existing standards and interpretations, which have been issued by the IASB, and which are expected to apply to the company are not yet effective and have not been applied in preparing these financial statements. The Company does not expect adoption of these new standards and interpretations, to have a material impact on the financial statements.

4. Determination of fair values

A number of the Company's accounting policies and disclosures require the determination of fair value, for both financial and non-financial assets and liabilities. Fair values have been determined for measurement and/or disclosure purposes based on the following methods. When applicable, further information about the assumptions made in determining fair values is disclosed in the notes specific to that asset or liability.

(i) Cash and cash equivalents, restricted cash, accounts receivable and accounts payable and accrued expenses

The fair value of cash and cash equivalents, restricted cash, accounts receivable and accounts payable and accrued expenses is estimated as the present value of future cash flows, discounted at the market rate of interest at the reporting date. As at December 31, 2011 and 2010, the fair value of accounts receivable and accounts payable and accrued expenses approximated their carrying value due to their short term to maturity.

(ii) Derivatives

The fair value of the conversion feature embedded in the convertible note is calculated using a Black Scholes option pricing model. Measurement inputs include share price on measurement date, exercise price of the instrument, expected volatility (based on weighted average historic volatility adjusted for changes expected due to publicly available information), weighted average expected life of the instruments (based on historical experience and general option holder behavior), expected dividends, and the risk-free interest rate (based on government bonds).

(iii) Convertible debentures

The fair value of host contract of the convertible debentures is determined for disclosure purposes by calculating the present value of the expected future cash flow using the market rate of interest at the reporting date.

(iv) Share based compensation

The Company accounts for its share based compensation using the fair value method of accounting for stock options granted to directors and employees using the Black-Scholes option-pricing model. Measurement inputs include share price on measurement date, exercise price of the instrument, expected volatility (based on weighted average historic volatility adjusted for changes expected due to publicly available information), weighted average expected life of the instruments (based on historical experience and general option holder behavior), expected dividends, and the risk-free interest rate (based on government bonds). A forfeiture rate is estimated on the grant date and is adjusted to reflect the actual number of options that vest.

5. Finance income and expenses

	Year Ended December 31, 2011	2010
Finance income:		
Interest income on bank deposits	$ 83	$ 45
Derivative gains – unrealized	4,946	692
	5,029	737
Finance expenses:		
Interest on loans and borrowings	(2,429)	(1,830)
Accretion of provisions	(267)	(248)
Net foreign exchange loss	(424)	(842)
	(3,120)	(2,920)
Net finance income (expenses)	$ 1,909	$ (2,183)

6. Supplemented cash flow information

Changes in non-cash working capital is comprised of:

	Year Ended December 31, 2011	2010
Source (use) of cash:		
Accounts receivable	$ (618)	$ 1,994
Prepaid expenses and other	52	384
Write-down of inventory held for sale	641	1,186
Inventory held for sale	409	1,331
Accounts payable and accrued expenses	(2,329)	(442)
	(1,845)	4,453
Other assets	–	843
	$ (1,845)	$ 5,296

7. Property, plant and equipment

	Canadian natural gas interests	Pipeline and facilities	Furniture and equipment	Total
Cost				
Balance as at January 1, 2010	$ 466	$ 3,888	$ 3,390	$ 7,744
Additions	–	–	52	52
Disposals	–	(57)	(124)	(181)
Balance as at December 31, 2010	466	3,831	3,318	7,615
Additions	–	–	158	158
Disposals	–	–	(91)	(91)
Balance as at December 31, 2011	$ 466	$ 3,831	$ 3,385	$ 7,682
Depletion, depreciation and amortization				
Balance as at January 1, 2010	$ (419)	$ –	$ (1,304)	$ (1,723)
Depletion and depreciation	(4)	–	(405)	(409)
Disposals	–	–	38	38
Balance as at December 31, 2010	(423)	–	(1,671)	(2,094)
Depletion and depreciation	(8)	–	(360)	(368)
Impairment	(35)	–	–	(35)
Disposals	–	–	39	39
Balance as at December 31, 2011	$ (466)	$ –	$ (1,992)	$ (2,458)
Net book value:				
As at January 1, 2010	$ 47	$ 3,888	$ 2,086	$ 6,021
As at December 31, 2010	$ 43	$ 3,831	$ 1,647	$ 5,521
As at December 31, 2011	$ –	$ 3,831	$ 1,393	$ 5,224

8. Exploration and evaluation assets

	Hungary	Australia	South Africa	Total
Balance as at January 1, 2010	$ 168,478	$ 39,314	$ –	$ 207,792
Additions	130	12,944	–	13,074
Impairment	(122,111)	–	–	(122,111)
Balance as at December 31, 2010	46,497	52,258	–	98,755
Additions	2,259	15,572	–	17,831
Impairment	(26,000)	–	–	(26,000)
Proceeds from farm-out transaction, net of transaction costs	–	(19,609)	–	(19,609)
Balance as at December 31, 2011	$ 22,756	$ 48,221	$ –	$ 70,977

8. Exploration and evaluation assets (continued)

Exploration and evaluation ("E&E") assets consist of the Company's exploration projects which are pending the determination of proven or probable reserves. Additions represent the Company's costs incurred on E&E assets during the period.

(a) Recoverability of exploration and evaluation assets:

The Company assesses the recoverability of intangible exploration assets, before and at the moment of reclassification to property, plant and equipment, using groups of cash generating units ("CGUs"). The group of CGUs includes both the E&E assets and CGU's related to oil and natural gas interests for that area, but is not larger than a segment.

The impairment of intangible exploration assets, and any eventual reversal thereof, is recognized as additional depletion, depreciation and amortization expense in the statement of operations and comprehensive loss as impairment of exploration and evaluation assets.

For the year ended December 31, 2011, the Company identified indicators that there was a potential for impairment of a portion of its Hungarian assets, specifically the depths of the Makó production license below the Algyö formation. Those identified indicators include a lack of progress in exploration activities during the year in those deeper zones, limited availability of funds to perform further exploratory activities in the near future in the deeper zones and limitation of discussions about a potential farm-out for the deeper zone play (see below for discussion of Letter of Intent with NIS for the Algyö formation).
The Company determined that the carrying value of the Hungarian properties exceeded its estimated recoverable amount and recorded an impairment of $26,000 (2010 - $122,111). The estimated recoverable value was assessed by the Company utilizing a valuation model based on potential joint venture partners as evidenced by discussions being held and an assessment of the valuation of the prospect based on potential farm-out arrangements.

(b) Hungary:

The Company holds a long-term Mining Plot (the "Production License") granted by the Hungarian Mining Authority. The Production License, covering approximately 245,700 acres, gives the exclusive right to explore for and develop petroleum and natural gas on properties located in south central Hungary near the town of Szolnok.

8. Exploration and evaluation assets (continued)

(b) Hungary (continued):

On June 9, 2011, the Company's wholly owned Hungarian subsidiary ("TXM") entered into a Letter of Intent ("LOI") with NIS, for the earning by NIS of an interest in producing the Algyö play within the Makó' production license in Hungary in an area of approximately 995 square kilometers, from a depth of 2,300 meters down to the base of the Algyö Formation (the "Agreement Area"). Under the terms of the LOI, TXM will retain all rights within the entire production license deeper than the base of the Algyö Formation such as the Szolnok and Endröd formations and, upon signing of a participation agreement NIS would make a $1,500 payment to TXM. NIS shall then, at its sole cost, drill, test and complete three wells in the Agreement Area. These wells, to be drilled and tested before December 31, 2012, shall be located so that each well tests an independent Algyö prospect. NIS will earn a 50% interest in production from each prospect if the discovery well is tied in and placed on production at the sole cost of NIS. After the drilling of the three wells is completed, NIS has the right to acquire a 50% interest in production from the entire Agreement Area by paying to TXM an additional $2,750 (the "earn-in"). If NIS does not fulfill their drilling obligations under the participation agreement, TXM will retain 100% interest in the Agreement Area.

If the NIS earn-in is completed, NIS and TXM will share future exploration, appraisal and development costs and production in the Agreement Area in accordance with their participating interests held under a joint operating agreement. TXM shall be the Operator under both the participation agreement and the joint operating agreement. Discussions on this agreement are ongoing.

(c) Australia:

The Company is the registered owner of four exploration permits ("the Permits"), comprising 7,000,000 acres in the Beetaloo Basin, Northern Territories, Australia.

In June 2011, the Company's majority owned subsidiary ("Falcon Australia") and Hess Australia (Beetaloo) Pty. Ltd. ("Hess") finalized an Evaluation and Participation Agreement (the "E&P Agreement"). Under the terms of the E&P Agreement, Hess paid $20.0 million to the Company (i) as a participation fee for the exclusive right to conduct operations for the exploration, drilling, development and production of hydrocarbons from three of the four Permits, and excluding an area comprising 100,000 acres surrounding the Shenandoah-1 well (the "Area of Interest") and (ii) as consideration for warrants to acquire 10,000,000 common shares in the capital of Falcon exercisable from November 14, 2011 through January 13, 2015 at an exercise price of CDN$0.19 per share (the "Hess Warrants"). The $20,000 of gross proceeds received from Hess were reduced by closing costs of $1,346 resulting in net proceeds of $18,654 which were allocated $17,709 to the farm-out transaction and $945 to the warrants.

8. Exploration and evaluation assets (continued)

(c) Australia (continued):

Initially, Hess shall acquire seismic data, at its sole cost of at least $40.0 million, over the Area of Interest within 18 months of the execution of the E&P Agreement. After acquiring the seismic data, Hess shall have the right to acquire a 62.5% working interest in the Area of Interest. If Hess acquires the working interest, they commit to drill and evaluate five exploration wells at their sole cost, one of which must be a horizontal well. All costs to plug and abandon the five exploration wells will also be borne solely by Hess. The drilling and evaluation of the five exploration wells must meet the minimum work requirements of the work program. Costs to drill wells after the five exploration wells will be borne 62.5% by Hess and 37.5% by Falcon Australia. As of December 31, 2011, Hess had completed approximately $10 million of the seismic program.

Under existing agreements with two advisors, the Company is obligated to pay a “success fee” in the aggregate amount of 5% for services provided in conjunction with the E&P Agreement with Hess. The success fee is based on the cash or cash-equivalent value of any net amount received directly or indirectly by the Company, including the participation fee and warrants, cost of seismic data commitment and cost of drilling commitment.

In November 2011, Falcon Australia, in accordance with the work program for Permit EP 98, completed the testing and stimulation of the Shenandoah-1 well at its sole cost, and the well has been plugged and abandoned. Falcon Australia provided Hess with the data obtained from these activities, and Hess paid Falcon Australia $2.0 million.

(d) South Africa:

The Company has applied for an exploration permit covering the Technical Cooperation Permit (“TCP”) that it secured in October 2009. All expenditures associated with the TCP and with the application for the exploration permit are charged to operations as exploration and evaluation expenses.

9. Share capital

As at December 31, 2011 and 2010, the Company was authorized to issue an unlimited number of common shares, without par value.

On April 11, 2011, Falcon issued 87,050,000 units (the “Units”) at $0.16 (CDN$0.15) per unit by way of a non-brokered private placement for aggregate gross proceeds of $13,674 (CDN$13,058), before offering costs of $194. Each Unit consists of one common share in the capital of Falcon (each, a “Common Share”) and three-quarters of one Common Share purchase warrant (each, a “Warrant”), each whole Warrant being exercisable into a Common Share for a period of 36 months from the date of its issuance at an exercise price of $0.19 (CDN$0.18) per share. As at the date of the close of the offering, the Warrants were valued at $6,541 and included in derivative liabilities. As at December 31, 2011, the fair value of the Warrants is $2,652 with the change in fair value since issue date of $3,889 included in net finance expenses (see Notes 5 and 12).

In 2010, the Company agreed to issue five million shares of common stock to two former officers (valued at $648). As these shares had not been issued at December 31, 2010 the value of the shares was included in contributed surplus at that date. In 2011 the common shares were issued and the aggregate related value of $648 was reclassified from contributed surplus to share capital.

9. Share capital (continued)

In October 2011, the Company granted 676,800 common shares to non–executive employees and consultants as a bonus consideration for services. These shares were valued at $107 based on $0.16 (CDN$0.15) per share. In October 2011, the Company issued 660,900 common shares in a private placement to certain officers and a director for $97, at a price of $0.16 (CDN$0.15) per share.

The following is a reconciliation of issued and outstanding common shares:

	Number of shares	Share capital
Balance as at January 1, 2010 and 2011	602,216,800	$ 331,215
Issuance of shares in a private placement, net of offering costs	87,050,000	6,924
Issuance of shares to two former officers	5,000,000	648
Options exercised	50,000	15
Shares issued to employees and consultants	676,800	107
Issuance of shares in a private placement to officers and a director	660,900	97
Balance as at December 31, 2011	695,654,500	$ 339,006

10. Net loss per share

Net loss per share – basic and diluted was calculated as follows:

	Year Ended December 31, 2011	2010
Net loss for the year	$ (34,561)	$ (150,247)
Weighted average number of common shares – basic and diluted		
Issued common shares as at beginning of period	602,216,801	602,216,801
Shares issued in a private placement	63,916,164	–
Shares issued to two former officers	3,208,219	–
Share options exercised	46,712	–
Shares issued to employees and consultants	146,485	–
Shares issued in a private placement to officers and a director	143,044	–
Weighted average number of common shares – basic and diluted	669,677,425	602,216,801

All outstanding convertible securities, options and warrants were excluded from the calculation of net loss per share as the effect of these assumed conversions and exercises was anti-dilutive.

11. Convertible debentures

On June 30, 2009, the Company completed an offering of 11,910 units at a price of $865 (CDN$1,000) per unit (the "Offering"). Each unit consisted of one 11% convertible unsecured debenture in the principal amount of $779 (CDN$900) (each, a "Debenture") that matures on the fourth anniversary of its issuance (June 30, 2013) pursuant to the terms of a trust indenture dated June 30, 2009 (the "Trust Indenture"), and 250 common shares in the capital of Falcon (the "Unit Shares") (collectively, a "Unit"). The Debentures bear interest at an annual rate of 11% calculated and payable semi-annually in arrears on January 1 and July 1 in each year commencing January 1, 2010. The Debentures are unsecured direct obligations of the Company. In certain circumstances the Trust Indenture may restrict the Company from incurring additional indebtedness for borrowed money or from mortgaging, pledging or charging its property to secure any additional indebtedness.

Optional Conversion Privilege

Each Debenture may be convertible into common shares of the Company ("Debenture Shares") at the option of the Debenture holder (the "Optional Conversion Privilege") at any time prior to the close of business on the earlier of the maturity date and the business day immediately preceding the date fixed by the Company for redemption of the Debentures (either of such dates, the "Optional Conversion Date"), at a conversion price of CDN$0.60 per common share (the "Conversion Price"), being a conversion ratio of approximately 1,667 Debenture Shares for each CDN$1,000 principal amount of Debentures. The Conversion Price is subject to adjustment upon the occurrence of certain events. Debenture holders converting their Debentures will receive accrued and unpaid interest in cash thereon up to, but not including, the Optional Conversion Date. No fractional shares will be issued. Notwithstanding the foregoing, no Debentures may be converted during the 10 business days preceding and including January 1 and July 1 in each year, commencing January 1, 2010 as the registers of the Indenture Trustee (as defined in the Trust Indenture) will be closed during such periods. The optional conversion privilege is an embedded derivative for accounting purposes and recorded as a liability at fair value (see Note 12).

As at December 31, 2011, the face value of the convertible debentures, due on maturity at June 30, 2013, is $10,512 (CDN$10,719).

As at December 31, 2011, convertible debentures are recorded at $5,960 (2010-$4,519).

12. Derivative liabilities

Derivative liabilities consist of the fair value of the convertible debt conversion feature, the fair value of the private placement warrants and the fair value of the Hess warrants. Changes in the fair value of the derivative liabilities are recorded as part of net finance expenses. The composition of the derivative liabilities as at December 31, 2011 and 2010, and the changes therein for the years then ended, are as follows:

12. Derivative liabilities (continued)

Fair value of:	Agent Warrants (Note 11)	Convertible Debt Conversion Feature (Note 11)	Private Placement Warrants (Note 9)	Hess Warrants (Note 8)	Total
Balance as at January 1, 2010	$ 46	$ 1,421	$ –	$ –	$ 1,467
Derivative gains - unrealized	(46)	(646)	–	–	(692)
Balance as at December 31, 2010	–	775	–	–	775
Fair value of derivatives	–	–	6,541	945	7,486
Derivative gains - unrealized	–	(734)	(3,889)	(324)	(4,947)
Balance as at December 31, 2011	$ –	$ 41	$ 2,652	$ 621	$ 3,314

13. Share based compensation

The Company, in accordance with the policies of the TSX Venture Exchange (“TSXV”), may grant options to directors, officers, employees and consultants, to acquire up to 10% of the Company’s issued and outstanding common stock. The exercise price of each option is based on the market price of the Company’s stock at the date of grant, which may be less a discount in accordance with TSXV policies. The exercise price of all options granted has been based on the market price of the Company’s stock at the date of grant, and no options have been granted at a discount to the market price. The options can be granted for a maximum term of five years. The Company records compensation expense over the vesting period based on the fair value at the grant date of the options granted. These amounts are recorded as contributed surplus. Any consideration paid on the exercise of these options together with the related contributed surplus associated with the exercised options is recorded as share capital.

A summary of the Company's stock option plan as at December 31, 2011 and 2010, and changes during the years then ended, is presented below:

	2011		2010	
	Number of options	Weighted average exercise price	Number of options	Weighted average exercise price
Outstanding as at beginning of year	21,764,500	$ 1.81	41,975,000	$ 1.90
Granted	17,810,000	0.15	5,725,000	0.16
Expired	(8,623,333)	1.28	(23,908,500)	0.87
Forfeited	(1,136,667)	0.46	(2,027,000)	1.44
Exercised	(50,000)	0.16	–	–
Outstanding as at end of year	29,764,500	$ 0.41	21,764,500	$ 1.81
Exercisable as at end of year	15,021,000	$ 0.57	14,402,633	$ 2.35

13. Share based compensation (continued)

Of the options granted during the years ended December 31, 2011 and 2010, all vest 1/3 at the date of grant, with the remainder vesting ratably at the anniversary date over the two years thereafter.

The exercise prices of the outstanding options are as follows:

Exercise price	Number of Options	Weighted average exercise price	Weighted average contractual life (years)
$ 0.15	150,000	$ 0.15	4.42
0.15	16,910,000	0.15	4.39
0.15	1,000,000	0.15	3.98
0.16	3,619,500	0.16	3.66
0.54	600,000	0.54	0.62
0.98	1,000,000	0.98	1.35
1.19	6,485,000	1.19	1.43
	29,764,500	$ 0.41	3.47

The fair value of the options was estimated using a Black Scholes model with the following weighted average inputs:

	2011	2010
Fair value as at grant date	$ 0.15	$ 0.11 – 0.12
Share price	0.15	0.15 – 0.17
Exercise price	0.15	0.15 – 0.17
Volatility	105% – 106%	112%
Option life	5.00 years	5.00 years
Dividends	Nil	Nil
Risk-free interest rate	2.23% – 2.44%	1.39% – 2.04%

A forfeiture rate of 16% (2010 - 16%) is used when recording share based compensation. This estimate is adjusted based on the actual forfeiture rate. Share based compensation cost of $2,435 (2010 - $3,516) was recorded during the year ended December 31, 2011. There was no share based compensation expense capitalized during 2011 and 2010.

14. Provisions

(a) Decommissioning provision:

A reconciliation of the decommissioning provision for the years ended December 31, 2011 and 2010 is provided below:

		2011		2010
Balance as at beginning of year	$	6,310	$	5,673
Assumed on an acquisition of assets		–		363
Provisions incurred		–		–
Revision to provisions		2,236		–
Accretion		267		274
Balance as at end of year	$	8,813	$	6,310
Current	$	150	$	–
Long-term		8,663		6,310
Balance as at end of year	$	8,813	$	6,310

The Company's decommissioning provision results from its ownership interest in oil and natural gas assets. The total decommissioning provision is estimated based on the Company's net ownership interest in the wells, estimated costs to reclaim and abandon these wells and the estimated timing of the costs to be incurred in future years. The Company has estimated the net present value of the decommissioning provision to be $8,813 as at December 31, 2011 (2010 – $6,310) based on an undiscounted total future liability of $13,124 (2010 – $14,094). These payments are expected to be made over the next 20 years with the majority of costs to be incurred between 2027 and 2031. The discount factor, being the risk free rate related to the liability, was 2.57% as at December 31, 2011 (2010 – 4.13%).

(b) Legal:

The Company may, from time to time, be involved in various claims, lawsuits, disputes with third parties, or breach of contract incidental to the operations of its business.

On November 10, 2009, as amended on March 16, 2011, the Company was served with a Complaint by a former vendor (the "Vendor") of TXM arising out of a dispute related to TXM's alleged failure to pay for certain oilfield equipment. On July 29, 2011, TXM and the Vendor entered into a settlement agreement resulting in a reduction of the provision of $1,533. All obligations due to the vendor have been paid as at December 31, 2011.

The Company is not currently involved in any claims, disputes, litigation or other actions with third parties which it believes could have a material adverse effect on its financial condition or results of operations.

14. Provisions (continued)

A reconciliation of the litigation provision for the years ended December 31, 2011 and 2010 is provided below:

	2011	2010
Balance as at beginning of year	$ 3,700	$ –
(Reversal of) litigation expense	(1,533)	3,700
Paid	(2,167)	–
Balance as at end of year	$ –	$ 3,700

15. Income taxes

The provision for income taxes in the consolidated financial statements differs from the results that would have been obtained by applying the combined federal and provincial tax rates to the Company's loss before income taxes. The difference results from the following:

	Year Ended December 31, 2011	2010
Loss before income taxes, including non-controlling interests	$ (34,561)	$ (150,247)
Combined federal and provincial tax rate	26.5%	28.5%
Computed income tax benefit	(9,159)	(42,820)
Increase (decrease) in income taxes resulting from:		
Effect of foreign income tax rates	4,437	25,171
Change in income tax rates	887	8,962
Effect of change in foreign exchange rates	688	(5,954)
Unrecognized benefit of loss carryforwards	(1,348)	(685)
Non-deductible stock based compensation	645	955
Derivatives	(937)	(186)
Other	(119)	(113)
Change in deferred tax benefits not recognized	4,906	14,670
Income tax expense	$ –	$ –

15. Income taxes (continued)

Income tax rates changed from 28.5% in 2010 to 26.5% in 2011 due to a reduction in both federal and provincial statutory income tax rates. The deductible temporary differences included in the Company's unrecognized deferred income tax assets are as follows:

	Year Ended December 31, 2011	2010
Non-capital losses	$ 142,458	$ 127,626
Exploration and evaluation assets and property, plant and equipment	163,419	127,806
Other	8,387	9,255
	$ 314,264	$ 264,687

The Company has accumulated loss carryforwards as at December 31, 2011 to reduce future years' taxable income as follows:

	2011	Expiration
Canada	25,764	2015 to 2031
United States	15,557	2027 to 2031
Hungary	34,598	No expiration
Australia	66,539	No expiration
	$ 142,458	

The other deductible temporary differences do not expire under current tax legislation. Deferred tax assets have not been recognized in respect of the tax losses, exploration and evaluation assets and other as it is not probable that future tax profit will be available against which the Company can utilize the benefits.

16. Segment Information

All of the Company's operations are in the petroleum and natural gas industry with its principal business activity being in the acquisition, exploration and development of petroleum and natural gas properties. The Company has producing petroleum and natural gas properties located in Canada and considers the results from its operations to relate to the petroleum and natural gas properties. The Company has unproven petroleum and natural gas properties in Hungary and Australia. An analysis of the Company's geographic areas is as follows:

	Canada	United States	Hungary	Australia	South Africa	Total
Year ended December 31, 2011:						
Revenue	$ 31	$ –	$ 2	$ –	$ –	$ 33
Net income (loss)	(2,577)	(2,279)	(28,717)	(708)	(280)	(34,561)
Balance as at December 31, 2011:						
Capital assets	–	166	27,814	48,221	–	76,201

	Canada	United States	Hungary	Australia	South Africa	Total
Year ended December 31, 2010:						
Revenue	$ 24	$ –	$ 4	$ –	$ –	$ 28
Net income (loss)	(7,647)	(2,640)	(136,949)	(2,598)	(413)	(150,247)
Balance as at December 31, 2010:						
Capital assets	44	286	51,688	52,258	–	104,276

17. Related party transactions

Remuneration of Directors and Senior Management

	For the year ended December 31,	
	2011	2010
Directors' fees	$ 158	$ 198
Short-term wages and benefits	1,286	890
Share based compensation	1,222	872
Termination benefits	–	720
	$ 2,666	$ 2,680

Remuneration of Directors and Senior Management includes all amounts earned and awarded to the Company's Board of Directors and Senior Management. Senior Management includes the Company's Chief Executive Officer and President, Chief Operating Officer and Chief Financial Officer.

Directors' fees include Board and Committee Chair retainers and meeting fees. Short-term wages and benefits include salary, benefits and bonuses earned or awarded during the year. Share-based compensation includes expenses related to the Company's long-term incentive compensation plans as disclosed in Note 13 and shares granted as disclosed in Note 9.

18. Commitments and contingencies

(a) Environmental:

Petroleum and natural gas producing activities are subject to extensive environmental laws and regulations. These laws, which are changing, regulate the discharge of materials into the environment and may require the Company to remove or mitigate the environmental effects of the disposal or release of petroleum or chemical substances at various sites. Environmental expenditures are expensed or capitalized depending on the future economic benefit of the cause of the expenditure. Expenditures that relate to an existing condition caused by past operations and that have no future economic benefit are expensed. Liabilities for expenditures of a non-capital nature are recorded when environmental assessment and/or remediation is probable, and the costs can be reasonably estimated.

(b) Lease commitments:

The Company has entered into lease agreements for office space in Denver, Colorado, for the period from January 2012 through April 2017, and in Budapest, Hungary, for the period from November 2010 through October 2013. The Company is obligated to pay the following minimum future rental commitments under non-cancelable operating leases with a remaining term of at least one year:

Year ending December 31,	
2012	$ 247
2013	291
2014	195
2015	202
2016	210
Thereafter	71
	$ 1,216

(c) Australia Work Program:

Under a revised work program approved by the Northern Territory of Australia Government, Department of Resources, on July 6, 2011, the Company is obligated to complete minimum work requirements by expending the following amounts in order to continue to hold the underlying permits in the Beetaloo Basin Project.

Year ending December 31,	
2012	$ 18,152
Less: Acquisition of seismic by Hess under the E&P Agreement	(16,626)
	$ 1,526

19. Financial Instruments and Risk Management

(a) Fair Value

The following tables provide fair value measurement information for financial assets and liabilities as at December 31, 2011 and 2010. The carrying value of cash and cash equivalents, restricted cash, accounts receivable, and accounts payable and accrued expenses included in the consolidated statement of financial position approximate fair value due to the short term nature of those instruments. These assets and liabilities are not included in the following tables.

	December 31, 2011		December 31, 2010	
	Carrying value	Fair value	Carrying value	Fair value
Financial assets:				
Held for trading:				
Cash and cash equivalents, including restricted cash	$ 15,409	$ 15,409	$ 7,325	$ 7,325
Loans and receivables:				
Accounts receivable	$ 1,602	$ 1,602	$ 1,025	$ 1,025
Financial liabilities:				
Other financial liabilities:				
Accounts payable and accrued expenses	$ 3,836	$ 3,836	$ 1,871	$ 1,871
Convertible debentures	$ 5,960	$ 9,670	$ 4,519	$ 9,227

The table below analyses financial instruments carried at fair value, by valuation method. The different levels have been defined as follows:

Level 1 Fair Value Measurements

Level 1 fair value measurements are based on unadjusted quoted market prices.

Level 2 Fair Value Measurements

Level 2 fair value measurements are based on valuation models and techniques where the significant inputs are derived from quoted indices.

Loans and borrowing – The fair value of the loans and borrowings is determined based on current risk free rates adjusted for estimated credit risk, industry risk and market risk premiums.

Level 3 Fair Value Measurements

Level 3 fair value measurements are based on unobservable information. No financial assets or liabilities have been valued using the Level 3 fair value measurements.

19. Financial Instruments and Risk Management (continued)

December 31, 2011	Carrying amount	Fair value
Financial liabilities:		
Conversion feature – convertible debt	41	41
Private placement warrants	2,652	2,652
Hess warrants	621	621
December 31, 2010		
Financial liabilities:		
Conversion feature – convertible debt	775	775

All instruments in the table are Level 2 instruments.

(b) Financial risk disclosures

The Company thoroughly examines the various financial instrument risks to which it is exposed and assesses the impact and likelihood of those risks. These risks may include credit risk, liquidity risk, market risk and other price risks. Where material, these risks are reviewed and monitored by the Board of Directors.

Credit Risk

The Company's credit risk is limited to cash and receivables. The Company maintains cash accounts at three financial institutions. The Company periodically evaluates the credit worthiness of financial institutions, and maintains cash accounts only in large high quality financial institutions, thereby minimizing exposure for deposits in excess of federally insured amounts. On occasion, the Company may have cash in banks in excess of federally insured amounts. The Company believes that credit risk associated with cash is minimal. Receivables are not significant to the Company. The Company's credit risk has not changed significantly from the prior year.

Liquidity Risk

The Company has in place a planning and budgeting process to help determine the funds required to support the Company's normal operating requirements on an ongoing basis and its planned capital expenditures. The Company's overall liquidity risk has not changed from the prior year. Also see Note 1.

The following are the contractual maturities of financial liabilities, including estimated interest payments:

19. Financial Instruments and Risk Management (continued)

December 31, 2011		Carrying amount		Contractual cash flows		One year or less		One to three years
Non-derivative financial liabilities:								
Accounts payable and accrued expenses	$	3,836	$	3,836	$	3,836	$	–
Convertible debentures		5,960		12,245		1,160		11,085
	$	9,796	$	16,081	$	4,936	$	11,085
Derivative financial liabilities:								
Convertible debt conversion feature	$	41	$	–	$	–	$	–
Private placement warrants		2,652		–		–		–
Hess warrants		621		–		–		–
	$	3,314	$	–	$	–	$	–

December 31, 2010		Carrying amount		Contractual cash flows		One year or less		One to three years
Non-derivative financial liabilities:								
Accounts payable and accrued expenses	$	1,871	$	1,871	$	1,871	$	–
Convertible debentures		4,519		16,382		1,181		15,201
	$	6,390	$	18,253	$	3,052	$	15,201
Derivative financial liabilities:								
Convertible debt conversion feature	$	775	$	–	$	–	$	–
	$	775	$	–	$	–	$	–

Currency Risk

Financial instruments that impact the Company's net income (loss) and comprehensive income (loss) due to currency fluctuations include Canadian dollar, Hungarian forint, Euro and Australian dollar denominated cash and cash equivalents, accounts receivable, reclamation deposits, accounts payable, and capital commitments for Hungarian and Australian operations.

19. Financial Instruments and Risk Management (continued)

The Company has a CDN$6,077 convertible debenture, which exposes Falcon to fluctuations in exchange rates between Canadian and U.S. dollars. Such an exposure does also arise as a result of revenue being realized in and expense items, including certain general and administrative and production costs and interest expense on the convertible debt, being incurred in Canadian dollars. A one cent strengthening/weakening of the Canadian dollar against the U.S. dollar would decrease/increase total shareholders' equity and income/loss by less than $100.

The Company's exposure to other currencies, including the Hungarian forint, Euro and Australian dollar, does not result in a significant change to total shareholders' equity and income when the respective currencies strengthen or weaken by one cent against the U.S. dollar.

Interest Rate Risk

The Company has no significant exposure to interest rate risk as its debentures have a fixed rate of interest.

20. Management of Capital

The Company's objectives when managing capital are to safeguard its ability to continue as a going concern in order to explore and develop its petroleum and natural gas properties. The Company manages the components of shareholders' equity and its cash as capital, and makes adjustments to these components in response to the Company's business objectives and the economic climate. To maintain or adjust its capital structure, the Company may issue new common shares or debt instruments, or borrow money or acquire or convey interests in other assets. The Company does not anticipate the payment of dividends in the foreseeable future.

The Company's investment policy is to hold excess cash in highly-liquid, short-term instruments, such as bankers' acceptances and guaranteed investment certificates issued by major Canadian chartered banks or United States financial institutions, with initial maturity terms of less than three months from the original date of acquisition, selected with regard to the Company's anticipated liquidity requirements.

The Company does not expect its current capital resources will be sufficient to meet future acquisition, exploration, development and production plans, operating requirements and convertible debenture obligations, and is dependent upon future debt and equity, or joint venture arrangements, to meet the obligations. See Note 2(c).

21. Supplemental Disclosure

The Company's consolidated statements of operations and comprehensive loss are prepared primarily by nature of expense, with the exception of compensation costs which are included in both exploration and evaluation expenses and general and administrative expenses, and share based compensation which is reflected as a separate financial statement component. The following is a summary of total compensation:

	For the year ended December 31, 2011	2010
Exploration and evaluation expenses	$ 20	$ –
General and administrative expenses	2,535	2,351
Share based compensation	2,435	3,516
	$ 5,590	$ 5,867

22. Explanation of transition from Canadian GAAP to IFRS

Consolidated statement of financial position as at January 1, 2010:

	Notes	Canadian GAAP	Effect of transition to IFRS	IFRS
Assets				
Current assets:				
Cash and cash equivalents		$ 11,804	$ –	$ 11,804
Restricted cash		1,184	–	1,184
Accounts receivable		2,955	–	2,955
Prepaid expenses and other		720	–	720
Inventory held for sale		4,196	–	4,196
Total current assets		20,859	–	20,859
Non-current assets:				
Exploration and evaluation assets	(a)	207,889	(97)	207,792
Property, plant and equipment	(a)	5,974	47	6,021
Other assets		8,277	–	8,277
Total non-current assets		222,140	(50)	222,090
Total assets		$ 242,999	$ (50)	$ 242,949
Liabilities				
Current liabilities:				
Accounts payable and accrued expenses		$ 2,683	$ –	$ 2,683
Non-current liabilities:				
Convertible debentures	(c)	4,031	(765)	3,266
Derivative liabilities	(c) (d)	–	1,468	1,468
Decommissioning provision	(e)	6,106	(433)	5,673
Total non-current liabilities		10,137	270	10,407
Total liabilities		12,820	270	13,090
Equity:				
Share capital		331,215	–	331,215
Contributed surplus	(d) (f)	31,829	2,528	34,357
Equity component of convertible debentures	(c)	5,057	(5,057)	–
Deficit		(137,922)	2,209	(135,713)
Total equity		230,179	(320)	229,859
Total liabilities and equity		$ 242,999	$ (50)	$ 242,949

22. Explanation of transition from Canadian GAAP to IFRS (continued)

Consolidated statement of financial position as at December 31, 2010:

	Notes	Canadian GAAP	Effect of transition to IFRS	IFRS
Assets				
Current assets:				
Cash and cash equivalents		$ 7,274	$ –	$ 7,274
Restricted cash		51	–	51
Accounts receivable		1,025	–	1,025
Prepaid expenses and other		391	–	391
Inventory held for sale		1,678	–	1,678
Total current assets		10,419	–	10,419
Non-current assets:				
Exploration and evaluation assets	(a)	99,262	(507)	98,755
Property, plant and equipment		5,477	44	5,521
Other assets		714	–	714
Total non-current assets		105,453	(463)	104,990
Total assets		$ 115,872	$ (463)	$ 115,409
Liabilities				
Current liabilities:				
Accounts payable and accrued expenses	(a)	$ 5,571	$ (3,700)	$ 1,871
Provision for legal matters	(a)	–	3,700	3,700
Total current liabilities		5,571	–	5,571
Non-current liabilities:				
Convertible debentures		4,519	–	4,519
Derivative liabilities	(c) (d)	–	775	775
Decommissioning provision	(e)	6,893	(583)	6,310
Total non-current liabilities		11,412	192	11,604
Total liabilities		16,983	192	17,175
Equity:				
Share capital		331,215	–	331,215
Contributed surplus	(d) (f)	36,150	1,724	37,874
Equity component of convertible debentures	(b)	5,057	(5,057)	–
Deficit		(284,955)	2,678	(282,277)
Equity attributable to common shareholders		87,467	(655)	86,812
Non-controlling interest		11,422	–	11,422
Total equity		98,889	(655)	98,234
Total liabilities and equity		$ 115,872	$ (463)	$ 115,409

22. Explanation of transition from Canadian GAAP to IFRS (continued)

Consolidated statement of operations and comprehensive loss for the year ended December 31, 2010

	Notes	Canadian GAAP	Effect of transition to IFRS	IFRS
Revenue:				
Oil and natural gas revenue		$ 28	$ –	$ 28
Other income (expense)		(386)	–	(386)
		(358)	–	(358)
Expenses:				
Exploration and evaluation expenses	(a) (b)	–	1,602	1,602
Production and operating expenses		26	–	26
Depletion, depreciation and amortization	(e)	832	(398)	434
Impairment of exploration and evaluation assets	(a) (b)	127,000	(4,889)	122,111
General and administrative expenses		11,323	–	11,323
Share based compensation	(f)	4,321	(805)	3,516
Write-down of inventory available for sale		1,186	–	1,186
Write off of receivable		4,345	–	4,345
Litigation expense	(a)	–	3,700	3,700
		149,033	(790)	148,243
Results from operating activities		(149,391)	790	(148,601)
Finance income	(c) (d)	45	692	737
Finance expenses	(e)	(1,907)	(1,013)	(2,920)
Net finance expenses		(1,862)	(321)	(2,183)
Net loss and comprehensive loss for the period		$ (151,253)	$ 469	$ (150,784)
Net loss and comprehensive loss attributable to:				
Common shareholders		(150,716)	469	(150,247)
Non-controlling interest		(537)	–	(537)
Net loss and comprehensive loss for the period		$ (151,253)	$ 469	$ (150,784)

22. Explanation of transition from Canadian GAAP to IFRS (continued)

Notes to reconciliations:

(a) IFRS 1 election for full cost oil and gas entities:

The Company elected to use the IFRS 1 exemption whereby the Canadian GAAP full cost pool was measured upon transition to IFRS as follows:

(i) exploration and evaluation assets were reclassified from the full cost pool to intangible exploration assets at the amount that was recorded under Canadian GAAP; and

(ii) the remaining full cost pool was allocated to the Canadian producing assets.

During 2010, certain costs capitalized as petroleum and natural gas properties under Canadian GAAP, including pre-license costs, have been charged to exploration and evaluation expenses in the consolidated statement of operations and comprehensive loss under IFRS. As at January 1, 2010 and December 31, 2010, this resulted in decreases of $50 and $463, respectively, to exploration and evaluation assets, and as at January 1, 2010, a $50 increase to deficit in the consolidated statement of financial position. For the year ended December 31, 2010, this resulted in an increase to exploration and evaluation expenses of $413.

As at December 31, 2010, the Company reflected $3,700 of litigation expense incurred as an addition to the full cost pool with a corresponding credit reflected in accounts payable and accrued expenses. The treatment of the $3,700 has been revised under IFRS and is reflected in the consolidated statement of operations and comprehensive loss for the year ended December 31, 2010 as litigation expense; however, there was no impact to net loss as a result of a corresponding reduction to the impairment of exploration and evaluation costs. In addition, the amount is reflected as a provision for legal matters in the consolidated statement of financial position at December 31, 2010.

As at January 1, 2010 and December 31, 2010, all but $47 and $44, respectively, of the Company's petroleum and natural gas properties were exploration and evaluation assets. These items have been reclassified to property, plant and equipment.

(b) Exploration and evaluation expenses:

For assets with activities that are temporarily suspended, the Company's accounting policy is to reflect exploration and evaluation expenses in its consolidated statements of operations and comprehensive loss. Under Canadian GAAP, these costs were capitalized as part of the full cost pool. This has resulted in a reduction of $1,189 to capitalized costs as at December 31, 2010. The reduction to capitalized costs has resulted in a corresponding reduction to impairment of exploration and evaluation assets for the year ended December 31, 2010.

Additionally, IFRS does not allow capitalization of expenditures incurred before an exploration license is obtained. As a result, expenditures capitalized as part of the full cost pool under Canadian GAAP of $50 and $413 as at January 1, 2010 and December 31, 2010, respectively, were expensed under IFRS.

22. Explanation of transition from Canadian GAAP to IFRS (continued)

(c) Convertible debentures:

Under Canadian GAAP, the convertible debentures conversion feature was reflected in equity. The debentures are convertible into shares of the Company's common stock at a price fixed in Canadian dollars and, consequently, because of changes in the Canadian dollar to US dollar exchange rate, the equivalent US dollar amount would not be known until the date of conversion. Therefore, under IFRS, the convertible debenture conversion feature is reflected as a liability. As the economic characteristics and risks of the conversion feature are not closely related to those of the host contract, the conversion feature is considered to be an embedded derivative. At each reporting period, the conversion feature is recognized at fair value, with changes in fair value being recognized in results of operations. This has resulted in a reduction to equity of $3,636, an increase to liabilities as at January 1, 2010 and December 31, 2010 of $1,421 and $775, respectively, and an increase to finance income for the year ended December 31, 2010 of $646.

(d) Agent warrants:

Agent warrants are classified as a derivative instrument under IFRS, and are reflected in the consolidated statement of financial position at fair value as at each reporting period. Changes in fair value are reflected in the consolidated statement of operations and comprehensive loss. Under Canadian GAAP, the warrants were reflected in equity at the fair value at the date of issuance. This has resulted in a reduction to contributed surplus of $263 and a reduction to deficit of $217 as at January 1, 2010, an increase to liabilities as at January 1, 2010 of $46, no change to liabilities as at December 31, 2010, and an increase to finance income for the year ended December 31, 2010 of $46.

(e) Decommissioning provision:

Under Canadian GAAP, asset retirement obligations were discounted at credit adjusted risk fee rates and for inflation. Under IFRS, the estimated cash flow to abandon and remediate wells and facilities has been adjusted for a risk free rate of interest, and a corresponding inflation factor, which results in a $433 decrease in the decommissioning provision with a corresponding decrease in deficit.

As a result of the change in the decommissioning provision, accretion expense decreased by $150 during the year ended December 31, 2010 under IFRS as compared to Canadian GAAP. In addition, under Canadian GAAP accretion of the discount of $398 for the year ended December 31, 2010 was included in depletion, depreciation and amortization. Under IFRS, it is included in finance expense.

(f) Share based compensation:

Under Canadian GAAP, the Company recognized an expense related to their share based compensation on a straight-line basis through the date of full vesting and did not incorporate a forfeiture multiple. Under IFRS, the Company is required to recognize the expense over the individual vesting periods for the graded vesting awards and estimate a forfeiture rate. This has resulted in an increase to contributed surplus and deficit of $2,791 as at January 1, 2010, and a decrease to share based compensation of $805 for the year ended December 31, 2010.

22. Explanation of transition from Canadian GAAP to IFRS (continued)

Material adjustments to the statements of cash flows

For the year ended December 31, 2010, pre-license costs of $413, and costs associated with assets whose activities have been temporarily suspended of $1,189 were previously capitalized and reflected as investing activities in the statement of cash flows. Under IFRS, these aggregate costs of $1,602 are expensed and reflected as operating activities in the statement of cash flows.

12346894.1

FALCON OIL & GAS LTD.

Consolidated Financial Statements

Years Ended December 31, 2010 and 2009

(Presented in U.S. Dollars)

KPMG LLP
Chartered Accountants
2700 205 – 5th Avenue SW
Calgary AB T2P 4B9

Telephone (403) 691-8000
Telefax (403) 691-8008
Internet www.kpmg.ca

INDEPENDENT AUDITORS' REPORT

To the Shareholders

Report on the Consolidated Financial Statements

We have audited the accompanying consolidated financial statements of Falcon Oil & Gas Ltd. ("the Company"), which comprise the consolidated balance sheet as at December 31, 2010, the consolidated statements of operations and comprehensive loss, shareholders' equity and cash flows for the year then ended, and notes, comprising 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 Canadian generally accepted accounting principles, 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 our 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, we consider 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 audit 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 consolidated financial position of the Company as at December 31, 2010, and the results of its consolidated operations and its consolidated cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

Emphasis of Matter

Without qualifying our opinion, we draw attention to Note 1 in the consolidated financial statements which describes that the Company's cash requirements in 2011 exceed available capital resources at December 31, 2010. Therefore the Company's ability to continue as a going concern is dependent upon raising additional capital. This condition, along with other matters as set forth in Note 1, indicate the existence of a material uncertainty that may cast significant doubt about the Company's ability to continue as a going concern.

Other Matter

The consolidated financial statements of Falcon Oil & Gas Ltd. for the year ended December 31, 2009, were audited by another auditor who expressed an unmodified opinion on those statements on April 29, 2010.

KPMG LLP Chartered Accountants
Calgary, Canada
April 29, 2011

FALCON OIL & GAS LTD.
CONSOLIDATED BALANCE SHEETS
December 31, 2010 and 2009
(U.S. Dollars, in thousands)

	2010	2009
ASSETS		
Current assets		
Cash and cash equivalents	$ 7,274	$ 11,804
Restricted cash	51	1,184
Amounts receivable (Note 4)	1,025	2,955
Prepaids and other	391	720
Inventory available for sale (Note 5)	1,678	4,196
Total current assets	10,419	20,859
Property and equipment		
Petroleum and natural gas properties (Note 3)	99,262	207,889
Pipeline and facilities	3,831	3,888
Furniture and equipment, net	1,646	2,086
Total property and equipment	104,739	213,863
Other assets	714	8,277
Total assets	$ 115,872	$ 242,999

The accompanying notes are an integral part of these consolidated financial statements.

FALCON OIL & GAS LTD.
CONSOLIDATED BALANCE SHEETS (CONTINUED)
December 31, 2010 and 2009
(U.S. Dollars, in thousands)

	2010	2009
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Accounts payable and accrued expenses	$ 5,571	$ 2,683
Long-term liabilities		
Convertible debentures (Note 6)	4,519	4,031
Asset retirement obligations (Note 7)	6,893	6,106
Total long-term liabilities	11,412	10,137
Total liabilities	16,983	12,820
Commitments and contingencies (Notes 1 & 14)		
Shareholders' equity (Notes 6 & 8)		
Share capital	331,215	331,215
Contributed surplus	36,150	31,829
Equity component of convertible debentures	5,057	5,057
Deficit	(284,955)	(137,922)
	87,467	230,179
Non-controlling interest	11,422	-
	98,889	230,179
Total liabilities and shareholders' equity	$ 115,872	$ 242,999

Going concern (Note 1)

Subsequent events (Note 15)

On behalf of the Board:

"*Gregory Smith*", Director **"*Robert Macaulay*", Director**

The accompanying notes are an integral part of these consolidated financial statements.

FALCON OIL & GAS LTD.
CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE LOSS
Years Ended December 31, 2010 and 2009
(U.S. Dollars, in thousands, except share and per share amounts)

	2010	2009
Petroleum revenue	$ 28	$ 69
Costs and expenses		
Production costs	26	43
General and administrative	11,323	13,294
Stock based compensation (Note 8)	4,321	5,452
Impairment of petroleum and natural gas properties (Note 3)	127,000	45,045
Depreciation, depletion, amortization and accretion	832	842
Write-down of inventory available for sale	1,186	1,559
Write off of receivable (Note 3)	4,345	-
	149,033	66,235
Other income (expense)		
Interest expense	(1,065)	(879)
Interest income	45	333
Gain (loss) on foreign exchange	(842)	2,573
Other income (expense)	(386)	211
	(2,248)	2,238
Net loss and comprehensive loss	$ (151,253)	$ (63,928)
Net loss and comprehensive loss attributable to:		
Owners of the Company	$ (150,716)	$ (63,928)
Non-controlling interest	(537)	-
Net loss and comprehensive loss	$ (151,253)	$ (63,928)
Net loss per common share – basic and diluted	$ (0.250)	$ (0.107)
Weighted average number of common shares outstanding – basic and diluted	602,216,801	598,214,479

The accompanying notes are an integral part of these consolidated financial statements.

FALCON OIL & GAS LTD.
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY
Years Ended December 31, 2010 and 2009
(U.S. Dollars, in thousands, except share amounts)

	Shares	Share Capital	Contributed Surplus	Equity Component of Convertible Debentures	Deficit
January 1, 2009	595,799,301	$ 331,179	$ 24,005	$ -	$ (73,994)
Common shares issued for cash (Note 6)	2,977,500	1,030	263	5,057	-
Common shares issued upon exercise of warrants	3,440,000	1,275	-	-	-
Share issuance costs	-	(160)	-	-	-
Agents warrants (Note 8)	-	(2,109)	2,109	-	-
Stock based compensation	-	-	5,452	-	-
Net loss	-	-	-	-	(63,928)
December 31, 2009	602,216,801	331,215	31,829	5,057	(137,922)
Settlement with stock to be issued (Note 8)	-	-	648	-	-
Stock based compensation	-	-	3,673	-	-
Non-controlling interest dilution gain (Note 8)	-	-	-	-	3,683
Net loss	-	-	-	-	(150,716)
December 31, 2010	602,216,801	$ 331,215	$ 36,150	$ 5,057	$ (284,955)

The accompanying notes are an integral part of these consolidated financial statements.

FALCON OIL & GAS LTD.
CONSOLIDATED STATEMENTS OF CASH FLOWS
Years Ended December 31, 2010 and 2009
(U.S. Dollars, in thousands)

	2010	2009
Cash flows from operating activities		
Net loss	$ (151,253)	$ (63,928)
Adjustments to reconcile net loss to net cash used in operating activities		
Stock based compensation	4,321	5,452
Depreciation, depletion and accretion	832	842
Impairment of petroleum and natural gas properties	127,000	45,045
Write off of receivable	4,345	-
Unrealized foreign exchange (gain) loss	842	(2,573)
Accretion of equity component of convertible debentures	(334)	632
Amortization of deferred financing costs	371	185
Other	89	-
Changes in non-cash working capital accounts		
Amounts receivable	1,994	9,437
Prepaids and other	384	900
Writedown of inventory available for sale	1,186	1,559
Inventory available for sale	1,331	497
Other assets	843	(14)
Accounts payable and accrued expenses	(442)	(10,298)
Net cash provided by (used in) operating activities	(8,491)	(12,264)
Cash flows from investing activities		
Petroleum and natural gas properties	(3,100)	(8,836)
Pipeline and facilities	56	-
Furniture and equipment	(51)	(226)
Increase in other assets	-	(2,381)
Net cash used in investing activities	(3,095)	(11,443)
Cash flows from financing activities		
(Increase) decrease in restricted cash	1,132	(1,184)
Proceeds from unit offering	-	10,302
Proceeds from unit offering by subsidiary, net	5,591	-
Proceeds from exercise of warrants and stock options	-	1,275
Offering costs	-	(1,530)
Net cash provided by financing activities	6,723	8,863
Effect of exchange rate on cash and cash equivalents	333	1,101
Net decrease in cash and cash equivalents	(4,530)	(13,743)
Cash and cash equivalents, beginning of year	11,804	25,547
Cash and cash equivalents, end of year	$ 7,274	$ 11,804

The accompanying notes are an integral part of these consolidated financial statements.

FALCON OIL & GAS LTD.
CONSOLIDATED STATEMENTS OF CASH FLOWS (CONTINUED)
Years Ended December 31, 2010 and 2009
(U.S. Dollars, in thousands)

	2010	2009
Supplemental schedule of cash flow information:		
Cash paid for interest	$ 1,092	$ 569
Supplemental disclosures of non-cash investing and financing activities:		
Acquisition of 25% working interest in Beetaloo Basin:		
Issuance of stock in Falcon Oil & Gas Australia Limited	$ 10,000	$ -
JIB receivable (Note 3)	1,725	-
	$ 11,725	$ -
Services exchanged for stock in Falcon Oil & Gas Australia Limited	$ 170	$ -
Petroleum and natural gas properties acquired in exchange for a note receivable and other assets	$ -	$ 5,308

The accompanying notes are an integral part of these consolidated financial statements.

NOTE 1 – ORGANIZATION AND GOING CONCERN

Falcon Oil & Gas Ltd. ("Falcon") was incorporated under the laws of British Columbia on January 18, 1980.

As of December 31, 2010, the Company has producing petroleum and natural gas properties in Alberta, Canada and exploration projects in Hungary and Australia. The Company's exploration projects in Hungary and Australia continue to be evaluated, and management believes that the carrying costs of these projects are recoverable. Should the Company be unsuccessful in these exploration activities, the carrying cost of these prospects may be charged to operations.

The Company is in the business of acquiring, exploring and developing petroleum and natural gas properties which, by its nature, involves a high degree of risk, and there can be no assurance that current exploration programs will result in profitable operations. The recoverability of the carrying value of the petroleum and natural gas properties and the Company's continued existence is dependent upon the preservation of its interests in the underlying properties, the discovery of economically recoverable reserves, the achievement of profitable operations, or the ability of the Company to obtain financing or, alternatively, upon the Company's ability to economically dispose of its interests. Certain of the Company's petroleum and natural gas properties are subject to the risks associated with foreign investment, including increases in taxes and royalties, renegotiation of contracts, currency exchange fluctuations and political uncertainty.

GOING CONCERN

For the year ended December 31, 2010, the Company incurred a net loss of $150,716 and, as at December 31, 2010, had a deficit of $284,955 and working capital of $4,848. The Company's 2011 cash requirements for operations and spending required to maintain its Australian permits exceed available capital resources at December 31, 2010. As a result, the Company's ability to continue as a going concern is dependent upon its ability to raise additional capital and secure an industry partner for its operations in Australia and Hungary.

The Company has been focused on securing equity financing and joint venture funding for its operations in the Beetaloo Basin located in the Northern Territory, Australia, and joint venture funding for its operations in the Makó Trough located in Hungary. As discussed in Note 15, on April 28, 2011, the Company entered into an Evaluation and Participation Agreement with Hess Australia (Beetaloo) Pty. Ltd. for the Beetaloo Basin project.

Additional capital may also be sought from existing shareholders and/or from the sale of additional common shares or other debt or equity instruments. As discussed in Note 15, on April 11, 2011 the Company completed a non-brokered private placement for aggregate proceeds of CDN$13,058. There is no assurance that additional capital will be available to the Company on acceptable terms or at all.

In the longer term, the recoverability of the carrying value of the Company's long-lived assets is dependent upon the Company's ability to preserve its interest in the underlying petroleum and natural gas properties, the discovery of economically recoverable reserves, the achievement of profitable operations, and the ability of the Company to obtain financing to support its acquisition, exploration, development and production activities.

These consolidated financial statements are prepared in accordance with Canadian generally accepted accounting principles ("Canadian GAAP") appropriate for a going concern. The going concern basis of accounting assumes the Company will continue to realize the value of its assets and discharge its liabilities and other obligations in the ordinary course of business. There is uncertainty as to whether the Company will be able to realize its assets and discharge its liabilities in the normal course of operations. Should the Company be required to realize the value of its assets in other than the ordinary course of business, the net realizable value of its assets may be materially less than the amounts shown in the consolidated financial statements. These consolidated financial statements do not include any adjustments to the amounts and classifications of assets and liabilities that may be necessary should the Company be unable to repay its liabilities and meet its other obligations in the ordinary course of business or continue operations.

NOTE 2 – SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

BASIS OF PRESENTATION

The accompanying consolidated financial statements include Falcon and its wholly owned subsidiaries: Mako Energy Corporation ("Mako"), a Delaware company, TXM Oil and Gas Exploration Kft., a Hungarian limited liability company doing business as TXM Energy, LLC ("TXM"), TXM Marketing Trading & Service, LLC ("TXM Marketing"), a Hungarian limited liability company, and Falcon Oil & Gas Australia Limited ("Falcon Australia") (collectively "the Company"). All significant intercompany transactions and balances have been eliminated on consolidation.

The accompanying consolidated financial statements have been prepared in accordance with Canadian GAAP and are presented in United States dollars.

PETROLEUM AND NATURAL GAS PROPERTIES

The Company utilizes the full cost method of accounting for petroleum and natural gas properties. Under this method, subject to a limitation based on estimated value, all costs associated with property acquisition, exploration and development, including costs of unsuccessful exploration, are capitalized within a cost center. No gain or loss is recognized upon the sale or abandonment of undeveloped or producing petroleum and natural gas properties unless the sale represents a significant portion of petroleum and natural gas properties and the gain significantly alters the relationship between capitalized costs and proved petroleum and natural gas reserves of the cost center, unless such a disposition would alter the depletion and depreciation rate by 20% or more.

Depreciation, depletion and amortization of petroleum and natural gas properties is computed on the units of production method based on proved reserves and production volumes before royalties. Amortizable costs include estimates of future development costs of proved undeveloped reserves.

Capitalized costs of petroleum and natural gas properties may not exceed an amount equal to the present value of the estimated future net cash flows from proved petroleum and natural gas reserves plus the cost, or estimated fair market value, if lower, of unproved properties. Should capitalized costs exceed this ceiling, impairment is recognized. The present value of estimated future net cash flows is computed by applying forecast prices of petroleum and natural gas to estimated future production of proved petroleum and natural gas reserves as of year end, less estimated future expenditures to be incurred in developing and producing the proved reserves and assuming continuation of existing economic conditions.

The Company's unproved properties are excluded from costs subject to depletion and are evaluated quarterly by management for the possibility of potential impairment. If unproved properties are considered to be impaired, they will be reclassified to proved properties and included in the ceiling test and the depreciation, depletion and amortization calculations on a country-by-country basis.

The amounts reflected as petroleum and natural gas properties represent costs to date, and are not necessarily indicative of present or future values. The recoverability of these amounts and any additional amounts required to place the Company's properties into commercial production are dependent upon certain factors. These factors include the existence of reserves sufficient for commercial production and the Company's ability to obtain the required financing necessary to develop its petroleum and natural gas properties.

ASSET RETIREMENT OBLIGATIONS

The Company recognizes the fair value of obligations associated with the retirement of long-lived assets in the period the asset is put into use, with a corresponding increase to the carrying amount of the related asset. The obligations recognized are statutory, contractual or legal obligations. The liability is adjusted over time for changes in the value of the liability through accretion charges which are included in depletion, depreciation and accretion expense.

NOTE 2 – SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

PROPERTY AND EQUIPMENT

Furniture and equipment is recorded at cost. Depreciation and amortization is recorded using the straight-line method over the estimated useful lives of the related assets of two to seven years. Pipeline and facilities are recorded at cost, and will be depreciated upon commencement of production. Expenditures for replacements, renewals, and betterments are capitalized. Maintenance and repairs are charged to operations as incurred.

REVENUE RECOGNITION

The Company recognizes petroleum and natural gas revenues from its interests in producing wells as petroleum and natural gas is produced and sold from these wells and ultimate collection is reasonably assured. Interest income is recognized as earned and when collection is reasonably assured.

IMPAIRMENT OF LONG-LIVED ASSETS

Long-lived assets, other than petroleum and natural gas properties, are assessed for impairment when events and circumstances warrant. The carrying value of a long-lived asset is impaired when the carrying amount exceeds the estimated undiscounted net cash flow from use and fair value. In that event, the amount by which the carrying value of an impaired long-lived asset exceeds its fair value is charged to operations. The Company has not recognized any impairment losses on non petroleum and natural gas long-lived assets.

INCOME TAXES

Income taxes are recorded using the liability method. Under this method, current income taxes are recognized for the estimated income taxes payable for the year. Future income tax assets and liabilities are recognized for the estimated income tax consequences attributable to differences between the financial statement carrying amounts of assets and liabilities and their respective income tax bases. Future income tax assets and liabilities are recognized using enacted or substantively enacted income tax rates. Future income tax assets are recognized with respect to deductible temporary differences and loss carry forwards only to the extent that their realization is considered more likely than not.

USE OF ESTIMATES

The preparation of financial statements in conformity with Canadian GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

The Company's consolidated financial statements are based on a number of significant estimates, including petroleum and natural gas reserve quantities which are the basis for the calculation of depreciation, depletion, amortization and impairment of petroleum and natural gas properties, and timing and costs associated with its asset retirement obligations.

The petroleum and natural gas industry is subject, by its nature, to environmental hazards and clean-up costs. At this time, management knows of no substantial costs from environmental accidents or events for which the Company may be currently liable. In addition, the Company's petroleum and natural gas business makes it vulnerable to changes in wellhead prices of crude oil and natural gas. Such prices have been volatile in the past and can be expected to be volatile in the future. By definition, proved reserves are based on forecasted petroleum and natural gas prices and estimated reserves. Price declines reduce the estimated value of proved reserves and increase annual depreciation, depletion and amortization expense (which is based on proved reserves).

NOTE 2 – SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

NET INCOME (LOSS) PER COMMON SHARE

Basic net income (loss) per common share is based on the weighted average number of common shares outstanding during the period. Diluted net income (loss) per common share reflects the potential dilution that could occur if securities or other contracts to issue common stock were exercised or converted into common stock. All outstanding convertible securities, options and warrants were excluded from the calculation of net loss per common share as the effect of these assumed conversions and exercises was anti-dilutive.

STOCK BASED COMPENSATION

The Company records compensation expense over the vesting period based on the fair value of options granted to employees, directors and consultants. These amounts are recorded as contributed surplus. Any consideration paid by employees, directors or consultants on the exercise of these options is recorded as share capital together with the related contributed surplus associated with the exercised options.

CASH EQUIVALENTS

For purposes of reporting cash flows, the Company considers as cash equivalents all highly liquid investments with a maturity of three months or less at the time of purchase.

INVENTORY AVAILABLE FOR SALE

Inventory available for sale is carried at the lower of cost or net realizable value using the specific identification method. Write downs to net realizable value may be reversed, to the extent of the original write down, if there is clear evidence of an increase in value due to a change in circumstances.

TRANSLATION OF FOREIGN CURRENCIES

The Company's foreign operations, conducted through its subsidiaries, are of an integrated nature and, accordingly, the temporal method of foreign currency translation is used for conversion of foreign-denominated amounts into U.S. dollars. Monetary assets and liabilities are translated into U.S. dollars at the rates prevailing on the balance sheet date. Other assets and liabilities are translated into U.S. dollars at the rates prevailing on the transaction dates. Revenues and expenses arising from foreign currency transactions are translated into U.S. dollars at the rates prevailing on the transaction dates. Exchange gains and losses are recorded as income or expense in the year in which they occur.

DEFERRED FINANCING COSTS

Deferred financing costs are reflected as a reduction to the carrying value of the underlying obligations, and are amortized over the lives of the related obligations using the effective interest method.

CAPITALIZED INTEREST

Interest is capitalized on petroleum and natural gas investments in unproved properties and exploration and development activities that are in progress and qualify for capitalized interest. Capitalized interest is calculated by multiplying the Company's weighted-average interest rate on debt by the amount of qualifying costs. For projects under construction that carry their own financing, interest is calculated using the interest rate related to the project financing. Interest and related costs are capitalized until each project is complete. Capitalized interest cannot exceed gross interest expense. As petroleum and natural gas costs excluded from the depletion, depreciation and amortization base are transferred to unproved or proved properties, any associated capitalized interest is also transferred.

NOTE 2 – SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

COMPARATIVE FIGURES

Certain comparative figures have been reclassified, where applicable, to conform to the current year's presentation. Such reclassifications had no effect on the Company's net loss in any of the years presented.

NEW CANADIAN ACCOUNTING STANDARDS

Business Combinations, Consolidated Financial Statements and Non-Controlling Interests

The CICA issued three new accounting standards in January 2009: Section 1582, Business Combinations ("Section 1582"), Section 1601, Consolidated Financial Statements ("Section 1601"), and Section 1602, Non-controlling Interests ("Section 1602"). These new standards will be effective for fiscal years beginning on or after January 1, 2011.

Section 1582 replaces Section 1581, Business Combinations, and establishes standards for the accounting for a business combination. It provides the Canadian equivalent to International Financial Reporting Standard IFRS 3 – Business Combinations. The section applies prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after January 1, 2011.

Sections 1601 and 1602 together replace Section 1600, Consolidated Financial Statements. Section 1601 establishes standards for the preparation of consolidated financial statements. Section 1601 applies to interim and annual consolidated financial statements relating to fiscal years beginning on or after January 1, 2011. Section 1602 establishes standards for accounting for a non-controlling interest in a subsidiary in consolidated financial statements subsequent to a business combination. It is equivalent to the corresponding provisions of International Financial Reporting Standard IAS 27 – Consolidated and Separate Financial Statements and applies to interim and annual consolidated financial statements relating to fiscal years beginning on or after January 1, 2011.

In August 2009, the CICA issued certain amendments to Section 3251, Equity. The amendments apply to entities that have adopted Section 1602, Non-controlling interests ("Section 1602"). The amendments require separate presentation on the consolidated statements of operations and comprehensive loss of loss attributable to owners of the Company and those attributable to non-controlling interests. The amendments also require that non-controlling interests be presented separately as a component of equity.

Although not mandatory until the year beginning January 1, 2011, the Company has adopted Sections 1582, 1601 and 1602, and reflected the impact of Section 1602 in the accompanying consolidated financial statements. There was no impact as a result of the adoption of Sections 1582 and 1601.

International Financial Reporting Standards

The AcSB has determined that Canadian accounting standards for publicly-listed companies will converge with International Financial Reporting Standards ("IFRS") effective for interim and annual periods beginning on or after January 1, 2011. The adoption of IFRS in 2011 will require restatement for comparative purposes of figures presented for the 2010 fiscal year. The Company understands there may be material differences between Canadian GAAP and IFRS, and is therefore carrying out a project with a view to understanding the possible future effects of the transition to IFRS.

(U.S. Dollars, in thousands, except share and per share amounts)

NOTE 3 – PETROLEUM AND NATURAL GAS PROPERTIES

Interests in petroleum and natural gas proven and unproven properties include the following acquisition, exploration and development costs:

	Hungary	Canada	Romania	Australia	South Africa	Total
December 31, 2009	**$ 168,528**	**$ 47**	**$ -**	**$ 39,314**	**$ -**	**$ 207,889**
Acquisition costs	-	-	-	11,725	16	11,741
Exploration costs	4,624	-	-	1,201	447	6,272
Development costs	-	-	-	-	-	-
Asset retirement obligation	345	-	-	18	-	363
Impairment loss	(127,000)	-	-	-	-	(127,000)
Depletion and depreciation	-	(3)	-	-	-	(3)
December 31, 2010	**$ 46,497**	**$ 44**	**$ -**	**$ 52,258**	**$ 463**	**$ 99,262**

	Hungary	Canada	Romania	Australia	South Africa	Total
January 1, 2009	**$ 210,926**	**$ 74**	**$ 29**	**$ 25,991**	**$ -**	**$ 237,020**
Acquisition costs	-	-	16	5,734	-	5,750
Exploration costs	2,047	-	-	7,400	-	9,447
Development costs	-	(5)	-	-	-	(5)
Asset retirement obligation	394	-	-	189	-	583
Impairment loss	(45,000)	-	(45)	-	-	(45,045)
Cost of ExxonMobil	161	-	-	-	-	161
Depletion and depreciation	-	(22)	-	-	-	(22)
December 31, 2009	**$ 168,528**	**$ 47**	**$ -**	**$ 39,314**	**$ -**	**$ 207,889**

For the year ended December 31, 2010, capitalized interest was nil (2009-$464).

The Company's Canadian properties are all proven and are subject to a ceiling test; the Company's properties in Hungary and Australia are unproven.

Impairment

The Company determined that the carrying value of the Hungarian petroleum and natural gas properties exceeded its estimated recoverable amount. Consequently, for the year ended December 31, 2010, the Company reflected an impairment of petroleum and natural gas properties of $127,000 (2009 - $45,045) in its consolidated statement of operations, with a corresponding reduction to petroleum and natural gas properties in the consolidated balance sheet.

NOTE 3 – PETROLEUM AND NATURAL GAS PROPERTIES (CONTINUED)

For the year ended December 31, 2010, associated with its property in Hungary, the Company has reflected as a charge to the consolidated statement of operations costs of $4,345 (2009 – nil), with a corresponding reduction to a receivable resulting from a prior production development agreement previously recorded as other assets in the consolidated balance sheet.

HUNGARY

The Company holds a long-term Mining Plot (the "Production License") granted by the Hungarian Mining Authority. The lands within the Production License were formerly part of the Company's two petroleum and natural gas exploration licenses – the Tisza License and the Makó License (collectively, the "Exploration Licenses"). The Production License, covering approximately 245,700 acres, gives TXM the exclusive right to explore for petroleum and natural gas on properties located in south central Hungary near the town of Szolnok. The Production License further gives the Company the exclusive right to commercially develop petroleum and natural gas within the area covered by that license.

The balance of the Exploration Licenses outside of the Production License expired on December 31, 2009, and was not eligible for extension. A "Closing Report" submitted in 2010 was accepted by the Mining Authority, and the Company no longer has any Exploration Licenses.

AUSTRALIA

On April 23, 2010, Falcon Australia received notice (the "Notice") from the Department of Resources, Northern Territory Government, that it became the registered owner of the final 25% working interest in four exploration permits ("the Permits"), comprising 7,000,000 acres in the Beetaloo Basin, Northern Territories, Australia, in which it already had a 75% working interest in. The final transfer of ownership was pursuant to Binding Heads of Agreement (the "Agreement") entered into on December 7, 2009, between Falcon and Falcon Australia, and PetroHunter Energy Corporation and Sweetpea Petroleum Pty Ltd ("Sweetpea"), PetroHunter's wholly owned subsidiary, (collectively "PetroHunter"). PetroHunter is a related entity, as the largest single shareholder of PetroHunter at the time of the transaction was also the President and CEO of the Company at that time. Under the Agreement, Falcon Australia issued to Sweetpea 50 million common shares of Falcon Australia (valued at $10 million) and Sweetpea settled a $1,725 obligation to Falcon Australia, for its share of joint interest billings to re-enter the Shenandoah-1 well, as additional consideration for the transfer of Sweetpea's undivided 25% working interest in the Permits. Falcon has been issued 150 million shares of Falcon Australia for conversion of a portion ($30,000) of Falcon Australia's debt payable to Falcon, which approximates Falcon's initial acquisition cost previously paid to Sweetpea for the 75% working interest in the Permits held by Falcon Australia as of the date of the Agreement. Falcon Australia now owns 100% of the Permits.

Under a revised work program approved by the Northern Territory of Australia Government, Department of Resources in June 2010, the Company's required minimum work program obligations, in order to continue to hold the underlying Permits in the Beetaloo Basin, is to expend $6,400 and $8,700 during the years ending December 31, 2011 and 2012, respectively.

As discussed in Note 15, on April 28, 2011 the Company entered into an Evaluation and Participation Agreement with Hess Australia (Beetaloo) Pty. Ltd.

CANADA

The Company has working interests ranging from 12.76% to 25% in four producing petroleum and natural gas wells in Alberta, Canada. During the year ended December 31, 2010, the Company has recorded depreciation, depletion and amortization expense of $3 (2009-$22).

(U.S. Dollars, in thousands, except share and per share amounts)

NOTE 3 – PETROLEUM AND NATURAL GAS PROPERTIES (CONTINUED)

SOUTH AFRICA

On October 27, 2009, Falcon secured a Technical Cooperation Permit (the "TCP") to evaluate the Karoo Basin in central South Africa. Falcon had up to one year to conduct a technical appraisal of the area covered by the TCP, which did not include any well or seismic work obligations. At or before the end of the one year period, Falcon had the exclusive option to apply for an exploration permit covering all or a portion of the TCP. Falcon submitted its application which was accepted on September 7, 2010. Upon receipt of an approved exploration permit, the Company will be required to make a minimum payment of approximately $400, and obtain an approved work program. The TCP covers approximately 7.5 million acres and is located approximately 120 miles northeast of Cape Town, South Africa.

NOTE 4 – AMOUNTS RECEIVABLE

Amounts receivable at December 31, 2010 and 2009 is comprised of the following:

	2010	2009
Joint interest owners	$ 214	$ 856
VAT and GST	271	1,131
Sale of inventory available for sale	-	350
Other	540	618
	$ 1,025	$ 2,955

NOTE 5 – INVENTORY AVAILABLE FOR SALE

Inventory available for sale consists of drill pipe, casing and tubing and is reflected as a current asset at its estimated net realizable value.

During the year ended December 31, 2010, the Company acquired inventory of $65, received $1,397 (2009-$497) from the sale of inventory available for sale and charged to operations $1,186 (2009-$1,559) as a write down to the carrying cost of the inventory to estimated net realizable value of $1,678 (2009-$4,196).

NOTE 6 – CONVERTIBLE DEBENTURES

On June 30, 2009, the Company completed an offering, on a best efforts basis, pursuant to a short form prospectus filed with the securities regulatory authorities in the provinces of British Columbia, Alberta, Saskatchewan, Manitoba, Ontario, Nova Scotia and New Brunswick, of 11,910 units at a price of $865 (CDN$1,000) per unit (the "Offering"). Each unit consisted of one 11% convertible unsecured debenture in the principal amount of $779 (CDN$900) (each, a "Debenture") that matures on the fourth anniversary of its issuance (June 30, 2013) pursuant to the terms of a trust indenture dated June 30, 2009 (the "Trust Indenture"), and 250 common shares in the capital of Falcon (the "Unit Shares") (collectively, a "Unit"). The Debentures bear interest at an annual rate of 11% calculated and payable semi-annually in arrears on January 1 and July 1 in each year commencing January 1, 2010. The Debentures are unsecured direct obligations of the Company. In certain circumstances the Trust Indenture may restrict the Company from incurring additional indebtedness for borrowed money or from mortgaging, pledging or charging its property to secure any additional indebtedness.

NOTE 6 – CONVERTIBLE DEBENTURES (CONTINUED)

Optional Conversion Privilege

Each Debenture may be convertible into common shares of the Company ("Debenture Shares") at the option of the Debenture holder (the "Optional Conversion Privilege") at any time prior to the close of business on the earlier of the maturity date and the business day immediately preceding the date fixed by the Company for redemption of the Debentures (either of such dates, the "Optional Conversion Date"), at a conversion price of CDN$0.60 per common share (the "Conversion Price"), being a conversion ratio of approximately 1,667 Debenture Shares for each CDN$1,000 principal amount of Debentures. The Conversion Price is subject to adjustment upon the occurrence of certain events. Debenture holders converting their Debentures will receive accrued and unpaid interest in cash thereon up to, but not including, the Optional Conversion Date. No fractional shares will be issued. Notwithstanding the foregoing, no Debentures may be converted during the 10 business days preceding and including January 1 and July 1 in each year, commencing January 1, 2010 as the registers of the Indenture Trustee (as defined in the Trust Indenture) will be closed during such periods.

Automatic Conversion Features

If during the two year period following the closing the volume weighted average trading price of the common shares is CDN$0.85 or greater for 20 consecutive trading days, the Debentures will automatically be converted (with no further action on the part of the holder) at the Conversion Price to Debenture Shares and Debenture holders will be entitled to receive accrued and unpaid interest, in cash, to the end of the first 12 month period or 24 month period after closing, as the case may be.

The Offering was conducted by an independent agent (the "Agent"). The Agent and members of any selling group were paid a cash commission equal to 6.25% of the aggregate gross proceeds of the Offering, and received non-transferrable warrants (the "Agent Warrants") to purchase 1,250,550 Falcon common shares. Each Agent Warrant entitles the holder thereof to acquire one Falcon common share for a period of two years following the closing of the Offering (June 30, 2011), at an exercise price of $0.52 (CDN$0.60).

(U.S. Dollars, in thousands, except share and per share amounts)

NOTE 6 – CONVERTIBLE DEBENTURES (CONTINUED)

The following is a summary of the Units sold under the Offering, and the convertible debentures and share capital issued subsequent to the filing of the final short form prospectus in respect of the Offering:

	US$	CDN$
The Offering:		
Units issued	11,910	11,910
Price per unit	$ 865	$ 1,000
Gross proceeds	$ 10,302	$ 11,910
Shares:		
Number of unit shares issued at $0.35 (CDN$0.40) per share	2,977,500	2,977,500
Number of Agent Warrants to acquire shares at $0.52 (CDN$0.60) per share	1,250,550	1,250,550
Allocation of gross proceeds:		
Convertible debentures	$ 4,215	$ 4,873
Equity component of convertible debentures	5,057	5,846
	9,272	10,719
Share capital	1,030	1,191
	$ 10,302	$ 11,910
Value ascribed to Agent Warrants	$ 263	$ 303
Offering costs:		
Allocated to deferred financing costs	$ 1,494	$ 1,722
Allocated to equity	160	190
	$ 1,654	$ 1,912

As of December 31, 2010 and 2009, convertible debentures consist of the following:

	2010	2009
Face amount, at issuance	$ 9,272	$ 9,272
Equity component of convertible debentures	(5,057)	(5,057)
Accretion of equity component of convertible debentures	299	632
Foreign currency translation adjustment	943	493
Offering costs attributable to convertible debentures	(1,494)	(1,494)
Amortization of offering costs attributable to convertible debentures	556	185
	$ 4,519	$ 4,031

The accretion of the equity component of the convertible debt and the amortization of offering costs are included in interest expense over the term of the convertible debentures.

(U.S. Dollars, in thousands, except share and per share amounts)

NOTE 6 – CONVERTIBLE DEBENTURES (CONTINUED)

The value ascribed to the Agent Warrants and to the equity component of the convertible debentures was the fair value at the date of the Offering using the Black-Scholes model, based on the following assumptions:

	Equity component of convertible debentures	Agent Warrants
Expected lives	4.00 years	2.00 years
Risk-free interest rate	1.20%	1.20%
Annualized volatility	121.19%	121.19%
Dividend rate	nil	nil

NOTE 7 – ASSET RETIREMENT OBLIGATIONS

At December 31, 2010, the estimated total undiscounted amount required to settle the asset retirement obligations was $9,480. Costs for asset retirement have been calculated assuming an inflation rate ranging from 3.0% to 5.0%. These obligations will be settled based on the estimated useful lives of the underlying assets, which extend up to 20 years into the future. Obligations have been discounted using a credit-adjusted risk-free interest rate ranging from 6.5% to 11.0%. Changes to asset retirement obligations for the years ended December 31, 2010 and 2009 were as follows:

	2010	2009
Asset retirement obligations – beginning of year	$ 6,106	$ 5,285
Liabilities incurred	363	583
Revisions to estimates	-	-
Liabilities settled	-	-
Liabilities conveyed	-	(97)
Accretion	424	335
Asset retirement obligations – end of year	$ 6,893	$ 6,106

NOTE 8 – SHAREHOLDERS' EQUITY

AUTHORIZED

The Company has authorized an unlimited number of common shares, without par value.

ISSUANCES

See Note 6 regarding the issuance of 2,977,500 common shares in connection with the Offering.

On August 3, 2010 and November 10, 2010, the Company agreed to issue 1,000,000 and 4,000,000 shares of common stock, respectively, to two past officers valued at $168 and $480, respectively. Total charges of $648 are reflected in stock based compensation in the consolidated statement of operations, with a corresponding credit to contributed surplus. Subsequent to December 31, 2010, the 1,000,000 shares were issued, and the 4,000,000 shares have yet to be issued.

As discussed in Note 15, on April 11, 2011, the Company completed a private placement of units.

(U.S. Dollars, in thousands, except share and per share amounts)

NOTE 8 – SHAREHOLDERS' EQUITY (CONTINUED)

WARRANTS

A summary of the number of common shares reserved pursuant to the Company's outstanding share purchase warrants for the years ended December 31, 2010 and 2009 is as follows:

	2010	**2009**
Balance, beginning of year	1,250,550	4,288,750
Agent Warrants (Note 6)	-	1,250,550
Warrants exercised	-	(3,440,000)
Warrants expired	-	(848,750)
Balance, end of year	1,250,550	1,250,550

Common shares reserved for share purchase warrants outstanding as of December 31, 2009 are as follows:

Number of Shares	**Exercise Price**	**Expiry Date**
1,250,550	\$0.52 (CDN\$0.60)	June 30, 2011

In 2009, the Company reclassified from share capital to contributed surplus $2,109, the value of certain unexercised share purchase warrants issued to agents in connection with certain previous offerings by the Company. The reclassification was based on the estimated fair value of such warrants as of the issuance date using the Black-Scholes option-pricing model.

STOCK BASED COMPENSATION

The Company, in accordance with the policies of the TSX Venture Exchange ("TSX-V"), may grant options to directors, officers, employees and consultants, to acquire up to 10% of the Company's issued and outstanding common stock. The exercise price of each option is based on the market price of the Company's stock at the date of grant, which may be less a discount in accordance with TSX-V policies. The exercise price of all options granted has been based on the market price of the Company's stock at the date of grant, and no options have been granted at a discount to the market price. The options can be granted for a maximum term of five years. The Company records compensation expense over the vesting period based on the fair value of options granted. These amounts are recorded as contributed surplus. Any consideration paid on the exercise of these options is recorded as share capital together with the related contributed surplus associated with the exercised options. Of the options granted during the year ended December 31, 2010, all vest 1/3 at the date of grant, with the remainder vesting ratably at the anniversary date over the two years thereafter. There were no options granted during the year ended December 31, 2009.

(U.S. Dollars, in thousands, except share and per share amounts)

NOTE 8 – SHAREHOLDERS' EQUITY (CONTINUED)

A summary of the Company's stock option plan as of December 31, 2010 and 2009, and changes during the years then ended, is presented below:

	2010		2009	
	Options	Weighted-Average Exercise Price	Options	Weighted-Average Exercise Price
Outstanding at beginning of year	41,975,000	$1.90	46,950,000	$1.90
Granted	5,725,000	$0.16	-	-
Exercised	-	-	-	-
Expired	(23,908,500)	$0.87	(3,195,000)	$3.11
Forfeited	(2,027,000)	$1.44	(1,780,000)	$2.07
Outstanding at end of year	21,764,500	$1.81	41,975,000	$1.48
Options exercisable at end of year	14,402,633	$2.35	32,576,000	$1.40

The following summarizes information about stock options outstanding and exercisable at December 31, 2010:

Options Outstanding	Options Exercisable	Exercise price	Weighted average remaining contractual life	Expiry date
5,999,000	5,999,000	$3.98	0.35 years	May 7, 2011
1,641,000	1,312,800	$2.83	0.94 years	December 9, 2011
600,000	360,000	$0.54	1.62 years	August 17, 2012
1,000,000	600,000	$0.98	2.35 years	May 6, 2013
7,335,000	4,401,000	$1.19	2.43 years	June 5, 2013
4,189,500	1,396,500	$0.16	4.66 years	August 30, 2015
1,000,000	333,333	$0.15	4.98 years	December 24, 2015
21,764,500	14,402,633			

At December 31, 2010, the weighted average remaining contractual life of stock options outstanding was 2.26 years.

The weighted average fair value of the options granted during the year ended December 31, 2010 was $0.16.

The Company measures compensation costs using the fair value-based method for employee and non-employee stock options. Compensation costs have been determined based on the fair value of the options at the grant date, for employees, and at the balance sheet for non-employees using the Black-Scholes option-pricing model.

(U.S. Dollars, in thousands, except share and per share amounts)

NOTE 8 – SHAREHOLDERS' EQUITY (CONTINUED)

The following assumptions were used for stock options granted:

	2010
Expected life of options	3.25 to 5.00 years
Risk-free interest rate	2.06% to 2.44%
Annualized volatility	112.18% to 113.76%
Dividend rate	Nil
Estimated forfeiture rate	Nil

Option-pricing models require the use of estimates and assumptions including the expected volatility of the Company's share price, the expected life of the option and the risk free interest rate. Changes in the underlying assumptions can materially affect the fair value estimates.

FALCON AUSTRALIA OFFERING

In January 2010, Falcon Australia commenced the private placement sale of up to 50 million shares of its common stock ("FA Share") to sophisticated or professional investors within the meaning of sections 708(8) and 708(11) of the Corporations Act 2001 (Australia) pursuant to an Offer Memorandum (the "Offer"), at a price of $1.00 per FA Share with an attached option. Each option entitles the holder to acquire one additional FA Share in respect of each FA Share sold, exercisable at $1.25 for a period of three years from date of issue. The acting broker to the Offer received as a brokerage fee 6.5% of the funds raised in the Offer together with Options (on the same terms as issued to investors), calculated at 6.5% of the number of shares issued in the Offer. In June and November 2010, Falcon Australia closed on gross proceeds from the Offer of $4,896 and $1,218, respectively, before costs of the Offer of $646. The proceeds from the Offer are to be utilized for operations in Australia. Giving effect to the closings of the Offer and the Agreement, Falcon has a 72.7% interest in Falcon Australia.

NON-CONTROLLING INTEREST

At December 31, 2010, non-controlling interest in Falcon Australia is comprised of the following:

	Shares	Amount
Issuance of shares to Sweetpea for 25% working interest	50,000,000	$ 9,553
Issuance of shares for services	280,000	95
Sale of shares pursuant to offer memorandum	6,113,237	2,982
Costs of offer memorandum	-	(671)
Net loss attributable to non-controlling interest	-	(537)
	56,393,237	$ 11,422

Deficit has been credited $3,683 for the dilution gain attributable to the change in ownership of Falcon Australia.

(U.S. Dollars, in thousands, except share and per share amounts)

NOTE 9 – RELATED PARTY TRANSACTIONS

Unless otherwise stated, transactions between related parties are measured at the exchange amount, being the amount of consideration agreed to between the parties.

In 2010 and 2009, the Company entered into certain agreements and transactions with PetroHunter, a related entity, whose largest single shareholder at that time was also the President and CEO of the Company at that time, including the acquisition of working interests in the Beetaloo Basin Project. See Note 3.

During the year ended December 31, 2010 and 2009, the Company incurred $128 (2009-$325) to a current director (2009 – two directors) of the Company for advisory and consulting services rendered.

NOTE 10 – SEGMENT INFORMATION

All of the Company's operations are in the petroleum and natural gas industry with its principal business activity being in the acquisition, exploration and development of petroleum and natural gas properties. The Company has producing petroleum and natural gas properties located in Canada and considers the results from its operations to relate to the petroleum and natural gas properties. The Company has unproven petroleum and natural gas properties in Hungary and Australia. An analysis of the Company's geographic areas is as follows:

	Canada	United States	Hungary	Australia	South Africa	Total
Year ended December 31, 2010						
Revenue	$ 24	$ -	$ 4	$ -	$ -	$ 28
Net income (loss)	(8,379)	(2,640)	(137,099)	(2,598)	-	(150,716)
As of December 31, 2010						
Capital assets	44	286	51,688	52,258	463	104,739

	Canada	United States	Hungary	Australia	Romania	Total
Year ended December 31, 2009						
Revenue	$ 39	$ -	$ 30	$ -	$ -	$ 69
Net income (loss)	(10,247)	(2,812)	(50,225)	(599)	(45)	(63,928)
As of December 31, 2009						
Capital assets	47	533	173,969	39,314	-	213,863

(U.S. Dollars, in thousands, except share and per share amounts)

NOTE 11 –FINANCIAL INSTRUMENTS

(a) Fair value

The fair value of financial instruments at December 31, 2010 and 2009 is summarized in the following table. Fair value estimates are made at the balance sheet date, based on relevant quoted market and other information about the financial instruments.

	December 31,			
	2010		2009	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Financial assets:				
Held for trading				
Cash and cash equivalents, and restricted cash	$ 7,325	$ 7,325	$ 12,988	$ 12,988
Loans and receivables				
Amounts receivable	1,025	1,025	2,955	2,955
Financial liabilities:				
Other financial liabilities				
Accounts payable and accrued liabilities	5,571	5,571	2,683	2,683
Convertible debentures	4,519	9,227	4,031	8,791

(b) Financial risk disclosures

The Company thoroughly examines the various financial instrument risks to which it is exposed and assesses the impact and likelihood of those risks. These risks may include credit risk, liquidity risk, market risk and other price risks. Where material, these risks are reviewed and monitored by the Board of Directors.

Credit Risk

The Company's credit risk is limited to cash and receivables. The Company maintains cash accounts at three financial institutions. The Company periodically evaluates the credit worthiness of financial institutions, and maintains cash accounts only in large high quality financial institutions, thereby minimizing exposure for deposits in excess of federally insured amounts. On occasion, the Company may have cash in banks in excess of federally insured amounts. The Company believes that credit risk associated with cash is minimal. Receivables are not significant to the Company. The Company's credit risk has not changed significantly from the prior year.

Liquidity Risk

The Company has in place a planning and budgeting process to help determine the funds required to support the Company's normal operating requirements on an ongoing basis and its planned capital expenditures. The Company's overall liquidity risk has not changed from the prior year. Also see Note 1.

Currency Risk

Financial instruments that impact the Company's net income (loss) and comprehensive income (loss) due to currency fluctuations include Canadian dollar, Hungarian forint, Euro and Australian dollar denominated cash and cash equivalents, accounts receivable, reclamation deposits, accounts payable, and capital commitments for Hungarian and Australian operations.

NOTE 11 –FINANCIAL INSTRUMENTS (CONTINUED)

The Company has a CDN$4.5 million convertible debenture, which exposes Falcon to fluctuations in exchange rates between Canadian and U.S. dollars. Such an exposure does also arise as a result of revenue being realized in and expense items, including certain general and administrative and production costs and interest expense on the convertible debt, being incurred in Canadian dollars. A one cent strengthening/weakening of the Canadian dollar against the U.S. dollar would decrease/increase total shareholders' equity and income/loss by less than $100.

The Company's exposure to other currencies, including the Hungarian forint, Euro and Australian dollar does not result in a significant change to total shareholders' equity and income when the respective currencies strengthen or weaken by one cent against the U.S. dollar.

Interest Rate Risk

The Company is not exposed to interest rate risk as it has no outstanding short term borrowings or investments.

Fair Value Estimation

The carrying value less impairment provision, if necessary, of trade receivables and payables approximate their fair values.

NOTE 12 – MANAGEMENT OF CAPITAL

The Company's objectives when managing capital are to safeguard its ability to continue as a going concern in order to explore and develop its petroleum and natural gas properties. The Company manages the components of shareholders' equity and its cash as capital, and makes adjustments to these components in response to the Company's business objectives and the economic climate. To maintain or adjust its capital structure, the Company may issue new common shares or debt instruments, or borrow money or acquire or convey interests in other assets. The Company does not anticipate the payment of dividends in the foreseeable future.

The Company's investment policy is to hold excess cash in highly-liquid, short-term instruments, such as bankers' acceptances and guaranteed investment certificates issued by major Canadian chartered banks or United States financial institutions, with initial maturity terms of less than three months from the original date of acquisition, selected with regard to the Company's anticipated liquidity requirements.

The Company does not expect its current capital resources will be sufficient to meet future acquisition, exploration, development and production plans, operating requirements and convertible debenture obligations, and is dependent upon future debt and equity, or joint venture arrangements, to meet the obligations. See Note 1.

(U.S. Dollars, in thousands, except share and per share amounts)

NOTE 13 – INCOME TAXES

Income tax expense or recovery is the sum of the Company's provisions for current income taxes and differences between the opening and ending balances of its future income taxes.

The provision for income taxes differs from the amount that would have been obtained by applying the statutory income tax rate of 28.5% (2009 – 30.0%) to the Company's income (loss) before income taxes for the year. For the years ended December 31, 2010 and 2009, the difference results from the following items:

	2010	2009
Expected income tax (recovery)	$ (42,954)	$ (19,179)
Effect of foreign income tax rates	25,171	4,814
Change in effective tax rates	8,129	(62)
Effect of change in foreign exchange rates	(3,427)	(647)
Unrecognized benefit of loss carryforwards	(685)	3,338
Non-deductible stock-based compensation	1,184	1,636
Equity component of convertible debentures and deferred financing costs	11	220
Other	(113)	82
Change in valuation allowance	12,684	9,798
Provision for income taxes	$ –	$ –

The income tax effects of temporary differences that give rise to significant portions of future income tax assets and liabilities at December 31, 2010 and 2009 are as follows:

	2010	2009
Future income tax assets		
Non-capital losses and resource deductions	$ 31,682	$ 23,645
Petroleum and natural gas properties	2,767	-
Other	1,163	-
Less: Valuation allowance	(35,612)	(22,928)
Future income tax liabilities	–	717
Petroleum and natural gas properties	–	717
	$ –	$ –

(U.S. Dollars, in thousands, except share and per share amounts)

NOTE 13 – INCOME TAXES (CONTINUED)

The Company has accumulated loss carryforwards at December 31, 2010 to reduce future years' taxable income as follows:

	2010	Expiration
Canada		
Non-capital losses	$ 20,463	2015 to 2030
Resource deductions	2,377	No expiration
	22,840	
United States	11,332	2027 to 2030
Hungary	26,985	No expiration
Australia	66,469	No expiration
	$ 127,626	

The benefit of the Company's income tax assets has not been recognized in the Company's accounts as it cannot be reasonably estimated at this time if it is more likely than not that such benefit will be realized.

NOTE 14 – COMMITMENTS AND CONTINGENCIES

(a) ENVIRONMENTAL

Petroleum and natural gas producing activities are subject to extensive environmental laws and regulations. These laws, which are constantly changing, regulate the discharge of materials into the environment and may require the Company to remove or mitigate the environmental effects of the disposal or release of petroleum or chemical substances at various sites. Environmental expenditures are expensed or capitalized depending on their future economic benefit. Expenditures that relate to an existing condition caused by past operations and that have no future economic benefit are expensed. Liabilities for expenditures of a non-capital nature are recorded when environmental assessment and/or remediation is probable, and the costs can be reasonably estimated.

(b) CONTINGENCIES

The Company may, from time to time, be involved in various claims, lawsuits, disputes with third parties, or breach of contract incidental to the operations of its business. Except for the following-described dispute, the Company is not currently involved in any claims, disputes, litigation or other actions with third parties which it believes could have a material adverse effect on its financial condition or results of operations.

On November 10, 2009, as amended on March 16, 2011, the Company was served with a Complaint by a former vendor of TXM (the "Vendor") arising out of a dispute related to TXM's alleged failure to pay for certain oilfield equipment. Falcon and TXM intend to vigorously defend against the claim as well as make any appropriate counter claims against the Vendor.

On October 15, 2010, the High Court of Justice, Queen's Bench Division, Commercial Court in the United Kingdom ruled that jurisdiction for this matter is to be in the United Kingdom ("UK"), and not Hungary as claimed by TXM. TXM has filed an appeal to have the lower court order reversed and, if upheld, this would stop all proceedings in the UK. The Company is filing for arbitration in Hungary, even as the lower court order is being appealed. There is no assurance that the Company will prevail in the appeal process or that arbitration in Hungary will be granted.

(U.S. Dollars, in thousands, except share and per share amounts)

NOTE 14 – COMMITMENTS AND CONTINGENCIES (CONTINUED)

Although the Company is of the opinion that it has a meritorious defense to the claim by the vendor, management has determined that an appropriate estimate of the potential liability should be recorded should the Company not prevail in the matter. Accordingly, the December 31, 2010 financial statements include an obligation of $3,700, including estimated interest and fees, related to this claim that is reflected as a charge to petroleum and natural gas properties with a corresponding increase to accounts payable and accrued expenses.

(c) LEASE COMMITMENTS

In April 2006, the Company entered into a lease agreement for office space in Denver, Colorado, for the period from June 2006 through June 2011; and in September 2006 entered into a lease for office space in Budapest, Hungary, for the period from July 2007 through 2013. The Company is obligated to pay the following minimum future rental commitments under non-cancelable operating leases with a remaining term of at least one year:

Year ending December 31,	
2011	$ 138
2012	138
2013	116
	$ 392

(d) AUSTRALIA WORK PROGRAM

Under a work program approved by the Northern Territory of Australia Government, Department of Resources, on March 31, 2010, the Company is obligated to complete minimum work requirements by expending the following amounts in order to continue to hold the underlying permits in the Beetaloo Basin Project (the “Work Program”).

Year ending December 31,	
2011	$ 6,400
2012	8,700
	$ 15,100

NOTE 15 – SUBSEQUENT EVENTS

PRIVATE PLACEMENT

On April 11, 2011, Falcon issued 87,050,000 units (the “Units”) at $0.16 (CDN$0.15) per unit by way of a non-brokered private placement for aggregate gross proceeds of CDN$13,058. Each Unit consists of one common share in the capital of Falcon (each, a “Common Share”) and three-quarters of one Common Share purchase warrant (each, a “Warrant”), each whole Warrant being exercisable into a Common Share for a period of 36 months from the date of its issuance at an exercise price of $0.19 (CDN$0.18) per share. A finders’ fee of $149 is due to a non-related entity.

NOTE 15 – SUBSEQUENT EVENTS (CONTINUED)

BEETALOO BASIN PROJECT - JOINT VENTURE

On April 28, 2011, Falcon Australia entered into an Evaluation and Participation Agreement (the "E&P Agreement") with Hess Australia (Beetaloo) Pty Ltd. ("Hess"). By the terms of the E&P Agreement, Hess will pay $17.5 million to Falcon Australia as a participation fee for the exclusive right to conduct operations for the exploration, drilling, development and production of hydrocarbons from three of the four Permits, and excluding an area comprising 100,000 acres surrounding the Shenandoah-1 well (the "Area of Interest"). In addition, Hess will pay Falcon $2.5 million as consideration for warrants to acquire 10,000,000 common shares in the capital of Falcon at an exercise price of CDN$0.19 per share.

Hess shall acquire seismic data, at its sole cost of at least $40.0 million, over the Area of Interest within 18 months of the execution of the E&P Agreement. After acquiring the seismic data, Hess shall have the right to acquire a 62.5% working interest in the Area of Interest. If Hess acquires the working interest, they commit to drill and evaluate five exploration wells at their sole cost, one of which must be a horizontal well. All costs to plug and abandon the five exploration wells will also be borne solely by Hess. The drilling and evaluation of the five exploration wells must meet the minimum work requirements of the Work Program (see Note 14). Costs to drill wells after the five exploration wells will be borne 62.5% by Hess and 37.5% by Falcon Australia.

By December 31, 2011, Falcon Australia must test and complete the Shenandoah-1 well at their sole cost, and in accordance with the Work Program. After testing and completion, Falcon Australia must provide Hess copies of the data obtained from such activities, and Hess must pay Falcon Australia $2.0 million for the data.

The Company will pay a "success fee" to two advisors in the aggregate amount of 5% for services provided in conjunction with the E&P Agreement with Hess. The success fee is based on the cash or cash-equivalent value of any net amount received directly or indirectly by the Company, including the participation fee, cost of seismic data commitment and cost of drilling commitment.

The transaction as a whole is subject to receipt of all governmental and regulatory consents, including the TSX-V.

FALCON OIL & GAS LTD.

(A Development Stage Company)

Consolidated Financial Statements

Years Ended December 31, 2009 and 2008

(Presented in U.S. Dollars)

AUDITOR'S REPORT

To the Shareholders and the Board of Directors
Falcon Oil & Gas Ltd.

We have audited the consolidated balance sheets of Falcon Oil & Gas Ltd. at December 31, 2009 and 2008, and the consolidated statements of operations and comprehensive loss, shareholders' equity and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company at December 31, 2009 and 2008, and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

"*Hein & Associates LLP*"
Denver, Colorado
April 29, 2010

FALCON OIL & GAS LTD.
(A Development Stage Company)
CONSOLIDATED BALANCE SHEETS
December 31, 2009 and 2008
(U.S. Dollars, in thousands)

	2009	2008
ASSETS		
Current assets		
Cash and cash equivalents	$ 11,804	$ 25,547
Restricted cash (Notes 2 & 6)	1,184	-
Amounts receivable (Note 4)	2,955	10,365
Prepaids and other	720	1,537
Inventory available for sale (Note 5)	4,196	6,852
Total current assets	20,859	44,301
Property and equipment		
Petroleum and natural gas properties (Note 3)	207,889	237,020
Pipeline and facilities	3,888	3,888
Furniture and equipment, net	2,086	2,343
Total property and equipment	213,863	243,251
Other assets (Note 3)	8,277	11,150
Total assets	$ 242,999	$ 298,702

The accompanying notes are an integral part of these consolidated financial statements.

FALCON OIL & GAS LTD.
(A Development Stage Company)
CONSOLIDATED BALANCE SHEETS (CONTINUED)
December 31, 2009 and 2008
(U.S. Dollars, in thousands)

	2009	2008
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Accounts payable and accrued expenses	$ 2,683	$ 12,227
Long-term liabilities		
Convertible debentures (Note 6)	4,031	-
Asset retirement obligations (Note 7)	6,106	5,285
Total long-term liabilities	10,137	5,285
Total liabilities	12,820	17,512
Commitments and contingencies (Notes 1 & 14)		
Shareholders' equity (Notes 6 & 8)		
Share capital	331,215	331,179
Contributed surplus	31,829	24,005
Equity component of convertible debentures	5,057	-
Deficit accumulated during development stage	(137,922)	(73,994)
Total shareholders' equity	230,179	281,190
Total liabilities and shareholders' equity	$ 242,999	$ 298,702

Going concern (Note 1)

Subsequent event (Note 15)

On behalf of the Board:

"Gregory Smith" ____________________,Director **"Thomas Harris"_________________, Director**

The accompanying notes are an integral part of these consolidated financial statements.

FALCON OIL & GAS LTD.
(A Development Stage Company)
CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE LOSS
Years Ended December 31, 2009 and 2008
(U.S. Dollars, in thousands, except share and per share amounts)

	2009	2008
Petroleum revenue	$ 69	$ 60
Direct costs		
Production costs	43	34
Depreciation, depletion, amortization and accretion	357	378
	400	412
Costs and expenses		
Accounting	766	852
Depreciation and amortization	485	450
Consulting	1,279	1,459
Director fees	258	258
Investor relations	1,190	610
Legal costs	1,448	1,553
Office and administrative	2,697	2,544
Payroll and related costs	3,668	2,908
Stock based compensation (Note 8)	5,452	8,481
Travel and promotion	1,988	2,309
Write-down of inventory available for sale	1,559	2,610
	20,790	24,034
Other income (expense)		
Interest expense	(879)	-
Interest income	333	1,548
Impairment of petroleum and natural gas properties (Note 3)	(45,045)	(6,970)
Gain (loss) on foreign exchange	2,573	(5,273)
Other income (expense)	211	(368)
	(42,807)	(11,063)
Loss before income taxes	(63,928)	(35,449)
Provision for income taxes (Note 13)	-	(462)
Net loss and comprehensive loss	$ (63,928)	$ (35,911)
Net loss per common share – basic and diluted	$ (0.107)	$ (0.063)
Weighted average number of common shares outstanding – basic and diluted	598,214,479	566,507,134

The accompanying notes are an integral part of these consolidated financial statements.

FALCON OIL & GAS LTD.
(A Development Stage Company)
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY
Years Ended December 31, 2009 and 2008
(U.S. Dollars, in thousands, except share amounts)

	Shares	Share Capital	Contributed Surplus	Equity Component of Convertible Debentures	Deficit Accumulated During Development Stage
January 1, 2008	565,199,163	$ 310,635	$ 15,524	$ -	$ (38,083)
Exercise of warrants	1,711,250	674	-	-	-
Stock based compensation of options	-	-	8,481	-	-
Conversion of special warrants into common shares (Note 8)	28,888,888	20,000	-	-	-
Share issuance costs	-	(130)	-	-	-
Net loss	-	-	-	-	(35,911)
December 31, 2008	595,799,301	331,179	24,005	-	(73,994)
Common shares issued for cash (Note 6)	2,977,500	1,030	263	5,057	-
Common shares issued upon exercise of warrants	3,440,000	1,275	-	-	-
Share issuance costs	-	(160)	-	-	-
Agents warrants (Note 8)	-	(2,109)	2,109	-	-
Stock based compensation	-	-	5,452	-	-
Net loss	-	-	-	-	(63,928)
December 31, 2009	602,216,801	$ 331,215	$ 31,829	$ 5,057	$ (137,922)

The accompanying notes are an integral part of these consolidated financial statements.

FALCON OIL & GAS LTD.
(A Development Stage Company)
CONSOLIDATED STATEMENTS OF CASH FLOWS
Years Ended December 31, 2009 and 2008
(U.S. Dollars, in thousands)

	2009	2008
Cash flows from operating activities		
Net loss	$ (63,928)	$ (35,911)
Adjustments to reconcile net loss to net cash used in operating activities		
Stock based compensation	5,452	8,481
Depreciation, depletion and accretion	842	828
Impairment of petroleum and natural gas properties	45,045	6,970
Writedown of inventory available for sale	1,559	2,610
Unrealized foreign exchange (gain) loss	(2,573)	5,273
Accretion of equity component of convertible debentures	632	-
Amortization of deferred financing costs	185	-
Other	-	464
Changes in non-cash working capital accounts		
Amounts receivable	9,437	(12,457)
Prepaids and other	900	454
Inventory available for sale	497	4,995
Other assets	(14)	(5,353)
Accounts payable and accrued expenses	(10,298)	15,214
Net cash provided by (used in) operating activities	(12,264)	(8,432)
Cash flows from investing activities		
Petroleum and natural gas properties	(8,836)	(32,679)
Pipeline and facilities	-	(139)
Furniture and equipment	(226)	(761)
Proceeds from ExxonMobil, net of transaction costs	-	21,316
Note receivable – PetroHunter	-	(5,000)
Increase in other assets	(2,381)	-
Net cash used in investing activities	(11,443)	(17,263)
Cash flows from financing activities		
Increase in restricted cash	(1,184)	-
Proceeds from unit offering	10,302	-
Proceeds from exercise of warrants and stock options	1,275	674
Offering costs	(1,530)	(130)
Net cash provided by financing activities	8,863	544
Effect of exchange rate on cash and cash equivalents	1,101	(5,294)
Net decrease in cash and cash equivalents	(13,743)	(30,445)
Cash and cash equivalents, beginning of year	25,547	55,992
Cash and cash equivalents, end of year	$ 11,804	$ 25,547

The accompanying notes are an integral part of these consolidated financial statements.

FALCON OIL & GAS LTD.
(A Development Stage Company)
CONSOLIDATED STATEMENTS OF CASH FLOWS (CONTINUED)
Years Ended December 31, 2009 and 2008
(U.S. Dollars, in thousands)

	2009	2008
Cash and cash equivalents is comprised of:		
Cash	$ 11,804	$ 25,547
Restricted cash (Notes 2 & 6)	1,184	-
	$ 12,988	$ 25,547
Supplemental schedule of cash flow information:		
Cash paid for interest	$ -	$ -
Cash paid for income taxes	$ 525	$ -
Supplemental disclosures of non-cash investing and financing activities:		
Petroleum and natural gas properties acquired with special warrants	$ -	$ 20,000
Petroleum and natural gas properties acquired in exchange for a note receivable and other assets	$ 5,308	$ -
Petroleum and natural gas property costs in accounts payable	$ 770	$ 624

The accompanying notes are an integral part of these consolidated financial statements.

NOTE 1 – ORGANIZATION AND GOING CONCERN

Falcon Oil & Gas Ltd. ("Falcon"), incorporated under the laws of British Columbia on January 18, 1980, is considered a development stage company as defined by Canadian Institute of Chartered Accountants (CICA) Accounting Guideline No. 11.

As of December 31, 2009, the Company has producing petroleum and natural gas properties in Alberta, Canada and exploration projects in Hungary and Australia. The Company's exploration projects in Hungary and Australia continue to be evaluated, and management believes that the carrying costs of these projects are recoverable. Should the Company be unsuccessful in these exploration activities, the carrying cost of these prospects may be charged to operations.

The Company is in the business of acquiring, exploring and developing petroleum and natural gas properties which, by its nature, involves a high degree of risk, and there can be no assurance that current exploration programs will result in profitable operations. The recoverability of the carrying value of the petroleum and natural gas properties and the Company's continued existence is dependent upon the preservation of its interests in the underlying properties, the discovery of economically recoverable reserves, the achievement of profitable operations, or the ability of the Company to obtain financing or, alternatively, upon the Company's ability to economically dispose of its interests. Certain of the Company's petroleum and natural gas properties are subject to the risks associated with foreign investment, including increases in taxes and royalties, renegotiation of contracts, currency exchange fluctuations and political uncertainty.

GOING CONCERN

For the year ended December 31, 2009, the Company incurred a net loss of $63,928 and, as at December 31, 2009, had a deficit accumulated during the development stage of $137,922 and working capital of $18,176. The Company has been focused on securing equity financing and joint venture funding for its operations in the Beetaloo Basin located in the Northern Territory, Australia, and joint venture funding for its operations in the Makó Trough located in Hungary.

In the near term, the Company's ability to continue as a going concern is dependent upon its ability to raise additional capital to fund its operations. Additional capital may be sought from existing shareholders and/or from the sale of additional common shares or other debt or equity instruments (See Note 15 below). There is no assurance such additional capital will be available to the Company on acceptable terms or at all.

In the longer term, the recoverability of the carrying value of the Company's long-lived assets is dependent upon the Company's ability to preserve its interest in the underlying petroleum and natural gas properties, the discovery of economically recoverable reserves, the achievement of profitable operations, and the ability of the Company to obtain financing to support its acquisition, exploration, development and production activities.

These consolidated financial statements are prepared in accordance with Canadian generally accepted accounting principles ("Canadian GAAP") appropriate for a going concern. The going concern basis of accounting assumes the Company will continue to realize the value of its assets and discharge its liabilities and other obligations in the ordinary course of business. Should the Company be required to realize the value of its assets in other than the ordinary course of business, the net realizable value of its assets may be materially less than the amounts shown in the consolidated financial statements. These consolidated financial statements do not include any adjustments to the amounts and classifications of assets and liabilities that may be necessary should the Company be unable to repay its liabilities and meet its other obligations in the ordinary course of business or continue operations.

NOTE 2 – SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

BASIS OF PRESENTATION

The accompanying consolidated financial statements include Falcon and its wholly owned subsidiaries: Mako Energy Corporation ("Mako"), a Delaware company, Falcon Oil & Gas USA, Inc. ("Falcon USA"), a Colorado company, TXM Oil and Gas Exploration Kft., a Hungarian limited liability company doing business as TXM Energy, LLC ("TXM"), TXM Marketing Trading & Service, LLC ("TXM Marketing"), a Hungarian limited liability company, FOG-TXM Kft. ("FOG-TXM"), a Hungarian limited liability company, JVX Energy S.R.L. ("JVX"), a Romanian limited liability company and Falcon Oil & Gas Australia Pty Ltd ("Falcon Australia") (collectively "the Company"). All significant intercompany transactions and balances have been eliminated on consolidation.

The accompanying consolidated financial statements have been prepared in accordance with Canadian GAAP and are presented in United States dollars.

PETROLEUM AND NATURAL GAS PROPERTIES

The Company utilizes the full cost method of accounting for petroleum and natural gas properties. Under this method, subject to a limitation based on estimated value, all costs associated with property acquisition, exploration and development, including costs of unsuccessful exploration, are capitalized within a cost center. No gain or loss is recognized upon the sale or abandonment of undeveloped or producing petroleum and natural gas properties unless the sale represents a significant portion of petroleum and natural gas properties and the gain significantly alters the relationship between capitalized costs and proved petroleum and natural gas reserves of the cost center, unless such a disposition would alter the depletion and depreciation rate by 20% or more.

Depreciation, depletion and amortization of petroleum and natural gas properties is computed on the units of production method based on proved reserves and production volumes before royalties. Amortizable costs include estimates of future development costs of proved undeveloped reserves.

Capitalized costs of petroleum and natural gas properties may not exceed an amount equal to the present value of the estimated future net cash flows from proved petroleum and natural gas reserves plus the cost, or estimated fair market value, if lower, of unproved properties. Should capitalized costs exceed this ceiling, impairment is recognized. The present value of estimated future net cash flows is computed by applying forecast prices of petroleum and natural gas to estimated future production of proved petroleum and natural gas reserves as of year end, less estimated future expenditures to be incurred in developing and producing the proved reserves and assuming continuation of existing economic conditions.

The Company's unproved properties are excluded from costs subject to depletion and are evaluated quarterly by management for the possibility of potential impairment. If unproved properties are considered to be impaired, they will be reclassified to proved properties and included in the ceiling test and the depreciation, depletion and amortization calculations on a country-by-country basis.

The amounts reflected as petroleum and natural gas properties represent costs to date, and are not necessarily indicative of present or future values. The recoverability of these amounts and any additional amounts required to place the Company's properties into commercial production are dependent upon certain factors. These factors include the existence of reserves sufficient for commercial production and the Company's ability to obtain the required financing necessary to develop its petroleum and natural gas properties.

NOTE 2 – SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

ASSET RETIREMENT OBLIGATIONS

The Company recognizes the fair value of obligations associated with the retirement of long-lived assets in the period the asset is put into use, with a corresponding increase to the carrying amount of the related asset. The obligations recognized are statutory, contractual or legal obligations. The liability is adjusted over time for changes in the value of the liability through accretion charges which are included in depletion, depreciation and accretion expense.

PROPERTY AND EQUIPMENT

Furniture and equipment is recorded at cost. Depreciation and amortization is recorded using the straight-line method over the estimated useful lives of the related assets of two to seven years. Pipeline and facilities are recorded at cost, and will be depreciated upon commencement of production. Expenditures for replacements, renewals, and betterments are capitalized. Maintenance and repairs are charged to operations as incurred.

REVENUE RECOGNITION

The Company recognizes petroleum and natural gas revenues from its interests in producing wells as petroleum and natural gas is produced and sold from these wells and ultimate collection is reasonably assured. Interest income is recognized as earned and when collection is reasonably assured.

IMPAIRMENT OF LONG-LIVED ASSETS

Long-lived assets, other than petroleum and natural gas properties, are assessed for impairment when events and circumstances warrant. The carrying value of a long-lived asset is impaired when the carrying amount exceeds the estimated undiscounted net cash flow from use and fair value. In that event, the amount by which the carrying value of an impaired long-lived asset exceeds its fair value is charged to operations. The Company has not recognized any impairment losses on non petroleum and natural gas long-lived assets.

INCOME TAXES

Income taxes are recorded using the liability method. Under this method, current income taxes are recognized for the estimated income taxes payable for the year. Future income tax assets and liabilities are recognized for the estimated income tax consequences attributable to differences between the financial statement carrying amounts of assets and liabilities and their respective income tax bases. Future income tax assets and liabilities are recognized using enacted or substantively enacted income tax rates. Future income tax assets are recognized with respect to deductible temporary differences and loss carry forwards only to the extent that their realization is considered more likely than not.

USE OF ESTIMATES

The preparation of financial statements in conformity with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

The Company's consolidated financial statements are based on a number of significant estimates, including petroleum and natural gas reserve quantities which are the basis for the calculation of depreciation, depletion, amortization and impairment of petroleum and natural gas properties, and timing and costs associated with its asset retirement obligations.

NOTE 2 – SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

The petroleum and natural gas industry is subject, by its nature, to environmental hazards and clean-up costs. At this time, management knows of no substantial costs from environmental accidents or events for which the Company may be currently liable. In addition, the Company's petroleum and natural gas business makes it vulnerable to changes in wellhead prices of crude oil and natural gas. Such prices have been volatile in the past and can be expected to be volatile in the future. By definition, proved reserves are based on forecasted petroleum and natural gas prices and estimated reserves. Price declines reduce the estimated value of proved reserves and increase annual depreciation, depletion and amortization expense (which is based on proved reserves).

NET INCOME (LOSS) PER COMMON SHARE

Basic net income (loss) per common share is based on the weighted average number of common shares outstanding during the period. Diluted net income (loss) per common share reflects the potential dilution that could occur if securities or other contracts to issue common stock were exercised or converted into common stock. All outstanding convertible securities, options and warrants were excluded from the calculation of net (loss) per common share as the effect of these assumed conversions and exercises was anti-dilutive.

STOCK BASED COMPENSATION

The Company has a stock based compensation plan which is described in Note 8. The Company records compensation expense over the vesting period based on the fair value of options granted to employees, directors and consultants. These amounts are recorded as contributed surplus. Any consideration paid by employees, directors or consultants on the exercise of these options is recorded as share capital together with the related contributed surplus associated with the exercised options.

CASH EQUIVALENTS

For purposes of reporting cash flows, the Company considers as cash equivalents all highly liquid investments with a maturity of three months or less at the time of purchase. Restricted cash at December 31, 2009 includes $1,184 (2008-nil) on deposit principally as escrowed interest payments to holders of Falcon's convertible debentures. See Note 6.

INVENTORY AVAILABLE FOR SALE

Inventory available for sale is carried at the lower of cost or net realizable value using the specific identification method. Write downs to net realizable value may be reversed, to the extent of the original write down, if there is clear evidence of an increase in value due to a change in circumstances.

TRANSLATION OF FOREIGN CURRENCIES

The Company's foreign operations, conducted through its subsidiaries, are of an integrated nature and, accordingly, the temporal method of foreign currency translation is used for conversion of foreign-denominated amounts into U.S. dollars. Monetary assets and liabilities are translated into U.S. dollars at the rates prevailing on the balance sheet date. Other assets and liabilities are translated into U.S. dollars at the rates prevailing on the transaction dates. Revenues and expenses arising from foreign currency transactions are translated into U.S. dollars at the rates prevailing on the transaction dates. Exchange gains and losses are recorded as income or expense in the year in which they occur.

DEFERRED FINANCING COSTS

Deferred financing costs are reflected as a reduction to the carrying value of the underlying obligations, and are amortized over the lives of the related obligations using the effective interest method.

NOTE 2 – SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

CAPITALIZED INTEREST

Interest is capitalized on petroleum and natural gas investments in unproved properties and exploration and development activities that are in progress and qualify for capitalized interest. Capitalized interest is calculated by multiplying the Company's weighted-average interest rate on debt by the amount of qualifying costs. For projects under construction that carry their own financing, interest is calculated using the interest rate related to the project financing. Interest and related costs are capitalized until each project is complete. Capitalized interest cannot exceed gross interest expense. As petroleum and natural gas costs excluded from the depletion, depreciation and amortization base are transferred to unproved or proved properties, any associated capitalized interest is also transferred.

COMPARATIVE FIGURES

Certain comparative figures have been reclassified, where applicable, to conform to the current year's presentation. Such reclassifications had no effect on the Company's net loss in any of the years presented.

ADOPTION OF NEW ACCOUNTING STANDARDS

Goodwill and intangible assets

Effective on January 1, 2009, the Company adopted Section 3064, "Goodwill and intangible assets" ("Section 3064"). Section 3064 replaces Sections 3062 "Goodwill and other intangible assets" and Section 3450 "Research and development costs". Section 3064 establishes standards for the recognition, measurement and disclosure of goodwill and intangible assets including internally developed intangible assets. The adoption of Section 3064 did not have a significant effect on the Company's consolidated financial statements.

Credit risk and fair value of financial assets and liabilities

In January 2009, the CICA issued EIC-173, "Credit Risk and the Fair Value of Financial Assets and Financial Liabilities". The EIC provides guidance on how to take into account credit risk of an entity and counterparty when determining the fair value of financial assets and financial liabilities. This standard was applied by the Company effective January 1, 2009 and did not have a significant effect on the Company's consolidated financial statements.

Financial instruments – recognition and measurement

During 2009, the CICA amended Section 3855 "Financial Instruments – Recognition and Measurement". This revised standard was applied by the Company effective for the year ended December 31, 2009, and the application did not have a significant effect on the Company's consolidated financial statements.

Financial instruments – disclosures

During 2009, the CICA amended Section 3862, "Financial Instruments – Disclosures", which requires enhanced disclosures of the fair values of financial instruments. Financial instruments recognized at fair value on the consolidated balance sheet must now be classified in fair value hierarchy levels based on their valuations. This revised standard was applied by the Company effective for the year ended December 31, 2009, and the requirements of the revised standard are included in Note 11.

NOTE 2 – SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

NEW CANADIAN ACCOUNTING STANDARDS

The Accounting Standards Board ("AcSB") of the CICA has issued new accounting standards that the Company is required to consider for adoption, as follows:

Business Combinations, Consolidated Financial Statements and Non-Controlling Interests

The CICA issued three new accounting standards in January 2009: Section 1582, Business Combinations ("Section 1582"), Section 1601, Consolidated Financial Statements ("Section 1601"), and Section 1602, Non-controlling Interests ("Section 1602"). These new standards will be effective for fiscal years beginning on or after January 1, 2011. The Company is in the process of evaluating the requirements of the new standards.

Section 1582 replaces Section 1581, Business Combinations, and establishes standards for the accounting for a business combination. It provides the Canadian equivalent to International Financial Reporting Standard IFRS 3 – Business Combinations. The section applies prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after January 1, 2011.

Sections 1601 and 1602 together replace Section 1600, Consolidated Financial Statements. Section 1601 establishes standards for the preparation of consolidated financial statements. Section 1601 applies to interim and annual consolidated financial statements relating to fiscal years beginning on or after January 1, 2011. Section 1602 establishes standards for accounting for a non-controlling interest in a subsidiary in consolidated financial statements subsequent to a business combination. It is equivalent to the corresponding provisions of International Financial Reporting Standard IAS 27 – Consolidated and Separate Financial Statements and applies to interim and annual consolidated financial statements relating to fiscal years beginning on or after January 1, 2011.

International Financial Reporting Standards

The AcSB has determined that Canadian accounting standards for publicly-listed companies will converge with International Financial Reporting Standards ("IFRS") effective for interim and annual periods beginning on or after January 1, 2011. The adoption of IFRS in 2011 will require restatement for comparative purposes of figures presented for the 2010 fiscal year. The Company understands there may be material differences between Canadian GAAP and IFRS, and is therefore monitoring this project with a view to understanding the possible future effects of the transition to IFRS.

(U.S. Dollars, in thousands, except share and per share amounts)

NOTE 3 – PETROLEUM AND NATURAL GAS PROPERTIES

Interests in petroleum and natural gas proven and unproven properties include the following acquisition, exploration and development costs:

	Hungary	Canada	Romania	Australia	United States	Total
December 31, 2008	**$ 210,926**	**$ 74**	**$ 29**	**$ 25,991**	**$ -**	**$ 237,020**
Acquisition costs	-	-	16	5,734	-	5,750
Exploration costs	2,047	-	-	7,400	-	9,447
Development costs	-	(5)	-	-	-	(5)
Asset retirement obligation	394	-	-	189	-	583
Impairment loss	(45,000)	-	(45)	-	-	(45,045)
Cost of ExxonMobil	161	-	-	-	-	161
Depletion and depreciation	-	(22)	-	-	-	(22)
December 31, 2009	**$ 168,528**	**$ 47**	**$ -**	**$ 39,314**	**$ -**	**$ 207,889**

	Hungary	Canada	Romania	Australia	United States	Total
January 1, 2008	**$ 229,671**	**$ 134**	**$ -**	**$ -**	**$ -**	**$ 229,805**
Acquisition costs	-	-	29	25,890	748	26,667
Exploration costs	6,586	-	-	52	6,126	12,764
Development costs	-	(21)	-	-	-	(21)
Inventory available for sale	(3,675)	-	-	-	-	(3,675)
Asset retirement obligation	(340)	-	-	49	96	(195)
Impairment loss	-	-	-	-	(6,970)	(6,970)
Proceeds from ExxonMobil, net of costs	(21,316)	-	-	-	-	(21,316)
Depletion and depreciation	-	(39)	-	-	-	(39)
December 31, 2008	**$ 210,926**	**$ 74**	**$ 29**	**$ 25,991**	**$ -**	**$ 237,020**

The Company's Canadian properties are all proven and are subject to a ceiling test; the Company's properties in Hungary and Australia are unproven. Capitalized interest totaled $464 (2008-nil) for the year ended December 31, 2009.

NOTE 3 – PETROLEUM AND NATURAL GAS PROPERTIES (CONTINUED)

HUNGARY

TXM holds a long-term Mining Plot (the "Production License") granted by the Hungarian Mining Authority. The lands within the Production License were formerly part of TXM's two petroleum and natural gas exploration licenses – the Tisza License and the Makó License (collectively, the "Exploration Licenses"). The Production License, covering approximately 245,700 acres, gives TXM the exclusive right to explore for petroleum and natural gas on properties located in south central Hungary near the town of Szolnok. The Production License further gives TXM the exclusive right to commercially develop petroleum and natural gas within the area covered by that license.

The Exploration Licenses expired on December 31, 2009 and are not eligible for extension. However, under Hungarian laws applicable to oil and gas exploration licenses, the licensee has the first priority in obtaining a mining plot covering all or part of the area, but is not guaranteed that it will receive a mining plot. The process requires the filing of a "Closing Report" within six months from the expiration of the license, and the filing of an application for the mining plot within the second six-month period.

In October 2009, the Hungarian Mining Authority granted the Company's application to expand the depths under the Production License. When originally issued in May 2007, the upper depth of the Production License was defined as 9,186 feet (2,800 meters) from the surface, and extended to the basement of the Basin Centered Gas Accumulation (the "BCGA"). As a result of additional technical analysis, including extensive review of 3D seismic and the data obtained from the wells previously drilled within the Production License, the amended Production License now incorporates depths beginning at 7,546 feet (2,300 meters) throughout the entire Production License. This revision makes the Production License depth consistent with other mining plots in the immediate area.

Agreement with ExxonMobil

On April 10, 2008, Falcon and TXM entered into a Production and Development Agreement (the "PDA"), as amended, with ExxonMobil Corporation affiliate Esso Exploration International Limited ("ExxonMobil") under which TXM and ExxonMobil became joint owners in a specified portion (the "Contract Area") of the Production License. Pursuant to a pre-existing agreement between ExxonMobil and MOL Hungarian Oil and Gas Plc. ("MOL"), and ExxonMobil's rights under the PDA, ExxonMobil sold one-half of its interest in the Contract Area to MOL, effective April 10, 2008. ExxonMobil, MOL and TXM also entered into a joint operating agreement (the "JOA"), dated April 10, 2008, governing operations not expressly addressed in the PDA. At that time, ExxonMobil became operator of the Contract Area under the JOA.

On October 30, 2009, Production Ventures East Hungary Kft., an affiliate of ExxonMobil ("Production Ventures"), completed certain operations on the Földeák-1 well, at which time the well was temporarily suspended. The conclusion of these operations was also the completion of the Initial Work Program, and the expenditure of Production Ventures' and MOL's $50 million financial obligation under the PDA. Production Ventures and MOL had 120 days from completion of the Initial Work Program to evaluate the results and, on February 19, 2010, provided notice that they would not proceed to the next phase of the PDA, the Appraisal Work Program, and would exit the PDA.

In accordance with the PDA, ExxonMobil's and MOL's respective participating interests in the Contract Area, the Földeák-1 well, and all other interests automatically reverted to TXM, and TXM became operator of the Contract Area.

(U.S. Dollars, in thousands, except share and per share amounts)

NOTE 3 – PETROLEUM AND NATURAL GAS PROPERTIES (CONTINUED)

Impairment

As of December 31, 2009, the Company determined that the carrying value of the Hungarian petroleum and natural gas properties exceeded its estimated fair value. Consequently, during the fourth quarter of 2009, the Company reflected an impairment of petroleum and natural gas properties of $45,000 in its consolidated statement of operations, with a corresponding reduction to petroleum and natural gas properties in the consolidated balance sheet as of December 31, 2009.

AUSTRALIA

On September 30, 2008, Falcon and Falcon Australia consummated the acquisition of an undivided 50% working interest in an aggregate 7,000,000-acre prospect in four Exploration Permits (collectively, the "Permits") in the Beetaloo Basin Project in the Northern Territory, Australia (the "Beetaloo Basin Project") pursuant to the terms of a Purchase and Sale Agreement, as amended on October 31, 2008 (together, the "Beetaloo PSA") with PetroHunter Energy Corporation and certain of its affiliates (collectively, "PetroHunter"), each of which is a non-arm's length party for the purposes of the TSX-V (See Note 9 below).

The purchase price was $25,000, $5,000 of which was paid in cash, and $20,000 of which was paid in Falcon's equity securities convertible into shares on a one-for-one basis based on the closing price of the Company's shares on August 22, 2008 (See SPECIAL WARRANTS in Note 8 below).

On June 11, 2009, pursuant to a Second Purchase and Sale Agreement (the "Second PSA") entered into with PetroHunter, the Company completed the acquisition of an additional undivided 25% working interest in the Beetaloo Basin Project. Under the terms of the Second PSA, the principal consideration paid by the Company for the acquisition was the exchange of the $5,000 note receivable from PetroHunter that was reflected as other assets at December 31, 2008. In addition, the Company paid certain vendors who had provided goods or rendered services for the Beetaloo Basin Project, prior to the Company's acquisition of its 50% interest in September 2008, in exchange for inventory and operator bonds of approximately the same value, and relinquished its rights to the unexpended testing and completion funds of approximately $874 as discussed below. On closing of this transaction, the Company became operator of the Beetaloo Basin Project, and PetroHunter and the Company entered into an escrow agreement governing the release of all remaining Falcon common shares previously issued to PetroHunter. The acquisition was reflected at the exchange value.

The following is a summary of the consideration paid by the Company to PetroHunter under the Second PSA:

Note receivable	$ 5,000
Beetaloo Basin Project:	
Vendor payments	1,215
Inventory	(971)
Operator bonds	(469)
Buckskin Mesa Project:	
Unexpended testing and completion funds	874
Asset retirement obligation	(97)
Total	$ 5,552

In July 2009, the Company re-entered the Shenandoah-1 well and reached a depth of 8,904 feet (2,714 meters) on October 11, 2009. Following further evaluation of the results, the Company plans to test the well in 2010.

NOTE 3 – PETROLEUM AND NATURAL GAS PROPERTIES (CONTINUED)

On December 7, 2009, Falcon and Falcon Australia entered into a Binding Heads of Agreement (the "Agreement") with PetroHunter and Sweetpea Petroleum Pty Ltd ("Sweetpea"), PetroHunter's wholly owned subsidiary, wherein Falcon Australia will issue to Sweetpea common shares of Falcon Australia in consideration for the transfer of Sweetpea's undivided 25% working interest in the Permits. The Company will enter into a Master Services Agreement (the "MSA") related to the operations of the Permits. Under the terms of the Agreement, Falcon will be issued 150 million shares of Falcon Australia for conversion of a portion ($30,000) of Falcon Australia's debt payable to Falcon, which approximates Falcon's initial acquisition cost previously paid to Sweetpea for the 75% working interest in the Permits held by Falcon Australia as of the date of the Agreement, and Sweetpea will be issued 50 million shares of Falcon Australia for its remaining 25% working interest in the Permits. On April 23, 2010, Falcon Australia received notice (the "Notice") from the Department of Resources, Northern Territory Government, that the registration of the transfer of the remaining 25% interest in the Permits was completed, satisfying all conditions precedent to closing. Pursuant to the Notice, Falcon Australia now owns 100% of the Permits.

The MSA shall provide that Falcon Australia will be delegated sole authority and responsibility for all daily operations of the Permits. A monthly management fee shall be paid to Falcon out of the proceeds of a private placement of Falcon Australia shares of common stock (see Note 15) at a rate of $200 to $500 per month, based on funds raised in the Falcon Australia private placement. The term of the MSA will be for a period of one year, with any extension occurring upon mutual agreement.

At December 31, 2009, Sweetpea owed Falcon Australia $1,800 for its share of joint interest billings to re-enter the Shenandoah-1 well. This amount is reflected in other assets in the accompanying 2009 financial statements and will be reclassified to petroleum and natural gas properties at closing, as partial consideration for the acquisition by Falcon Australia of Sweetpea's remaining 25% working interest in the Permits

CANADA

The Company has working interests ranging from 12.76% to 25% in four producing petroleum and natural gas wells in Alberta, Canada. During the year ended December 31, 2009, the Company has recorded depreciation, depletion and amortization expense of $22 (2008-$39).

UNITED STATES

On October 31, 2008, the Company consummated the acquisition of an undivided 25% working interest in five wells, including the 40-acre tract surrounding each of the wells (collectively, the "Five Wells"), from PetroHunter situated within PetroHunter's 20,000-acre Buckskin Mesa project (the "Buckskin Mesa Project") located in the Piceance Basin, Colorado, and agreed to undertake a testing and completion program in respect of the Five Wells pursuant to the terms of the Purchase and Sale Agreement (the "Buckskin PSA"). Under the Buckskin PSA, the Company agreed to pay 100% of the first $7,000 of testing and completion work to be undertaken in connection with the Five Wells. After performance of the testing and completion work, the Company had up to 60 days to review and analyze the results and, at its election, could exercise an option (the "Buckskin Mesa Option") to acquire an additional undivided 25% working interest in the Five Wells (for a total of 50%) and an undivided 50% working interest in the remainder of the 20,000-acre Buckskin Mesa Project.

On February 24, 2009, the Company notified PetroHunter that it would not exercise the Buckskin Mesa Option. Of the $7,000 advanced to PetroHunter, approximately $874 had not been expended, and was reflected as other assets at December 31, 2008. On June 11, 2009, pursuant to the Second PSA, the Company relinquished its rights to the unexpended testing and completion funds, and reassigned the undivided 25% working interest in the Five Wells to PetroHunter. The Company was relieved of all obligations related to the Five Wells, including reclamation and plugging and abandonment. For the year ended December 31, 2008, the Company reflected impairment of $6,970 in its consolidated statement of operations, equal to the $6,126 of testing and completion work, $748 of acquisition costs and $96 of assets associated with the retirement obligation.

(U.S. Dollars, in thousands, except share and per share amounts)

NOTE 3 – PETROLEUM AND NATURAL GAS PROPERTIES (CONTINUED)

SOUTH AFRICA

On October 27, 2009, Falcon secured a Technical Cooperation Permit (the "TCP") to evaluate the Karoo Basin in central South Africa. Falcon has up to one year to conduct a technical appraisal of the area covered by the TCP, which does not include any well or seismic work obligations. At the end of the one year period, Falcon has the option to apply for an exploration license covering all or a portion of the TCP upon the payment of $400. The TCP covers approximately 7.5 million acres and is located approximately 120 miles northeast of Cape Town, South Africa.

NOTE 4 – AMOUNTS RECEIVABLE

Amounts receivable at December 31, 2009 and 2008 is comprised of the following:

	2009	2008
Joint interest owners	$ 856	$ 6,541
VAT – Hungary	961	-
GST – Australia	132	2,500
GST – Canada	38	67
Sale of inventory available for sale	350	1,133
Other	618	124
	$ 2,955	$ 10,365

NOTE 5 – INVENTORY AVAILABLE FOR SALE

Inventory available for sale consists of drill pipe, casing and tubing and is reflected as a current asset at its estimated net realizable value. During the year ended December 31, 2008, $3,675 was reclassified from petroleum and natural gas properties to inventory available for sale, and the Company received $4,995 from the sale of inventory available for sale at approximately its carrying value. At December 31, 2008, the Company charged to operations $2,610 as a write down to the carrying cost of the inventory to estimated net realizable value of $6,852.

During the year ended December 31, 2009, the Company received $497 from the sale of inventory available for sale at approximately its carrying value, and transferred $600 of inventory available for sale from the Makó Trough to the Beetaloo Basin that is reflected in petroleum and natural gas properties. At December 31, 2009, the Company charged to operations $1,559 as a write down to the carrying cost of the inventory to estimated net realizable value of $4,196.

NOTE 6 – CONVERTIBLE DEBENTURES

On June 30, 2009, the Company completed an offering, on a best efforts basis, pursuant to a short form prospectus filed with the securities regulatory authorities in the provinces of British Columbia, Alberta, Saskatchewan, Manitoba, Ontario, Nova Scotia and New Brunswick, of 11,910 units at a price of $865 (CDN$1,000) per unit (the "Offering"). Each unit consisted of one 11% convertible unsecured debenture in the principal amount of $779 (CDN$900) (each, a "Debenture") that matures on the fourth anniversary of its issuance (June 30, 2013) pursuant to the terms of a trust indenture dated June 30, 2009 (the "Trust Indenture"), and 250 common shares in the capital of Falcon (the "Unit Shares") (collectively, a "Unit"). The Debentures bear interest at an annual rate of 11% calculated and payable semi-annually in arrears on January 1 and July 1 in each year commencing January 1, 2010. The Debentures are unsecured direct obligations of the Company. In certain circumstances the Trust Indenture may restrict the Company from incurring additional indebtedness for borrowed money or from mortgaging, pledging or charging its property to secure any additional indebtedness.

NOTE 6 – CONVERTIBLE DEBENTURES (CONTINUED)

Optional Conversion Privilege

Each Debenture may be convertible into common shares of the Company ("Debenture Shares") at the option of the Debenture holder (the "Optional Conversion Privilege") at any time prior to the close of business on the earlier of the maturity date and the business day immediately preceding the date fixed by the Company for redemption of the Debentures (either of such dates, the "Optional Conversion Date"), at a conversion price of CDN$0.60 per common share (the "Conversion Price"), being a conversion ratio of approximately 1,667 Debenture Shares for each CDN$1,000 principal amount of Debentures. The Conversion Price is subject to adjustment upon the occurrence of certain events. Debenture holders converting their Debentures will receive accrued and unpaid interest in cash thereon up to, but not including, the Optional Conversion Date. No fractional shares will be issued. Notwithstanding the foregoing, no Debentures may be converted during the 10 business days preceding and including January 1 and July 1 in each year, commencing January 1, 2010 as the registers of the Indenture Trustee (as defined in the Trust Indenture) will be closed during such periods.

Automatic Conversion Features

If during the two year period following the closing the volume weighted average trading price of the common shares is CDN$0.85 or greater for 20 consecutive trading days, the Debentures will automatically be converted (with no further action on the part of the holder) at the Conversion Price to Debenture Shares and Debenture holders will be entitled to receive accrued and unpaid interest, in cash, to the end of the first 12 month period or 24 month period after closing, as the case may be.

Redemption

The Debentures will not be redeemable before the date that is 10 days prior to one year following the closing. The Company will have the one time option, exercisable within five days of such date and subject to providing prior written notice to the Debenture holders, to redeem the outstanding Debentures (in whole or in part) 30 days following delivery of such notice, in cash, at a redemption price equal to 110% of their principal amount plus accrued and unpaid interest thereon up to but excluding the redemption date.

The Offering was conducted by an independent agent (the "Agent"). The Agent and members of any selling group were paid a cash commission equal to 6.25% of the aggregate gross proceeds of the Offering, and received non-transferrable warrants (the "Agent Warrants") to purchase 1,250,550 Falcon common shares. Each Agent Warrant entitles the holder thereof to acquire one Falcon common share for a period of two years following the closing of the Offering (June 30, 2011), at an exercise price of $0.52 (CDN$0.60).

(U.S. Dollars, in thousands, except share and per share amounts)

NOTE 6 – CONVERTIBLE DEBENTURES (CONTINUED)

The following is a summary of the Units sold under the Offering, and the convertible debentures and share capital issued subsequent to the filing of the final short form prospectus in respect of the Offering:

	US$	CDN$
The Offering:		
Units issued	11,910	11,910
Price per unit	$ 865	$ 1,000
Gross proceeds	$ 10,302	$ 11,910
Shares:		
Unit shares issued at $0.35 (CDN$0.40) per share	2,977,500	2,977,500
Agent Warrants to acquire shares at $0.52 (CDN$0.60) per share	1,250,550	1,250,550
Allocation of gross proceeds:		
Convertible debentures	$ 4,215	$ 4,873
Equity component of convertible debentures	5,057	5,846
	9,272	10,719
Share capital	1,030	1,191
	$ 10,302	$ 11,910
Value ascribed to Agent Warrants	$ 263	$ 303
Offering costs:		
Allocated to deferred financing costs	$ 1,494	$ 1,722
Allocated to equity	160	190
	$ 1,654	$ 1,912
One year of escrowed interest payments at 11% per annum reflected in restricted cash	$ 1,020	$ 1,179

As of December 31, 2009, convertible debentures consist of the following:

Face amount	$ 9,272
Discount – equity component of convertible debentures	(5,057)
Accretion of discount – equity component of convertible debentures	632
Foreign currency translation adjustment	493
Offering costs attributable to convertible debentures	(1,494)
Amortization of offering costs attributable to convertible debentures	185
	$ 4,031

The discount and the offering costs are being accreted and amortized to interest expense over the term of the convertible debentures.

(U.S. Dollars, in thousands, except share and per share amounts)

NOTE 6 – CONVERTIBLE DEBENTURES (CONTINUED)

The value ascribed to the Agent Warrants and to the equity component of the convertible debentures was the fair value at the date of the Offering using the Black-Scholes model, based on the following assumptions:

	Equity component of convertible debentures	Agent Warrants
Expected lives	4.00 years	2.00 years
Risk-free interest rate	1.20%	1.20%
Annualized volatility	121.19%	121.19%
Dividend rate	nil	nil

NOTE 7 – ASSET RETIREMENT OBLIGATIONS

At December 31, 2009, the estimated total undiscounted amount required to settle the asset retirement obligations was $8,796. Costs for asset retirement have been calculated assuming an inflation rate ranging from 3.0% to 5.0%. These obligations will be settled based on the estimated useful lives of the underlying assets, which extend up to 20 years into the future. Obligations have been discounted using a credit-adjusted risk-free interest rate ranging from 6.5% to 11.0%. Changes to asset retirement obligations for the years ended December 31, 2009 and 2008 were as follows:

	2009	2008
Asset retirement obligations – beginning of year	$ 5,285	$ 5,140
Liabilities incurred	583	145
Revisions to estimates	-	(339)
Liabilities settled	-	-
Liabilities conveyed	(97)	-
Accretion	335	339
Asset retirement obligations – end of year	$ 6,106	$ 5,285

NOTE 8 – SHAREHOLDERS' EQUITY

AUTHORIZED

The Company has authorized an unlimited number of common shares, without par value.

ISSUANCES

See Note 6 regarding the issuance of 2,977,500 common shares in connection with the Offering.

(U.S. Dollars, in thousands, except share and per share amounts)

NOTE 8 – SHAREHOLDERS' EQUITY (CONTINUED)

WARRANTS

A summary of the number of common shares reserved pursuant to the Company's outstanding share purchase warrants for the years ended December 31, 2009 and 2008 is as follows:

	2009	**2008**
Balance, beginning of year	4,288,750	8,518,150
Agent Warrants (Note 6)	1,250,550	-
Warrants exercised	(3,440,000)	(1,711,250)
Warrants expired	(848,750)	(2,518,150)
Balance, end of year	1,250,550	4,288,750

Common shares reserved for share purchase warrants outstanding as of December 31, 2009 are as follows:

Number of Shares	**Exercise Price**	**Expiry Date**
1,250,550	\$0.52 (CDN\$0.60)	June 30, 2011

In 2009, the Company reclassified from share capital to contributed surplus \$2,109, the value of certain unexercised share purchase warrants issued to agents in connection with certain previous offerings by the Company. The reclassification was based on the estimated fair value of such warrants as of the issuance date using the Black-Scholes option-pricing model.

SPECIAL WARRANTS

As partial consideration for the Beetaloo Basin acquisition, as described in Note 3, the Company issued \$20,000 of equity securities (the "Special Warrants") automatically convertible into common shares of the Company for no additional consideration on a one-for-one basis. Based on the closing price of the Company's shares on August 22, 2008, the maximum number of shares that could be issued was 28,888,888. On December 22, 2008, the Company filed a final non-offering short form prospectus qualifying the distribution of the 28,888,888 common shares upon the conversion of the Special Warrants at a price of CDN\$0.72 per share.

STOCK BASED COMPENSATION

The Company, in accordance with the policies of the TSX-V, may grant options to directors, officers, employees and consultants, to acquire up to 10% of the Company's issued and outstanding common stock. The exercise price of each option is based on the market price of the Company's stock at the date of grant, which may be less a discount in accordance with TSX-V policies. The exercise price of all options granted has been based on the market price of the Company's stock at the date of grant, and no options have been granted at a discount to the market price. The options can be granted for a maximum term of five years. The Company records compensation expense over the vesting period based on the fair value of options granted. These amounts are recorded as contributed surplus. Any consideration paid on the exercise of these options is recorded as share capital together with the related contributed surplus associated with the exercised options. Of the options granted during the year ended December 31, 2008, all vest 20% at the date of grant, with the remainder vesting ratably at the anniversary date over the four years thereafter. There were no options granted during the year ended December 31, 2009.

(U.S. Dollars, in thousands, except share and per share amounts)

NOTE 8 – SHAREHOLDERS' EQUITY (CONTINUED)

A summary of the Company's stock option plan as of December 31, 2009 and 2008, and changes during the years then ended, is presented below:

	2009		2008	
	Options	Weighted-Average Exercise Price	Options	Weighted-Average Exercise Price
Outstanding at beginning of year	46,950,000	$1.90	36,090,000	$1.90
Granted	-	-	13,610,000	$1.09
Exercised	-	-	-	-
Expired	(3,195,000)	$3.11	(1,342,000)	$3.45
Forfeited	(1,780,000)	$2.07	(1,408,000)	$2.91
Outstanding at end of year	41,975,000	$1.48	46,950,000	$1.59
Options exercisable at end of year	32,576,000	$1.40	29,986,000	$1.37

The following summarizes information about stock options outstanding and exercisable at December 31, 2009:

Options Outstanding	Options Exercisable	Exercise price	Weighted average remaining contractual life	Expiry date
15,500,000	15,500,000	$0.25	0.25 years	April 2, 2010
2,450,000	2,450,000	$0.50	0.80 years	October 10, 2010
7,949,000	6,359,200	$3.98	1.35 years	May 7, 2011
4,291,000	3,432,800	$2.83	1.94 years	December 9, 2011
600,000	360,000	$0.54	2.62 years	August 17, 2012
1,000,000	400,000	$0.98	3.35 years	May 6, 2013
10,185,000	4,074,000	$1.19	3.43 years	June 5, 2013
41,975,000	32,576,000			

At December 31, 2009, the weighted average remaining contractual life of stock options outstanding was 1.54 years.

The weighted average fair value of the options granted during the year ended December 31, 2008 was $0.90.

The Company measures compensation costs using the fair value-based method for employee and non-employee stock options. Compensation costs have been determined based on the fair value of the options at the grant date, for employees, and at the balance sheet for non-employees using the Black-Scholes option-pricing model.

(U.S. Dollars, in thousands, except share and per share amounts)

NOTE 8 – SHAREHOLDERS' EQUITY (CONTINUED)

The following assumptions were used for stock options granted:

	2008
Expected life of options	3.50 to 5.00 years
Risk-free interest rate	1.69% to 3.45%
Annualized volatility	119%
Dividend rate	nil
Estimated forfeiture rate	nil

Option-pricing models require the use of estimates and assumptions including the expected volatility of the Company's share price, the expected life of the option and the risk free interest rate. Changes in the underlying assumptions can materially affect the fair value estimates.

NOTE 9 – RELATED PARTY TRANSACTIONS

Unless otherwise stated, transactions between related parties are measured at the exchange amount, being the amount of consideration agreed to between the parties.

In 2008 and 2009, the Company entered into certain agreements and transactions with PetroHunter, a related entity, whose largest single shareholder is also the President and CEO of the Company, including the acquisition of working interests in the Beetaloo Basin Project and the Buckskin Mesa Project. See Note 3.

During the year ended December 31, 2009, the Company incurred $325 (2008-$372) to two current directors (2008 – three directors) of the Company for advisory and consulting services rendered.

NOTE 10 – SEGMENT INFORMATION

All of the Company's operations are in the petroleum and natural gas industry with its principal business activity being in the acquisition, exploration and development of petroleum and natural gas properties. The Company has producing petroleum and natural gas properties located in Canada and considers the results from its operations to relate to the petroleum and natural gas properties. The Company has unevaluated petroleum and natural gas properties in Hungary and Australia. An analysis of the Company's geographic areas is as follows:

(U.S. Dollars, in thousands, except share and per share amounts)

NOTE 10 – SEGMENT INFORMATION (CONTINUED)

	Hungary	Canada	Romania	Australia	United States	Total
Year ended December 31, 2009						
Revenue	$ 30	$ 39	$ -	$ -	$ -	$ 69
Net income (loss)	(50,225)	(10,247)	(45)	(599)	(2,812)	(63,928)
As of December 31, 2009						
Capital assets	173,969	47	-	39,314	533	213,863

	Hungary	Canada	Romania	Australia	United States	Total
Year ended December 31, 2008						
Revenue	$ -	$ 60	$ -	$ -	$ -	$ 60
Net income (loss)	(9,326)	(16,075)	-	(1)	(10,509)	(35,911)
As of December 31, 2008						
Capital assets	216,534	74	29	25,991	623	243,251

NOTE 11 –FINANCIAL INSTRUMENTS

(a) Fair value

The fair value of financial instruments at December 31, 2009 and 2008 is summarized in the following table. Fair value estimates are made at the balance sheet date, based on relevant quoted market and other information about the financial instruments.

	December 31, 2009		December 31, 2008	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Financial assets:				
Held for trading				
Cash and cash equivalents	$ 12,988	$ 12,988	$ 25,547	$ 25,547
Loans and receivables				
Amounts receivable	2,955	2,955	10,365	10,365
Financial liabilities:				
Other financial liabilities				
Accounts payable and accrued liabilities	2,683	2,683	12,227	12,227

NOTE 11 –FINANCIAL INSTRUMENTS (CONTINUED)

(b) Financial risk disclosures

The Company thoroughly examines the various financial instrument risks to which it is exposed and assesses the impact and likelihood of those risks. These risks may include credit risk, liquidity risk, market risk and other price risks. Where material, these risks are reviewed and monitored by the Board of Directors.

Credit Risk

The Company's credit risk is limited to cash and receivables. The Company maintains cash accounts at three financial institutions. The Company periodically evaluates the credit worthiness of financial institutions, and maintains cash accounts only in large high quality financial institutions, thereby minimizing exposure for deposits in excess of federally insured amounts. On occasion, the Company may have cash in banks in excess of federally insured amounts. The Company believes that credit risk associated with cash is minimal. Receivables are not significant to the Company. The Company's credit risk has not changed significantly from the prior year.

Liquidity Risk

The Company has in place a planning and budgeting process to help determine the funds required to support the Company's normal operating requirements on an ongoing basis and its planned capital expenditures. The Company's overall liquidity risk has not changed from the prior year.

Currency Risk

Financial instruments that impact the Company's net income (loss) and comprehensive income (loss) due to currency fluctuations include Canadian dollar denominated cash and cash equivalents, and Hungarian Forint and Euro denominated cash and cash equivalents, accounts receivable, reclamation deposits, accounts payable, and capital commitments for Hungarian and Australian operations.

Interest Rate Risk

The Company is not exposed to interest rate risk as it has no outstanding short term borrowings or investments.

Fair Value Estimation

The carrying value less impairment provision, if necessary, of trade receivables and payables approximate their fair values.

NOTE 12 – MANAGEMENT OF CAPITAL

The Company's objectives when managing capital are to safeguard its ability to continue as a going concern in order to explore and develop its petroleum and natural gas properties. The Company manages the components of shareholders' equity and its cash as capital, and makes adjustments to these components in response to the Company's business objectives and the economic climate. To maintain or adjust its capital structure, the Company may issue new common shares or debt instruments, or borrow money or acquire or convey interests in other assets. The Company does not anticipate the payment of dividends in the foreseeable future.

The Company's investment policy is to hold excess cash in highly-liquid, short-term instruments, such as bankers' acceptances and guaranteed investment certificates issued by major Canadian chartered banks or United States financial institutions, with initial maturity terms of less than three months from the original date of acquisition, selected with regard to the Company's anticipated liquidity requirements.

(U.S. Dollars, in thousands, except share and per share amounts)

NOTE 12 – MANAGEMENT OF CAPITAL (CONTINUTED)

The Company does not expect its current capital resources will be sufficient to meet future acquisition, exploration, development and production plans, operating requirements and convertible debenture obligations, and is dependent upon future debt and equity, or joint venture arrangements, to meet the obligations. See Note 1.

NOTE 13 – INCOME TAXES

Income tax expense or recovery is the sum of the Company's provisions for current income taxes and differences between the opening and ending balances of its future income taxes.

The provision for income taxes differs from the amount that would have been obtained by applying the statutory income tax rate of 30% (2008 – 31.0%) to the Company's income (loss) before income taxes for the year. For the years ended December 31, 2009 and 2008, the difference results from the following items:

		2009		2008
Expected income tax (recovery)	$	(19,179)	$	(11,132)
Effect of foreign income tax rates		4,814		88
Change in effective tax rates		(62)		(211)
Effect of change in foreign exchange rates		(647)		3,154
Unrecognized benefit of loss carryforwards		3,338		4,344
Non-deductible stock-based compensation		1,636		2,629
Equity component of convertible debentures		220		-
Other		82		1,128
Change in valuation allowance		9,798		-
Local income taxes		-		462
Provision for income taxes	$	-	$	462

The income tax effects of temporary differences that give rise to significant portions of future income tax assets and liabilities at December 31, 2009 and 2008 are as follows:

		2009		2008
Future income tax assets				
Non-capital losses and resource deductions	$	23,645	$	19,887
Less: Valuation allowance		(22,928)		(13,130)
Future income tax liabilities		717		6,757
Petroleum and natural gas properties and other		717		6,757
	$	-	$	–

(U.S. Dollars, in thousands, except share and per share amounts)

NOTE 13 – INCOME TAXES (CONTINUED)

The Company has accumulated loss carryforwards at December 31, 2009 to reduce future years' taxable income as follows:

		2009	Expiration
Canada			
Non-capital losses	$	16,008	2010 to 2029
Resource deductions		2,385	No expiration
		18,393	
United States		4,430	2029
Hungary		14,202	No expiration
Australia		40,178	No expiration
	$	77,203	

The benefit of the Company's income tax assets has not been recognized in the Company's accounts as it cannot be reasonably estimated at this time if it is more likely than not that such benefit will be realized.

NOTE 14 – COMMITMENTS AND CONTINGENCIES

(a) ENVIRONMENTAL

Petroleum and natural gas producing activities are subject to extensive environmental laws and regulations. These laws, which are constantly changing, regulate the discharge of materials into the environment and may require the Company to remove or mitigate the environmental effects of the disposal or release of petroleum or chemical substances at various sites. Environmental expenditures are expensed or capitalized depending on their future economic benefit. Expenditures that relate to an existing condition caused by past operations and that have no future economic benefit are expensed. Liabilities for expenditures of a non-capital nature are recorded when environmental assessment and/or remediation is probable, and the costs can be reasonably estimated.

(b) CONTINGENCIES

The Company may, from time to time, be involved in various claims, lawsuits, disputes with third parties, or breach of contract incidental to the operations of its business. Except for the following-described dispute, the Company is not currently involved in any claims, disputes, litigation or other actions with third parties which it believes could have a material adverse effect on its financial condition or results of operations.

On November 10, 2009, the Company was served with a Complaint by a former vendor of TXM (the "Vendor"), claiming that the Company owes the Vendor approximately $3.2 million, plus interest, arising out of a dispute related to TXM's alleged failure to pay for certain oilfield equipment. Falcon and TXM have advised the Vendor, and continue to assert, that the claim is without merit and that they intend to vigorously defend against it as well as make any appropriate counter claims against the Vendor. The accompanying financial statements do not include any obligation related to this claim.

(U.S. Dollars, in thousands, except share and per share amounts)

NOTE 14 – COMMITMENTS AND CONTINGENCIES (CONTINUED)

(c) LEASE COMMITMENTS

In April 2006, the Company entered into a lease agreement for office space in Denver, Colorado, for the period from June 2006 through 2011; and in September 2006 entered into a lease for office space in Budapest, Hungary, for the period from July 2007 through 2013. The Company is obligated to pay the following minimum future rental commitments under these non-cancelable operating leases:

Year ending December 31,	
2010	$ 924
2011	774
2012	621
2013	259
	$ 2,578

(d) AUSTRALIA WORK PROGRAM

Under a work program approved by the Northern Territory of Australia Government, Department of Resources, on March 31, 2010, the Company is obligated to complete minimum work requirements by expending the following amounts in order to continue to hold the underlying permits in the Beetaloo Basin Project.

Year ending December 31,	
2010	$ 6,400
2011	3,900
2012	5,000
	$ 15,300

NOTE 15 – SUBSEQUENT EVENT

In January 2010, Falcon Australia commenced the private placement sale of up 50 million shares of its common stock (“FA Share”) to sophisticated or professional investors within the meaning of sections 708(8) and 708(11) of the Corporations Act 2001 (Australia) pursuant to an Offer Memorandum (the “Offer”), at a price of $1.00 per FA Share with an attached option. Each option entitles the holder to acquire one additional FA Share in respect of each FA Share sold, exercisable at $1.25 for a period of three years from date of issue. Closing is expected to occur on or about June 30, 2010. As of April 23, 2010 all conditions precedent to closing, including consent from the Northern Territory government for the transfer to Falcon Australia of the remaining undivided 25% working interest from Sweetpea to Falcon Australia, have been satisfied (See Note 3). The acting broker to the Offer will receive as a brokerage fee 6.5% of the funds raised in the Offer together with Options (on the same terms as issued to investors), calculated at 6.5% of the number of shares issued in the Offer.

PART VI

ADDITIONAL INFORMATION

1. RESPONSIBILITY

The Directors, whose names appear on Page 4 of this document, and the Company, accept full responsibility both individually and collectively for all of the information contained in this document, and for the Company's compliance with the AIM Rules and ESM Rules. To the best of the knowledge and belief of the Directors and the Company (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. To the extent that information has been sourced from a third party, this information has been accurately reproduced and, as far as the Directors and the Company are aware, no facts have been omitted which may render the reproduced information inaccurate or misleading.

RPS Energy (whose registered office appears on page 4 of this document) accepts full responsibility for the information contained in Part IV of this document. To the best of the knowledge and belief of RPS Energy (who have taken all reasonable care to ensure that such is the case) the information contained in Part IV of this document is in accordance with the facts and does not omit anything likely to affect its import.

2. INCORPORATION AND REGISTERED OFFICE

The Company was incorporated and registered in British Columbia, Canada on 18 January 1980 under the laws of the Province of British Columbia with the name Sanfred Resources Ltd. ("Sanfred").

On 21 December 1999, Sanfred consolidated its authorised and issued share capital. On the same date Sanfred changed its name to Falcon Oil & Gas Ltd. On 2 March 2005, Falcon transitioned from the British Columbia Company Act to the new Business Corporations Act (British Columbia). Other than the subsidiaries through which Falcon acts, the Company has no commercial name other than its registered name and does not operate under any other name.

Falcon is a public company and the principal legislation under which it operates and under which the New Common Shares will be issued is the BCA and the regulations made thereunder.

The registered office of the Company is 810-675 Hastings Street West, Vancouver, British Columbia, V6B 1N2, Canada. The Company's head office is at Styne House, Upper Hatch Street, Dublin 2, Ireland with telephone number +353 1 417 1900. The address of the Company's corporate website on which information required by Rule 26 of the AIM Rules and ESM Rules can be found is http://www.falconoilandgas.com.

Falcon has no administrative, management or supervisory bodies other than the Board, and the committees as set out in Section 12 of Part I of this document, namely the Audit Committee, the Corporate Governance Committee, the Compensation Committee, the Nomination Committee and the Reserves Committee.

The principal activity of the Company is that of oil and gas exploration and development. On Admission, Falcon will be the holding company of the Group. Details of Falcon's principal subsidiaries and associated undertakings (each of which are considered to be likely to have a significant effect on the assessment of the assets and liabilities, the financial position and/or the profits and losses of the Group) are set out below:

Name of Subsidiary	*Country of Incorporation*	*Proportion of Ownership Interest*	*Principal Activity*
TXM Marketing Trading and Services Kft. ("TXM Marketing")	Hungary	100%	Not trading
Makó Energy Corporation ("Makó")	Delaware, USA	100%	Parent company of TXM
TXM Oil and Gas Exploration Kft. ("TXM")	Hungary	100% wholly owned subsidiary of Makó	Exploration relating to production licences held in Hungary
Falcon Oil & Gas Australia Ltd. ("Falcon Australia")	Australia	72.7% owned by Falcon	Exploration

Name of Subsidiary	*Country of Incorporation*	*Proportion of Ownership Interest*	*Principal Activity*
Falcon Oil & Gas Ireland Ltd. (“Falcon Ireland”)	Ireland	100%	Service company for corporate headquarters

As at the date of this document, the Company holds 100 per cent. of the entire issued share capital of TXM Marketing, a company incorporated in Hungary with company registration number 01-09-878912.

As at the date of this document, the Company holds 100 per cent. of the entire issued share capital of Makó Energy Corporation, a company incorporated in Delaware, USA with company registration number 20051258295.

As at the date of this document, the Company, directly or indirectly holds, 100 per cent. of the entire issued share capital of TXM, a company incorporated in Hungary with company registration number 01-09-734527.

As at the date of this document, the Company holds 72.7 per cent. of the entire issued share capital of Falcon Australia, a company incorporated in Australia with company registration number 53 132 857008.

As at the date of this document, the Company holds 100 per cent. of the entire issued share capital of Falcon Oil & Gas Ireland Ltd, a company incorporated in Ireland with company registration number 512417.

Save as disclosed in this Part VI, there are no undertakings in which the Company holds a proportion of the capital likely to have a significant effect on the assessment of its own assets and liabilities, financial position, or profits and losses.

3. SHARE CAPITAL

Common Shares

3.1 The Company’s authorised capital consists of an unlimited number of Common Shares, without par value. Immediately prior to the Placing, 696,954,500 Common Shares were issued and outstanding. Holders of Common Shares are entitled to one vote for each Common Share held at all meetings of shareholders of the Company, to participate rateably in any dividend declared by the Board on the Common Shares and to participate equally with all outstanding Common Shares on any distribution of the Company’s assets on a winding-up, liquidation or dissolution of the Company. All of the Common Shares are fully paid.

In addition, the Company has warrants, options and debentures outstanding, details of which are set out in Sections 4, 5, 6 and 8 of this Part VI.

3.2 In the three years up to the date of this document, there have been the following changes to the Existing Issued Share Capital of the Company:

3.2.1 As at 1 January 2009, there were 595,799,301 Common Shares in issue.

3.2.2 In June 2009, the Company issued 2,977,500 Common Shares pursuant to an offering of units (consisting of C$900 worth of Debentures and 250 Common Shares) in a debenture offering resulting in an increase in the number of Common Shares in issue to 598,776,801.

3.2.3 In July 2009, 150,000 Common Shares were cancelled and re-issued resulting in no change to the number of Common Shares in issue.

3.2.4 In September 2009, the Company issued 3,440,000 Common Shares pursuant to an exercise of stock options, resulting in an increase in the number of Common Shares in issue to 602,216,801.

3.2.5 In February 2011, the Company issued 50,000 Common Shares pursuant to an exercise of stock options, resulting in an increase in the number of Common Shares in issue to 602,266,801.

3.2.6 In February 2011, the Company issued 44,533,333 Common shares pursuant to an offering of units (comprising one Common Share and three quarters of one common share purchase warrant) in a private placement resulting in an increase in the number of Common Shares in issue to 646,800,134.

3.2.7 In February 2011, the Company issued 1,000,000 Common Shares to an ex-employee as compensation for his employment, resulting in an increase of Common Shares in issue to 647,800,134.

3.2.8 In April 2011, the Company issued 42,516,666 Common Shares pursuant to an issuance of units (comprising one Common Share and three quarters of one common share purchase warrant) in a private placement resulting in an increase of Common Shares in issue to 690,316,800.

3.2.9 In May 2011, the Company issued 4,000,000 Common Shares to an ex-employee as compensation for his employment resulting in an increase of Common Shares in issue to 694,316,800.

3.2.10 In October 2011, the Company issued 676,800 Common Shares to certain employees of the Company as a bonus for services rendered and 660,900 Common Shares in a private placement resulting in an increase in the number of Common Shares in issue to 695,654,500.

3.2.11 In October 2011 209,000 incorrectly registered Common Shares were cancelled and re-issued in the correct name, resulting in no change to the number of Common Shares in issue.

3.2.12 In October 2012, the Company issued 600,000 Common Shares pursuant to an exercise of stock options, resulting in an increase in the number of Common Shares in issue to 696,254,500.

3.2.13 In December 2012, the Company issued 400,000 Common Shares pursuant to an exercise of stock options, resulting in an increase in the number of Common Shares in issue to 696,654,500.

3.2.14 In December 2012, the Company issued 300,000 Common Shares to an ex-employee as compensation for his employment resulting in an increase in the number of Common Shares in issue to 696,954,500.

3.3 The Directors are generally authorised to issue an unlimited number of Common Shares.

3.4 The Directors require Shareholder approval to issue shares if the issue of shares will result in the creation of a control person (as defined by the TSX-V Corporate Financial Manual).

3.5 The New Common Shares will be issued pursuant to the authorities and powers set out in the Articles of Association of the Company as described in Section 7 of this Part VI.

3.6 The New Common Shares will rank *pari passu* in all respects with the Existing Common Shares, including the right to receive all dividends and other distributions declared, made or paid after the Admission on the Common Shares.

3.7 The Company's Existing Issued Share Capital at the date of this document, and its Enlarged Issued Share Capital immediately following Admission is as follows:

	As at the date of this Document		*As at Admission*	
	Class of share	*Number of Common Shares in issue*	*Class of share*	*Number of Common Shares in issue*
Issued	Common shares	696,954,500	Common shares	817,336,473

3.8 The percentage of immediate dilution of Shareholders' interest as a result of the issue of New Common Shares pursuant to the Placing will be 14.7 per cent.

3.9 Saved as disclosed in this Part VI and apart from the issue of the New Common Shares:

3.9.1 no share or loan capital of the Company has been issued or is proposed to be issued;

3.9.2 save as disclosed in Section 4, 5, 6 and 8 of this Part VI, there are no outstanding convertible securities, exchangeable securities or securities with warrants issued by the Company;

3.9.3 there are no shares in the Company not representing capital;

3.9.4 there are no shares in the Company held by or on behalf of the Company itself or by subsidiaries of the Company;

3.9.5 there are no acquisition rights and/or obligations over authorised but unissued share capital of the Company or an undertaking to increase the share capital of the Company;

3.9.6 no person has any preferential subscription rights for any share capital of the Company; and

3.9.7 no commissions, discounts, brokerages or other special terms have been granted by the Company since its incorporation in connection with the issue or sale of any share or loan capital of the Company.

3.10 There are no mandatory takeover bids and/or squeeze-out or sell-out rules outstanding in respect of the Company and its securities and none has been made either in the last financial year or the current financial year of the Company. No public takeover bids have been made by third parties in respect of the Company's Existing Share Capital in the current financial year nor in the last financial year.

3.11 The Common Shares are not redeemable or convertible.

3.12 The Company has established a depository interest scheme with the Depository as summarised in Section 15 of Part I of this document. All of the Common Shares will be in registered form. No temporary documents of title will be issued.

3.13 None of the Existing Common Shares have been sold or made available to the public in conjunction with the application for Admission.

4. WARRANTS

4.1 On 10 February 2011 and 8 April 2011, the Company issued 44,533,333 units and 42,516,666 units (for a total of 87,049,999 units), respectively, at an issuance price of C$0.15 per unit, each unit consisting of one Common Share and three quarters of one common share purchase warrant. Each whole warrant entitles the holder to acquire one Common Share at an exercise price of C$0.18 per Common Share for a period of 36 months from the date of issuance. There were twelve different subscribers to this offering, including a number of the Company's Insiders (as defined by the TSX-V).

4.2 Pursuant to the Hess Agreement, the Company also issued warrants entitling Hess to purchase 10,000,000 Common Shares exercisable until 13 January 2015 at an exercise price of C$0.19 per share.

4.3 As at the date of this document, the total number of Common Shares issuable under warrants are as follows:

Number of Common Shares issuable under warrants	*Exercise Price*	*Date of Issue*	*Expiry Date*	*Percentage of Existing Issued Share Capital*	*Percentage of Enlarged Issued Share Capital*
33,400,000	C$0.18	10/02/2011	10/02/2014	4.79%	4.09%
31,887,500	C$0.18	08/04/2011	08/04/2014	4.58%	3.90%
10,000,000	C$0.19	13/07/2011	13/01/2015	1.43%	1.22%

Note: A significant number of warrants are held by significant shareholders, as set out in Section 12.1 of this Part VI and by Directors as set out in Section 8.2 of this Part VI.

5. STOCK OPTIONS

5.1 At the date of this document the outstanding stock options granted by the Company are as follows:

As at the date of this document					*Immediately following Admission*	
Number of Common Shares issuable under stock options	*Percentage of Existing Issued Share Capital*	*Exercise Price*	*Date of Grant*	*Expiry Date*	*Number of Common Shares issuable under stock options*	*Percentage of Enlarged Issued Share Capital*
1,000,000	0.14%	C$1.00	06/05/2008	06/05/2013	1,000,000	0.12%
5,985,000	0.85%	C$1.180	05/06/2008	05/06/2013	5,985,000	0.73%
3,312,000	0.48%	C$0.170	30/08/2010	30/08/2015	3,312,000	0.41%
16,390,000	2.35%	C$0.145	23/05/2011	23/05/2016	16,390,000	2.01%
150,000	0.02%	C$0.145	01/06/2011	01/06/2016	150,000	0.02%
6,000,000	0.86%	C$0.10	01/05/2012	01/05/2017	6,000,000	0.73%

Note: Eoin Grindley (Chief Financial Officer) is, pursuant to his employment contract, entitled to 3,000,000 stock options which have not yet been granted.

5.2 The above stock options were granted on the following terms:

5.2.1 The stock options may be exercised in whole or in part by the holder giving to the Company a written notice exercising the stock option; and

5.2.2 The number and the price of the stock options may be adjusted by the Directors upon the occurrence of a stock split, stock dividend, recapitalisation, combination of shares, exchange of shares or other change affecting the outstanding Common Shares as a class without the Company's receipt of consideration.

6. DEBENTURES

6.1. The Company has issued Debentures worth C$10,719,000 (approximately US$11 million) convertible at the option of the Debenture holder at a price of C$0.60 per Common Share. The Debentures bear an interest rate of 11 per cent. per annum and will mature on 30 June 2013. As at the date of this document, Debentures worth C$10,656,900 remain outstanding. Further details of the Debentures are provided in Section 15.4.11.

7. ARTICLES OF ASSOCIATION

Objects and Purposes of the Company

7.1 The Company's Articles of Association place no restrictions on the objects and purposes of the Company.

Alteration of Capital

7.2 Subject to the BCA and any regulatory or stock exchange requirements applicable to the Company, the Company may by special resolution of the Shareholders (i) create one or more classes or series of shares or, if none of the shares of a class or series of shares are allotted or issued, eliminate that class or series of shares, (ii) increase or reduce or eliminate the maximum number of shares that the Company is authorised to issue out of any class or series of shares or establish a maximum number of shares that the Company is authorised to issue out of any class or series of shares for which no maximum is established, or (iii) subdivide or consolidate all or any of its unissued or fully paid issued shares.

Voting Rights

7.3 The Shareholders are entitled to one vote per Common Share at a shareholder meeting.

Transfer of Common Shares

7.4 Neither the Company's articles nor the BCA impose any pre-emptive rights upon the transfer of the Common Shares.

Requirement to Disclose Interests in Common Shares

7.5 Subject to the BCA and any regulatory or stock exchange requirements applicable to the Company, the articles of the Company do not contain any provisions relating to mandatory disclosure of an ownership interest in the Common Shares above a certain threshold.

Dividends

7.6 Shareholders are entitled to receive on a *pro rata* basis such dividends, if any, as and when declared by Falcon's board of directors at its discretion from funds legally available therefor, and upon the liquidation, dissolution or winding up of Falcon are entitled to receive on a pro rata basis the net assets of Falcon after payment of debts and other liabilities, in each case subject to the rights, privileges, restrictions and conditions attaching to any other series or class of shares ranking senior in priority to or on a pro rata basis with the holders of Common Shares with respect to dividends or liquidation. All rights are the same for residents or non-residents of Canada.

The directors are authorised to declare dividends as they deem advisable. All dividends must be paid in to Shareholders in accordance with the number of Common Shares held in the Company. Dividends shall not pay interest and fractional dividends in the smallest monetary unit of the currency may be disregarded when making dividend payments.

The directors may set a date as the record date for the purposes 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. If no record date is set, the record date is 5 p.m. on the date on which the directors pass the resolution declaring the dividend. A resolution declaring a dividend may direct payment of the dividend wholly or partly by the distribution of specific assets or of fully paid shares or of bonds, debentures or other securities of the Company or in any one or more of those ways. No dividend will bear interest against the Company.

Pursuant to the terms of the BCA, the Company may pay dividends out of profits, capital, or otherwise, unless the Company is insolvent or the payment of the dividend would render the Company insolvent.

Capitalisation of Surplus

7.7 The directors may capitalise any surplus of the Company and may issue as fully paid, shares or any bonds, debentures or other securities of the Company as a dividend representing the surplus or any part of the surplus.

General Meetings

7.8 Annual general meetings must be held at least once in each calendar year and not more than 15 months after the last annual reference date. The directors may, whenever they see fit, call a meeting of Shareholders. The Company must send notice of the shareholder meeting at least 21 days before the meeting. A quorum for a meeting of Shareholders is two persons who are, or who represent by proxy, Shareholders who, in the aggregate, hold at least five per cent. of the issued shares entitled to be voted at the meeting. If there is only one Shareholder entitled to vote at a meeting of Shareholders, the quorum is one person who is, or who represents by proxy, that Shareholder, present in person or by proxy, may constitute the meeting.

Variation of Rights

7.9 Pursuant to the BCA, the Company may by special resolution of the Shareholders vary or delete any special rights or restrictions attached to the Common Shares.

Constitution of the Board

7.10 Pursuant to the Company's articles, since the Company is a public company, the Company will have at least three directors. If the number of directors is at any time fixed or set hereunder, the Shareholders may elect or appoint the directors needed to fill any vacancies in the board of directors up to that number. Decisions of the Board are made by a majority vote and in the case of an equality of votes the chair of the meeting of directors does not have a second or casting vote.

Permitted Directors' Interests

7.11 In the event that a director (the "Interested Director") has a disclosable interest in a contract or transaction that is material to the Company, whether such contract or transaction has been made or is proposed, the Interested Director is liable to account to the Company for any profit that accrues to the Interested director under or as a result of the contract or transaction only if and to the extent provided in the BCA and the Interested Director must abstain from voting in respect of such contract or transaction, except in certain limited circumstances.

Directors' Term of Office

7.12 All directors cease to hold office immediately before the election or appointment of directors at an annual general meeting but are eligible for re-election or re-appointment.

Directors' Remuneration

7.13 The remuneration of the directors may from time to time be determined by the nominating and compensation committee, or, if the directors so decide, by the Shareholders of the Company.

Restrictions on Voting by Directors

7.14 An Interested Director may not vote in respect of any material contract or material transaction in which such director has a disclosable interest, subject to certain limited exceptions.

Borrowing Powers

7.15 The directors may from time to time authorise the Company to borrow money or otherwise incur debt.

8. DIRECTORS INTERESTS

8.1 As at the date of this document and immediately following Admission, the interests of the Directors in the issued share capital of the Company (including related financial products as defined in the AIM Rules and ESM Rules, including the interests of each Director's family (which shall bear the meaning given to it as set out in the AIM Rules and ESM Rules) (all of which are beneficial) required to be notified to the Company pursuant to Rule 17 of the AIM Rules and ESM Rules the existence of which is known or which could, with reasonable diligence, be ascertained by the Directors are, and following Admission, will be, as follows:

	As at the date of this document		*Immediately following Admission*	
	Number of Common Shares	*Percentage of Existing Issued Share Capital*	*Number of Common Shares*	*Percentage of Enlarged Issued Share Capital*
John Craven	500,000	0.07%	2,857,143	0.35%
Philip O'Quigley	1,000,000	0.14%	1,513,696	0.19%
Gregory Smith	420,000	0.06%	470,000	0.06%
Igor Akhmerov[1]	38,000,000	5.45%	38,000,000	4.65%
David Harris	–	0.00%	150,000	0.02%

Note:

1 Igor Akhmerov's Common Shares are held through Ruby Blue Ltd. (a company in which Mr Akhmerov is the sole shareholder), which is disclosed as a significant shareholder in Section 12 of this Part VI. In addition, Igor Akhmerov holds a 12 per cent. minority equity interest in Soliter Holdings Corp which is disclosed as a significant shareholder in Section 12 of this Part VI.

Warrants

8.2 The Company has granted the following warrants to the Directors as at the date of this document:

Name	*Number of warrants*	*Exercise Price C$*	*Date of Issue*	*Expiry Date*
John Craven	375,000	0.18	08/04/2011	08/04/2014
Daryl H. Gilbert	750,000	0.18	08/04/2011	08/04/2014
Gregory Smith	300,000	0.18	08/04/2011	08/04/2014
Igor Akhmerov[1]	28,500,000	0.18	08/04/2011	08/04/2014

Note:

1 Igor Akhmerov's warrants are held through Ruby Blue Ltd. (a company in which Mr Akhmerov is the sole shareholder), which is disclosed as a significant shareholder in Section 12 of this Part VI.

8.3 In addition, as at the date of this document the Company had granted the following options over Common Shares to the Directors:

	Number of options	*Exercise price*	*End of exercise period*
John Craven	300,000	C$0.170	30/08/2015
John Craven	800,000	C$0.145	23/05/2016
Philip O'Quigley	6,000,000	C$0.100	01/05/2017
Dr. György Szabó	750,000	C$1.180	05/06/2013
Dr. György Szabó	250,000	C$0.170	30/08/2015
Dr. György Szabó	1,500,000	C$0.145	23/05/2016
JoAchim Conrad	300,000	C$0.170	30/08/2015
JoAchim Conrad	400,000	C$0.145	23/05/2016
Igor Akhmerov	400,000	C$0.145	23/05/2016
Daryl H. Gilbert	1,900,000	C$1.180	05/06/2013
Daryl H. Gilbert	300,000	C$0.170	30/08/2015
Daryl H. Gilbert	500,000	C$0.145	23/05/2016
Gregory Smith	300,000	C$0.170	30/08/2015
Gregory Smith	500,000	C$0.145	23/05/2016

8.4 Save as disclosed above, none of the Directors, nor any member of their immediate family or any person connected with them holds or is beneficially or non-beneficially interested directly or indirectly, in any shares or options to subscribe for, or securities convertible into, Common Shares.

8.5 The persons, including the Directors, referred to in Section 8.1 of this Part VI, do not have voting rights in respect of the share capital of the Company (issued or to be issued) which differ from any other shareholder of the Company.

8.6 The Directors are not aware of any arrangements in place or under negotiation the operation of which may, at a subsequent date, result in a change of control of the Company.

8.7 None of the Directors has any interest, whether direct or indirect, in any transactions which are or were unusual in their nature or conditions or which are or were significant to the business of the Company or the Group and which were effected since its incorporation and which remains in any respect outstanding or unperformed.

8.8 There are no outstanding loans or guarantees provided by the Company for the benefit of any of the Directors nor are there any outstanding loans or guarantees provided by any of the Directors for the benefit of the Company.

8.9 None of the Directors nor any member of their immediate family (as defined in the AIM Rules and ESM Rules) nor any related parties (as defined in the AIM Rules and ESM Rules) are interested in any related financial product (as defined in the AIM Rules and ESM Rules) whose value in whole or in part is determined directly or indirectly by reference to the price of the Common Shares, including a contract for difference or a fixed odds bet.

8.10 The full names, functions and dates of appointment of the Directors are as follows:

Name	*Function*	*Business Address*	*Date of Appointment*
John Craven	Non-Executive Chairman	Styne House, Upper Hatch Street, Dublin 2, Ireland	Appointed to the Board on 22 December 2009, and subsequently appointed as Non-Executive Chairman on 7 September 2011
Philip O'Quigley	Chief Executive Officer	Styne House, Upper Hatch Street, Dublin 2, Ireland	25 September 2012
Dr. György Szabó	Director and Managing Director, Hungary	Közraktár u. 30-32, H-1093 Budapest, Hungary	24 April 2006
Daryl H. Gilbert	Non-Executive Director	Suite 2370, 440 – 2nd Avenue SW, Calgary, Alberta T2P 5E9	21 September 2007
JoAchim Conrad	Non-Executive Director	İstinye Mah. Darüşşafaka Cad., Seba Center No:45 Kat:4 Pk:34460, Sarıyer İstanbul, Turkey	6 October 2008
Gregory Smith	Non-Executive Director	4303-9th Street SE, Calgary, Alberta, Canada T2G 3C8	22 December 2009
Igor Akhmerov	Non-Executive Director	Claridenstrasse 22, CH-8002 Zurich, Switzerland	21 September 2007; resigned 29 May 2008; re-elected 14 December 2010
David Harris	Non-Executive Director	27 Tuscany Hills Pt. NW, Calgary, Alberta, Canada T3L 2C7	25 September 2012

9. DIRECTORS' OTHER INTERESTS

9.1 The directorships and partnerships held by the Directors in companies not within the Group, as at the date hereof and during the five years prior to publication of this document are as follows:

Name of Director	*Current Directorships/Partnerships*	*Past Directorships/Partnerships*
John Craven	Discover EXploration	Cove Energy Petroceltic International plc
Philip O'Quigley	Providence Resources Prepay Power Limited Helium Enterprises	n/a
Dr. György Szabó	n/a	n/a
Daryl H. Gilbert	AltaGas Ltd. Penn West Petroleum Ltd. Crocotta Energy Inc. MGM Energy Corp. Charger Energy Corp. Suroco Energy Inc. PRD Energy Inc. Longview Oil Corp. Cequence Energy Ltd. Zedi Inc. JOG Capital Inc. Omers Energy Inc. Exoro Energy Inc. Trident Exploration Corp. Beaumont Energy Inc. Bondi Energy Inc. Gilbert Energy Advisory Corporation	Seaview Energy Inc. Galleon Energy Inc. Spry Energy Ltd. AltaGas Income Trust Rondo Petroleum Inc. Nexstar Energy Ltd. Conifer Exploration Ltd. Grey Hawk Exploration Inc. Canera Resources Ltd. Cadence Energy Inc.

Name of Director	*Current Directorships/Partnerships*	*Past Directorships/Partnerships*
JoAchim Conrad	BosphorusGaz Corporation	Elektrizitätsgesellschaft Laufenburg AG ("EGL")
Gregory Smith	Maglin Site Furniture Inc. Armistice Resources Ltd. Oakridge Financial Management Inc.	Tyler Resources Ltd. CDG Investments Inc. IVG Enterprises Ltd. TriWestern Energy Corp. Sportsclick Inc.
Igor Akhmerov	AGSol S.A. Aion Renewables S.p.A. Aion Renewables SA (Pty Ltd) Avalon S.r.l. Antares Wind S.r.l. Avelar Energy Ltd. Avelar Energy South Africa (Pty) Ltd. Avelar Yenilenebilir Enerji Elektrik Uretimi Sanayi ve Ticaret Anonim Sirketi Avelar Management Ltd. Avelar Management Ltd. Avelar Solar Investments II S.r.l. Aveleos S.A. Aveleos Green Investments S.r.l. Ecoware S.p.A. En Plus S.r.l. Energetic Source S.p.A. Energetic Source Green Energy S.r.l. Energetic Source Green Investments S.r.l. Energetic Source Green Power S.r.l. Energetic Source Renewables S.r.l. Energetic Source Solar Energy S.r.l. Energetic Source Solar Production S.r.l. Energia Fotovoltaica 3 Soc. Agr. A R.l. Energia Fotovoltaica 8 Soc. Agr. A R.l. Energia Fotovoltaica 9 Soc. Agr. A R.l. Energia Fotovoltaica 26 Soc. Agr. A R.l. Energia Fotovoltaica 33 Soc. Agr. A R.l. Energia Fotovoltaica 40 Soc. Agr. A R.l. Energia Fotovoltaica 44 Soc. Agr. A R.l. Energia Fotovoltaica 62 Soc. Agr. A R.l. Energia Fotovoltaica 64 Soc. Agr. A R.l. Energia Fotovoltaica 65 Soc. Agr. A R.l. Energia Fotovoltaica 71 Soc. Agr. A R.l. Energia Fotovoltaica 91 Soc. Agr. A R.l. ENS Solar One S.r.l ENS Solar Two S.r.l ENS Solar Three S.r.l ENS Solar Four S.r.l Flyenergia S.p.A. Geogastock S.p.A. Helios Technology S.p.A Kerself Installations S.r.l. Nadir Energia S.r.l. SAEM Energie Alternative S.r.l. Saemsolar S.r.l. Zenith Energia S.r.l.	n/a
David Harris	n/a	GLJ Petroleum Consultants

9.2 Mr. Gilbert was a director of Globel Direct, Inc. ("Globel") which was the subject of cease trade orders issued by the Alberta Securities Commission ("ASC") on 22 November 2002 and the British Columbia Securities Commission ("BCSC") on 22 November 2002 for failure to file certain financial statements. Globel filed such financial statements and the cease trade orders were removed on 20 December 2002 and 23 December 2002, respectively. On 12 June 2007, Globel was granted protection from its creditors by the Court of Queen's Bench of Alberta pursuant to the Companies' Creditors Arrangement Act, which protection expired on 7 December 2007, following which the monitor was discharged on 12 December 2007 and a receiver/manager was appointed. Subject to the completion of matters relating to the wind-up of the administration of the receivership, the receiver was discharged on 3 September 2008. Globel has ceased operations, and as a result became the subject of cease trade orders issued by the ASC on 24 September 2008 and the BCSC on 30 September 2008 for failure to file certain disclosure documents. In October 2008, a statement of claim was filed against the officers and directors of Globel by that same lender alleging breach of fiduciary responsibilities leading to the failure of the company. This action was not pursued by the claimants, has not received leave of the court to proceed and is currently inactive.

9.3 Mr. Smith was a director of Sportsclick Inc. which was the subject of an order of the Supreme Court of Nova Scotia in July 2009 protecting it from proceedings by creditors pursuant to the Bankruptcy and Insolvency Act and appointed Ernst & Young Inc. as receiver.

9.4 Save as set out above, none of the Directors has any business interests or activities outside the Company which are significant with respect to the Company.

9.5 Save as set out above, none of the Directors have:

9.5.1 any unspent convictions in relation to indictable offences;

9.5.2 any bankruptcy order made against him or entered into any individual voluntary arrangements;

9.5.3 has been a Director of a company which has been placed in receivership, compulsory liquidation, creditors' voluntary liquidation, administration, been subject to a company voluntary arrangement or any composition or arrangement with its creditors generally or any class of its creditors whilst he was a Director of that company or within the 12 months after he ceased to be a Director of that company;

9.5.4 been a partner in any partnership which has been placed in compulsory liquidation, administration or been the subject of a partnership voluntary arrangement whilst he was a partner in that partnership or within the 12 months after he ceased to be a partner in that partnership;

9.5.5 been the owner of any assets or a partner in any partnership with any assets which have in either case been placed in receivership in the case of a partnership whilst he was a partner in that partnership or within the 12 months after he ceased to be a partner in that partnership; or

9.5.6 been publicly criticised by any statutory or regulatory authority (including recognised professional bodies) or

9.5.7 been disqualified by a court from acting as a Director of any company or from acting in the management or conduct of the affairs of a company.

10. DIRECTORS' AND MANAGEMENTS' TERMS OF APPOINTMENT

10.1 **John Craven,** *age 63, Chairman of the Board*

Mr. Craven was appointed to the Board in December 2009 and was appointed as Chairman of the Board in September 2011. Mr. Craven is paid directors' fees of US$48,000 annually. Mr. Craven does not have a service contract with the Company or any of its subsidiaries.

10.2 **Philip O'Quigley,** *age 49, Director and Chief Executive Officer*

Mr. O'Quigley was appointed as a Director in September 2012. Mr. O'Quigley accepted the position of Chief Executive Officer pursuant to an employment contract dated 10 April 2012. Mr. O'Quigley receives an annual salary of US$340,000, which may be increased by up to US$100,000 on achieving certain targets, and is eligible for a bonus of up to 50 per cent. of the sum of Mr. O'Quigley's annual salary plus the annual contribution to his pension plan. The Company can terminate Mr. O'Quigley's employment contract on 12 months notice, or payment in lieu of notice.

10.3 **Dr. György Szabó,** *age 72, Director*

Dr. Szabó was appointed as a Director in April 2006. Dr. Szabó was paid consultancy fees of US$180,000 in 2012 for his consultancy work performed for TXM under two consultancy contracts. Further details of these consultancy contracts are set out in Sections 15.5.15 and 15.5.16 of this Part VI.

10.4 **Daryl H. Gilbert,** *age 61, Director*

Mr. Gilbert was appointed as a Director in September 2007. Mr. Gilbert receives annual directors' fees of US$42,000. Mr. Gilbert does not have a service contract with the Company or any of its subsidiaries.

10.5 **JoAchim Conrad,** *age 48, Director*

Mr. Conrad was appointed as a Director in October 2008. Mr. Conrad receives an annual directors' fee of US$36,000. Mr. Conrad does not have a service contract with the Company or any of its subsidiaries.

10.6 **Gregory Smith,** *age 65, Director*

Mr. Smith was appointed as a Director in December 2009. Mr. Smith receives annual directors' fees of US$42,000. Mr. Smith does not have a service contract with the Company or any of its subsidiaries.

10.7 **Igor Akhmerov,** *age 47, Director*

Mr. Akhmerov was appointed as a Director in December 2010. Mr. Akhmerov receives annual directors' fees of US$42,000. Mr. Akhmerov does not have a service contract with the Company or any of its subsidiaries.

10.8 **David Harris,** *age 53, Director*

Mr. Harris was appointed as a Director in September 2012. Mr. Harris receives annual directors' fees of US$36,000. Mr. Harris does not have a service contract with the Company or any of its subsidiaries.

10.9 **Eoin Grindley,** age 43, Chief Financial Officer

Mr. Grindley entered into an employment agreement on 10 April 2012 whereby Mr. Grindley was appointed as the Company's Chief Financial Officer. Mr. Grindley is paid an annual salary of €160,000 which may be increased by up to €40,000 on achieving certain targets, and is eligible for a bonus of up to 50 per cent. of his initial salary. The Company can terminate Mr. Grindley's employment agreement on six months notice, or payment in lieu of notice.

11. STOCK OPTION SCHEME

11.1 Falcon's Stock Option Plan was approved by the Company's shareholders at the Company's Annual and Special General Meeting on 25 September 2012. Ten per cent. of the number of issued and outstanding Common Shares from time to time are reserved for issuance upon the issuance of stock options granted pursuant to the Stock Option Plan. As at the date of this document, 32,837,000 stock options are issued and outstanding.

11.2 The stock options are non-assignable and may be granted for a term not exceeding five years. Options may be granted under the Stock Option Plan only to persons or corporations, partnerships or other entities that are: (1) permitted by the rules and policies of all regulatory authorities having jurisdiction over Falcon to be granted a stock option and from whom a prospectus and registration exemption under applicable securities law is available; (2) selected by the Company's Compensation Committee to receive benefits under this plan; and (3) at that time a director, officer, employee of consultant or have agreed to commence serving in any of the foregoing capacities (the "Participants").

11.3 The Company's Compensation Committee may grant stock options to Participants upon such terms and conditions as the Compensation Committee may determine in accordance with the following provisions:

11.3.1 Each award of stock options ("Award") shall specify the number of Common Shares to which it pertains;

11.3.2 Each Award shall specify the purchase price paid per Common Share upon the exercise of a stock option (the "Option Price"), which shall not be less than the Discounted Market Price (as defined by the TSX-V Corporate Finance Manual) per share of Common Shares on the date the Award becomes effective;

11.3.3 The exercise price of each Award granted to a Participant (an "Optionee") within 90 days of a distribution by a prospectus shall be the greater of the Discounted Market Price per share of Common Share on the date the Award becomes effective and the per share price paid by the public investors for shares acquired by the distribution by a prospectus;

11.3.4 Each Award shall specify that the consideration to be paid in satisfaction of the Option Price shall be paid in cash in the form of currency or cheque or other cash equivalent acceptable to the Company;

11.3.5 Subject to the prior approval of the TSX-V, any Award may provide that Common Shares issuable upon the exercise of a stock option shall be subject to restrictions whereby the Company has the right or obligation to repurchase all or a portion of such shares if the director, officer, employee or consultant's service to the Company is terminated before a specified time, or if certain other events occur or conditions are not met;

11.3.6 Subject to any contrary provisions in the Stock Option Plan, successive Awards may be made to the same Participant regardless of whether any stock options previously awarded to the Participants remain unexercised;

11.3.7 The Company's Compensation Committee will determine the vesting schedule for each stock option in accordance with the rules and policies of the applicable regulatory authorities, which schedule will be set out in the agreement with the Participants. In no case will a stock option vest at a rate that is less than 20 per cent. per year over five years from the date the Award becomes effective;

11.3.8 Each Award shall specify the term of the stock option, which shall not be greater than five years from the date the Award becomes effective;

11.3.9 Each Award shall be evidenced by an agreement which shall be executed on behalf of the Company by any officer thereof, and delivered to and accepted by the Participants and shall contain such terms and provisions as the Compensation Committee may determine consistent with the Stock Option Plan;

11.3.10 Each Award shall be subject to the requirements that:

11.3.10.1 disinterested shareholder approval shall be obtained for any reduction in the Option Price if the Participant is an Insider (as defined in the Stock Option Plan) of the Company at the time of the proposed amendment;

11.3.10.2 shareholder approval by a simple majority of shareholders shall be obtained for any amendment to previously issued stock options where the shareholders approved the initial Award or where the Participant is an Insider of the Company at the time of the proposed amendment;

11.3.10.3 Each Award to an employee or consultant shall include a representation by the Company that the Participant is a *bona fide* employee or consultant, as the case may be;

11.3.10.4 Prior to receiving an Award, a corporation, partnership or other entity that is, directly or indirectly, wholly owned by an individual or individuals otherwise eligible to receive a grant of stock options (excluding a corporation in which a consultant has an interest) (a "Permitted Optionee") must provide a written representation to the Company that such Permitted Optionee will not effect or permit any transfer of ownership or option of shares or other equity interests of the Permitted Optionee nor issue any further shares or other equity of any class in the Permitted Optionee to any other individual or entity as long as the Award remains outstanding, except with the prior written consent of the TSX-V;

11.3.10.5 A Participant can receive Awards to purchase no more than five per cent. of the Common Shares listed on the TSX-V on a yearly basis;

11.3.10.6 Awards to any one consultant are restricted to two per cent. of the Company's issued Common Shares in any 12 month period;

11.3.10.7 Awards issued to any one consultant performing investor relations activities must vest in stages over 12 months with no more than 25 per cent. of the Award vesting in any three month period;

11.3.10.8 Awards to all employees hired by the Company for the principal purpose of conducting investor relations activities are restricted to an aggregate of two per cent. of the Company's issued shares (calculated at the date the option is granted) in any 12 month period; and

11.3.10.9 Awards to all Insiders (as defined in the Stock Option Plan) in the aggregate are restricted to 10 per cent. of the Company's issued shares in any 12 month period; and

11.3.11 The number of Common Shares reserved for issue to any one person pursuant to the Stock Option Plan may not exceed five per cent. of the outstanding Common Shares listed on the TSX-V on a yearly basis and the award of stock options to Insiders (as defined in the Stock Option Plan) are restricted to ten per cent. of issued Common Shares in any 12 month period. The exercise price of options issued may not be less than the Discounted Market Price per Common Share on the date of grant.

12. SIGNIFICANT SHAREHOLDERS

12.1 Insofar as is known to the Directors, the following persons hold, as at the date of this document, and are expected (based on the information available as at the date of this document), following Admission, to hold directly or indirectly three per cent. or more of the issued share capital:

	As at the date of this document		*Immediately following Admission*	
Shareholder	*Number of Common Shares*	*Percentage of Existing Issued Share Capital*	*Number of Common Shares*	*Percentage of Enlarged Issued Share Capital*
Burlingame Asset Management[1]	125,253,839	17.97%	125,253,839	15.32%
Soliter Holdings Corp[2]	85,572,277	12.28%	112,810,134	13.80%
Persistency[3]	49,269,484	7.07%	59,304,484	7.26%
Ruby Blue Ltd.[4]	38,000,000	5.45%	38,000,000	4.65%

Note:

1. Burlingame Asset Management's associated entities hold a total of 15,000,000 warrants.
2. Igor Akhmerov holds a 12 per cent. minority equity interest in Soliter Holdings Corp.
3. Persistency Private Equity Limited, an entity associated with Persistency Private Equity Holdings, holds a total of 15,000,000 warrants.
4. Igor Akhmerov's Common Shares are held through Ruby Blue Ltd. (a company in which Mr Akhmerov is the sole shareholder), and are also disclosed within Section 8 of this Part VI. Ruby Blue Ltd. also holds a total of 28,500,000 warrants.

12.2 None of the major holders of Common Shares listed above has voting rights different from the other holders of Common Shares.

12.3 Save as disclosed in this Section 12, there are no persons, so far as the Directors are aware, who will immediately following Admission be interested, directly or indirectly, in three per cent. or more of the issued share capital, nor, so far as the Directors are aware, are there any persons or persons who are or, following Admission will or are likely to be, directly or indirectly, jointly or severally, able to exercise control over the Company.

12.4 Save as disclosed in this document, no arrangements are in place, the operation of which may at a later date result in a change of control of the Company.

13. DISCLOSURE REQUIREMENTS AND NOTIFICATION OF INTERESTS IN SHARES

13.1 The AIM Rules and ESM Rules require an AIM or ESM company to issue a notification without delay of any relevant changes, being changes to the legal or beneficial interest, whether direct or indirect, to the holding of a significant shareholder, such a shareholder being three per cent. or more of any class of an AIM security and five per cent. or more of any class of an ESM security respectively, which increases or decreases such holding through any single percentage.

13.2 There are no requirements under the articles or Canadian Securities laws for the Directors or Shareholders who hold three per cent. or more of the Company's share capital to notify the Company of their interests in the Company's share capital or changes in such interests. The UK Disclosure and Transparency rules do not apply to Falcon, as it is not a UK incorporated company. The Company has requested that the registrar notify it of significant Shareholders and relevant changes to significant Shareholders but this may not reveal all interests in Common Shares that require notification by the Company. Therefore, where a Shareholder acquires between three per cent. and ten per cent. of the Company's shares (or increases or decreases their shareholding within this range) the Company may not be aware of changes to these shareholdings and may not be able to announce these in accordance with the AIM Rules and ESM Rules.

14. TAXATION

PART A: UK TAXATION

General

14.1 The following statements do not constitute tax advice and are intended only as a general guide to current UK tax law and published practice of the UK HM Revenue & Customs department, both of which are subject to change at any time, possibly with retrospective effect.

The statements refer to certain limited aspects of the UK tax treatment of Shareholders and (except to the extent stated otherwise) apply only to persons who:

- are the absolute owner (i.e. the legal and beneficial owner) of the Common Shares (and the shares are not held through an Individual Savings account or a Self Invested Personal Pension);
- hold their Common Shares as investments and not as securities to be realised in the course of a trade; and

- have not (and are not deemed to have) acquired their Common Shares by virtue of an office or employment (whether current, historic or prospective) and are not officers or employees of any member of the Group.

These statements may not apply to certain classes of investors who are subject to different tax rules. Such persons may include (but are not limited to): dealers in securities, insurance companies, collective investment schemes and Shareholders who are exempt from UK taxation.

An investment in the Company involves a number of complex tax considerations not addressed here. For instance, the returns from the Company to investors could be adversely affected by various factors such as changes in tax legislation in any of the countries in which the Company has assets or changes in tax treaties negotiated by those countries.

Prospective investors should consult their own independent professional advisers on the potential tax consequences of subscribing for, purchasing, holding or selling Common Shares under the laws of their country and/or state of citizenship, domicile or residence.

Taxation of dividends

14.2 (a) ***The Company***

The Company is not required to withhold UK tax at source from the dividends it pays to Shareholders in respect of its Common Shares.

Dividends paid or credited or deemed to be paid or credited to a non-resident Shareholder by the Company are subject to Canadian withholding tax at the rate of 25 per cent unless reduced by the terms of an applicable tax treaty.

(b) ***Shareholders***

A Shareholder's liability to UK tax on dividends paid by the Company will depend upon that person's specific circumstances.

UK resident individual Shareholders

Individual Shareholders who are resident in the UK for UK tax purposes, are subject to income tax on dividends received from the Company but will be entitled to a tax credit equal to one-ninth of the amount of the dividend receipt. For instance, if the Company pays a £90 dividend to an individual, the related tax credit is £10 and that Shareholder will be liable to tax on the gross dividend of £100.

When calculating that Shareholder's liability to income tax on the dividend, the tax credit (which equates to ten per cent. of the gross dividend) is set off against the tax chargeable on the gross dividend.

Individual Shareholders who are not liable to UK tax on dividends received from the Company are not entitled to a tax credit in respect of those dividends.

The UK income tax regime applies progressive rates of tax according to the amount of an individual's taxable income. Dividends are treated as the top slice of an individual's income.

Basic rate taxpayers

A Shareholder, who is liable to UK tax at the basic rate, will be charged to tax on the gross dividend at the dividend ordinary rate of ten per cent. (2012/2013), so the tax credit will fully discharge that Shareholder's income tax liability on the dividend. For example, a basic rate taxpayer in receipt of a £90 dividend will be liable to ten per cent. tax on the gross dividend of £100, and the ten per cent. tax credit will reduce the actual liability to nil.

Higher rate taxpayers

A Shareholder liable to UK tax at the higher rate will be charged to income tax on the gross dividend at the dividend upper rate of 32.5 per cent. (2012/2013), unless, when it is treated as the top slice of the Shareholder's income, all or part of it exceeds the threshold for the additional rate of income tax.

The ten per cent. tax credit attached to the dividend will only partially discharge the Shareholder's 32.5 per cent. tax liability. An income tax charge of 22.5 per cent. of the gross dividend (25 per cent. of the net dividend) will remain. For example, tax of £22.50 will be due on a dividend of £90 received by an Individual Shareholder (representing 32.5 per cent. of the gross dividend of £100, less the ten per cent. tax credit).

Additional rate taxpayers

A Shareholder liable to UK tax on their income at the additional rate will be charged to tax on the gross dividend at the dividend additional rate of 42.5 per cent. (2012/2013).

In this situation, the ten per cent. tax credit attached to the dividend will only partially discharge the Shareholder's 42.5 per cent. tax liability. An income tax charge of 32.5 per cent. of the gross dividend (36.1 per cent. of the net dividend) will remain. For example, tax of £32.50 will be due on a dividend of £90 received by an individual Shareholder (representing 42.5 per cent. of the gross dividend of £100 less the ten per cent. tax credit).

Draft legislation proposes to reduce the dividend additional rate to 37.5 per cent. with effect from 6 April 2013. If enacted, an income tax liability at the rate of 27.5 per cent. of the gross dividend (30.6 per cent. of the net dividend) will remain. For example, tax of £27.50 will be due on a dividend of £90 received by an individual Shareholder (representing 37.5 per cent. of the gross dividend of £100, less the ten per cent. tax credit).

UK resident corporate Shareholders

A corporate Shareholder (within the charge to UK corporation tax) which is a 'small company' for the purposes of the UK taxation of dividends legislation will not generally be subject to UK corporation tax on dividends from the Company, providing the payer is resident in a 'qualifying territory' at the time the dividend is received. A 'qualifying territory' for these purposes is any territory with which the UK has a double tax treaty that has an appropriate non-discrimination clause.

Other corporate Shareholders (within the charge to UK corporation tax) will not be subject to tax on dividends from the Company provided the dividends fall within an exempt class and certain conditions are met. In general, almost all dividends received by corporate Shareholders will fall within an exempt class. Examples of dividends that fall within exempt classes include dividends paid on shares that are non-redeemable ordinary shares, and dividends paid to a person holding less than ten per cent. of the issued share capital of the Company (or any class of that share capital).

The exemptions are not comprehensive and are subject to anti-avoidance rules. If the conditions for exemption are not, or cease to be, satisfied, or such a Shareholder elects for an otherwise exempt dividend to be taxable, the Shareholder will be subject to UK corporation tax on dividends received from the Company. Corporation tax is charged on dividends at the rate applicable to that company.

Taxation of chargeable gains

14.3 A disposal or deemed disposal of Common Shares by a Shareholder who is resident (or, in the case of an individual, ordinarily resident) in the UK for tax purposes, may give rise to a chargeable gain or an allowable loss for the purposes of UK taxation of chargeable gains, depending on the Shareholder's circumstances and subject to any available exemption or relief.

(a) *UK resident individual Shareholders*

For a Shareholder within the charge to UK capital gains tax, capital gains tax is charged on gains on the disposal of Common Shares. The rate is 18 per cent. (2012/2013) for individuals who are subject to income tax at the basic rate; and 28 per cent. (2012/2013) for all trustees and personal representatives, and individuals who are subject to income tax at the higher or additional rates. There is no allowance reflecting any inflation during the period of ownership. However, an individual Shareholder is entitled to realise £10,600 (2012/2013) of gains (the annual exempt amount) in each tax year without being liable to tax. The annual exempt amount for trusts is £5,300 (2012/2013).

An individual Shareholder may qualify for entrepreneurs' relief on a qualifying disposal of shares if certain conditions are met. These conditions include holding at least five per cent. of the issued share capital and voting rights and being an officer or employee of the Company. If these conditions are met, this will reduce the rate of capital gains tax to ten per cent. for gains up to a lifetime limit of £10,000,000 (2012/2013).

(b) *UK resident corporate Shareholders*

For a corporate Shareholder, within the charge to UK corporation tax, a disposal (or deemed disposal) of Common Shares may give rise to a chargeable gain or allowable loss for the purposes of UK corporation tax.

Indexation allowance on the cost apportioned to the Common Shares may be available to reduce the amount of chargeable gain realised on a subsequent disposal to the extent that such gains arise due to inflation. Indexation allowance may not create or increase any allowable loss.

Corporation tax is charged on chargeable gains at the rate applicable to that company.

A gain accruing to a corporate Shareholder on a disposal of shares in the Company may qualify for the substantial shareholding exemption if certain conditions regarding the amount of shareholding and length of ownership, the investing company and the company invested in are fulfilled. If the substantial shareholding exemption applies, gains are exempt from tax and losses do not accrue.

Inheritance tax

14.4 Inheritance tax may be payable where an individual dies (wherever they are domiciled) holding Common Shares, or where certain gifts are made of Common Shares by individuals or certain trustees.

Shares which are listed on AIM are currently treated as unquoted for the purpose of the inheritance tax legislation. This could change. This means that such shares can qualify for Business Property Relief at 100 per cent. if the company's activities are not wholly or mainly dealing in securities, stocks or shares, land or buildings of the making of holding of investments. If the company is the holding company of a group whose activities are not wholly or mainly any of those described above its shares may also qualify. Once the Common Shares have been held for at least two years they should then qualify for business property relief which means that a number of the charges outlined below will not arise or will be reduced. However, where shares are listed on an overseas exchange (such as the Toronto Stock Exchange) which is a recognised exchange, such shares may only qualify for Business Property Relief in shareholders' hands where the holding is a controlling holding, and the relief will only be available at 50 per cent.

The inheritance tax rules are complex and specialist advice should be taken.

Death of individual Shareholders

Any Common Shares held by an individual Shareholder at the time of his or her death will be treated as part of their estate for inheritance tax purposes and valued on a quarter up basis. Subject to any reliefs or exemptions that value will be taxable at 40 per cent. (2012/2013). The main reliefs that apply are the spouse or civil partner exemption and the nil rate band. Where the shares pass to a surviving spouse or civil partner (or certain trusts for them) their value is not generally taxable. If the total taxable value of the estate is below the available nil rate band of £325,000 (2012/2013) no inheritance tax will be payable. The available nil rate band may be reduced by previous lifetime gifts or increased if a spouse or civil partner predeceased the Shareholder and did not use their full nil rate band.

If the shares are sold at a loss by the estate within 12 months of the death, and a net loss has been made on all such sales of quoted shares or securities, then a claim can be made to substitute the sale prices of the various holdings for the value at the date of death and so reduce the overall inheritance tax payable.

Gifts of shares by individual Shareholders

Gifts of Common Shares by individual Shareholders to other individuals are potentially exempt transfers and not taxable at the time of gift. If the Shareholder survives seven years from the date of the gift it will never be chargeable to inheritance tax. If, however, the Shareholder dies before seven years have elapsed the gift will become chargeable. It is possible that no tax will be payable if the gift falls within the individual's available nil rate band as explained above, although it would then reduce the available nil rate band for the rest of the estate. A form of taper relief is available to reduce any tax payable on gifts which become chargeable if made more than three years before the death.

Gifts to trusts (other than charities) are generally chargeable transfers at the time they are made. Any available nil rate band will be offset against the value transferred before tax is calculated. The tax rate for such lifetime gifts is 20 per cent. (or 25 per cent. if paid by the donor).

Stamp Duty and Stamp Duty Reserve Tax

14.5 An instrument of transfer relating to Common Shares represented by DIs, which is executed in the United Kingdom or which relates to any matter or thing done or to be done in the United Kingdom, may be liable to UK stamp duty at the rate of 0.5 per cent. of the consideration rounded up to the nearest £5.

An agreement to transfer Common Shares will not be liable to SDRT so long as:

(a) the relevant Common Shares are not registered in a register maintained by or on behalf of the Company in the United Kingdom; and

(b) the Common Shares are not paired with shares issued by a company incorporated in the United Kingdom.

An agreement to transfer Common Shares represented by DIs will not be liable to SDRT so long as at the time of the agreement:

(a) the Company is not incorporated nor has its central management and control exercised, in the United Kingdom;

(b) the Common Shares are not registered in a register kept in the United Kingdom by or on behalf of the Company; and

(c) the Common Shares are of the same class in the Company as the Common Shares which are listed on TSX-V.

PART B: IRISH TAXATION

14.6 The following statements do not constitute tax advice and are intended only as a general guide to current Irish tax law and published Revenue practice in Ireland.

The statements refer to certain limited aspects of the Irish tax treatment of Shareholders and (except to the extent stated otherwise) apply only to persons who:

- are the absolute owner (i.e. the legal and beneficial owner) of the Common Shares (and the shares are not held through an Individual Savings account or a Self Invested Personal Pension);

- hold their Common Shares as investments and not as securities to be realised in the course of a trade; and
- have not (and are not deemed to have) acquired their Common Shares by virtue of an office or employment (whether current, historic or prospective) and are not officers or employees of any member of the Group.

These statements may not apply to certain classes of investors who are subject to different tax rules. Such persons may include (but are not limited to): dealers in securities, insurance companies, collective investment schemes and Shareholders who are exempt from Irish taxation.

An investment in the Company involves a number of complex tax considerations not addressed here. For instance, the returns from the Company to investors could be adversely affected by various factors such as changes in tax legislation in any of the countries in which the Company has assets or changes in tax treaties negotiated by those countries.

Prospective investors should consult their own independent professional advisers on the potential tax consequences of subscribing for, purchasing, holding or selling Common Shares under the laws of their country and/or state of citizenship, domicile or residence.

Taxation of Dividends

14.7 Irish resident Shareholders who are individuals will be subject to income tax, social security and the universal social charge depending on their circumstances on the gross dividend income received. Depending on the individual's personal circumstances, foreign withholding tax may apply to the gross dividend. A credit for foreign withholding tax deducted should be available in Ireland in respect of the Irish tax liability on the same income. An Irish resident Shareholder which is a company will be subject to Irish Corporation Tax on the income. Depending on the particulars of the case, it may be possible for the Irish resident corporate shareholder to elect to have the dividend income treated as trading income and therefore taxable at the trading Corporation Tax rate. In such circumstances a credit should be available for both withholding tax deducted on any dividend payment and also for underlying tax suffered on the income.

Capital Gains Tax

14.8 The Common Shares constitute chargeable assets for Irish Capital Gains Tax ("CGT") purposes and, accordingly, individual Shareholders who are resident or ordinarily resident in Ireland, depending on their circumstances, may be liable to Irish tax on capital gains on a disposal of Common Shares. The Irish CGT rate is currently 33 per cent. As it is not expected that the Company will derive the greater part of their value directly or indirectly from land, buildings, minerals or interests or other assets in relation to mining or minerals or the searching for minerals within Ireland, the Shareholders who are neither resident or ordinarily resident in Ireland and who do not hold the Common Shares for the purposes of a trade carried on in Ireland should not be subject to Irish tax on capital gains arising on the disposal of the Common Shares. An Irish resident individual, who is a Shareholder who ceases to be an Irish resident for a period of less than five years and who disposes of Common Shares during that period, may in certain circumstances be liable, on a return to Ireland, to CGT on any gain realised. Depending on the exact circumstances of the situation it may be possible for corporate resident shareholders to claim an exemption from Irish Capital Gains Tax on the disposal of their shareholding in the company.

Capital Acquisitions Tax

14.9 Capital acquisitions tax ("CAT") covers both gift tax and inheritance tax. Irish CAT may be chargeable on an inheritance or a gift of Common Shares where either the disponer or beneficiary of the gift is Irish tax resident. The current rate of CAT is 33 per cent. Shareholders should consult their tax advisors with respect to the CAT implications of any proposed gift or inheritance of Common Shares.

PART C: CANADIAN TAXATION

14.10 The following section is generally applicable to holders who, for the purposes of the Income Tax Act (Canada) ("Tax Act") and at all relevant times: (i) have not been and will not be, or be deemed to be, resident in Canada at any time while they hold Common Shares; and (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. Holders who meet all of the foregoing requirements are referred to herein as "non-resident Holders", and this portion of the summary only addresses such non-resident Holders. Special rules, which are not discussed in this section, may apply to a non-resident Holder that is an insurer carrying on business in Canada and elsewhere or an "authorised foreign bank" (as defined in the Tax Act).

Dividends

Dividends paid or credited or deemed to be paid or credited to a non-resident Holder by the Company are subject to Canadian withholding tax at the rate of 25 per cent. unless reduced by the terms of an applicable tax treaty.

Disposition of Common Shares

A non-resident Holder generally will not be subject to tax under the Tax Act in respect of a capital gain realised on the disposition or deemed disposition of a Common Share unless the Common Share constitutes "taxable Canadian property" of the non-resident Holder thereof for purposes of the Tax Act and the gain is not exempt from tax pursuant to the terms of an applicable tax treaty.

Provided that the Common Shares are listed on a "designated stock exchange" for purposes of the Tax Act (which currently includes tiers 1 and 2 of the TSX-V) at the time of disposition, the Common Shares generally will not constitute "taxable Canadian property" of a non-resident Holder, unless at any time during the 60 month period immediately preceding the disposition: (i) the non-resident Holder, persons with whom the non-resident Holder did not deal at "arm's length" for the purposes of the Tax Act, or the non-resident Holder together with all such persons, owned 25 per cent. or more of the issued shares 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 Tax Act), "timber resource properties" (as defined in the Tax Act) or options in respect of, or interests in, or for civil law rights in, such property whether or not such property exists.

Certain withholding and reporting obligations will also generally apply in connection with the disposition of Common Shares by a non-resident Holder that constitutes or are deemed to constitute "taxable Canadian property" (and are not "treaty-protected property" as defined in the Tax Act).

Non-resident Holders who may hold Common Shares as "taxable Canadian property" should consult their own tax advisors.

15. MATERIAL CONTRACTS

The following material contracts are those contracts which have been entered into by a member of the Group:

(a) in the two years immediately preceding the date of this document (other than in the ordinary course of business);

(b) which contain any provision under which any member of the Group has any obligation or entitlement which is material to the Group as at the date of this document (other than those entered into in the ordinary course of business); and

(c) any other material subsisting agreement which relates to the assets and liabilities of the Group (notwithstanding whether such agreements are within the ordinary course of business or were entered into outside of the two years immediately preceding the date of this document):

15.1 ***Contracts Related to the Australian Assets***

15.1.1 *The Hess Agreement*

On 28 April 2011, Falcon Australia and Hess entered into the Beetaloo Evaluation and Participation Agreement, amended by letter on 13 August 2012 (the "Hess Agreement"). Under the terms of the Hess Agreement, Hess has paid Falcon Australia: (i) a US$17,500,000 participation fee; and (ii) US$2,000,000 for Falcon Australia providing Hess copies of data obtained from the Shenandoah-1 well work program. Further, Hess Oil & Gas Holdings Inc. paid the Company $2,500,000 as consideration for the issuance of 10,000,000 warrants (the "Hess Warrants") to acquire Common Shares, each Hess Warrant exercisable into one Common Share on payment of C$0.19 per Common Share. The Hess Warrants are exercisable commencing 14 November 2011 and expire on 13 January 2015. The Hess Warrants are subject to adjustment as provided for in the warrant certificate.

Initially, Hess is obligated to acquire 2D seismic data, at its sole cost of at least US$40,000,000, for the Hess Area of Interest. Hess will grant Falcon Australia a perpetual, royalty-free and irrevocable licence to use, prepare derivative works, and disclose all of the seismic data acquired pursuant to the Hess Agreement. After acquiring the seismic data, Hess will have the right to acquire a 62.5 per cent. working interest (the "Hess Interest") in the Hess Area of Interest. Pursuant to an amendment to the Hess Agreement dated 13 August 2012, the deadline for Hess' delivery of notice of its intention to acquire the Hess Interest has been extended to 30 June 2013.

If Hess acquires the working interest, it is required to drill and evaluate five exploration wells at its sole cost, one of which must be a horizontal well. Pursuant to the 13 August 2012 amendment to the Hess Agreement, Hess has agreed, subject to proceeding to the development phase, to carry Falcon Australia, on the first development well, up to a gross cost of US$10,000,000. Costs to drill wells after the five exploration wells and the first development well (and after the initial US$10,000,000) will be borne 62.5 per cent. by Hess and 37.5 per cent. by Falcon Australia. The drilling and evaluation of the five exploration wells must meet the minimum work requirements of the work program agreed with the Northern Territory Government Department of Resources. Hess will bear all costs to plug and abandon the exploration wells. The Company and Hess Corporation have entered into reciprocal guarantees regarding Falcon Australia and Hess' respective payment and performance of their obligations under the Hess Agreement. The acreage interests are subject to government and native title holder royalties of 12 per cent. and non-government royalties of approximately 13 per cent. on production values.

15.1.2 *Falcon – PetroHunter Agreement*

On 7 December 2009, the Company entered into an agreement among the Company, Falcon Australia, PetroHunter Energy Corporation and Sweetpea. Under the terms of the Binding Heads of Agreement: (i) Falcon Australia agreed to acquire an additional 25 per cent. interest in exploration permits EP-76; EP-98; EP-99 and EP-117 from Sweetpea in consideration for the issuance to Sweetpea of 50 million ordinary shares in the capital of Falcon Australia; and (ii) the Company was issued 150 million ordinary shares in the capital of Falcon Australia for the conversion of Falcon Australia's US$30 million debt payable to Falcon.

15.2 ***Contracts Relating to South African Interests***

15.2.1 *The Chevron Agreement*

On 12 December 2012, the Company and Chevron Business Development South Africa Limited ("Chevron") entered into a cooperation agreement (the "Chevron Agreement") pursuant to which the Company and Chevron agreed to cooperate and work together in order to seek exploration opportunities in the Karoo Basin in South Africa (the "Area of Interest") and obtain an exploration right from the Republic of South Africa pursuant to the 2002 Mineral and Petroleum Resources Development Act (the "Exploration Right").

Under the terms of the Chevron Agreement, Falcon will, for a period of five years, work exclusively with Chevron in jointly obtaining exploration permits in the Area of Interest. Chevron has paid the Company US$1,000,000 for certain data and auditable costs and expenses incurred by the Company and its affiliates in relation to the Area of Interest.

The Chevron Agreement terminates on 12 December 2017.

15.3 ***Contracts Related to the Hungarian Assets***

15.3.1 *The NIS Agreement*

On 22 January 2013, the Company and TXM entered into an oilfield services contract (the "NIS Agreement") with NIS and Naftna industrija Srbije jsc pursuant to which NIS agreed to undertake a three-well (the "Obligation Wells") drilling exploration program targeting prospects located down to the base of the "Algyö Play" in the Pannonian Basin, Hungary (the "NIS Area"), prior to 14 January 2014 or as otherwise agreed by the parties (the "Drilling Obligation). Under the terms of the NIS Agreement, NIS has paid TXM a fee of US$1,500,000 plus VAT in consideration for the provision by TXM of the acquired geological and geophysical data and the knowledge base of the hydrocarbon model of the NIS Area.

In addition, following the completion of the Drilling Obligation, NIS has the right and the option in its sole discretion either to earn a right of negotiation from TXM for future drilling operations in the NIS Area or to keep its right to receive from TXM a cost-based fee of services and a success-based fee for services from the production of hydrocarbons of the Obligation Wells and the prospects drilled and completed for production by NIS.

15.4 ***Other Contracts entered into by any member of the Group***

15.4.1 *The Placing Agreement*

On 14 March 2013, the Company (1), Davy (2), GMP (3) and the Directors (4) entered into the Placing Agreement.

Pursuant to the Placing Agreement, Davy and GMP have agreed, each as agents for the Company, to use their respective reasonable endeavours to procure subscribers for the Placing Shares at the Placing Price.

The Company has agreed to pay each of GMP and Davy one per cent. on the aggregate value of the Placing Shares placed with certain existing Shareholders and Directors who are subscribing pursuant to the Placing and five per cent. on the aggregate value of the Placing Shares placed by each of Davy and GMP with shareholders other than such existing Shareholders and Directors such amounts to be withheld by Davy and GMP from the Placing proceeds with the balance to be paid to the Company by Davy and GMP, as applicable, within three business days of Admission.

The Company and each of the Executive Directors have given certain customary warranties and indemnities as to the accuracy of the information in this document and as to other matters in relation to the Company, the Placing and Admission with the Executive Directors' individual liability capped at their annual salary for the financial year ended 31 December 2012, such warranties expire on publication of audited financial statements for the 12 month period ending 31 December 2013.

The Placing is conditional, *inter alia*, on:

(i) the Placing Agreement becoming unconditional and not having been terminated in accordance with its terms prior to Admission; and

(ii) Admission occurring by no later than 8.00 a.m. (London time) on 28 March 2013 (or such later date as the Company, Davy and GMP may agree, being no later than 30 April 2013).

15.4.2 *The Nominated Adviser, ESM Adviser and Broker Agreement*

On 14 March 2013, the Company (1) and Davy (2) entered into a nominated adviser, ESM Adviser and broker agreement for an initial period of 12 months from the date of Admission and terminable thereafter by the Company or Davy on three months' written notice. Pursuant to this agreement, Davy will receive, conditional on Admission, an annual retainer of €35,000 for the provision of nominated adviser and broker services on an on-going basis.

The Company has agreed to comply with its legal and regulatory obligations (including under the AIM Rules and ESM Rules) and to consult and discuss with Davy in connection with any announcements and statements to be made by it. The Company has also agreed to provide Davy with any information which Davy believes is necessary in order to enable it to carry out its obligations to the Company, the London Stock Exchange or the Irish Stock Exchange as nominated adviser and ESM Adviser.

The Nominated Adviser, ESM Adviser and Broker Agreement contains indemnities given by the Company in favour of Davy.

15.4.3 *The Lock In Agreement*

An agreement was entered into on 14 March 2013 between Davy, GMP (1), the Company (2) and each of the Director Shareholders (3), pursuant to which the Director Shareholders have each agreed, conditionally on Admission with Davy, GMP and the Company not to dispose of any interest in any Common Shares held immediately prior to the Placing for a period of 12 months from the date of Admission, except in limited circumstances, or with the prior written consent of Davy, GMP and the Company.

15.4.4 *Salman Partners Engagement Letter*

On 23 January 2013 the Company entered into a Financial Advisory Agreement with Salman Partners Inc. ("Salman") whereby Salman agreed to provide the Company with advice concerning the retirement of the Company's existing Debentures. Salman will assist in the marketing of the Company to a number of institutional investors who are Debenture holders. As compensation for these services Salman will receive a non-refundable retainer fee of C$25,000 and will receive an aggregate cash commission of 1.5 per cent. of the face value of the Debentures that are retired as a result of Salman's services. The Financial Advisory Agreement may be terminated at any time by either party by giving written notice of termination which will be effective five days following receipt thereof.

15.4.5 *Credit Facility*

On 14 May 2012, the Company entered into a credit facility (the "Facility") with Falcon Australia whereby the Company provided Falcon Australia with a credit facility up to a maximum amount of US$12,500,000. The principal amount drawn under this Facility bears an interest rate per annum which is the aggregate of two per cent. per annum plus (ii) LIBOR up to a maximum aggregate percentage of 7 per cent. per annum (the "Interest Rate"). Interest accrues daily and is compounded monthly on the aggregate outstanding principal amount under the Facility from and including the first day of a 90 day period (the "Funding Period") to (but excluding) the last day of that Funding Period or, in the case of prepayment or repayment of the principal amount, to (but excluding) the date of such prepayment or repayment, at the Interest Rate. The Borrower must pay accrued interest in arrears on the last day of each Funding Period and on the day of repayment or prepayment for any reason of all or the relevant part of any portion of financial accommodation made under the Facility. Falcon Australia has drawn US$9,434,332 under the Facility.

The Facility terminates 13 months from 14 May 2012, reviewable annually at the sole discretion of the Company (the "Termination Date"). Falcon Australia must repay all principal outstanding, together with any amount owing under or relating to the Facility on: (i) the Termination Date; or (ii) the date upon which Falcon Australia no longer has any interest in any of the assets and undertakings of the Company subject to prepayment on the sale of a portion of Falcon Australia's interest in the Hess Agreement or any of the assets of the Hess Agreement (the "Project Assets"). If a portion of the Project Assets are sold, Falcon Australia must repay a portion of all money that Falcon Australia is liable to pay to the Company under the obligations in the Facility, under each Security (defined below) and under any other document as agreed by the Company and Falcon Australia. This repayment must be equal to or greater than 75 per cent. of the cash consideration received by Falcon Australia (after certain deductions) for the Project Assets sold.

At the request of the Company, Falcon Australia is obligated to secure the priority of, among other things: (i) a fixed and floating charge over all of Falcon Australia's property, assets and undertaking and (ii) a mining mortgage (the "Security"). The Facility is currently unsecured.

Falcon Australia may only use the principal drawn under the Facility to: (i) repay money already advanced by the Lender to the Borrower which was outstanding as at the date of entering into the Facility; (ii) fund the obligations of Falcon Australia under the terms of the Hess Agreement; (iii) for Falcon Australia's general working capital requirements; (iv) to pay interest on the Facility; or (v) for any other purpose approved in writing by the Company.

15.4.6 *Unit Offering*

On 10 February 2011 and 8 April 2011, the Company issued 44,533,333 units and 42,516,666 units (for a total of 87,049,999 units), respectively, at an issuance price of C$0.15 per unit, each unit consisting of one Common Share and three quarters of one common share purchase warrant. Each whole warrant entitles the holder to acquire one Common Share at an exercise price of C$0.18 per Common Share for a period of 36 months from the date of issuance. There were twelve different subscribers to this offering, including a number of the Company's Insiders (as defined by the TSX-V Corporate Finance Manual).

15.4.7 *Hess Warrants*

On 13 July 2011, the Company issued to Hess Oil and Gas Holdings Inc. ("Hess Oil and Gas") 10,000,000 warrants which entitled Hess Oil and Gas to acquire 10,000,000 Common Shares at an exercise price of C$0.19 per Share (the "Hess Warrants"). The term of the Hess Warrants began on 14 November 2011 and expires on 13 January 2015. The Hess Warrants are subject to adjustment as provided for in the warrant certificate.

15.4.8 *Private Placement*

On 14 October 2011, the Company issued a total of 676,800 Common Shares to employees and completed a private placement for a total of 660,900 Common Shares, each at a subscription price of C$0.15. The full private placement was subscribed by insiders of Falcon.

15.4.9 *Falcon Australia Placement*

Under the terms of the private placement outlined in an offer memorandum originally dated 27 January 2010, revised on 23 March 2010 and further revised on 11 May 2010, Falcon Australia intended to sell up to 50,000,000 common shares in the capital of Falcon Australia ("FA Shares") at a price of US$1.00 per FA Share with an attached option (the "FA Offering"). Each option entitled the holder to acquire one additional FA Share in respect of each FA Share issued for a period of three years from the date of issue, at an exercise price of US$1.25. In June 2010 and November 2010, Falcon Australia closed on gross proceeds from the FA Offering of US$4,896,000 and US$1,217,578, respectively.

15.4.10 *MPS Agreement*

In connection with the FA Offering, on 8 December 2009, Falcon Australia entered into an agreement with Martin Place Securities ("MPS") pursuant to which MPS agreed to act as the lead manager to the FA Offering. Under the terms of the FA Offering, Falcon Australia paid MPS A$452,477.29. In addition, Falcon Australia issued 397,361 stock options representing approximately 6.5 per cent. of the funds raised through the FA Offering to a number of different entities, as instructed by MPS. The stock options bore the same terms as those issued in the FA Offering.

15.4.11 *The Trust Indenture*

On 30 June 2009 (the "Subscription Date"), Falcon entered into a trust indenture (the "Trust Indenture") between Falcon, and Computershare Trust Company of Canada (the "Trustee"). The Trust Indenture authorizes the issuance of convertible debentures bearing an annual interest rate of 11 per cent. in an aggregate principal amount C$100,000,000. Debentures may be issued in denominations of C$1,000 and integral multiples thereof and will mature on 30 June 2013 (the "Maturity Date"). The outstanding principal amount of the Debentures, together with all outstanding and unpaid interest will become due and payable on the Maturity Date. The Debentures are unsecured direct obligations of the Company. In certain circumstances the Trust Indenture restricts the Company from incurring additional indebtedness (except for certain indebtedness permitted under the Trust Indenture) by borrowing money or from mortgaging, pledging or charging its property to secure any indebtedness. The Debentures are transferrable subject to compliance with the Trust Indenture and all regulatory requirements.

If the volume weighted average price of the Common Shares on the TSX-V had been C$0.85 or greater for 20 consecutive trading days in the two year period following 9 June 2009 the Debentures would have automatically converted into Common Shares at C$0.60 per Common Share (the "Conversion Price") and holders of the Debentures ("Debenture holders") would have been entitled to received accrued and unpaid interest, in cash, to the end of the first 12 month period or 24 month period after the Subscription Date, as the case may be. This two-year automatic conversion period has expired.

Each Debenture will be convertible into Common Shares at the option of the Debenture holder at any time prior to the close of business on the Maturity Date. The right to convert and the Conversion Price are subject to adjustment on the occurrence of certain events as set out in the Trust Indenture.

Falcon had a one-time option to redeem the Debentures which has expired.

15.5 *Consultancy Agreements*

15.5.1 *Dr. Gábor Bada*

On 28 December 2012, Dr. Bada entered into an employment agreement (the "Bada Employment Agreement") with TXM pursuant to which Dr. Bada agreed, subject to certain conditions, to perform certain geological services for TXM. Dr. Bada received a salary (including bonus) of US$78,256 in 2012 and will receive a salary of approximately US$82,440 in 2013. In addition, on 1 January 2013, Dr. Bada verbally agreed the terms on which he was to provide geological services to TXM as a consultant. Dr. Bada will be paid a consultancy fee of US$20,000 in 2013 in relation to this work. The Bada Employment Agreement contains standard confidentiality provisions.

Under the terms of the Bada Employment Agreement, Dr. Bada shall not, during his employment, establish other employment or other legal "working" relationships without the prior written consent of TXM (this prohibition does not apply to academic study, lecturing activity or work protected by copyright) and engage in conduct which may jeopardize the economic interests of TXM.

The Bada Employment Agreement may be terminated by, among other things, mutual consent or by notice (in which case the notice period shall be determined in accordance with the provisions of the Hungarian Labour Code.)

15.5.2 *FTI Consulting*

On 21 May 2012, the Company engaged FTI Consulting LLP ("FTI") to provide business communications services for work surrounding the Company's anticipated admission to AIM. FTI has been paid £24,238.70 in total since the appointment, and will be paid a £10,000 one-off payment for work to be completed in connection with the Company's anticipated admission to AIM. On admission to AIM, FTI will charge a monthly retainer fee, the exact amount of which is to be agreed by FTI and the Company. All fees are exclusive of VAT and any outlays incurred by FTI in connection with the engagement. FTI's appointment will continue until terminated according to FTI's Terms of Business.

15.5.3 *Zöld Vonal Agreement*

On 1 October 2011, Zöld Vonal 2000 Kft. entered into an agreement (the "Zöld Agreement") with TXM, pursuant to which Zöld Vonal 2000 Kft. agreed to provide certain environmental consultancy services to TXM on a monthly fixed fee of €3,000 + VAT with a mileage fee of HUF 120 per kilometre. For the year 2012, the total fees invoiced under the Zöld Agreement were HUF 10,577,7000.

15.5.4 *Denver Ex-employee Consulting Agreements*

The Company has entered in to consulting agreements with six ex-employees of the Company in Denver, Colorado. As consideration for their services as consultants, the stock options granted to the employees during their term of employment with the Company shall continue with the same terms and vesting plan as in place on the date of the consulting agreements entered into with the Company.

Under the terms of these consulting agreements, the ex-employee consultants are not eligible at any time to participate in any profit sharing, receive any equity under any option or stock plan (except the previously granted options contemplated by each consultancy agreement), health insurance, life insurance, dental insurance, 401K plan or other benefit plan offered by the Company.

Each ex-employee consultant may terminate his consultant agreement at any time, in his sole discretion, by providing the Company ten days' prior written notice.

15.5.5 *Law Consulting Arrangement*

In 2012 the Company engaged Carol Law as a consultant for the provision of certain technical services pursuant to which Ms Law was paid US$100,000 in January 2013. No written agreement was entered into with Ms Law. This consultancy arrangement has now been terminated.

15.5.6 *Méltányosság Agreement*

On 1 October 2011, Méltányosság Politikaelemzó Központ ("MPK") entered into an agreement (the "MPK Services Agreement") with TXM, pursuant to which MPK agreed to provide certain social research services to TXM.

In addition, on 1 January 2012, MPK entered into an agreement (the "MPK Agreement") with TXM, pursuant to which MPK agreed to conduct certain political studies and provide certain advisory services to TXM. Under the MPK Agreement, MPK receives a quarterly fixed fee of HUF 4,000,000. For the year 2012, the total fees invoiced under the MPK Services Agreement and the MPK Agreement were HUF 22,700,000.

15.5.7 *Redterv Agreement*

On 5 January 2012, Redterv Kft. entered into an agreement (the "Redterv Agreement") with TXM, pursuant to which Redterv Kft. agreed to provide certain engineering services to TXM. Services are provided on an as-requested basis at a daily rate of HUF 150,000 + VAT. For the year 2012, the total fees invoiced under the Redterv Agreements were HUF 13,100,000.

15.5.8 *Argyll Agreement*

On 1 July 2011, Argyll Mérnökiroda Bt. entered into an agreement (the "Argyll Agreement") with TXM, pursuant to which Argyll Mérnökiroda Bt. agreed to provide certain engineering services to TXM at a monthly fixed fee of HUF 600,000 + VAT. For the year 2012, the total fees invoiced under the Argyll Agreement were HUF 7,500,000.

15.5.9 *KPMG Agreement*

On 11 November 2011, KPMG Hungária Kft. entered into an agreement (the "KPMG Agreement") with TXM, pursuant to which KPMG Hungária Kft. agreed to provide certain accounting consulting services to TXM. For the year 2012, the total fees invoiced under the KPMG Agreement were HUF 5,842,500.

15.5.10 *Mueller Agreement*

On 22 June 2010, Mueller & Co., LLC ("Mueller") entered into an agreement (the "Mueller Agreement") with Falcon Australia, pursuant to which Mueller agreed to act as co-financial advisor to Falcon Australia in connection with any proposed transaction or series of transactions with one or more purchasers who acquires, directly or indirectly, all or any portion of Falcon Australia's assets (excluding a public or private sale of Falcon Australia's securities to investors in Falcon Australia) (a "Sale Transaction"). Under the terms of the Mueller Agreement, Falcon Australia has paid Mueller a retainer fee of 250,000 ordinary shares in the capital of Falcon Australia and, subject to certain conditions, Mueller was entitled to a success fee.

The success fee was equal to two per cent. of: (i) the aggregate fair market value of any securities issued to Falcon Australia and any other non-cash consideration delivered by the purchaser and received by Falcon Australia; (ii) the actual cash consideration received by Falcon Australia or the Company; and (iii) the cash or fair market value of any non-cash consideration actually received by Falcon Australia from a purchaser as a consequence of the purchaser's decision not to proceed with the closing of a Sale Transaction.

The Mueller Agreement was terminated on 18 May 2011. Mueller was entitled to a success fee for each Sale Transaction completed prior to 18 November 2012.

Mueller was paid US$75,412 in 2012 in advisory and success fees. The Mueller Agreement contains standard confidentiality provisions.

15.5.11 *Moyes Agreement*

On 4 June 2009, Moyes & Co., Inc. ("Moyes") entered into an agreement (the "Moyes Agreement") with the Company, pursuant to which Moyes agreed to provide certain advisory services to the Company relating to various transactions including, but not limited to, a potential farm-out or sale of Falcon Australia's interests in four onshore exploration permits in the Beetaloo Basin, Northern Territory, Australia (the "Beetaloo Transaction"). Under the terms of the Moyes Agreement, Moyes was entitled to a retainer fee (the "Beetaloo Retainer") and, subject to certain conditions, Moyes is entitled to a success fee for each Beetaloo Transaction completed prior to 16 June 2013.

The success fee equals the greater of (i) three per cent. of the cash or cash equivalent value of the Net Benefit (defined below) received by the Company from the Beetaloo Transaction or (ii) US$250,000. The net benefit payable means the net amount received directly or indirectly by the Company or other working interest owner, before expenses and fees (or cash equivalent) are paid to other intermediaries in relation to the completion of a Beetaloo Transaction (the "Net Benefit").

On 1 February, 2010 the Company and Moyes agreed to an addendum to the Moyes Agreement (the "Karoo Addendum") wherein Moyes agreed to provide certain advisory services to the Company relating to various transactions including, but not limited to, the farm-out or sale of the Company's interests in the TCP (the "Karoo Transaction"). Under the terms of the addendum, Moyes was entitled to a monthly retainer in addition to the Beetaloo Retainer. In addition, Moyes will also be paid a success fee in connection with the closing of each Karoo Transaction being the greater of: (i) three per cent. of the cash or cash equivalent value of any funding or transaction net to the Company's benefit; or (ii) US$250,000. Moyes is entitled to a success fee for each Karoo Transaction completed prior to 16 June 2013.

On 26 April 2011 the Company and Moyes agreed to an addendum to the Karoo Addendum pursuant to which the marketing of the Company's interest in the Makó Production Licence would be governed by and subject to the terms of the Karoo Addendum. Moyes is entitled to a success fee for each Mako Transaction completed prior to 16 June 2013.

The Moyes Agreement was terminated on 16 June 2012. Moyes & Co. Inc. was paid US$236,141 in advisory and success fees in 2012. The Moyes Agreement contains standard confidentiality provisions.

15.5.12 *TDE Consulting Agreement*

On 20 December 2010, Trade Development and Engineering Limited Liability Company ("TDE") entered into a consulting agreement (the "TDE Agreement") with TXM, pursuant to which TDE agreed to provide certain administration consulting services to TXM. The fees payable by TXM to TDE under the TDE Agreement vary depending on the type and amount of consulting services provided by TDE. For the year 2012, the total fees invoiced under the TDE Agreement were HUF 119,374,000. The TDE Agreement contains standard confidentiality provisions.

The TDE Agreement may be terminated by TXM at any time, with or without cause, for any reason whatsoever, upon TXM providing the Consultant with thirty days' prior written notice.

15.5.13 *Szűcs Agreement*

On 13 July 2010, Szücs Bálint Law Firm entered into an agreement (the "Szűcs Agreement") with TXM, pursuant to which Szűcs Bálint Law Firm agreed to provide certain legal services to TXM. The fees payable under the Szűcs Agreement will vary according to the services provided. For the year 2012, the total fees invoiced under the Szűcs Agreement were HUF 7,596,680.

TXM may terminate the Szűcs Agreement by providing Szűcs Bálint Law Firm with 60 days' prior written notice.

15.5.14 *John Carroll*

On 1 September 2012, Mr. John Carroll entered into a consultancy agreement (the "JC Consultancy Agreement") with Falcon Australia pursuant to which Mr. Carroll agreed, subject to certain conditions, to perform certain oil and gas services exclusively for Falcon Australia. Under the terms of the JC Consultancy Agreement, Falcon Australia pays Mr. Carroll a monthly fee of A$18,700 (including GST). The JC Consultancy Agreement contains standard confidentiality provisions.

Falcon Australia may terminate the JC Consultancy Agreement at any time by giving three month written notice to Mr. Carroll.

15.5.15 *Dr. György Szabó Consulting Agreement*

On 27 February 2009, Dr. György Szabó entered into a consulting agreement (the "GS Consulting Agreement") with TXM, pursuant to which Dr. Szabó agreed to act as Managing Director of TXM, to perform certain oil and gas services for TXM and to not compete directly or indirectly with TXM during his employment with TXM. Dr. Szabó is paid a monthly fee of US$5,000. The GS Consulting Agreement contains standard confidentiality provisions.

TXM may terminate the GS Consulting Agreement at any time, with or without cause, for any lawful reason whatsoever, upon TXM providing Dr. Szabó with sixty days' prior written notice.

The GS Consulting Agreement expired on 31 December 2009, however Dr. Szabó has continued to provide general managerial services to TXM and to receive the same monthly fee. Dr. Szabó was paid US$60,000 pursuant to the GS Consulting Agreement in 2012.

15.5.16 *P&S Consulting Agreement*

On 4 May 2005, P&S Mérnöki Kereskedelmi-Tanácsadó Bt. ("P&S") entered into a consulting agreement (the "P&S Agreement") with TXM, pursuant to which P&S agreed to provide certain consulting services to TXM in connection with TXM's objectives of drilling wells on the Makó and Tisza licences. The P&S Agreement was amended on 28 November 2005 and further amended on 1 June 2006, 1 January 2008, 1 January 2009 and 1 April 2010. P&S is wholly-owned by a family member of Dr. Szabó, a current Director of the Company.

Under the terms of the P&S Agreement, TXM was obligated to pay P&S a monthly services fee of HUF 750,000. The P&S Agreement contains standard confidentiality provisions and provides that P&S shall not compete with TXM during the term of the P&S Agreement.

TXM may terminate the P&S Agreement at any time, with or without cause, for any lawful reason whatsoever, upon TXM providing P&S with 30 days prior written notice.

TXM and P&S have further amended the terms of the P&S Agreement by oral agreement. Pursuant to the amended P&S Agreement, P&S is paid a monthly fee of US$8,500 (effective 1 January 2013) plus reasonable expenses incurred by Dr. Szabó as an employee of P&S, such amounts thereafter paid to Dr. Szabó from P&S.

15.5.17 *Cactus Services Agreement*

On 1 January 2009, Cactus Corp. Pty Limited entered into a professional services agreement (the "Cactus Services Agreement") with Falcon Australia, pursuant to which Cactus Corp. Pty Limited agreed to provide certain accounting, tax, financial and legal consulting services to Falcon Australia. Under the terms of the Cactus Services Agreement, Cactus Corp. Pty Limited provides the consulting services at a rate of A$175 per hour and is entitled to a retainer fee of A$500 per calendar month. The Cactus Services Agreement contains standard confidentiality provisions and provides that Cactus Corp. Pty Limited shall not compete with Falcon Australia.

The Cactus Services Agreement may be terminated by either party at any time upon giving three month prior written notice to the other party.

15.5.18 *Makó Agreements*

On 5 June 2008, Makó Energy Corporation ("Makó") entered into a management services agreement (the "Makó Services Agreement") with TXM, pursuant to which Makó agreed to provide certain management and supervision services to TXM. Either party may terminate the Makó Services Agreement by providing the other party with thirty days' prior written notice.

In addition, on 5 June 2008, Makó entered into a framework services agreement (the "Framework Agreement") with TXM, pursuant to which Makó agreed to act as an intermediary services provider for TXM in connection with certain design, construction, maintenance and operation of oil field installation activities required by TXM. TXM may terminate the Framework Agreement by providing Makó with ten days' prior written notice.

The fees payable by TXM to Makó under the Makó Services Agreement and the Framework Agreement (collectively, the "Makó Agreements"), respectively, vary depending on the type and amount of consulting services provided by Makó. For the year 2012, the total fees invoiced under the Makó Agreements were HUF 75,019,095 The Makó Agreements contain standard confidentiality provisions.

15.5.19 *DTM Consulting Agreement and RSM Consulting Agreement*

On 9 December 2005, DTM entered into a consulting agreement (the "DTM Consulting Agreement") with TXM pursuant to which DTM agreed to provide certain tax, payroll, accounting, electronic banking and management information consulting services to TXM. The DTM Consulting Agreement may be terminated by TXM at any time upon providing DTM with 30 days' prior written notice.

Furthermore, on 6 January 2012, RSM DTM Hungary Adótanácsadó és Pénzügyi Szolgáltató Zrt. ("RSM") entered into a consulting agreement (the "RSM Consulting Agreement") with TXM, pursuant to which RSM agreed to provide certain tax, accounting and legal consulting services to TXM in connection with the Makó Mining Plot and other oil and gas projects. Each party may terminate, at its sole discretion, the RSM Consulting Agreement by giving the other parties sixty days' prior notice.

The fees payable by TXM to DTM and RSM, respectively, under the DTM Consulting Agreement and the RSM Consulting Agreement (collectively, the "DTM-RSM Agreements") vary depending on the type and amount of consulting services provided by TXM. For the year 2012, the total fees invoiced under the DTM-RSM Agreements were HUF 105,565,065. The DTM-RSM Agreements contain standard confidentiality provisions.

15.5.20 *JD Griffin & Associates*

J D Griffin & Associates ("JD Griffin"), based in Denver Colorado, performed outsource accounting services for the Company. JD Griffin's primary obligation was the preparation of the financial statements for publication under International Financial Reporting Standards. This involved interpretation of applicable accounting standards for inclusion in the Company's published financial statements on a yearly and quarterly basis. JD Griffin was paid US$93,800 for their services in 2012. JD Griffin's contract was terminated in 2012.

15.5.21 *NGA Consulting*

NGA Consulting ("NGA") provided IT support services to the Company's office in Denver, Colorado. NGA's obligations included maintenance of the Company's servers and the provision of IT support services. NGA was paid US$116,337 in 2012. NGA's contract was terminated in 2012.

15.5.22 *Lapadanco Consulting Agreement*

On 6 August, 2009 the Company entered into an agreement with Lapandanco, Inc. ("Lapadanco") wherein Lapadanco agreed to review and interpret technical data, assess hydrocarbon entrapment areas and formulate strategies to evaluate and exploit oil & gas prospects. Lapadanco was paid US$126,319 in 2012. Lapadanco's contract was terminated in 2012.

15.5.23 *Hoyer Consulting Contract*

On 1 November 2009 the company entered into an agreement with Hoyer Petrophysics Inc. ("Hoyer") whereby Hoyer agreed to provide certain services to the Company, including petrophysical analysis, geological/geophysical evaluation and 3D mapping. Hoyer was paid US$51,240 in 2012. Hoyer's contract was terminated in 2012.

16. WORKING CAPITAL

In the opinion of the Directors, having made due and careful enquiry, the working capital available to the Group will be sufficient for its present requirements, that is for at least twelve months from the date of Admission.

17. LITIGATION

There are no legal or arbitration proceedings (including any proceedings which are pending or threatened by or against any member of the Group of which the Directors are aware), which may have or have had during the twelve months preceding the date of this document, a significant effect on the financial position of the Group as a whole.

18. AUDITORS

18.1 KPMG LLP, an Ontario limited liability partnership, whose registered address is Suite 4600, 333 Bay Street, Toronto, Ontario, M5H 2S5, Canada, and whose partners are Chartered Accountants under each respective Provincial Institutes of Chartered Accountants in Canada, is the Group's auditor and audited the accounts of the Group for the 12 months ended 31 December 2011 and 31 December 2010. KPMG LLP is a member firm of the KPMG network of member firms affiliated with KPMG International Cooperative, a Swiss entity.

18.2 Hein & Associates LLP, Certified Public Accountants, whose address is 717-7th Street, Suite 1600, Denver, Colorado, U.S.A., 80202, audited the accounts of the Group for the 12 months ended 31 December 2009. In July 2010, in order to transition to IFRS reporting and to accommodate the Company's expanding global operations, Hein & Associates resigned and KPMG LLP were appointed as the Company's auditors.

19. SIGNIFICANT CHANGE

There has been no significant change in the financial or trading position of Falcon since 30 September 2012, being the date to which the last interim financial information was published.

20. EMPLOYEES

20.1 Details of the number of the Group's permanent employees (including Executive Directors) during each of the three financial periods covered by the historical financial information, the last of which ended on 31 December 2011 is as follows:

Financial period ended	*Number of employees*
31 December 2011	20
31 December 2010	17
31 December 2009	24

20.2 As at the date of this document, the Company has 15 permanent employees (including Executive Directors), broken down as follows:

Job Function	*Hungary*	*Ireland*	*Total*
Management & Administration	4	5	9
Technical	6	0	6
Total	10	5	15

20.3 As at the date of this document, the Company employs 10 contractors who are integral to the business function, broken down as follows:

Job Function	*Hungary*	*Australia*	*Total*
Management & Administration	2	1	3
Technical	7	0	7
Total	9	1	10

21. RELATED PARTY TRANSACTIONS

Save as set out in Part V of this document and Section 15 of this Part VI, there have been no related party transactions entered into by the Company for the period covered by the historical financial information up to the date of this document.

22. GENERAL

22.1 It is estimated that the total expenses payable by the Company in connection with the Placing and Admission will amount to approximately US$2 million (including VAT). The total proceeds which it is expected will be raised by the Placing are US$25 million (£16.9 million) and the net proceeds after deduction of expenses are estimated at US$23 million (£15.5 million).

22.2 Davy has given and has not withdrawn its written consent to the inclusion in this document of its name and the references thereto in the form and context in which they appear. Davy has no material interest in the Company.

22.3 GMP has given and has not withdrawn its written consent to the inclusion in this document of its name and the references thereto in the form and context in which they appear. GMP has no material interest in the Company.

22.4 RPS Energy has given and has not withdrawn its written consent to a) the inclusion of its report set out in Part IV of this document in the form and context they appear and has authorised the contents of the report referred to above for the purpose of the AIM Rules and ESM Rules; and b) the inclusion in this document of references to its name in the form and context in which they appear.

22.5 Where information has been sourced from a third party this information has been accurately reproduced. So far as the Directors are aware and are able to ascertain from information provided by that third party, no facts have been omitted which would render the reproduced information inaccurate or misleading.

22.6 Save as set out in this document, there are no patents, intellectual property rights, licences or any industrial, commercial or financial contracts or new manufacturing contracts which are or may be material to the business or profitability of the Group.

22.7 Save as set out in this document, the Directors are not aware of any environmental issues that may affect the Group's utilisation of its tangible fixed assets.

22.8 There have been no interruptions in the business of Falcon which may have or have had in the 12 months preceding the publication of this document a significant effect on the financial position of Falcon or which are likely to have a material effect on the prospects of the Group for the next 12 months.

22.9 Save as set out in this document, the Directors are not aware of any trends, uncertainties, demands, commitments or events that are reasonably likely to have a material effect on the Group's prospects in the period commencing on the date of this document until at least the current financial year.

22.10 Save as set out in this document, no person (excluding professional advisers otherwise disclosed in this document and trade suppliers) has:

22.10.1 received, directly or indirectly from the Group within the 12 months preceding the date of the application for Admission; or

22.10.2 entered into contractual arrangements (not otherwise disclosed in this document) to receive, directly or indirectly, from the Group, on or after Admission, any of the following:

22.10.3 fees totalling £10,000 or more;

22.10.4 securities in the Company where these have a value of £10,000 or more calculated by reference to the Placing Price; or

22.10.5 any other benefit with the value of £10,000 or more at the date of Admission.

22.10.6 Save as set out in this document, the Group has had no principal investments and there are no principal investments in progress and there are no principal future investments on which the Board has made a firm commitment.

23. PUBLICATION OF THIS DOCUMENT

Copies of this document shall be available free of charge during normal business hours on any day (except Saturdays, Sundays and public holidays) from the offices of Falcon at Styne House, Upper Hatch Street, Dublin 2, Ireland for a period of one month from the date of Admission and available on the Company's website, www.falconoilandgas.com, from the date of Admission.

Dated 22 March 2013

PART VII

DEFINITIONS

The following words and expressions shall have the following meanings in this document unless the context otherwise requires:

"€" or **"EUR"** or **"Euro"**	the currency introduced at the start of the third stage of the European economic monetary union pursuant to the Treaty establishing the European Communities as amended;
"£" or **"Sterling"** or **"p"** or **"pounds"** or **"pence"**	the lawful currency of the United Kingdom;
"$"** or **"US$" or **"USD"**	the lawful currency of the United States;
"A$" or **"AUD"**	the lawful currency of Australia;
"C$" or **"CAD"**	the lawful currency of Canada;
"Admission Document" or **"the Document"**	this document;
"Admission"	the admission of the Common Shares to trading on AIM and ESM and admission becoming effective in accordance with the AIM Rules and ESM Rules;
"AIM"	AIM, the market operated by the London Stock Exchange;
"AIM Rules"	the AIM Rules for Companies published by the London Stock Exchange governing admission to, and the operation of, AIM as in force as at the date of this document or, where the context so required, as amended or modified after the date of this document;
"Algyö Formation"	a thick sequence of sedimentary rocks deposited on the prograding basin margin slopes in the Pannonian Basin;
"Algyö Play"	a group of geologically related leads and prospects in the upper Miocene sedimentary column of the Makó Trough (between 2,300 and 3,500 metres depth), believed to share common genetics and similar petroleum charge and accumulation system. The Algyö Play is the subject of the NIS Agreement as described in Section 15.3.1 of Part VI of this document;
"Articles" or **"Articles of Association"**	the articles of incorporation of the Company;
"Australia"	the Commonwealth of Australia and the word "Australian" shall be construed accordingly;
"Beetaloo Exploration Permits"	exploration permits EP-76, EP-98, EP-99 and EP-117 held by Falcon Australia, located in the Beetaloo Basin, Northern Territory, Australia and issued by the Northern Territory Government;
"Board" or **"Falcon Board"**	the board of directors of the Company from time to time;
"BCA"	the Business Corporations Act (British Columbia);
"Central Bank"	the Central Bank of Ireland;

"Chevron"	Chevron Business Development South Africa Limited, a company established and existing under the laws of South Africa;
"Chevron Agreement"	the agreement dated 12 December 2012 between Falcon and Chevron, as further described in Section 15.2.1 of Part VI of this document;
"City Code"	the United Kingdom City Code on Takeovers and Mergers issued from time to time by or on behalf of the UK Panel on Takeovers and Mergers;
"Common Shares"	the common shares of no par value in the capital of Falcon including, if the context requires, the New Common Shares;
"CPR"	the Competent Person's Report issued by RPS Energy on the Group's Hungarian and Australian assets contained in Part IV of this document;
"CREST"	the computerised settlement system to facilitate the transfer of title of shares in uncertificated form, operated by Euroclear UK & Ireland Limited;
"CREST Regulations"	the Uncertificated Securities Regulations 2001 (SI 2001/3755) and the Companies Act 1990 (Uncertificated Securities) Regulations 1996, as amended;
"Davy"	J&E Davy, trading as Davy; including its affiliate Davy Corporate Finance and any other affiliates, or any of its subsidiary undertakings;
"Debentures"	debentures issued to certain debenture holders worth C$10,719,000 convertible at the option of the debenture holder at a price of C$0.60 per Common Share. The Debentures bear an interest rate of 11 per cent. per annum and will mature on 30 June 2013. As at the date of this document, Debentures worth C$10,656,900 remain outstanding;
"Deep Makó Trough"	refers to the deeper (depth greater than 3,500m) part of the Makó Trough unconventional petroleum system comprising overpressured, hydrocarbon bearing shale and sand formations;
"Depositary"	Computershare Investor Services plc;
"Depositary Interests" or **"DIs"**	dematerialised depositary interests representing entitlements to Common Shares issued by the Depositary;
"Director Shareholder"	a Director who owns Common Shares in the capital of the Company;
"**Discounted Market Price**"	as defined by the TSX-V Corporate Finance Manual, means the last closing price of the Company's listed Common Shares on the TSX-V before either the issuance of the news release or the filing of the price reservation form with the TSX-V required to fix the price at which the Common Shares are to be issued or deemed to be issued, less the following maximum discounts based on closing price (and subject, notwithstanding the application of any such maximum discount, to a minimum price per share of C$0.05 and a minimum

	exercise price per warrant or stock option, as the case may be, of C$0.10):

Closing Price	*Discount*
Up to C$0.50	– 25%
C$0.51 to $2.00	– 20%
Above C$2.00	– 15%

"Directors"	the directors of the Company as at the date of this document being John Craven, Philip O'Quigley, Dr. György Szabó, Daryl H. Gilbert, JoAchim Conrad, Gregory Smith, Igor Akhmerov and David Harris, or the directors of the Company from time to time, as the context may require;
"Existing Common Shares"	the 696,954,500 Common Shares in issue immediately prior to the Placing;
"Existing Issued Share Capital"	the Existing Common Shares;
"Enlarged Issued Share Capital"	the Existing Common Shares together with the New Common Shares in issue upon Admission;
"ESM"	the Enterprise Securities Market, a market regulated by the Irish Stock Exchange;
"ESM Rules"	the ESM Rules for Companies issued by the Irish Stock Exchange governing admission to, and the operation of, ESM as in force as at the date of this document or, where the context so required, as amended or modified after the date of this document;
"Executive Director"	an executive Director of the Company;
"Falcon" or the **"Company"**	Falcon Oil & Gas Ltd, incorporated and registered in British Columbia, Canada with corporate number BC0203059 whose registered office is 810-675 Hastings Street West, Vancouver, British Columbia, V6B 1N2, Canada;
"Falcon Australia"	Falcon Oil & Gas Australia Ltd., a company incorporated in Australia with company registration number 53 132 857008. Falcon owns 72.7 per cent. of the issued share capital of Falcon Australia, along with Sweetpea (24.2 per cent.), and others (3.1 per cent.);
"Falcon Group" or the **"Group"**	Falcon and its subsidiaries and subsidiary undertakings;
"FSA" or **"United Kingdom Financial Services Authority"**	the Financial Services Authority acting in its capacity as the competent authority for listing in the UK for the purposes of Part VI of the FSMA;
"FSMA"	the Financial Services and Markets Act 2000 (as amended);
"GMP"	GMP Securities Europe LLP, a limited liability partnership registered in England and Wales with registered number OC324747 and whose registered office is at Stratton House, 5 Stratton Street, London, W1J 8LA, United Kingdom;
"Hess"	Hess Australia (Beetaloo) Pty Limited, a company established and existing under the laws of Australia;
"Hess Agreement"	the agreement dated 28 April 2011 between Falcon Australia and Hess, as further described in Section 15.1.1 of Part VI of this document;

"Hess Area of Interest"	the area within Falcon Australia's Beetaloo Exploration Permits covered by the Hess Agreement, namely exploration permits EP-76, EP-117 and EP-98 (less an area within exploration permit EP-98 which includes the Shenandoah-1 well-bore and approximately 100,000 acres (approximately 405 km^2) of land surrounding the Shenandoah-1 well-bore;
"HM Revenue and Customs"	Her Majesty's Revenue and Customs;
"HUF" or **"Hungarian Forint"**	the lawful currency of Hungary;
"Hungary"	the Republic of Hungary, and the word "Hungarian" shall be construed accordingly;
"Ireland" or the **"Republic of Ireland"**	the island of Ireland excluding Northern Ireland, and the word "Irish" shall be construed accordingly;
"Irish Prospectus Regulations"	the Prospectus (Directive 2003/71 EC) Regulations 2005 of Ireland;
"Irish Prospectus Rules"	the Prospectus Rules issued by the Central Bank of Ireland from time to time under Section 51 of the Investment Funds, Companies and Miscellaneous Provisions Act 2005 of Ireland;
"Irish Stock Exchange"	the Irish Stock Exchange Limited;
"Irish Takeover Rules"	the Irish Takeover Panel Act, Takeover Rules 2007 to 2008, as amended;
"ISIN"	International Securities Identification Number;
"Joint Brokers"	Davy and GMP, and "Joint Broker" means either one of them;
"Karoo Basin"	a sedimentary basin located in central and southern Africa, formed approximately 300 million years ago, which contains a sequence of layers capped by basaltic volcanic rocks. The Karoo Basin is approximately 173 million acres (approximately 700,000 km^2) in size. Falcon holds a TCP over acreage within the Karoo Basin, as further described in Section 5 of Part I of this document;
"Liquid Fuels Charter"	the Charter for the South African Petroleum Liquid Fuels Industry Empowering Historically Disadvantaged South Africans in the Petroleum and Liquid Fuels Industry, signed and released in November 2000 by the South African Petroleum Industry Association ("SAPIA"), each of the SAPIA member companies and the African Minerals and Energy Forum;
"London Stock Exchange"	London Stock Exchange plc;
"Makó Energy Corporation"	Makó Energy Corporation, a company established and existing under the laws of Delaware with registration number 20051258295, and a wholly owned subsidiary of Falcon;
"Makó Production Licence"	the production licence granted to TXM by the Hungarian Office for Mining and Geology, as further described in Section 5 of Part I of this document;
"Makó Trough"	a sub-basin of the Pannonian Basin, situated in the southeastern part of Hungary;

"MOL" or **"MOL Group"**	Magyar Olaj és Gázipari Nyilvánosan muködo Részvénytársaság (Hungarian Oil and Gas Public Limited Company), a public limited company established and existing under the laws of Hungary;
"New Common Shares"	120,381,973 new Common Shares to be issued and allotted by the Company pursuant to the Placing;
"NIS"	Pannon Naftagas LLC, company established and existed under the laws of Hungary. Gazprom Group owns approximately 56 per cent. of NIS;
"NIS Agreement"	the agreement dated 22 January 2013 between Falcon, TXM and NIS as further described in Section 15.3.1 of Part VI of this document;
"Nomination Committee"	the nomination committee established by the Board, as described in Section 12 of Part I of this document;
"Official List(s)"	the official list of the UKLA and/or the official list maintained by the Irish Stock Exchange, as the context may require;
"Pannonian Basin"	a large sedimentary basin, formed approximately 20 million years ago and located in Central Europe and surrounded by the mountain ranges of the Alps, Carpathians and Dinardes;
"Placing"	the placing of New Common Shares at the Placing Price on behalf of the Company to the relevant placees;
"Placing Agreement"	the Placing Agreement dated 14 March 2013 between the Company, the Directors and the Joint Brokers, a summary of which is set out in Section 15.4.1 of Part VI of this document;
"Placing Price"	14 pence per New Common Share;
"Prospectus Rules"	the UK Prospectus Rules brought into effect on 1 July 2005 pursuant to Commission Regulation (EC) No. 809/2004, as amended;
"QCA Guidelines"	the Corporate Governance Guidelines for Smaller Quoted Companies published by the Quoted Companies Alliance in September 2010;
"Registrar"	Computershare Trust Company of Canada;
"Reserve Committee"	the reserve committee extablished by the Board, as described in Section 12 of Part I of this document;
"Restricted Jurisdiction"	each and any of the United States of America, Canada (and its territories and possessions), Japan, and South Africa;
"RPS Energy"	Cambrian Consultants America Inc., dba RPS;
"Shareholder"	a holder of Common Shares in the capital of the Company from time to time;
"South Africa"	the Republic of South Africa, and the word "South African" shall be construed accordingly;
"Stock Option Plan"	the stock option plan approved by Falcon's shareholders at Falcon's Annual Special and General Meeting on 25 September 2012, as described in Section 11 of Part VI of this document;

"Sweetpea"	Sweetpea Petroleum Pty. Ltd, a company established and existing under the laws of Australia, a wholly owned subsidiary of PetroHunter Energy Corp.;
"Technical Cooperation Permit" or **"TCP"**	The technical cooperation permit dated 27 October 2009 and granted to Falcon by the South African Agency for Promotion of Petroleum Exploration, as further described in Section 5 of Part I of this document;
"TSX Venture Exchange" or **"TSX-V"**	TSX Venture Exchange, a stock exchange in Canada;
"TSX-V Corporate Finance Manual"	the corporate finance policy manual as published by the TSX-V in force as at the date of this document or, where the context so required, as amended or modified after the date of this document;
"TXM"	TXM Oil and Gas Exploration Kft., a company established and existing under the laws of Hungary with company registration number 01-09-734527 and a wholly owned subsidiary of Falcon;
"UK" or **"United Kingdom"**	the United Kingdom of Great Britain and Northern Ireland;
"UK Disclosure and Transparency Rules"	the Disclosure Rules and Transparency Rules issued by the FSA acting in its capacity as the competent authority for the purposes of Part V of FSMA;
"UK Governance Code"	the UK Governance Code published by the Financial Reporting Council;
"United Kingdom Listing Authority" or **"UKLA"**	the United Kingdom Listing Authority, being the Financial Services Authority acting in its capacity as the competent authority for the purposes of the FSMA;
"uncertificated" or **"in uncertificated form"**	recorded on the relevant register of the shares or securities of the company concerned 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", "USA", "United States" or **"United States of America**	the United States of America, each State thereof (including the District of Columbia), its territories, possessions and all areas subject to its jurisdiction;

PART VIII

GLOSSARY OF TECHNICAL TERMS AND ABBREVIATIONS

The glossary below contains selected technical terms and abbreviations related to the exploration for and production of oil and/or gas along with certain abbreviations used in the oil and gas industry.

"2D"	Two dimensional.
"2D seismic data"	A vertical section of seismic data consisting of numerous adjacent traces acquired sequentially.
"3D seismic data"	Seismic data capable of showing a three dimensional image of the reservoir. Strictly, 3D is a closely spaced grid of 2D seismic lines with interpolation to create a seismic cube. The cube can be sliced vertically to create 2D lines or sliced horizontally to create time views of the traveling signal.
"3D"	Three dimensional.
"Archean"	A geological eon covering the time period between 3,900 to 2,500 million years ago.
"Anticline"	convex-upward formation of rock layers (a fold with the strata sloping down on the sides from a common crest. In association with a sealing rock, an anticline may form a trap for hydrocarbons. Anticlines may be faulted or unfaulted.
"API"	Abbreviation for the American Petroleum Institute.
"API gravity"	A specific gravity scale developed by the API for measuring the relative density of various petroleum liquids.
"appraisal"	The phase of petroleum operations that immediately follows successful exploratory drilling. During appraisal, delineation wells might be drilled to determine the size of the oil or gas field and how to develop it most efficiently.
"AVO"	Abbreviation for amplitude versus offset, a general term for referring to the dependency of the seismic attribute, amplitude, with the distance between the source and receiver (offset).
"AVO analysis"	A technique applied to seismic data to determine thickness, porosity, density, velocity, lithology and fluid content of rocks.
"basin"	A large area with a general containment and an often thick accumulation of rock.
"Bcf"	Abbreviation for billion cubic feet, a unit of measurement for large volumes of natural gas.
"Bcfd"	Abbreviation for billion cubic feet per day, a common unit of measurement for large production rates of gas.
"BCGA"	Abbreviation for basin centred gas accumulations.
"bopd"	Abbreviation for barrel of oil condensate or natural gas liquids per day, a common unit of measurement for volume of crude oil. The volume of a barrel is equivalent to 42 US gallons (approximately 159 litres).

“brine”	A mixture of water and a soluble salt.
“Cambrian”	A geological time period, covering the time period between 570 and 500 million years ago.
“carbonate”	A group of minerals found mostly in limestone and dolostone that includes aragonite, calcite and dolomite. Calcite is the most abundant and important of the carbonate minerals.
“Carboniferous”	A geological time period, covering the time period between 365 and 290 million years ago.
“casing”	Steel pipe cemented in place during the construction process to stabilise the wellbore. The casing forms a major structural component of the wellbore and serves several important functions: preventing the formation wall from caving into the wellbore, isolating the different formations to prevent the flow or crossflow of formation fluid, and providing a means of maintaining control of formation fluids and pressure as the well is drilled. The casing string provides a means of securing surface pressure control equipment and downhole production equipment. Casing is available in a range of sizes and material grades.
“clay”	Fine-grained sediments less than 0.0039 milimetres in size.
“condensate”	A part of the hydrocarbon stream that is a vapor in the formation and condenses to a liquid after being cooled. Normally the volatile condensate has a composition of C5 to C8 and an API gravity of 40.
“consolidated”	An approximate level of rock strength where sufficient cementation is present to allow the rock to remain intact during drilling and production. Often the unconfined compressive strength is greater than 1,000 to 1,500 pounds per square inch.
“contingent resources”	Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingent Resources are a class of discovered recoverable resources.
“conventional oil”	Oil in liquid form capable of flowing naturally.
“conventional gas”	Natural gas in a normal media, capable of flowing without other influences.
“Cretaceous”	A geological time period and system, covering the time between 140 to 65 million years ago.
“crude oil”	Petroleum that exists in the liquid phase in natural underground reservoirs and remains liquid at atmospheric conditions of pressure and temperature. A general term for unrefined petroleum or liquid petroleum.
“delta”	Mouth of river deposits, usually fan shaped with significant variation in composition, sorting and thickness. Quality of the reservoir rock may vary widely.

“development”	The phase of petroleum operations that occurs after exploration has proven successful, and before full-scale production.
“development plan”	The design specifications, timing, and cost estimates of the development project.
“Devonian”	A geological time period, covering the time between 405 and 365 million years ago.
“dry gas”	A natural gas containing insufficient quantities of hydrocarbons heavier than methane to allow their commercial extraction or to require their removal in order to render the gas suitable for fuel use.
“exploration”	The initial phase in petroleum operations that includes generation of a prospect or play or both, and drilling of an exploration well.
“exploration permit”, or **“permit”**	A grant extended by a government to permit a company to explore for oil, gas or mineral resources within a strictly defined geographic area, typically beneath government-owned lands or lands in which the government owns the rights to produce oil, gas or minerals.
“exploration well”	A well drilled to look for oil and gas in an area with unknown producing potential.
“farm-in”	An agreement whereby an outside party pays a concession owner all or a percentage of the drilling costs of a well in order to obtain a working interest in the land or well.
“farm-out”	A contractual agreement with an owner who holds a working interest in an oil and gas lease selling a percentage of a lease to an outside operator for drilling a well.
“fault”	A rock split or rupture with associated movement occuring on either side.
“field”	One or more reservoirs grouped by or related to the same general geologic structural feature or stratagraphic condition.
“formation”	Any distinct, mapable layer.
“gas field”	An accumulation, pool or group of pools of gas in the subsurface. A gas field consists of a reservoir in a shape that will trap hydrocarbons and that is covered by an impermeable or sealing rock. In the oil and gas business the term “gas field” implies that the accumulation is commercial.
“gas”	A naturally occurring mixture of hydrocarbon gases that is highly compressible and expansible – same as natural gas.
“GOR”	Abbreviation for gas/oil ratio.
“GPoS” or **“PoS”**	Abbreviation for Geological Probability of Success. Applied to exploration wells to indicate the chances of achieving a specified outcome. Typically, exploration wells have a GpoS in the range 10 – 40 per cent.

"gross"	If referring to volumes of oil or gas or currency, "gross" is the amount before the deduction of royalties and taxes. If referring to ownership in oil and gas rights, "gross" is the ownership interest before considering any interests held directly or indirectly by other companies.
"H2S"	Abbreviation for Hydrogen Sulphide.
"HI"	Abbreviation for Hydrogen Index.
"HP-HT"	Abbreviation for high pressure, high temperature.
"hydraulic fracture stimulation" or **"fraccing"**	A process through which a large number of fractures are created hydraulically in a rock through the application of high presure, with the aim of allowing natural gas and/or crude oil trapped in the sub surface formations to move through these fractures to the well-bore, from where it can then flow to the surface.
"hydrocarbon"	A compund formed essentially of carbon and hydrogen.
"impermeable"	Rock with passages so small that no effective flow can take place. All manmade and natural substances have some permeability, given high pressure, time, enough surface area and a low permeability fluid.
"interpretation"	In geophysics, analysis of data to generate reasonable models and predictions about the properties and structures of the subsurface. Interpretation of seismic data is the primary concern of geophysicists.
"joule" or **"J"**	A derived unit of energy, work, or amount of heat in the International System of Units.
"JV"	Joint venture (incorporated or unincorporated).
"Karoo"	A term extrapolated from the main Karoo Basin in South Africa, to describe the sedimentary fill of a number of basins which occurred during the late Paleozoic and early Mesozoic interval and lasted 120 million years.
"LNG"	Liquefied natural gas. Natural gas, mainly methane and ethane, which has been compressed and cooled to the liquefaction point for shipping.
"LPG"	Abbreviation for liquid petroleum gas.
"Mbo"	Abbreviation for thousand barrels of oil.
"Mbopd"	Abbreviation for thousand barrels of oil per day.
"Mcf"	Abbreviation for thousand cubic feet of gas.
"Mcfpd"	Abbreviation for thousand cubic feet of gas per day.
"mD"	Abbreviation for permeability in millidarcies.
"MD"	Abbreviation for measured depth.
"MDT"	Abbreviation for Modular (formation) dynamic tester.

“methane”	The lightest, least complex and most abundant of the hydrocarbon gases and the principal component of natural gas. Methane (CH4) is a colourless odourless gas that consists of one carbon atom and four hydrogen atoms and is stable under a wide range of pressure and temperature conditions.
“Miocene”	A geological epoch of time, covering the period between 25 and 5.3 million years ago.
“Mmbo”	Abbreviation for million barrels of oil.
“Mmbopd”	Abbreviation for million barrels of oil per day.
“Mmcf”	Abbreviation for million cubic feet of gas.
“Mmcfpd”	Abbreviation for million cubic feet of gas per day.
“mudlog”	A continuous record of information on mud or cuttings that are circulated to the surface.
“natural gas”	A naturally occurring mixture of hydrocarbon gases that is highly compressible and expansible.
“net”	If referring to volumes of oil or gas or currency, “net” is an amount after the deduction of royalties and taxes. If referring to ownership in oil and gas rights, “net” is the ownership interest after considering any interests held directly or indirectly by other companies.
“oil field”	An accumulation, pool or group of pools of oil in the subsurface. An oil field consists of a reservoir in a shape that will trap hydrocarbons and that is covered by an impermeable or sealing rock.
“OPEC”	Organisation of the Petroleum Exporting Countries.
“P10”	Value that an uncertain outcome (eg, for quantities of hydrocarbons) has a 10 per cent. chance of equalling or exceeding.
“P50”	Value that an uncertain outcome (eg, for quantities of hydrocarbons) has a 50 per cent. chance of equalling or exceeding.
“P90”	Value that an uncertain outcome (eg, for quantities of hydrocarbons) has a 90 per cent. chance of equalling or exceeding.
“pay zone”	A hydrocarbon producing interval.
“permeability”	The ability of a rock to transmit fluids.
“Permian”	A geologic time period, covering the time between 290 to 250 million years ago.
“petroleum”	A naturally occurring mixture consisting predominantly of hydrocarbons in the gaseous, liquid or solid phase.
“pipeline”	A tube or system of tubes used for transporting crude oil and natural gas from the field or gathering system to the refinery.
“play”	A pay zone or set of pay zones with proven commercial reserves.
“Pliocene”	A geological time period, covering the time between 5.3 and 2.6 million years ago.

“porosity”	The percentage of the rock volume that is not rock grains and could be occupied by fluids. Pores may or may not be connected.
“Pre-Cambrian”	A geological time preiod from the beginning of earth to 570 million years ago.
“pressure”	The force distributed over a surface, usually measured in pounds force per square inch (lbf/in2), or p.s.i., in US oilfield units.
“production”	The phase that occurs after successful exploration and development and during which hydrocarbons are drained from an oil or gas field.
“prospect”	A prospect is a potential accumulation that is sufficiently well defined to be a viable drilling target. For a prospect, sufficient data and analysis exist to identify and quantify the technical uncertainties, to determine reasonable ranges of geological chance factors and engineering a petrophysical parameters, and to estimate prospective resources. In addition, a viable drilling target requires that 70 per cent. of the median potential production area be located within the block or licence area of interest
“prospective resources”	Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective resources have both an associated chance of recovery and a chance of development. Prospective resources are further subdivided in accordance with the level of certainty associated with the recoverable estimates assuming their discovery and development and may be sub-classified based on project maturity.
“Proterozoic”	A geological eon which covering the time between 2,500 and 541 million years ago.
“proven reserves”	An incremental category of estimated recoverable volumes associated with a defined degree of uncertainty. Proved reserves are those quantities of petroleum which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods, and government regulations. If deterministic methods are used, the term reasonable certainty is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90 per cent. probability that the quantities actually recovered will equal or exceed the estimate. Often referred to as 1P, also as “Proven”.
“remaining recoverable reserves”	The total volume of a resource that is both technically and economically recoverable.
“reserves”	Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must further satisfy four criteria: They must be discovered, recoverable, commercial, and remaining (as of a given date) based on the development project(s) applied.
“reservoir”	An independent hydrocarbon holding rock.

“resources”	In the context of this document, the term “resources” encompasses all quantities of petroleum naturally ccuring 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.
“royalty”	A per cent. interest paid to the mineral owner on the value of fluids produced from a lease.
“sand”	A small piece of rock or mineral between 0.0625 mm and 2 mm in diameter. Sand is also a term used for quartz grains or for sandstone.
“sandstone”	Granular sedimentary rocks with grain sizes between 0.0625 and 2mm. The pore space where hydrocarbons may be held is between the grains.
“scf”	Abbreviation for standard cubic feet measured at 14.7 pounds per square inch and 60° F.
“sedimentary”	A deposit made up of pieces of other rocks. A sedimentary basin refers to a geographical basin of sedimentary rocks.
“seismic”	Pertaining to waves of elastic energy, such as that transmitted by P-waves and S-waves which are studied by geophysicists to interpret the composition, fluid content, extent and geometry of rocks in the subsurface.
“shale”	A common sedimentary rock with porosity but little matrix permeability. Shales are one of the petroleum source rocks. Shales usually consist of particles finer than sand grade (less than 0.0625 mm) and include both silt and clay grade material.
“shut-in”	To stop a well from flowing and close the valves.
“Silurian”	A geologic time period covering between 425 and 40 million years ago.
“source rock”	A rock rich in organic matter which, if heated sufficiently, will generate oil or gas.
“spud”	To start the well drilling process by removing rock, dirt and other sedimentary material with the drill bit.
“Stb”	Abbreviation for stock tank barrels measured at 14.7 pounds per square inch and 60° F.
“structure”	A geological feature produced by deformation of the Earth’s crust. Most structures in oil and gas exploration are either anticlines or synclines.
“Sw”	Abbreviation for water saturation.
“syncline”	Basin or trough-shaped fold in rock in which rock layers are downwardly convex. The youngest rock layers form the core of the fold and outward from the core progressively older rocks occur. Synclines typically do not trap hydrocarbons because fluids tend to leak up the limbs of the fold.
“Tcf”	Abbreviation for trillion cubic feet of gas.

"Tcfe"	Abbreviation for trillion cubic feet of gas equivalent.
"tectonism"	The process of deformation that produces, in the earth's crust, its continents and ocean basins, plateaus and mountains, folds of strata, and faults.
"thermal maturity"	The thermal maturity of an oil shale refers to the degree to which the organic matter has been altered by geothermal heating. If the oil shale is heated to a high enough temperature, as may be the case if the oil shale were deeply buried, the organic matter may thermally decompose to form oil and gas.
"tight"	Non specific term meaning lower permeability.
"trend"	A indefinite term normally used to identify a producing formation over a large area of production.
"Triassic"	A geological time period, covering the time between 250 to 200 million years ago.
"TVDSS"	Abbreviation for true vertical depth (sub-sea).
"unconventional resources"	Hydrocarbon from unconventional and more difficult to produce resources such as (hydrocarbon): shale gas, shale oil, heavy and viscous oil, hydrates, tight gas, etc.
"unrisked prospective resources"	Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects, assuming that the GPoS is equal to 100 per cent.
"well-bore"	The well-bore itself, including the openhole or uncased portion of the well. Borehole may refer to the inside diameter of the wellbore wall, the rock face that bounds the drilled hole.
"wireline log"	Related to any aspect of logging that employs an electrical cable to lower tools into the borehole and to transmit data. Wireline logging is distinct from measurements-while-drilling (MWD) and mud logging.
"working interest"	An interest in an oil and natural gas lease that gives the owner of the interest the right to drill for and produce oil and natural gas on the leased acreage and requires the owner to pay a share of the costs of drilling and production operations.
"zone"	Reservoir rock which is bounded above and below by impermeable rock.