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 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 resident and taking advice in the United Kingdom) is duly authorised under the Financial Services and Markets Act 2000 of the United Kingdom, 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.

If you sell or have sold or otherwise transferred all of your Ordinary Shares in Petroceltic, please forward this document, together with the enclosed Form of Proxy, at once to the purchaser or transferee or to the stockbroker, bank or other agent through whom the sale or transfer was effected, for onward transmission to the purchaser or transferee. However, these documents should not be forwarded or transmitted in or into any jurisdiction in which such act would constitute a violation of the relevant laws in such jurisdiction. If you have sold or otherwise transferred only part of your holding of Ordinary Shares in Petroceltic, you should retain these documents and consult the stockbroker, bank or other agent through which the sale or transfer was effected.

Shareholders and prospective investors should carefully consider the section entitled "Risk Factors" in Part II of this document before taking any action. All statements regarding the Petroceltic's business, financial position and prospects should be viewed in light of the risk factors set out in Part II 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 United Kingdom Listing Authority or to the official list of the Irish Stock Exchange (together the "Official Lists"). 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 to have a nominated adviser. Each ESM company is required pursuant to ESM Rules to have an ESM adviser. The nominated adviser and ESM adviser are required to make declarations to the London Stock Exchange and 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.

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 Ordinary Shares to the Official Lists. No application has been made for the Ordinary Shares to be listed on any other recognised investment exchange.

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 of the Enlarged Company Shares on AIM and ESM. This document does not comprise a prospectus within the meaning of section 85 of the FSMA or the Irish Prospectus Regulations and does not constitute an offer of transferable securities to the public in the United Kingdom or Ireland, within the meaning of, respectively, section 102B of the FSMA and the Irish Prospectus Regulations. **This document has not been approved or examined by and will not be filed with the United Kingdom Financial Services Authority, the London Stock Exchange, the United Kingdom Listing Authority, the Central Bank or the Irish Stock Exchange.**

PETROCELTIC INTERNATIONAL PLC

(Incorporated and registered in Ireland under the Companies Acts 1963 to 1983 of Ireland with registered number 101176)

Proposed Merger of Petroceltic and Melrose

Readmission to AIM and ESM

Notice of Extraordinary General Meeting

Davy

Nominated Adviser, ESM Adviser & Broker

BofA Merrill Lynch	**Lambert Energy Advisory**	**Nplus1 Brewin**	**HSBC**
Financial Adviser to Petroceltic	*Financial Advisers to Melrose*		

Application will be made for the Enlarged Company Shares to be admitted to trading on AIM, a market operated by the London Stock Exchange, and ESM, a market operated by the Irish Stock Exchange. The New Petroceltic Shares will rank *pari passu* in all respects with the Existing Petroceltic Shares, including the right to receive all dividends or other distributions declared, made or paid on the Ordinary Shares after Readmission. It is expected that Readmission will become effective and that dealings in the Ordinary Shares of Petroceltic will commence on AIM and ESM on 11 October 2012.

Petroceltic, whose registered office appears on page 29 of this document, and the Directors and Proposed Directors, whose names appear on page 29 of this document, accept individual and collective responsibility for the information contained in this document, including individual and collective responsibility for compliance with the AIM Rules and ESM Rules. To the best of the knowledge and belief of Petroceltic and the Directors and Proposed Directors (each of whom has taken all reasonable care to ensure that such is the case) the information contained in this document is in accordance with the facts and contains no omission likely to affect the import of such information.

This document also comprises a circular to Petroceltic's shareholders for the purpose of convening an extraordinary general meeting of Petroceltic to approve the Merger and resolutions to implement the Merger. Notice convening the Extraordinary General Meeting of Petroceltic to be held at The Westin Dublin, College Green, Westmoreland Street, Dublin 2, Ireland on 20 September 2012 at 12.30 p.m. is set out in the end of this document. The enclosed Form of Proxy for use at the EGM should be completed and returned in accordance with the instructions printed thereon as soon as possible and to be valid must be received no later than 12.30 p.m. on 18 September 2012.

Davy, which is regulated in Ireland by the Central Bank, is acting as nominated adviser and ESM adviser (pursuant to the AIM Rules and ESM Rules respectively) and broker to Petroceltic. Davy is acting exclusively for Petroceltic 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 and Proposed Directors have received advice and guidance as to the nature of their responsibilities and obligations to ensure compliance by Petroceltic 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.

BofA Merrill Lynch, which is authorised and regulated in the United Kingdom by the FSA, is acting exclusively for Petroceltic and no one else in connection with the Merger and this document and will not be responsible to anyone other than Petroceltic for providing the protections afforded to clients of BofA Merrill Lynch nor for providing advice in relation to the Merger or this document or any matter referred to herein.

Lambert Energy Advisory, which is authorised and regulated in the United Kingdom by the FSA, is acting exclusively for Melrose and no one else in connection with the Merger and this document and will not be responsible to anyone other than Melrose for providing the protections afforded to clients of Lambert Energy Advisory nor for providing advice in relation to the Merger or this document or any matter referred to herein.

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None of BofA Merrill Lynch, Lambert Energy Advisory, Nplus1 Brewin or HSBC accepts any responsibility whatsoever for the contents of this document or for any statement made or purported to be made by it, or on its behalf, in connection with the Merger or any matter or arrangement referred to in this document. Each of BofA Merrill Lynch, Lambert Energy Advisory, Nplus1 Brewin and HSBC accordingly disclaims, to the fullest extent permitted by law, all and any liability whether arising in tort, contract or otherwise it might otherwise have in respect of this document or any other statement.

The distribution of this document outside Ireland and the United Kingdom may be restricted by law and therefore persons outside Ireland and the United Kingdom into whose possession this document comes should inform themselves about and observe any restrictions as to the Ordinary Shares of Petroceltic or the distribution of this document. **This document does not constitute an offer to sell or issue, or the solicitation of an offer to buy or subscribe for, Ordinary Shares of Petroceltic in any jurisdiction in which such offer or solicitation is unlawful.** This document should not be copied or distributed by recipients and, in particular, should not be distributed, published, reproduced or otherwise be made available by any means, including electronic transmission, in, into or from the United States of America, Canada, Australia, the Republic of South Africa or Japan or any other jurisdiction where to do so would be in breach of any applicable law and/or regulation. The Ordinary Shares of Petroceltic have not been, nor will be, registered in the United States of America under the United States Securities Act 1933, as amended, or under the securities laws of any state of the United States of America, Canada, Australia, the Republic of South Africa or Japan and, subject to certain exemptions, they may not be offered or sold, directly or indirectly, within or into the United States of America, Canada, Australia, the Republic of South Africa or Japan or to, or for the account or benefit of, United States persons or any national, citizen or resident of the United States of America, Canada, Australia, the Republic of South Africa or Japan.

Copies of this document will be available free of charge to the public during normal business hours on any weekday (except Saturdays, Sundays and public holidays) from the registered office of Petroceltic for the period from the date of this document until the date of Readmission. Copies of this document are also available on Petroceltic's website at www.petroceltic.ie

The contents of this document should not be construed as legal, business or tax advice. Each prospective shareholder should consult his, her or its own legal adviser, independent financial adviser or tax adviser for legal, financial or tax advice.

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PART I

LETTER FROM THE CHAIRMAN OF PETROCELTIC

Petroceltic International plc

(incorporated and registered in Ireland under the Companies Acts 1963 to 1983 of Ireland with registration number 101176)

Directors:
Robert Arnott – *Non-Executive Chairman*
Brian O'Cathain – *Chief Executive*
Tom Hickey – *Corporate Development Director*
Andrew Bostock – *Senior Non-Executive Director*
Con Casey – *Non-Executive Director*
Hugh McCutcheon – *Non-Executive Director*

Registered Office:
6th Floor
75 St. Stephen's Green
Dublin 2
Ireland

Proposed Directors:
Robert F M Adair – *Non-Executive Director*
David H Thomas – *Chief Operating Officer*
James D Agnew – *Senior Independent Director*
Alan J Parsley – *Non-Executive Director*

17 August 2012

To Shareholders of Petroceltic and, for information only, to members of the 2004 Share Scheme and the 2009 Share Scheme

Dear Shareholder,

Proposed Merger of Petroceltic and Melrose
Readmission to AIM and ESM
Notice of Extraordinary General Meeting

1. INTRODUCTION

On 17 August 2012, the Boards of Petroceltic and Melrose announced that they had reached an agreement on the terms of a recommended Merger of Petroceltic and Melrose. The Merger will create a regionally focused North Africa, Mediterranean and Black Sea independent oil and gas company with a balanced and diversified portfolio comprising production, development and high-impact exploration assets.

Under the terms of the Merger, Melrose Shareholders will receive 17.6 New Petroceltic Shares for every Melrose Share held. In addition, a special dividend of 4.7 pence per Melrose Share will be paid by Melrose to Melrose Shareholders who are on Melrose's register of members at the Reduction Record Time within 14 days of the Effective Date.

Following the Merger becoming Effective, based on the Exchange Ratio of 17.6 New Petroceltic Shares for every Melrose Share held, existing Melrose Shareholders will hold 46 per cent of the Enlarged Company and existing Petroceltic Shareholders will hold 54 per cent of the Enlarged Company, on an undiluted basis.

It is intended that the Merger will be implemented by means of a court-sanctioned scheme of arrangement of Melrose under Part 26 of the UK Companies Act, pursuant to which Petroceltic will acquire the entire issued and to be issued share capital of Melrose.

The Merger represents a reverse takeover for Petroceltic under the AIM Rules and ESM Rules, and as such will be conditional, amongst other things, on the admission to trading on AIM and ESM of Petroceltic, and the approval of Petroceltic Shareholders. It is expected that the Readmission will become effective and dealings in the Enlarged Company Shares will commence on AIM and ESM on 11 October 2012.

The purpose of this document is to provide information about the proposed admission of the Enlarged Company Shares to trading on AIM and ESM, and the reasons for, and details of, the Merger, to explain why the Directors consider the Merger to be in the best interests of Petroceltic and Petroceltic Shareholders as a whole and to recommend that Petroceltic Shareholders vote in favour of the Resolutions at the Extraordinary General Meeting.

2. BACKGROUND TO AND REASONS FOR THE MERGER

Over recent years, Petroceltic and Melrose have separately developed and expanded their oil and gas, exploration, development and production activities with a strategic focus on the North Africa, Mediterranean and Black Sea regions. The Petroceltic and Melrose Boards have separately concluded that the long-term interests of their respective companies would best be advanced through the creation of a single larger entity focused on the same regions and believe that the Merger will create a well funded business capable of sustained long-term growth through organic success and focused regional acquisition activity.

The Petroceltic and Melrose Boards believe that the Merger will create a regionally focused North Africa, Mediterranean and Black Sea independent oil and gas company with a portfolio balanced between producing and high impact development and exploration assets. The Petroceltic and Melrose Boards believe that the Merger will enhance the financial flexibility and funding options of the Enlarged Group, with respect to its active exploration drilling campaign and future development of Petroceltic's Ain Tsila discovery in Algeria.

The Petroceltic and Melrose Boards believe that the combination has compelling strategic and commercial logic and that the Enlarged Group will be in a stronger strategic and financial position to deliver greater value to shareholders than if Petroceltic and Melrose were to remain as separate entities.

(a) Regionally focused North Africa, Mediterranean and Black Sea independent oil and gas company

The Enlarged Group will have 2P reserves of 84.2 MMboe, contingent resources of 357 MMboe and unrisked prospective resources of 1,365 MMboe in the North Africa, Mediterranean and Black Sea regions, creating a regionally focused independent oil and gas company with significant scale. The Petroceltic and Melrose Boards believe that the Enlarged Group will benefit from enhanced geographic, asset and funding diversification, better positioning it to take advantage of future business development opportunities in these regions.

(b) Balanced and diversified portfolio

The Petroceltic and Melrose Boards believe that the complementary asset bases of the two companies, which comprise Melrose's cash generating production base in Bulgaria and Egypt, Petroceltic's potential development upside of the Ain Tsila gas discovery in Algeria and the high-impact exploration portfolios of both companies in the Kurdistan Region of Iraq, Italy, Romania, Bulgaria and Egypt, balanced across proven and frontier plays, creates a diversified, enlarged entity with current production as well as potential medium and long-term upside through exploration and development programmes. The Petroceltic and Melrose Boards consider that the combined portfolio of the Enlarged Group will provide enhanced optionality with respect to capital allocation and asset optimisation.

(c) Active drilling campaigns

The Petroceltic and Melrose Boards intend that the Enlarged Group will embark on an active exploration drilling campaign in the next 18 months, with 6 exploration wells planned in Kurdistan Region of Iraq, Italy, Romania, Bulgaria and Egypt. The wells in the Kurdistan Region of Iraq, Italy and Bulgaria are targeting an estimated 259 MMboe of unrisked prospective recoverable resources (based on the sum of the mean estimates for these prospects). This estimate excludes the estimated prospect sizes for the exploration wells in Romania which will be more precisely defined once the 3D seismic survey, which is currently being acquired on the acreage, has been interpreted.

(d) Greater financial flexibility

The commencement of the development of Petroceltic's Algerian discovery in 2014 and planned appraisal and exploration campaigns in Italy and the Kurdistan Region of Iraq require substantial capital investment and as such are expected to benefit from the Enlarged Group's increased scale and anticipated improved access to funding.

The Enlarged Group will be well capitalised with a new $300 million facility provided by HSBC available from the date the Merger becomes Effective for a period of 18 months to, amongst other things, refinance all current outstandings under Melrose's existing reserve based lending and subordinate facilities. The Petroceltic and Melrose Boards believe that the commitment of HSBC, an existing lender to Melrose, represents an important element of the long-term funding strategy for the Enlarged Group. Melrose's proven capability to obtain asset backed finance combined with the cash flows from Melrose's producing assets and Petroceltic's on-going farm-out campaign in respect of a portion of its interest in the Ain Tsila asset are expected by the Petroceltic and Melrose Boards to provide greater funding certainty in relation to the future development of the Algerian discovery and the execution of appraisal and exploration drilling campaigns. The Petroceltic and Melrose Boards believe that the Enlarged Group will benefit from Melrose's existing relationships with reserve based lending banks and that the increased scale of the Enlarged Group will allow greater access to other funding sources, including capital markets.

Further information in relation to the HSBC Senior Secured Facility is set out in paragraph 20.1.6 of Part VII of this document.

(e) *Complementary management teams*

The combination will bring together the complementary skill-sets and shared management culture of the experienced operational teams of Petroceltic and Melrose. The Petroceltic team has a proven track-record in delivering high-impact exploration and appraisal results in North Africa. The Melrose team has delivered numerous on-shore and off-shore fields through development into production on fast-tracked schedules.

If the Merger becomes Effective, and subject to (i) satisfying eligibility criteria, (ii) market and trading conditions, and (iii) obtaining any necessary approvals including approval of the Enlarged Company Board, the Enlarged Company intends to make an application for a premium listing on the Official List of the UK Listing Authority and to be admitted to trading on the London Stock Exchange as soon as reasonably practicable and, in any event, within 12 months following the Merger becoming Effective. It will also consider seeking a listing on the Official List of the Irish Stock Exchange and admission to trading on the main securities market of the Irish Stock Exchange, as soon as reasonably practicable thereafter. Were such a move to be effected, a different set of laws, rules and regulations will become applicable to the Enlarged Company and certain amendments to its corporate governance practices and articles of association may be needed at that time. The Petroceltic and Melrose Boards expect that a premium listing in London would broaden the range of investors and funds capable of investing in the Enlarged Company, and thereby contribute to the development of an active and liquid market in its shares. However, there is no certainty that such application will be successful at the time envisaged, or at all. In the event that such application is unsuccessful, the Enlarged Company Shares will continue to trade on AIM and ESM.

3. BACKGROUND INFORMATION ON MELROSE

Melrose is an independent oil and gas exploration, development and production company founded in 1992 and headquartered in Edinburgh, United Kingdom. Melrose was floated on the main market of the London Stock Exchange in 1999.

Melrose has a portfolio of production, development and exploration assets with its primary assets in Egypt, Bulgaria and Romania. Melrose's core producing fields are located in Egypt and Bulgaria and Melrose produced an average of 34.3 Mboepd in 2011 and held proved plus probable reserves of 84.2 MMboe at year end 2011, both on a working interest basis. Melrose's profit for the year ended 31 December 2011 was US$51.6 million.

In Egypt, Melrose holds 100 per cent interests in three concession areas in the on-shore Nile Delta, Egypt and a 40 per cent interest in the Mesaha frontier exploration block in the south of the country.

In Bulgaria, Melrose has a 100 per cent interest in the Galata concession, off-shore Bulgaria, in the shallow waters of the Black Sea. Two gas fields, Kavarna and Kaliakra are on production within the concession and one new development, Kavarna East is being planned. The concession also has further exploration potential.

Melrose also has exploration acreage off-shore Romania with two exploration concessions, Muridava and Est Cobalcescu, awarded in the Romanian 10th Licencing Round. Melrose operates both blocks with interests of 40 per cent and 70 per cent respectively, and is currently acquiring a major 3D seismic survey with a view to embarking on a six well drilling programme in 2013 and 2014. Although the blocks have potential, the planned work programme is relatively capital intensive and therefore Melrose has plans to reduce its equity to 40 per cent on both blocks, whilst retaining ownership. Melrose is in advanced discussions with a company who wishes to acquire a 30 per cent interest in the Est Cobalcescu, block which will optimise Melrose's holdings in each block.

Melrose also holds a 66.67 per cent operated interest in five on-shore exploration licences in the South Mardin region of southern Turkey, but has no activity planned on this acreage.

Melrose also held a 27.5 per cent non-operated interest in the Rhône Maritime exploration concession in the French Mediterranean Sea. Melrose submitted a request to the French authorities to extend the licence term but the prescribed time for a response by the French authorities has passed without contact being made. Melrose has applied to the French authorities to assert its right in connection with the Rhône Maritime exploration licence.

Further information in relation to Melrose is set out in Part VIII of this document.

4. BACKGROUND INFORMATION ON PETROCELTIC

Petroceltic is an upstream oil and gas exploration and development company incorporated in Ireland whose shares are quoted on AIM and ESM. Petroceltic is headquartered in Dublin and its operations are focused on the Middle East and North Africa region and the Mediterranean basin. Petroceltic's core areas are in Algeria, Italy and the Kurdistan Region of Iraq.

Petroceltic was awarded a PSC in September 2004 which came into force in April 2005, over a permit area situated in the Illizi Basin in South Eastern Algeria (the "**Isarene PSC**"). Petroceltic currently operates the Isarene PSC with a 56.625 per cent participating interest, Sonatrach, the Algerian national oil and gas company, holds a 25 per cent participating interest, and Enel holds an 18.375 per cent participating interest, which it acquired from Petroceltic in 2012. A declaration of commerciality was submitted to the competent authorities for approval for the Ain Tsila field in August 2012, approval is expected by the end of 2012 and the major construction and development phase is planned to commence in 2014 and first gas is expected in 2017. Petroceltic has a regional office in Algiers.

Since 2004, Petroceltic has acquired a portfolio of interests in on-shore permits in the western Po Valley area and off-shore permits in the Central Adriatic and the Sicily Channel.

In 2011, Petroceltic entered into two PSCs in respect of what the Petroceltic Board believes to be two highly prospective exploration blocks, Dinarta and Shakrok, in the central north of the Kurdistan Region of Iraq. Petroceltic has a 20 per cent paying interest (16 per cent participating interest), Hess is operator with an 80 per cent paying interest (64 per cent participating interest) and the Kurdistan Regional Government hold the rights to a 20 per cent carried interest.

Further information in relation to Petroceltic is set out in Part VII of this document.

5. PRINCIPAL TERMS AND CONDITIONS OF THE MERGER

5.1 *Summary of the terms and conditions of the Merger*

Under the terms of the Merger, Melrose Shareholders will be entitled to receive 17.6 New Petroceltic Shares for every Melrose Share held. In addition, a special dividend of 4.7 pence per Melrose Share will be paid by Melrose to Melrose Shareholders who are on Melrose's register of members at the Reduction Record Time within 14 days of the Effective Date.

Following completion of the Merger, based on the Merger Ratio of 17.6 New Petroceltic Shares for every Melrose Share held, existing Melrose Shareholders will hold 46 per cent of the Enlarged Company, and existing Petroceltic Shareholders will hold 54 per cent of the Enlarged Company, in each case on an undiluted basis.

It is intended that the Merger will be implemented by means of a court-sanctioned scheme of arrangement of Melrose under Part 26 of the UK Companies Act, pursuant to which Petroceltic will acquire the entire issued and to be issued share capital of Melrose.

The Scheme requires approval by Melrose Shareholders by the passing of a resolution at the Court Meeting. This resolution must be approved by a majority in number of the holders of Melrose Shares present and voting, either in person or by proxy, representing not less than three-fourths in value of the Melrose Shares held by such holders. In addition, the Scheme will require separate approval by the passing of a special resolution at the Melrose General Meeting. The Melrose Court Meeting and the Melrose General Meeting will be held at 3.00 p.m. and 3.20 p.m. respectively on 20 September 2012 at Tods Murray LLP, Edinburgh Quay, 133 Fountainbridge, Edinburgh, EH3 9AG, United Kingdom. The Scheme and the Reduction of Capital must also be sanctioned by the Court at a Scheme Court Hearing. All Melrose Shareholders are entitled to attend the Scheme Court Hearing in person or through counsel to support or oppose the sanctioning of the Scheme. In addition, the Ordinary Resolutions must be approved by Petroceltic Shareholders at the Extraordinary General Meeting.

The Merger represents a reverse takeover for Petroceltic under the AIM Rules and ESM Rules, and as such will be conditional, amongst other things, on the admission to trading on AIM and ESM of the Enlarged Company

Shares, the approval of Petroceltic Shareholders and the approval of the Bulgarian Commission on Protection of Competition. Further information on the conditions of the Merger will be set out in the Scheme Circular and will be published on Melrose's website (www.melroseresources.com).

The New Petroceltic Shares will be issued credited as fully paid and will rank *pari passu* in all respects with the Ordinary Shares in issue at the time the New Petroceltic Shares are issued, including the right to receive and retain dividends and other distributions declared, made or paid by reference to a record date falling after the date hereof.

Fractions of New Petroceltic Shares will not be allotted or issued to Melrose Shareholders, but the entitlements of Melrose Shareholders will be rounded up or down (with 0.5 being rounded up) to the nearest whole number of New Petroceltic Shares.

Further information in relation to the Scheme will be set out in the Scheme Circular, which is expected to be published and sent to Melrose Shareholders on or about 24 August 2012.

5.2 *Irrevocable Undertakings to vote in favour of the Scheme*

Petroceltic has received hard irrevocable undertakings to vote (or procure to be voted) in favour of the resolutions to approve the Merger at the Court Meeting and the Melrose General Meeting from Robert Adair and Skye (a company connected to Robert Adair) who together are interested in an aggregate of 58,431,929 Melrose Shares, representing approximately 50.95 per cent of the issued share capital of Melrose and from the other Melrose Directors, who together are interested in an aggregate of 1,514,159 Melrose Shares representing 1.32 per cent of the issued share capital of Melrose, being in aggregate a total of 59,946,088 Melrose Shares, representing 52.27 per cent of the issued share capital of Melrose.

The irrevocable undertakings given by Robert Adair and Skye (a company connected to Robert Adair) and the Melrose Directors will cease to apply and shall lapse if (i) the Merger is not implemented by the date which is nine months from the date of the Rule 2.7 Announcement; or (ii) Petroceltic proposes any variation to the Merger unless the principal terms of the revised Merger (including the Exchange Ratio, the amount of the Special Dividend payable to Melrose Shareholders and, if Petroceltic elects to implement the Merger by way of a takeover offer, an acceptance condition of not less than 75 per cent unless a lower acceptance level is agreed to by Melrose with consent of the UK Panel on Takeovers and Mergers), are no less favourable than the terms set out in the Rule 2.7 Announcement; or (iii) the Merger lapses or is withdrawn without becoming effective or wholly unconditional.

Further information in relation to the irrevocable undertakings to vote in favour of the Scheme and in relation to the Robert Adair / Skye Trust and Security Arrangements is set out in paragraph 20.1.3 of Part XII of this document.

5.3 *Transaction Agreements*

As part of the Merger, Petroceltic has entered into a number of agreements including, *inter alia,* the following:

5.4.1. Mutual Confidentiality Agreement

5.4.2. Relationship Agreement

5.4.3. Co-operation Agreement

Details of these agreements are contained in paragraph 20.1 of Part XII of this document.

6. ENLARGED COMPANY BOARD AND CORPORATE GOVERNANCE

6.1 *Enlarged Company Board*

The Enlarged Company will be led by a management team comprising Brian O'Cathain of Petroceltic as Chief Executive Officer, David Thomas of Melrose as Chief Operating Officer and Tom Hickey of Petroceltic as Chief Financial Officer.

The Boards of Petroceltic and Melrose expect that Robert Adair of Melrose will become Non-Executive Chairman of the Enlarged Company and that Hugh McCutcheon will become Non-Executive Deputy Chairman of the Enlarged Company. Robert Adair's appointment as Executive Chairman of Melrose will be terminated pursuant to a change of control clause in his service agreement upon the Merger becoming Effective and he will receive a payment based on his existing contractual entitlements.

The Enlarged Company Board will include the management team and Robert Arnott and Con Casey as Non-Executive Directors from Petroceltic's current Board and Alan Parsley and James Agnew as Non-Executive Directors from Melrose's current Board.

The Enlarged Group will be headquartered in Dublin and the existing Melrose head office in Edinburgh will be retained. All other existing Petroceltic and Melrose offices will also be retained.

Petroceltic does not envisage that the Merger will result in any other material changes to the terms and conditions of employment of Melrose Group's management and employees, the location of Melrose Group's places of business or the redeployment of Melrose Group's fixed assets.

On Readmission, the composition of the Enlarged Company Board is expected to be as follows:

Robert F M Adair	Non-Executive Chairman
Brian O'Cathain	Chief Executive Officer
Tom Hickey	Chief Financial Officer
David Thomas	Chief Operating Officer
James Agnew	Senior Independent Director
Hugh McCutcheon	Non-Executive Director and Deputy Chairman
Robert Arnott	Non-Executive Director
Con Casey	Non-Executive Director
Alan Parsley	Non-Executive Director

The profiles of the Enlarged Company Board are set out in paragraphs 5 and 6 of Part XII of this document.

6.2 *Corporate Governance*

The Enlarged Company Board will be committed to maintaining the highest standards of corporate governance commensurate with the size, stage of development and financial status of the Enlarged Group post the Merger becoming Effective.

Further information in relation to the Enlarged Company's proposed corporate governance policies is set out in paragraph 11 of Part XII of this document.

7. SUMMARY OF INFORMATION CONTAINED IN THE COMPETENT PERSON'S REPORTS

Upon the Merger becoming Effective, the Enlarged Group would have 2P reserves of 84.2 MMboe (as at 31 December 2011), 357 MMboe of contingent resources and unrisked prospective resources of 1,365 MMboe.

Melrose had 2P and 3P reserves on a working interest basis of 84.2 MMboe and 111.9 MMboe respectively as at 31 December 2011 and has best estimate net attributable unrisked prospective resources of 15.5 MMboe and 22.3 MMboe in the main selected prospects in Egypt and Bulgaria respectively. Further information is provided in the Melrose Competent Person's Report in Appendix IV.

The Ain Tsila field in Algeria has estimated gross resources of 2.2 Tcf of sales gas, 70 MMbbl of condensate and 113 MMbbl of LPG, together approximately 305 MMboe of contingent resources on a 56.625 per cent working interest basis for Petroceltic. Further information is provided in the Petroceltic Competent Person's Report on Algeria in Appendix I.

Petroceltic estimates that the B.R 268.RG permit (the **"Elsa Discovery"**) has net entitlement best estimate unrisked contingent resources of 52.3 MMbbls and best estimate unrisked prospective resources of 30 MMbbls. Further information on the Elsa Discovery is contained in the Competent Person's Report in Appendix III of this document.

In addition, Petroceltic has net attributable unrisked prospective resources of 571 MMbbl in the Kurdistan Region of Iraq and 723 MMbbl in Italy, which includes 113 MMbbl in its Carpignano Sesia prospect in the Po Valley region in Italy and excludes the Elsa Discovery. Further information is provided in the Petroceltic Competent Person's Report on the Kurdistan Region of Iraq and Italy in Appendix II.

8. SUMMARY FINANCIAL INFORMATION ON PETROCELTIC AND MELROSE

8.1 *Petroceltic Group*

The following table summarises selected audited consolidated financial information of the Petroceltic Group as at, and for the years ended, 31 December 2011, 31 December 2010 and 31 December 2009. This data has been extracted from the Petroceltic Historical Financial Information in Part IX of this document which has been prepared in accordance with IFRS as adopted by the EU. Investors should read the whole of this document and not just rely on the summary information set out below.

US$'000	2011	2010	2009
Turnover	419	270	210
Operating Loss	(9,723)	(14,475)	(7,972)
Loss After Tax	(8,173)	(12,561)	(6,116)
Operating Cash Flow	8,452	(26,531)	19,331
Net Assets	317,775	266,048	158,837

8.2 *Melrose Group*

The following table summarises selected audited consolidated financial information of the Melrose Group as at, and for the years ended, 31 December 2011, 31 December 2010 and 31 December 2009. This data has been extracted from the Melrose Historical Financial Information in Part X of this document which has been prepared in accordance with IFRS as adopted by the EU. Investors should read the whole of this document and not just rely on the summary information set out below.

US$'000	2011	2010	2009
Turnover	291,002	240,381	224,398
Operating Profit	120,003	54,129	55,117
Profit/(Loss) After Tax	51,600	(11,685)	(23,886)
Operating Cash Flow	195,921	129,510	106,035
Net Debt[1]	322,676	418,862	474,255
Net Assets	362,548	314,995	329,073

Note 1: Net debt has been derived from the consolidated balance sheet of Melrose, and is comprised of bank loans (both long-term liabilities and short-term liabilities) net of cash and cash equivalents.

9. CURRENT TRADING, TRENDS AND PROSPECTS

9.1 *Petroceltic Group*

Petroceltic has no revenue generating operations, with the exception of a royalty from the Kinsale Head gas field. In February 2012, Petroceltic completed the sale of an 18.375 per cent interest in the Isarene Permit to Enel, receiving in excess of US$100 million. Petroceltic is entitled to receive further contingent cash consideration from Enel that will be determined by the final approved production profile of the Ain Tsila field, included in the DOC submitted to the petroleum authorities in Algeria. The proceeds of the sale to Enel were used in part to repay the US$30 million bridging facility with Macquarie Bank. The prospects for Petroceltic are dependent on, amongst other things, its development of the Ain Tsila field in Algeria, and the result of its planned exploration and appraisal activities in Italy and the Kurdistan Region of Iraq.

9.2 *Melrose Group*

Melrose has had a period of solid progress since the start of the financial year 2012 and has continued with its stated strategy of accelerating its planned financial de-gearing process. In Egypt and Bulgaria, Melrose's producing fields have performed as projected, with average production in line with market expectations during the first half of the year. Following the recent completion of two successful high angle development wells in the West and South Khilala fields in Egypt, Melrose is confident of achieving its full year production guidance of 28.0 Mboepd on a working interest basis. Melrose's arrears from EGPC as at 31 December 2011 were US$101 million. Notwithstanding the political environment in Egypt, throughout the period Melrose has received regular payments from the Egyptian Government for its hydrocarbon sales in line with a new payment schedule.

Melrose continues to reduce its financial gearing and remains well advanced towards achieving its gearing target of around 60 per cent by year end, reduced from 89 per cent as at the 31 December 2011.

On 22 March 2012, Melrose announced that the Romanian National Agency of Mineral Resources had approved the transfer of a 40 per cent working interest in the Muridava concession to Midia Resources. In addition, Melrose is actively involved in a process to farm-out a 30 per cent interest in the Est Cobalcescu concession. Melrose will retain operatorship of both these concessions. In France, Melrose had submitted a request to the French authorities to extend the licence term of the Rhône Maritime exploration licence, but the prescribed time for response passed without contact being made. Melrose has applied to the French authorities to assert its rights in connection with the Rhône Maritime exploration licence.

10. DIVIDEND POLICY

It is not the intention of the Enlarged Company to make distributions by way of dividend payments for the foreseeable future following the completion of the Merger. The Petroceltic and Melrose Boards consider that it is in the Enlarged Company Shareholders' best interests to reinvest the profits of the Enlarged Group in its business growth opportunities, including the Algerian Ain Tsila gas development and the international exploration inventory. The Enlarged Company Board will regularly review and possibly adjust the dividend policy as the Enlarged Group's asset portfolio and financial position evolve over forthcoming years.

11. IMPLEMENTATION OF THE MERGER

Implementation of the Merger is subject to the conditions and the further terms set out in Appendix I of the Scheme Circular. After all other conditions to the Scheme have been satisfied, the Scheme will become effective upon delivery of the Court Orders to UK Companies House.

Upon the Scheme becoming effective:

- the Scheme Shares will be cancelled and new ordinary shares in the capital of Melrose will be issued to Petroceltic, whereupon Melrose will become a wholly-owned subsidiary of Petroceltic;
- the New Petroceltic Shares due to each Scheme Shareholder pursuant to the Scheme will be allotted to each Scheme Shareholder upon the Effective Date and dealings in New Petroceltic Shares are expected to commence on the London Stock Exchange and Irish Stock Exchange at 8.00 a.m. on the Business Day following the Effective Date, with share certificates to be posted within 14 days; and
- the New Petroceltic Shares will be allotted and issued credited as fully paid and will rank *pari passu* in all respects with the Ordinary Shares in issue at the time the New Petroceltic Shares are issued pursuant to the Merger, including the right to receive and retain dividends and other distributions declared, made or paid by reference to a record date falling on or after the Effective Date.

Applications will be made to the UK Listing Authority and the London Stock Exchange for the cancellation of the listing of the Melrose Shares on the Official List and of the trading in Melrose Shares on the London Stock Exchange's main market for listed securities respectively, with effect from 8.00 a.m. on the Business Day following the Effective Date.

12. RISK FACTORS

Prior to making an investment decision in relation to the Enlarged Company Shares, prospective investors should carefully consider the section entitled "Risk Factors" in Part II of this document.

13. EXTRAORDINARY GENERAL MEETING

Set out at the end of this document is a notice convening the EGM to be held at The Westin Dublin, College Green, Westmoreland Street, Dublin 2, Ireland on 20 September 2012 at 12.30 p.m. for the purposes of considering and, if thought fit, passing the Resolutions. The full text of each of the Resolutions is set out in the notice at the end of this document.

The implementation of the Merger is conditional upon the passing of each of the Ordinary Resolutions. Each of the Ordinary Resolutions is proposed as an ordinary resolution. This means that, for each of the Ordinary Resolutions to be passed, more than half of the votes cast (in person or by proxy) at the Extraordinary General Meeting for each Ordinary Resolution must be in favour of that resolution. The Special Resolution is proposed as a special resolution. This means that, for the Special Resolution to be passed, at least three quarters of the votes cast (in person or by proxy) must be in favour of the resolution.

The implementation of the Merger is not conditional on the Special Resolution being passed.

Resolution 1 – Approval of the Merger

Resolution 1 proposes that the Merger be approved and the Directors be authorised to implement the Merger.

Resolution 2 – Increase in authorised share capital

If the Merger becomes Effective, Petroceltic will be required to issue approximately 2,018,529,533 New Petroceltic Shares (assuming no further Melrose Shares are issued after the date of this document). As at the date of this document, Petroceltic does not have sufficient authorised but unissued Ordinary Shares to issue such number of New Petroceltic Shares. Accordingly, Resolution 2 proposes, subject to the Merger becoming Effective (save for delivery and registration of the Court Orders, where applicable, and Readmission), to increase the authorised share capital of Petroceltic from €60,355,284.40 to €147,855,285.40 by the creation of a further 7,000,000,000 Ordinary Shares.

Resolution 3 – General authority to allot shares

Resolution 3 proposes, subject to the Merger becoming Effective (save for delivery and registration of the Court Orders, where applicable, and Readmission), to provide the Petroceltic Board with the requisite authority to allot relevant securities (within the meaning of the 1983 Act) up to an aggregate nominal amount of €43,515,513.25, which is equal to the sum of (i) the aggregate nominal value of the New Petroceltic Shares expected to be issued in connection with the Merger (being €25,231,619.16) and (ii) one-third of the aggregate nominal value of the expected Enlarged Issued Share Capital (being €18,283,894.09).

This authority will expire on the earlier of the conclusion of the annual general meeting of Petroceltic in 2013 and close of business on 11 September 2013.

Resolution 4 – Disapplication of pre-emption rights

Resolution 4 (the Special Resolution) will be proposed as a special resolution. The authority in Resolution 4, which is subject to the Merger becoming Effective, will allow the Petroceltic Board to allot shares for cash otherwise than in accordance with statutory pre-emption rights up to an aggregate nominal value of €2,742,584.11 (which is equal to approximately 5 per cent of the aggregate nominal value of the expected Enlarged Issued Share Capital) and in the event of a rights issue.

This authority will expire on the earlier of the conclusion of the annual general meeting of Petroceltic in 2013 and close of business on 11 September 2013.

The implementation of the Merger is not conditional on the Special Resolution being passed.

14. ACTION TO BE TAKEN IN RESPECT OF THE EXTRAORDINARY GENERAL MEETING

A Form of Proxy is enclosed with this document for use by Existing Petroceltic Shareholders at the Extraordinary General Meeting or any adjournment thereof. Existing Petroceltic Shareholders are asked to complete, sign and return the Form of Proxy in accordance with the instructions printed thereon so as to be received by the Registrars, Computershare Investor Services (Ireland) Limited, at Heron House, Corrig Road, Sandyford Industrial Estate, Dublin 18, as soon as possible but in any event no later than 12.30 p.m. on 18 September 2012 (or, in the case of an adjournment, not later than 48 hours before the time fixed for the holding of the adjourned meeting).

If you hold Petroceltic Shares in CREST, you may also choose to utilise the CREST electronic proxy appointment service in accordance with the procedures set out in the notice convening the Extraordinary General Meeting at the end of this document. Alternatively, you may give proxy instructions by utilising the Registrars' online proxy appointment service at www.eproxyappointment.com and following the instructions. Further details are set out on the Form of Proxy.

Proxies sent electronically (either by the CREST system or online) must also be sent as soon as possible and, in any event, so as to be received no later than 12.30 p.m. on 18 September, 2012 (or, in the case of an adjournment, not later than 48 hours before the time fixed for the holding of the adjourned meeting).

The completion and return of a Form of Proxy (or electronic appointment of a proxy) will not preclude Existing Petroceltic Shareholders from attending the Extraordinary General Meeting and voting in person should they wish to do so. Accordingly, whether or not Existing Petroceltic Shareholders intend to attend the Extraordinary General Meeting, they are urged to complete and return the Form of Proxy as soon as possible.

15. IRREVOCABLE UNDERTAKINGS TO APPROVE THE RESOLUTIONS

The Directors have irrevocably undertaken to Melrose to vote in favour of the Resolutions to be proposed at the Extraordinary General Meeting, in respect of their beneficial holdings totalling 17,767,842 Existing Petroceltic Shares in aggregate, which represent approximately 0.75 per cent of the Existing Petroceltic Shares.

16. FURTHER INFORMATION

Your attention is drawn to Parts II to XIV, and Appendices I to IV, of this document which provide further additional information on the matters detailed above.

17. RECOMMENDATION

The Petroceltic Board, in making its recommendation, has considered the long-term development plans and funding requirements associated with its assets against the background of current geo-political circumstances and the uncertain status of global equity and financing markets. The development of Petroceltic's Ain Tsila field in Algeria, which is scheduled to produce first gas in 2017, will require substantial capital investment and, given its significant size, the development could be subject to execution and cost escalation risks. In addition, planned exploration and appraisal campaigns in Italy and the Kurdistan Region of Iraq, in the event of success, may also require significant further investment in appraisal and/or development in order to maximise value.

The Merger will allow Petroceltic Shareholders to:

(i) retain a significant interest in Petroceltic's assets, most notably the Ain Tsila development;

(ii) diversify Petroceltic's portfolio by gaining exposure to the attractive portfolio of Melrose's producing and exploration assets;

(iii) access Melrose's extensive experience and track-record in both on-shore and off-shore field development that should be complementary to Petroceltic's skills and applicable to Petroceltic's assets in Algeria and Italy;

(iv) reduce funding uncertainty and obtain greater financial flexibility including improved access to funding sources; and

(v) benefit from future business development opportunities available to a stronger regional player.

The Directors believe that a combination with Melrose will accelerate the delivery of value to shareholders, whilst diversifying financial, commercial and execution risk.

The Directors believe that the Merger is in the best interests of Petroceltic and Petroceltic Shareholders as a whole and, accordingly unanimously recommend that Petroceltic Shareholders approve the Resolutions at the Extraordinary General Meeting, as they have irrevocably undertaken to do in respect of their own beneficial holdings of 17,767,842 Ordinary Shares, representing approximately 0.75 per cent of the Existing Petroceltic Shares.

Yours faithfully

Robert Arnott

CHAIRMAN

PART II

RISK FACTORS

An investment in the Enlarged Company Shares is subject to a number of risks. Accordingly, investors should consider the following risks and uncertainties together with all of the other information set out in this document prior to making any investment decision. If any of the following risks actually materialises, the Enlarged Group's business, financial condition and results of operations could be materially adversely affected and the value of the Enlarged Company Shares could decline.

These risks and uncertainties include risks relating to: (i) Petroceltic's and Melrose's and, if the Merger becomes Effective, the Enlarged Group's business; (ii) the oil and gas industry; (iii) the Merger; and (iv) investment in the Enlarged Company Shares.

The risks and uncertainties described below are not the only ones Petroceltic, Melrose and the Enlarged Group face. Additional risks and uncertainties not presently known to the Enlarged Company Directors or that the Enlarged Company Directors currently deem immaterial may also have a material adverse effect on Petroceltic, Melrose or the Enlarged Group's business, financial condition and results of operations and could negatively affect the price of the Enlarged Company Shares.

1. RISKS RELATING TO PETROCELTIC'S AND MELROSE'S AND, IF THE MERGER BECOMES EFFECTIVE, THE ENLARGED GROUP'S BUSINESS

There are a number of legal, regulatory, political, civil, economic and other issues in relation to the geographic regions in which Petroceltic, Melrose and, if the Merger becomes Effective, the Enlarged Group will operate, any of which could have a material adverse effect on Petroceltic's, Melrose's or, if the Merger becomes Effective, the Enlarged Group's operations

Both Melrose and Petroceltic have, and if the Merger becomes Effective, the Enlarged Group will have, assets located in the North African and Middle East region, which has been subject to ongoing political and security concerns

1.1 The geopolitical situation in North Africa and the Middle East, where the majority of Petroceltic's and Melrose's assets are, and the Enlarged Group's assets will be, located, has changed dramatically since early 2011. In Bahrain, Libya, Egypt, Iran, Tunisia, Yemen and Syria revolutionary, political and civil activities, termed the "Arab Spring", have ousted long-standing leaderships in several of the aforementioned countries and created turbulent political situations in others. While such instances of instability in the North Africa and Middle East region have not so far materially affected Petroceltic's or Melrose's assets, there can be no assurance that such instability in the region will not escalate in the future and as such have a material adverse effect on the England Group's business. In addition, such instability may in future spread to additional countries in the North Africa and Middle East region in which Petroceltic and Melrose currently operate and where the Enlarged Group will operate, such as Algeria, and governments in the North Africa and Middle East region may not be successful in maintaining domestic order and stability, all of which could adversely affect the Enlarged Group's business, as well as result in a decrease in the price of the Enlarged Company Shares.

1.2 Melrose has assets located in Egypt, a region which has been subject to ongoing political and security concerns, especially in recent years and, in common with other countries in the region, has experienced occasional civil unrest. The Enlarged Group's activities could be disrupted or face a significant impairment in value if such civil unrest or occasional violent activities in Egypt escalate or if the Egyptian government does not continue to be generally successful in maintaining or improving the prevailing levels of domestic order and stability. All sales of Melrose's oil and gas in Egypt are made to the government through EGPC. Oil and gas companies active in Egypt carry a high level of receivables with EGPC and increased political and economic instability could result in further delays in payment of the receivables. Any material delay or failure by EGPC to meet its agreed schedule of payments to Melrose could have a significant adverse impact on the Enlarged Group's business, results of operations, financial condition or prospects.

1.3 Terrorist activities or armed conflict involving any of the countries where Petroceltic and Melrose operate and where the Enlarged Group will operate may disrupt their business activities and adversely affect their financial condition. If events of this nature occur and persist, the resulting political and social instability could adversely affect prevailing oil and gas prices and cause a reduction in revenues. In addition, oil and gas production facilities, transportation systems and storage facilities could be the direct targets of terrorist attacks, and the Enlarged Group's operations could be adversely impacted if infrastructure integral to its operations is destroyed or damaged.

1.4 Petroceltic has an interest in exploration assets in the Kurdistan Region of Iraq. Political, economic, legal and social conditions in the Kurdistan Region of Iraq and in Iraq generally could materially and adversely affect Petroceltic's and, if the Merger becomes Effective, the Enlarged Group's business and its prospects. Petroceltic cannot, and the Enlarged Group will not, be able to completely protect its title to assets in the Kurdistan Region of Iraq as the Iraqi Oil Minister has historically disputed the validity of PSCs entered into with the KRG and future oil laws passed by the Iraq Government may adversely affect title to assets. Proceeds from exports of oil and gas from the Kurdistan Region of Iraq are received and administered by the Iraq Government, which, in turn, is obliged to pass on oil contractors' entitlements to the contractors through the KRG. To date, the Iraq Government has not passed on the Kurdistan Region of Iraq's oil contractors' full entitlements to export sales proceeds. Consequently, there is currently uncertainty relating to the receipt of proceeds from oil that is exported.

Petroceltic has, and if the Merger becomes Effective the Enlarged Group will have, Italian assets which have been and may in the future be impacted by an Italian off-shore drilling moratorium or other legislation

1.5 A number of Petroceltic's off-shore Italian permits and a number of its off-shore permit applications have been delayed in each instance due to a 2010 Legislative Decree DL 128/10 (the **"2010 Decree"**) which restricted certain off-shore oil and gas activities in Italy. On 26 June 2012 legislative Decree DL 83/2012 (the **"2012 Decree"**) was announced in the Italian Official Journal. The 2012 Decree, which is effective immediately, has been ratified by both houses of the Italian Parliament with no substantial modifications and will become law once published in the Italian Official Journal. Although the 2012 Decree removes the uncertainty concerning exploration, development and production activities in Italian waters, there can be no certainty that Petroceltic will be able to recommence some or all of its planned off-shore exploration and development activities in Italy which may result in a material loss in value in some or all of Petroceltic's and the Enlarged Group's Italian off-shore interests. The legal position and risks regarding Petroceltic's off-shore Italian interests is described more fully under paragraphs 3.2.3 – 3.2.6 and 3.2.29 – 3.2.35 of Part VII of this Document.

Investment in emerging markets is only suitable for sophisticated investors

1.6 Generally, investment in companies operating in emerging markets is only suitable for sophisticated investors who fully appreciate the significance of the risks involved in, and are familiar with, emerging markets. Investors should note that emerging markets such as those in which the Enlarged Group will operate in following the Merger, are subject to rapid change and that the information set forth in this document may become outdated relatively quickly. Moreover, financial turmoil in any emerging market tends to adversely affect prices in equity markets of all emerging market countries as investors move their money to more stable, developed markets. As has happened in the past, financial problems or an increase in the perceived risks associated with investing in emerging economies could dampen foreign investment in, and adversely affect the economies of, emerging markets in which the Enlarged Group will operate. Thus, even if these economies remain relatively stable, financial turmoil in other emerging markets could adversely affect, following the Merger, the Enlarged Group's business, as well as result in a decrease in the price of the Enlarged Company Shares.

The Enlarged Group will be exposed to risks associated with operations in emerging markets

1.7 The Enlarged Group's international operations may be susceptible to political, social and economic instability and civil disturbances. A material risk for Petroceltic and Melrose, and, if the Merger becomes Effective, the Enlarged Group concerns longer collection times of accounts receivable other than in the UK and Ireland. Other risks for Petroceltic and Melrose, and, if the Merger becomes Effective, the Enlarged Group in operating in such areas include:

a) disruption to operations, including strikes, civil actions, international conflict or political interference;

b) changes to the fiscal regime including changes in the rates of income and corporation taxes or changes to the terms of the production sharing contracts or the concession agreements;

c) reversal of current policies encouraging foreign investment or foreign trade by the governments of certain of the countries in which the Enlarged Group operates;

d) limited access to markets for periods of time;

e) increased inflation;

f) restrictive actions by local governments, including the imposition of tariffs and limitations on imports and exports;

g) mollification, modification or renegotiation of contracts; and

h) expropriation or forced divestment of assets.

1.8 Any of the above factors could result in disruptions to the Enlarged Group's business, increased costs or reduced future growth opportunities. Potential losses caused by these disruptions may not be covered by insurance.

1.9 Once the Enlarged Group, or an operator of assets in which the Enlarged Group has an interest, has established hydrocarbon exploration and/or production operations in a particular country, it may be expensive and logistically burdensome to discontinue such operations should economic, political, physical or other conditions subsequently deteriorate. All of these factors could materially adversely affect the Enlarged Group's business, results of operations, financial condition or prospects.

Petroceltic and Melrose, and if the Merger becomes Effective, the Enlarged Group will, operate in countries with less developed legal systems

1.10 The countries in which Petroceltic and Melrose, and, if the Merger becomes Effective, the Enlarged Group will operate, may have less developed legal systems than countries with more established economies, which may result in risks such as:

a) effective legal redress in the courts of such jurisdictions, whether in respect of a breach of law or regulation or in an ownership dispute, being more difficult to obtain;

b) a higher degree of discretion on the part of governmental authorities;

c) a lack of judicial or administrative guidance on interpreting applicable rules and regulations;

d) inconsistencies or conflicts between and within various laws, regulations, decrees, orders and resolutions; or

e) relative inexperience of the judiciary and courts in such matters.

In certain jurisdictions the commitment of local business people, government officials and agencies and the judicial system to abide by legal requirements and negotiated agreements may be more uncertain, creating particular concerns with respect to licences and agreements for business. These may be susceptible to revision or cancellation and legal redress may be uncertain or delayed. There can be no assurance that joint ventures, licences, licence applications or other legal arrangements will not be adversely affected by the actions of government authorities or others and the effectiveness of and enforcement of such arrangements in these jurisdictions cannot be assured.

Petroceltic and Melrose are, and if the Merger becomes Effective, the Enlarged Group will be, exposed to the risks of fraud and corruption.

1.11 As upstream oil and gas exploration and production companies, Petroceltic and Melrose are, and if the Merger becomes Effective, the Enlarged Group will be, exposed to the risks of fraud and corruption both internally and externally. In addition, some of Petroceltic's and Melrose's activities are, and if the Merger becomes Effective, the Enlarged Group's activities will be, located in countries where corruption may exist. Petroceltic and Melrose seek to comply fully with legislation such as the UK Bribery Act 2010 and have put in place internal control policies and external diligence and compliance policies. However, there can be no assurance that such procedures and established internal controls will adequately protect them against fraudulent and/or corrupt activity and such activity could have an adverse effect on Petroceltic's and Melrose's, and if the Merger becomes Effective, the Enlarged Group's business, reputation, results of operations, financial condition and/or prospects.

Failure to meet work commitments, premature termination, suspension or withdrawal of licences or failure to extend licences may have an adverse effect on Petroceltic's and Melrose's, and, if the Merger becomes Effective, the Enlarged Group's reserves and prospects

1.12 Following the Merger becoming Effective, the Enlarged Group will have 47 licences, permits and production sharing contracts, many of which have work programme commitments that must be carried out within certain agreed timeframes. Failure to carry out any of these work 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 Petroceltic or Melrose, and, if the Merger becomes Effective, the Enlarged Group losing those relevant interests and the associated resource potential therein and also restrict the ability to obtain new licences in the relevant jurisdictions. Petroceltic and Melrose, and, if the Merger becomes Effective, the Enlarged Group's rights to exploit many of their oil and gas assets 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.

1.13 If Petroceltic and Melrose, and, if the Merger becomes Effective, the Enlarged Group are unable or unwilling to fulfil the specific terms of any of their existing or future rights, concessions, licences, permits and other authorisations or if they operate their businesses in a manner that violates applicable law, government regulators may impose fines or suspend or terminate the relevant right, concession, licence, permit or other authorisation, any of which could have a material adverse effect on the Enlarged Group's results of operations, cash flows and financial condition. 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 Petroceltic and Melrose, and, if the Merger becomes Effective, the Enlarged Group.

Petroceltic's and Melrose's, and, if the Merger becomes Effective, the Enlarged Group's success depends on the ability to find, acquire, appraise, develop and produce oil and gas reserves that are economically recoverable

1.14 Exploration, appraisal, development and production of oil and natural gas reserves are speculative and involve a significant degree of risk. The long-term commercial success of the Enlarged Group, meaning the capability to generate positive net income on a sustainable basis, will depend on its ability to find, acquire, develop and commercially produce oil and natural gas reserves, principally through its assets in Egypt, Bulgaria, Algeria, Italy, the Kurdistan Region of Iraq, Romania and other countries in which it may own or acquire assets. Risks normally incidental to such activities including blowouts, oil spills, explosions, fires, equipment damage or failure, natural disasters, geological uncertainties, unusual or unexpected rock formations, abnormal pressures, availability of technology and engineering capacity, availability of skilled resources, maintaining project schedules and managing costs, as well as technical, fiscal, regulatory, political and other conditions. Furthermore, given the early stage of development of the Petroceltic Group's assets outside of Algeria, and the Melrose Group's assets outside of Egypt and Bulgaria, no proved or probable reserves have been estimated in connection with these assets as of the date of this document. There is no assurance that oil and gas will be discovered on the existing oil and gas assets of the Petroceltic Group and of the Melrose Group, or assets acquired in the future by the Enlarged Group or, if there are oil and gas discoveries that the Enlarged Group will be able to realise those reserves as intended. Additionally, the Enlarged Group may be unable to reach an agreement with government authorities on the terms on which it may commence production to commercialise reserves.

1.15 A proportion of Petroceltic's and Melrose's, and, if the Merger becomes Effective, the Enlarged Group's activity will be conducted off-shore. Exploration and development of off-shore hydrocarbon reserves and the infrastructure required to produce them involves an increased risk relative to on-shore activity and may result in additional costs relating to the technical difficulties of operating off-shore.

The Enlarged Group's business will require substantial capital expenditure and will be primarily reliant on existing cash reserves, debt facilities and cash flows from production

1.16 The Enlarged Group's activities are heavily capital intensive and the Enlarged Group will need to continue to make substantial capital expenditures in the exploration and development stage of its business. To date, the Petroceltic Group's capital expenditures have been primarily financed with capital contributions from its Shareholders and the proceeds from farm down of interests in its assets. To date, the Melrose Group's capital expenditures have been primarily financed through cash flows from production and long-term debt financing. There can be no certainty that the Enlarged Group will achieve sustainable or positive cash flows from its operating activities.

1.17 While the Directors and the Proposed Directors believe that the working capital available to the Enlarged Group is sufficient for its present requirements, that is for at least twelve months from the date of this document, following the Merger becoming Effective, and after this period of twelve months, the Enlarged Group may need to raise additional external capital to fund (i) future development activities, which may result from exploration success, (ii) work commitments on its interests, (iii) acquisitions or (iv) for other purposes. These capital requirements may be in excess of the Enlarged Group's cash reserves and available debt finance. In addition, after this period of twelve months, the Enlarged Group may need to raise new finance to fund other aspects of its operations including exploration, appraisal and production. The Enlarged Group's ability to fund its obligations and activities after this period of twelve months may be dependent upon obtaining appropriate external financing in the form of debt, joint ventures and/or farm-outs (or a combination thereof), and new equity.

There can be no certainty that covenants contained in the Enlarged Group's debt facility will not be breached or that the facility will be refinanceable

1.18 Melrose has entered into the HSBC Senior Secured Facility which will become available, upon the Merger becoming Effective. Petroceltic will accede to the HSBC Senior Secured Facility upon the Merger becoming Effective. The HSBC Senior Secured Facility will, amongst other purposes, repay or prepay all of Melrose's current outstandings under its existing reserves based lending facility post the Merger becoming Effective, and provide the Enlarged Group with further funding. The HSBC Senior Secured Facility will expire after 18 months and the Enlarged Group will need to obtain further facilities for the longer term. There can be no guarantee that the Enlarged Group will be able to refinance the facility when needed or that such refinancing will be available on terms favourable to the Enlarged Group. A number of factors (including conditions in the credit, debt and equity markets and general economic conditions) may make it difficult for the Enlarged Group to obtain replacement financing on favourable terms or at all. Failure to obtain replacement financing on a timely basis, on acceptable terms or at all, could result in a number of significant adverse impacts on the Enlarged Group, including forfeiture or disposal of its interest in some or all of its oil and gas assets, significant penalties and other costs, restricting the ability of the Enlarged Group to operate its business.

Petroceltic and Melrose, and, if the Merger becomes Effective, the Enlarged Group, may be subject to risks associated with the EU debt crisis and wider market conditions

1.20 Petroceltic and Melrose have, and, if the Merger becomes Effective, the Enlarged Group will have a proportion of their assets and liabilities either based in, or having exposure to, the EU and, accordingly, they are exposed to risks in connection with the current EU debt crisis. If the EU debt crisis continues or escalates it may impact upon the ability of Petroceltic and Melrose, or if the Merger becomes Effective, the Enlarged Group to source additional financing or to access the capital markets, which could have a material adverse effect on Petroceltic's and Melrose's, and, if the Merger becomes Effective, the Enlarged Group's business, prospects, financial condition or results of operations.

1.21 The current global recessionary environment and the volatility of international markets have caused governments and central banks to undertake unprecedented intervention designed to stabilise global and domestic financial systems, stimulate new lending and support structurally important institutions at risk of failing. Many developed economies have experienced recession over the past year and growth has slowed in many emerging economies, with serious adverse consequences for asset values, employment levels, consumer confidence and levels of economic activity. Interest rate yield curves have flattened; interest rates have fallen in absolute terms in many markets; and trade flows have contracted. Global equity markets are volatile following severe declines and various currencies have depreciated significantly against the US dollar. Numerous governments and central banks have responded by proposing programmes to make substantial funds and guarantees available to boost liquidity and confidence in their financial systems, as well as cutting taxes and lowering interest rates. Petroceltic's and Melrose's, and, if the Merger becomes Effective, the Enlarged Group's financial condition and business prospects are affected by global and local economic and market conditions. A further deterioration of these conditions could have a material adverse effect on Petroceltic's and Melrose's, and, if the Merger becomes Effective, the Enlarged Group's business, prospects, financial condition and results of operations, and the trading price of Petroceltic Shares and Melrose Shares, and, if the Merger becomes Effective, the Enlarged Company Shares.

Dry wells may lead to a downgrading of the potential value of Petroceltic's and Melrose's, and, if the Merger becomes Effective, the Enlarged Group's licences, concessions or production sharing contracts or require further funds to continue exploration work

1.22 Many of the areas being explored by Petroceltic and Melrose, and, if the Merger becomes Effective, the Enlarged Group, have a number of prospects for the discovery of oil and gas. Should drilling be undertaken in a particular geographic area but no oil and gas is discovered (a "**dry well**"), this may lead to a downgrading of the potential value of the licences, concessions or production sharing contracts concerned and may impact the value of other licences, concessions or production sharing contracts within the same geological basin, as well as implying that the other prospects within that geographic area may be less likely to yield exploration success, thereby potentially decreasing the value of Petroceltic's and Melrose's, and, if the Merger becomes Effective, the Enlarged Group's assets. If this is the case, once the minimum work commitments under the relevant licences, concessions or production sharing contracts have been satisfied, Petroceltic and Melrose, and, if the Merger becomes Effective, the Enlarged Group may relinquish their interests in the licences, concessions or production sharing contracts, in which case they would have no further exploration rights, even though they may have identified a number of additional prospects in that area.

1.23 Dry wells may also result in Petroceltic and Melrose, and, if the Merger becomes Effective, the Enlarged Group requiring substantially more funds if any of them chooses to continue exploration work and drill further wells beyond the existing minimum work commitments. Such funding may be unavailable or may have to be obtained on unfavourable terms, leading to a potential deterioration in financial position. Drilling a dry well would also mean that Petroceltic and Melrose, and, if the Merger becomes Effective, the Enlarged Group may not be able to recover the costs incurred in drilling that well or make a return on its investment, resulting in significant exploration expenditure being written off. Any of these circumstances may have a material adverse effect on the business, prospects, financial position and results of operations of Petroceltic and Melrose, and, if the Merger becomes Effective, the Enlarged Group.

The Enlarged Group will have to undertake significant development activities

1.24 Petroceltic's and Melrose's, and, if the Merger becomes Effective, the Enlarged Group's ability to develop successfully their licences, concessions and production sharing contracts for hydrocarbon production depends on the Enlarged Group's operating ability to conduct complex development projects in a timely and cost-effective manner. This in turn relies on the availability of and access to skilled personnel and contractors in the area of the development activity. There can be no guarantee that the Enlarged Group will be successful in meeting its development programme timelines on budget without significant time delays or capital budget overruns.

There is a risk that recovery of hydrocarbons may not be technically or economically feasible

1.25 Petroceltic's and Melrose's, and, if the Merger becomes Effective, the Enlarged Group's ability to develop successfully their licences, concessions and production sharing contracts for hydrocarbon production depends not only upon the presence of significant in-place hydrocarbon resources in the concession areas, but also on the ability of Petroceltic and Melrose, and, if the Merger becomes Effective, the Enlarged Group to recover such resources in a commercially viable manner. There can be no guarantee that Petroceltic, Melrose, or the Enlarged Group will be able to recover any hydrocarbons in their concession areas or that they will be able to do so at a cost that makes production commercially feasible.

1.26 Further, even if recovery of such hydrocarbons is technically feasible in the Enlarged Group's concessions, there is a risk that it may not be commercially viable due to the costs of the technology, drilling, equipment and other resources needed to extract the hydrocarbons from the reservoirs, all of which will depend to a significant extent on the specific conditions of each particular reservoir. The commercial viability of any particular reservoir will be largely a function of the prevailing prices for oil and natural gas compared to the costs of extracting hydrocarbons from that reservoir, such that a higher cost base for a particular reservoir, whether due to its particular geophysical qualities or otherwise, could make profitable extraction from that reservoir impossible. If Petroceltic and Melrose, and, if the Merger becomes Effective, the Enlarged Group, are unable to recover additional hydrocarbons from their licences, concessions and production sharing contracts at all due to geological factors or technical infeasibility, or if they are able to recover hydrocarbons only at a cost which makes production commercially unviable, this would have a material adverse effect on Petroceltic's and Melrose's, and, if the Merger becomes Effective, the Enlarged Group's business, prospects, financial condition and results of operations.

1.27 Future oil and natural gas exploration may involve unprofitable efforts, not only from unsuccessful wells, but from wells that are productive but do not produce sufficient revenues to return a profit after deduction of expenditures, including the cost of drilling and operating expenses. Completion of a well does not assure a profit on the investment or the recovery of drilling, completion and operating costs. In addition, drilling hazards or environmental damage may greatly increase the cost of operations, and field operating conditions may adversely affect the production from productive wells. These conditions include delays in obtaining governmental approvals or consent, restrictions on production from particular wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions.

Petroceltic and Melrose, and, if the Merger becomes Effective, the Enlarged Group will be required to rely on third-party operators and other joint venture partners and are typically required to consult these partners in relation to significant matters

1.28 It is common in the oil and gas industry for companies to form joint ventures with other companies through which exploration, development and operating activities for a particular property or concession area are conducted. In such cases, one company is designated by agreement amongst the joint venture, to manage or "operate" the joint venture. The operator is the primary point of contact for the national oil company or the government and is responsible for maintaining positive relationships with the relevant authorities. The operator is also responsible for implementing the field work by entering into agreements with various sub-contractors to provide drilling rigs and other equipment and services necessary for carrying out exploration and development operations. As a result, the Enlarged Group may have limited ability to exercise influence over the operations and associated costs of those assets which it does not operate, and which could adversely affect Petroceltic's, Melrose's, and, if the Merger becomes Effective, the Enlarged Group's financial performance.

1.29 The Carisio exploration permit in the Po Valley in Italy is operated for Petroceltic by a third party, ENI, and the Dinarta and Shakrok blocks in the Kurdistan Region of Iraq are operated for Petroceltic by Hess. As a result, Petroceltic and, if the Merger becomes Effective, the Enlarged Group may have limited ability to exercise influence over the operations of these assets or their associated costs, which could adversely affect Petroceltic's and, if the Merger becomes Effective, the Enlarged Group's financial performance. Petroceltic is, and if the Merger becomes Effective, the Enlarged Group will be dependent on the competence and judgement of third-party operators with regard to these non-operated assets. The participants in these assets proportionately share liability for any claims and liabilities which may arise as a result of the operator's activities carried out for the benefit of the participants (as the case may be). Should ENI or Hess become subject to any liabilities, the proposed Enlarged Group may also be subject to a part of such liability. In addition, Petroceltic is, and if the Merger becomes Effective, the Enlarged Group will be dependent on their partners' operations for the timing and quality of activities and may be less able to control these activities or the forward plans for the development of their non-operated assets.

Petroceltic and Melrose have, and, if the Merger becomes Effective, the Enlarged Group will have contractual arrangements in place with a number of third parties for sales and service providers

1.30 Petroceltic and Melrose are expected to continue to have material contracts in place with parties for marketing and sales activities and, from time to time, with service contractors for drilling, construction and other activities. Should any of these parties experience any difficulties or default on such contractual agreements, this could adversely affect Petroceltic, Melrose and, if the Merger becomes Effective, the Enlarged Group's business, prospects, financial condition and results of operations. In particular, there are a limited number of possible counterparties for Petroceltic, Melrose and, if the Merger becomes Effective, the Enlarged Group's gas sales agreements. Should current marketing and sales arrangements experience any interruption, there can be no guarantee that alternative arrangements can be put in place. In addition, it is not possible to guarantee that any future contracts will be available or can be entered into on economically beneficial terms.

If the Merger becomes Effective, the Enlarged Group may not be able to manage the expansion of its operations effectively through organic growth or acquisitions

1.31 There is no certainty that all, or indeed any, of the elements of the strategy for the Enlarged Group will develop as anticipated or that the Enlarged Group will become profitable. In the event that the Enlarged Group's operations are successful, Petroceltic and Melrose's current systems, procedures and controls will need to be expanded and strengthened to support the Enlarged Group's future operations. There can be no assurance that the Enlarged Group will be able to manage effectively the expansion of its operations through organic growth or acquisitions. Any failure of the Enlarged Group to manage effectively its growth and development could have a material adverse effect on its business, prospects, financial condition or results of operations.

Petroceltic and Melrose are, and if the Merger becomes Effective, the Enlarged Group will be dependent on the attraction and retention of key employees

1.32 Petroceltic's and Melrose's success, and if the Merger becomes Effective, the Enlarged Group's success depends, to a large extent, on certain of its key personnel. The loss of the services of any key personnel could have a material adverse effect on Petroceltic, Melrose and, if the Merger becomes Effective, the Enlarged Group. The competition for qualified personnel in the oil and gas industry is intense. There can be no assurance that Petroceltic, Melrose or, if the Merger becomes Effective, the Enlarged Group will be able to continue to attract and retain all personnel necessary for the development and operation of its business.

Petroceltic and Melrose, and, if the Merger becomes Effective, the Enlarged Group are subject to future decommissioning liabilities

1.33 Petroceltic and Melrose, and, if the Merger becomes Effective, the Enlarged Group, through its licence interests, have assumed certain obligations in respect of the decommissioning of their fields and related infrastructure and are expected to assume additional decommissioning liabilities in respect of their future operations. These liabilities are derived from legislative and regulatory requirements concerning the decommissioning of wells, transportation and production facilities and require Petroceltic and Melrose, and, if the Merger becomes Effective, the Enlarged Group, to make provision for and/or underwrite the liabilities relating to such decommissioning. Any significant increase in the actual or estimated decommissioning costs that Petroceltic and Melrose, and, if the Merger becomes Effective, the Enlarged Group incurs may adversely affect the results of operations and financial condition of the companies. There can be no assurance that Petroceltic and Melrose, and, if the Merger becomes Effective, the Enlarged Group will not in the future incur decommissioning charges since local or national governments may require decommissioning to be carried out in circumstances where there is no current express obligation to do so, particularly in case of future licence renewals.

Petroceltic and Melrose, and, if the Merger becomes Effective, the Enlarged Group may be adversely affected by litigation or adverse publicity

1.34 Save as provided in paragraph 21 of Part XII of this document, Petroceltic and Melrose currently have no material outstanding litigation or disputes. There can be no guarantee that the past, current or future actions of Petroceltic and Melrose will not result in litigation, and there have been a number of cases where the rights and privileges of oil and gas companies have been the subject of litigation. Defence and settlement costs can be substantial, even with respect to claims that have no merit. Due to the inherent uncertainty of the litigation process, there can be no assurance that the resolution of any particular legal proceeding will not have a material adverse effect on Petroceltic's and Melrose's, and, if the Merger becomes Effective, the Enlarged Group's business, financial condition or results of operations. In addition, the adverse publicity surrounding such claims may have a material adverse effect on business performance and reputation.

Fluctuations in currency exchange rates may impact the business, results of operations and/or financial condition of Petroceltic and Melrose, and, if the Merger becomes Effective, the Enlarged Group

1.35 The US Dollar is the primary currency in which the Petroceltic Group conducts business, with some costs, assets and liabilities denominated in Algerian Dinars, Euro or Sterling. Similarly, the majority of the Melrose Group's revenue and expenditure is denominated in US Dollars, with a proportion of the Melrose Group's Bulgarian revenues received in Bulgarian Leva, which is pegged to the Euro, and certain limited overhead costs and capital expenditures incurred in Sterling, Egyptian Pounds, Bulgarian Leva and Euro. Melrose also incurs borrowings in US Dollars for both corporate purposes and development projects. Petroceltic and Melrose generally seek to match the currency of their revenue and expenses for their operations to reduce their exposure to currency fluctuations but, in limited circumstances, the revenue and expenses may be in different currencies and, therefore, subject to foreign exchange risk, which may have an adverse effect on the Enlarged Group's results of operations and financial position. In addition, Petroceltic and Melrose may have other expenditure (in particular central administrative costs) and equity funding denominated in other currencies, most notably Sterling and Euro. Petroceltic and Melrose each present their consolidated financial statements in US Dollars and, consequently, the presentation of the consolidated financial statements may be affected by movements in foreign exchange rates and particularly by Sterling/US Dollar and Euro/US Dollar exchange rates.

Petroceltic's and Melrose's, and if the Merger becomes Effective, the Enlarged Group's risk management policies and procedures may leave it exposed to unidentified or unanticipated risks

1.36 Petroceltic's and Melrose's activities are, and, if the Merger becomes Effective, the Enlarged Group's activities will be, exposed to commodity price, foreign exchange, interest rate, counterparty (including credit), operational, regulatory and other risks. Petroceltic's and Melrose's, and, if the Merger becomes Effective, the Enlarged Group's policies and procedures to identify, monitor and manage risks may not be fully effective in the future. Failure to mitigate all risks associated with Petroceltic's and Melrose's, and, if the Merger becomes Effective, the Enlarged Group's business could have a material adverse effect on Petroceltic's and Melrose's, and, if the Merger becomes Effective, the Enlarged Group's business, results of operations and financial condition.

2. RISKS RELATING TO THE OIL AND GAS INDUSTRY

The oil and gas industry is intensely competitive and Petroceltic and Melrose, and, if the Merger becomes Effective, the Enlarged Group, may not be able to compete effectively

2.1 The oil and gas industry is intensely competitive, particularly in securing access to exploration acreage, gas markets, oil services and rigs, technology and processes and human resources. Petroceltic's and Melrose's, and, if the Merger becomes Effective, the Enlarged Group's competitive position depends on geological, geophysical and engineering expertise, financial resources, the ability to develop their properties and the ability to select, acquire and develop proved reserves. Petroceltic and Melrose compete, and, if the Merger becomes Effective, the Enlarged Group will compete with a substantial number of other companies which have a larger technical staff and greater financial and operational resources. Many such companies not only engage in the acquisition, exploration, development and production of oil and gas reserves, but also undertake refining operations and market refined products. Petroceltic and Melrose compete, and, if the Merger becomes Effective, the Enlarged Group will compete with major and independent oil and gas companies and other industries supplying energy and fuel in the marketing and sale of oil and gas to transporters, distributors and end users, including industrial, commercial and individual consumers.

2.2 Petroceltic and Melrose compete, and, if the Merger becomes Effective, the Enlarged Group will compete with other oil and gas companies in attempting to secure drilling rigs and other equipment necessary for drilling and completion of wells and to construct production and transmission facilities. Such equipment may be in short supply from time to time. The costs of third party services and equipment have increased significantly over recent years and may continue to rise. Scarcity of equipment and services and increased prices may, in particular, result from any significant increase in regional exploration and development activities which in turn may be the consequence of increased or continued high prices for oil or gas. Additionally, companies not previously investing in oil and gas may choose to acquire reserves to establish a firm supply or simply as an investment. Competition for exploration and production licences may, therefore, increase in the future, and may lead to increased costs associated with Petroceltic's and Melrose's, and, if the Merger becomes Effective, the Enlarged Group's activities, and fewer available growth opportunities. Such competition in the oil and gas industry could have a material adverse effect on Petroceltic's and Melrose's, and, if the Merger becomes Effective, the Enlarged Group's business, prospects, financial condition or results of operations.

Current reserves and resources data in this document are only estimates and are inherently uncertain

2.3 The reserves and resources data set forth in this document including the Petroceltic Competent Person's Reports contained in Appendix I, II and III, and the Melrose Competent Person's Report contained in Appendix IV involve subjective judgements and determinations and are based on the best available geological, technical, contractual and economic information. The estimation of underground accumulations of oil and gas is a subjective process aimed at understanding the statistical probabilities of recovery. These are not exact determinations. Estimates of the quantity of economically recoverable oil and gas reserves, rates of production, net present value of future cash flows and the timing of development expenditures depend upon several variables and assumptions, including the following: (i) historical production from the area compared with production from other comparable producing areas; (ii) interpretation of geological and geophysical data; (iii) effects of regulations adopted by governmental agencies; (iv) future percentages of international sales; (v) future oil and gas prices; (vi) capital expenditure; and (vii) future operating costs, tax on the extraction of commercial minerals, development costs and workover and remedial costs. The assumptions upon which the estimates of Petroceltic's and Melrose's hydrocarbon reserves, resources or production profiles have been based may change over time or prove to be incorrect. Petroceltic and Melrose, and, if the Merger becomes Effective, the Enlarged Group may be unable to recover and produce the estimated levels or quality of hydrocarbons set out in this document and if this proves to be the case, Petroceltic's and Melrose's, and, if the Merger becomes Effective, the Enlarged Group's business, prospects, financial condition or results of operations could be materially adversely affected.

2.4 As all reserves and resources estimates are subjective, each of the following items may differ materially from those assumed in estimating reserves and resources: (i) the quantities and qualities of oil and gas that are ultimately recovered; (ii) the production and operating costs and capital expenditure incurred; (iii) the amount and timing of additional exploration and future development expenditures; and (iv) future oil and gas prices.

2.5 Many of the factors, assumptions and variables used in estimating reserves and resources are beyond Petroceltic's and Melrose's control and may prove to be incorrect over time. Evaluations of reserves and resources necessarily involve multiple uncertainties. The accuracy of any reserves or resources evaluation depends on the quality of available information and petroleum engineering and geological interpretation. Exploration drilling, interpretation and testing and production after the date of the estimates may require substantial upward or downward revisions to Petroceltic's and Melrose's, and, if the Merger becomes Effective, the Enlarged Group's reserves or resources data. Moreover, different reservoir engineers may make different estimates of reserves and cash flows based on the same available data. Actual production, revenues and expenditures with respect to reserves and resources will vary from estimates, and the variances may be material. The estimation of reserves and resources may also change because of acquisitions and disposals, new discoveries and extensions of existing fields as well as the application of improved recovery techniques.

Oil and gas exploration is speculative, capital intensive and can result in a complete loss of capital

2.6 The risks associated with oil and gas exploration include, but are not limited to, encountering unusual or unexpected geological formations or pressures, seismic shifts, unexpected reservoir behaviour, unexpected or different fluids or fluid properties, premature decline of reservoirs, uncontrollable flow of oil, gas or well fluids, inaccurate subsurface seismic drilling, equipment failures, extended interruptions due to (amongst other things) adverse weather conditions, environmental hazards, industrial accidents, lack of availability of exploration and production equipment, explosions, pollution, oil or gas escapes, industrial action and shortages of manpower. Encountering any of these can greatly increase the cost of operations. Extreme weather, adverse geological conditions and other field operating conditions may delay drilling or appraisal activities and can also increase costs. Oil and gas exploration and appraisal projects often involve unprofitable activities, resulting either from dry wells or from wells that may be put into production but do not generate sufficient revenues to return a profit after development, operating and other costs. Completion of a well does not guarantee a profit on the investment or recovery of the costs associated with that well. Any of the above factors could result in a total loss of investment in certain projects, which could have a material adverse effect on Petroceltic's and Melrose's, and, if the Merger becomes Effective, the Enlarged Group's business, prospects, financial condition and results of operations.

Companies within the oil and gas industry may be exposed to commodity price fluctuations

2.7 Oil and gas prices are unstable and are subject to fluctuation. Any material decline in oil and/or gas prices could result in a reduction of Petroceltic's and Melrose's, and, if the Merger becomes Effective, the Enlarged Group's net production revenue and an impairment in the value of its assets. It may become uneconomic to produce from some wells as a result of lower prices, which could result in a reduction in the volumes and value of Petroceltic's and Melrose's, and, if the Merger becomes Effective, the Enlarged Group's reserves. Petroceltic and Melrose, and, if the Merger becomes Effective, the Enlarged Group, might also elect not to produce from certain wells at lower prices. All of these factors could result in a material decrease in Petroceltic's and Melrose's, and, if the Merger becomes Effective, the Enlarged Group's net production revenue. As such, fluctuations in oil and gas prices could materially and adversely affect Petroceltic's and Melrose's, and, if the Merger becomes Effective, the Enlarged Group's business, financial condition, results of operation and prospects resulting potentially in a reduction in its acquisition and development activities.

2.8 Volatility and uncertainties of the oil and gas industry continue to persist. Any discussion of price or demand is subjective and as such there are many differing opinions on the cause of recent price changes and on the outlook for the future prices.

2.9 The relatively high prices for oil, gas and other commodities may benefit the Enlarged Group in the short-term; however, there is no certainty as to how long these market conditions will last. Along with other oil and gas producers, Petroceltic and Melrose face, and, if the Merger becomes Effective, the Enlarged Group will face the potential that the demand and prices for oil and gas may fall, perhaps significantly, which may impact on future revenues received by Petroceltic and Melrose, and, if the Merger becomes Effective, the Enlarged Group, for oil and natural gas.

Companies within the oil and gas industry are reliant on the availability of equipment and are subject to access restrictions

2.10 Oil and gas exploration and development activities are dependent on the availability of drilling and related equipment in the particular areas where such activities will be conducted. Demand for such limited equipment or access restrictions may affect the availability of such equipment to Petroceltic and Melrose, and, if the Merger becomes Effective, the Enlarged Group and may delay exploration and development activities. There can be no assurance that sufficient drilling and completion equipment, services and supplies will be available when needed. Shortages could delay Petroceltic's and Melrose's, and, if the Merger becomes Effective, the Enlarged Group's proposed exploration, development, and sales activities and could have a material adverse effect on their financial condition. If the demand for, and wage rates of, qualified rig crews rise in the drilling industry then the oil and gas industry may experience shortages of qualified personnel to operate drilling rigs. This could delay Petroceltic's and Melrose's, and, if the Merger becomes Effective, the Enlarged Group's drilling operations and adversely affect financial condition and results of operations.

The oil and gas industry is sensitive to the cost of new technologies and technology transfer risk

2.11 The oil and gas industry is characterised by rapid and significant technological advancements and introductions of new products and services utilising new technologies. Other oil and gas companies may have greater financial, technical and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies either before Petroceltic and Melrose, and, if the Merger becomes Effective, the Enlarged Group does so or in circumstances where Petroceltic, Melrose, and, if the Merger becomes Effective, the Enlarged Group, are not able to do so. There can be no assurance that Petroceltic and Melrose, and, if the Merger becomes Effective, the Enlarged Group will be able to respond to such competitive pressures and implement such technologies on a timely basis or at an acceptable cost. One or more of the technologies currently utilised by Petroceltic and Melrose or implemented in the future by the Enlarged Group may become obsolete. If Petroceltic and Melrose, and, if the Merger becomes Effective, the Enlarged Group, are unable to utilise the most advanced commercially available technology, their respective business, financial condition, results of operations and prospects could be materially adversely affected.

Companies operating within the oil and gas industry are subject to stringent regulations including environmental, and health and safety

2.12 Petroceltic's, Melrose's and, if the Merger becomes Effective, the Enlarged Group's operations are subject to environmental, health and safety regulations in the jurisdictions in which they operate. Whilst both Petroceltic and Melrose believe that each carries out its activities and operations in material compliance with these environmental, safety and health and sanitary regulations, there can be no guarantee that their contractors or staff will individually comply with the policies and practices in place.

2.13 The discharge of oil, gas or other pollutants into the air, soil or water may give rise to liabilities to foreign governments and third parties and may require Petroceltic and Melrose, and, if the Merger becomes Effective, the Enlarged Group, to incur significant costs to remedy such discharge. No assurance can be given that changes in environmental laws or their application to Petroceltic and Melrose, and, if the Merger becomes Effective, the Enlarged Group's operations will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise adversely affect the Petroceltic and Melrose, or Enlarged Group, financial condition, results of operations or prospects. The obtaining of exploration, development or production licences and permits may become more difficult or be the subject of delay by reason of governmental, regional or local environmental consultation, approvals or other considerations or requirements. These factors may lead to delayed or reduced exploration, development or production activity in addition to increased costs.

Oil and gas exploration may cause damage to persons, property and the environment for which the Enlarged Group may not be adequately insured

2.14 Exploration for oil and gas carries inherent risks. Petroceltic's and Melrose's, and, if the Merger becomes Effective, the Enlarged Group's exploration, development and production activities present several risks such as those of explosions in wells and pipelines and escape of hazardous materials and contamination; major process safety incidents; failure to comply with approved policies; effects of natural disasters and pandemics; social unrest; civil war and terrorism; exposure to general operational hazards; personal health and safety; and crime. The occurrence of any of these events or other accidents could result in personal injuries, loss of life, severe environmental damage entailing containment, clean-up and repair expenses, equipment damage and civil proceedings against Petroceltic, Melrose or the Enlarged Group, any of which could result in material legal sanctions and financial liabilities, as well as significant reputational damage, and may have a material adverse effect on Petroceltic's, Melrose's and if the Merger becomes Effective, the Enlarged Group's business, prospects, financial condition or results of operations. Petroceltic's and Melrose's, and, if the Merger becomes Effective, the Enlarged Group's insurance policies may not cover all liabilities, and the proceeds of insurance applicable to covered risks may not be adequate to cover expenses relating to such losses or liabilities. Insurance may not be available for all risks. In certain circumstances, Petroceltic, Melrose or the Enlarged Group may elect not to obtain insurance to deal with specific events due to the high premiums associated with such insurance or for other reasons.

Labour disputes would result in interruption or shutdowns which could have a material adverse effect on the Enlarged Group's operations

2.15 Petroceltic's and Melrose's, and, if the Merger becomes Effective, the Enlarged Group's contractors or service providers may be limited in their flexibility in dealing with their staff due to the presence of staff associations among their staff. If there is a material disagreement between contractors or service providers and their staff belonging to staff associations, Petroceltic's and Melrose's, or the Enlarged Group's operations could suffer an interruption or shutdown that could have a material adverse effect on business, results of operations or financial condition.

3. RISKS RELATING TO THE MERGER

There are risks that the Merger will not be implemented on a timely basis or at all

3.1 Implementation of the Merger is conditional upon, among other things: (i) approval of the Merger at the Melrose Court Meeting and Melrose General Meeting; and (ii) approval of the Ordinary Resolutions at the Extraordinary General Meeting. There are risks that the conditions of the Merger will not be satisfied on a timely basis or at all. If such conditions are not satisfied, or, where applicable, not waived, the Merger will not be implemented, the benefits expected to result from the Merger will not be achieved and the market price of the Ordinary Shares and the Melrose Shares may be affected.

Implementation of the Merger is conditional upon receiving certain consents and regulatory approvals

3.2 Implementation of the Merger is also conditional upon receiving certain consents, clearances and regulatory approvals including clearance from the Bulgarian Commission for Protection of Competition. A substantial delay in obtaining satisfactory clearance or approvals or the imposition of unfavourable terms or conditions in the clearance or regulatory approvals could adversely affect the business, financial condition or results of operations of Petroceltic, Melrose or, if the Merger becomes Effective, the Enlarged Group.

The Readmission may not occur when expected

3.3 As the Merger is classified as a reverse takeover for the purpose of the AIM Rules and ESM Rules, the admission to trading of the Existing Petroceltic Shares on AIM and ESM will be cancelled upon the Merger becoming Effective and applications will be made for the immediate admission to trading of the Enlarged Company Shares on AIM and ESM. There is no assurance that such Readmission will take place when anticipated.

Part V (Expected Timetable of Principal Events) of this document contains further information on the expected dates of these events.

The Merger will have a dilutive effect on proportionate shareholdings

3.4 On the Merger becoming Effective, Petroceltic Shareholders will experience dilution in their proportionate ownership and voting interest in the Enlarged Group as compared to their proportionate ownership and voting interest in Petroceltic as a result of the issuance by Petroceltic of New Petroceltic Shares to Melrose Shareholders in consideration for the Merger.

Implementation of the Merger will result in entry into new business activities for Petroceltic and Melrose

3.5 Implementation of the Merger will result in a combination of the current business activities currently carried on by each of Petroceltic and Melrose as separate entities. The combination of these activities will expose holders of Existing Petroceltic Shares and holders of Melrose Shares to different business risks than those to which they were exposed prior to the Merger. In particular, holders of Existing Petroceltic Shares will gain exposure to the risks inherent in the Melrose Group's operations in Egypt, Bulgaria, Romania and Turkey and holders of Melrose Shares will gain exposure to the risks inherent in the Petroceltic Group's operations in Algeria, Italy and in the Kurdistan Region of Iraq.

If the Merger becomes Effective, the Enlarged Group may experience difficulties in integrating the existing businesses carried on by Petroceltic and Melrose

3.6 Petroceltic and Melrose currently operate and, until the Merger becomes Effective, will continue to operate, as two separate and independent businesses. The Merger will lead to the integration of these two businesses and the success of the Enlarged Group will depend, in part, on the effectiveness of the integration process and the ability of the Enlarged Group and the Enlarged Company Directors to realise the anticipated advantages from combining the respective businesses. The integration of the assets of Melrose and Petroceltic requires the dedication of substantial management effort, time and resources which may divert management's focus and resources from other strategic opportunities and from operational matters during this process. The integration process may result in the loss of key employees and the disruption of ongoing business and employee relationships that may adversely affect the Enlarged Group's ability to achieve the anticipated advantages of the Merger. Moreover, some of the potential challenges in combining the businesses may not become known until after the Merger becomes Effective, in particular due to the substantial increase in the scale of the combined operations and the number of jurisdictions in which it would operate.

3.7 The geographical spread of Petroceltic's and Melrose's and, if the Merger becomes Effective, the Enlarged Group's operations may make it more difficult to implement and impress upon local workforces the Enlarged Group's policies on matters such as health and safety and can present challenges in the supervision of sub-contracted employees.

3.8 Uncertainty about the effects of the Merger, including effects on employees, partners, contractors, regulators and customers may adversely affect the business and operations of Petroceltic and Melrose. These uncertainties could cause customers, business partners, regulators and other parties that have business relationships with Petroceltic and Melrose to defer the consummation of other transactions or other decisions concerning those businesses, or to seek to change existing business relationships.

Petroceltic's and Melrose's and, if the Merger becomes Effective, the Enlarged Group's Merger related costs may exceed its expectations

3.9 Petroceltic's and Melrose's and, if the Merger becomes Effective, the Enlarged Group's Merger related costs may exceed expectations. The Enlarged Group expects to incur a number of costs in relation to the Merger, including integration and post-Effective Date costs in order to successfully combine the operations of Petroceltic and Melrose. The actual costs of the integration process may exceed those estimated and there may be further additional and unforeseen expenses incurred in connection with the Merger. In addition, Petroceltic and Melrose will incur legal, accounting, transaction fees and other costs relating to the Merger, some of which are payable whether or not the Merger becomes Effective.

4. RISKS RELATING TO THE ENLARGED COMPANY SHARES

The value of the Enlarged Company Shares may fluctuate

4.1 If the Merger becomes Effective, the value of the Enlarged Company Shares could fluctuate significantly.

4.2 The value of the Enlarged Company Shares may, in addition to being affected by the Enlarged Group's actual or forecast operating results, fluctuate significantly as a result of a large number of factors, some specific to the Enlarged Group and its operations and some which may affect oil and gas companies generally and which are outside the Enlarged Group's control, including, inter alia:

a) the results of exploration, development and appraisal programmes and production operations;

b) changes in the financial performance of the Enlarged Group, its peers or the industry;

c) changes in laws, rules and regulations applicable to the Enlarged Group and its operations;

d) general economic, political and other conditions, in particular, in Algeria, Italy, the Kurdistan Region of Iraq, Egypt, Bulgaria, Romania and Turkey;

e) fluctuations in the prices of oil, gas and other petroleum products; and

f) fluctuations in the capital markets.

The Enlarged Company Shares may be unsuitable as an investment

4.3 The Enlarged Company Shares may not be a suitable investment for all recipients of this document. Before making a final decision, investors are advised to consult an appropriate independent investment adviser authorised under FSMA if they are in the UK, under the European Communities (Markets in Financial Instruments) Regulations 2007 (Nos 1 to 3) or the Investment Intermediaries Act 1995 (as amended) if they are in Ireland, or if they are not in the UK or Ireland, another appropriately authorised financial adviser who specialises in advising on acquisitions of shares and other securities. The value of the Enlarged Company Shares and the income received from them can go down as well as up and investors may not recover all or any part of their original investment.

Melrose Shareholders are moving from a more regulated market to a less regulated market

4.4 The ordinary shares of Melrose are currently listed on the Official List of the UKLA and admitted to trading on the main market of the London Stock Exchange. Following completion of the Merger, the Enlarged Company Shares will be admitted to trading on AIM and ESM. Existing Melrose Shareholders and prospective Enlarged Company Shareholders should note that the AIM Rules and ESM Rules are less demanding than those of the Official Lists, and that the AIM and ESM regulatory regimes are less onerous than the Official List. No applications are currently being made for admission of the Enlarged Company Shares to the Official List.

The Enlarged Group may be unable to transition to a Premium Listing following the Merger

4.5 Following the Merger becoming Effective, and subject to: (i) satisfying eligibility criteria; (ii) obtaining any necessary approvals; and (iii) market and trading conditions; it is intended that the Enlarged Company will make an application within twelve months following completion of the Merger to obtain a Premium Listing and will also consider seeking a listing in Ireland on the ISE. There can be no guarantee that the Enlarged Company will meet such eligibility criteria or that a transition to a Premium Listing will be achieved. If the Enlarged Company does not achieve a Premium Listing, the Enlarged Company may not comply with the higher standards of corporate governance or other requirements which it would be subject to upon achieving a Premium Listing. Furthermore, investors in the Enlarged Group may not benefit from the enhanced liquidity and broader shareholder base which can accompany a Premium Listing.

Investors may not be able to realise returns on their investment in the Enlarged Company Shares within a period that they would consider to be reasonable

4.6 There can be no assurance that an active or liquid trading market for the Enlarged Company Shares will develop or, if developed, that it will be maintained. 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. Accordingly, AIM/ESM may not provide the liquidity normally associated with the Official List or some other stock exchanges. The Enlarged Company Shares may therefore be difficult to sell compared to the shares of companies listed on the Official List, and the share price may be subject to greater fluctuations than might otherwise be the case.

The Enlarged Company will principally aim to achieve capital growth and, at present, the intended dividend policy for the Enlarged Company will be that all funds available for distribution should be reinvested in the business of the Enlarged Group. There can be no assurance as to the level of future dividends. The declaration, payment and amount of any future dividends of the Enlarged Company are subject to the discretion of the Enlarged Company Board, and will depend on, among other things, the Enlarged Company's earnings, financial position, cash requirements and availability of profits. A dividend may never be paid and at present, there is no intention to pay a dividend.

The share prices of publicly quoted companies can be highly volatile and shareholdings illiquid. The price at which the Enlarged Company Shares are quoted and the price which investors may realise for their Enlarged Company Shares may be influenced by a large number of factors, some of which are general or market specific, others which are sector specific and others which are specific to the Enlarged Group and its operations. These factors include, without limitation, the performance of the Enlarged Group and the overall stock market, large purchases or sales of Enlarged Company Shares by other investors, changes in legislation or regulations and changes in general economic, political or regulatory conditions and other factors which are outside of the control of the Enlarged Group.

Shareholders may be exposed to fluctuations in currency exchange rates

4.7 The Enlarged Company Shares are priced in Euro and will be quoted and traded in Stg pence on AIM and Euro on ESM. An investment in the Enlarged Company Shares by an investor whose principal currency is not Sterling or Euro will expose the investor to foreign currency exchange rate risk. Any depreciation of Sterling or Euro in relation to such foreign currency will reduce the value of an investment in the Enlarged Company Shares in foreign currency terms.

The ability of non-EU shareholders to bring actions or enforce judgements against the Enlarged Group or the Enlarged Company Directors may be limited

4.8 The ability of an overseas shareholder to bring an action against Petroceltic may be limited under law. Petroceltic is a public limited company incorporated in Ireland. The rights of holders of Ordinary Shares are governed by the laws of Ireland and by Petroceltic's Memorandum and Articles of Association.

These rights may differ from the rights of shareholders in corporations incorporated in other jurisdictions. All of the Enlarged Company Directors are residents of Ireland or the United Kingdom. Consequently, it may not be possible for a non-EU shareholder to effect service of process within the overseas shareholder's country of residence upon either the Enlarged Company or the Enlarged Company Directors, or to enforce a judgement obtained in a court of the overseas shareholder's country of residence against either the Enlarged Company or the Enlarged Company Directors.

The information contained in Part XI of this document relating to taxation may be subject to legislative change

4.9 The information contained in Part XI of this document relating to taxation is not exhaustive and only addresses certain limited aspects of taxation for shareholders in the UK and Ireland. The information contained in Part XI of this document relating to taxation may be subject to legislative change which could affect the value of the Enlarged Company Shares or investments held by the Enlarged Group or affect the Enlarged Group's ability to provide returns to and/or alter the post-tax returns to shareholders. Shareholders who are in any doubt as to their tax position in any jurisdiction should consult their own independent tax advisers.

The Enlarged Group's largest Shareholder, Skye, will, following the Merger, be in a position to be able to exercise influence over the affairs of the Enlarged Group. The interests of Skye may differ from those of other shareholders

4.10 As at the Latest Practicable Date, 57,391,423 Melrose Shares, representing approximately 50.04 per cent of total Melrose Shares were held by Skye. Following the Merger, 1,010,089,045 Enlarged Company Shares representing approximately 23.02 per cent of the Enlarged Company Shares will be held by Skye. This concentration of ownership may have the effect of delaying, preventing or deterring a change in control of the Enlarged Company, depriving shareholders of an opportunity to receive a premium for their Enlarged Company Shares as part of any sale of the Enlarged Group, and affecting the market price of the Enlarged Company Shares. In addition, Skye will be able to exercise significant influence over matters requiring Enlarged Company Shareholder approval, including the election of directors and significant corporate transactions. The interests of Skye may be different from, and conflict with, the interests of the Enlarged Group or the Enlarged Group's other shareholders. Differences between the interests of Skye and the other shareholders of the Enlarged Group may lead to conflicts or restrict the Enlarged Group's ability to implement its business strategy.

4.11 The Relationship Agreement between Petroceltic, Robert Adair and Skye, the key terms of which are described in paragraph 20.1.2 of Part XII, is intended to ensure that commercial transactions and relationships with Skye are conducted on an arm's length basis. The Relationship Agreement may not, however, contemplate all instances in which the interests of Skye and its shareholders differ from those of minority shareholders in the Enlarged Company. To the extent that Skye or its shareholders take actions not prohibited by the Relationship Agreement that favour their interests over those of other shareholders, the Enlarged Group's business, financial condition and results of operations, as well as the trading price of the Enlarged Company Shares, could be adversely affected. In the event of non-compliance by Skye with any provision of the Relationship Agreement, there may be difficulties for Petroceltic in seeking compliance.

PART III

GENERAL INFORMATION

1. FORWARD-LOOKING STATEMENTS

This document contains forward-looking statements regarding the financial conditions, results of operations, cash flows, dividends, financing plans, business strategies, operating efficiencies or synergies, budgets, capital and other expenditures, competitive positions, growth opportunities, plans and objectives of management and other matters relating to the Enlarged Group. Statements in this document that are not historical facts are hereby identified as "forward-looking statements".

In some instances, these forward-looking statements can be identified by the use of forward-looking terminology, including the terms "believes", "expects", "intends", "may", "will" or "should" or, in each case, their negative or other variations or comparable terminology. Save for those forward-looking statements required to be included in this document in accordance with the AIM Rules and ESM Rules, such forward-looking statements, including, without limitation, those relating to the future business prospects, revenues, liquidity, capital needs, interest costs and income, in each case relating to the Enlarged Group wherever they occur in this document, are necessarily based on assumptions reflecting the views of Petroceltic, involve a number of risks and uncertainties that could cause actual results to differ materially from those suggested by the forward-looking statements and speak only as at the date of this document.

Forward-looking statements may and often do differ materially from actual results. Any forward-looking statements in this document are based on certain factors and assumptions, including the Directors and the Proposed Directors' current view with respect to future events and are subject to risks relating to future events and other risks, uncertainties and assumptions relating to the Enlarged Group's operations, results of operations, growth strategy and liquidity. Whilst the Directors and the Proposed Directors consider these assumptions to be reasonable based upon information currently available, they may prove to be incorrect.

Important factors which may cause actual results to differ include, but are not limited to, those described in Part II "Risk Factors" of this document. Given these risks and uncertainties, prospective investors should not place any reliance on forward-looking statements.

Save as required by law or by the AIM Rules and ESM Rules, Petroceltic undertakes no obligation to release publicly the results of any revisions to any forward-looking statements in this document that may occur due to any change in the Directors and Proposed Directors' expectations or to reflect events or circumstances after the date of this document.

Forward-looking statements contained in this document do not in any way seek to qualify the working capital statement contained in paragraph 17 of Part XII (Additional Information) of this document.

2. MARKET AND INDUSTRY DATA

The data, statistics and information and other statements in this document regarding the markets in which the Enlarged Group operates, or the Enlarged Group's position therein, are based on the Enlarged Group's records or are taken or derived from statistical data and information derived from the sources described in this document.

The Directors and the Proposed Directors confirm that information sourced from a third party has been accurately reproduced, and as far as the Directors and the Proposed Directors are aware and are able to ascertain from information published by that third party, no facts have been omitted which would render the reproduced information inaccurate or misleading.

3. MINERAL RESERVE AND MINERAL RESOURCE REPORTING

Petroceltic Competent Person's Reports

Unless otherwise indicated, the Petroceltic Competent Persons have, in compiling the Petroceltic Competent Person's Reports contained in Appendix I, II and III to this document, used the definitions and guidelines set out in accordance with the 2007 Petroleum Resources Management System prepared by the Oil and Gas Resources Committee of the Society of Petroleum Council (details of which are set out in Appendix I, II and III to this document).

Investors should not place undue reliance on the forward-looking statements in the Petroceltic Competent Person's Reports or on the ability of the Petroceltic Competent Person's Reports to predict actual reserves or resources. Contingent resources relate to undeveloped accumulations and may include non-commercial resources. It should be noted that prospective resources relate to inferred, undiscovered and/or undeveloped mineral resources and accordingly by their nature are highly speculative. A possibility exists that the prospects will not result in the successful discovery of economic resources in which case there would be no commercial development.

The information on resources in this document and the Petroceltic Competent Person's Reports is based on economic and other assumptions that may prove to be incorrect. The basis of preparation for the Petroceltic Competent Person's Reports is set out in more detail in such Competent Person's Reports.

Melrose Competent Person's Report

Unless otherwise indicated, the Melrose Competent Person has, in compiling the Melrose Competent Person's Report contained in Appendix IV to this document used, the definitions and guidelines set out accordance with the 2007 Petroleum Resources Management System prepared by the Oil and Gas Resources Committee of the Society of Petroleum Council (details of which are set out in Appendix IV to this document).

Investors should not place undue reliance on the forward-looking statements in the Melrose Competent Person's Report or on the ability of the Melrose Competent Person's Report to predict actual reserves or resources. It should be noted that prospective resources relate to inferred, undiscovered and/or undeveloped mineral resources and accordingly by their nature are highly speculative. A possibility exists that the prospects will not result in the successful discovery of economic resources in which case there would be no commercial development.

The information on resources in this document and the Melrose Competent Person's Report is based on economic and other assumptions that may prove to be incorrect. The basis of preparation for the Melrose Competent Person's Reports is set out in more detail in such Competent Person's Report.

4. SOURCES AND PRESENTATION OF FINANCIAL INFORMATION

Unless otherwise indicated, historical financial information relating to Petroceltic (such as turnover and operating profit) for the years ended 31 December 2011, 31 December 2010 and 31 December 2009 has been extracted without material adjustment from the financial information in Part IX (which has been prepared in accordance with IFRS as adopted by the EU).

Unless otherwise indicated, historical financial information relating to Melrose (such as turnover and operating profit) for the years ended 31 December 2011, 31 December 2010 and 31 December 2009 has been extracted without material adjustment from the financial information in Part X (which has been prepared in accordance with IFRS as adopted by the EU).

5. CURRENCY PRESENTATION

Unless otherwise indicated, all references in this document to "sterling", "pound Sterling", "GBP", "Stg", "£", "pence" or "p" are to the lawful currency of the United Kingdom; references to "Euro" or "€" are to the official currency of the Eurozone; and references to "US dollars", "USD" or "US$" are to the lawful currency of the US.

The basis for conversion of foreign currency for the purpose of inclusion of the financial information set out in Parts IX and X of this document is described in those Parts.

6. TIME OF DAY

Unless otherwise indicated, all references in this document to time of day are references to the time in Dublin and London.

7. PERCENTAGES

Percentages in tables have been rounded and accordingly may not add up to 100 per cent. Certain financial data has been rounded. As a result of this rounding, the totals of data presented in this document may vary slightly from the actual arithmetic totals of such data.

8. DEFINITIONS

Certain terms used in this document, including capitalised terms and certain technical terms, are defined and explained in Part XIII: "Definitions" and Part XIV: "Glossary of Technical Terms and Abbreviations".

PART IV

DIRECTORS, PROPOSED DIRECTORS, COMPANY SECRETARY, REGISTERED OFFICE AND ADVISERS

Directors	Robert Arnott – *Non-Executive Chairman* Brian O'Cathain – *Chief Executive* Tom Hickey – *Corporate Development Director* Andrew Bostock – *Senior Non-Executive Director* Con Casey – *Non-Executive Director* Hugh McCutcheon – *Non-Executive Director*
Proposed Directors	Robert F M Adair – *Non-Executive Director* David H Thomas – *Chief Operating Officer* James D Agnew – *Senior Independent Director* Alan J Parsley – *Non-Executive Director*
Company Secretary	Peter Dunne
Registered Office of Petroceltic and Directors' Business Address	6th Floor 75 St. Stephen's Green Dublin 2 Ireland
Registered Office of Melrose	No. 1 Portland Place London W1B 1PN United Kingdom
Registered Office of Enlarged Company and Enlarged Company Directors' Business Address	6th Floor 75 St. Stephen's Green Dublin 2 Ireland
Nominated Adviser, ESM Adviser and Broker	Davy Davy House 49 Dawson Street Dublin 2 Ireland
Financial Adviser to Petroceltic	Merrill Lynch International Merrill Lynch Financial Center 2 King Edward Street London EC1A 1HQ United Kingdom
Financial Advisers to Melrose	Lambert Energy Advisory Limited 17 Hill Street London W1J 5LJ United Kingdom Nplus1 Brewin LLC 7 Drumsheugh Gardens Edinburgh EH3 7QH United Kingdom HSBC Bank plc 8 Canada Square London E14 5HQ United Kingdom

English Legal Advisers to Petroceltic	Herbert Smith LLP Exchange House Primrose Street London EC2A 2HS United Kingdom
Irish Legal Advisers to Petroceltic	McCann FitzGerald Riverside One Sir John Rogerson's Quay Dublin 2 Ireland
Algerian Legal Advisers to Petroceltic	Thompson & Knight LLP Residence PTT, Villa 45 A Hydra 16035, Algiers Algeria
Italian Legal Advisers to Petroceltic	Studio Legale Trotta Piazza della Libertà, 10 00192, Rome Italy
Kurdistan Region of Iraq Legal Advisers to Petroceltic	Nuri Yaba Law Office English Village Villa No. 405 Erbil Kurdistan Region of Iraq
British Virgin Islands (BVI) Legal Advisers to Petroceltic	Ogier LLP 41 Lothbury London EC2R 7HF United Kingdom
English Legal Advisers to Melrose	DLA Piper UK LLP 3 Noble Street London EC2V 7EE United Kingdom
Scottish Legal Advisers to Melrose	Tods Murray LLP Edinburgh Quay 133 Fountainbridge Edinburgh EH3 9AG United Kingdom
Egyptian Legal Advisers to Melrose	DLA Matouk Bassiouny 12 Mohamed Ali Genah Street Garden City Cairo Egypt
Bulgarian Legal Advisers to Melrose	Spasov & Bratanov Lawyers' Partnership Office Center "Slavyanska", Floor 2 29A Slavyanska Street Sofia 1000 Bulgaria

Turkish Legal Advisers to Melrose	Şengülar and Şengülar Cumhuriyet Cad. No: 25 Çınar Apt. Kat. 4 Taksim 34437 Istanbul Turkey
Romanian Legal Advisers to Melrose	CMS Cameron McKenna SCA S-Park 11-15, Tipografilor Street B3-B4, 4th Floor District 1 013714 Bucharest, Romania
Dutch Legal Advisers to Melrose	DLA Piper Nederland N.V. Amstelveenseweg 638 PO Box 75258 1070 AG Amsterdam Netherlands
Bermudan Legal Advisers to Melrose	Conyers Dill & Pearman Limited Clarendon House, 2 Church Street PO BOX HM 666 Hamilton HM CX Bermuda
Cayman Islands Legal Advisers to Melrose	Campbells PO Box 884 Grand Cayman, KY1 1103 Cayman Islands
Luxembourg Legal Advisers to Melrose	Wildgen 69, Bld. de la Pétrusse L-2320 Luxembourg
Auditors of Petroceltic	KPMG 1 Stokes Place St. Stephen's Green Dublin 2 Ireland
Auditors of Melrose	KPMG Audit Plc Saltire Court 20 Castle Terrace Edinburgh EH1 2EG United Kingdom
Registrars to Petroceltic	Computershare Investor Services (Ireland) Limited Heron House Corrig Road Sandyford Industrial Estate Dublin 18 Ireland
Registrars to Melrose	Share Registrars Limited 9 Lion and Lamb Yard Farnham Surrey GU9 7LL United Kingdom

Competent Person as to Kurdistan Region of Iraq and Italian assets	DeGolyer and MacNaughton 5001 Spring Valley Road Suite 800 East Dallas Texas, 75244 United States
Competent Person as to Algerian and the BR.268.RG (the Elsa Discovery) assets	AGR Petroleum (ME) Ltd 802 Saba Tower 1 PO Box 346097 Jumeirah Lakes Towers, Dubai UAE
Competent Person as to Egyptian and Bulgarian assets	Senergy (GB) Limited 39 Charing Cross Road London WC2H 0AR United Kingdom
Company website	www.petroceltic.ie

PART V

EXPECTED TIMETABLE OF PRINCIPAL EVENTS

All references to time in this document and in the expected timetable are to the time in Dublin, Ireland and 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.

		Time and/or date[(1)]
Petroceltic and Melrose joint announcement of the Merger		17 August 2012
Publication of the Admission Document		17 August 2012
Posting of the Admission Document and Scheme Circular		24 August 2012
Latest time and date for receipt of Melrose Forms of Proxy for the Melrose Court Meeting	*3.00 pm*	18 September 2012 [(2)]
Latest time and date for receipt of Melrose Forms of Proxy for the Melrose General Meeting	*3.20 pm*	18 September 2012 [(2)]
Latest time and date for receipt of Forms of Proxy for the Petroceltic Extraordinary General Meeting	*12.30 pm*	18 September 2012 [(4)]
Scheme Voting Record Time for Melrose Court Meeting and Melrose General Meetings	*6.00 pm*	18 September 2012
Petroceltic Extraordinary General Meeting	*12.30 pm*	20 September 2012
Melrose Court Meeting	*3.00 pm*	20 September 2012
Melrose General Meeting	*3.20 pm*	20 September 2012 [(3)]
Suspension of listing and of dealings in, and time for registration of transfers of, and disablement in CREST of, Melrose Shares	*8.00 am*	8 October 2012 [(1)]
Reduction Record Time	*6.00 pm*	8 October 2012 [(1)]
Melrose Court Hearing to sanction the Scheme and to confirm the Reduction of Capital		9 October 2012
Effective Date of the Scheme		10 October 2012 [(1)]
De-listing of Melrose Shares from the main market of the London Stock Exchange	*by 8.00 am*	11 October 2012 [(1)]
Readmission and dealings in the Enlarged Company Shares to commence on AIM and ESM and crediting of New Petroceltic Shares to CREST accounts	*8.00 am*	11 October 2012 [(1)]
Latest date for despatch of share certificates (where applicable) in respect of New Petroceltic Shares		by 24 October 2012 [(1)]

Notes:

(1) These dates are indicative only and will depend, among other things, on the date upon which the conditions of the Merger are satisfied or (if capable of waiver) waived and the dates upon which the Court sanctions the Scheme and confirms the Capital Reduction and the dates on which the Court Orders are delivered to the Registrar of Companies.

(2) Forms of Proxy for the Melrose General Meeting must be lodged not later than 48 hours prior to the time appointed for the Melrose General Meeting. The Forms of Proxy for the Melrose Court Meeting may be handed to the Chairman of the meeting at the start and still be valid.

(3) The Melrose General Meeting will commence at 2.20 pm or, if later, immediately after conclusion of the Melrose Court Meeting.

(4) Forms of Proxy for the Petroceltic Extraordinary General Meeting must be lodged not later than 48 hours prior to the time appointed for the Petroceltic Extraordinary General Meeting.

MERGER AND ADMISSION STATISTICS

Number of Existing Petroceltic Shares (as at 16 August 2012)	2,369,605,049
Number of New Petroceltic Shares expected to be issued pursuant to the Merger	2,018,529,533
Number of Enlarged Company Shares expected to be in issue upon completion of the Merger	4,388,134,582
Expected number of New Petroceltic Shares as a percentage of the Number of Enlarged Company Shares expected to be in issue upon the Merger becoming Effective	46.0 per cent
AIM Symbol	PCI.L
ESM Symbol	EG5
ISIN Code	IE0003186172

PART VI

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 BP Statistical Review of World Energy June 2012, the websites of International Energy Agency (IEA), Energy Information Administration (EIA), Organisation of the Petroleum Exporting Countries (OPEC), and Wood Mackenzie.

1. Oil and gas exploration and development in Algeria

1.1 Algeria contained an estimated 12.2 billion barrels of proved oil reserves at the end of 2011, the fourth largest in Africa (behind Libya, Nigeria and Angola). The hydrocarbons sector is the backbone of the economy, accounting for roughly 60 per cent of budget revenues, 30 per cent of GDP, and over 97 per cent of export earnings. According to the 2012 BP Statistical Energy Review, the country's oil production has reached 1.7 MMbopd and oil consumption has reached 0.3 MMbopd.

1.2 Algerian oilfields produce high quality light crude oils with very low sulphur and mineral contents. The main areas of exploration for oil and gas are in the east, on the border with Tunisia and Libya and in the central area where large gas discoveries have been made.

1.3 The Algerian government-owned company formed to exploit the hydrocarbon resources of the country is Sonatrach and it plays a key role in both upstream and downstream oil and gas industries. Sonatrach is responsible for exploration and production, transport, refining, processing, marketing and distribution. Through its subsidiaries, Sonatrach has a domestic monopoly on oil production, refining, and transportation. Sonatrach's holds some oil concessions 100 per cent in its own right, and has a number of joint ventures with foreign oil companies, where its interest levels vary. Since the new Hydrocarbon Law of 2005, Sonatrach usually holds a 51 per cent interest in concessions awarded after the date.

1.4 In December 2011, the Algerian energy minister announced that changes will be made to the country's Hydrocarbon Law to boost foreign companies' interest in exploration investments. The frequent delays involved in Algerian projects, stringent financial terms in favour of the Algerian state, and a windfall tax on foreign oil producers have discouraged international companies' interest in recent bidding rounds. In March 2011, Algeria awarded only 2 out of 10 oil and gas permits on offer in its latest licensing round. The winning bidders were Sonatrach and CEPSA.

1.5 Sonatrach operates the largest oil field in Algeria, Hassi Messaoud, located southeast of Algiers. It is reported to have produced around 350 Mbopd of crude oil in 2010, about 28 per cent of Algeria's total. Other important oil and gas fields operated by Sonatrach include Hassi R'mel, Tin Fouye Tabankort Ordo, Zarzaitine, Haoud Berkaoui/Ben Kahla, and Ait Kheir.

1.6 Algeria is taking steps toward maintaining its oil production capacity by developing new oilfields to compensate for the decline in older fields. Some of the new capacity would replace declines in older fields, as the country's long-term target is to sustain crude oil production capacity at its current level. Foreign oil operators have steadily increased their share of Algeria's oil production. The largest foreign oil producers operating in Algeria are Anadarko Petroleum Corporation, ENI, BG Group plc, BP plc, CEPSA, ConocoPhillips, Gazprom OAO, Repsol S.A., E.ON Ruhrgas, Royal Dutch Shell plc, Statoil ASA and Total S.A.

1.7 The country uses seven coastal terminals to export crude oil, refined products, LPG, NGL and LNG. These facilities are located at Arzew, Skikda, Algiers, Annaba, Oran, Bejaia, and La Skhirra in Tunisia. Arzew handles about 40 per cent of Algeria's total hydrocarbon exports.

1.8 Sonatrach operates over 3,900 kilometres of crude oil pipelines in the country. The most important pipelines carry crude oil from the Hassi Messaoud field to export terminals. Sonatrach also operates oil condensate and LPG pipeline networks that link Hassi R'mel and other fields to Arzew. Sonatrach has expanded the Hassi Messaoud-Arzew pipeline, the longest in the country, to include a second, parallel line that more than doubles the capacity of the existing line.

1.9 In 2011, Algeria's estimated crude oil exports were 750 Mbopd, of which the largest portion went to North America, mainly to the United States of America.

1.10 Algeria is also an important exporter of natural gas. According to the 2012 BP Statistical Energy Review, in 2011 Algeria had proved natural gas reserves of 4.5 Tcm, which is 2.2 per cent of the world total. Algeria's 2011 natural gas production was of 78 Bcm and natural gas consumption was 28 Bcm.

1.11 Algeria's largest natural gas field is Hassi R'Mel, discovered in 1956. Located in the eastern part of the country, it holds proved reserves of about 85 Tcf. The remainder of Algeria's natural gas reserves come from associated (i.e. they occur alongside crude oil reserves) and non-associated fields in the south and southeast regions of the country.

1.12 Sonatrach dominates natural gas production and wholesale distribution in Algeria, while state-owned Sonelgaz controls retail distribution. Algeria has increasingly allowed greater foreign investment in the sector, and foreign gas producers, including BHP Billiton plc, BP plc, ENI, Repsol S.A., Statoil ASA and Total S.A., have entered into partnership agreements with Sonatrach.

1.13 In addition to its upstream strength, Algeria has a strong downstream sector that includes refining, distribution and marketing, petrochemicals and lubricants. Algeria's four refineries meet most of its domestic requirements but capacity under-utilisation has meant that it still has to rely on imported refined products to meet its demand.

2. Oil and gas exploration and development in Italy

2.1 According to the 2012 BP Statistical Energy Review, Italy had proved oil reserves of 1.4 billion barrels at the end of 2011 or 0.1 per cent of the world's reserves. Italy produced an average of 1.1 MMbopd of crude oil in 2011, 0.1 per cent of the world total and an increase of 3.9 per cent compared to 2010. New upstream discoveries remain limited and it is anticipated that Italy's reserves will progressively decline in coming years. Italy's total domestic hydrocarbon production currently meets less than 10 per cent of the country's needs.

2.2 Italy is among Europe's largest energy consumers. Italian oil demand is increasingly concentrated in the transportation sector. In 2011, Italy consumed an average of 1.5 MMbopd, 1.8 per cent of the world's total and a drop from 2010 of 2.7 per cent.

2.3 Italy is highly dependent on external sources for its oil supply, importing over 90 per cent of its oil needs. While oil supply sources are diversified over some 30 different countries, Libya and Russia are the dominant sources of oil, each accounting for almost a quarter of all Italian crude oil imports. Saudi Arabia, Iraq and Iran together represent an additional quarter of oil imports.

2.4 The Italian oil market is fully open. Imports, exports, trade and prices are free. The government intervenes only to protect competition and to avoid abuse of dominant positions.

2.5 ENI has a dominant position in the Italian upstream oil and gas sector, although a number of private Italian and foreign companies have established a significant presence, such as Royal Dutch Shell plc, Total S.A., Edison Oil Company and Enel S.p.A.. Such non-OECD companies as Tamoil Italia S.p.A. (Libya), Kuwait Petroleum Italia S.p.A. (Kuwait) and NK Lukoil OAO (Russia) have refining and marketing operations in Italy.

2.6 Italy plays an important role as Europe's largest refining centre, and is a net exporter of refined products, providing finished products to other countries. According to the 2012 BP Statistical Energy Review, Italy had a 2011 refinery capacity of 2.3MMbopd, 2.5 per cent of the world total. There are 16 major refineries operating in Italy, 12 of which are located along the coast and are supplied by sea. The other four are situated in the Po Valley, in the north of Italy, and are supplied by pipelines from Genoa, Venice and Vado Ligure. Total crude oil refining capacity stands at around 100 million tonnes annually.

2.7 Italy has 16 crude oil tanker ports, four of which (Taranto, Milazzo, Falconara and Augusta) can receive cargo ships of up to 300 DWT. As most refineries are along the Mediterranean coast, there are relatively few crude oil pipelines in Italy.

2.8 There are two major crude oil pipelines: the Central European Line (CEL) from Genoa (1 MMbopd capacity), which supplies inland refineries in northern Italy and the Swiss refinery of Collombey; and the Trans-Alpine Pipeline (TAL) from Trieste, which supplies Germany, Austria and the Czech Republic. The trunk line, from Trieste to Ingolstadt (TAL-IG), has a capacity of 850 Mbopd. There is no connection between the eastern and western halves of the northern pipeline network, raising concerns of accessibility during a supply disruption.

2.9 In April 2007, the European Commission and representatives of seven European governments signed an agreement to begin construction of the Pan-European Pipeline (also known as the Constanta-Trieste Pipeline), which would link Constanta, Romania with Trieste, Italy, allowing crude oil from the Black Sea region to bypass the congested Bosporus Straits. It will be over 1,300 kilometres long, with a transport capacity of more than 1.2 MMbopd of crude oil.

2.10 Around two-thirds of Italy's gas reserves are located off-shore. In 2011, Italy had proved natural gas reserves of 0.1 Tcm and natural gas production of 7.7 Bcm, 0.2 per cent of the world's total. During the same period, Italy consumed 71.3 Bcm of natural gas, 2.2 per cent of the world's total.

2.11 Demand for natural gas in Italy has grown rapidly over the last decades, notably as part of a national programme to alleviate the country's dependence on oil imports. This growth is almost entirely attributable to the increase in demand for power generation. Power generation accounts for almost 40 per cent of total gas demand in Italy. The residential and commercial sector is the second biggest source of demand growth for natural gas.

2.12 Import dependency for natural gas is very high, standing at around 91 per cent in 2011. Algeria and Russia account for two-thirds of Italy's imports. There are seven delivery points for imported natural gas in Italy: five are gas pipelines (Mazara, Gela, Tarvisio, Passo Gries and Gorizia) and two are LNG terminals. Two pipeline entry points (Tarvisio and Mazara) account for almost two-thirds of Italy's gas imports. Italy's biggest entry point is the TAG pipeline interconnection through Tarvisio in the North-East of the country (maximum capacity of 4.99 Mcmh).

2.13 Italy has two LNG regasification terminals in operation: at Panigaglia in Liguria and the North Adriatic Sea off-shore terminal near Rovigo, which began operations in 2009. A third LNG regasification terminal at Livorno in Tuscany is currently under construction.

2.14 Gas storage infrastructure plays an important part in the Italian gas market. Storage is filled in the low-demand summer months and emptied during the peak-demand winter months. Ten storage facilities operate in Italy, totalling about 9 Bcm of commercial working capacity.

2.15 In the summer of 2010, the Italian Government passed the 2010 Decree imposing a moratorium on offshore oil and gas exploration close to the coast and/or any natural reserves in response to BP's disaster in the Gulf of Mexico in April 2010. In June 2012, the 2012 Decree was passed pursuant to which the 2010 Decree would no longer apply to i) applications for any titles that were under review at the time the 2010 Decree came into force, and any connected or subsequent proceedings; ii) any titles, including exploration licenses that had already been issued prior to the 2010 Decree coming into force; and iii) any proceedings connected with or subsequent to such titles, including possible extensions of the same. The 2012 Decree was ratified by the Italian parliament on 3 August 2012. It is believed that the new law could lead to at least €15 billion in investments as Italy intends to double output from its own oil and gas resources, which currently account for some 10 per cent of national needs.

3. Oil and gas exploration and development in the Kurdistan Region of Iraq

3.1 The Kurdistan Region of Iraq is a semi-autonomous, federally recognised, political region in the Republic of Iraq with its own national flag, army and border control. The Iraqi Constitution granted the Kurdistan Region of Iraq executive, legislative and judicial powers, as well as authority over the region's administrative requirements. Broadly, under the Iraqi Constitution, the National Federal Government of Iraq (the "**Iraq Government**") has exclusive competency over certain matters, the KRG has joint competency with the Iraqi Government over certain matters and the KRG has sole competency over all matters that are not either exclusively reserved to the Iraq Government or the subject of joint competency between the Iraq Government and the KRG.

3.2 In August 2007, the KRG enacted the Kurdistan Oil Law asserting the jurisdiction of the KRG over oil and gas resources in the Kurdistan Region of Iraq, signed oil production sharing, development and exploration contracts with several foreign firms and began exporting its own oil. The Kurdistan Oil Law and the PSC's granted by the KRG were subsequently disputed by the Iraqi Oil Minister. The KRG ceased oil exports after four months in 2009. Exports subsequently resumed in February 2011, only to be halted again in April 2012. In early August 2012, the KRG resumed with the warning that they will be halted if no payments were received by contractors by the end of the month.

3.3 The acceptance of the jurisdiction of the KRG over the oil and gas industry in the Kurdistan Region of Iraq is increasing within international oil companies, with the recent entry of Total S.A., Exxon Mobil Corporation and Chevron Corporation, in addition to other large international oil and gas companies such as Talisman Energy Limited, Hess Corporation, Marathon Oil Corporation and Murphy Oil Corporation. Nevertheless certain elements within the Iraq Government continue to question the validity of this jurisdiction of the KRG on oil policy. Furthermore, in the current global economic climate and the political climate within Iraq, the Kurdistan Region of Iraq's high dependency on the oil industry makes its economy vulnerable to fluctuations in the oil price.

3.4 The Kurdistan Region of Iraq represents highly prospective but still under-explored acreage adjacent to one of the most prospective oil exploration areas in the Middle East. Licensing and drilling activity have only taken off since the enactment of the Kurdistan Oil Law in 2007 and activity is moving at a rapid pace with several major discoveries already made.

3.5 According to the 2012 BP Statistical Energy Review, Iraq holds the world's fifth largest proved oil reserves of 143.1 billion barrels (after Venezuela, Saudi Arabia, Canada and Iran) and 3.6 Tcm of proved reserves of gas. The US Geological Survey estimates that the Kurdistan Region of Iraq holds as yet undiscovered hydrocarbons of approximately 40 billion barrels of oil and 1.8 Tcm of gas.

3.6 The first international oil and gas companies to enter the Kurdistan Region of Iraq following the Iraq war in 2003 were Genel Energy plc, DNO International ASA, Addax Petroleum and WesternZagros Resources Limited. All signed exploration contracts with the KRG between 2004 and 2007 before the enactment of the Kurdistan Oil Law.

3.7 The next post-war phase in the development of oil and gas in the Kurdistan Region of Iraq followed the enactment of the Kurdistan Oil Law, when seven new PSCs were issued, with OMV Group, MOL Hungarian Oil and Gas Plc, Gulf Keystone Petroleum Ltd., Heritage Oil and Reliance Industries Limited taking the bulk of the exploration acreage. Over the last few years over 40 small and medium sized international oil companies have been awarded PSCs in the Kurdistan Region of Iraq including Marathon Oil Corporation, Murphy Oil Corporation, Talisman Energy Inc., Sterling Energy plc, Korean National Oil Corporation, Sinopec International Petroleum Exploration and Production Corporation, Longford Energy Inc, ShaMaran Petroleum Corporation, Oil Search Limited and Dana Gas PJSC. More recently, large international oil companies, including Total S.A., Exxon Mobil Corporation, Chevron Corporation, Hess Corporation, Repsol S.A. and Maersk Oil (Part of the A.P. Moller – Maersk Group) have acquired positions.

3.8 The Iraqi Oil Minister has historically disputed the validity of PSCs entered into with the KRG. The dispute has halted progress in the region. Exports from certain fields were suspended in 2009, but then were resumed in February 2011 after the January 2011 meeting between the KRG and the Iraq Government. The agreement between the two governments on resumption of exports and the first advance payments by the Iraq Government to the KRG in May 2011 provide a more stable outlook for contractors in the Kurdistan Region of Iraq. Nevertheless, there can be no assurance that the Iraq Oil Ministry will not continue to challenge the validity of the PSCs granted by the KRG or that the Iraq Oil Ministry and the KRG will not agree, as part of negotiations on the new oil and gas law, contractor entitlements which are less favourable to those set out in the PSCs.

3.9 The Kurdistan Region of Iraq is connected to international markets via the main Kirkuk – Ceyhan pipeline which exports oil through Turkey to the Mediterranean coast. This pipeline crosses the Iraq –Turkey border within the KRG's controlled area. This export route currently transports some 500 Mbopd. The KRG has recently announced plans to carry oil from the existing Kurdish discoveries to the Ceyhan pipeline via a new trunk line within the Kurdistan Region of Iraq.

4. Oil and gas exploration and development in Egypt

4.1 Egypt is North Africa's third largest oil producer and is the fifth largest in Africa. It is the second largest gas producer in Africa behind Algeria and the third largest in terms of gas reserves behind Nigeria and Algeria. It is a very mature oil province with the first oil discovery made approximately 140 years ago. The country has been producing oil since 1910. However gas production has grown rapidly since the 1990s fuelled by strong domestic demand and long-term gas export contracts.

4.2 According to the 2012 BP World Statistical Review, at the end of 2011 Egypt had proved oil reserves of 4.3 billion barrels of oil and 2.2 Tcm of proved gas reserves. At the end of 2011, oil production was 735 Mbopd and gas production was 61.3 Bcm.

4.3 ENI, BP plc and Apache Corporation are the largest producers of oil holding almost 60 per cent of oil reserves attributable to non Egyptian state investors. BP plc, ENI and BG Group plc are the largest producers of gas, holding over 60 per cent of the gas reserves attributable to non Egyptian state investors.

4.4 From the 1960s onwards, oil production was increased due to the discovery of fields located in the Gulf of Suez. Production from these fields reached a peak of 912 Mbopd in 1993. The subsequent decline in production has largely been offset by the emergence of the Western Desert as a key oil producing province. Apache Corporation is the lead operator in this area.

4.5 A series of successful licensing rounds in the 1990s led to new acreage in the Mediterranean Sea being awarded. A number of significant gas discoveries resulted which rapidly increased Egyptian gas reserves and the sanctioning of gas exports in 2001. Gas export projects that have since been sanctioned include two LNG projects and two pipeline projects.

4.6 In the last 10 years, exploration drilling in Egypt has maintained a rolling average success rate of above 25 per cent. The increased bias towards gas is expected to continue as further exploration in the Mediterranean and Western Desert is likely to increase gas reserves.

4.7 The EGPC is keen to promote further liquid production and is expected to re-negotiate fiscal terms on mature assets to ensure maximum oil recovery. It is expected, however that this will only partially offset the trend.

4.8 The most significant oil pipeline in Egypt is the SUMED system, routed from Ain Sukhna on the West Bank of the Gulf of Suez to the Sidi Kerir terminal on the Mediterranean coast. The line capacity is 2.4 MMbopd and carries crude from Saudi Arabia, Iran and Egypt. The Gulf of Suez, Nile Delta and the Western Desert are also served by major pipeline routes.

4.9 Egypt has nine oil refineries with a total capacity of around 680 Mbopd.

4.10 Domestic gas infrastructure transports gas from Egypt's main gas producing regions i.e. Nile Delta and the Western Desert to demand centres around Suez, Cairo and Alexandria.

4.11 Egyptian gas export pipelines include the proposed Arab Gas Pipeline Project which exports gas to Jordan and Syria and is expected to be extended through Syria on to Lebanon and Turkey; Israel Gas Pipeline which commenced sales in 2008 but has since the 2011 Egyptian regime change been subject to continuous sabotage causing severe disruption to Israeli supply.

4.12 Two LNG projects have been developed, namely SEGAS (Spanish Egyptian Gas Company) which made its first shipment in 2005 and ELNG (Egyptian LNG), which acts as a tolling facility and shipped its first cargo in 2005.

5. Oil and gas exploration and development in Bulgaria

5.1 Oil production in Bulgaria commenced in 1954 and peaked in 1966, at over 9 Mbopd and 300 bopd of condensate. Current production derives from approximately half of the 25 oil and gas fields discovered since 1949, most of which are depleted or nearing depletion. Gas production commenced in 1965. In 2004 the off-shore Galata field was brought onstream which produced peak production rates of 60 MMcfpd.

5.2 At the end of 2011 remaining commercial oil reserves totalled 1 MMbbl with remaining recoverable gas reserves totalling 50 Bcf.

5.3 Recent exploration results in Bulgaria have been mixed with the most notable successes in recent years being the Kaliakra and Kavarna discoveries which were on trend with the Galata field.

5.4 Future exploration is expected to be focussed in the Black Sea with the recent Romanian deepwater discovery in 2012 stimulating interest in Bulgaria's Black Sea acreage. In July 2012 a consortium comprising Total S.A. Repsol S.A. and OMV Petrom SA bid successfully to attain a permit to explore and develop the deepwater Khan Asparuh block located in the Black Sea.

5.5 Bulgaria is also considered to have some potential for shale gas production. However in January 2012, the Bulgarian government announced a complete ban on hydraulic fracturing and no unconventional gas wells have been drilled in Bulgaria to date.

5.6 Bulgaria's oil infrastructure is extremely limited due to the small scale of its domestic production with most oil being exported from the fields by truck. Bulgaria has three oil refineries. The largest, Burgas, on the Black Sea coast can handle 70 MMbbl of oil per annum.

5.7 Bulgaria liberalised its oil prices in the 1990s and the majority of the country's demand is supplied via imports indexed to the price of Urals blend. Having joined the EU in 2007 Bulgaria is legally obliged as part of the process of gas market liberalisation to reform its gas pricing. Currently almost all domestic gas production is sold directly to Bulgargaz, the state-owned gas transmission company which is also responsible for purchasing imported gas from Russia. Gas prices today are currently below the level of the cost of imports however in line with EU free trade and competition legislation it is expected that this differential will be eliminated by 2016.

6. Oil and gas exploration and development in Romania

6.1 Romania is Central and Eastern Europe's second largest oil and gas producer behind the Ukraine. It is a mature oil province with oil production commencing in the mid 19th century and peaking at around 300 Mbopd in the late 1970s. Gas production began in the early 20th century peaking at 3.4 Bcfd in 1985.

6.2 According to the 2012 BP World Statistical Review, at the end of 2011 Romania had proved oil reserves of 600 MMbbl and proved gas reserves of 0.1 Tcm. Oil production at the end of 2011 was 88 Mbopd and gas production was at 11 Bcm.

6.3 SNGN Romgaz SA, the state owned company, and OMV Petrom SA, the former national oil company, dominate both production and reserves. Since the privatisation of Petrom in 2004 foreign involvement and investment has grown significantly and ten licensing rounds have now been held since the 1990s.

6.4 The on-shore exploration outlook was enhanced in July 2011 when OMV Petrom SA announced potentially the largest on-shore gas and condensate discovery in Romania in the last six years in the Oltenia region of southwest Romania.

6.5 The Dominio-1 well drilled by ExxonMobil Corporation / OMV Petrom SA led to the first gas discovery in the deepwater Black Sea. The estimated recoverable gas ranges from 1.5 to 3 Tcf and is the largest single discovery in the Black Sea to date. There are a number of smaller fields which have been discovered in the shallower waters, including the Lebada, Ana and Doina fields.

6.6 Interest in the country's shale gas opportunities is also growing with Chevron Corporation, MOL plc, East West Petroleum Corporation and Sterling Resources Limited among the companies involved. However, as with some other European countries, public concern relating to the environmental impact of hydraulic fracturing has tended to delay shale gas projects.

6.7 Approximately 97 per cent of gas in Romania is produced by SNGN Romgaz SA and OMV Petrom SA with the remaining 3 per cent representing production from foreign companies, including Amromco Petroleum LLC, Aurelian Oil & Gas plc, Regal Petroleum plc, Raffles Energy Pte Limited, Europa Oil & Gas plc and Wintershall AG. Approximately 75 per cent of Romanian gas demand is met by with the majority of the remainder imported from Russia. It is anticipated that this will change in the coming years with around 50 per cent of the country's requirements being met by domestic production.

6.8 Romania has eight gas storage facilities with a combined working capacity of approximately 100 Bcf. Six of the facilities are operated by SNGN Romgaz SA. There is insufficient storage capacity to supply demand and the government is looking for foreign investors to help it increase its gas storage capacity to over 150 Bcf.

6.9 A feasibility study has been undertaken for the construction of an LNG regasification terminal at Constanta on the Black Sea coast.

6.10 There are five major oil refineries in Romania with an overall combined capacity of 300 Mbopd, well in excess of domestic oil production. There are is a limited network of crude pipelines in the southeast of the country which link its refineries to the Black Sea coast.

PART VII

INFORMATION ON PETROCELTIC

1. OVERVIEW

1.1 Petroceltic is an upstream oil and gas exploration and production company incorporated in Ireland whose shares are quoted on AIM and ESM. Petroceltic is headquartered in Dublin with regional offices in London, Algiers, Erbil and Rome.

1.2 Petroceltic's operations are focused on the Middle East and North Africa region and on the Mediterranean basin.

1.3 Petroceltic's core areas are in Algeria, Italy and the Kurdistan Region of Iraq.

1.3.1 **Algeria**: Petroceltic was awarded a PSC in September 2004, which came into force in April 2005, over the Isarene field situated in the Illizi Basin in South Eastern Algeria (the **"Isarene PSC"**). Petroceltic operates the Isarene PSC with a 56.625 per cent interest. Sonatrach, the Algerian national oil and gas company, holds a 25 per cent interest, and Enel holds an 18.375 per cent interest. Since April 2005, during the exploration and appraisal extension periods of the Isarene PSC, approximately US$300 million of capital expenditure has been undertaken to June 2012. A significant gas development opportunity has been identified, known as the Ain Tsila discovery. Petroceltic estimates the field to contain gross contingent resources of 2.2 Tcf of gas and 183 MMbbl of liquid hydrocarbons in the form of condensate and LPG. The Declaration of Commerciality was made in respect of the Ain Tsila field in August 2012. The major construction and development phase is planned to commence in 2014 and first gas is expected in 2017.

1.3.2 **Italy:** Since 2004, Petroceltic has acquired a portfolio of interests in the western Po Valley area and in the Central Adriatic Sea and the Sicily Channel. Included in this portfolio are:

- a 47.5 per cent interest in the Carisio Licence in the western Po Valley area, containing the Carpignano Sesia (formerly Rovasenda) prospect. This licence has been operated by ENI since April 2011. Planning for a well on this prospect is at an advanced stage and it is planned to spud the first well in early 2013. Petroceltic estimates that this prospect has gross mean prospective resources of 237MMbbl and is potentially geologically analogous to the nearby ENI operated Villafortuna-Trecate field: and
- a 40 per cent operated interest (with two agreements in place that could grant Petroceltic a 55 per cent operated interest) in the off-shore B.R 268.RG Permit which contains the "Elsa Discovery". This is discussed further in paragraphs 3.2.19 and 3.2.20 of this Part VII.

A number of Petroceltic's off-shore permits, including the Elsa Discovery, were suspended and a number of permit applications have been delayed due to the 2010 Decree which restricted certain off-shore oil and gas activities in Italy. On 26 June 2012, the 2012 Decree was announced in the Italian Official Journal. The 2012 Decree, which is effective immediately, has been ratified by both houses of the Italian Parliament with no substantial modifications and will become law once published in the Italian Official Journal. Petroceltic believes, that the 2012 Decree will provide a clear framework for the safe resumption of exploration and development on off-shore permits that were in existence prior to the enactment of the 2010 Decree. This is discussed further in paragraphs 3.2.3 to 3.2.5, and 3.2.29 to 3.2.35 of this Part VII.

1.3.3 **Kurdistan Region of Iraq**: In 2011, Petroceltic entered into two PSCs in respect of two highly prospective exploration blocks, Dinarta and Shakrok, in the central north of the Kurdistan Region of Iraq (together the **"Kurdistan PSCs"**). Petroceltic has a 20 per cent paying interest (16 per cent participating interest), Hess is operator with an 80 per cent paying interest (64 per cent participating interest) and the KRG holds the rights to a 20 per cent carried interest. The Directors believe that the prospects contained in the Dinarta and Shakrok PSCs each have significant exploration potential. Each Kurdistan PSC has an initial three year exploration period during which the partners will acquire 2D seismic and drill a minimum of one exploration well. A 875 kilometre 2D seismic acquisition campaign covering both blocks commenced in May 2012 and two exploration wells are currently planned to be drilled before July 2014.

1.4 For the year ended 31 December 2011, Petroceltic had revenue of US$419,000 (2010: US$270,000), which was earned from a royalty on the Kinsale Head gas field, which includes the south-west Kinsale and Ballycotton gas fields in the Celtic Sea off-shore Ireland.

1.5 Petroceltic's strategy is to continue the policy of dual focus of organic development of its core areas, and of looking to acquire assets that have the potential to grow and transform the business.

2. HISTORY AND DEVELOPMENT

2.1 Petroceltic was incorporated on 6 May 1984 with the name Ennex International plc. In 1984 Petroceltic was admitted to trading on ESM and in 2001 was admitted to trading on AIM. In 2003, it changed its name to Petroceltic with a strategy of moving into the oil and gas sector. Between 2003 and 2005 Petroceltic first accrued interests in Algeria, Italy and Tunisia. In 2011, Petroceltic acquired its interests in the Kurdistan Region of Iraq. Petroceltic relinquished its interests in Tunisia in 2010.

2.2 Over the last three years, Petroceltic has raised equity finance to fund its exploration and development activities and for working capital purposes by way of three share placings, one in 2009, raising gross proceeds of US$40 million, one in 2010, raising gross proceeds of US$120.5 million and another in 2011, raising gross proceeds of US$60 million.

2.3 In 2011, Petroceltic put in place a 12 month bridging facility with Macquarie Bank for US$30 million to finance on-going capital investment and working capital. The facility was repaid in full in February 2012 when the funds from the Enel farm-out deal were received by Petroceltic (discussed further in paragraph 3.1.3 of this Part VII). Warrants to acquire approximately 59 million shares in Petroceltic are held by Macquarie.

2.4 In 2008, Petroceltic entered into a strategic alliance and financing arrangements with Iberdrola to develop its oil and gas assets in North Africa and Italy. As part of these arrangements Iberdrola invested US$55 million cash through a placing of shares for a 22.64 per cent stake in Petroceltic. In addition, Iberdrola had a two year option agreement to invest a further US$55 million to acquire a 49 per cent financing interest in any single asset in Petroceltic's then portfolio and a joint business committee was formed. Iberdrola, in line with its asset disposal programme for 2008-2010, sold its entire shareholding in Petroceltic in January 2010 to a group of existing and new Petroceltic Shareholders and the two year option agreement was terminated. Since the shareholding had been subject to a lock-in arrangement, Petroceltic gave its consent to the sale in exchange for the early termination of the option Iberdrola held to acquire a 49 per cent interest in any of Petroceltic's upstream assets, and consequently Petroceltic agreed to the repayment of a US$7.3 million option fee paid by Iberdrola in January 2009.

3. PETROCELTIC GROUP STRUCTURE AND PRINCIPAL OIL & GAS ASSETS

Petroceltic is the holding company of the Petroceltic Group, comprising its wholly owned subsidiaries which own and operate its oil and gas assets. Details of the principal subsidiaries of Petroceltic are set out in paragraph 3 of Part XII of this document.

The following table summarises the principal oil and gas interests of Petroceltic in Algeria, Italy and the Kurdistan Region of Iraq.

Country	Asset	Size of area (km²)	Petroceltic Interest	Status	Operator	Partner(s)	Date of Grant	Date of Expiry of current phase	Extension Rights (if any)
Algeria	Isarene PSC	2,564.8 km²	56.625%	Exploration	Petroceltic	Sonatrach Enel	26/04/2005	26/4/2010	10/8/2012[1]
Italy – Po Valley	Carisio permit	728 km²	47.5%	Exploration	ENI	ENI Condotte	18/05/2006	14/10/2012	14/10/2018
Italy – Po Valley	Ronsecco permit	746 km²	100%	Exploration	Petroceltic	N/A	29/11/2010	29/11/2016	29/11/2022
Italy – Po Valley	Vercelli permit	536.7 km²	100%	Exploration	Petroceltic	N/A	10/07/2002	10/07/2014	N/A
Italy – Po Valley	Case Sparse permit	24.2 km²	100%	Exploration	Petroceltic	N/A	07/10/2008	07/10/2014	07/10/2020
Italy – Central Adriatic Sea	B.R 268.RG permit	127 km²	60%[2] (paying interest) (40% participating interest)	Exploration	Petroceltic	Vega	24/03/2005	30/09/2011* *currently suspended	30/09/2017

Country	Asset	Size of area (km²)	Petroceltic Interest	Status	Operator	Partner(s)	Date of Grant	Date of Expiry of current phase	Extension Rights (if any)
Italy – Abruzzo	Civitaquana permit	615.4 km²	40% paying interest (35% participating interest)	Exploration	Vega	Vega	24/07/2007	17/12/2013	17/12/2019
Italy – Central Adriatic Sea	B.R 270 permit	144.5 km²	100%	Exploration	Petroceltic	N/A	15/06/2012	15/06/2018	15/06/2024
Italy – Central Adriatic Sea	B.R 271 permit	327.1 km²	100%	Exploration	Petroceltic	N/A	15/06/2012	15/06/2018	15/06/2024
Kurdistan Region of Iraq	Dinarta PSC	1,319 km²	20% paying interest (16% participating interest)	Exploration	Hess	Hess KRG	26/07/2011	26/07/2016	Rolling 1 year extensions subject to max of 7 Contract Years.
Kurdistan Region of Iraq	Shakrok PSC	418 km²	20% paying interest (16% participating interest)	Exploration	Hess	Hess KRG	26/07/2011	26/07/2016	Rolling 1 year extensions subject to max of 7 Contract Years.

Notes:

1. See paragraph 3.1.20 of this Part VII
2. Under a 2009 agreement between Petroceltic and Vega, upon the drilling of the Elsa-2 well, Petroceltic would increase its participating interest in the Elsa Discovery to 70 per cent and its paying interest to 100 per cent. Petroceltic subsequently entered into a farm-out agreement with Orca pursuant to which, upon drilling of the Elsa-2 well, it would reduce its participating and paying interest to 55 per cent. Both these agreements remain subject to drilling of the Elsa-2 appraisal well. Until both farm-out arrangements are completed, the Petroceltic participating and paying interest is 40 per cent and 60 per cent respectively. Further information on these agreements is provided in paragraphs 20.2.9 and 20.2.10 of the Part XII of this document.
3. In addition Petroceltic has made an application for an off-shore permit in the Sicily Channel.

3.1 Algeria

Overview

3.1.1 Petroceltic was awarded the Isarene PSC in September 2004, which came into force in April 2005. On completion of the minimum work commitments of the five year exploration period, Petroceltic was entitled under the Isarene PSC to apply for an appraisal extension period of two years to evaluate any potentially commercial hydrocarbon discoveries. Upon completion of a drilling programme in 2009, Petroceltic applied for and was granted a two year appraisal extension to April 2012. In April 2012, Petroceltic, Enel and Sonatrach agreed to a 3 month extension (which was further extended to August 2012) to complete discussions to facilitate a Declaration of Commerciality (**"DOC"**) to be made in accordance with the terms of the Isarene PSC. On 9 August 2012, Petroceltic, Enel and Sonatrach made a DOC on the Ain Tsila field having agreed a final discovery report (**"Discovery Report"**) and undertaken a gas feasibility study. Further information in relation to the DOC is contained in paragraphs 3.1.19 – 3.1.23 of this Part VII.

3.1.2 During the appraisal extension period, Petroceltic completed a six well appraisal programme that was completed on time and under budget. Over 90 per cent of the gross hydrocarbons in place in the Isarene field area were discovered in the Ain Tsila discovery, which is considered to be a significant gas condensate discovery.

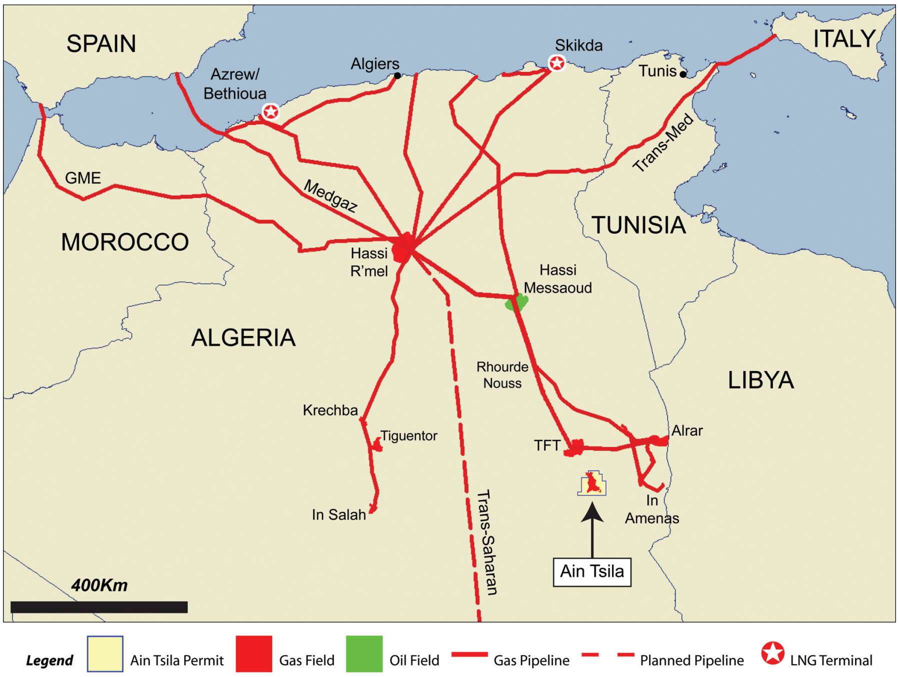
3.1.3 During 2011, Petroceltic reached an agreement to sell an 18.375 per cent interest in the Isarene PSC to Enel. The interest formally transferred in February 2012 and Petroceltic received in excess of US$100 million from Enel representing 24.5 per cent of all back costs incurred in the exploration period of the Isarene PSC and 49 per cent of the costs of the six well appraisal programme. Petroceltic is entitled to receive a further contingent cash consideration from Enel, the exact amount of which will be determined by the final approved production profile, included in the DOC submitted to ALNAFT, the relevant authority in Algeria, from the Ain Tsila field. This payment is due once the DOC has been approved by ALNAFT. Based on figures included in the DOC, Petroceltic expects this payment to be no more than US$25 million.

3.1.4 Petroceltic has initiated a second phase farm-out process in respect of an additional 18.375 per cent interest in the Isarene PSC that it expects to announce by early 2013. There can be no certainty that such a sale can be completed or of the timing or terms of any such sale.

Geographic and Geological Setting

3.1.5 The Isarene field is located within the Illizi Basin in South Eastern Algeria and covers an area of 2,564.8km². The original permit covered in excess of 10,000km². It is bordered by a number of fields with proven oil and gas production, such as the In Amenas project to the east, being one of Algeria's largest wet gas projects, and the Tin Fouye Tabankort field to the north.

3.1.6 The location of the Isarene field, in which the Ain Tsila field is contained, is illustrated in the map below.



3.1.7 The source of hydrocarbons in the Illizi Basin are Silurian shales found in Carboniferous, Devonian and Ordovician reservoirs. The Ordovician sandstones are the most important reservoirs in terms of hydrocarbon volumes.

3.1.8 The area is predominantly expected to yield gas but is also prospective for LPG and condensate.

3.1.9 For a more detailed description of the geographic and the geological setting of the Algerian interests, see the Petroceltic Competent Person's Report at Appendix I to this document.

Summary of activities during the Exploration and Appraisal Extension Periods

3.1.10 Petroceltic is the operator under the Isarene PSC and holds a participating interest of 56.625 per cent. Enel holds a participating interest of 18.375 per cent. Sonatrach holds a 25 per cent interest, carried during the exploration and appraisal period of the Isarene PSC.

3.1.11 The Isarene PSC provided for minimum work commitments of 600 kilometres of 2D seismic and one exploration well to be drilled during the first exploration period, between 2005 and 2008, and 100 kilometres of 2D seismic and a second exploration well to be drilled during the second exploration period, between 2008 and 2010. On completion of the minimum work commitments, Petroceltic was entitled under the Isarene PSC to apply for an appraisal extension period of two years to evaluate any potentially commercial hydrocarbon discoveries.

3.1.12 Petroceltic exceeded the minimum work commitments in the first exploration period. In the second exploration period, Petroceltic focussed on four prospective areas, being Ain Tsila, Isarene North East, Isarene North West and Hassi Tab Tab. In 2009, Petroceltic drilled in all the prospective areas, except Hassi Tab Tab, which had been previously drilled and tested by Petroceltic in 2006. Included in this programme was the AT-1 well that was drilled on Ain Tsila and confirmed its significant commercial potential.

3.1.13 Upon completion of the 2009 drilling programme, Petroceltic applied for and was granted a two year appraisal extension to April 2012. In April 2012, Petroceltic, Enel and Sonatrach agreed to a 3 month extension, which was further extended to August 2012.

3.1.14 During the appraisal extension stage, Petroceltic drilled six delineation wells on the Ain Tsila Discovery. The table below summarises certain key information in relation to the testing of each of the wells drilled during the appraisal period:

Well	Type	Maximum flow rate Gas (MMcfpd)	Maximum flow rate Condensate (bblpd)	Date tested
AT-4	Vertical	1.4	0	Jan-Feb 2011
AT-5Z	Pilot + Horizontal	3.5	60	Jul 2011
AT-6	Vertical	0	0	Aug-Sep 2011
AT-8	Vertical	38.6	1,181	Sept-Oct 2011
AT-7	Vertical	4.9	0	Oct-Nov 2011
AT-9	Pilot + Horizontal	67.6	1,005	Nov-Dec 2011

3.1.15 In addition to the AT-1 discovery well, both AT-8 and AT-9 indicated a potential for well delivery in excess of 30 MMcfpd and supported Petroceltic's planned wet gas production plateau rate of 355 MMcfpd for the Ain Tsila field.

3.1.16 Over 90 per cent of the gross hydrocarbons in place in the Isarene permit were discovered in the Ain Tsila field. At the end of the appraisal programme, Petroceltic's best estimate of gas initially in place in the Ain Tsila field had increased from 5.5 Tcf in April 2011 to 10.1 Tcf.

3.1.17 Capital expenditure in accordance with the Isarene PSC was US$163.8 million during the exploration period (April 2005 to April 2010) and US$135.9 million during the appraisal extension period (April 2010 to June 2012).

3.1.18 Petroceltic estimates the field to contain gross resources of 2.2 Tcf of sales gas, 70 MMbbl of condensate and 113 MMbbl of LPG, together approximately 305 MMboe of gross contingent resources on a 56.625 per cent working interest basis.

Declaration of Commerciality for the Ain Tsila Field

3.1.19 Petroceltic, Enel and Sonatrach made the DOC on 8 August 2012 on submission of a Final Discovery Report and signing of an agreement for Sonatrach to market all of the gas produced from the Ain Tsila field, using a formula linked to Brent oil pricing.

3.1.20 The applicable legislation provides that ALNAFT, the competent authority, has 60 days to approve the DOC, although this period is subject to extension. Approval by ALNAFT would commence the 30 year exploitation phase of the PSC. Petroceltic has a reasonable expectation that the approval of the DOC by ALNAFT will enable a reserves auditor to recognise reserves in Ain Tsila.

3.1.21 The Discovery Report proposes the following development and production activities. The front end engineering and design (FEED) study will be conducted in 2013. Between 2014 and 2016, the central processing facilities will be constructed and development drilling will commence. First gas is planned for the third quarter of 2017 initially from an estimated 18 vertical wells produced at an annual average wet gas plateau rate of 355 MMcfpd. The plateau length is 14 years and continuous drilling of 12 wells per year estimated to be required during the period to maintain this production plateau.

3.1.22 The processing facilities at Ain Tsila are expected to follow a similar design to other regional gas developments, such as BHP Billiton's Ohanet field. From the processing plant, gas and liquid products will be transported via pipelines to one of the region's infrastructure hubs, such as the one situated adjacent to the Total S.A. operated Tin Fouye Tabankort field complex.

3.1.23 Dry gas will be exported as pipeline gas to either Southern Europe or as LNG cargoes. There are three possible pipeline options – the Medgaz or GME pipelines into Spain or the Transmed pipeline into Italy, and two LNG export terminals at Skikada and Azrew.

Summary of the Algerian petroleum regime

Key legislation

3.1.24 The award of oil and gas interests and the conduct of operations were previously governed by the terms of Act No 86-14 of 28 August 1986 (the "**1986 Act**") as subsequently amended and supplemented by Law No 91-12 dated 7 September 1991 and Law No 91-21 dated 4 December 1991, as well as several implementation decrees notably Decree No. 87-158 dated 21 July 1987.

3.1.25 A new act No.05-07 of 28 April 2005 (the "**New Act**") has been enacted and published in the Official Gazette on 19 July 2005.

3.1.26 The New Act was then subsequently modified and supplemented by Ordinance No 06-10 of 29 July 2006. This Ordinance has also modified the 1986 Act by introducing a provision in relation to windfall tax. In addition, thirty implementation decrees have supplemented the New Act including the Decree No 07-336 relating to the calculation of transfer tax. This is discussed in further detail in paragraph 3.1.40 of this Part VII.

The Isarene PSC was granted under and is governed by the 1986 Act. Therefore, this summary shall mainly focus on the provisions of 1986 Act, unless provisions of the New Act are relevant, in which case they shall also be set out.

Transition Provisions

3.1.27 Pursuant to the New Act *"[any] partnership contract entered into prior to the date of publication of [the New Act], as well as the amendments to such contracts signed prior to that date of publication, shall remain in force until their date of expiry."*

3.1.28 Although the drafting of the provision is somewhat unclear, it does establish that prior rights should continue in existence. However, it does not expressly address the question as to what laws should apply to such partnership contract. Many PSCs include some form of stabilisation wording, which although not always free from challenge or conflicting interpretation, provides a helpful argument that the previous regime should continue to apply as any substantial amendment would be contrary to the principle of preserving the free will of the parties as embodied in the PSC. The general view is that exploration and production rights granted prior to the entry into force of the New Act will therefore continue to be governed by the previous legal framework, subject to the exception detailed below at paragraph 3.1.40 and the drafting of the relevant stabilisation provisions in the PSC.

3.1.29 Further to the enactment of the New Act:

- the activities of the foreign oil company remain governed by the 1986 Act as far as the foreign oil company's relations with Sonatrach are concerned; and
- the activities of Sonatrach are governed by the New Act as far as Sonatrach's relations with ALNAFT (the National Agency for the Development of Hydrocarbon Resources / Agence Nationale pour la Valorisation des Ressources en Hydrocarbures), and the authorities, are concerned.

3.1.30 In accordance with the New Act, Sonatrach and ALNAFT entered into parallel contracts for each contract concluded under the 1986 Act. Such parallel contracts provide inter alia that the mining title will now be held by ALNAFT. The parallel contracts have been approved by decree.

Production sharing contracts

3.1.31 Under the 1986 Act, upstream interests are held via four forms of associations including PSCs entered into by Sonatrach and the foreign company. The PSC must be submitted to the State and approved by decree published in the Algerian Official Gazette. The terms of the 1986 Act were fairly short with the majority of the provisions governing the day to day operations set out in the PSC. However the particulars relating to the conduct and the performance of the petroleum operations were provided by Decree 94-43 dated 30 January 1994 relating to the protection of the fields.

Overview of the responsibilities and functions of the relevant stakeholders

3.1.32 Under the 1986 Act, Sonatrach exercised a dual role as follows:

- the role of overseeing the exercise of petroleum operations which was the responsibility of the Ministry of Energy and Mines; and
- the role of a commercial profit making company.

3.1.33 The functions and prerogatives described in the first point in paragraph 3.1.32 previously exercised by Sonatrach, have been reallocated by virtue of the New Act to two new entities:

- Hydrocarbon Regulatory Authority / ARH (Agence Nationale de Controle et de Regulation des Activities dans le Domaine des Hydrocarbures) which assumes a regulatory role; and
- ALNAFT which is the entity which enters into the upstream exploration and exploitation contracts, approves development plans and collects the royalties and taxes. Its role is very much similar to many of the functions performed by Sonatrach under the 1986 Act.

Award of hydrocarbon interests

3.1.34 According to the Algerian Constitution, mining resources, including hydrocarbons, are the property of the national community. Both the 1986 Act and the New Act have adopted this principle by granting foreign companies a right to a share of production of hydrocarbons while excluding any rights over underground reserves. Such rights are determined in accordance with the form of the contracts provided by the law and the requirements and formulas detailed in such contracts.

3.1.35 Under the 1986 Act, mining licences were awarded directly to Sonatrach (as state oil company).

3.1.36 The PSC generally provides for two distinct phases; an exploration phase and an exploitation phase of 15 to 25 years. The maximum exploration term is generally five years extendable for two to five years. The exploration phase may be divided into two or three periods (in general on first period of three years and one or two optional periods of two years each). A minimum work programme corresponds to each such period.

Production

3.1.37 The PSCs provide that for each year of the contract's duration, the total annual production of hydrocarbon shall be divided as follows:

- a minimum share of 51 per cent shall return in full to Sonatrach;
- a maximum share of 49 per cent shall revert to the foreign company and corresponds to the reimbursement of its costs and to its remuneration. Such share is calculated by implementation of a contractual formula based on a ratio of revenues to investments. This is discussed further in paragraph 20.2.5 of Part XII of this document.

Assignment

3.1.38 Under the 1986 Act, a foreign company may assign all or a part of its contractual interests, subject to Sonatrach's approval and rights of pre-emption. Sonatrach is also required to approve any change of control of the foreign company. An assignment would be subject to a transfer tax described in paragraph 3.1.41 of this Part VII.

Taxation

3.1.39 The 1986 Act provided for the following fiscal treatment:

- royalty (with the possibility of certain rebates for isolated blocks or fields requiring secondary or tertiary recovery);
- there is a withholding tax, but it is structured as a payment on behalf of the foreign company so as to facilitate (but not guarantee) a credit in its home jurisdiction;
- petroleum Tax on earnings which is paid by Sonatrach on the totality of the production including the share of the foreign company; and
- exemption from all other taxes relating to the petroleum activities.

3.1.40 Where a contract was awarded under the 1986 Act, the foreign company will remain subject to the previous fiscal terms except for: a) the windfall tax created by Ordinance No 06-10 of

29 July 2006, whereby foreign companies are liable for the payment of windfall tax on profits corresponding to their share of production of liquid hydrocarbons (including LPG and condensate) when the price per barrel exceeds US$30. Such windfall tax is not applicable on the revenue generated from the marketing of dry gas; and b) 1 per cent tax on transfers created by the New Act that should be paid by the seller, whatever the form of transfer. The percentage is calculated on the basis of the value of the interests being transferred.

3.1.41 Different rules and calculation methods apply to the calculation of windfall and transfer taxes depending on the type of contract which Sonatrach has concluded with its foreign partner(s).

3.1.42 A number of exemptions provided under the 1986 Act continue to apply and notably, all petroleum operations (exploration and production) are exempt from customs duties and VAT and Tax on Professional Activity.

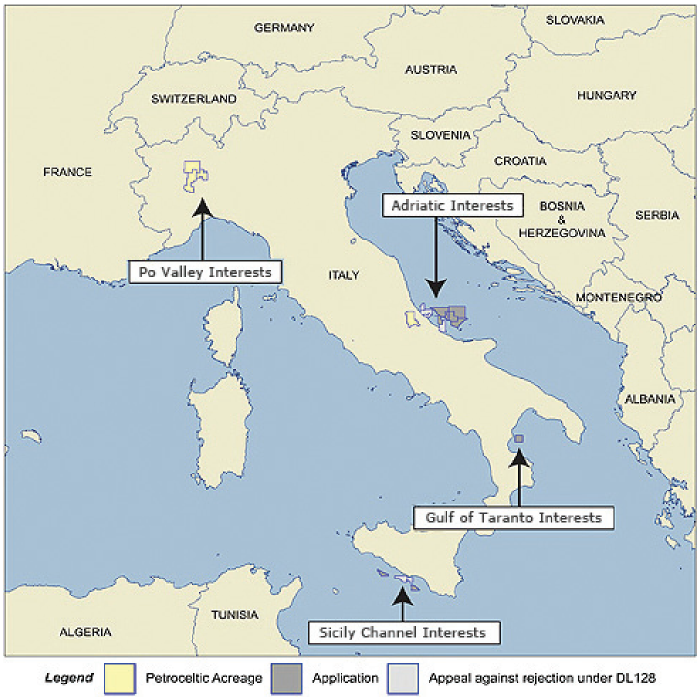
3.1.43 Further to the enactment of the New Act, foreign companies are also exempt from paying local social security contributions in relation to those employees who are already covered by the social protection system of another country.

3.2 Italy

Overview

3.2.1 Since 2004, Petroceltic has acquired a portfolio of interests in permits in the western Po Valley area and off-shore permits in the Central Adriatic Sea.

3.2.2 The location of Petroceltic's Italian interests is illustrated on the map below.



3.2.3 In the summer of 2010, Italy passed the 2010 Decree which came into force in August 2010. The 2010 Decree prohibited off-shore exploration and production activities involving liquid hydrocarbons within five nautical miles of the Italian coast and applied even to on-going operations that had previously been authorised. In addition, off-shore drilling activities located within 12 miles of certain designated protected marine and coastal areas were also suspended.

3.2.4 The 2010 Decree had affected certain of Petroceltic's off-shore exploration plans and off-shore permit applications, including the suspension of its off-shore applications in the Central Adriatic Sea and a delay in the award of new permit applications.

3.2.5 On 26 June 2012, the 2012 Decree was announced in the Italian Official Journal, and has subsequently been ratified by both houses in the Italian Parliament, with no substantial modifications, and will become law following publication in the Italian Official Journal. Petroceltic believes that the enactment of the 2012 Decree will provide a clear framework for the safe resumption of exploration and development on permits that were in existence prior to the enactment of the 2010 Decree.

3.2.6 Since 2004, Petroceltic's capital expenditure on its Italian assets has been approximately US$10.6 million to June 2012. Currently Petroceltic does not have any infrastructure, transportation or marketing arrangements in place in relation to its assets in Italy.

Po Valley area

3.2.7 Petroceltic has an interest in four permits in the western Po Valley area; the Carisio Permit, the Ronsecco Permit, the Vercelli Permit and the Case Sparse Permit.

3.2.8 Petroceltic's permits in the western Po Valley area are located to the west of Milan in the Lombardy and Piedmont Regions and approximately 30 kilometres west of the Villafortuna-Trecate field, one of Europe's largest on-shore oil fields which had peak production in 1997 of approximately 82 Mbopd and 27 MMcfpd of gas.

3.2.9 Operatorship of the Carisio permit was transferred to ENI on 1 April 2011 in return for access to reprocessed 2D seismic data and other technical studies on the Carisio permit and 500 kilometres of existing 2D seismic data on the Ronsecco permit, which lies adjacent and to the south of Carisio.

3.2.10 The Carisio permit covers an area of 728km², in which the Carpignano Sesia (previously Rovasenda) prospect has been identified consisting of Triassic to early Jurassic limestone and dolomite reservoirs. Two plays have been identified in the Ronsecco permit, a deep oil and gas prone Triassic carbonate play and a shallow gas prone Miocene sandstone play.

3.2.11 Petroceltic estimates that the Carpignano Sesia prospect has gross mean prospective resources of 237 MMboe[2.] and is potentially geologically analogous to the nearby ENI operated Villafortuna-Trecate field. Petroceltic believes that it may be possible to develop the Carpignano Sesia prospect via the existing Villafortuna facilities which are believed to have available processing capacity. Notional development studies carried out by ENI (as operator) indicate that a 23 kilometre flowline could connect Carpignano Sesia to Villafortuna production facilities.

3.2.12 Drill planning activities, including permitting, site selection, and drilling preparations, are ongoing and ENI, the operator, currently plans to spud a well on the Carpignano Sesia prospect by early 2013, subject to receipt of necessary approvals.

3.2.13 Petroceltic is actively seeking to farm-out a further interest in the Carisio permit with a view to sharing the risks and rewards of drilling the Carpignano Sesia prospect.

3.2.14 The Directors believe that a successful well on the Carpignano Sesia prospect would de-risk some of Petroceltic's other Triassic prospects in the western Po Valley area.

3.2.15 Further information on Petroceltic's interests in the western Po Valley area is contained in the Competent Persons Report in Appendix II.

Central Adriatic Sea

3.2.16 Petroceltic has an interest in the following four permits in the Central Adriatic Sea, the B.R 268.RG permit (the Elsa Discovery), the Civitaquana permit, the B.R 270 permit and the B.R 271 permit.

3.2.17 The Elsa Discovery was discovered in 1992 by ENI and is situated in the B.R 268.RG permit in the central Adriatic Sea, 7 kilometres off-shore Italy in water depths of 30 to 50 meters close to several commercial discoveries of oil including the Rospo Mare, Ombrina and Miglianico fields.

3.2.18 Petroceltic holds a 40 per cent interest in the Elsa Discovery and had intended to appraise it by drilling and testing the Elsa-2 appraisal well in late 2010 adjacent to the existing discovery well, Elsa-1, in which a 65 metre oil column was logged in 1992 in the Lower Cretaceous Maiolica Formation.

3.2.19 Petroceltic has entered into the following agreements that would increase its participating interest in the Elsa Discovery to 55 per cent and also part finance the cost of drilling and testing the Elsa-2 appraisal well:

- in December 2009, Petroceltic entered into a farm-in agreement with Vega, a wholly owned subsidiary of Cygam Energy Inc. to assume operatorship and increase its participating

2. Assumed conversion factor is 1 MMboe = 5.349 Bcf of gas, 1 MMboe – 1.145 bbl of condensate and 1 MMboe = 1.609 bbl of LPG.

interest in the Elsa Discovery to 70 per cent, subject to Petroceltic paying 100 per cent of the drilling and completion costs for the proposed Elsa-2 appraisal well (the **"Vega Farm-In Agreement"**);

- in May 2010, Petroceltic entered into an agreement with Orca to transfer a 15 per cent participating interest in the Elsa Discovery to Orca, thereby reducing Petroceltic's interest to 55 per cent. In exchange, Orca agreed to pay 30 per cent of the drilling and completion costs for the proposed Elsa-2 well up to a maximum amount of US$11.52 million and 15 per cent of all costs reasonably incurred in relation to the Elsa Discovery to date (the **"Orca Farm-Out Agreement"**); and
- in May 2010, Petroceltic entered into an investment agreement with Gemini who agreed to provide US$14 million towards the funding for the Elsa-2 appraisal well in exchange for an entitlement to receive revenues derived from the oil and gas production from the Elsa field once it is brought into development (the **"Gemini Investment Agreement"**).

3.2.20 For a more detailed summary of the terms of the Vega Farm-In Agreement and Orca Farm-Out Agreement, please see paragraphs 20.2.9 and 20.2.10 of Part XII of this document.

3.2.21 Petroceltic estimates that the Elsa Discovery has net entitlement best estimate unrisked contingent resources of 52.3 MMbbls and net entitlement best estimate unrisked prospective resources of 30 MMbbls. Further information on the Elsa Discovery is contained in the Competent Person's Report in Appendix III of this document.

3.2.22 The enactment of the 2010 Decree has prevented the Elsa-2 appraisal well from being drilled and Petroceltic has had the Elsa Discovery suspended to preserve the value of the licence. The Vega Farm-In Agreement and the Orca Farm-Out Agreement are subject to the drilling of the Elsa-2 appraisal well and therefore have not been completed. The Gemini Investment Agreement has now lapsed and the Gemini fund that had agreed to make the proposed investment is now fully invested in other projects. Gemini has indicated to Petroceltic that they would consider entering into a similar agreement once the timing of drilling of the Elsa-2 well is clarified.

3.2.23 Following the enactment of the 2012 Decree, Petroceltic will seek to extend the licence terms and will review its plans for drilling the Elsa-2 appraisal well. Upon drilling of the Elsa-2 well, the Vega Farm-In Agreement and Orca Farm-Out Agreement are expected to be completed and Petroceltic will then have a 55 per cent participating interest in the Elsa Discovery.

3.2.24 Petroceltic also has a 35 per cent participating interest in the on-shore exploration permit, Civitaquana, operated by Vega. This permit is currently suspended.

3.2.25 Petroceltic purchased 1,100 kilometres of 2D seismic data from ENI in 2009 to assist in the evaluation of 10 exclusive permit applications in the Central Adriatic Sea. Following the enactment of the 2010 Decree, a number of Petroceltic's Central Adriatic permit applications were combined and re-perimetered to exclude areas covered by the moratorium on drilling. The number of permit applications reduced from 11 to 6. Environmental impact assessments have been approved for four of these applications.

3.2.26 The areas covered by the permits applications are in water depths of 30 to 150 metres and are located adjacent to existing oil and gas fields which have demonstrated three working hydrocarbon plays in this region: the Cretaceous Miglianico/Elsa basin floor fan, the Cretaceous to Miocene Rospo Mare/Ombrina Mare platform carbonate oil plays and the Santo Stefano Mare Pliocene biogenic gas play.

3.2.27 In June 2012, Petroceltic was awarded two permits (B.R 270 and B.R 271) with four permit applications remaining outstanding. Petroceltic expects the remaining permit applications to be granted in 2012 and will then fast-track the technical evaluation of these permits by acquiring geophysical data. Petroceltic currently holds a 100 per cent interest in these permits and permit applications. Under the Orca Farm-Out Agreement, Orca will be entitled to a 15 per cent working interest in these permits on the drilling of the Elsa-2 appraisal well.

Sicily Channel

3.2.28 Petroceltic has one licence application in the Sicily Channel, d29G.R-NP, in association with Northern Petroleum (operator). Both parties hold a 50 per cent interest in this application.

Summary of the Italian petroleum regime

3.2.29 In order to explore for and produce petroleum in Italy a licence and authorisation is required from the Ministry for Economic Development (Ministero dello Sviluppo Economico) and, in the case of onshore activities, the approval of the government of the region in which the exploration or production activities are to be conducted; whereas the licensing of offshore activities is entirely coordinated by the Ministry for Economic Development. To qualify for such licences, authorisations and approvals, it is necessary to demonstrate appropriate technical and economic capacity.

3.2.30 Exploration permits and production concessions are issued in a unitary process which involves national, regional and local administrations. The permit or concession provides all of the authorisations required to construct the facility required for the relevant hydrocarbon activity. However, the holder of the permit or the concession must enter into agreements with the local authorities in respect of liability for environmental damage and for decommissioning the facilities used to conduct the hydrocarbon activity.

3.2.31 A permit is granted for a period of six years, which is renewable for two subsequent three-year terms, provided that the obligations set out in the permit work programme are met. On a discovery of hydrocarbons the permit holder will be awarded a concession, if the discovery is judged by the Ministry for Economic Development to be economic. The permit holder shall apply for a concession within 120 days of the issue by the National Mineral Office for Hydrocarbons and Geothermal Energy (Ufficio Nazionale Minerario per gli Idrocarburi e la Geotermia), of a certificate acknowledging the discovery.

3.2.32 If the concession is awarded to a person other than the permit holder, the permit holder is entitled to receive from the concession holder financial compensation which will be determined by the Ministry for Economic Development, in the event that the permit holder and the concession holder cannot agree the level of compensation.

3.2.33 The concession is granted for a period of twenty years which may be renewed for a subsequent period of ten years if this is necessary to complete the full exploitation of the field. It may then be extended for subsequent periods of five years. Any breach or unjustified delay in the execution of the work programme may entitle the Ministry for Economic Development to revoke a permit or concession or impose a fine on the holder of the permit or concession. Permits and concessions may be revoked if there has been significant environmental or archaeological damage. Public authorities and certain non-governmental entities can request such a revocation.

3.2.34 In August 2010, the Italian government brought into force the 2010 Decree which prohibited offshore exploration and production activities involving liquid hydrocarbons within five miles of the Italian coast and offshore drilling activities located within twelve miles of any marine and coastal areas that are subject to any environmental protection measures.

3.2.35 New legislation, the 2012 Decree, was published on 26 June 2012 and ratified by the Italian parliament on 3 August 2012. Under the new legislation the restrictions under the 2010 Decree will no longer apply to:

- applications for any titles that were under review at the time the 2010 Decree came into force, and any connected or subsequent proceedings;
- any titles, including exploration licenses that had already been issued prior to the 2010 Decree coming into force; and
- any proceedings connected with or subsequent to such titles, including possible extensions of the same.

3.3 Kurdistan Region of Iraq

Overview

3.3.1 In 2011, Petroceltic entered into 2 PSCs in respect of two highly prospective exploration blocks, Dinarta and Shakrok, in the central north of the Kurdistan Region of Iraq. Petroceltic has a 20 per cent paying interest (16 per cent participating interest). Hess is operator with a 80 per cent paying interest (64 per cent participating interest) and the KRG holds the rights to a 20 per cent carried interest.

3.3.2 The KRG's interest is carried by Hess and Petroceltic through all stages of the PSC, including development. The carried amounts are cost recoverable under the terms of the Kurdistan PSCs.

3.3.3 The Dinarta and Shakrok PSCs each contain minimum work commitments for the initial three years of exploration and Petroceltic's first phase financial commitment, including signature and other bonuses, is approximately US$90 million and is inclusive of the KRG carry.

3.3.4 The operator Hess, on behalf of its partners (including Petroceltic), is currently acquiring 875 kilometres of 2D seismic. The partners plan to drill at least one exploration well in each of Dinarta and Shakrok is planned before July 2014.

3.3.5 The initial exploration phase is due to end in 2014.

3.3.6 Petroceltic's capital expenditure, including signature bonuses, on its Kurdistan assets to date has been approximately US$53.84 million.

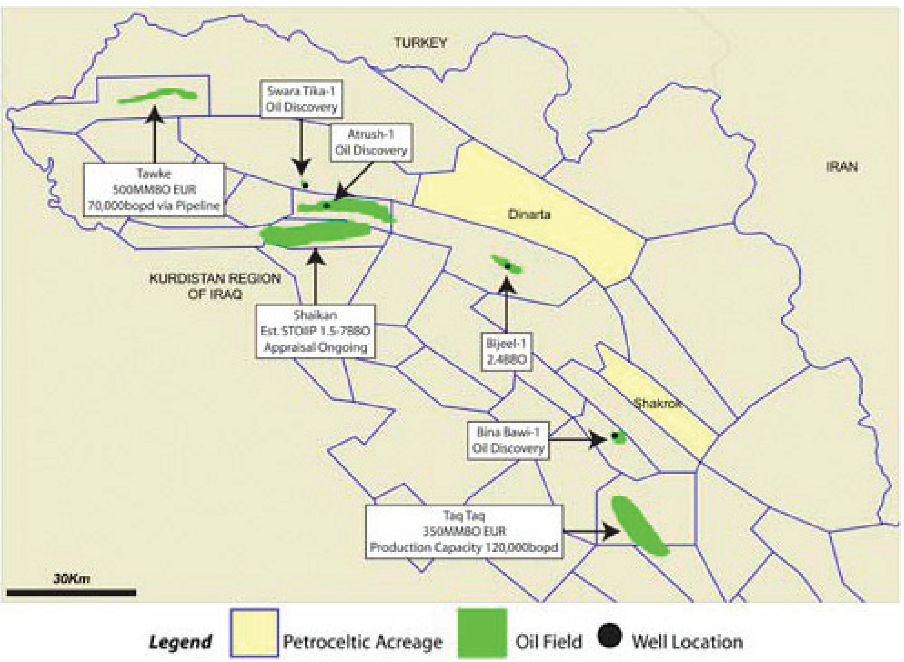
3.3.7 The Kurdistan PSCs provide for an exploration term of five to seven years for each block with an initial three year "sub-period" during which the minimum work commitments must be fulfilled. The minimum work commitments are fieldwork, at least 750 kilometres of 2D seismic and the drilling of one exploration well.

3.3.8 The Kurdistan PSCs provide for a 20 year development period for both oil and gas.

Geographical and Geological Setting

3.3.9 The Kurdistan PSCs are in an area to the north and east of the Kurdish capital. Dinarta is a block covering an area of 1,319km² containing three major surface anticlines which are adjacent to recent Shaikan, Atrust and Swara Tika Triassic/Jurassic oil discoveries. The Shakrok block covers an area of 418km² and contains two substantial surface structures, approximately 30 kilometres from the Taq Taq field (which produces 100 Mbopd) and the Bina Bawi oil discovery. Petroceltic's primary exploration targets in these two blocks are light oil plays in the stacked lower Jurassic and/or Triassic dolomite reservoir units. This play has been proven at Shaikan with light oil and condensate tested from Triassic Kurrachine dolomites at rates in excess of 40 Mbopd.

3.3.10 The location of Dinarta and Shakrok PSCs is illustrated in the map below.



3.3.11 The Directors believe that Dinarta is a highly prospective undrilled block in a proven but largely unexplored area adjacent to from existing discoveries in Kurdistan. The block contains a number of identified surface structures, the largest of which, the Chinara Anticline, is 25 kilometres along strike from the Swara Tika-1 well, reported to have had a significant new oil discovery. The other structures on the block also have significant potential surface closure areas with multiple reservoir targets believed to be present in the Jurassic and Triassic strata preserved in this block. The resource potential of the identified structures is considered to be significant.

3.3.12 The Directors believe that Shakrok is a highly prospective undrilled block in a proven but largely unexplored area adjacent to existing discoveries at the nearby Taq Taq oil field and the Bina Bawi oil discovery. The block contains significant surface anticlines, and, similar to Dinarta, multiple reservoir targets are believed to be present in the Jurassic and Triassic strata preserved in the block.

3.3.13 For a more detailed description of the geographical and geological setting of the Kurdistan PSCs, see the Petroceltic Competent Person's Report at Appendix II to this document.

Summary of the Kurdistan Region of Iraq petroleum regime

Constitutional and legislative framework

3.3.14 The Iraq Constitution contains a list of powers which are reserved exclusively for the Iraq Government and a list of powers which are shared by the Iraq Government and the governments of the Iraq Regions and Governorates. Jurisdiction over matters which are not exclusively reserved to the Iraq Government resides with the Iraq Regions and Governorates. With regard to powers shared by the Iraq Government and the Iraq Regional Governments, priority is given to the laws of the Regions and the Governorates in the event of conflict.

3.3.15 The Iraq Constitution provides that "Oil and gas are owned by all the people of Iraq in all the Regions and Governorates", however, the management of oil and gas resources (including jurisdiction over the signing of oil and gas exploration, development and production agreements) is not reserved exclusively to the Iraq Government. As a consequence, in 2007 the KRG enacted the Kurdistan Region Oil and Gas Law to assume jurisdiction over the management of oil and gas matters in the Kurdistan Region of Iraq and repealed within the Kurdistan Region of Iraq all previous Iraq laws relating to such oil and gas resources that are inconsistent with the Kurdistan Region Oil and Gas Law.

3.3.16 In February 2007, the Iraq Federal Oil and Energy Committee proposed the 2007 Draft Federal Hydrocarbon Law which was intended to relate to the whole of Iraq, including the Kurdistan Region of Iraq. This has not been enacted and the timing for approval of any Federal Hydrocarbon Law, and in what form it will be approved, is unclear.

3.3.17 In August 2011, two new competing versions of the law were proposed and it is unclear at this time if either of the versions will be forwarded further for debate. The Iraq Council of Ministers has, more recently, suggested that it will not consider either of these two drafts. Consideration of a Federal Hydrocarbon Law has ground to a standstill and there is currently an impasse between the Iraq Government and the KRG. Until these issues are resolved there will be inherent risks that the Iraq Government may take steps to oppose and to interfere with PSCs awarded by the KRG.

3.3.18 However, the Iraq Constitution contains provisions which protect the Kurdistan Region of Iraq from any amendment to the Iraq Constitution which would dilute its rights without the consent of the people of the Kurdistan Region of Iraq.

3.3.19 There is a possible risk (through implementation of (Federal) Law No. 19 of 2010) that the KRG's counterparties to PSCs could face an assessment for unpaid taxes brought by the Iraq Government, even if the PSCs in question are found to be valid. The KRG would not accept the right of the Iraq Government to impose taxation in the Kurdistan Region of Iraq because taxation is not an exclusive power of the Iraq Government under the Iraq Constitution. No Federal taxation (other than Customs Duties) has been levied in the Kurdistan Region of Iraq since 1992.

Export payments

3.3.20 The Iraqi Oil Minister has consistently disputed the validity of PSCs entered into with the KRG. In May 2009, when the KRG announced the launch of oil exports from the Kurdistan Region of Iraq, the Iraq Oil Ministry reiterated its belief that the contracts signed with the KRG since August 2007 are "illegal and illegitimate" and publicly stated that, out of principle, it opposed the PSCs that the KRG had signed prior to that date. Exports were subsequently suspended from the Tawke and Taq Taq fields in September and October 2009, respectively, amid uncertainty as to when and how contractors would be paid their entitlements under the PSCs (including cost recovery) for such oil exports.

3.3.21 In January 2011, following a meeting between the KRG, the Federal Prime Minister and the Federal Ministers of Oil and Finance, the parties announced an agreement on the resumption of oil exports from the Kurdistan Region. Exports subsequently resumed in February 2011, only to be halted again in April 2012. In early August 2012 the KRG resumed oil exports with the warning that they would be halted if no payments were received by contractor parties to PSCs, by the end of the month.

3.3.22 The agreement between the two governments on resumption of exports and the first advance payments by the Iraq Government to the KRG provided a more stable outlook for contract parties to PSCs in the Kurdistan Region of Iraq. Nevertheless, the Iraq Oil Ministry has not ceased to challenge the validity of the PSCs granted by the KRG; and in case any Federal Hydrocarbon Law is again considered, the Iraq Government may be expected to press for PSC contractor entitlements which are different (and materially less favourable) to those set out in the PSCs. Contracts awarded by the Iraq Government to international oil companies in southern Iraq are technical service contracts, rather than PSCs, with compensation being paid to those companies on a fee per barrel basis.

3.3.23 The revenues relating to all oil produced in Iraq (including the Kurdistan Region of Iraq) is collected in a single fund, which is administered by the Iraq Government. Under the Iraq Constitution, the Iraq Regions are entitled to a portion of export oil revenues generated by Iraq. Historically, payments to the KRG pursuant to this entitlement have been set at a net 17 per cent of the State Budget (after Kurdistan Region of Iraq's share of pan-federal costs).

3.3.24 The KRG and Iraq Government disagree on whether the costs of the extraction of oil in the Kurdistan Region of Iraq (including the costs incurred by contractors under the PSCs) should be taken from the KRG's net 17 per cent share or whether such costs should be deducted (and paid by the Iraq Government to the PSC contractors) prior to calculating that share. The ongoing uncertainty on this issue has meant that contractors in the Kurdistan Region of Iraq have not received due payment for exported oil. Following the suspension of exports in 2009, all crude oil produced in the Kurdistan Region of Iraq was sold locally for a significantly cheaper price than the international market price.

Award and approval of a PSC under the Kurdistan Oil and Gas Law

3.3.25 The KRG Minister of Natural Resources (the "**Minister**") is responsible for negotiating, agreeing and executing all authorisations, including petroleum contracts under the KRG Oil and Gas Law. The Minister must have the approval of the Kurdistan Regional Oil & Gas Council in order to conclude a petroleum contract. Companies seeking the award of a petroleum contract must enter a joint operating agreement approved by the Minister. The Minister may invite applications for PSCs (and other authorisations) by public notice.

3.3.26 The Minister's invitation shall specify the area, the proposed activities, the award criteria, the applicable fees, the deadline and the manner in which applications are to be made. The Minister shall publish invitations to tender for authorisations, notices of grants of authorisations and notices of termination of authorisations in the media in the manner required by regulation.

3.3.27 The petroleum contract is commonly but not mandatorily based on a model PSC published by the Ministry of Natural Resources of the Kurdistan Region of Iraq.

3.3.28 Financial and technical qualifications for PSC contractors include a demonstration of the financial and technical capabilities and evidence of compliance with the United Nations' "Ten Principles of the Global Compact". The Minister may "give preference" to a holder of an authorisation who "partners" with local companies. A party to a PSC must maintain an office in the Kurdistan Region of Iraq.

3.3.29 The terms of all authorisations will be available to the public. Company compliance reports will also be public documents. The KRG has published the texts of most of its PSCs and ancillary documentation on its website.

3.3.30 In 2011, Petroceltic submitted bids for two exploration licences, SW Gharib Onshore and El QA'A Plain Onshore, currently being tendered by EGPC on behalf of the Egyptian Government. Petroceltic's bidding partners are Dana Petroleum, a subsidiary of Korean National Oil Company, (Operator) holding 37.5 per cent, Beach Petroleum holding 25 per cent, and Petroceltic holding 37.5 per cent. The results of these applications have not yet been declared by EGPC.

4. FISCAL TERMS

Algeria

Economic Terms

4.1 During the exploration phase, the Contractor finances both its and, by way of an advance, Sonatrach's funding obligations. In the absence of a discovery, the Contractor cannot claim any reimbursement of sums paid on Sonatrach's behalf.

4.2 In the event of a discovery, the Contractor is entitled to reimbursement by Sonatrach of monies paid on its behalf during the exploration phase and to a part of the production funds.

4.3 Once production has commenced on any discoveries, the hydrocarbons produced in any one year will be divided between Sonatrach and the Contractor on a monthly basis in accordance with their participation interests and in accordance with the allocation of production provision in the Isarene PSC. The allocation is determined according to a formula whereby the amount of production to be distributed is equal to 73.9 per cent *A – B where:

- A is a percentage figure that reflects the average daily production of hydrocarbons in a month; and
- B represents the "R" factor.

A equals 54 per cent if the monthly average daily production of hydrocarbons exceeds 60 Mboepd. If the monthly average daily production is below 60 Mboepd, A is determined by a weighted average of percentage values in accordance with the monthly average daily production (those values range from 59 per cent at 0 – 20 Mboepd, 53 per cent at 20 – 40 Mboepd, and 50 per cent at 40 – 60 Mboepd).

B represents the "R" factor which is the ratio of the inflation adjusted aggregate annual value of oil and gas production to the inflation adjusted annual expenditure on oil and gas operations. The annual value of oil is calculated by multiplying the volume of oil extracted by the price notified by Sonatrach on a monthly basis during that year and the annual value of gas is calculated by multiplying the volume of dry gas extracted by the monthly price obtained for that gas (which will be determined by the gas marketing agreement with Sonatrach). Where the "R" factor:

- is less than or equal to six, B is zero;
- is greater than six but less than eight, B is between 17 per cent and 34 per cent; and
- is greater than eight, B is 34 per cent.

4.4 Sonatrach will pay a royalty on the totality of production issuing from all deposits of hydrocarbons that have been declared commercially exploitable. Sonatrach will pay profit tax. Additionally, transport costs are covered by Sonatrach.

4.5 Costs of liquefaction of dry gas and separation of LPG are covered by the parties pro rata to their part of the production.

4.6 The parties make an annual payment in accordance to their participation rates to an escrow account to cover the costs of abandonment and reinstatement of the sites.

5. CORPORATE GOVERNANCE

5.1 The Directors are committed to maintaining the highest standards of corporate governance commensurate with the size, stage of development and financial status of the Petroceltic Group. The Petroceltic Board sets Petroceltic Group strategy, ensuring that the necessary resources are in place, and also reviews management and financial performance.

The Petroceltic Board

5.2 The Petroceltic Board, as at the date of this Document, comprises seven Directors: three Executive Directors and four Non-Executive Directors. The Petroceltic Board met formally on 16 occasions during 2011. An agenda and supporting documentation was circulated in advance of each meeting. All the Directors bring independent judgment to bear on issues affecting the Petroceltic Group and all have full and timely access to information necessary to enable them to discharge their duties. The Petroceltic Board undertakes a regular performance review process including a review of the Petroceltic Board committees. The review covers a number of areas such as board composition, types of meetings, material required for meetings and strategic decisions.

5.3 The Directors have a wide and varying array of experiences in the oil and gas industry. Appropriate training is provided on the first occasion that a new Director is appointed, if that person is without previous public company experience. Each Director comes up for re-election automatically at least once every three years and each new Director is subject to election at the first annual general meeting after appointment.

5.4 The roles of Chairman and Chief Executive are not combined and there is a clear division of responsibilities between them.

Audit Committee

5.5 The Petroceltic Audit Committee comprises four Non-Executive Directors and is chaired by Con Casey, a Chartered Certified Accountant, who has recent relevant financial reporting experience. The duties of the committee include the review of the accounting principles, policies and practices adopted in preparing the financial statements, external compliance matters and the review of the Petroceltic Group's financial results. The external auditors have the opportunity to meet with the members of the Petroceltic Audit Committee without executive management present at least once a year.

Remuneration Committee

5.6 The Petroceltic Remuneration Committee, chaired by Andrew Bostock, currently comprises four Non-Executive Directors. The committee determines the contract terms, remuneration and other benefits of the Executive Directors.

Nominations Committee

5.7 The Petroceltic Nominations Committee, chaired by Robert Arnott, comprises four Non-Executive Directors and the Petroceltic Chief Executive and is responsible for identifying and recruiting new Directors.

6. HEALTH AND SAFETY

6.1 Petroceltic's aim is to conduct all of its business activities with honesty and integrity, maintaining the highest standards of health, safety and environmental protection within all of its activities. Petroceltic's health and safety policy contains the following four key aims:

6.1.1 prevent accidents or ill-health to people;

6.1.2 avoid accidental releases to the environment;

6.1.3 contribute to the welfare and the development of its personnel and the communities in which it works; and

6.1.4 safeguard its investments.

6.2 Petroceltic sets targets for HSE performance and monitors this performance in all areas. In 2010/2011, Petroceltic had three lost time incidents over 1.5 million operational man-hours. This performance is comparable with industry averages in accordance with the International Association of Drilling Contractors' drilling statistics.

6.3 Wherever Petroceltic operates, it follows the requirements of its HSE management systems to ensure that it consistently complies with regulatory and other applicable requirements, or, where no such regulations exist, will apply industry standards. This includes identifying, assessing and managing HSE risks and preventing pollution. Petroceltic develops specific HSE plans for each operational project and selects competent contractors for the project, ensuring such contractors are effectively managed. Petroceltic aims to continually improve HSE performance through monitoring, regular reporting and periodic audits, which includes reporting and investigating any incidents to prevent recurrence.

6.4 Petroceltic periodically reviews its policy commitments and delivery systems relating to health and safety to ensure they continue to meet both company and stakeholder needs.

7. ENVIRONMENTAL MATTERS

7.1 Petroceltic is subject to environmental regulations in the jurisdictions in which it operates.

7.2 Petroceltic's practice with respect to environmental practices and responsibilities is to conduct its operations in accordance with practices generally accepted and used throughout the international oil and gas industry.

7.3 Environmental impact assessments are conducted at all sites prior to the commencement of operations and assessments are conducted post operation. Compliance during operation is the responsibility of the asset manager.

7.4 Management believes that Petroceltic meets all applicable environmental standards and regulations, in all material respects, and has included appropriate amounts in its capital expenditure budget to continue to meet its environmental obligations. Petroceltic's operations to date have not been negatively affected by any environmental laws or regulations.

8. CORPORATE AND SOCIAL RESPONSIBILITY

Petroceltic values its relationships with investors, industry partners, host governments and communities very highly and aims to be open, transparent, trust-worthy and ethical in all interactions with partners and stakeholders. Petroceltic particularly strives to build enduring relationships with the communities located in the proximity of its operations by investing in sustainable social initiatives which are appropriate to its operational status and stage of development.

PART VIII

INFORMATION ON MELROSE

1. Overview

1.1 Melrose is an oil and gas exploration, development and production company whose shares are admitted to the official list of the UK Listing Authority and traded on the main market of the London Stock Exchange. Melrose is headquartered in Edinburgh with regional offices in Cairo, Varna and Sofia.

1.2 Melrose's oil and gas assets are as follows:

1.2.1 **Egypt**: Melrose has a 100 per cent operated interest in 18 on-shore production licences and two exploration licences, El Mansoura and South East El Mansoura, all of which are located in the Nile Delta. In addition, Melrose has a 40 per cent operated interest in the Mesaha frontier exploration licence in southern Egypt which covers an area of 43,000 km^2. In 2011, Melrose produced oil and gas from its fields in the Nile Delta at a daily average rate of 26.8 Mboepd and had 2P reserves of 74.5 MMboe as at 31 December 2011, both on a working interest basis. Melrose has an active development and exploration programme on its assets in Egypt.

1.2.2 **Bulgaria:** Melrose has a 100 per cent operated interest in the Galata concession which includes three production licences for the Galata, Kavarna and Kaliakra gas fields and an exploration licence, all in shallow waters in the Black Sea off-shore Bulgaria. In 2011, Melrose produced gas at an average daily rate of 42 MMcfpd on a working interest basis from the Kaliakra and Kavarna gas fields. Melrose's Bulgarian assets had 2P reserves of 9.6 MMboe as at 31 December 2011. Melrose is undertaking a development plan for a new gas discovery, Kavarna East, which it plans to bring into production in 2013 but the timing of this development may be delayed to optimise the further production from the Galata Field. 3D seismic data was acquired in 2011 over an under-explored central area of the Galata concession. Interpretation of this data has been completed and will be used to optimise exploration drilling plans for the area to the north of the Galata field trend.

1.2.3 **Romania:** Melrose has two exploration licences, Muridava and Est Cobalcescu, in the western Black Sea off-shore Romania, which were awarded to Melrose and its partners in 2010 under the Romanian 10th Licensing Round. Melrose has a 40 per cent and 70 per cent operated interest in each licence respectively. 3D seismic data is currently being acquired over these licences and a six well exploration drilling programme is currently expected to commence in 2013.

1.2.4 **Turkey:** Melrose has a 66.67 per cent operated interest in five exploration licences in southern Turkey, known as South Mardin. Melrose's first exploration well in Turkey, South West Kanun-1, was drilled in 2011 but failed to encounter hydrocarbons and Melrose intends to withdraw from these licences.

1.2.5 **France:** Melrose had a 27.5 per cent non-operated interest in the Rhône Maritime exploration concession in the French Mediterranean Sea and a 2D Seismic programme has recently been completed over the licence area. Melrose submitted a request to extend the licence term but the prescribed time for a response has passed. In the interim legal options are being evaluated in relation to this licence.

1.3 For the year ended 31 December 2011, Melrose produced 34.3 Mboepd (2010: 41.4 Mboepd) on a working interest basis and 18.7 Mboepd (2010: 17.9 Mboepd) on a net entitlement basis. Increased production volumes from the Kaliakra and Kavarna gas fields off-shore Bulgaria offset natural production declines in Egyptian production. Approximately 86 per cent of 2011 production was gas with the balance comprising hydrocarbon liquids including oil, condensate and LPG.

1.4 As at 31 December 2011, Melrose's 2P reserves were 84.2 MMboe on a working interest basis. Further information on Melrose's reserves and resources is provided in the Melrose Competent Person's Report in Appendix IV.

1.5 Melrose has in place a senior secured borrowing facility of US$375 million and a subordinated secured facility of US$70 million. As at 31 December 2011, amounts drawn under these facilities were US$381.5 million (2010: US$489 million). All borrowings are denominated in US$, amortised in installments from April 2012 and have final repayment dates at the end of 2014. Melrose has entered into the HSBC Senior Secured Facility which will become available upon the Merger becoming Effective. Petroceltic will accede to the HSBC Senior Secured Facility on the Merger becoming Effective. The HSBC

Senior Secured Facility will refinance all of Melrose's current outstandings under its existing reserves based lending facility. Details of the HSBC Senior Secured Facility are set out in paragraph 20.1.6 of Part XII.

2. HISTORY AND DEVELOPMENT

2.1 Melrose was initially established in the mid-1990s through the acquisition of a number of mature oil interests in the Permian Basin of west Texas and New Mexico. In 1998, Melrose acquired a controlling interest in Odyssey Petroleum which had assets in the Nile Delta. It acquired its initial interests in Bulgaria through the acquisition of Petreco S.A.R.L. whose interests included an undeveloped gas discovery at Galata in the Black Sea.

2.2 In 1999, Melrose was admitted to the official list of the UK Listing Authority and to trading on the main market of the London Stock Exchange.

2.3 Melrose consolidated its position in Egypt in 2006 through the acquisition of its joint operating partner, Merlon Petroleum for US$265 million, to achieve a 100 per cent working interest in two exploration concessions and eighteen development leases in the Nile Delta.

2.4 In 2007, Melrose was awarded eight exploration concessions with a combined area of approximately 3,908 km^2 in the South Mardin Basin in south-east Turkey, near the Syrian border. Melrose operates the concessions and holds a 66.67 per cent interest in them.

2.5 In July 2010 Melrose was awarded two off-shore exploration blocks, EX-27 (Muridava) and EX-28 (Est Cobalcescu), in the Romanian 10^{th} Licensing Round.

2.6 Melrose divested of its US oil and gas assets in the Permian Basin in west Texas and east New Mexico in 2010 and in south east Texas in 2011.

3. MELROSE GROUP STRUCTURE AND PRINCIPAL OIL & GAS ASSETS

Melrose is the holding company of the Melrose Group comprising its wholly owned subsidiaries which own and operate its oil and gas assets. Details of the principal subsidiaries of Melrose are set out in paragraph 3 of Part XII of this document.

The following table summarises the principal oil and gas interests of Melrose in Egypt, Bulgaria, Romania, and Turkey.

Country	Asset	Melrose Interest	Partner(s)	Operator
Egypt				
Production Interest	Qantara*	100%		Melrose
	South Bilqas	100%		Melrose
	South El Mansoura*	100%		Melrose
	El Tamad*	100%		Melrose
	Sinfas	100%		Melrose
	Abu Arida	100%		Melrose
	West El Mansoura	100%		Melrose
	Aga	100%		Melrose
	Al Rawda*	100%		Melrose
	Salaka	100%		Melrose
	Tummay-Turbay	100%		Melrose
	West Dikirnis*	100%		Melrose
	North Dikirnis	100%		Melrose
	East Abu Khadra*	100%		Melrose
	West Al Khilala*	100%		Melrose
	South Al Khilala*	100%		Melrose
	South Zarqa*	100%		Melrose
	El Mansoura (South Batra)*	100%		Melrose
	Damas	100%		Melrose
	South Damas	100%		Melrose
	North East Abu Zahra*	100%		Melrose

* Subject to a 3% overriding royalty interest in favour of Stratton Corporation.

Country	Asset	Melrose Interest	Partner(s)	Operator
Exploration Interest	El Mansoura	100%		Melrose
	South East El Mansoura	100%		Melrose
	Mesaha	40%	Beach Energy, Hellenic Petroleum Kuwait Energy	Melrose
Bulgaria				
Production Interest	Galata Production Concession	100%		Melrose
	Kavarna Production Concession	100%		Melrose
	Kaliakra Production Concession	100%		Melrose
Exploration Interest	Block Galata	100%		Melrose
Romania				
Exploration Interest	Muridava	40%	Petromar Resources Sterling Resources	Melrose
	Est Cobalcescu	70%**	Petromar Resources	Melrose
Turkey				
Exploration Interest	South Mardin Concessions (no activity planned)	67%	Southwind Energy Guney Yildeza Petrol	Melrose

** May be reduced to 40% subject to finalisation of a farm-out agreement.

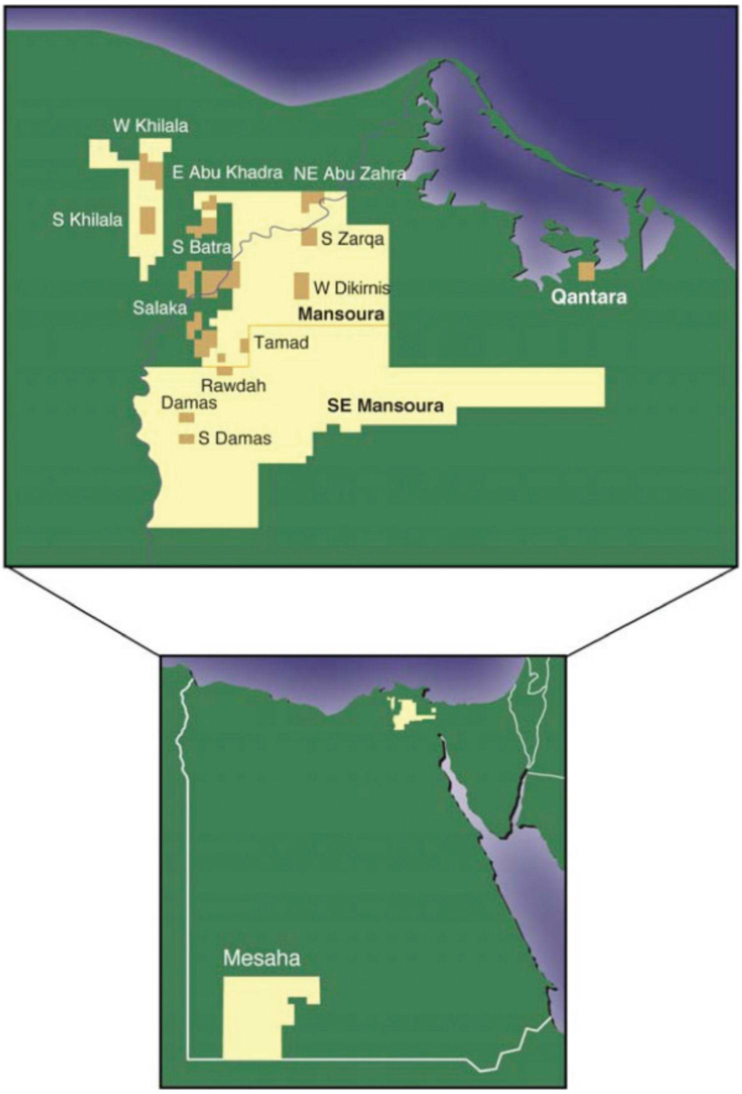
The locations of Melrose's assets are illustrated in the map below.

3.1 **Egypt**

Overview

3.1.1 Melrose has a 100 per cent operated interest in 18 on-shore production licences and 2 exploration licences, El Mansoura and South East El Mansoura, all of which are located in the Nile Delta. In addition, Melrose has a 40 per cent operated interest in the Mesaha frontier exploration licence in southern Egypt.

3.1.2 The locations of the Melrose's Egyptian assets are illustrated on the map below.



3.1.3 Further information on Melrose's Egyptian assets is detailed in the Competent Person's Report set out in Appendix IV of this document.

The Nile Delta Producing Concessions

3.1.4 Melrose has a 100 per cent operated interest in 18 on-shore production licences in the Nile Delta.

3.1.5 In 2011, Melrose produced oil and gas from 11 fields in the Nile Delta at a daily average rate of 26.8 Mboepd on a working interest basis or 11.2 Mboepd on a net entitlement basis. The production stream comprised 128.9 MMcfpd of gas and 4.6 Mbopd of hydrocarbon liquids on a working interest basis and 53.4 MMcfpd of gas and 2 Mboepd of hydrocarbon liquids on a net entitlement basis.

3.1.6 Approximately 70 per cent of Melrose's Egyptian production volumes in 2011 were derived from the West Dikirnis oil and gas field and the West Khilala gas field in the El Mansoura concession. Melrose also has a further nine smaller producing fields in the El Mansoura, South East El Mansoura and Qantara concessions. Production at these nine fields is tied back via pipeline to Melrose's processing centre situated at South Batra, where Melrose made its first major field discovery in Egypt. Ongoing development activity by Melrose includes the expansion of Melrose's West Dikirnis LPG plant and the installation of compression facilities at West Khilala.

3.1.7 Melrose sells all of its oil and gas in Egypt to EGPC, at international market prices for its liquid production and under fixed price contracts for its gas production. Oil and gas companies active in Egypt often carry a high level of receivables with EGPC. Melrose's arrears from EGPC as at 31 December 2011 were US$101 million. Notwithstanding the political environment in Egypt, throughout 2012 Melrose has received regular payments from the Egyptian Government for its hydrocarbon sales in line with a new payment schedule.

3.1.8 Since early 2011, there have been significant political changes and civil unrest in Egypt which have resulted in free parliamentary and presidential elections in 2012. During this period, Melrose has experienced minor operational disruptions.

3.1.9 As at 31 December 2011, Melrose's Egyptian assets had 2P reserves of 74.5 MMboe on a working interest basis.

The Nile Delta Exploration Concessions

3.1.10 Melrose has a 100 per cent operated interest in two exploration concessions, El Mansoura and South East El Mansoura, in the Nile Delta.

3.1.11 The El Mansoura licence is relatively mature and Melrose's primary focus is on development work on existing producing fields. The South East El Mansoura licence is under-explored and Melrose believes that it contains both Tertiary Deltaic prospects in the northern area of the block and Cretaceous and Jurassic prospects in the central and southern areas.

3.1.12 Melrose has acquired 3D seismic data over the South East El Mansoura concession. This data has been processed and has confirmed the presence of several prospects and leads in the Cretaceous oil play which exists in the central and western area of the concession. Melrose has selected one prospect, Al Hajarisah, for drilling in 2013.

Mesaha Frontier Exploration Licence

3.1.13 In 2007, Melrose acquired a 40 per cent operated interest in the 43,000 km^2 Mesaha frontier exploration concession in southern Egypt (the **"Mesaha Exploration Concession"**). Melrose's partners in the Mesaha Exploration Concession are Kuwait Energy, Hellenic Petroleum and Beach Energy.

3.1.14 A 1,041 km 2D seismic programme was completed on the Mesaha Exploration Concession to complement a regional 2D seismic survey acquired in 2010. An exploration well is currently expected to be initiated in 2012.

Summary of the Egyptian Petroleum Regime

3.1.15 The Egyptian petroleum regime is based on PSCs with terms enforceable under Egyptian law. The parties to the PSC are the Egyptian government and the contractor. The production sharing element of the contract is linked to production rates, however it is the contractor that bears the exploration risk.

3.1.16 Since 2003, the three licensing bodies – EGPC (Egyptian General Petroleum Corporation), EGAS (Egyptian Natural Gas Holding Company) and GANOPE (Ganoub El Wadi Petroleum Holding Company) – all offer bid rounds according to the nature of the asset. Previously, EGPC offered all blocks.

3.1.17 The exploration licence grants the holder exclusive rights to explore and drill for hydrocarbons in a defined area. The contract period for the exploration phase can range from between seven to nine years and is divided into three phases. At the end of each of the first and second phases the contractor must relinquish 25 per cent of the original area and at the end of the final phase any area except that converted into a development lease must be relinquished.

3.1.18 In an exploration licence round the invitation to bid is based on a number of variable / biddable parameters. These include the contract period, relinquishment amount (after each phase), minimum work obligations, production sharing split and bonuses (signature and production).

3.1.19 Any development will result in a 50:50 joint venture company (comprising one of EGPC, EGAS or GANOPE and the PSC contractor party) being set up to operate the field.

3.1.20 A development licence must be granted before development work on a field can begin and this follows a period of delineation to establish the extent and boundaries of the field. Typically, an oil development licence is granted for a period of 20 years with one five year extension period and a gas development licence is granted for a period of 25 years.

3.2 Bulgaria

Overview

3.2.1 Melrose has a 100 per cent operated interest in one exploration licence and three production concessions in shallow waters off-shore Bulgaria in the Black Sea (the **"Galata Concession"**).

3.2.2 Melrose acquired its interest in the Galata Concession in 1998. A development plan for the Galata field was initiated in 2002 and production commenced in 2004. From 2004 until early 2009, the Galata field supplied a significant percentage of Bulgaria's domestic gas. In 2009, the Galata field was shut-in in order to prepare it for use as a gas storage facility. The field still contains approximately 5 Bcf of cushion gas which could be produced in the future in the event that the gas storage project does not progress.

3.2.3 Further information on Melrose's Galata Concession is detailed in the Competent Persons Report set out in Appendix IV of this document.

Gas Production on the Galata Concession

3.2.4 Melrose discovered the Kaliakra gas field in 2007 and the Kavarna gas fields in 2008. The Kaliakra and Kavarna fields are located near to the Galata field. They were brought onto production by laying single subsea completions tied back to the existing Galata field infrastructure and gas production from those fields commenced in November 2010.

3.2.5 2011 was the first full year of production from the Kaliakra and Kavarna gas fields and they produced at a combined average daily rate of 42 MMcfpd on a working interest basis.

3.2.6 Melrose sells its gas from the Galata Concession to Bulgargaz EAD, a Bulgarian state owned utility company, and Agropolychim, an independent industrial gas purchaser.

3.2.7 As at 31 December 2011, the Galata Concession had 2P reserves of 9.6 MMboe. Further information on Melrose's reserves and resources is detailed in the Melrose Competent Persons Report in Appendix IV of this document.

Exploration on the Galata Concession

3.2.8 In 2010, Melrose made a further gas discovery, Kavarna East, with 2P reserves of 8.2 Bcf. This field is due to be brought into production using a shared subsea flowline with the Kavarna field.

3.2.9 In 2011, Melrose drilled an unsuccessful exploration well on the Kaliakra East prospect to test a structure near the Kaliakra field. The main reservoir target was found to be eroded and the well was subsequently plugged and abandoned.

3.2.10 Melrose recently acquired a total of 512 km^2 3D seismic data on an area to the north of the existing Galata Kaliakra field trend. The interpretation of the 3D seismic data has been completed confirming the presence of a number of potential reservoir structures.

3.2.11 Eight structures have been identified in the area and Melrose has estimated a total combined unrisked P50 prospective resource of 125 Bcf. The highest ranked prospect is Kamchia, which has an estimated P50 prospective resource of 27 Bcf and a chance of success estimated at 40 per cent. Preparations are underway to drill this well in early 2013 as part of a programme that will include completion of the Kavarna East discovery.

3.2.12 In 2011, Melrose secured an extension to its Galata exploration licence until February 2013, after which it may apply for a further 2 year extension.

Summary of the Bulgarian petroleum regime

3.2.13 In Bulgaria licensing of acreage can be undertaken by way of competitive bidding (i.e. licensing rounds) and through direct granting of exploration permits. Since 1989 three licensing rounds have been conducted.

3.2.14 Exploration for oil and gas is undertaken via a permit for prospecting and exploration while the production of oil and gas is permitted only through the granting of a production concession. Permits are granted by the Bulgarian Council of Ministers based on a proposal from the Ministry of Environment and Water.

3.2.15 An exploration permit is granted for a period of three years with two extensions available of two years each. Parts of the permit area may be subject to mandatory relinquishment prior to any extension.

3.2.16 A production concession is granted for a period of up to 35 years with the possibility to extend for a further 15 years. A permit holder will be directly nominated as a concessionaire for a production concession provided it has declared and registered the commercial discovery. The permit holder must file a written application for a concession within six months of receiving the certificate of a registered commercial discovery.

3.3 Romania

Overview

3.3.1 Melrose has two exploration licences, Muridava and Est Cobalcescu off-shore Romania, in the western Black Sea (the **"Romanian Exploration Blocks"**). Melrose operates the Muridava block with a 40 per cent working interest; Sterling Resources Limited holds a 40 per cent interest and Petromar Resources S.A (**"Petromar"**) holds a 20 per cent interest. Melrose operates the Est Cobalcescu block with a 70 per cent working interest (which may be reduced to 40 per cent working interest subject to agreement of final terms of a farm-out agreement), and Petromar holds a 30 per cent working interest.

3.3.2 The Romanian Exploration Blocks were awarded to Melrose and its partner Petromar in 2010 under the Romanian 10th Licensing Round and came into force after their formal ratification by the Romanian Council of Ministers in October 2011. The licences have a three year initial term which may be followed by an optional three year extension. The firm three year work programme for each block comprises seismic acquisition and three wells.

3.3.3 In 2012, Melrose farmed out a 40 per cent interest in the Muridava block to Midia Resources SRL (**"Midia"**), a wholly-owned subsidiary of Sterling Resources Limited.

3.3.4 The Romanian Exploration Blocks have a combined area of approximately 2,000 km^2 in shallow waters and are under-explored as they are located in an area formerly subject to a maritime boundary dispute between Romania and Ukraine.

3.3.5 Melrose believes that the Romanian Exploration Blocks may contain multiple oil and gas exploration prospects in the Cretaceous, Eocene, Miocene and Pliocene formations.

3.3.6 Melrose has placed the unrisked resource potential of the Romanian Exploration Blocks in the range of between 1 Tcfe and 2 Tcfe.

3.3.7 Melrose's current work programme for the Romanian Exploration Block is for 1,900 km^2 of 3D seismic data, currently being acquired, and a six-well exploration drilling programme to commence in 2013.

Summary of the Romanian petroleum regime

3.3.8 The Ministry of Economy and Finance in Romania has responsibility for petroleum policy and strategy. The petroleum resources are managed by the National Agency for Mineral Resources (**"NAMR**"), which was established in 1993.

3.3.9 The Romanian upstream sector is licensed via concession fiscal terms, with licences being awarded by NAMR through competitive licensing rounds. The winning bid is selected, following the closing date for tenders, on a scoring system. The concession agreement is then negotiated between the winning bidder and the Romanian government prior to being submitted for approval by the Romanian government. It is the date of ratification that sets the effective start date of the petroleum concession.

3.3.10 The tenth round was announced by NAMR in 2009 and offered 30 exploration concessions, including blocks in the Black Sea that had previously been subject to a border dispute with Ukraine. The winners were announced in 2010 and officially ratified in 2011. NAMR publishes a list of available blocks in the Official Gazette and following the ascension of Romania to the EU licensing rounds, are also announced in the Official Journal of the EU.

3.3.11 The National Energy Regulatory Authority (**"ANRE"**) is responsible for the regulation of gas prices for end users and currently prices are subject to a subsidisation or "social tariff". However as a member of the EU, Romania is duty bound to comply with EU requirement for gas market liberalisation and unbundling, which will lead to the gradual abolition of the social tariff.

3.4 **Other Licences**

3.4.1 In 2007, Melrose acquired an operated interest in five exploration licences in southern Turkey (the **"South Mardin Exploration Licences"**). Melrose has a 66.67 per cent operating interest in the South Mardin Exploration Licences.

3.4.2 Melrose's first exploration well in Turkey, South West Kanun, was drilled in 2011 to test the Cretaceous and Ordovician interval but failed to encounter hydrocarbons. Given the results of this well, Melrose is unlikely to pursue further exploration activities in the areas, subject to the South Mardin Exploration Licences.

3.4.3 Melrose held a 27.5 per cent non-operated interest in a 9,375km² off-shore permit in the deep water Rhône Maritime exploration concession in the French Mediterranean Sea and a 2D seismic programme has recently been completed over the licence area. Melrose has submitted a request to the French authorities to extend the licence term and is currently awaiting clarification regarding the status of the request since the prescribed time for a response by the French authorities has passed with no such response being made. On 9 August 2012, Melrose lodged an appeal with the French Authorities in respect of the non-extension of the licence. Melrose is considering its further legal options in relation to the licence.

3.4.4 In 2012, Melrose submitted bids for two exploration licences, Patraikos and Ioannina, currently being tendered by the Greek Government. Melrose's bidding partners are Hellenic Petroleum S.A. and Edison International SpA, with each company holding a 33.3 per cent interest in the bidding group. The results of these applications have not yet been declared by the Greek government.

4. FISCAL TERMS

4.1 **Egypt**

Overview

4.1.1 Melrose operates all of its interests in Egypt under concession agreements. Pursuant to these agreements, Melrose, as contractor, enters into an agreement with one of Egypt's three concession agreements entities; EGPC, EGAS or GANOPE. The El Mansoura concession became effective on 22 June 1998 and was amended on 9 May 2005. The Qantara concession became effective on 22 June 1998, the South East El Mansoura Concession became effective on 26 July 2005 and, most recently, the Mesaha concession became effective on 9 October 2007.

4.1.2 The concession agreements specify an exploration period during which Melrose is responsible for all exploration activities on the concession and is subject to requirements to perform certain work programmes. The concession agreements typically have an initial term of three or four years and allow Melrose, as the contractor, to extend the exploration term for two additional two year periods. The development phase of a concession agreement commences when commercial quantities of oil and/or gas are discovered. The concession agreements require Melrose to form an operating company with its government partner or partners within a defined period following a commercial discovery, and to enter into a development lease for the development of a certain block (or field) within one of its concessions. Melrose formed the Mansoura Petroleum Company to operate the El Mansoura and South East El Mansoura concessions, and the Qantara Petroleum Company to operate the Qantara concession. The terms of a development lease are pre-agreed in the relevant concession agreement but must be ratified by the Parliament of Egypt. A development lease typically has an initial term of 20 years that can be extended further up to a total term of 35 years.

Relinquishment

4.1.3 Melrose is required to relinquish a minimum of 25 per cent of the original exploration area at the end of each exploration period. At the end of the final exploration period, Melrose is required to relinquish the remaining area save for those parts in which a commercial discovery has been made. Melrose may also relinquish areas at any time if they choose to do so.

Economic Terms

4.1.4 Concession agreements specify the rights and responsibilities of the parties thereto in relation to the exploration, development and production of oil and gas. During the exploration period Melrose is responsible for all costs relating to exploration activities on the concession.

4.1.5 The following table summarises the terms of Melrose's concession agreements:

	El Mansoura Concession[1]	South East El Mansoura Concession	Qantara Concession	Mesaha Concession[6]
Summary terms:				
Melrose interest	100%	100%	100%	40%
Effective date	22/06/1998	26/07/2005	22/06/1998	9/10/2007
Exploration and development period:				
Expiration of exploration period[2]	21/12/2012	26/07/2014	21/08/2024[3]	09/10/2016
Initial development lease period	20 years	20 years	20 years	20 years
Maximum development lease period	35 years	35 years	35 years	35 years
Production Sharing:				
Cost oil	35%	35%	35%	35%/30%[4]
Maximum annual cost recovery exploration expenditures	25%	25%	33⅓%	20%
Development expenditures	25%	25%	33⅓%	20%
Operating costs	100%	100%	100%	100%
Excess cost oil recovery:				
Egyptian partner	70%	85%	85 to 91%	100%
Melrose	30%	15%	9 to 15%	0%
Profit oil:	65%	65%	65%	65%/70%[5]
Egyptian partner	80 to 85%	82 to 87%	85 to 91%	70 to 75%
Melrose	15 to 20%	13 to 18%	9 to 15%	25 to 30%

1. Amended on 9 May 2005.
2. Assumes all extensions will be exercised.
3. The Qantara concession was converted to a development lease in 1999.
4. 35 per cent in the first five years. 30 per cent thereafter.
5. 65 per cent in the first five years. 70 per cent thereafter.
6. In the case of the Mesaha concession, different proportions apply for different hydrocarbons.

4.1.6 The production sharing and cost recovery provisions in the concession agreements specify how Melrose allocates the production on the concession during the development period. Production from a concession is split between cost oil, which accounts for 35 per cent of annual production (in the case of the Mesaha Exploration Concession, declining to 30 per cent after the first five years) and profit oil, which accounts for 65 per cent of annual production (in the case of the Mesaha Exploration Concession, increasing to 70 per cent after the first five years), respectively.

4.1.7 Cost oil is specifically allocated to Melrose to recover operating, exploration and development expenditures in relation to commercial exploration, production and development of oil and gas on a concession from the gross reserves on the concession. These cost recovery mechanisms permit Melrose to recover each year between one-fifth (in the case of the Mesaha Exploration Concession) and one-third (in the case of the Qantara concession) of the aggregate exploration expenditures and development expenditures incurred during the lifetime of the concession; they also permit Melrose to recover all annual operating costs incurred in producing oil or gas.

4.1.8 Melrose is able to carry forward for up to ten years any exploration and development expenditures that it does not recover. Under the annual cost recovery, if the annual cost oil exceeds the amount of exploration and development expenditures Melrose can recover each year ("excess cost oil"), Melrose can retain a percentage of the amount that it would otherwise receive as cost oil, with the remainder being shared with its respective Egyptian partners. The percentage that it retains varies by concession. The concession agreements provide that the Egyptian government is entitled to a royalty of 10 per cent of the total value of oil and gas produced, which is payable by EGPC, or GANOPE, from its share of production. Income tax is payable on Melrose's profits in Egypt at a rate of 40.6 per cent. However, the concession agreements provide that EGPC or GANOPE is responsible for paying that tax from its share of production. The concession agreements specify that Melrose receives its payments pursuant to the production sharing and cost recovery provisions on a quarterly basis.

4.1.9 Melrose's ownership interests in the El Mansoura and Qantara concessions are subject to a 3 per cent net profit interest in the profit and excess cost revenue under the terms of the original operating agreements.

4.1.10 Melrose sells oil produced under the concession agreements to EGPC at prevailing market prices. The development lease terms also provide for a gas sales agreement between Melrose and its Egyptian partner on the one hand, and EGAS on the other hand. Under this gas sales agreement, sale prices vary by concession but are in each case linked to the market price of oil and average gas prices in the Mediterranean. Melrose sells gas at a price that is fixed if the price of oil is at least US$22 per barrel.

4.2 **Bulgaria**

4.2.1 Melrose was awarded the Galata concession in 2001.

4.2.2 The concession regime in Bulgaria requires royalty payments of between 2.5 per cent and 25 per cent to the government, depending on the number of times the production company has recovered its investments on a project. In addition, the operating company is subject to a 10 per cent corporation tax levy on its income and must make bonus payments of up to US$5 million based on the attainment of pre-determined production levels.

4.2.3 The concession term is for 25 years which may be extended by a further 10 years and is subject to Melrose fulfilling minimum work programme commitments.

4.3 **Romania**

4.3.1 Melrose entered into concession agreements with the Romanian authorities in March 2011 in respect of two blocks, Muridava and Est Cobalcescu. This was formally ratified by the Romanian regulatory authorities on 24 October 2011. The fiscal regime in Romania is tax- and royalty-based, with the royalty rate ranging from 3.5 per cent to 13.5 per cent depending upon quarterly production thresholds. The corporation tax rate is 16 per cent.

4.4 **Turkey**

4.4.1 Melrose has a 66.67 per cent interest in five blocks in the South Mardin basin in Turkey, pursuant to a license agreement which became effective on 3 September 2007. The fiscal regime in Turkey requires a royalty payment of 12.5 per cent and, in addition, the operating company is subject to a 20 per cent corporation tax on its income as well as a branch tax of 15 per cent.

4.4.2 The license agreement has an initial exploration term of four years with the option of two further extensions of two years each. Melrose is operator of the blocks and, alongside its partners, is subject to a minimum work programme.

5. CORPORATE AND SOCIAL RESPONSIBILITY

5.1 Melrose operates a formal corporate and social responsibility policy which provides the basis of an ongoing programme of social welfare and development initiatives which to date have mostly been associated with providing financial, technical and operational support to the development of sustainable education projects in the region of its existing producing interests. In addition, Melrose also established the Melrose Resources plc Charitable Trust (**"**the **Trust"**) in 2008. The Trust uses funds raised through charitable events to help finance social projects in and around Melrose's areas of operation.

5.2 In Egypt, Melrose has been instrumental in supporting and funding a recently-opened 28 room school close to its West Dikirnis facilities and also supports a girl's school in Tammeya.

5.3 In Bulgaria, Melrose also provides support for selected educational initiatives, including the Karim Dom Centre in Varna, which provides support to over 200 children with special needs.

PART IX

PETROCELTIC HISTORICAL FINANCIAL INFORMATION

Presentation of Petroceltic Financial Information

The financial information relating to Petroceltic, incorporated by reference in this Document, as summarised in the paragraph headed "Incorporation of relevant Petroceltic information by reference" below, as at the 12 months ended 31 December 2011, 31 December 2010 and 31 December 2009 has been extracted (to the extent that it has been reproduced in this Document) without material adjustment from the published annual report and audited financial statements of Petroceltic for the 12 months ended 31 December 2011, 31 December 2010 and 31 December 2009. Financial information for Petroceltic in this Document for the years ended 31 December 2011, 31 December 2010 and 31 December 2009 has been prepared in accordance with International Financial Reporting Standards (IFRS) as adopted by the EU.

Petroceltic will publish its interim results for the six month period ended 30 June 2012 on 24 August 2012, and they will be available on that date on Petroceltic's website, (www.petroceltic.ie).

Incorporation of relevant Petroceltic information by reference

The table below sets out the various Petroceltic documents which are incorporated by reference into this Document so as to provide the information required under the AIM and ESM Rules and to ensure that Shareholders and others are aware of all information which, according to the particular nature of the Enlarged Group and of the Ordinary Shares, is necessary to enable Shareholders and others to make an informed assessment of the assets and liabilities, financial position, profits and losses and prospects of the Enlarged Group.

Company	Document	Link
Petroceltic	Annual Report year ended 31 December 2011	http://www.petroceltic.annualreport11.com/
	Annual Report year ended 31 December 2010	http://www.petroceltic.annualreport10.com/
	Annual Report year ended 31 December 2009	http://www.petroceltic.com/investor-centre/financial-reports/fr-2009.aspx

PART X

MELROSE HISTORICAL FINANCIAL INFORMATION

Presentation of Melrose Financial Information

The financial information relating to Melrose, incorporated by reference in this Document, as summarised in the paragraph headed "Incorporation of relevant Melrose information by reference" below, as at the 12 months ended 31 December 2011, 31 December 2010 and 31 December 2009 has been extracted (to the extent that it has been reproduced in this Document) without material adjustment from the published annual report and audited financial statements of Melrose for the 12 months ended 31 December 2011, 31 December 2010 and 31 December 2009. Financial information for Melrose in this Document for the years ended 31 December 2011, 31 December 2010 and 31 December 2009 has been prepared in accordance with International Financial Reporting Standards (IFRS) as adopted by the EU.

Melrose will publish its interim results for the six month period ended 30 June 2012 on 22 August 2012 and they will be available on that date on Melrose's website, (www.melroseresources.com).

Incorporation of relevant Melrose information by reference

The table below sets out the various Melrose documents which are incorporated by reference into this Document so as to provide the information required under the AIM and ESM Rules and to ensure that Shareholders and others are aware of all information which, according to the particular nature of the Enlarged Group and of the Ordinary Shares, is necessary to enable Shareholders and others to make an informed assessment of the assets and liabilities, financial position, profits and losses and prospects of the Enlarged Group.

Company	Document	Link
Melrose	Annual Report year ended 31 December 2011	http://online.hemscottir.com/ir/mrs/ar_2011/ar.jsp
	Annual Report year ended 31 December 2010	http://online.hemscottir.com/ir/mrs/ar_2010/ar.jsp
	Annual Report year ended 31 December 2009	http://online.hemscottir.com/ir/mrs/ar_2009/ar.jsp

PART XI

TAXATION

PART A: INTRODUCTION

The following is a general summary of the Irish and UK tax considerations applicable to certain Irish and UK shareholders of the Enlarged Company following the Merger becoming Effective. These statements deal only with the position of Enlarged Company Shareholders who are resident (and, in the case of individuals only, ordinarily resident and domiciled) solely in Ireland or the UK for tax purposes (except where the position of a non-Irish or non-UK resident shareholder is expressly referred to) and who hold their Existing Petroceltic Shares or will hold any New Petroceltic Shares acquired by them as an investment and who are the absolute beneficial owners of the Existing Petroceltic Shares and of all dividends of any kind paid in respect of them and who will be the absolute beneficial owners of any New Petroceltic Shares acquired by them and of all dividends paid in respect of them. The tax position of certain categories of shareholders who may be subject to special rules including, but not limited to, persons who have acquired their Existing Petroceltic Shares or who are acquiring their New Petroceltic Shares (or who are deemed to have acquired their Existing Petroceltic Shares or will be deemed to acquire their New Petroceltic Shares) in connection with an employment or office, dealers in securities, insurance companies, collective investment schemes, financial institutions or companies qualifying for the substantial shareholding exemption is not considered.

These comments are intended only as a general guide based on current legislation and revenue practice in Ireland and the United Kingdom (which may change in the future) and do not constitute legal or tax advice. It is not intended to provide specific advice and no action should be taken or omitted to be taken in reliance upon it. Any person who is in doubt as to their tax position, or who is subject to tax in any jurisdiction other than Ireland or the UK, should consult their professional advisors. Enlarged Company Shareholders should be aware that future legislative, administrative and judicial changes could affect the taxation consequences described below.

PART B: IRISH TAXATION

1. CAPITAL GAINS TAX ("CGT")

1.1 The Enlarged Company Shares constitute chargeable assets for Irish CGT purposes and, accordingly, Enlarged Company 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 Enlarged Company Shares. The Irish CGT rate is currently 30 per cent. As it is not expected that the Enlarged 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 Enlarged Company Shareholders who are neither resident or ordinarily resident in Ireland and who do not hold the Enlarged Company 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 Enlarged Company Shares. An Irish resident individual, who is an Enlarged Company Shareholder who ceases to be an Irish resident for a period of less than five years and who disposes of Enlarged Company Shares during that period, may in certain circumstances be liable, on a return to Ireland, to CGT on any gain realised.

2. TAXATION OF DIVIDENDS

2.1 Irish resident Enlarged Company Shareholders who are individuals will be subject to income tax, social security and the universal social charge depending on their circumstances on the aggregate of the net dividend received and the withholding tax deducted. The withholding tax deducted will be available as a credit against the individual's income tax liability. An Enlarged Company Shareholder may claim to have the withholding tax refunded to him to the extent that it exceeds his income tax liability. An Irish resident Enlarged Company Shareholder which is a company will not be subject to Irish corporation tax on dividends received from the Enlarged Company and tax will not be withheld at source by the Enlarged Company provided the appropriate declaration is validly made. A company which is a close company, as defined under Irish legislation, may be subject to a corporation tax surcharge on such dividend income to the extent that it is not distributed within the appropriate time frame. Enlarged Company Shareholders who are Irish approved pension funds or Irish approved charities are generally exempt from tax on their dividend income and will not have tax withheld at source by the Enlarged Company from dividends, provided the appropriate declaration is validly made.

2.2 UK resident Enlarged Company Shareholders (including both individuals and companies) will not be subject to Irish tax on dividends received. Irish withholding taxes will not be deducted from dividends paid to UK resident Enlarged Company Shareholders provided the appropriate declarations are validly made.

3. IRISH CAPITAL ACQUISITIONS TAX

3.1 Capital acquisitions tax (**CAT**) covers both gift tax and inheritance tax. Irish CAT may be chargeable on an inheritance or a gift of Enlarged Company Shares as such shares would be considered Irish property, notwithstanding that the gift or inheritance is between two non-Irish resident and non-ordinarily Irish resident individuals. The current rate of CAT is 30 per cent. Enlarged Company Shareholders should consult their tax advisors with respect to the CAT implications of any proposed gift or inheritance of Enlarged Company Shares.

4. STAMP DUTY

4.1 Transfers or sales of Enlarged Company Shares will be subject to ad valorem stamp duty. This is payable by the purchaser. The Irish rate of stamp duty on shares is currently 1 per cent.

PART C: UNITED KINGDOM TAXATION

1. DIVIDENDS

1.1 No UK tax will be withheld by the Enlarged Company when it pays a dividend.

1.2 A UK resident individual shareholder who is liable to income tax at the basic rate will be subject to tax on the gross dividend at the rate of 10 per cent.

1.3 A UK resident individual Enlarged Company Shareholder who is a higher rate taxpayer will be liable to income tax on the gross dividend at the rate of 32.5 per cent. Enlarged Company Shareholders subject to the additional rate of tax will be liable to income tax on the gross dividend at the rate of 42.5 per cent.

1.4 A UK resident individual Enlarged Company Shareholder who holds less than 10 per cent of the issued shares in the Enlarged Company will be entitled to a tax credit, currently at the rate of 1/9th of the cash dividend paid (equal to 10 per cent of the aggregate of the net dividend and related tax credit). The individual is treated as receiving for tax purposes gross income equal to the cash dividend plus the tax credit. The tax credit is set against the individual's tax liability on that gross income. After taking account of any available tax credit, a basic rate taxpayer's liability will be eliminated (since the 10 per cent tax credit is deemed to cover all that is due for a basic rate taxpayer), a higher rate taxpayer will pay tax at an effective rate of 25 per cent and an additional rate taxpayer will pay tax at an effective rate of 36.1 per cent.

1.5 It should be noted that from 6 April 2013, the rate of income tax payable by additional rate taxpayers on a cash dividend and tax credit will be reduced to 37.5 per cent. This will result in an effective dividend tax rate of 30.56 per cent for additional rate taxpayers, after taking into account the 10 per cent tax credit, if this is available.

1.6 UK resident Enlarged Company Shareholders who do not pay income tax or whose liability to income tax on the dividend and related tax credit is less than the tax credit (including pension funds, charities and certain individuals) are not entitled to claim repayment of any part of the tax credit associated with the dividend from HM Revenue & Customs.

1.7 UK resident individual shareholders who hold their shares in an Individual Savings Account are exempt from tax on dividends paid by the Enlarged Company.

1.8 A UK resident corporate Enlarged Company Shareholder will be subject to corporation tax on any dividend received from the Enlarged Company, currently 24 per cent for companies paying the main rate of corporation tax.

1.9 UK resident Enlarged Company Shareholders will not have any Irish tax withheld from dividends paid by the Enlarged Company (whether individual or corporate shareholders) provided relevant declarations are validly made (as noted in Part B: Irish Taxation, paragraph 2.2 in this Part XI).

1.10 A UK resident individual Enlarged Company Shareholder who is either not ordinarily resident or non-UK domiciled can elect to be taxed on the dividend only when it is remitted to the UK. This is a complex area of UK taxation and specific detailed advice should be obtained before taking any action in this regard. For example, if you are regarded as a "long-term" resident (ie resident in the UK for 7 of the last 9 tax years) you will be required to pay an annual charge of £30,000 to enable the remittance basis of taxation to be used (this increases to £50,000 for those who have been UK resident for at least 12 of the previous 14 years).

2. TAXATION OF CHARGEABLE GAINS

2.1 A disposal of Enlarged Company Shares by an Enlarged Company Shareholder who is either resident or ordinarily resident in the UK may, subject to the Enlarged Company Shareholders, circumstances and any available exemption or relief, give rise to a chargeable gain (or allowable loss) for the purposes of UK taxation of chargeable gains.

2.2 For UK resident Enlarged Company Shareholders subject to the charge of corporation tax on chargeable gains, indexation allowance should be available to reduce the amount of chargeable gain realised on a disposal of Enlarged Company Shares (but not to create or increase any loss).

2.3 For UK resident Enlarged Company Shareholders who are subject to capital gains tax, such as individuals, trustees and personal representatives, an annual exemption is available, such that capital gains tax is chargeable only on gains arising from all sources during the tax year in excess of this figure. The annual exemption is £10,600 for the tax year 2012 – 2013. Capital gains tax chargeable will be at the current rate of 18 per cent (for basic rate taxpayers) and 28 per cent (for higher and additional rate taxpayers) during the tax year 2012 – 2013.

2.4 An Enlarged Company Shareholder who is neither UK resident nor UK ordinarily resident will not be subject to UK tax on a gain arising on a disposal of Enlarged Company Shares unless (i) the Enlarged Company Shareholder carries on a trade, profession or vocation in the UK through a branch, agency or permanent establishment and, broadly, holds the Enlarged Company Shares for the purposes of the trade, profession, vocation, branch, agency or permanent establishment or (ii) the shareholder falls within the anti-avoidance rules applying to individuals who are temporarily not resident or ordinarily resident in the UK.

2.5 Similar to the position with UK dividends, a UK resident Enlarged Company Shareholder who is UK resident but non-UK domiciled may elect to be taxed on the capital gain only when it is remitted to the UK (note that "ordinary residence" has no bearing in these circumstances). As mentioned previously (in Part C: United Kingdom Taxation, paragraph 1.10 of this Part XI), detailed UK tax advice should be obtained before considering whether to adopt the remittance basis of UK taxation.

3. UK STAMP DUTY AND STAMP DUTY RESERVE TAX ("SDRT")

3.1 No stamp duty or SDRT will be payable by an Enlarged Company Shareholder on the allotment, issue or registration of Enlarged Company Shares.

3.2 Since the Enlarged Company is incorporated outside of the UK no SDRT should apply to agreements to transfer the Enlarged Company Shares provided that the Enlarged Company Shares will not be registered on any register kept in the UK and are not paired with shares issued by a body corporate incorporated in the UK.

3.3 Legal instruments transferring the Enlarged Company Shares should not be within the scope of UK stamp duty provided that such instruments are executed outside of the UK and do not relate to any matter or thing done or to be done in the UK. Where such an instrument is chargeable to stamp duty in both the UK and Ireland and has been duly stamped in one of those countries it is deemed to be stamped in the other country up to the amount of duty it bears but must be stamped for any excess.

3.4 The above comments are intended as a guide to the general UK stamp duty and SDRT position. Special rules apply to persons such as market intermediaries, charities, persons connected with depositary arrangements or clearance services and to certain sale and repurchase and stock borrowing arrangements.

PART XII

ADDITIONAL INFORMATION

1. RESPONSIBILITY

Petroceltic, the Directors and the Proposed Directors, whose names appear on page 2 of this document, accept responsibility for the information contained in this document. To the best of the knowledge and belief of Petroceltic, the Directors and the Proposed Directors (who have taken all reasonable care to ensure that such is the case), the information contained in this document is in accordance with the facts and does not omit anything likely to affect the import of such information.

AGR Petroleum (ME) Limited accepts responsibility for its reports contained in Appendix I and Appendix III of this document. To the best of the knowledge of AGR Petroleum (ME) Limited, which has taken all reasonable care to ensure that such is the case, the information contained in such reports is in accordance with the facts and does not omit anything likely to affect the import of such information.

DeGolyer and MacNaughton accepts responsibility for its report contained in Appendix II of this document. To the best of the knowledge of DeGolyer and MacNaughton, which has taken all reasonable care to ensure that such is the case, the information contained in such report is in accordance with the facts and does not omit anything likely to affect the import of such information.

Senergy (GB) Limited accepts responsibility for its report contained in Appendix IV of this document. To the best of the knowledge of Senergy (GB) Limited, which has taken all reasonable care to ensure that such is the case, the information contained in such reports is in accordance with the facts and does not omit anything likely to affect the import of such information.

2. INCORPORATION AND REGISTERED OFFICE

Petroceltic was incorporated on 16 May 1984 in Ireland under the Companies Acts 1963 to 1983 with registration number 101176 under the name Ennex International Public Limited Company. The name Ennex International Public Limited Company was changed to Petroceltic International Public Limited Company on 4 November 2003. The liability of the members of Petroceltic is limited.

The principal legislation under which Petroceltic operates and under which the Enlarged Company Shares will be issued are the Irish Companies Acts and the regulations made thereunder.

Petroceltic is domiciled in Ireland with its registered office and principal place of business at 6th Floor, 75 St. Stephen's Green, Dublin 2, Ireland. The telephone number of Petroceltic's registered office is +353 1 421 8300.

3. ORGANISATIONAL STRUCTURE

Following the Merger becoming Effective, Petroceltic will be the ultimate holding company in the Enlarged Group.

Petroceltic Group

Details of Petroceltic's principal subsidiaries and associated undertakings (each of which are wholly owned and considered by Petroceltic 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 Petroceltic Group) are set out below:

Name	Country of Incorporation	Percentage Ownership
Petroceltic Investments Limited	Ireland	100%
Petroceltic Ksar Hadada Limited	Jersey	100%
Petroceltic Kurdistan Limited	British Virgin Islands	100%
Petroceltic Italia S.r.l.	Italy	100%
Petroceltic CSI Limited	Jersey	100%
Petroceltic Jersey (2009) Holdings Limited	Jersey	100%
Petroceltic Ain Tsila Limited	Jersey	100%

Melrose Group

Details of Melrose's principal subsidiaries and associated undertakings (each of which are wholly owned and considered by Melrose 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 Melrose Group) are set out below:

Name	Country of Incorporation	Ownership
Melrose Petroleum El Mansoura Company	Cayman Islands	100%*
Melrose Petroleum Qantara Company	Cayman Islands	100%*
Melrose Petroleum South East El Mansoura Company	Cayman Islands	100%*
Odyssey Petroleum (Qantara) Ltd	Bermuda	100%*
Odyssey Petroleum (El Mansoura) Ltd	Bermuda	100%*
Melrose Egypt Mesaha Ltd	Bermuda	100%
Melrose Resources S.A.R.L.	Luxembourg	100%
Melrose Resources Bulgaria EOOD	Bulgaria	100%*
Melrose Mediterranean Ltd	England	100%
Melrose Energy Company	Texas	100%
Melrose Petroleum Company	Texas	100%
Melrose Resources Turkey Ltd	Scotland	100%
Melrose Resources Romania B.V.	Netherlands	100%

* Indirect

Melrose also holds an interest of 50 per cent in each of the joint operating companies Mansoura Petroleum Company (which operates the El Mansoura Concession), Al Rawda Petroleum Company (which operates the South East El Mansoura Concession) and Qantara Petroleum Company (which operates the Qantara Concession). Each of the joint operating companies are incorporated under the laws of Egypt. EGAS holds the remaining 50 per cent in Mansoura Petroleum Company and Al Rawda Petroleum Company. EGPC holds the remaining 50 per cent in Qantara Petroleum Company.

4. DIRECTORS

The Directors at the date of this document and their respective current roles are set out below:

Robert Arnott	Non-Executive Chairman
Brian O'Cathain	Chief Executive Officer
Tom Hickey	Corporate Development Director
Andrew Bostock	Senior Non-Executive Director
Con Casey	Non-Executive Director
Hugh McCutcheon	Non-Executive Director

The business address of all of the Directors is Petroceltic, 6th Floor, 75 St. Stephen's Green, Dublin 2, Ireland.

5. PROFILES OF THE DIRECTORS

The management expertise and experience of each of the Directors is set out below.

Robert Arnott: Non-Executive Chairman (54)

Mr Arnott has over 25 years' experience of the upstream industry in both technical and business development roles, with ten years' direct experience in investment banking as an upstream oil and gas analyst. During that time Mr Arnott has worked with Goldman Sachs, Morgan Stanley and UBS.

He is a Research Fellow with the Oxford Institute of Energy Studies and until 2008 advised the Norwegian EP company DNO on its strategy in Kurdistan and Yemen. Mr Arnott joined the Petroceltic Board as the Senior Non-Executive Director in January 2010 and was appointed as Chairman of Petroceltic in May 2010. He is also a Non-Executive Director of Spring Energy, a private Norwegian oil and gas company focused on exploration off-shore Norway. Mr Arnott is currently Chairman of the Petroceltic Nominations Committee and a current member of the Petroceltic Audit Committee and Petroceltic Remuneration Committee.

Brian O'Cathain: Chief Executive Officer (52)

Mr O'Cathain is a geologist and petroleum engineer with over 25 years' experience in senior technical and commercial roles in upstream oil and gas exploration and production companies. He has previously held the positions of Managing Director of Tullow Oil's international business and Chief Executive of Afren plc. In senior management positions with Enterprise Oil and Shell International, Mr O'Cathain was principally involved with acquisitions, divestments and corporate strategy. He has experience in working in West Africa, the North Sea, the Gulf of Mexico and South Asia.

Tom Hickey: Corporate Development Director (44)

Mr Hickey was previously an Executive Director and Chief Financial Officer of Tullow Oil plc from 2000 to 2008. During this time Tullow grew via a number of significant acquisitions including the US$570 million acquisition of Energy Africa in 2004 and the US$1.1 billion acquisition of Hardman Resources in 2006. Prior to joining Tullow, Mr Hickey was an Associate Director of ABN AMRO Corporate Finance (Ireland) Limited.

Mr Hickey is a Fellow of the Institute of Chartered Accountants in Ireland, and he is also a Non-Executive Director of PetroNeft Resources plc.

Andrew Bostock: Senior Non-Executive Director (49)

Mr Bostock is an experienced upstream oil and gas director with over 25 years' operational and commercial experience in the sector. After beginning his career with Shell International, he progressed through increasingly senior technical and commercial roles in a number of independent oil and gas companies, including Enterprise Oil, Talisman Energy and Venture Production, before serving as an Executive Director of Dana Petroleum plc between 2001 and 2006.

Mr Bostock joined the Petroceltic Board as the Senior Non-Executive Director in June 2007. He is currently Chairman of the Petroceltic Remuneration Committee and a current member of the Petroceltic Nominations Committee and Petroceltic Audit Committee.

Con Casey: Non-Executive Director (51)

Mr Casey is a Chartered Certified Accountant, a partner of LHM Casey McGrath and has been a member of the Petroceltic Board since October 2000. He has over 25 years' experience in advising companies in the natural resources sector as well as acting as adviser to a number of publicly quoted companies and semi-state organisations and he specialises in the area of corporate finance.

As Non-Executive Director, Mr Casey monitors the executive activity and contributes to the development of strategy. He is currently Chairman of the Petroceltic Audit Committee and a current member of the Petroceltic Nominations Committee and Petroceltic Remuneration Committee.

Hugh McCutcheon: Non-Executive Director (58)

Mr McCutcheon was formerly head of Corporate Finance at Davy, having joined Davy in 1989 after a successful career in PriceWaterhouse where he qualified as a Chartered Accountant. He was Head of Corporate Finance at Davy from 2001 to 2011. Throughout this period Mr McCutcheon maintained a continuous focus on and interest in the natural resources sector and has advised oil and gas companies including Tullow Oil plc, Dragon Oil plc, Providence Resources plc and Aminex plc.

Mr McCutcheon has an honours degree in Economics from Trinity College Dublin, and is a Fellow of the Institute of Chartered Accountants in Ireland. He is a current member of the Petroceltic Remuneration Committee, Petroceltic Nominations Committee and Petroceltic Audit Committee.

For further information on the Directors, including the companies of which each of the Directors has been a director at any time in the past five years, see paragraph 13 of this Part XII.

6. THE ENLARGED COMPANY DIRECTORS

On Readmission the structure of the Enlarged Company Board is expected to be as follows:

Robert F M Adair	Non-Executive Chairman
Brian O'Cathain	Chief Executive Officer
Tom Hickey	Chief Financial Officer
David H Thomas	Chief Operating Officer
James D Agnew	Senior Independent Director
Hugh McCutcheon	Non-Executive Director and Deputy Chairman
Robert Arnott	Non-Executive Director
Con Casey	Non-Executive Director
Alan Parsley	Non-Executive Director

The names, proposed positions and proposed business addresses of each of the Proposed Directors are set out below:

Name	Proposed Position in Enlarged Company Board	Business Address
Robert F M Adair	Non-Executive Chairman	Petroceltic, 6th Floor, 75 St. Stephen's Green, Dublin 2, Ireland.
David H Thomas	Chief Operating Officer	Petroceltic, 6th Floor, 75 St. Stephen's Green, Dublin 2, Ireland.
James D Agnew	Senior Independent Director	Petroceltic, 6th Floor, 75 St. Stephen's Green, Dublin 2, Ireland.
Alan J Parsley	Non-Executive Director	Petroceltic, 6th Floor, 75 St. Stephen's Green, Dublin 2, Ireland.

The profiles of the Proposed Directors are set out below. The profiles of each of the remaining members of the Enlarged Company Board are set out in paragraph 5 of this Part XII.

Robert FM Adair, *MA, ACA, CTA, FGS* **Non-Executive Chairman (56)**

After graduating in geology from Oxford University, Robert Adair qualified as a Chartered Accountant and then specialised in oil and gas taxation. Robert was the original founder of a predecessor company of Melrose in the 1990's and now commits 50 per cent. of his time to the affairs of Melrose. He is chairman of Skye, Melrose's principal shareholder, and also Terrace Hill Group plc.

David H Thomas, *BSc, MSc* **Chief Operating Officer (54)**

David Thomas holds a BSc in Mining Engineering and an MSc in Petroleum Engineering. He has over 30 years of experience in the oil and gas business, primarily gained in Europe, Africa and Asia. From 1978 to 1995 he worked with Conoco before moving to join Lasmo plc, where his last position was as Group General Manager Operations. Subsequently, he served as a Regional Vice President for Eni and then as President and Chief Operating Officer for Centurion Energy, before joining Melrose in mid-2007. He has held Directorships with Centurion and many of Eni's international subsidiaries. He was appointed Chief Executive of Melrose in 2007.

James D Agnew, *MA, CA* **Senior Independent Director (53)**

James Agnew is currently chairman of UK Corporate Broking at Deutsche Bank. He joined Deutsche Bank in 2002 having previously been Head of Corporate Broking at Merrill Lynch. He is a member of the UK Panel on Takeovers and Mergers and the London Stock Exchange Primary Markets Group. James qualified as a Chartered Accountant with KPMG. He was appointed an Independent Non-Executive Director of Melrose in November 2007.

Alan J Parsley, *BSc, PhD* **Non-Executive Director (68)**

Dr Alan Parsley initially joined Shell as an exploration geologist in 1969 before moving to Britoil in 1977, where he held various technical management roles including Exploration Manager. Following Britoil's acquisition by BP in 1988, Alan rejoined Shell in The Hague as the Head of Exploration New Ventures. He then moved to Syria in 1992 to take on the role of Chief Executive, Shell Syria, before returning to The Hague in 1995 as Head of Exploration and subsequently Head of New Business Ventures. In 1999, Alan moved to Australia where he was appointed as Chairman of Shell Australia, before returning to Europe and retiring in 2004. Alan is a graduate of the University of Edinburgh, and holds both a BSc and a PhD in Geology. He was appointed an independent Non-Executive Director of Melrose in November 2008.

7. INTERESTS OF THE DIRECTORS AND THE PROPOSED DIRECTORS

As at the Latest Practicable Date, the interests (all of which are beneficial) of the Directors and the Proposed Directors in the Existing Petroceltic Shares, which have been or would be required to be notified by each Director and each Proposed Director to Petroceltic pursuant to sections 53 or 64 of the 1990 Act or which are or would be required pursuant to section 59 of the 1990 Act to be entered into the register referred to therein, together with such interests as are expected to subsist immediately following the Readmission, are set out below:

	Interests as at Latest Practicable Date		Interests immediately following the Readmission	
Director	**No. of shares**	**Percentage of Existing Petroceltic Shares**	**No. of shares**	**Percentage of Enlarged Issued Share Capital**
Brian O'Cathain	3,776,820	0.16%	3,776,820	0.09%
Tom Hickey	5,882,856	0.25%	5,882,856	0.13%
Andrew Bostock	3,000,000	0.13%	3,000,000	0.07%
Con Casey	4,008,166	0.17%	4,008,166	0.09%
Hugh McCutcheon	1,100,000	0.05%	1,100,000	0.03%

7.1 There are no shareholdings in Petroceltic held by the Proposed Directors.

7.2 The interests of the Enlarged Company Directors together represent approximately 0.75 per cent of the Existing Petroceltic Shares as at the Latest Practicable Date and are expected to represent approximately 0.40 per cent of the Enlarged Issued Share Capital on the Readmission.

7.3 Details of options and awards over the Existing Petroceltic Shares held by the Directors are set out below. They are not included in the interests of the Directors in the table above.

7.4 The Directors had the following interests in the 2004 Share Scheme as at the Latest Practicable Date:

Option Holder	**Date of grant**	**No. of shares under option**	**Exercise price per Ordinary Share (Stg)**	**Expiry date**
Brian O'Cathain (Std)[1]	19/04/2007	5,281,690	0.1391	25/03/2014
Brian O'Cathain (Spr)[1]	19/04/2007	5,281,690	0.1391	25/03/2014
Brian O'Cathain (Std)	26/08/2008	5,000,000	0.064	25/08/2015
Brian O'Cathain (Spr)	26/08/2008	5,000,000	0.064	25/08/2015

Notes:

[1] These options were granted in Euro, the exercise price shown reflects the Sterling equivalent at grant date rates

Std = Standard; Spr = Super

7.5 Details of the 2004 Share Scheme are contained in paragraph 10.2 of this Part XII.

7.6 The Directors had the following interests in the 2009 Share Scheme as at the Latest Practicable Date:

Award Holder	Date of grant	No. of awards	Exercise price per award (Stg)	Expiry date
Brian O'Cathain	14/07/2009	7,500,000	0.089	14/07/2016
Tom Hickey	13/06/2011	16,300,000	0.114	10/06/2018
Brian O'Cathain	13/06/2011	15,200,000	0.114	10/06/2018

Details of the 2009 Share Scheme (including the basis on which the number of Ordinary Shares issued on exercise of an award is calculated) are contained in paragraph 10.3 of this Part XII.

7.7 Save as disclosed in this section no Director or Proposed Director has any interests (beneficial or non-beneficial) in the share capital of Petroceltic or any of its subsidiaries.

7.8 Save as disclosed in this document, no Director or Proposed Director, or member of a Director or Proposed Director's family, has a related financial product referenced to the Existing Petroceltic Shares or the New Petroceltic Shares.

7.9 No Director has or has had any interest in any transaction which is or was unusual in its nature or conditions, or which is or was significant to the business of Petroceltic and which was effected by Petroceltic during the current or immediately preceding financial year or during any further financial year and which remains in any respect outstanding or unperformed.

7.10 There are no outstanding loans granted by Petroceltic or any member of the Petroceltic Group to any of the Directors, nor has any guarantee been provided by Petroceltic or any member of the Petroceltic Group for their benefit, save that each of the Directors has the benefit of an indemnity from Petroceltic under which it agrees to indemnify them against liabilities that they may incur as a result of their lawful actions in connection with the discharge of their duties as officers of Petroceltic. The Enlarged Company Directors will also have the benefit of indemnity insurance in accordance with the provisions of the Articles of Association.

8. DIRECTORS SERVICE CONTRACTS AND LETTERS OF APPOINTMENT

8.1 Executive Directors' service contracts

At the date of this document, there are two Executive Directors, each of whom is employed by Petroceltic.

The terms of the Executive Directors' service contracts are summarised below:

Name	Title	Contract date	Salary	Notice by Petroceltic
Brian O'Cathain	Chief Executive Officer	01/12/2009	€438,750	12 months except as provided below
Tom Hickey	Corporate Development Director	01/11/2010	€315,000	6 months, except as provided below

8.1.1 Termination Provisions

Other than entitlement to notice and a payment in lieu of notice, the Executive Directors are not entitled to compensation on termination of their respective contracts.

8.1.2 Change of Control

The Executive Directors are entitled to leave Petroceltic on two months' notice on a change of control of Petroceltic, provided that any such notice is given within three months of the date of the change of control. In so leaving, the Director shall not have any entitlement to compensation or damages in respect of the termination of the employment.

8.1.3 Benefits

Under the terms of the service contracts with each of the Executive Directors, Petroceltic must pay an amount equivalent to 10 per cent of the relevant Director's annual basic salary into a pension scheme nominated by the Director. Each Executive Director is required to pay a further 5 per cent of his annual basic salary into the relevant pension scheme.

Each of the Executive Directors is eligible to participate in any bonus scheme which the Petroceltic Board may in its sole discretion from time to time adopt based on performance. Any bonus scheme is entirely discretionary on the part of Petroceltic and may be terminated unilaterally, without notice or cause by Petroceltic at any time. Any bonus shall be subject to satisfactory performance by Petroceltic and by the relevant Director.

Each of the Executive Directors is entitled to additional standard benefits such as private medical insurance and life assurance cover and a car allowance. Executive Directors are also eligible for participation in the 2009 Share Scheme.

8.1.4 Restrictive Covenants

The Executive Directors' service contracts contain: (i) six or twelve month post termination restrictive covenants against competing with the Petroceltic Group or any of Petroceltic's associated companies; and (ii) six or twelve month post termination restrictive covenants against soliciting, employing or engaging (or seeking to employ or engage) any person who is, at the date of termination of his employment, an officer, executive, manager, employee of or consultant to the Petroceltic Group or any of Petroceltic's associated companies.

8.2 Non-Executive Directors letters of appointment

At the date of this document there are four Non-Executive Directors. The terms of the Non-Executive Directors' letters of appointment are summarised below:

Name	Title	Appointment letter date	Fee per annum	Notice period
Robert Arnott	Non-Executive Chairman	01/02/2010	€65,000	6 months
Con Casey[1]	Non-Executive Director	14/09/2009	€40,000	6 months
Andrew Bostock	Non-Executive Director	01/02/2010	€40,000	6 months
Hugh McCutcheon	Non-Executive Director	13/12/2011	€40,000	6 months

Notes:

[1] Con Casey's Non-Executive Director fee is invoiced monthly by LHM Casey McGrath and subject to VAT.

8.2.1 Termination Provisions

Petroceltic may elect to terminate the appointment of each Non-Executive Director immediately and make a payment of fees in lieu of any applicable period of notice. Otherwise, the Non-Executive Directors are not entitled to compensation on termination of their appointments.

8.2.2 Change of Control

The letters of appointment of the Non-Executive Directors do not contain any change of control provisions.

8.3 Retirement of Directors under the Articles of Association

Under the Articles of Association, all Directors must retire by rotation. At each annual general meeting of Petroceltic, one third of the Directors, or if their number is not three or a multiple of three, the number nearest to one third, shall retire from office. The Directors to retire in this manner shall be those who have been longest in office since their last appointment or reappointment but as between persons who became or were last reappointed Directors on the same day, those to retire shall (unless they otherwise agree among themselves) be determined by lot.

9. PROPOSED DIRECTORS SERVICE CONTRACTS AND LETTERS OF APPOINTMENT

9.1 Executive Proposed Directors' service contracts

Petroceltic intends to enter into a service contract with David Thomas on terms substantially similar to those of the existing Executive Directors (including provisions as to notice and post-termination restrictions). The service contract will be conditional upon Readmission occurring and the levels of remuneration under such service contract will be set by the Petroceltic Remuneration Committee, taking into account such factors as the committee deems appropriate.

9.2 Non-Executive Proposed Directors' letters of appointment

Petroceltic intends to enter into letters of appointment with Robert Adair, James Agnew and Alan Parsley on terms substantially similar to those of the existing Non-Executive Directors. These letters of appointment will be conditional upon Readmission occurring and the levels of remuneration will be set by the Petroceltic Remuneration Committee, taking into account such factors as the committee deems appropriate.

9.3 Other than as set out in paragraphs 9.1 and 9.2 of this Part XII, no service contracts have been entered into by Petroceltic or any of its subsidiaries with any Director or Proposed Director. None of the Directors' service contracts with Petroceltic or any of its subsidiaries have been entered into or amended within the period of 6 months ending on the date of this document.

10. EMPLOYEE INCENTIVE ARRANGEMENTS

10.1 Petroceltic has granted share options under the 2004 Share Scheme and made share awards under the 2009 Share Scheme. Since 2009, no share options have been granted under the 2004 Share Scheme.

10.2 The following is a summary of the key terms of the 2004 Share Scheme that continue to be applicable at the date of this document:

- The 2004 Share Scheme was adopted by Petroceltic Shareholders on 21 April 2004 and subsequently amended on 28 July 2006. Under its terms, no further options may be granted under the scheme as from the fifth anniversary of the date of its adoption.
- On grant, participants received an equal number of shares under standard and super options.
- The exercise of an option is dependent upon satisfaction of performance conditions stated in writing by the Petroceltic Remuneration Committee at the date of grant, which conditions must be objective, may not be waived or amended by Petroceltic unless an event occurs that causes the Petroceltic Remuneration Committee to consider that a waiver of or amendment to the performance conditions would be a fairer measure of performance and the Petroceltic Remuneration Committee considers that a waiver of or amendment to the performance conditions would not make them more difficult to satisfy and shall be linked to that which is, in the opinion of the Petroceltic Remuneration Committee, sustained improvement in the underlying financial performance of Petroceltic.
- Options may only be exercised if predetermined growth rates in the market price of Ordinary Shares are achieved, being an increase from the market value at the date of grant of, in the case of standard options, the higher of (i) the annual percentage increase in the general index of retail prices for all items (as published by the Central Statistics Office of Ireland) plus 5 per cent for each year from the date of grant to the date of exercise on a compound interest basis and (ii) 10 per cent per annum compounded from year to year from the date of grant to the exercise date and, in the case of super options, 20 per cent per annum compounded from year to year from the date of grant to the exercise date.
- Specified proportions of the standard options and super options granted to each participant on a grant date are exercisable following the passing of specified periods of time following the grant date of each class of option.
- The exercise price of an option is the higher of the price per Ordinary Share determined in writing by the Petroceltic Remuneration Committee and the nominal value per Ordinary Share.
- If a participant ceases to be a Petroceltic Group employee, his options will lapse and will not be capable of exercise save in certain limited circumstances.

- Options are exercisable within a limited period in the event of (i) a person making an offer to acquire Ordinary Shares (which was either unconditional or was made on a condition such that if it were satisfied the person making the offer would have control (within the meaning of section 432 of the Taxes Consolidation Act 1997 of Ireland (as amended)) of Petroceltic) and such person obtaining control of Petroceltic and any condition subject to which the offer was made being satisfied; (ii) Petroceltic being reconstructed or amalgamated with another company; or (iii) Petroceltic being wound up voluntarily, and will lapse thereafter.
- Options automatically lapse (to the extent not already lapsed or exercised) on the seventh anniversary of the date of grant.
- If there is a variation in the equity share capital of Petroceltic (being, in relation to the equity share capital of Petroceltic, a capitalisation issue, an offer or invitation made by way of rights issue, a subdivision, a consolidation or a reduction): (i) the number and/or the nominal value of Ordinary Shares over which an option is granted; (ii) the exercise price; and (iii) where an option has been exercised but at the date of the variation no Ordinary Shares have been allotted or transferred pursuant to such exercise, the number of Ordinary Shares which may be so allotted or transferred and the price at which they may be acquired shall be adjusted in such manner as the Petroceltic Board shall determine so that (as nearly as may be without involving fractions of an Ordinary Share or an exercise price calculated to more than two decimal places) the exercise price shall remain unchanged. Save in the case of a capitalisation issue, any such adjustment shall be confirmed by the auditors of Petroceltic to be in their opinion fair and reasonable.

10.3 The following is a summary of the key terms of the 2009 Share Scheme:

- The 2009 Share Scheme was adopted by the Petroceltic Remuneration Committee on 14 July 2009 and subsequently amended on 20 December 2011. No awards may be made under the plan on or after the tenth anniversary of the date of its adoption.
- Executives may be selected to participate in the plan at the discretion of the Petroceltic Remuneration Committee.
- On or before the making of an award, the Petroceltic Remuneration Committee must specify the performance condition that must be fulfilled before the relevant award(s) can be exercised. Upon the occurrence of such event or events as a result of which, or in such circumstances as, the Petroceltic Remuneration Committee considers it is fair and reasonable to do so, the Petroceltic Remuneration Committee may adjust or change the performance condition in respect of any award or substitute a different performance condition provided that the adjusted or substitute performance condition is, in the reasonable opinion of the Petroceltic Remuneration Committee, no more difficult to achieve than the original performance condition when it was set.
- Subject to satisfaction of the relevant performance condition, an award will first be exercisable on the date specified on the date of award and no award may be exercised later than seven years after the award date.
- The exercise price of an award is the market value of the Ordinary Shares on grant, although on exercise the value above such exercise price will be delivered in Ordinary Shares, calculated in accordance with the formula set out in the following bullet point, for which the award holder will pay nominal value.
- The number of Ordinary Shares received by a participant on the exercise of an award is calculated as follows:

$$S = \frac{V}{X} + \frac{(V/X \text{ x EUR}0.0125)}{X}$$

and

$$V = N \text{ x } (X - Y)$$

where:

S = the number of Ordinary Shares legal title to which is to be delivered to the participant, rounded down to the nearest whole Ordinary Share;
V = the aggregate value of Ordinary Shares that the participant is entitled to receive;
N = the total number of Ordinary Shares over which the award is being exercised;
X = the market value of the Ordinary Shares on the relevant exercise date; and
Y = the market value of the Ordinary Shares on the award date.

- If a participant ceases to be a Petroceltic Group employee, his awards will lapse and will not be capable of exercise save in certain limited circumstances.
- Awards are exercisable within a limited period in the event of (i) a person making an offer to acquire Ordinary Shares (which was either unconditional or was made on a condition such that if it were satisfied the person making the offer would have control (within the meaning of section 432 of the Taxes Consolidation Act 1997 of Ireland (as amended)) of Petroceltic) and such person obtaining control of Petroceltic and any condition subject to which the offer was made being satisfied (and in which case the performance conditions would not apply); (ii) Petroceltic being reconstructed or amalgamated with another company; or (iii) Petroceltic being wound up voluntarily, and will lapse thereafter.
- Awards automatically lapse (to the extent not already lapsed or exercised) on the seventh anniversary of the date of award.
- The maximum number of Ordinary Shares that may be issued pursuant to awards under the plan, when aggregated with the number of Ordinary Shares issued or remaining issuable pursuant to awards and/or options granted to Petroceltic executives in the previous ten years under the 2009 Share Scheme and any other share incentive scheme operated by Petroceltic, may not exceed 12 per cent of Petroceltic's issued ordinary share capital on that date.
- If there is a variation in the equity share capital of Petroceltic (for example a capitalisation or rights issue, sub-division, consolidation or reduction); (i) the number and/or the nominal value of Ordinary Shares over which an award is made; (ii) the exercise price; and (iii) the performance condition in respect of that award, shall be adjusted in such manner as the Petroceltic Remuneration Committee shall determine to be fair and reasonable.

10.4 Melrose employees will be eligible to participate, following the Merger becoming Effective, in the 2009 Share Scheme. Petroceltic intends to make option grants to Melrose employees at the same time as the 2012 annual grants are made to current Petroceltic employees (such annual grant having been delayed as a result of the proposed transaction). The level of such option grants, and the performance criteria which will apply, have not yet been set, but Petroceltic shall take into account such factors as would usually be considered by Petroceltic in respect of option grants being made to employees joining the Petroceltic Group and shall, following the Merger becoming Effective, further consult in this regard with Melrose.

11. ENLARGED COMPANY CORPORATE GOVERNANCE

While there is no required corporate governance regime in Ireland for companies whose shares are traded on the AIM and ESM markets, the Enlarged Company Board is committed to the highest standards of corporate governance commensurate with the size, stage of development and financial status of the Enlarged Group on the Merger becoming Effective. The Enlarged Company Board will also take account of institutional shareholder and governance rules and guidance on disclosure and shareholder authorisation. The Enlarged Company Board intends to meet at least eight times a year and may meet at other times at the request of one or more of the Enlarged Company Directors.

The Enlarged Company Board will establish three principal committees: the Enlarged Company Audit Committee, the Enlarged Company Remuneration Committee, and the Enlarged Company Nominations Committee.

Following Readmission, it is anticipated that the members of each committee will be as follows:

	Chairman	Members
Enlarged Company Audit Committee	Hugh McCutcheon	James Agnew Con Casey Alan Parsley
Enlarged Company Remuneration Committee	Con Casey	James Agnew Robert Arnott Alan Parsley
Enlarged Company Nominations Committee	Robert Adair	Brian O'Cathain James Agnew Hugh McCutcheon Robert Arnott

Enlarged Company Audit Committee

The Enlarged Company Audit Committee will consist of not less than three members, at least one of whom will have recent and relevant financial experience, and the quorum for meetings of the Enlarged Company Audit Committee will be two members. Each of the members of the Enlarged Company Audit Committee shall be independent Non-Executive Directors. The chairman of the Enlarged Company Audit Committee shall be an independent Non-Executive Director and shall not be the chairman of the Enlarged Company. The Enlarged Company Audit Committee will meet at such times as may be necessary and at least three times a year.

Its responsibilities will include: monitoring the integrity of the Enlarged Company's financial statements and formal announcements; reviewing significant financial reporting issues and accounting policies and disclosures in financial reports; reviewing the effectiveness of the Enlarged Company's internal controls and risk management systems; considering how the Enlarged Group's internal audit requirements shall be satisfied and making recommendations to the Enlarged Company Board; making recommendations to the Enlarged Company Board on the appointment or re-appointment of the Enlarged Group's external auditors; overseeing the Enlarged Company Board's relationship with the external auditors and, where appropriate, the selection of new external auditors; and ensuring that an effective whistle-blowing procedure is in place.

Enlarged Company Remuneration Committee

The Enlarged Company Remuneration Committee will consist of not less than three members and the quorum for meetings of the Enlarged Company Remuneration Committee will be two members. Each of the members of the Enlarged Company Remuneration Committee shall be independent Non-Executive Directors. The chairman of the Enlarged Company Remuneration Committee shall be an independent Non-Executive Director. The Enlarged Company Remuneration Committee will meet at such times as may be necessary and not less than twice a year.

The Enlarged Company Remuneration Committee will be responsible for determining and agreeing with the Enlarged Company Board the remuneration policy for the Enlarged Company Chief Executive, Chairman, Enlarged Company Executive Directors and senior executives; approving the design of, and determining targets for, an annual performance-related pay scheme for the Enlarged Company Executive Directors and senior executives; reviewing the design of share incentive plans for approval by the Enlarged Company Board and Enlarged Company Shareholders and determining the annual award policy to Enlarged Company Executive Directors and senior executives under existing plans; and within the terms of the agreed policy, determining the remainder of the remuneration packages (principally comprising salary and pension) for each Enlarged Company Executive Directors and senior executives.

Enlarged Company Nominations Committee

The Enlarged Company Nominations Committee will consist of not less than three members appointed by the Enlarged Company Board. A majority of members of the Enlarged Company Nominations Committee will be independent Non-Executive Directors. The quorum for meetings of the Enlarged Company Nominations Committee will be two members. The chairman of the Enlarged Company Nominations Committee will be the chairman of the Enlarged Company. The chairman of the Enlarged Company will not however chair the Enlarged Company Nominations Committee when it is dealing with the appointment of a successor to the chairmanship. The Enlarged Company Nominations Committee will meet at such time as may be necessary and not less than twice a year.

The Enlarged Company Nominations Committee's responsibilities will include reviewing the structure, size and composition of the Enlarged Company Board and making recommendations to the Enlarged Company Board with regard to any changes required; succession planning for Enlarged Company Directors and other senior executives; identifying and nominating, for Enlarged Company Board approval, candidates to fill Enlarged Company Board vacancies as and when they arise; reviewing annually the time commitment required of Non-Executive Directors and making recommendations to the Enlarged Company Board with regard to membership of the Enlarged Company Audit Committee and Enlarged Company Remuneration Committee in consultation with the Chairman of each of these committees.

12. EMPLOYEES AND INDUSTRIAL RELATIONS

Employees of the Petroceltic Group

Details of the average number of the Petroceltic Group's permanent employees (including Executive Directors) during each of the three financial periods the last of which ended on 31 December 2011 are as follows:

Financial period ended	Number of employees
31 December 2009	25
31 December 2010	31
31 December 2011	34

The table below sets out the average number of employees of the Petroceltic Group for the financial period ended 31 December 2011, as well as a breakdown of the persons employed by category:

Job Function	Ireland	Algeria	Italy	Total
Operations and exploration	13	3	2	**18**
Finance	4	4	-	**8**
Administration	3	4	1	**8**

Petroceltic consultants and temporary employees

The Petroceltic Group instructs a number of consultants who are integral to the business function.

As at 31 December 2011 the Petroceltic Group employed the following consultants:

Job Function	Dublin/London	Italy	Algeria	Total
Operations	15	3	34	**52**
Administration	1	1	3	**5**

Employees of the Melrose Group

Details of the average number of Melrose's permanent employees (including Executive Directors) during each of the three financial periods the last of which ended on 31 December 2011 are as follows:

Financial Period Ended	Number of employees
31 December 2009	134
31 December 2010	134
31 December 2011	139

The table below sets out the average number of employees of the Melrose Group for the financial period ended 31 December 2011, as well as a breakdown of the persons employed by category:

Job Function	USA (now closed)	Egypt	Bulgaria	UK	Total
Operations	4	32	30	18	**84**
Administration	-	29	6	20	**55**

Melrose consultants and temporary employees

The Melrose Group instructs Bell Tree Consultants to undertake reservoir simulation work on its behalf.

13. DIRECTORS AND PROPOSED DIRECTORS' CONFIRMATIONS

13.1 Save as disclosed at paragraphs 13.6 to 13.9 of this Part XII, as at the Latest Practicable Date, none of the Enlarged Company Directors have:

- any unspent convictions in relation to fraudulent offences or unspent convictions in relation to indictable offences;
- been declared bankrupt or been subject to any individual voluntary arrangement;
- been a director of any company or been a member of the administrative, management or supervisory body of an issuer or a senior manager of an issuer, which has been placed in receivership, compulsory liquidation, creditors' voluntary liquidation, administration, company voluntary

arrangement or any composition or arrangement with its creditors generally or any class of its creditors whilst he was acting in that capacity for that company or within the 12 months after he ceased to be so acting;

- been a partner in any partnership which has been placed in compulsory liquidation, administration or partnership voluntary arrangement whilst he was a partner of that partnership or within 12 months after he ceased to be a partner in that partnership;
- been the owner of any asset placed in receivership or been a partner in any partnership which had an asset placed in receivership whilst he was a partner of that partnership or within the 12 months after he ceased to be a partner of that partnership; or
- been subject to any public criticisms by any statutory or regulatory authorities (including recognised professional bodies) or been disqualified by a court from acting as a director of a company or from acting as a member of the administrative, management or supervisory bodies of a company or from acting in the management or conduct of the affairs of any company.

13.2 Save as disclosed in this document, none of the Enlarged Company Directors have been interested, whether directly or indirectly, in any transaction which is or was unusual in its nature or conditions or significant to the business of the Enlarged Group taken as a whole and which was effected by the Enlarged Group and remains in any respect outstanding or unperformed.

13.3 Save as otherwise disclosed in this document, no Enlarged Company Director has or has had any interest, direct or indirect, in any assets which have been acquired by, disposed of by, or leased to the Enlarged Group or which are proposed to be acquired by, disposed of by, or leased to the Enlarged Group.

13.4 Save as disclosed in this paragraph 13 and paragraph 19 of this Part XII there are no contracts, existing or proposed, between any Enlarged Company Director and the Enlarged Company.

13.5 The details of those companies and partnerships outside Petroceltic and Melrose in which the Directors and the Proposed Directors are, or have been, members of the administrative, management or supervisory bodies ("directors") or partners at any time during the five years prior to the date of this document are as follows:

Directors

Name	Current Directorships / Partnerships	Previous Directorships / Partnerships
Andrew Bostock	Westvale Energy Limited	Tythegston Power Limited (dissolved) Purepower Holdings Limited (in liquidation) Purepower Group Limited (in liquidation) Machine Productions Limited
Brian O'Cathain	Black Mountain Consulting Ltd	None
Tom Hickey	O'Rahilly Row Ltd Petroneft Resources Plc Ikon Science Ltd	Tullow Oil Plc Senscomm Photonics Ltd
Hugh James McCutcheon	Anthemis Advisers Limited Origin Enterprises Plc	J&E Davy Holdings Davy Corporate Finance
Robert John Arnott	Spring Energy AS Brimham Resources Ltd	DNO (UK) Ltd Impax Environmental Markets Plc Edgo Energy Ltd
Con Casey	Albativ Resources Ltd Atrium Wealth Management Ltd CMG Interactive Ltd LHM Casey McGrath Ltd LHM Casey McGrath Outsource Services Ltd Shackleton Financial & Business Advisors Ltd VP Power Ltd	Ardmore Exploration Ltd Caspian Oil & Gas Ltd Gostem Ltd Needlepoint Trust Company Casey McGrath & Associates Ltd CMG Group Ltd Professional Practice Financial Planning Ltd

Proposed Directors

Name	Current Directorship / Partnerships	Previous Directorships / Partnerships
Robert Adair	First Car Wash Plc Mister Clean Limited Consolidated General Minerals Plc Butters Group Limited Pen Hill LLP The lnvicta Film Partnership No. 37, LLP The Invicta Film partnership No 34, LLP Dart Films LLP Tay Hotel (Dundee) LLP Terrace Hill Group Plc Skye Holdings Limited Skye Securities Limited Westview Investments Limited Petreco Limited Skye Investments Limited Earlycall Limited Broadspan Limited Earthrapid Limited Terrace Hill Residential Plc Terrace Hill Lettings ICP Capital Limited ICP Holdings Limited ICP General Partner Limited Blair Underwriting Limited Castell Underwriting Limited Nameco (No. 921) Limited Rudyco Limited Hurrian Resources Limited David Scott Underwriting Limited Insurance Capital Partners LP IQ Capital LP Bestport LP Diamond Film Partners Leed Petroleum PLC Opal Film Partners Scion Films (Creation 2) Production Partnership Trieste Film Partners Turin Film Partners	Leed Resources Plc Plexus Holdings Plc Wharrels Hill LLP Ingenious Film Partners 2 LLP AERW & RFMA Consultancy Partnership Terrace Hill Partnership Skye Petroleum Cowesby Estate Partnership Chameleon Trust Plc Crossroads Ventures (UK) Limited Crossroads Ventures (US) Limited Honiton Energy Limited Honiton Energy Services Limited Honiton Energy Holdings Limited Hubbell Realty Revera Asset Management Limited
James Agnew	Hendersyde Park Farm & Estate	None

Name	Current Directorship / Partnerships	Previous Directorships / Partnerships
David Thomas	Eni MOG Limited Hurrian Resources Limited	Britannia Exploration, Inc ENI BBH Limited Eni Energy Limited Eni International Exploration Limited Eni MHH Limited Eni Neptune Limited Eni Resources Limited
Alan Parsley	None	None

13.6 Andrew Bostock was a Non-Executive Director of Purepower Group Limited ("Purepower Group") from January 2008 to November 2011 and its subsidiary Purepower Holdings Limited ("Purepower Holdings") from July 2007 to September 2011. Purepower Group was placed into creditors' voluntary liquidation on 25 November 2011 with an estimated deficiency as regards non-preferential creditors of approximately £2.39 million. Purepower Holdings had previously been placed into creditors' voluntary liquidation on 12 September 2011 with an estimated deficiency as regards non-preferential creditors of approximately £13.75 million, included within which was approximately £10.43 million owed to Purepower Group.

13.7 Robert Adair was a Non-Executive Director of The Beckenham Group PLC until his resignation on 1 July 2004. On 17 November 1994, an administrative receiver was appointed in respect of this company and ceased to act on 8 November 2005. The total creditor shortfall was approximately £40 million. The company was dissolved on 18 July 2006.

13.8 Robert Adair was a Non-Executive Director of Telematix Limited until June 2001. Telematix Limited went into liquidation on 24 August 2001, and was dissolved on 21 October 2006. The total creditor shortfall was approximately £1 million.

13.9 Robert Adair was a Non-Executive Director of Safe Gard Europe Limited prior to this company going into receivership. On 6 January 2005, administrative receivers were appointed in respect of this company, which went into liquidation on 6 January 2006. The total creditor shortfall was approximately £55 million.

14. SHARE CAPITAL

Issued share capital

14.1 The issued fully paid up share capital of Petroceltic as at the date of this document is, and at the date of the Readmission is expected to be, as follows:

Date	Class	Number issued	Number authorised	Nominal value per share €
16 August 2012	Existing Petroceltic Shares	2,369,605,049	3,000,000,000	0.0125
the Readmission	Enlarged Company Shares	4,388,134,582	10,000,000,000	0.0125

The authorised share capital of Petroceltic also comprises 200,000,000 Deferred Shares of €0.114276427 each, none of which are, or following Readmission will be, issued.

Changes in share capital prior to the Readmission

Save as otherwise disclosed in this document there are no acquisition rights or obligations in relation to the issue of shares in the capital of Petroceltic or an undertaking to increase the capital of Petroceltic.

14.2 As at the Latest Practicable Date, there were 9,696 shareholders holding 2,369,605,049 Existing Petroceltic Shares.

14.3 The following options and awards over the Ordinary Shares of Petroceltic had been granted to Directors and other employees of Petroceltic and remained outstanding at 31 December 2011. Further details of Director's interests are found in paragraphs 7.4 and 7.6 of this Part XII.

Share Scheme	Number of options/awards	Grant date	Exercise period	Exercise Price (Stg)
2004 Share Scheme				
	6,500,000	01/10/2006	Up to 05/11/2013	0.125
	10,563,380	26/03/2007	Up to 25/13/2014	0.1391
	1,000,000	31/07/2007	Up to 30/07/2014	0.1155
	19,900,000	26/08/2008	Up to 25/08/2015	0.064
2009 Share Scheme				
	26,980,000	14/07/2009	Up to 14 /07/2016	0.089
	41,300,000	10/06/2011	Up to 10/06/2018	0.114
	16,300,000	03/10/2011	Up to 03/10/2018	0.044
	46,020,000	21/12/2011	Up to 21/12/ 2018	0.079
	Total: 168,563,380			

Outstanding Warrants

14.4 The following warrants of Petroceltic, further details of which can be found in paragraph 20.2.1 of this Part XII, remain outstanding at the date of this document.

Date	Warrant Holder	No. of Outstanding Warrants	Subscription Price (Stg)	Expiry Date
20/10/2011	Macquarie	15,000,000	0.0452	31/12/2015
08/11/2011	Macquarie	15,000,000	0.0561	31/12/2015
01/12/2011	Macquarie	2, 842,294	0.0686	31/12/2015
03/01/2012	Macquarie	7,921,027	0.0780	31/12/2015
03/01/2012	Macquarie	10,000,000	0.0780	31/12/2015
10/02/2012	Macquarie	8,306,481	0.0824	31/12/2015
	Total	**59,069,802**		

Recent changes in Petroceltic's share capital

14.5 In January 2009, 6,000,000 new Ordinary Shares were issued pursuant to the exercise of certain options under Petroceltic's 1997 share option scheme, resulting in an increase in the number of Ordinary Shares in issue to 965,797,049.

14.6 In April 2009, Petroceltic issued 392,464,000 new Ordinary Shares at a price of Stg7 pence per share pursuant to a conditional placing to existing and new institutional shareholders, raising gross proceeds of US$40 million (Stg 27.5 million), and resulting in an increase in the number of Ordinary Shares in issue to 1,358,261,049. The proceeds were used to support Petroceltic's drilling programme in Algeria and to accelerate Petroceltic's ongoing appraisal and drilling activities in Italy.

14.7 In August 2009, 6,000,000 new Ordinary Shares were issued pursuant to the exercise of certain options resulting in an increase in the number of Ordinary Shares in issue to 1,364,261,049.

14.8 In November 2009, 6,000,000 new Ordinary Shares were issued pursuant to the exercise of certain options, resulting in an increase in the number of Ordinary Shares in issue to 1,370,261,049.

14.9 In December 2009, 6,000,000 new Ordinary Shares were issued pursuant to the exercise of certain options, resulting in an increase in the number of Ordinary Shares in issue to 1,376,261,049.

14.10 In April 2010, 635,294,000 new Ordinary Shares were issued at a price of Stg12.75 pence per share pursuant to a placing, raising gross proceeds of US$120.5 million (Stg£ 81.0 million), and resulting in an increase in the number of Ordinary Shares in issue to 2,011,555,049. The shares were placed with both existing and new institutional shareholders and proceeds were used to support Petroceltic's appraisal programme in Algeria, to fund proposed drilling activities in Italy and for general corporate purposes.

14.11 In May 2010, 2,800,000 new Ordinary Shares were issued pursuant to the exercise of certain options, resulting in an increase in the number of Ordinary Shares in issue to 2,014,335,049.

14.12 In May 2011, 3,750,000 new Ordinary Shares were allotted to Con Casey in respect of certain options exercised by him to which he was entitled under the 2004 Share Scheme, resulting in an increase in the number of Ordinary Shares in issue to 2,018,105,049.

14.13 In June 2011, Petroceltic issued a total of 351,000,000 new Ordinary Shares at Stg10.5 pence per share pursuant to a placing, raising gross proceeds of approximately US$60 million (Stg£37.5 million) and resulting in an increase in the number of Ordinary Shares in issue to 2,369,105,049. The shares were placed with both new and existing institutional shareholders, and funds were raised to complete the expanded Algerian drilling and appraisal programme, to advance drilling plans for its prospects in Italy and for general corporate purposes. Both Brian O'Cathain and Tom Hickey subscribed for shares in this placing. Further details are contained in paragraph 20.2.3 of Part XII.

14.14 In June 2011, 500,000 new Ordinary Shares were issued pursuant to the exercise of certain options, resulting in an increase in the number of Ordinary Shares in issue to 2,369,605,049.

14.15 Save as disclosed in this document, during the three years immediately preceding the date of this document, there has been no issue of share capital of Petroceltic fully or partly paid either for cash or other consideration and no such issues are proposed and no share capital of any member of the Petroceltic Group is under option or agreed, conditionally or unconditionally, to be put under option.

Authority to allot

14.16 Authority was granted to the Petroceltic Board, at an extraordinary general meeting of Petroceltic in April 2010, to allot and issue relevant securities (as defined in the 1983 Act) of an amount equal to the authorised but unissued share capital at the date of the passing of that resolution and to allot and issue any shares purchased by Petroceltic pursuant to the provisions of the 1990 Act and held as treasury shares. This authority will expire on 20 April 2015 unless previously renewed, revoked or varied by Petroceltic in a general meeting.

14.17 Authority was granted at the 2012 annual general meeting of Petroceltic to empower the Petroceltic Board pursuant to section 24 of the 1983 Act to allot equity securities (as defined by section 23 of the 1983 Act) for cash (in accordance with the Petroceltic Board's then existing authority to allot and issue relevant securities (as defined in section 20 of the 1983 Act) pursuant to section 20 of the 1983 Act) as if section 23(1) of the 1983 Act did not apply to any such allotment, provided that the powers conferred by such resolution shall be limited to: (a) the allotment of equity securities (including, without limitation, any shares purchased by Petroceltic pursuant to the provisions of the 1990 Act and held as treasury shares) in connection with any offer of securities, open for a period fixed by the Petroceltic Board, by way of rights issue, open offer or otherwise in favour of ordinary shareholders and/or any persons having a right to subscribe for or convert securities into ordinary shares in the capital of Petroceltic (including without limitation, any person entitled to options under any of Petroceltic's share option schemes) and subject to such exclusions or other arrangements as the Petroceltic Board may deem necessary or expedient in relation to legal or practical problems under the laws of, or the requirements of any recognised body or stock exchange, in any territory; and (b) (in addition to the power conferred by paragraph (a)) the allotment of equity securities (including without limitation, any shares purchased by Petroceltic pursuant to the provisions of the 1990 Act and held as treasury shares) up to a maximum of 5 per cent of the aggregate nominal value of the issued ordinary share capital of Petroceltic at the close of business on the date of the 2012 annual general meeting. This authority shall expire on the earlier of the close of business on 11 September 2013 and the date of the next annual general meeting of Petroceltic unless previously renewed, varied or revoked by Petroceltic in general meeting. Petroceltic may before any such expiry make an offer or agreement which would or might require any such securities to be allotted in pursuance of such offer or agreement after such expiry and the Petroceltic Board may allot equity securities pursuant to such offer or agreement as if the powers conferred thereby had not expired.

14.18 The Extraordinary General Meeting is being convened for the purpose of approving and giving effect to the Merger. The Resolutions, if passed, will among other things (and subject to the Merger becoming Effective, save, in the case of the Resolutions listed at sub-paragraphs (a) and (b) below, for the delivery and registration of the Court Orders, where applicable, and Readmission):

(a) approve an increase in the authorised share capital of Petroceltic from €60,355,285.40 to €147,855,285.40 by the creation of a further 7,000,000,000 Ordinary Shares;

(b) authorise the Petroceltic Board (in substitution for the existing authority outlined at paragraph 14.16 above) to allot relevant securities (within the meaning of the 1983 Act) up to an aggregate nominal amount of €43,515,513.25 during the period commencing on the date of the passing of the resolution and expiring on the earlier of the conclusion of the annual general meeting of Petroceltic in 2013 and close of business on 11 September 2013, provided that Petroceltic may before such expiry make an offer or agreement which would or might require relevant securities to be allotted after such expiry and the directors may allot relevant securities in pursuance of such offer or agreement as if the authority hereby conferred had not expired; and

(c) empower the Petroceltic Board (in substitution for the existing authority, which is described at paragraph 14.17 above) to allot equity securities (within the meaning of section 23 of the 1983 Act) for cash pursuant to the authority conferred by Resolution 3 in the Notice of Extraordinary General Meeting as if sub-section (1) of section 23 of the 1983 Act did not apply to any such allotment, provided that this power shall be limited: (a) to the allotment of equity securities in connection with a rights issue, open offer or other invitation to or in favour of the holders of Ordinary Shares where the equity securities respectively attributable to the interests of such holders are proportional (as nearly as may be) to the respective numbers of Ordinary Shares held by them (but subject to such exclusions or other arrangements as the Petroceltic Board may deem necessary or expedient to deal with fractional entitlements that would otherwise arise or with legal or practical problems under the laws of, or the requirements of any recognised regulatory body or any stock exchange in, any territory, or otherwise howsoever); and (b) to the allotment (otherwise than pursuant to sub-paragraph (a) above) of equity securities up to an aggregate nominal amount of €2,742,584.11, and shall expire at the earlier of the conclusion of the annual general meeting of Petroceltic in 2013 and close of business on 11 September 2013, provided that Petroceltic may before such expiry make an offer or agreement which would or might require equity securities to be allotted after such expiry and the Petroceltic Board may allot equity securities in pursuance of such offer or agreement as if the power hereby conferred had not expired.

Settlement of New Petroceltic Shares

14.19 The New Petroceltic Shares will, when issued, be in registered form and, subject to the provisions of the CREST Regulations, the Enlarged Company Directors may permit the holding of New Petroceltic Shares in uncertificated form and title to the Ordinary Shares may be transferred by means of a relevant system (as defined in the CREST Regulations). Where the Ordinary Shares are held in certificated form, share certificates will be sent to the registered share owners by normal post at the shareholders' own risk. No temporary documents of title have been or will be issued in respect of New Petroceltic Shares.

15. CONSTITUTIONAL DOCUMENTS AND OTHER RELEVANT LAWS AND REGULATIONS

Memorandum

15.1 The principal objects of Petroceltic, as set out in part 3 of its Memorandum of Association, include to carry on the business of an investment holding company, to purchase, take on, lease or otherwise acquire any mines, minerals, mining rights, concessions, licences and metalliferous or other lands or property in any part of the world, to carry on all or any of the business of mine, oil well or quarry owners and managers and to engage in all aspects of exploration for and exploitation of oil, gas hydrocarbons and minerals.

Articles of Association

15.2 The current Articles of Association of Petroceltic were adopted on 21 April 2010. Except for the increase in authorised share capital contemplated by the Resolutions, no amendments to the Articles of Association will be made in connection with the Merger. Petroceltic's Articles of Association are available for inspection as described in paragraph 26 of Part XII of this document and are available for inspection at Petroceltic's registered office and on the Petroceltic website.

15.3 The Articles of Association contain (among others) provisions to the following effect:

Deferred Shares

15.4 The holder(s) of the Deferred Shares shall not, by virtue of or in respect of their holding of Deferred Shares have the right to receive notice of any general meeting of Petroceltic or to attend, speak or vote at any such meeting. The Deferred Shares shall on a return of assets in a winding up entitle their holder(s) only to repayment of the amounts paid up on such shares after repayment of the capital paid up on the Ordinary Shares plus the payment of €12,697,380 per Ordinary Share.

Voting rights

15.5 Votes may be given either personally or by proxy. Subject to any rights or restrictions for the time being attached to any class or classes of shares, on a show of hands every member present in person and every proxy shall have one vote, so, however, that no individual shall have more than one vote, and on a poll every member shall have one vote for every share of which he is the holder. On a poll, a member entitled to more than one vote need not cast all his votes or cast all the votes he has in the same way. Where there is an equality of votes, whether on a show of hands or on a poll the chairman of the meeting at which the show of hands takes place or at which the poll is demanded shall be entitled to a casting vote in addition to any other vote he may have.

Restrictions on voting

15.6 Unless the Directors otherwise determine, no member shall be entitled to vote at a general meeting or at any separate meeting of the holders of any class of shares in Petroceltic, either in person or by proxy, in respect of any share held by him unless all moneys payable by him in respect of that share up to the date of the meeting have been paid.

Dividends

15.7 Subject to the provisions of the Irish Companies Acts, Petroceltic may by ordinary resolution declare dividends in accordance with the respective rights of the members, but no dividend shall exceed the amount recommended by the Directors. The Directors may, subject to approval by Petroceltic at any general meeting in respect of any dividend declared or proposed to be declared at that general meeting or declared or paid at any time prior to or at the next following annual general meeting (and provided that an adequate number of unissued Ordinary Shares are available for the purpose), offer holders of Ordinary Shares the right, prior to or contemporaneously with their announcement of the dividend in question and any related information as to Petroceltic's profits for such financial period or part thereof, to elect to receive in lieu of such dividend (or part thereof) an allotment of additional Ordinary Shares credited as fully paid. Subject to the provisions of the Irish Companies Acts, the Directors may pay interim dividends if it appears to them that they are justified by the profits of Petroceltic available for distribution.

Distribution of assets on a winding-up

15.8 If Petroceltic shall be wound up and the assets available for distribution among the members as such shall be insufficient to repay the whole of the paid up or credited as paid up share capital, such assets shall be distributed so that, as nearly as may be, the losses shall be borne by the members in proportion to the capital paid up or credited as paid up at the commencement of the winding up on the shares held by them respectively. If on a winding up the assets available for distribution among the members shall be more than sufficient to repay the whole of the share capital paid up or credited as paid up at the commencement of the winding up, the excess shall be distributed among the members in proportion to the capital at the commencement of the winding up paid up or credited as paid up on the said shares held by them respectively provided that this shall not affect the rights of the holders of shares issued upon special terms and conditions.

Variation of rights

15.9 Without prejudice to any special rights conferred on the holders of any existing shares of any class of shares and subject to the provisions of the Irish Companies Acts, any share in Petroceltic may be issued with such preferred, deferred or other special rights or such restrictions, whether in regard to dividend, voting, return of capital or otherwise, as Petroceltic may from time to time by ordinary resolution determine. Whenever the share capital is divided into different classes of shares, the rights attached to any class may be varied or abrogated with the consent in writing of the holders of three-fourths in nominal value of the issued shares of that class, or with the sanction of a special resolution passed at a separate general meeting of the holders of the shares of the class and may be so varied or abrogated either whilst Petroceltic is a going concern or during or in contemplation of a winding-up. The quorum at any such separate general meeting, other than an adjourned meeting, shall be two persons holding or representing by proxy at least one-third in nominal value of the issued shares of the class in question and, at an adjourned meeting, one person holding shares of the class in question or his proxy shall be a quorum.

Transfer of shares

15.10 The shares of any member may be transferred by instrument in writing in any usual form or in any other form which the Directors may approve. Any instrument of transfer shall be executed by or on behalf of the transferor and (except in the case of fully-paid shares) by or on behalf of the transferee. Title to any shares in Petroceltic may also be evidenced and transferred by electronic means without a written instrument, in accordance with statutory regulations made from time to time under section 239 of the 1990 Act or under any other regulations having similar effect. The Directors shall have the power to implement any arrangements they think fit for such evidencing and transfer which accord with such regulations, and, in particular shall where they consider it appropriate be entitled to dis-apply, vary or amend all or any part of the provisions of the Articles of Association with respect to the requirement for written instruments of transfer and share certificates or where such provisions are inconsistent with such statutory regulations as aforesaid, in order to give effect to such regulations.

15.11 The Directors may, in their absolute discretion and without giving any reason, refuse to register the transfer of a share, or any renunciation of any allotment made in respect of a share, which is not fully paid provided that any such refusal shall not prevent dealings in the shares from taking place on an open and proper basis or any transfer of a share to a minor or a person of unsound mind.

15.12 The Directors may also refuse to register any transfer (whether or not it is in respect of a fully paid share) unless it is accompanied by the certificate for the shares to which it relates and such other evidence as the Directors may reasonably require to show the right of the transferor to make the transfer save where the transferor is a Stock Exchange Nominee (as such term is defined in the Companies (Amendment) Act 1977 of Ireland), it is in respect of only one class of shares, it is in favour of not more than four transferees and it is lodged at Petroceltic's registered office or at such other place as the Directors may appoint.

Allotment of shares

15.13 (a) Subject to the provisions of the Irish Companies Acts relating to authority, pre-emption or otherwise in regard to the issue of new shares and to any resolution of Petroceltic in general meeting passed pursuant thereto, all unissued shares (including treasury shares) shall be at the disposal of the Directors, and they may (subject to the provisions of the Irish Companies Acts) allot, grant options over or otherwise dispose of them to such persons on such terms and conditions and at such times as they may consider to be in the best interests of Petroceltic and its shareholders.

(b) Without prejudice to the generality of the powers conferred on the Directors by the preceding paragraph and the powers and rights of the Directors under or in connection with any share option schemes or arrangements which were adopted or entered into by Petroceltic prior to the adoption of the Articles of Association, the Directors may from time to time grant options to subscribe for the unallotted shares in the capital of Petroceltic to persons in the service or employment of Petroceltic or any subsidiary of Petroceltic (including Directors holding executive offices) on such terms and subject to such conditions as the members of Petroceltic in general meeting may from time to time approve.

(c) Petroceltic may issue warrants to subscribe (by whatever name they are called) to any person to whom Petroceltic has granted the right to subscribe for shares in Petroceltic (other than under a share option scheme for employees) certifying the right of the registered holder thereof to subscribe for shares in Petroceltic upon such terms and conditions as the right may have been granted.

(d) If by the conditions of allotment of any share the whole or part of the amount or issue price thereof shall be payable by instalments, every such instalment when due shall be paid to Petroceltic by the person who for the time being shall be the holder of such share.

Alteration of capital

15.14 Petroceltic may by ordinary resolution:

(a) increase its share capital;

(b) consolidate and divide all or any of its share capital into shares of a larger amount;

(c) subject to the provisions of the Irish Companies Acts, sub-divide its shares, or any of them, into shares of smaller amount; or

(d) cancel any shares which have not been taken or agreed to be taken by any person and diminish the amount of its share capital by the amount of the shares so cancelled.

Purchase of own shares

15.15 Subject to the provisions of, and to the extent permitted by, the Irish Companies Acts and to any rights conferred on the holders of any class of shares, Petroceltic may purchase any of its shares of any class on such terms and conditions and in such manner as the Directors may from time to time determine.

15.16 (a) Subject to the provisions of, and to the extent permitted by, the Irish Companies Acts, to any rights conferred on the holders of any class of shares and to the following paragraphs, Petroceltic may purchase any of its shares of any class ("**Acquired Shares**" or "**Acquired Share**", as appropriate) on such terms and conditions and in such manner as the Directors may from time to time determine.

(b) Petroceltic shall not exercise any authority granted under section 215 of the 1990 Act to make market purchases of its own shares unless the authority required by such section shall have been granted by special resolution of Petroceltic (a **"section 215 Resolution**").

(c) Petroceltic shall not be required to select the Acquired Shares to be purchased on a pro rata basis or in any particular manner as between the holders of shares of the same class or as between the holders of shares of different classes or in accordance with the rights as to dividends or capital attached to any class of shares.

(d) For the purposes of any section 215 Resolution:

(i) the aggregate nominal value of the Acquired Shares authorised to be acquired pursuant to any such section 215 Resolution shall not exceed 10 per cent of the aggregate nominal value of the aggregate share capital of Petroceltic as at the close of business on the date of the passing of such section 215 Resolution;

(ii) the minimum price which may be paid for any Acquired Share shall be the nominal value thereof;

(iii) the maximum price which may be paid for any Acquired Share (a **"Relevant Share"**) shall be an amount equal to 105 per cent of the higher of:-

(A) the average of the Relevant Price for shares of the same class as the Relevant Share in respect of each of the ten business days immediately preceding the day on which the Relevant Share is purchased; and

(B) (if there shall be any), the average of the middle market prices for shares of the same class as the Relevant Share, as derived from the London Stock Exchange Daily Official List (or any successor publication thereto), for the ten business days immediately preceding the day on which the Relevant Share is purchased; and

(iv) for the purposes of the Articles of Association, the expression **"Relevant Price"** shall mean, in respect of any business day on which there shall be a dealing on the Irish Stock Exchange in respect of shares of the same class as the Relevant Share, the closing quotation price in respect of such shares for such business day as published in The Irish Stock Exchange Daily Official List (or any successor publication thereto) and, in respect of any business day on which there shall be no such dealing, the price which is equal to (A) the mid-point between the high and low market guide prices in respect of such shares for such business day as published in The Irish Stock Exchange Daily Official List (or any successor publication thereto), or (B) if there shall be only one such market guide price so published, the market guide price so published.

(e) For the purposes of any resolution of Petroceltic proposing to determine, in accordance with section 209 of the 1990 Act, the re-issue price range at which any treasury shares for the time being held by Petroceltic may be re-issued off-market:

(i) the maximum price at which a treasury share may be re-issued off-market shall be an amount equal to 120 per cent of the Appropriate Price;

(ii) the minimum price at which a treasury share may be re-issued off-market shall be an amount equal to 95 per cent of the Appropriate Price;

(iii) for the purposes of the Articles of Association, the expression **"Appropriate Price"** shall mean the higher of:

(A) the average of the Relevant Price for shares of the class of which such treasury share is to be re-issued in respect of each of the ten business days immediately preceding the day on which the treasury share is re-issued; and

(B) (if there shall be any), the average of the middle market prices for shares of the class of which such treasury share is to be re-issued, as derived from the London Stock Exchange Daily Official List (or any successor publication thereto), for the ten business days immediately preceding the day on which such treasury shares is re-issued; and

(iv) for the purposes of the Articles of Association, the expression **"Relevant Price"** shall mean, in respect of any business day on which there shall be a dealing on the Irish Stock Exchange in respect of shares of the class of which the treasury share is to be re-issued, the closing quotation price in respect of such shares for such business day as published in the Irish Stock Exchange Daily Official List (or any successor publication thereto) and, in respect of any business day on which there shall be no such dealing, the price which is equal to (A) the mid-point between the high and low market guide prices in respect of such shares for such business day as published in the Irish Stock Exchange Daily Official List (or any successor publication thereto), or (B) if there shall be any one such market guide price so published, the market guide price so published.

Reduction of capital

15.17 Petroceltic may by special resolution reduce its share capital, any capital redemption reserve fund or any share premium account in any manner and with and subject to any incident authorised, and consent required, by law.

Disclosure of interests

15.18 Without prejudice to the provisions of sections 81 to 88 of the 1990 Act, the Directors may at any time and from time to time if, in their absolute discretion, they consider it to be in the interests of Petroceltic to do so, give a notice to the holder or holders of any share (or any of them) requiring such holder or holders to notify Petroceltic in writing within such period as may be specified in such notice (which shall not in the case of a holder or holders of not less than 0.25 per cent of the class of shares concerned, be less than fourteen days or in any other case twenty-eight days from the date of service of such notice) of full and accurate particulars of all or any of the following matters, namely:

(a) his interest in such share;

(b) if his interest in the share does not consist of the entire beneficial interest in it, the interests of all persons having any beneficial interest direct or indirect in the share (provided that one joint holder of a share shall not be obliged to give particulars of interests of persons in the share which arise only through another joint holder); and

(c) any agreement in respect of the share entered into by him or any person having any beneficial interest in the share to which section 73 of the 1990 Act applies and any arrangements (whether legally binding or not) entered into by him or any person having any beneficial interest in the share whereby it has been agreed or undertaken or the holder of such share can be required to transfer the share or any interest therein to any person (other than a joint holder of the share) or to act in relation to any meeting of Petroceltic or of any class of shares of Petroceltic in a particular way or in accordance with the wishes or directions of any other person (other than a person who is a joint holder of such share).

Restriction of Voting Rights

15.19 (a) If at any time the Directors shall determine that a Specified Event (as defined in sub-paragraph (g) below) shall have occurred in relation to any share or shares, the Directors may serve a notice to such effect on the holder or holders thereof. Upon the expiry of 14 days from the service of any such notice (referred to as a **"Restriction Notice"** in the Articles of Assocation), for so long as such Restriction Notice shall remain in force:

(i) no holder or holders of the share or shares specified in such Restriction Notice (referred to as **"Specified Shares"** in the Articles of Association) shall be entitled to attend, speak or vote either personally, by representative or by proxy at any general meeting of Petroceltic or at any separate general meeting of the holders of the class of shares concerned; and

(ii) the Directors shall, where the Specified Shares represent not less than 0.25 per cent of the class of shares concerned, be entitled:-

(A) to withhold payment of any dividend (including shares issuable in lieu of dividends) in respect of the Specified Shares; and/or

(B) in case the Specified Event is one described in sub-paragraphs (g) (i) or (iii) below, to refuse to register any transfer of the Specified Shares or any renunciation of any allotment of new shares or debentures made in respect thereof unless such transfer or renunciation is shown to the satisfaction of the Directors to be an arm's length transfer or a renunciation to another beneficial owner unconnected with the holder or any person appearing to have an interest in the Specified Shares (subject always to the provisions of sub-paragraph (h) below).

(b) A Restriction Notice shall be cancelled by the Directors immediately after the holder or holders concerned shall have remedied the default by virtue of which the Specified Event shall have occurred. A Restriction Notice in respect of any Specified Share shall automatically cease to have effect in respect of any shares on receipt by Petroceltic of evidence satisfactory to it that the shares have been sold to a bona fide unconnected third party (in particular by way of sale through the Irish Stock Exchange or an overseas exchange or by acceptance of a takeover offer) or upon registration of the relevant transfer provided that a Restriction Notice shall not cease to have effect in respect of any transfer where no change in the beneficial ownership of the share shall occur and for this purpose it shall be assumed that no such change has occurred where a transfer form in respect of the share is presented for registration having been stamped at a reduced rate of stamp duty by virtue of the transferor or transferee claiming to be entitled to such reduced rate as a result of the transfer being one where no beneficial interest passed the Directors shall cause a notation to be made in the Petroceltic register of members against the name of any holder or holders in respect of whom a Restriction Notice shall have been served indicating the number of the Specified Shares and shall cause such notation to be deleted upon cancellation or cesser of such Restriction Notice.

(d) Any determination of the Directors and any notice served by them pursuant to the provisions of the Articles of Association shall be conclusive as against the holder or holders of any share and the validity of any notice served by the Directors in pursuance of the Articles of Association shall not be questioned by any person.

(e) If, while any Restriction Notice shall remain in force in respect of any Specified Shares, any further shares shall be issued in respect thereof pursuant to a capitalisation issue made in pursuance of the Articles of Association, the Restriction Notice shall be deemed also to apply in respect of such further shares which shall as from the date of issue thereof form part of the Specified Shares for all purposes of the Articles of Association.

(f) On the cancellation of any Restriction Notice, Petroceltic shall pay to the holder (or, in the case of joint holders, the first named holder) on the Petroceltic register of members in respect of the Specified Shares as of the record date for any such dividend so withheld, all such amounts as have been withheld pursuant to the provisions of the Articles of Association subject always to the provisions of the Articles of Association dealing with unclaimed dividends, which shall be deemed to apply, mutatis mutandis, to any amount so withheld.

(g) For the purposes of the Articles of Association the expression "**Specified Event**" in relation to any share shall mean any of the following events:

(i) the failure of the holder or any of the holders thereof to pay any call or installment of a call in the manner and at the time appointed for payment thereof;

(ii) the failure by the holder thereof or any of the holders thereof to comply, to the satisfaction of the Directors, with all or any of the terms of the Articles of Association dealing with disclosure of interests (as outlined above) in respect of any notice or notices given to him or any of them thereunder; or

(iii) the failure by the holder thereof or any of the holders thereof to comply, to the satisfaction of the Directors, with the terms of any notice given to him or any of them pursuant to the provisions of section 81 of the 1990 Act.

(h) For the purposes of sub-paragraph (a)(ii)(B) above, the Directors shall be required to accept, as an arm's length transfer to another beneficial owner, any transfer which is presented for registration in pursuance of:

(i) any bona fide sale made on any bona fide stock exchange, unlisted securities market or over-the-counter exchange; or

(ii) the acceptance of any general offer made to all the holders of any class of shares in the capital of Petroceltic.

General meetings

15.20 Petroceltic shall in each year hold a general meeting as its annual general meeting in addition to any other meeting in that year and shall specify the meeting as such in the notices calling it. A copy of every balance sheet (including every document required by law to be annexed thereto) which is to be laid before the annual general meeting of Petroceltic together with a copy of the directors report and auditors report shall be sent, by post, electronic mail, or any other means of electronic communication not less than 21 clear days before the date of the annual general meeting to every person entitled under the provisions of the Irish Companies Acts to receive them provided that in the case of those documents sent by electronic mail or any other means of electronic communication, such documents shall be sent with the consent of the recipient to the address of the recipient notified to Petroceltic by the recipient for such purposes.

15.21 All general meetings other than annual general meetings shall be called extraordinary general meetings. All business shall be deemed special that is transacted at an extraordinary general meeting, and also all that is transacted at an annual general meeting, with the exception of declaring a dividend, the consideration of the accounts, balance sheets and the reports of the directors and auditors, the election of directors in the place of those retiring by rotation, the re-appointment of the retiring auditors and the fixing of the remuneration of the auditors.

15.22 The Directors may convene general meetings. Extraordinary general meetings may also be convened on such requisition, or in default may be convened by such requisitionists and in such manner as may be provided by the Irish Companies Acts. If at any time there are not within the State sufficient Directors capable of acting to form a quorum any Director or any two members of Petroceltic may convene an extraordinary general meeting in the same manner or nearly as possible as that in which general meetings may be convened by the Directors.

Directors

Numbers

15.23 Unless otherwise determined by ordinary resolution, the number of Directors (other than alternate Directors) shall not be less than three nor more than fifteen. A Director shall not be required to hold a share qualification.

Appointment of Additional Directors

15.24 (a) No person other than a Director retiring by rotation or retiring in accordance with sub-paragraph (b) below shall be appointed a Director at any general meeting unless he is recommended by the Directors or, not less than seven nor more than forty-two days before the date appointed for the meeting, notice executed by a member qualified to vote at the meeting has been given to Petroceltic of the intention to propose that person for appointment stating the particulars which would, if he were so appointed, be required to be included in Petroceltic's register of Directors together with notice executed by that person of his willingness to be appointed.

(b) Petroceltic may by ordinary resolution appoint a person to be a Director either to fill a vacancy or as an additional Director and may also determine the rotation in which any additional Directors are to retire. The Directors may appoint a person who is willing to act to be a Director, either to fill a vacancy or as an additional Director provided that the appointment does not cause the number of Directors to exceed any number fixed by or in accordance with the Articles as the maximum number of Directors. A Director so appointed shall hold office only until the next following annual general meeting and shall not be taken into account in determining the Directors who are to retire by rotation at the meeting. If not re-appointed at such annual general meeting, such Director shall vacate office at the conclusion thereof.

Remuneration

15.25 The ordinary remuneration of the Directors shall be determined from time to time by Petroceltic in general meeting and shall be divisible among the Directors as they may agree, or, failing agreement, equally, except that any Director who shall hold office for part only of the period in respect of which such remuneration is payable shall be entitled only to rank in such division for a proportion of the remuneration related to the period during which he has held office. Any Director who holds any additional office (including for this purpose the office of chairman or Deputy chairman) or who serves on any committee, or who otherwise performs services which in the opinion of the Directors are outside the scope of the ordinary duties of a Director, may be paid such extra remuneration by way of fee, salary, superannuation commission or otherwise as the Directors may determine. The Directors may be paid all travelling, hotel and other expenses properly incurred by them in connection with their attendance at meetings of Directors or committees of Directors or general meetings or separate meetings of the holders of any class of shares or of debentures of Petroceltic or otherwise in connection with the discharge of their duties.

Retirement

15.26 At each annual general meeting of Petroceltic one third of the Directors, or if their number is not three or a multiple of three, the number nearest to one third shall retire from office. The Directors to retire in this manner shall be those who have been longest in office since their last appointment or reappointment but as between persons who became or were last reappointed Directors on the same day those to retire shall (unless they otherwise agree among themselves) be determined by lot. A Director who retires at an annual general meeting may, if willing to act, be reappointed. If he is not reappointed (or deemed to be reappointed pursuant to the Articles of Association) he shall retain office until the meeting appoints someone in his place or, if it does not do so, until the end of the meeting.

Voting at board meetings

15.27 Questions arising at any meeting of Directors shall be decided by a majority of votes. Where there is an equality of votes, the chairman of the meeting shall have a second or casting vote. A person who holds office only as an alternate Director shall, if his appointor is not present, be counted in the quorum but notwithstanding that such person may act as alternate Director for more than one Director he shall not count as more than one for the purposes of determining whether a quorum is present.

Restrictions on voting

15.28 Save as otherwise provided by the Articles of Association, a Director shall not vote at a meeting of the Directors or a committee of Directors on any resolution concerning a matter in which he has, directly or indirectly, an interest which is material or a duty which conflicts or may conflict with the interests of Petroceltic. A Director shall not be counted in the quorum present at a meeting in relation to a resolution on which he is not entitled to vote.

15.29 A Director shall (in the absence of some other material interest than is indicated below) be entitled to vote (and be counted in the quorum) in respect of any resolutions concerning any of the following matters, namely:-

(a) the giving of any security, guarantee or indemnity to him in respect of money lent by him to Petroceltic or any of its subsidiary or associated companies or obligations incurred by him at the request of or for the benefit of Petroceltic or any of its subsidiary or associated companies;

(b) the giving of any security, guarantee or indemnity to a third party in respect of a debt or obligation of Petroceltic or any of its subsidiary or associated companies for which he himself has assumed responsibility in whole or in part and whether alone or jointly with others under a guarantee or indemnity or by the giving of security;

(c) any proposal concerning any offer of shares or debentures or other securities of or by Petroceltic or any of its subsidiary or associated companies for subscription, purchase or exchange in which offer he is entitled to participate as a holder of securities or is to be interested as a participant in the underwriting or sub-underwriting thereof;

(d) any proposal concerning any other company in which he is interested, directly or indirectly and whether as an officer or shareholder or otherwise howsoever, provided that he is not the holder of nor has an interest in (within the meaning of Part IV, Chapter 2 of the 1990 Act) 1 per cent or more of the issued shares of any class of such company or of the voting rights available to members of such company (any such interest being deemed for the purposes of this Article to be a material interest in all circumstances);

(e) any arrangement for the benefit of the employees of Petroceltic or any subsidiary which does not award any privilege or benefit not generally awarded to the employees to whom such arrangement relates; or

(f) any proposal concerning insurance which Petroceltic proposes to maintain or purchase for the benefit of Directors or for the benefit of persons including the Directors.

Directors' interests

15.30 Subject to the provisions of the Irish Companies Acts, and provided that he has disclosed to the Directors the nature and extent of any material interest of his, a Director notwithstanding his office:-

(a) may be a party to, or otherwise interested in, any contract transaction or arrangement with Petroceltic or any subsidiary or associated company thereof or in which Petroceltic or any subsidiary or associated company thereof is otherwise interested;

(b) may be a director or other officer of, or employed by, or a party to any contract transaction or arrangement with, or otherwise interested in, any body corporate promoted by Petroceltic or in which Petroceltic or any subsidiary or associated company thereof is otherwise interested; and

(c) shall not be accountable, by reason of his office, to Petroceltic for any remuneration or other benefit which he derives from any such office or employment or from any such transaction or arrangement or from any interest in any such body corporate unless Petroceltic otherwise directs and no such contract transaction or arrangement shall be liable to be avoided on the ground of any such interest or benefit. Subject as aforesaid no Director or intending Director shall be disqualified by his office from contracting with Petroceltic either as seller, buyer or otherwise, nor shall any such contract or any contract transaction or arrangement entered into by or on behalf of the other company in which any Director shall be in any way interested be avoided nor shall any Director so contracting or being so interested be liable to account to Petroceltic for any profit realised by any such contract or arrangement by reason of such Director holding that office or of the fiduciary relationship thereby established.

15.31 The nature of a Director's interest must be declared by him at the meeting of the Directors at which the question of entering into the contract or arrangement is first taken into consideration, or if the Director was not at the date of that meeting interested in the proposed contract or arrangement, at the next meeting of the Directors held after he became so interested, and in a case where the Director becomes interested in a contract or arrangement after it is made at the first meeting of the Directors held after he becomes so interested.

Borrowing powers

15.32 The Directors may exercise all the powers of Petroceltic to borrow money, and to mortgage or charge its undertaking, property, assets and uncalled capital or any part thereof, and to issue debentures, debenture stock and other securities, whether outright or as collateral security for any debt, liability or obligation of Petroceltic or of any third party without limitation as to amount.

Indemnities

15.33 Subject to the provisions of and so far as may be admitted by the Irish Companies Acts, every Director, managing director, auditor, secretary or other officer of Petroceltic shall be entitled to be indemnified by Petroceltic against all costs, charges, losses, expenses and liabilities incurred by him in the execution and discharge of his duties or in relation thereto. Subject to the provisions of and so far as may be admitted by the Irish Companies Acts, the Directors may purchase and maintain insurance at the expense of Petroceltic for the benefit of any Director, auditor, secretary or other officer of Petroceltic against any liability which may attach to him or loss or expenditure which he may incur in relation to anything done or alleged to have been done or omitted to be done by him as a Director, auditor, secretary or other officer of Petroceltic.

Other relevant laws and regulations – disclosure of interest in shares

15.34 Part IV of the 1990 Act makes provision for the disclosure of interests in shares in an Irish public limited company whose shares are admitted to trading on ESM and AIM. The 1990 Act requires notification of interests in, and changes in interests of, 5 per cent or more of the relevant share capital (or of any class of relevant share capital) of an Irish public limited company. The notification obligation arises where there is a change in the percentage of shares in which a person has an interest from below to above the 5 per cent threshold, or from above to below that threshold, or where 5 per cent is exceeded both before and after the transaction but the percentage level, in whole numbers, changes (fractions of a percentage being rounded down to the next whole number). "Relevant share capital" is defined as issued share capital carrying full voting rights.

15.35 The obligation to notify must be performed within the period of 5 clear business days from the date upon which the obligation arises. The notification to the relevant company must be in writing and must specify the share capital to which it relates; the number of shares comprised in that share capital in which the person making the notification knows he was interested immediately after the time when the obligation arose, or in a case where the person no longer has a notifiable interest in shares comprised in the share capital, state that he no longer has an interest; identify the notifier and give his address and, except where the notice is stating that the notifier no longer has a notifiable interest in the shares, give details of the registered holder of the shares and the number of shares held by such holder. Where a person fails to comply with the notification requirements described above, no right or interest of any kind whatsoever in respect of the shares concerned, held by such person, shall be enforceable by such person, whether directly or indirectly, by action or legal proceeding. However, such person may apply to the High Court of Ireland to have the rights attaching to the shares concerned reinstated.

15.36 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, to the holding of a significant shareholder, a significant shareholder being 3 per cent or more of any class of an AIM security and 5 per cent or more of any class of an ESM security respectively, which increase or decrease such holding through any single percentage.

16. SIGNIFICANT SHAREHOLDERS

16.1 As at the date of this document, insofar as is known to the Directors, the name of each person who, directly or indirectly, is interested in three per cent or more of the ordinary issued share capital of Petroceltic, and the amount of such person's interest, is set out below:

Name of Shareholder	Number of Existing Petroceltic Shares	Percentage of Petroceltic issued share capital	Percentage of Enlarged Company issued share capital following the Merger[1]
JP Morgan	141,226,816	5.96%	3.22%
Worldview Capital Management	121,986,753	5.14%	2.78%
Scottish Widows	117,053,832	4.94%	2.67%
Credit Suisse Group AG	101,588,861	4.29%	2.32%

Note:

[1] *These figures assume no further Petroceltic or Melrose Shares are issued prior to the effective date other than in connection with the Merger.*

16.2 The Directors are aware of the following interests in Melrose which at the date of this Document would represent an interest in three per cent or more of the Enlarged Company's share capital or voting rights and which may be notifiable under the AIM Rules or ESM Rules (in the case of an interest of five per cent or more) following the Merger becoming Effective and the Readmission occurring:[1]

Name of Shareholder	Number of Melrose Shares	Percentage of Melrose issued share capital	Number of Enlarged Company Shares following the Merger	Percentage of Enlarged Company issued share capital following the Merger
Robert F M Adair	58,431,929	50.95%	1,028,401,950	23.44%
Skye Investments Ltd[2]	57,391,423	50.04%	1,010,089,045	23.02%
Caledonia Investments PLC	11,785,302	10.28%	207,421,315	4.73%
Aberforth Partners	9,724,291	8.48%	171,147,522	3.90%

Notes:

1. *The number of Enlarged Company Shares following the Merger and the percentage of Enlarged Company issued share capital following the Merger has been calculated by multiplying the relevant Melrose Shareholder's interest by the Exchange Ratio and dividing by the sum of the total number of Existing Petroceltic Shares plus an estimate of the total number of New Petroceltic Shares to be issued to Melrose Shareholders pursuant to the Merger. The actual number of Enlarged Company Shares following the Merger and the percentage of Enlarged Company issued share capital held by each Melrose Shareholder may differ to the above because as part of the Merger it has been agreed to round the fractional entitlements of Melrose Shareholders up.*

2. *Skye Investments Ltd holding is also included in Robert Adair's total holding. Details of the security interests over the shareholding of Robert Adair and Skye Investments Ltd are contained in paragraph 20.1.3 of this Part XII.*

16.3 Save as disclosed in paragraphs 16.1 and 16.2 above, the Directors and the Proposed Directors are not aware of any interest which will represent an interest in the Enlarged Company's issued share capital or voting rights which is notifiable under the AIM Rules or ESM Rules following the Merger becoming Effective and the Readmission occurring.

16.4 So far as Petroceltic is aware, on the Merger becoming Effective, no person or persons, directly or indirectly, jointly or severally, will own or exercise or could exercise control over the Enlarged Company.

16.5 There are no differences between the voting rights enjoyed by the shareholders described in paragraph 16.1 above and those enjoyed by any other holder of Existing Petroceltic Shares.

17. WORKING CAPITAL

The Directors and the Proposed Directors are each of the opinion that, having made due and careful enquiry and after taking into account the HSBC Senior Secured Facility available to the Enlarged Group, the working capital available to the Enlarged Group is sufficient for its present requirements, that is for at least the next twelve months from the date of Readmission.

18. NO SIGNIFICANT CHANGE

Petroceltic

There has been no significant change in the financial or trading position of the Petroceltic Group since 31 December 2011, being the date to which the last audited financial information has been published (see Part IX).

Melrose

There has been no significant change in the financial or trading position of the Melrose Group since 31 December 2011, being the date to which the last audited financial information has been published (see Part X).

19. RELATED PARTY TRANSACTIONS

Petroceltic

Save as disclosed in the Petroceltic Historical Financial Information in Part IX of this document, there were no related party transactions entered into by Petroceltic during the financial years ended 31 December 2009, 31 December 2010 and 31 December 2011. Details of the related party transactions to which Petroceltic has been party for the period from 1 January 2012 to the Latest Practicable Date are as follows:

- The Petroceltic Group uses the taxation and payroll services of LHM Casey McGrath on an arms length basis. Con Casey, a Director, is a partner in LHM Casey McGrath. The total fees invoiced to the Petroceltic Group for these services for the period from 1 January 2012 to 30 June 2012 was US$20,766 (€16,438).

Melrose

Save as disclosed in the Melrose Historical Financial Information in Part X of this document, there were no related party transactions entered into by Melrose during the financial years ended 31 December 2009, 31 December 2010 and 31 December 2011. There were no related party transactions to which Melrose has been party for the period from 1 January 2012 to the Latest Practicable Date.

20. MATERIAL CONTRACTS

The following contracts entered into by companies in the Petroceltic Group or the Melrose Group are:

(a) contracts entered into other than in the ordinary course of business of the Petroceltic Group or the Melrose Group which are or may be material for the two years immediately preceding the publication of this document;

(b) contracts entered into other than in the ordinary course of business of the Petroceltic Group or the Melrose Group which contain any outstanding material obligation or entitlement as at the date of this document; and

(c) contracts which are material subsisting agreements which have been entered into at any time and which are included within, or which relate to the assets and liabilities (as defined in the AIM Note for Mining and Oil & Gas Companies) of any member of the Petroceltic Group or the Melrose Group (notwithstanding whether such agreements are (i) within the ordinary course or (ii) were entered into outside of the two years immediately preceding the date of this document).

20.1 *Documents in relation to the Merger*

20.1.1 Mutual Confidentiality Agreement

On 7 February 2012, Petroceltic and Melrose entered into a confidentiality agreement, subsequently amended on 26 July 2012, pursuant to which Petroceltic and Melrose agreed to keep confidential certain information provided by the other party for the purposes of evaluating the Merger.

The confidentiality obligations will not apply to confidential information the disclosure of which is required by any applicable law, including by stock exchange regulations or by a governmental order, decree, regulation or rule, provided that the recipient of the information shall make all reasonable efforts to give prompt written notice to the disclosing party prior to such disclosure.

Under the agreement the parties agreed to defend, indemnify and hold each other harmless from any and all liability arising from the non-authorised disclosure of information by that party to a third party.

20.1.2 Relationship Agreement

Robert Adair, Skye and Petroceltic entered into a Relationship Agreement on 16 August 2012 which is conditional on the Readmission and which will govern the relationship between Robert Adair, Skye and the Enlarged Group following the Merger becoming Effective.

Robert Adair and Skye have undertaken to use all reasonable endeavours to procure that the Enlarged Group carries on its business independently of Robert Adair, Skye and their associates, that all arrangements between any member of the Enlarged Group and Robert Adair, Skye or their associates are conducted on arm's length terms and that they shall refrain from voting on related party transactions on which they are required by relevant market rules to abstain from voting.

Robert Adair and Skye have undertaken to vote in favour of all ordinary course resolutions proposed at the Enlarged Company's annual general meetings for a period of 24 months from Readmission and to vote in favour of any capital raising recommended by the Enlarged Group's advisers and by the Enlarged Company Board. Robert Adair and Skye have also undertaken not to (and to procure that their associates do not), amongst other things, exercise their rights as shareholders to requisition shareholder meetings, remove any director of the Enlarged Company, bring forward or support a derivative action against any director or oppose any authorised action or recommendation of the Enlarged Company Board, unless consent has been granted in respect of such action by the Enlarged Company Board.

Robert Adair and Skye have agreed to a partial lock-up over a period of up to 18 months from Readmission. Under the terms of the lock-up, 10 per cent of Robert Adair and Skye's aggregate holding will be free of any restrictions, 90 per cent of Robert Adair and Skye's aggregate holding will be subject to a restriction on disposal for 12 months from Readmission and 45 per cent of Robert Adair and Skye's aggregate holding will be subject to a restriction on disposal for 18 months from Readmission. The lock-up is subject to certain customary exceptions including disposals pursuant to a court order, acceptance of a takeover offer or participation in a scheme of arrangement, and creation and enforcement of security interests and disposals to connected persons who enter into a deed of adherence in respect of the Relationship Agreement. Robert Adair and Skye have further agreed to orderly marketing provisions which will govern any disposal of shares by Robert Adair or Skye.

Robert Adair and Skye have also agreed to a standstill agreement, pursuant to which they have agreed not to acquire or offer to acquire (and to procure that none of their associates or concert parties will acquire or offer to acquire) any securities in the Enlarged Group which would result in their percentage holding in the Enlarged Group increasing by 2 per cent, or make an offer (as defined in Irish Takeover Rules) for all or any part of the share capital of the Enlarged Company.

The Relationship Agreement shall terminate on the earlier of: (i) the Enlarged Company ceasing to be admitted to either ESM and AIM, or the official lists maintained by the Irish Stock Exchange and the FSA and to trading on the main securities markets of the Irish Stock Exchange and the London Stock Exchange; and (ii) Robert Adair, Skye and their associates ceasing to be entitled to exercise or control the exercise of 10 per cent or more of the voting rights in the Enlarged Company.

20.1.3 Irrevocable Undertakings (Melrose Shares)

The following holders, controllers or beneficial owners of Melrose Shares have given irrevocable undertakings to vote in favour of the Melrose Scheme at the Melrose Court Meeting and the resolutions to be proposed at the Melrose General Meeting to give effect to the Melrose Scheme:

(a) *Part A*

Name	Number of Melrose Shares	Percentage of Melrose Shares in issue
Robert Adair and Skye (a company connected to Robert Adair)	58,431,929	50.95%

The undertakings listed in this Part A will remain binding if a higher competing offer for Melrose is made. The undertakings will cease to be binding if: (i) the Merger is not implemented by the date which is 9 months from the date of the first public announcement in connection with the Merger; or (ii) Petroceltic proposes any variation to the terms of the Merger unless the revised principal terms (including the exchange ratio and amount of special dividend payable to Melrose Shareholders) are no less favourable than the terms set out in the Rule 2.7 Announcement and if Petroceltic elects to implement the Merger by way of a takeover, an acceptance of not less than 75 per cent, unless a lower acceptance condition is agreed by Melrose with UK Panel consent; or (iii) the Merger lapses or is withdrawn without having become wholly unconditional, save in circumstances where within three days of the Merger having lapsed or been withdrawn Petroceltic announces a new offer for Melrose on terms no less favourable to Melrose shareholders than the principal terms of the Merger.

A substantial majority of the Melrose Shares in which Robert Adair and Skye are interested are subject to charges in favour of third parties. In each case where such consent is required, the beneficiary of the charge has consented to Robert Adair and Skye providing the irrevocable undertaking described herein. However, in the event that any beneficiary of the charges granted by Robert Adair or Skye enforces its security interest in such Melrose Shares, the irrevocable undertaking shall not be binding on the party enforcing such security interest.

(b) *Part B*

Name	Number of Melrose Shares	Percentage of Melrose Shares in issue
David Archer	504,830	0.44%
Anthony Richmond-Watson	777,769	0.68%
David Thomas	150,000	0.13%
William Wyatt	81,560	0.07%

The undertakings listed in this Part B will remain binding if a higher competing offer for Melrose is made. The undertakings will cease to be binding if: (i) the Merger is not implemented by the date which is 9 months from the date of the first public announcement in connection with the Merger; or (ii) Petroceltic proposed any variation to the terms of the Merger unless such revision or variation includes terms no less favourable to the Melrose Shareholders than those set out in the Rule 2.7 Announcement; and (iii) the Merger lapses or is withdrawn without having become wholly unconditional, save in circumstances where within three days of the Merger having lapsed or been withdrawn Petroceltic announces a new offer for Melrose on terms no less favourable to Melrose shareholders than the principal terms of the Merger.

20.1.4 Irrevocable Undertakings (Petroceltic Shares)

The following holders, controllers or beneficial owners of Existing Petroceltic Shares have given irrevocable undertakings to Melrose to vote in favour of the Resolutions and in favour of any other resolution(s) of the shareholders of Petroceltic proposed at the Extraordinary General Meeting.

Name	Number of Existing Petroceltic Shares	Percentage of Existing Petroceltic Shares in issue
Brian O'Cathain	3,776,820	0.16%
Tom Hickey	5,882,856	0.25%
Andrew Bostock	3,000,000	0.13%
Con Casey	4,008,166	0.17%
Hugh McCutcheon	1,100,000	0.05%

The aforementioned undertakings will cease to be binding if: (i) Petroceltic announces that it does not intend to proceed with the Merger and no new revised or replacement offer is announced in accordance with Rule 2.7 of the UK Takeover Code at the same time; (ii) Melrose announces that it has withdrawn its recommendation to Melrose Shareholders to vote in favour of the resolutions proposed at the Melrose Court Meeting and Melrose General Meeting in respect of the Merger; or (iii) the Merger is not implemented by the date which is 9 months from the date of the first public announcement in connection with the Merger by Petroceltic and/or Melrose.

20.1.5 Co-operation Agreement

Under the Co-operation Agreement between Petroceltic and Melrose dated 16 August 2012, Petroceltic and Melrose have agreed to provide each other with such information and assistance as they may reasonably require for the purposes of obtaining regulatory clearances and in particular to enable Petroceltic to make the filing to the Bulgarian Regulatory Authority five business days after the date of announcement of the Merger in accordance with Rule 2.7 of the UK Takeover Code (provided that such assistance will not require Melrose or Petroceltic to maintain its recommendation of the Merger or to adjourn shareholder meetings or court hearings in connection with the Melrose Scheme or to make any change to the timetable for implementation of the Merger). The Co-operation Agreement also sets out certain agreements reached between Petroceltic and Melrose in relation to the treatment of the Melrose Share Plans. The Co-operation Agreement will terminate if the Scheme (or offer if the Merger is implemented by way of a contractual takeover offer) is withdrawn or lapses (subject to certain caveats), if Melrose withdraws its recommendation of the Scheme or the Scheme does not complete before the date which is nine months from the first public announcement of the Merger by Melrose and/or Petroceltic or otherwise as agreed between Petroceltic and Melrose.

20.1.6 HSBC Senior Secured Facility

On 17 August 2012, Melrose entered into US$300 million revolving senior secured facility agreement with, among others, HSBC Bank Plc ("**HSBC**") ("**HSBC Senior Secured Facility**"). The facility under the HSBC Senior Secured Facility will become available and Melrose will be permitted to draw under the facility after the satisfaction of certain conditions precedent including, without limitation, the Restructuring Completion Date having occurred (Restructuring Completion Date being as defined in the HSBC Senior Secured Facility and meaning the date on which the Scheme has been sanctioned by the Court (or in the case of an offer, the date that the offer becomes unconditional in all respects)), and provided that Melrose is not in breach of certain key representations and undertakings under the HSBC Senior Secured Facility. The purpose of the facility is to repay Melrose's existing reserve based lending facility and subordinated facility, for general corporate and working capital purposes of the group and for issuing letters of credit. The facility may be utilised by way of loans or letters of credit.

The HSBC Senior Secured Facility includes a period of up to 150 days (or such later date which HSBC may agree) (the "**Certain Funds Period**") from signing during which the facility cannot be cancelled by HSBC and funding must proceed unless certain pre-agreed major events of default occur in relation to Melrose. The HSBC Senior Secured Facility also includes a clean-up period of 30 days following the financial close, ((the "**Financial Close**") being the date on which HSBC notifies Melrose that all conditions precedent have been satisfied or waived, during which only a number of limited circumstances applying to Melrose can trigger an early repayment of the facility).

The amount available for drawing (as calculated on pre-agreed re-determination dates) will be limited by the value of the reserves and contingency resources (according to pre-agreed valuation methodology) of certain petroleum assets of Melrose located in Egypt and Bulgaria and following the accession of Petroceltic and certain of its subsidiaries, Petroceltic's interests in the Ain Tsila West Gas Field (Algeria), the Shakrok and Dinarta Blocks (Kurdistan Region of Iraq) and the Elsa and Capignano Fields (Italy).

The term of the HSBC Senior Secured Facility is 18 months from the signing date. The total commitments of the lender reduce over the term of the facility in accordance with a schedule with the first repayment due on 1 March 2013, and thereafter every quarter. Usual fees are payable under the HSBC Senior Secured Facility.

Interest accrues on drawn amounts under the facility at LIBOR plus a margin that stands at 2.75 per cent per annum and increases to 5.5 per cent per annum over certain specified intervals. A commitment fee is payable on undrawn amounts which is calculated at 30 per cent of the margin, from time to time. Upfront fees on the facility will be split equally between Petroceltic and Melrose.

Petroceltic, Petroceltic Limited, Petroceltic Italia and Petroceltic Kurdistan Limited will, together with a number of subsidiaries of Melrose in each of Luxembourg, Bulgaria, Cayman Islands, Bermuda and the Netherlands, accede to the HSBC Senior Secured Facility as borrowers and guarantors ("**Acceding Obligors**") within 7 days of the Financial Close. The facility will be secured by charges over shares in the Acceding Obligors (other than in Petroceltic) and charges over bank accounts provided by certain of the Acceding Obligors, in each case in favour of HSBC.

The HSBC Senior Secured Facility also contemplates that Petroceltic's interests in the Ain Tsila West Gas Field will be hived down to a new special purpose vehicle over which share security will be granted following completion of the hive down process. Petroceltic must use its reasonable endeavours to complete the hive down and grant the share security.

The HSBC Senior Secured Facility contains representations and warranties, covenants and events of default typical for a loan facility of its nature. It also includes financial covenants relating to the tangible net worth and total net borrowings of the group and a loan cover ratio.

The facility must be prepaid in the event of a change of control or a delisting of Petroceltic, subject to certain customary exceptions. Disposal proceeds, compensation and insurance proceeds received by a borrower must also be applied in prepayment of the facility and a reduction of the available commitments under the facility rateably subject to certain pre-agreed exceptions. HSBC and Petroceltic have agreed in a side letter to the HSBC Senior Secured Facility that the HSBC Senior Secured Facility may not be amended prior to the Restructuring Completion Date without the prior written permission of Petroceltic.

20.2 Petroceltic Group

20.2.1 Macquarie Warrant Deed

Petroceltic entered into a warrant deed with Macquarie Bank Limited ("**Macquarie**") on 20 October 2011 (the "**Warrant Deed**") giving Macquarie the right to subscribe for Ordinary Shares in the capital of Petroceltic. The Warrant Deed was entered into in connection with the granting of a bridge facility agreement entered into between Petroceltic and Macquarie (the "**Macquarie Facility**"), further details of which are provided in paragraph 20.2.2 below. The Macquarie Facility has since been repaid in full however this repayment does not affect the rights of Macquarie under the Warrant Deed.

Under the Warrant Deed, warrants became issuable upon the occurrence of certain milestone events linked to the Macquarie Facility. Details of the outstanding warrants and the subscription price for such warrants are contained in paragraph 14.4 of this Part XII. No further warrants are issuable under the Warrant Deed.

The holder of the warrants can exercise its rights to be issued with Ordinary Shares in the capital of Petroceltic at the subscription price from issuance of the warrants until 31 December 2015. The holder can also choose to exercise its election by way of a nominal exercise which enables the holder to surrender a certain number of warrants and, in respect of the balance of unsurrendered warrants, pay only the nominal value of the shares rather than the subscription price. The calculation for the number of shares obtained on a nominal exercise is based upon a formula contained within the Warrant Deed.

The Warrant Deed contains adjustment provisions, which are designed to ensure that where Petroceltic subdivides or consolidates its share capital or issues Ordinary Shares by way of capitalisation of profits or reserves, then the number of Ordinary Shares issuable under the Warrant Deed (and the subscription price payable on exercise of the underlying warrants) shall be adjusted so that the economic value of the warrants is not affected by such subdivision, consolidation or capitalisation. The Warrant Deed also provides that, on any other reorganisation of the share capital of Petroceltic or the rights attaching to any shares comprising any part of such share capital, the number of Ordinary Shares issuable under the Warrant Deed (and the subscription price payable) shall be adjusted in accordance with the principles of adjustment applicable on a subdivision, consolidation or capitalisation. Petroceltic shall ensure that rights commensurate with those due to be exercised by warrant holders under the Warrant Deed are replicated in any such reorganised structure on substantially the same commercial terms.

In the event of Petroceltic making any general offer or invitation to the holders of Ordinary Shares to subscribe for additional shares in the capital of Petroceltic (however structured), Petroceltic shall make a like offer or invitation to each warrantholder to participate on the same terms as the Ordinary Share holders as if its warrants had been exercised. If at any time an offer or invitation is made by Petroceltic to all holders of its Ordinary Shares for the purchase by Petroceltic of any of its Ordinary Shares, Petroceltic shall simultaneously give notice thereof to the warrantholders and each such warrantholder shall be entitled, at any time whilst such offer or invitation is open for acceptance, to exercise his subscription rights on terms that the Ordinary Shares arising on exercise of those subscription rights shall be included in the offer by Petroceltic to purchase Ordinary Shares on the same terms and conditions as if the Ordinary Shares arising upon the exercise of the subscription rights had been in issue on the record date for such offer or invitation

The warrants are freely assignable by Macquarie without the consent of Petroceltic, subject to the execution of a deed of adherence to the Warrant Deed by the acquiring party.

As part of the Warrant Deed, Petroceltic has given certain undertakings and warranties to the warrant holder relating to Petroceltic and the Ordinary Shares issuable under the terms of the Warrant Deed. This includes an undertaking by Petroceltic to ensure the listing of any shares issued in connection with the warrants on AIM and ESM. The Warrant Deed is governed by Irish Law and any disputes are to be referred to the exclusive jurisdiction of the Irish courts, other than disputes in relation to the adjustment provisions or calculation of the market price of shares which are to be referred to expert determination.

Petroceltic and Macquarie entered into a deed of amendment amending the Warrant Deed on 4 November 2011 (the "**Deed of Amendment**"). This Deed of Amendment made changes to one of the milestone events linked to the Macquarie Facility and introduced a new provision whereby if Petroceltic issued Ordinary Shares for cash (other than in connection with existing warrants or share options), or issued securities convertible into Ordinary Shares or giving the right to acquire Ordinary Shares for cash, prior to 1 May 2012, and the price payable for such Ordinary Shares (the "**Equity Issue Price**") was lower than the subscription price of the warrants, the warrants shall be amended so that the subscription price shall be reduced to the Equity Issue Price.

20.2.2 Macquarie Bridge Facility

On 10 October 2011, Petroceltic announced the agreement of a US$30 million bridge facility with Macquarie. Documentation in relation to the Macquarie Facility was entered into between Petroceltic (as borrower), Petroceltic Investments Limited, Petroceltic Jersey (2009) Holdings Ltd and Petroceltic Kurdistan Limited (as original guarantors) and Macquarie (as lender) on 7 November 2011 (the "**Macquarie Bridge Facility**").

Under the terms of the Macquarie Bridge Facility Agreement, Petroceltic was able to draw down up to US$30 million for the purposes of working capital costs of Petroceltic's Algerian and Kurdistan Region of Iraq interests and the development of any hydrocarbon project acquisitions approved by Macquarie, as well as any financing costs connected to the Macquarie Bridge Facility. Petroceltic was to repay all amounts outstanding under the Macquarie Bridge Facility upon the earlier of (a) receipt of funds from Enel under the Enel SPA (as defined in paragraph 20.2.6 of this Part XII below), and (b) 31 October 2012. US$23,413,000 was drawn on the Macquarie Facility as at 31 December 2011 with a further US$3 million drawn post year-end.

In addition to normal fees and interest at 6 per cent payable under the Macquarie Bridge Facility, Macquarie was also entitled to warrants over the Ordinary Shares of Petroceltic based on the timing and extent of amounts drawn in lieu of arrangement and facility fees (see paragraph 20.2.1 of this Part XII for further details).

The Macquarie Facility was secured on the proceeds receivable under the Enel SPA, as well as share pledges over Petroceltic Jersey (2009) Holdings Ltd and Petroceltic Kurdistan Limited, a fixed and floating charge over the assets of Petroceltic International Limited and charges over bank accounts held by Petroceltic and Petroceltic Investments Limited.

The Macquarie Facility was repaid in full on 13 February 2012.

20.2.3 Placing Agreement May 2011

On 13 May 2011, Petroceltic announced a placing pursuant to which 351,000,000 Existing Petroceltic Shares (the "**2011 Placing Shares**") were issued and placed with institutional investors (the "**2011 Placing**") raising gross proceeds of approximately US$60 million.

In connection with the 2011 Placing, Petroceltic entered into a placing agreement with Merrill Lynch International, J&E Davy and Mirabaud Securities LLP (the "**Joint Bookrunners**") on 12 May 2011, pursuant to which the Joint Bookrunners agreed to use their reasonable endeavours to procure placees to subscribe for the 2011 Placing Shares and underwrite the issue. The obligations of the Joint Bookrunners were subject to certain conditions, including the obtaining of approval for the issue of the 2011 Placing Shares from Petroceltic shareholders (which was obtained on 10 June 2011) and the admission of the 2011 Placing Shares to trading on AIM and ESM (which occurred on 13 June 2011). Under the placing agreement, Petroceltic gave customary warranties to the Joint Bookrunners with respect to the business of the Petroceltic Group and certain matters connected with the 2011 Placing and also gave certain indemnities to the Joint Bookrunners in connection with the 2011 Placing and the performance by the Joint Bookrunners of their services.

20.2.4 Head Office Lease

Petroceltic Investments Limited (as tenant) and Petroceltic (as guarantor) entered into a lease with Shelbourne Development Limited (as landlord) on 19 February 2010 for the sixth floor and part basement of 75 St. Stephens Green, together with the use of six car parking spaces (the

"**Lease**"). The commencement date of the Lease was 1 February 2010 and the term is four years and nine months. Rent payable under the Lease is €300,000 per annum (excluding VAT), payable quarterly in advance and a security deposit of €75,000 plus VAT was payable on the date of signing the Lease. Under the Lease the tenant is also liable to pay the landlord's costs in insuring the building and a service charge (as defined in a head lease between the landlord and Shelbourne Development (Europe) Limited dated 29 May 2007 (the "**Head Lease**")).

Under the terms of the Lease the tenant has given certain covenants to the landlord, which includes an obligation to repair the property, not to make alterations to the property and without landlord consent, restrictions on the use of the property and restrictions on the transfer of the Lease. The tenant has also given an indemnity to the landlord against all liabilities arising from any act, omission or negligence of the tenant or any person on the property with the tenant's permission.

The landlord has the right to forfeit the Lease if: (a) rent remains unpaid for 28 days after becoming payable; (b) any covenants of the tenant under the Lease are not performed or observed; or (c) the tenant has a winding-up petition presented against it or passes a winding-up resolution. The Lease is governed by Irish law.

In connection with the Lease, Petroceltic Investments Limited (as sub-tenant) and Petroceltic (as guarantor) entered into a licence to sub-let with Shelbourne Development (Europe) Limited (as head landlord) and Shelbourne Development Limited (as tenant) on 19 February 2010 (the "**Licence to Sub-Let**"). Under the terms of the Licence to Sub-Let the head landlord granted its consent to the entry into of the Lease in return for the sub-tenant entering into certain covenants with the head landlord, including an undertaking to pay the rent under the Lease and observe the covenants under the Lease and the Head Lease, not to transfer the Lease without head landlord's consent and granted an indemnity to the head landlord for any liabilities incurred as a result of breaches of the covenants and conditions in the Lease and Head Lease.

Algeria

20.2.5 Isarene PSC

Petroceltic and Sonatrach entered into the Isarene PSC for the exploration and exploitation of hydrocarbons in the Isarene Field (Blocks 228, 229A) on 26 September 2004. Petroceltic is the operator under the Isarene PSC. The Isarene PSC was approved by Presidential Decree number 05-24 on 13 January 2005 and came into force on 26 April 2005, the date of a notification from Sonatrach confirming the publication of the approval decree in the official gazette.

On 27 April 2011, Petroceltic agreed to farm-out a 18.375 per cent participating interest to Enel pursuant to a sale and purchase agreement described in paragraph 20.2.6 of this Part XII of this document. Enel agreed to become a party to the Isarene PSC by way of an amendment to the Iserene PSC dated 28 April 2011 (the "**Isarene PSC Amendment**"). The key changes introduced by the Isarene PSC Amendment are: (i) the definition of the **"Contractor"** which under the Isarene PSC only referred to Petroceltic, was changed to include both Petroceltic and Enel; and (ii) that the participating interests of the three parties were amended to reflect the farm-out of Petroceltic's interest.

The current parties and participating interests in the Israene PSC, following the Isarene PSC Amendment, are Sonatrach with 25 per cent, Petroceltic with 56.625 per cent and Enel with 18.375 per cent.

The initial contract area under the Isarene PSC comprised Blocks 228 and 229a in the Isarene Perimeter, covering an area of approximately 10,871 km².

The exploration phase under the Isarene PSC comprises:

- a first period of three years from the effective date of the Isarene PSC (the *"***First Period of Exploration***"*); and
- a second period of two years, on the request of the Contractor and if the minimum work programme for the first period has been implemented by the Contractor (the *"***Second Period of Exploration***"*).

The First or Second Period of Exploration may be extended by up to two years subject to certain conditions set out in the Isarene PSC. However, if a discovery is made during the extension period that is geologically distinct from the discoveries made during the First or the Second Period of Exploration, the Contractor shall have no right to the production that may arise from such discovery.

The exploration phase was extended by two years from 26 April 2010 by an extension agreement to the Isarene PSC dated 25 March 2010. A second extension of three months was granted by a letter from Sonatrach to Petroceltic dated 24 April 2012. A third extension of fifteen days was granted by a letter from Sonatrach dated 24 July 2012 in order to make a DOC over the Ain Tsila field.

During the First Period of Exploration, the minimum work programme to be carried out by the Contractor is the acquisition of 600km of 2D seismic data with expenditure of US$3.6 million and the drilling of one exploration well with expenditure of US$4 million.

During the Second Period of Exploration, the minimum work programme to be carried out by the Contractor is the acquisition of 100km of 2D seismic data with expenditure of US$600,000 and the drilling of one exploration well with expenditure of USD 4 million.

Upon entry into the Isarene PSC, Sonatrach placed at the Contractor's disposal 582km of 2D seismic data from 2002/2003 valued at US$3.12 million. It is within Contractor's discretion whether to use this data or not.

A management council, comprising a committee of three representatives from each of the Contractor and Sonatrach, makes all the decisions relating to the performance of the Isarene PSC including determining whether the minimum work programme has been completed, the budget and the declaration of commerciality of any hydrocarbon discovery.

The Contractor undertakes within ninety days from the date of the Isarene PSC to put in place a guarantee in favour of Sonatrach from the Exterior Bank of Algeria to guarantee the minimum work programme during the First Period of Exploration.

If the Contractor does not meet the minimum work programme obligations, it must (i) relinquish all areas not subject to a provisional authorisation to exploit or an exploration permit and (ii) pay to Sonatrach the full value works not carried out or not completed.

At the end of the First Period of Exploration, the contract area will be reduced by 30 per cent. At the end of the exploration phase, including any extensions, all areas not subject to a provisional authorisation to exploit or an exploration permit will be relinquished.

For every liquid hydrocarbon field declared commercially exploitable, the duration of the exploitation phase of twenty five years (development and production) starting from the date a provisional exploitation authorisation or an exploitation licence is granted. For every natural gas field declared commercially exploitable, the duration of the exploitation phase is of thirty years (development and production) starting from the date a provisional exploitation authorisation or an exploitation licence is granted.

A hydrocarbon deposit is deemed to be commercially exploitable if the sale of crude oil or natural gas can cover the costs of exploration, development and exploitation as well as transportation and operating costs, royalties and taxes, and yield a net profit.

In relation to a natural gas deposit, a feasibility study must be conducted which indicates any potential gas export markets and the export prices offered by potential buyers. Such feasibility study is considered as one of the elements of a DOC.

The management committee decides whether a new discovery or an existing discovery of Sonatrach is commercial on the basis of the operator's reports. The Isarene PSC provides that if any field is declared commercial, the parties shall submit a request for an exploitation licence together with a final discovery report to the Algerian Government. However, due to a change in Algerian law, an exploitation licence is no longer requested by the parties. The development and exploitation of a field may start once ALNAFT has approved the development plan.

Any associated gas discovered in the contractual perimeter may be used for petroleum operations, in particular for injection and as fuel gas. If the quantities of associated gas are not considered to be commercially exploitable, Sonatrach has the right, at its cost, to take such quantities for other uses. If Sonatrach decides not to take such quantities of associated gas, the parties can agree, at a shared cost, to store such gas or to inject it in the field. If the quantities of associated gas are considered to be commercially exploitable, the Isarene PSC relating to the exploitation of natural gas shall apply.

The Isarene PSC contains a number of provisions relating specifically to natural gas discoveries, and in particular to gas production. The parties may agree to market the gas either through Sonatrach or jointly through a joint marketing body in which Sonatrach has the majority of voting rights on the board. In case of joint marketing, the management committee decides if it is necessary to carry out a feasibility study in relation to a development project. This study will be realised by a joint team. The management council decides if the field is commercial on the basis of both the final discovery report and the feasibility study. The Contractor has decided to market its share of gas through Sonatrach, which will return gas proceeds to each of Petroceltic and Enel in accordance with their participating interests.

The Contractor is in charge of exploration and appraisal operations, whereas during the exploitation phase a contractual joint operating entity is created in order to conduct and execute petroleum operations. The operating entity is composed of an equal number of representatives from Sonatrach and the Contractor. Exploration, appraisal, development, exploitation and operating costs are funded by the parties in accordance with their participating interests.

However, during the exploration phase the Contractor will have financed its and, by way of an advance, Sonatrach's funding obligations. In the absence of a discovery, it cannot claim any reimbursement of sums paid on Sonatrach's behalf. In the event of a discovery, it is entitled to reimbursement by Sonatrach of monies paid on its behalf during the exploration phase and to a part of the production funds.

The Contractor shall pay US$3 million to Sonatrach for the use of an existing Sonatrach well, which amount is deductible from Sonatrach's share of any development costs.

Sonatrach is responsible for the entirety of the transportation costs of all the oil and gas production. Petroceltic commits to pay Sonatrach an annual amount of US$150,000 (inflation adjusted) for the duration of the Isarene PSC for the training of Sonatrach personnel. The Contractor is also expected to contribute to the costs of building new transportation capacity if the existing transportation capacity is not sufficient. Costs of liquefaction of dry gas and separation of LPG are covered by the parties pro rata to their part of the production. The parties make an annual payment in accordance to their participation rates to an escrow account to cover the costs of abandonment and reinstatement of the sites.

The hydrocarbons produced in any one year will be divided between Sonatrach and the Contractor on a monthly basis in accordance with their participation interests and with the allocation of production provision in the Isarene PSC. The allocation is determined according to a formula whereby the amount of production to be distributed is equal to 73.9% *A – B where:

- A is a percentage figure that reflects the average daily production of hydrocarbons in a month; and
- B represents the "R" factor.

A equals 54 per cent if the monthly average daily production of hydrocarbons exceeds 60 Mboepd. If the monthly average daily production is below 60 Mboepd, A is determined by a weighted average of percentage values in accordance with the monthly average daily production (those values range from 59 per cent at 0 – 20 Mboepd, 53 per cent at 20 – 40 Mboepd, and 50 per cent at 40 – 60 Mboepd).

B represents the "R" factor which is the ratio of the inflation-adjusted aggregate annual value of oil and gas production to the inflation-adjusted annual expenditure on oil and gas operations. The annual value of oil is calculated by multiplying the volume of oil extracted by the price notified by Sonatrach on a monthly basis during that year and the annual value of gas is calculated by multiplying the volume of dry gas extracted by the price obtained for that gas (which will be determined by the gas marketing agreement with Sonatrach). Where the "R" factor:

- is less than or equal to six, B is zero;
- is greater than six but less than eight, B is between 17 per cent and 34 per cent; and
- is greater than eight, B is 34 per cent.

Abandonment costs are considered to be an exploitation cost and calculated as part of B.

Petroceltic does not have to pay any royalty or petroleum tax. It is exempted from VAT on goods and equipment directly allocated to the exploration and exploitation activities under the

Isarene PSC as listed in the relevant government regulation and for services, studies and the lease of goods themselves or for their account. Petroceltic is also exempted from corporation tax. Since 1 August 2006, Petroceltic is liable for the payment of a windfall tax on profits corresponding to its share of production of liquid hydrocarbons (including LPG and condensate) when the price of a barrel exceeds US$30. Such windfall tax is not applicable to revenues generated from the marketing of dry gas.

The annual share of production revenue to be paid in kind or in cash to the Contractor cannot exceed a maximum of 49 per cent of annual production. If during a given year, the total share of production revenue paid to the Contractor exceeds 49 per cent of the total production for that year, the part of the exploration advance exceeding 49 per cent shall be carried forward to be paid by Sonatrach in subsequent years.

The Isarene PSC can be terminated by Sonatrach on ninety days' notice to the Contractor if the Contractor:

- is in breach of its payment obligations;
- is in material breach of the contract;
- is in breach of legislation; or
- becomes bankrupt or declared insolvent.

The Contractor can renounce all of its rights and obligations within the contract area on a hundred and twenty days' notice to Sonatrach, provided that it brings to conclusion any works envisaged under a work programme or budget or pays Sonatrach the value of such works, and transfers to Sonatrach the exploitation activity.

Force majeure is defined as including all events that are unforeseeable, irresistible or involuntary and are beyond the parties' fault or negligence which render it impossible for a certain period to perform the obligations under the contract. If the Contractor is subject to a force majeure event which prevents it from participating in petroleum operations, Sonatrach can carry on such operations and the exploitation of deposits alone. If a force majeure event persists for two years, the parties can agree to renegotiate their obligations or terminate the contract.

Any assignment of a part of Petroceltic's interests in the Isarene PSC must be submitted for the prior approval of Sonatrach and the Ministry of Energy. The Contractor is permitted to assign up to 49 per cent of its interests in the Isarene PSC before the expiry of the development period (until the commercial production). If the assignee is not an affiliated company, Sonatrach has a pre-emption right and the assignment must be approved by Sonatrach and the Government.

The Isarene PSC is governed by Algerian law. Certain disputes, notably in relation to management council decisions and declaration of commerciality of deposits, are to be resolved by expert determination. Other disputes, that cannot be resolved by conciliation, will be referred to arbitration in accordance with the UNCITRAL rules.

20.2.6 Enel SPA

Petroceltic and Enel entered into a sale and purchase agreement dated 27 April 2011 for the sale of an 18.375 per cent interest in the Isarene PSC, which represented 24.5 per cent of Petroceltic's overall interest (the **"Enel SPA"**). After the sale was finalised in February 2012, Petroceltic held a 56.625 per cent interest in the Isarene PSC and Sonatrach continued to hold 25 per cent.

On acquiring its stake, Enel acquired a 24.5 per cent interest in any income and benefits since the commencement of the Isarene PSC, and a 24.5 per cent interest in any costs, charges and expenses incurred after 26 April 2010 as a Contractor under the Isarene PSC.

The Enel SPA provides for Petroceltic and Enel to enter into a joint operating agreement at completion.

The consideration paid by Enel was as follows:

- an amount, not exceeding US$25,725,000, to equal 24.5 per cent of the phase 1 appraisal costs, being the costs incurred on or after 27 April 2010 in implementing the first phase of petroleum operations as set out in the work programme and budget, as defined in the Enel SPA;

- an amount equal to the sum of (i) 24.5 per cent of the total aggregate costs incurred before 26 April 2010 in connection with the petroleum operations and (ii) US$4,500,000, not to exceed US$150,000,000;
- appraisal costs, as defined in the Enel SPA; and
- a reserves bonus, up to a maximum of US$75,000,000, on the competent authority approving a declaration of commerciality in relation to deposits within the Isarene field.

Under the Enel SPA, Petroceltic agrees to indemnity Enel against any costs, charges, expenses, liabilities and obligations of whatever nature (other than decommissioning liabilities, the liability for which is apportioned between Petroceltic and Enel in the manner specified in the Enel JOA) arising under the Isarene PSC that accrue and relate to the period before 27 April 2010, irrespective of when they fall due for payment.

Petroceltic's overall liability for any claim brought in relation to commercial warranties is limited to the total amount of consideration paid by Enel.

The Enel SPA is governed by English law.

Any disputes arising under the Enel SPA are to be settled by arbitration according to the rules of the International Chamber of Commerce. The seat of arbitration is Geneva.

On 14 February 2012, Petroceltic announced that it had received in excess of US$100 million from Enel under the Enel SPA. The reserves bonus remains outstanding and conditional upon the Isarene declaration of commerciality.

20.2.7 Enel JOA

On 2 February 2012, Enel and Petroceltic entered into a joint operating agreement relating to the Isarene PSC (the **"Enel JOA"**).

The parties and participating interests in the Enel JOA are Petroceltic with 75.5 per cent and Enel with 24.5 per cent. Together they represent the 75 per cent interest held by the Contractor under the Isarene PSC. Sonatrach retains a 25 per cent interest in the Isarene PSC but is not party to the Enel JOA.

The purpose of the Enel JOA is to establish between the parties their respective rights and obligations with regard to the rights, obligations and operations stated under the Isarene PSC.

The operator under the Enel JOA is Petroceltic and it has exclusive responsibility for the conduct of all petroleum operations required to be performed by the Contractor under the Isarene PSC. In accordance with the Isarene PSC, after the commencement of the exploitation period, Petroceltic is to transfer its responsibilities as operator to the joint body.

All rights and interests under the Isarene PSC, all joint property and any hydrocarbons to which the Contractor is entitled under the Isarene PSC shall be owned by the parties in accordance with their respective participating interests.

The obligations of the parties and the expenses incurred by the operator in connection with joint operations shall be charged to the joint account of the parties, and the parties shall fund all costs and expenses of joint operations in accordance with their participating interests.

Petroceltic, as operator, represents the Contractor in dealings with the Government of Algeria, Sonatrach and the management council, established under the Isarene PSC. When the subject matter under consideration is the commercialisation of natural gas, each party has a right to participate in any such meetings in accordance with its participating interest, in the form of a joint Contractor team to be established as a sub-committee of the operating committee.

The operator shall represent the parties and defend or oppose any claim or suit brought against them in relation to the Isarene PSC. It may in its sole discretion compromise or settle any such claim or suit for an amount not to exceed US$25,000, exclusive of legal fees. The operator must obtain operating committee approval to any amounts in excess of US$25,000.

The operator shall not bear any damage, loss, cost, expense or liability resulting from performing the duties and functions of operator.

The parties shall indemnify the operator against all damages, losses, costs, expenses and liabilities arising in connection with joint operations, even if caused by a pre-existing defect or by negligence or strict liability of the operator, except if caused by the operator's gross negligence or wilful misconduct.

The operator may resign by giving 120 days' notice to the non-operator party. If the resignation is due to an assignment to a third party, the non-operator party has the right to approve the appointment of any successor prior to such nomination being submitted to the Government for approval.

The operator can be removed upon receipt of notice from the non-operator party if it becomes insolvent, is wound up or liquidated, a court order is made for its dissolution or a receiver is appointed over a substantial part of its assets.

The operator can also be removed if it has committed a material breach of the Enel JOA which has not been remedied within thirty days.

The operating committee is composed of one representative and one alternative representative from each party. Each representative shall have voting rights in accordance with its nominating party's participating interest.

The operating committee has the power and duty to supervise, control and direct joint operations as necessary to fulfil the obligations under Isarene PSC and properly explore and exploit the contract area.

With the exception of reserved matters, all decisions by the operating committee shall be decided by the votes of at least two parties having in aggregate a participating interest of at least 65 per cent.

The operator shall implement a work programme in accordance with the requirements of the Isarene PSC. Within three months after completion of the work programme, and if the operating committee considers a discovery to be a commercial discovery, the operator shall submit a final discovery report to the management council under the Isarene PSC, upon approval of the operating committee.

If the discovery in the final discovery report is deemed a commercial discovery by the operating committee, the operator shall attempt to secure through Sonatrach the approval of a development plan and first annual work programme and budget for the development of the discovery. On approval by the management council, the Contractor shall establish the joint body and enter into a joint venture with Sonatrach in respect of the administration and operation of the joint body.

No later than 1 September each year the operator shall deliver a proposed preliminary work programme and budget to the parties and no later than 30 September each year the operator shall deliver a proposed work programme and budget detailing the joint operations for that year.

The operator shall seek the other parties' consent for any expenditure on joint operations of over US$150,000.

Any party can request the operator to carry out any operation within the contract area at the sole risk, cost and expense of such party, subject to certain terms and conditions and to the approval of the management council.

The following operations can be carried out on a sole risk basis:

- drilling of any well;
- deepening, sidetracking or testing and completing any well, that is not at a commercial rate;
- development and production of an undeveloped discovery; and
- continuation of production activities from any exploitation area within the period provided in the Isarene PSC.

Sole risk operations are financed by the sole risk party.

A non-sole risk party can participate in a sole risk operation by giving notice to all parties that it elects to do so and subject to financial contributions to the sole risk party.

If a party fails to advance or pay its share of any cash call, such party shall be deemed to be in default. The operator shall give notice of such default to all parties. Each party not in default shall pay to the operator a proportion of the defaulting party's cash call.

Until a default is remedied, the defaulting party shall have no right to its participating share of hydrocarbons. A defaulting party shall also not be entitled to vote at meetings of the operating committee.

If a defaulting party remains in default for forty five days, the non-defaulting parties can require the defaulting party to withdraw from the Enel JOA and the Isarene PSC.

The abandonment of wells drilled as joint operations will require the approval of the operating committee.

The parties shall use reasonable endeavours to enter into a fully termed decommissioning agreement prior to the approval of a development plan for any commercial discovery. Such agreement should provide for the provision of security sufficient for the discharge of the parties' anticipated liabilities for decommissioning costs.

Any party can withdraw from the Enel JOA by giving notice to the other parties. Within thirty days of such notice, the other parties may also give notice that they wish to withdraw. If all parties serve notice, they shall proceed to abandon the contract area and terminate the Enel JOA and the Isarene PSC. Partial withdrawal from the Isarene PSC is possible.

The withdrawing party assigns its participating interest to each of the other parties free of cost and in proportion to their participating interests.

Under the Enel JOA the rights, duties, obligations and liabilities of the parties are several and are not joint or collective.

The force majeure provision in the Enel JOA is the same as in the Isarene PSC.

An assigning party cannot make an assignment the without the written consent of all parties which results in the assignor or assignee holding a participating interest of less than 5 per cent. Any assignment must be approved in writing by the other parties to be deemed valid.

A party subject to a change of control shall obtain the necessary Algerian Government approval with respect to such change of control and furnish any replacement security required by the Algerian Government. The party must provide evidence that following the change of control it shall continue to have the financial capability to satisfy its payment obligations under the Enel JOA and Isarene PSC. If the party cannot provide such evidence, it may be required to provide security to cover its share of any obligations or liabilities.

In the event of a change of control (other than from the change of control of a party's ultimate parent company or to an affiliate), the other parties have a pre-emptive right to acquire such party's participating interest.

The Enel JOA is governed by English law. Parties should attempt to resolve disputes by mutual agreement. Otherwise, disputes will be referred to arbitration in accordance with the rules of the International Chamber of Commerce. The seat of arbitration shall be Geneva. Any disputes in relation to assignment are to be resolved by expert determination.

Kurdistan Region of Iraq

20.2.8 Kurdistan PSC

Petroceltic and Hess entered into the Dinarta and Shakrok PSCs with the KRG on 26 July 2011. Petroceltic holds a 16 per cent working interest in each PSC, with Hess and KRG holding 64 per cent and 20 per cent interests respectively.

Dinarta is an unexplored 1,319 km^2 block and Shakrok block is a 418 km^2 block. The Dinarta PSC, and the Shakrok PSC were entered into on substantially identical terms, save as described below in the combined summary of the terms of both PSCs. In the summary below, the term "**contractor**" is used to refer to both Petroceltic and Hess, and the term "**contractor entity**" is used to refer to each of Petroceltic or Hess separately.

Under each PSC, all rights, duties and obligations attaching to KRG's participating interest of 20 per cent is carried by the contractor entities in proportion to their participating interests. Hess is designated as operator under each of the PSCs. The contractor is responsible for the conduct, management, control and administration of petroleum operations under each PSC.

The PSCs have an exploration period of five years starting from 26 July 2011, which may be extended to a maximum term of seven years in certain circumstances. The exploration period is split into two sub-periods: a period of three years followed by a period of two years, each of which may be extended by a further year. At the end of the base exploration period, the contractor is required to relinquish a certain proportion of each contract area.

The minimum work obligations for the first exploration sub-period under each PSC require the commitment of a minimum financial amount of US$40 million to be paid by the contractor with each contractor entity contributing in accordance with its paying interest, and require the:

- conduct of geological and geophysical studies;
- performance of field work comprising structural, stratographic and lithographic mapping and sampling;
- acquisition of 250 line kilometres of two dimensional seismic data, or a three dimensional seismic data program by agreement; and
- drilling of one exploration well, including testing and coring as appropriate.

The minimum work obligations for the second exploration sub-period under each PSC also require the commitment of a minimum financial amount of US$40 million to be paid by the contractor with each contractor entity contributing in accordance with its paying interest, and require the:

- acquisition, interpretation and processing of further seismic data, if the contractor feels that the first exploration well justifies the acquisition of such further data; and
- drilling of one exploration well, including testing and coring as appropriate.

Under each PSC, each contractor entity is required to provide joint and several guarantees from its ultimate parent company in respect of the contractors minimum work obligations in each exploration sub-period. If the contractor satisfies the minimum work obligations without having spent the minimum financial commitment for each sub-period, the contractor will be considered to have satisfied its minimum exploration obligations in respect of each such period.

The development period for commercial discoveries of oil and gas is twenty five years. The contractor is entitled to an automatic five year extension if commercial production is still possible at the end of this period.

Each PSC establishes a management committee which is responsible for petroleum operations and comprises two representatives of KRG and two members appointed by Petroceltic and Hess. Meetings of the management committee are required to take place three times each year. Unanimous approval of the management committee is required for all matters. The contractor has the tie-breaking vote during the exploration period in respect of the approval of exploration work programmes and budgets. On all other matters, if the committee is unable to reach unanimous agreement at the second meeting, the vote of the KRG shall be regarded as the tie-breaking vote.

The PSCs contain provisions relating to the sale and marketing of gas. The contractor undertakes not to sell or commit to dispose of its entitlement to gas or KRG's entitlement to gas. It is acknowledged by the contractor entities that it is in their interests to market and dispose of their entitlement to gas on a jointly dedicated basis together with the KRG. KRG may at any time designate a gas field as being exclusively dedicated and reserved for domestic or export markets. KRG has the exclusive right to conduct all export gas marketing operations with respect to natural gas and to purchase and resell to export markets the contractor's entitlement to natural gas. The contractor and the KRG are each entitled to conduct domestic gas marketing operations and shall cooperate and coordinate these operations.

Under each PSC, each contractor entity shall give priority to subcontractors from the Kurdistan Region and other parts of Iraq to the extent their credentials are, in the contractor's sole opinion, comparable in all material respects with those operating in the international petroleum industry. In addition the contractor shall give, and shall require its subcontractors to give, preference to citizens of the Kurdistan Region of Iraq and other parts of Iraq to the extent such citizens have the technical competence and experience and are available at a competitive rate. This obligation is subject to the contractor not being required to violate any law applicable to it, particularly in respect of corrupt practices. The contractor also has various obligations to train its personnel from the Kurdistan Region of Iraq and to make various payments to the KRG to assist with matters such as the recruitment of personnel to the KRG's Ministry of Natural Resources, to fund the technological and logistical support to the KRG in administering the oil and gas industry, and to contribute to the KRG's natural environment fund. All such expenses are cost recoverable.

Under each PSC, each contractor entity is required to pay to the KRG a portion of petroleum produced and saved from the contract area in the form of a royalty, either in kind or in cash, as directed by the government. The KRG is entitled to a royalty equal to 10 per cent of crude oil and 10 per cent of non-associated natural gas produced from each contract area. If taken in cash, the crude oil or non-associated natural gas is valued at the "International Market Price" (as defined in the relevant PSC).

In terms of cost recovery, the contractor is entitled to recover all costs and expenditure incurred in carrying out petroleum operations, which encompasses exploration, gas marketing, development, production and decommissioning operations and includes the cost of carrying the KRG's duties and obligations. From first production, the contractor is entitled to recover such petroleum costs from up to 40 per cent of crude oil and up to 50 per cent of gas, available for that purpose after deduction of the volumes of production to meet royalty payments.

Following deduction of volumes for royalty payments and cost recovery, the entitlement of the contractor and KRG to "Profit Petroleum", being "Profit Oil" and "Profit Gas" (each as defined in the relevant PSCs) produced in a calendar year is determined in accordance with an "R" factor, which is calculated as cumulative revenues actually received by the contractor divided by cumulative costs incurred by the contractor.

In relation to "Profit Gas", where "R" is:

- less than or equal to 1, the contractor and KRG are entitled to 38 per cent of Profit Gas each;
- greater than or equal to 2.75, the contractor and KRG are entitled to 19 per cent of Profit Gas each; and
- as the value for R increases and moves between 1 and 2.75, the contractors and KRG are entitled to a percentage of Profit Gas which moves on a sliding scale between 38 per cent and 19 per cent.

In relation to "Profit Oil" (which includes associated gas), where "R" is:

- less than or equal to 1, the contractor and KRG are entitled:
  - under the Shakrok PSC, to 32 per cent of Profit Oil each; and
  - under the Dinarta PSC, to 30 per cent of Profit Oil each; and
- greater than or equal to 2, the contractor and KRG are entitled;
  - under the Shakrok PSC, to 16 per cent of Profit Oil each; and
  - under the Dinarta PSC, to 15 per cent of Profit Oil each; and
- as the value for "R" increases and moves between 1 and 2, the contractor and KRG are entitled to a percentage of Profit Oil which moves on a sliding scale between 32 per cent and 16 per cent under the Shakrok PSC and between 30 per cent and 15 per cent under the Dinarta PSC.

"Profit Petroleum" which is not allocated to the KRG or the contractor is to be attributed and allocated to the KRG. Each contractor entity is to be attributed and allocated its pro rata share of the Profit Petroleum attributed to the contractor.

The contractor is required to make certain further payments to KRG when certain production milestones are achieved, and each contractor entity is required to make "Capacity Building Payments" in an amount equal to the value, as determined in the PSC, to 20 per cent of the "Profit Petroleum" attributed to such contractor entity.

The PSCs are governed by English law. KRG reserves certain foreign immunities.

Italy

Elsa Discovery

20.2.9 Vega Farm-In Agreement

Petroceltic and Vega entered into (the **"Vega Farm-In Agreement"**) on 15 December 2009, which was amended by an amendment letter from Petroceltic to Vega dated 29 October 2010 (the **"Amendment Letter"**).

Pursuant to the Vega Farm-In Agreement, Vega, which at the time held a 60 per cent interest in the B.R 268.RG exploration permit (the **"Elsa Exploration Permit"**), would assign 30 per cent of its interest in the Elsa Exploration Permit to Petroceltic. At the time of the agreement, Petroceltic already held a 40 per cent interest in the Elsa Exploration Permit.

Under the Vega Farm-In Agreement, Petroceltic became operator of the Elsa Exploration Permit from the date of the agreement and since then has conducted operations in accordance with a joint operating agreement between Petroceltic and Vega dated 24 March 2005 (the "**Vega JOA**"). The Vega Farm-In Agreement envisages that a new joint operating agreement will be entered into by Petroceltic and Vega which would replace and supersede the Vega JOA. No new joint operating agreement has been signed to date.

According to the Vega Farm-In Agreement, official transfer of operatorship to Petroceltic requires government consent and registration. The transfer of operatorship was effective on 4 January 2010.

The assignment of Vega's interest to Petroceltic under the Vega Farm-In Agreement would become effective as follows:

- 10 per cent would be assigned upon receipt of evidence that all long-lead items required to drill the Elsa-2 exploration well have been ordered; and
- 20 per cent would be assigned upon spudding of the Elsa-2 exploration well on or before 31 October 2010, subject to any extensions granted by the government and approved by both parties. This date was amended to 31 October 2012 by the Amendment Letter.

Approval for the assignment may be necessary. If such approval is not obtained within sixty (60) days of the assignment conditions being met, the parties shall work together to try to obtain the approval. If such approval has not been obtained within 120 days of the assignment conditions being met, Vega shall hold the interest on trust for Petroceltic for the term of the Elsa Exploration Permit.

Following the assignment of Vega's interest under the Vega Farm-In Agreement, Vega would hold a 30 per cent interest in the Elsa Exploration Permit and Petroceltic would hold a 70 per cent interest.

In consideration for the assignment of the Vega interest and the transfer of operatorship, Petroceltic agrees to perform all Elsa-2 well operations and to pay all exploration costs related to the Elsa Exploration Permit and all costs of Elsa-2 well operations under the Vega JOA, including logging, drill stem testing and all possible abandonment costs from the date of the Vega Farm-In Agreement to the date when the target depth of the Elsa-2 well has been achieved and the parties can make a decision whether to conduct a production test of the Elsa-2 well (the "**Casing Point**"). After the Casing Point, each party agrees to pay a share of costs incurred in accordance with its participating interests.

No party can assign its rights under the Vega Farm-In Agreement without the prior written consent of the other party, which cannot be unreasonably withheld.

The Vega Farm-In Agreement is governed by English law. Any disputes arising under the agreement are to be resolved by arbitration according to the rules of the International Chamber of Commerce. The seat of arbitration is London.

The Vega Farm-In Agreement appends the Elsa Exploration Permit work obligations, as approved by the Ministry of Economic Development. As operator, Vega was obliged to fulfil two commitments:

- the acquisition and reprocessing from previous operators of a minimum of 150 kilometres of 2D seismic data within 12 months from the granting of the Elsa Exploration Permit. According to the appendix in the Vega Farm-In Agreement, this commitment has been fulfilled; and
- drill an exploratory well to a target depth of approximately 5000m, to commence within 48 months of the grant of the Elsa Exploration Permit. A drill rig could not be obtained in time, so Vega submitted an application for the extension of 18 months to commence such work obligation. The request was approved, extending the commencement of drilling to 31 October 2010.

20.2.10 Orca Farm-Out Agreement

Petroceltic Italia and Orca entered into the Orca Farm-Out Agreement on 31 May 2010.

Pursuant to the Orca Farm-Out Agreement, Petroceltic Italia would assign 15 per cent of its interest in the Elsa Exploration Permit and 15 per cent of its interest in certain off-shore licence applications in the Adriatic (the **"Adriatic Permits"**) to Orca.

The assignments of Petroceltic Italia's interests under the Orca Farm-Out Agreement become effective upon receipt by Petroceltic Italia of the consideration from Orca. The payment of consideration by Orca is conditional upon Petroceltic Italia having in place a firm contract for drilling of the Elsa-2 well.

Once the assignments have become effective, in respect of the Elsa Exploration Permit, Orca is to become a party to the Vega JOA, and in respect of the Adriatic Permit, Petroceltic Italia and Orca are to execute a new operating agreement to apply thereto. The transfer has not yet occurred so no joint operating agreement has been signed in relation to the Adriatic Permits.

From the date of the Orca Farm-Out Agreement to the date that all necessary consents and approvals have been obtained for the assignments, Petroceltic Italia shall hold the transferable interests on trust for Orca.

The interest shares in the Elsa Exploration Permit set out in the Orca Farm-Out Agreement show Petroceltic Italia as having 40 per cent and Vega as having 60 per cent at the date of the agreement; and Petroceltic Italia having 55 per cent Vega having 30 per cent and Orca having 15 per cent on the date when all consents and approvals have been obtained.

If the necessary consents and approvals have not been obtained within six (6) months of Petroceltic Italia receiving consideration for the assignments or the parties receive a notification that such assignments shall not be approved, the parties shall agree a further course of action.

In consideration for the assignments, Orca shall pay to Petroceltic Italia 30 per cent of the Elsa-2 well costs up to a maximum of US$11,519,422 and sunk costs relating to the Elsa Exploration Permit and the Adriatic Permits being a total of US$695,063. Even if Orca has not paid the full amount of the 30 per cent of the Elsa-2 well costs, such obligation will be deemed satisfied if the Italian Minister of Energy considers the well drilled is sufficient to meet the work commitments under the Elsa Exploration Permit or if the operator encounters insurmountable difficulties in drilling.

Neither party may assign its rights under the agreement without the prior written consent of the other party, which cannot be unreasonably withheld. Orca is permitted to assign its right to a wholly owned subsidiary without consent.

The Orca Farm-Out Agreement is governed by English law. The parties should attempt to resolve any disputes by mutual agreement. Otherwise, any disputes are to be resolved by arbitration in accordance with the rules of the London Court of International Arbitration.

20.2.11 Vega JOA

Petroceltic Italia (under its previous name Petroceltic Elsa S.r.l) and Vega entered into the Vega JOA effective from 24 March 2005.

The parties and participating interests under the Vega JOA are Petroceltic Italia with 40 per cent and Vega with 60 per cent.

The purpose of the Vega JOA is to establish between the parties their respective rights and obligations with regard to the rights, obligations and operations in relation to the Elsa Exploration Permit.

At the date of the agreement, Vega was the operator. However, further to the Vega Farm-In Agreement, Petroceltic Italia became the operator. The operator has exclusive responsibility for the conduct of all petroleum activity in relation to the Elsa Exploration Permit. The operator undertakes to carry out the work programmes in conformity with the planned schedule and within the budget limits.

All petroleum discovered and produced in the contract area shall be owned by the parties in accordance with their respective participating interests and the parties shall fund all costs and expenses of joint operations in accordance with their participation interests.

The operator may settle or defend any claims from third parties for an amount which does not exceed €25,000. Any claims in excess of such amount must be reported to the other parties and the operator shall comply with any direction of the operating committee in relation to such claims.

The operator shall not be liable to the non-operating party for anything done or omitted in the fulfilment of its duties, except if caused by the gross negligence or wilful misconduct of the operator.

The operator may resign by giving notice to the other party. If the resignation is due to an assignment to a third party and following such assignment the operator's interest is less than 20 per cent, the operator must notify the other party before such assignment takes place.

It the operator commits gross negligence or wilful misconduct but denies such action, the other party can request the matter to be referred to arbitration. If the arbitral decision is against the operator, the operator may be removed from its duties as operator on the unanimous vote of the other parties.

The operator forfeits its duties if it becomes insolvent or is wound up.

The operating committee is composed of one representative and one alternative representative from each party. The chairman of the operating committee is a representative of the operator. Each representative shall have voting rights in accordance with its nominating party's participating interest.

The operating committee has the power to decide upon the work programme and budget for joint operations and upon any matters regarding the supervision and direction of any petroleum activity.

With the exception of certain matters, all decisions passed by the operating committee shall be decided by the votes of at least two parties having in aggregate a participating interest of at least 65 per cent. If there are only two parties, a decision can be passed by an affirmative vote of a party holding at least 86 per cent of the aggregate participating interests.

The operating committee may set up other committees as it sees fit.

Within 90 days from the signature of the agreement, the operator shall submit a work programme and budget to the operating committee setting out at a minimum the work prescribed by the Elsa Exploration Permit. The operating committee shall approve the work programme and budget within 30 days of the date of submission.

The operator shall subsequently submit to the operating committee on or before 30 September each year the work programme and budget for the succeeding calendar year.

The work programme and budget shall be adopted by the operating committee on or before 15 December each year.

The parties shall fund the work programmes in proportion to their interests.

If, as a result of operations under the agreement, petroleum is discovered in the contract area in sufficient quantities to lead to the obtainment of a concession, the parties shall meet to decide whether to make such an application.

The parties will proceed with the appraisal of any formation which shows petroleum. The operator shall prepare a pre-feasibility study to assist the operating committee in deciding whether to proceed with an appraisal.

The appraisal shall include works and the conduct of a feasibility study to estimate the size and characteristics of the deposit of petroleum discovered.

Once the appraisal programme has been completed, the operator shall prepare a work project for the complete development and exploitation of the field discovered.

The following operations can be carried out on a sole risk basis:

- drilling of an exploration well;
- drilling of an appraisal well; and
- completion, recompletion, production tests, deepening, sidetracking or reworking of an inactive well which has been drilled as an exploration or appraisal well but no petroleum had been found.

A party proposing to carry out any such works shall initially seek approval from the operating committee. If the operating committee resolves against carrying out such work, the proposing party shall give the other parties notice that it intends to undertake the work on a sole risk basis through the operator.

At this point, the other parties have the option to opt into the works.

Sole risk operations are financed by the sole risk party.

A non-sole risk party can participate in a sole risk operation by notice to all parties that it elects to do so and be subject to financial contributions to the sole risk party.

If a party fails to pay its share of any cash call, such party shall be deemed to be in default. The operator shall send the defaulting party a reminder to pay its share. If the defaulting party still fails to pay, the operator shall give notice of such default to all parties. Each party not in default shall pay to the operator a proportion of the defaulting party's cash call.

Until a default is remedied, the defaulting party shall have no right to its participating share of any production. A defaulting party shall also not be entitled to participate at meetings of the operating committee.

If a defaulting party remains in default for ninety days, it shall be deemed to have relinquished its rights under the Elsa Exploration Permit.

Any party can relinquish its interest in the Elsa Exploration Permit by notifying the other parties and offering them its interest. If no party agrees to take up the relinquished interest within sixty days, the Elsa Exploration Permit shall be relinquished entirely and the Vega JOA terminated.

If the relinquishing party is the operator, its notice of relinquishment shall also be a notice of resignation.

If a party is subject to a force majeure event its affected obligations except its payment obligations under the Vega JOA shall be suspended. The definition of force majeure is non-exhaustive and includes anything that is beyond the reasonable control of the party.

Each party may assign its share of ownership in the Elsa Exploration Permit, subject to Petroceltic Italia's right of pre-emption which applies in case Vega receives an offer by a third party to acquire its interest in the Elsa Exploration Permit. Upon receipt of such offer Vega is obliged to offer Petroceltic Italia the opportunity to acquire such interest on the same terms that were made available to the third party.

Following the assignment, the assignor's or assignee's participating interest shall not be less than 10 per cent.

The Vega JOA is governed by Italian law. Any disputes will be referred to arbitration in accordance with the rules of the International Chamber of Commerce. The seat of arbitration shall be Rome. Any disputes over technical matters shall be resolved by expert determination.

Po Valley, Italy

20.2.12 Carisio JOA

On 8 January 2007, British Gas International B.V. ("**BG**") and Costruzioni Condotte ("**Condotte**") entered into a joint operating agreement in relation to the Carisio permit, effective from 18 May 2006 (the "**Carisio JOA**").

The original parties and participating interests under the Carisio JOA were BG with 95 per cent and Condotte with 5 per cent.

On 28 February 2008, a Ministerial Decree declared the transfer of BG's 95 per cent interest to Petroceltic Italia, effective as of 28 December 2007. Petroceltic Italia subsequently transferred a 47.5 per cent interest to ENI which was declared by Ministerial Decree on 27 March 2009, effective as of 24 February 2009.

The current participation interests in the Carisio permit are ENI with 47.5 per cent, Petroceltic Italia with 47.5 per cent and Condotte with 5 per cent.

Both Petroceltic Italia and ENI are now party to the Carisio JOA.

ENI became operator under the Carisio JOA on 1 April 2011. The operator has exclusive responsibility for the conduct of all petroleum activity in relation to the Carisio permit. The operator undertakes to carry out the work programmes in conformity with the planned schedule and within the budget limits.

Any hydrocarbon discovered and produced in the Carisio permit shall be owned by the parties to the JOA in proportion to their respective participating interests. The parties shall fund all costs and expenses of the JOA in accordance with their respective participating interests.

The operator may settle or defend any claims from third parties for an amount not exceeding €30,000. Any claims in excess of such amount must be reported to the other parties and the operator shall comply with any direction of the operating committee in relation to such claims.

The operator shall not be liable to the non-operating party for anything done or omitted in the fulfilment of its duties, except if caused by the gross negligence or wilful misconduct of the operator.

The operator may resign by giving notice to the other party. If the resignation is due to an assignment to a third party and following such assignment the operator's interest is less than 20 per cent, the operator must notify the other party before such assignment takes place.

It the operator commits gross negligence or wilful misconduct, the other party can request the matter to be referred to arbitration. If the arbitral decision is against the operator, the operator may be removed from its duties as operator with the unanimous vote of the other parties.

The operator shall necessarily forfeit its duties if it becomes insolvent or is wound up, i.e. it must resign its operatorship.

The operating committee is composed of a representative for each party to the Carisio JOA; the parties shall also designate a deputy representative in case the first designated representative is impeded from participating in the meetings. The chairman of the operating committee is a representative of the operator. Each representative shall have voting rights in accordance with its nominating party's participating interest.

The operating committee has the power to decide upon the work programme and budget for joint operations and upon any matters regarding the supervision and direction of any petroleum activity.

With the exception of reserved matters, all decisions passed by the operating committee shall be decided by the votes of at least two parties having in aggregate a participating interest of at least 65 per cent. If there are only two parties, a decision may be passed by an affirmative vote of a party holding at least 86 per cent of the aggregate participating interests.

Within 90 days from the signature of the agreement, the operator shall submit a work programme and budget to the operating committee setting out as a minimum work prescribed by the Carisio Exploration Permit. The operating committee shall approve the work programme and budget within 30 days of the date of submission.

The operator shall subsequently submit to the operating committee by October 31 of each year the work programme and budget for the following calendar year.

The work programme and budget shall be adopted by the operating committee on or before December 15 each year.

If, as a result of operations under the agreement, petroleum is discovered in the contract area in sufficient quantities to lead to the obtainment of a concession, the parties shall meet to decide whether to make such an application.

The parties will proceed with the appraisal of any formation which shows petroleum. The operator shall prepare a pre-feasibility study to assist the operating committee in deciding whether to proceed with an appraisal.

The appraisal shall include works and the conduct of a feasibility study to estimate the size and characteristics of the deposit of petroleum discovered.

Once the appraisal programme has been completed, the operator shall prepare a work project for the complete development and exploitation of the field discovered.

The following operations can be carried out on a sole risk basis:

- drilling of an exploration well;
- drilling of an assessment well; and
- completion, recompletion, production tests, deepening, sidetracking or reworking of an inactive well which has been drilled as an exploration or assessment well, but no petroleum had been found.

- completion, recompletion, production tests, deepening, sidetracking or reworking of an active well which has been drilled as an exploration or assessment well, but no petroleum in marketable quantities had been found at the target depth.

A party proposing to carry out any such works shall initially seek approval from the operating committee. If the operating committee resolves against carrying out such work, the proposing party shall give the other parties notice that it intends to undertake the work on a sole risk basis through the operator.

At this point, the other parties have the possibility to opt into the works.

Sole risk operations are financed by the sole risk party.

A non-sole risk party can participate in a sole risk operation by notice to all parties that it elects to do so. It will be subject to financial contributions to the sole risk party.

If a party fails to pay its share of any cash call, such party shall be deemed to be in default. The operator shall send the defaulting party a reminder to pay its share. If the defaulting party still fails to pay, the operator shall give notice of such default to all parties. Each party not in default shall pay to the operator a proportion of the defaulting party's cash call.

Until a default is remedied, the defaulting party shall have no right to its participating share of any production. A defaulting party shall also not be entitled to participate at meetings of the operating committee.

If a defaulting party remains in default for ninety days, it shall be deemed to have relinquished its rights under the Carisio Exploration Permit.

Any party can relinquish its interest in the Permit by notifying the other parties and offering them its interest. If no party agrees to take up the relinquished interest within sixty days, the Carisio Exploration Permit shall be relinquished entirely and the Carisio JOA terminated.

If the relinquishing party is the operator, its notice of relinquishment shall also be a notice of resignation.

If a party is subject to a force majeure event, all of its affected obligations, except its payment obligations, under the Carisio JOA shall be suspended. The definition of force majeure is non-exhaustive and includes anything that is beyond the reasonable control of the party.

Each party may assign its share of ownership in the Carisio Exploration Permit, subject to the other partners' right of pre-emption. Following the assignment, the assignor's or assignee's participating interest shall not be less than 10 per cent.

The Carisio JOA is governed by Italian law.

Any disputes will be referred to an arbitration panel that shall settle the dispute without procedural formalities and as final settlement, provided both parties receive a fair hearing. The seat of arbitration is Milan. Any disputes over technical matters shall be resolved by a technical expert appointed by the parties (or by the arbitration panel, if the parties fail to agree on the appointment of such expert).

20.3 Melrose Group

Egypt

El Mansoura

20.3.1 El Mansoura Concession Agreement

On 22 June 1998, the Arab Republic of Egypt ("**ARE**"), EGPC, Odyssey Petroleum (El-Mansoura) Ltd and Melrose Petroleum (El Mansoura) Company (formerly known as Merlon Petroleum (El-Mansoura) Company) ("**Melrose El Mansoura**") (collectively the "**Contractor**") entered into a concession agreement issued by virtue of Law No. 8 of 1998 for petroleum exploration and exploitation in the El-Mansoura area, Nile Delta (the "**El Mansoura Concession Agreement**"), as amended by an amending agreement of 9 May 2005 (the "**El Mansoura Amending Agreement**"). Odyssey Petroleum (El-Mansoura) Ltd and Melrose El Mansoura are now both wholly owned subsidiaries of Melrose. The El Mansoura Concession Agreement establishes the obligations of the Contractor and EGPC with respect to exploring the concession area, establishing a commercial oil or gas discovery, converting such discovery into a development lease and bringing the development to production.

The El Mansoura Concession Agreement provides for an initial three year exploration period with two options for additional extensions of the exploration period of three and two years, respectively, exercisable by the Contractor. The Contractor shall:

- spend a minimum of US$6 million on exploration operations and activities during the initial three year exploration period and drill two wells and acquire seismic surveys;
- if the first three year extension of the exploration period is exercised, spend a minimum of US$3 million and drill two further wells; and
- if the second two year extension of the exploration period is exercised, spend a minimum of US$2 million and drill one further well.

The El Mansoura Amending Agreement provides for a third extension of the exploration period by three years (with a possible further three year option exercisable by the Contractor), under which the Contractor shall:

- spend a minimum of US$5 million for drilling two wells and performing exploration operations and activities; and
- if the fourth three year extension is exercised, spend a minimum of US$5 million for drilling two wells.

Bonuses are payable to EGPC by the Contractor on (i) the effective date; and (ii) at such times as the average daily production exceeds certain levels.

Letters of guarantee provided by the Contractor to EGPC guarantee the execution of all the Contractor's minimum spending obligations. In addition, any excess money spent or wells drilled over the course of the initial exploration period or any extension thereafter, may be subtracted from the minimum required expenditure or wells commitment in any succeeding extension period (as the case may be).

The Contractor shall also relinquish to ARE 25 per cent of the original area not then converted into a development lease at the end of both the third and sixth year. In the event the fourth extension is not exercised, the remainder of the original area not converted into a development lease shall be relinquished after the third extension. If the fourth extension is exercised, a further 25 per cent of the original area not converted to a development lease is relinquished at the end of the third extension and the remainder of that area is relinquished at the end of the fourth extension. The El Mansoura Concession Agreement is terminated if neither a commercial oil nor gas discovery is established by the end of the eighth year of the exploration period (as may be extended). As the exploration period set out in the El Mansoura Concession Agreement has expired, exploration area not converted into a development lease will have now been relinquished in accordance with the terms of the agreement.

If commercial production of oil in regular shipments is not established in a development block within four years from the date of a commercial discovery of oil, the development block is deemed relinquished (unless there is a commercial gas discovery within the development lease). If commercial production of gas is not established in accordance with an agreement between EGPC and the Contractor for the supply of gas to EGPC, the relevant development lease is deemed relinquished.

On a commercial discovery, the Contractor and EGPC agree to form an Egyptian private company (the charter of which is prescribed by the El Mansoura Concession Agreement) to be owned on a 50:50 basis. Under the terms of the charter, the operating company is to act as the agent of the Contractor and EGPC only, and is not to own any direct interest in the development activities or assets on its own behalf.

ARE is entitled to a royalty payable by EGPC in cash or kind of 10 per cent of the total quantity of petroleum produced and saved from the area during the development period (including any renewal). All gas produced shall be disposed of to EGPC under a long-term gas sales agreement in accordance with the El Mansoura Concession Agreement. Bonuses are payable to EGPC by the Contractor on (i) the effective date and (ii) at such time as the average daily production exceeds certain prescribed levels.

Each Contractor is entitled to recover, on a quarterly basis, exploration, development and certain operating costs out of 35 per cent of petroleum produced and saved from the development leases and not used in petroleum operations ("**Cost Recovery Petroleum**"). If such costs are not recovered from the Cost Recovery Petroleum in a particular tax year, the excess cost can be carried forward until fully recovered (up to termination of the El Mansoura Concession Agreement). If the value of the Cost Recovery Petroleum exceeds the recoverable costs (including carried forward costs) in a particular quarter, then the value of such excess shall be split 70 per cent to EGPC and 30 per cent to the Contractor. The cost recovery provisions under the El Mansoura Concession Agreement are linked to the production from development leases in the concession area converted prior to the end of the second extension and separately for those converted since the end of the second extension.

The remaining 65 per cent of the petroleum shall be divided between EGPC and the Contractor in various proportions depending on the amount of petroleum that is produced (the "**Production Sharing Petroleum**").

EGPC becomes the owner of all assets acquired by the Contractor which are subsequently charged to the cost recovery process under the El Mansoura Concession Agreement by the Contractor and, in the case of certain operational assets not charged to the cost recovery process, upon termination of the El Mansoura Concession Agreement. Land shall become the property of EGPC as soon as it is purchased.

The Contractor is solely responsible to third parties for any damage caused by the Contractor's exploration operations and the Contractor indemnifies ARE and/or EGPC against all damages for which they may be liable on account of any such operations.

If changes in existing legislation or regulations regarding the exploration, development and production of petroleum occur after the date of the El Mansoura Concession Agreement which significantly affect the economic interest of the El Mansoura Concession Agreement to the Contractor's disadvantage or impose on the Contractor an obligation to remit to ARE sales proceeds from the Contractor's petroleum, the parties shall negotiate possible modifications to restore the economic balance which existed as at the date of the El Mansoura Concession Agreement.

ARE may requisition the production from the area, the oil and/or gas field itself and, if necessary, related facilities in case of national emergency due to war or imminent expectation of war or internal causes however ARE must indemnify EGPC and the Contractor for any subsequent loss.

ARE has the right to cancel the El Mansoura Concession Agreement with respect to a Contractor if that Contractor:

- knowingly has submitted any material false statements to ARE;
- assigns any interest in the El Mansoura Concession Agreement to another party, without ARE's consent;
- is adjudicated bankrupt;
- does not comply with a court decision obtained in accordance with the terms of the El Mansoura Concession Agreement;
- intentionally extracts any mineral other than petroleum; or
- commits a material breach of the El Mansoura Concession Agreement or of certain Egyptian laws.

The non-performance or delay in performance by EGPC and/or the Contractor of any obligation under the El Mansoura Concession Agreement shall be excused if and to the extent that such non-performance or delay is caused by force majeure. Force majeure shall be any order, regulation or direction of ARE, or the governments of Bermuda or Cayman Islands with respect to the Contractor whether in the form of a law or otherwise or any act of god, insurrection, riot, war, strike and other labour disturbance, fires, floods or any cause not due to the fault or negligence of EGPC and/or the Contractor, provided that any such cause is beyond their reasonable control.

Neither the EGPC nor the Contractor (except for an affiliated company of the Contractor) may assign any of its rights or obligations under the El Mansoura Concession Agreement without the written consent of ARE.

The El Mansoura Concession Agreement is governed by the laws of ARE. Any dispute or claim arising between ARE and the parties shall be referred to the jurisdiction of the appropriate ARE court and shall be finally settled by such court. Any dispute or claim between EGPC and the Contractor shall be settled by arbitration in accordance with the Arbitration Rules of the Cairo Regional Center for International Commercial Arbitration.

20.3.2 Mansoura Joint Operating Agreement

On 14 April 1998, Odyssey Petroluem (El-Mansoura) Ltd. and Melrose El Mansoura entered into a joint operating agreement to establish and clarify their respective rights and obligations as Contractor members in relation to the El Mansoura Concession. Both companies are now wholly owned subsidiaries of MELROSE. Under the terms of the joint operating agreement, the companies granted in favour of Stratton Corporation an overriding royalty interest equal to three per cent of the Contractor's share of petroleum saved and sold from the El Mansoura area as excess cost recovery petroleum and as production sharing petroleum and such overriding royalty interest continues to be paid by the companies.

El Mansoura Concession development leases

20.3.3 West Al Khilala development lease

Melrose El Mansoura, EGAS and EGPC obtained the formal approval on 2 August 2006 from the Minister of Petroleum to convert the eight complete and two partial development blocks comprising the gas discovery of West Al Khilala-1 well into the West Al Khilala development lease via an operating company pursuant to the El Mansoura Concession Agreement. The total area of the West Al Khilala lease is approximately 24.7 km². Under the terms of the development lease, the parties agreed on a proposed development plan to: (i) construct gas treatment facilities at the site of the discovery well; (ii) extend a 15 km long 10 inch pipeline to transport the gas to a delivery point in the Gasco Abu Madi/Talkha 22 inch gas pipeline; and (iii) temporarily truck condensates produced to South Batra Gas Plant until the condensate pipeline is constructed. Under the terms of the development lease, the gas sales contract executed for the gas sales of the South Belkas development lease includes the production of gas from West Al Khilala.

20.3.4 South Al Khilala development lease

Melrose El Mansoura, EGAS and EGPC obtained approval on 22 July 2009 from the Minister of Petroleum to convert the six development blocks comprising the gas discovery of the South Al Khilala-1 well into the South Al Khilala development lease via an operating company pursuant to the El Mansoura Concession Agreement. The total area of the South Al Khilala lease is approximately 17.4 km². Under the terms of the development lease, the parties agreed on a proposed development plan to extend a 6 inch pipeline for approximately 11 km from the South Al Khilala-1 well to the West Al Khilala field production facilities where gas will be processed.

20.3.5 West Dikirnis development lease

Melrose El Mansoura, EGAS and EGPC obtained approval on 23 September 2007 from the Minister of Petroleum to convert the six development blocks comprising the oil and gas discovery of West Dikirnis-1 and 2 wells into the West Dikirnis development lease via an operating company pursuant to the El Mansoura Concession Agreement. The total area of the West Dikirnis lease is approximately 17.5 km². Under the terms of the West Dikirnis development lease, the parties agreed a proposed development plan to expand the oil and gas treatment facilities at the South Batra Gas Plant and extend two 20 km pipelines from the West Dikirnis Field to the South Batra Gas Plant via a ten inch pipeline to transport unprocessed liquids production, and a six inch pipeline to transport gas production.

20.3.6 El Mansoura development lease

Melrose El Mansoura and EGPC obtained approval on 14 October 2003 from the Minister of Petroleum to convert the twenty-six development blocks comprising the gas discovery of El Mansouriya -1 well and South Batra-1 well into the El Mansoura development lease pursuant to the El Mansoura Concession Agreement. The total area of the El Mansoura Lease is approximately 76 km². Under the terms of the development lease, the parties agreed a proposed development plan including drilling one well in the El Mansoura development lease within four years from the date of approval of the lease.

20.3.7 South El Mansoura development lease

Melrose El Mansoura and EGPC obtained approval on 14 October 2003 from the Minister of Petroleum to convert the ten development blocks comprising the gas discovery of South El Mansoura-1 well into the South El Mansoura development lease pursuant to the El Mansoura Concession Agreement. The total area of the South El Mansoura lease is approximately 29 km². Under the terms of the development lease, the parties agreed a proposed development plan including drilling one well in the South El Mansoura development lease within four years from the date of approval of the lease.

20.3.8 El Tamad development lease

Melrose El Mansoura, EGAS and EGPC obtained approval on 12 December 2005 from the Minister of Petroleum to convert the two development blocks comprising the oil and gas discovery of El Tamad-1 well into the El Tamad development lease via an operating company pursuant to the El Mansoura Concession Agreement. The total area of the El Tamad development lease is approximately 5.8 km². Under the terms of the development lease, the parties agreed a proposed development plan including (i) the construction of separate facilities at wells El Tamad 1 and 2; (ii) extending two 4 inch pipelines, the first being 21 km long to transport the oil produced to a tie-in point with PPC's eight inch pipeline west of Damietta branch of the River Nile and the second being 9 km long to transport the gas produced to the South El Mansoura Gas Plant; and (iii) the execution of an early production scheme from wells El Tamad-1 and 2 and trucking the oil to the South Batra Gas Plant.

20.3.9 East Abu Khadra development lease

Melrose El Mansoura, EGAS and EGPC obtained approval from the Minister of Petroleum on 4 March 2009 to convert the three development blocks comprising the gas discovery of East Abu Khadra-1 well into the East Abu Khadra development lease via an operating company pursuant to the El Mansoura Concession Agreement. The total area of the East Abu Khadra development lease is approximately 8.7 km². Under the terms of the East Abu Khadra development lease, the parties agreed a proposed development plan to extend a 4 inch pipeline consisting of two sections, one 7.7 km long extending from the East Abu Khadra-1 discovery well to the South Belqas well where it will be tied-in to the existing 4 inch pipeline extending from the South Belqas to Abu Arida-1 well; and one 7 km long extending from the Abu Arida-1 well to the South Batra-8 well where it will be tied-in to the existing 4 inch pipeline from the South Batra-8 to the South Batra Gas Plant where gas will be treated.

20.3.10 South Zarqa development lease

Melrose El Mansoura, EGAS and EGPC obtained approval on 27 November 2008 from the Minister of Petroleum to convert the four development blocks comprising the gas discovery of the South Zarqa-1 well into the South Zarqa development lease via an operating company pursuant to the El Mansoura Concession Agreement. The total area of the South Zarqa development lease is approximately 11.6 km². Under the terms of the development lease, the parties agreed a proposed development plan to extend a 253 km long 10 inch pipeline from the South Zarqa-1 well to the South Batra Gas Plant where production will be treated.

20.3.11 North East Abu Zahra development lease

Melrose El Mansoura, as operator on behalf of the Contractor, EGAS and EGPC obtained approval on 27 November 2008 from the Minister of Petroleum to convert the four development blocks and three sub blocks comprising the gas discovery of the North East Abu Zahra-1 well into the North East Abu Zahra development lease via an operating company pursuant to the El Mansoura Concession Agreement. The total area of the North East Abu Zahra development lease is approximately 15.145 km². Under the terms of the development lease, the parties agreed a proposed development plan to extend a 8.5 km long 10 inch pipeline from the North East Abu Zahra-1 well to the South Zarqa-1 well and a 25 km long 10 inch pipeline from the South Zarqa-1 well to the South Batra Gas Plant where production will be treated.

El Mansoura Concession Gas Sales Agreements

20.3.12 West Khilala Gas Sales Amendment Letter

Melrose El Mansoura, EGPC and EGAS entered into a gas sales letter of agreement on 29 August 2002 (amended on 29 January 2006) for the South Belkas development lease (the

"**South Belkas GSA**"). Following the approval dated 2 August 2006 of the application to convert the discovery well West Khilala-1 into the West Khilala development lease, the parties to the letter agreed to a second amendment to the gas sales letter of agreement on 3 October 2006 with effect from 2 August 2006 (the "**West Khilala Gas Sales Amendment Letter**").

Under the terms of the West Khilala Gas Sales Amendment Letter, the parties agreed that:

- the gas produced from the West Khilala development lease under the El Mansoura Concession Agreement shall be treated as an addition to the daily production quota in the South Belkas GSA;
- the Contractor and EGPC/EGAS (as sellers) would make available for delivery and EGPC (as buyer) would take and purchase a quantity of natural gas produced from the West Khilala development lease that depends on West Khilala proven recoverable reserves of 99.4 Bcf and production plateau of:

Date	Daily production quantity (MMcfpd)
Starting from the Start-Up Date (est. January 2007)	30.00
Starting from January 2008 through Dec. 2012	30.00
Starting from January 2013	27.70
Starting from January 2014	20.80
Starting from January 2015	15.30
Starting from January 2016	11.10
Starting from January 2017	7.90
Starting from January 2018	5.50
Starting from January 2019	3.70

- all terms and conditions of the South Belkas GSA shall apply, with no change, to the gas produced from the West Khilala development lease.

20.3.13 South Khilala Gas Sales Agreement

EGPC and Melrose El Mansoura (collectively the sellers) entered into a gas sales agreement on 1 September 2009 for the sale to EGPC of the gas produced from the South Khilala development lease (the "**South Khilala GSA**") in the quantities set out below:

Date	Daily production quantity (MMcfpd)
Starting from the Start-Up Date	15.00
Starting from January 1, 2010	15.00
Starting from January 1, 2011	15.00
Starting from January 1, 2012	10.90
Starting from January 1, 2013	6.60
Starting from January 1, 2014	4.10
Starting from January 1, 2015	2.60
Starting from January 1, 2016	1.70
Starting from January 1, 2017	1.10
Starting from January 1, 2018	0.70
Starting from January 1, 2019	0.60

The sellers shall not be required to make available for delivery more than 110 per cent of the DCQ. However, if EGPC wishes to take and purchase gas in excess of that amount, it may notify the sellers of this requirement and the sellers shall (if they have such excess available) use all reasonable endeavours to meet such requirements.

The sellers are required to inform EGPC of the last determined recoverable reserves upon which the DCQ may be increased or decreased, with such changes being approved by EGPC within three (3) months from receipt of such notice (such approval not to be unreasonably withheld). Within 30 days of issuing such approval EGPC shall notify the sellers when the date of the new DCQ shall come into force. The minimum take is not less than 75 per cent of the ACQ.

If there is a sellers' shortfall, then EGPC shall, in the subsequent contract year, have the right to take a quantity equal to the difference between the calculated quantity and the quantity actually delivered by the sellers in the previous contract year at a price equal to 90 per cent of the gas price. There will be a shortfall if the sellers fail to deliver 75 per cent of the DCQ multiplied by the number of days in each relevant contract year, less the aggregate of all quantities that have not been made available due to force majeure, pipeline shut-down, maintenance or other operational requirements.

If in any contract year EGPC has paid for, but not taken, any quantity of gas, EGPC shall accrue a make-up gas right to such quantity that shall be recorded in a separate account called the "Take-or-Pay Account". If EGPC has taken a quantity of gas in excess of 75 per cent of the ACQ then such excess shall be set against and reduce quantities of gas in the Take-or-Pay Account to the extent thereof and, to that extent, no payment shall be due for such gas. Upon termination of the South Khilala GSA, the sellers shall have no obligation to deliver such make-up gas and EGPC shall have no right to any cash refund for any quantity of gas recorded in the Take-or-Pay Account.

Quantities of gas taken in excess of the ACQ in any contract year shall be carried forward and used to reduce the quantities of gas required to be taken up by EGPC to meet the minimum take during subsequent contract years. The maximum amount of carry forward gas which may be counted against the ACQ shall be 20 per cent of the ACQ for that said contract year.

The gas price shall be calculated according to the following formula: PG = F x H, where:

- PG = the value of the gas in US$ per thousand cubic feet;
- H = the number of million British Thermal Units per thousand cubic feet of gas; and
- F = the value of the gas in US$ per million British Thermal Units determined according to the table set out at clause 6 of the South Khilala GSA.

EGPC may pay the Contractor either in cash or in kind by giving notice in writing at least ninety (90) days prior to the commencement of each calendar quarter. Should EGPC fail to make payment in cash or in kind of any undisputed amount thereunder when said payment is due, then such unpaid amount shall incur interest charges equal to LIBOR plus 2.5 per cent from the date when such amount would have been due and payable.

The South Khilala GSA shall remain in force and effect until the production of gas is no longer economically sustainable or until the date of expiration of the Contractor's rights under the El Mansoura Concession Agreement, whichever first occurs.

The force majeure provision of the El Mansoura Concession Agreement shall apply to the South Khilala GSA. However, lack of gas market outlets or failure by the buyer's customers to take contracted quantities, though not constituting a force majeure under the El Mansoura Concession Agreement, shall be treated as a force majeure for EGPC as buyer under the South Khilala GSA, if such event(s) are (i) beyond the reasonable control of EGPC and (ii) materially adversely affect multiple customers of EGPC, and (iii) beyond the reasonable control of said multiple customers by reason of the force majeure.

The assignment provisions of the El Mansoura Concession Agreement shall apply to the South Khilala GSA.

The South Khilala GSA is governed by the laws of ARE. Any dispute or claim arising out of the South Khilala GSA shall be settled in accordance with the provisions of the El Mansoura Concession Agreement.

20.3.14 West Dikirnis Gas Sales Agreement

EGPC and Melrose El Mansoura entered into a gas sales agreement on 7 November 2007 (the "**West Dikirnis GSA**") for the sale to EGPC of the gas produced from the West Dikirnis development lease in accordance with the El Mansoura Concession Agreement and the terms of this agreement were varied by letter agreement dated 30 June 2009 between the parties pursuant to which the North Dikirnis gas production will be delivered to South Batra Gas Plant through the West Dikirnis pipeline.

Under the terms of the amended agreement, both parties agreed that the gas produced from the North Dikirnis development lease under the El Mansoura Concession Agreement would be treated as an addition to the DCQ under the West Dikirnis GSA in the quantities set out below:

Date	**Daily production quantity (MMcfpd)**
Starting from the Start-Up Date (Q2 2009)	5.00
April 2010	1.80

All terms and conditions of the West Dikirnis GSA shall apply, with no change, to the gas produced from the North Dikirnis development lease.

The remaining provisions are the same as under the South Khilala GSA.

20.3.15 El Mansoura and South El Mansoura Gas Sales Agreement

EGAS, EGPC and Melrose El Mansoura entered into a gas sales agreement on 17 November 2003 in relation to the El Mansoura and South El Mansoura development leases (the "**El Mansoura and South El Mansoura GSA**") for the sale of quantities of gas produced from the El Mansoura and South El Mansoura development leases to EGAS and EGPC (as buyers) in the quantities set out below:

	Daily production quantity (MMcfpd)		
	El Mansoura Development Lease		South El Mansoura Development Lease
Date	South Batra Field	El Mansouriya Field	
Starting from the Start-Up Date	30.00	10.00	10.00
Starting from mid-2004	30.00	10.00	10.00
Starting from January 1, 2005	100.00	10.00	9.00
Subsequent production phase (*)	100.00	10.00	8.00

The Contractor has the right to request an increase or decrease in the daily production quantity based on additional information on the fields' proven recoverable reserves.

At the end of each production year, the sellers render to EGPC a statement for an amount of gas, if any, equal to the amount by which the quantity of gas of which EGPC has taken delivery falls below 75 per cent of the annual DCQ. Within 60 days of receipt of the statement, EGPC shall pay the Contractor for the amount of the "Take or Pay Shortfall".

After the end of each production year, if deliveries of gas by the Contractor and the sellers to EGPC fall below 75 per cent of the annual DCQ, (the "**Shortage Quantity**") EGPC has the right to purchase in the following production year such Shortage Quantity at 90 per cent of the price as calculated in accordance with the El Mansoura and South El Mansoura GSA.

The gas price is calculated according to the following formula: $PG = H^* B^* (0.18 - 0.003^*B)$.

- PG = the value of the gas in US$ per Mcf;
- B = the monthly average price of Brent crude oil, expressed in US$ per barrel; and
- H = the number of (Million) British Thermal Units per Mcf of the gas based on the gross calorific value.

The El Mansoura and South El Mansoura GSA shall remain in force and effect until:

- production of gas from the El Mansoura development lease and the South El Mansoura development lease, and from any other development leases that may be included under the terms of the El Mansoura and South El Mansoura GSA is not economically sustainable;
- the date of expiration of the rights of the Contractor under the El Mansoura Concession Agreement;
- the execution of a formal gas sales agreement; or
- the mutual agreement of the parties to terminate the El Mansoura and South El Mansoura GSA,

whichever occurs first.

20.3.16 El Tamad Gas Sales Amendment Letter

EGAS, EGPC and Melrose El Mansoura (as "**Contractor**") entered into an agreement on 14 February 2006 to amend the terms of the El Mansoura and South El Mansoura GSA to be effective from 12 December 2005 following the approval of the application to convert the El Tamad oil and gas discovery into the El Tamad development lease (the "**El Tamad Gas Sales Amendment Letter**").

Under the terms of the El Tamad Gas Sales Amendment Letter, the parties agreed that:

- The Contractor and EGPC would make available for delivery and EGPC would take and purchase a quantity of natural gas produced from the El Tamad development lease that depends on El Tamad recoverable oil and gas reserves estimated to be 2.1 million barrels of oil and 7 Bcf of gas.
- Daily gas production quantities will be agreed upon in writing by the Contractor and EGAS/EGPC following the start of production and according to the well(s) performance and reservoir behaviour. This gas production is treated as an addition to the DCQ under the El Mansoura and South El Mansoura GSA.
- Associated gas produced from the El Tamad field will be compressed and commingled with high pressure, treated gas and delivered to the Egyptian Natural Gas Company (GASCO).
- The quality of gas delivered to EGPC, pursuant to the El Mansoura Concession Agreement, would be required at all times to satisfy EGAS/EGPC National Grid quality and specifications in the El Mansoura and South El Mansoura GSA.
- All terms and conditions of the El Mansoura and South El Mansoura GSA would be applied to El Tamad development lease gas production.

20.3.17 East Abu Khadra Gas Sales Agreement

EGPC and Melrose (El Mansoura) (collectively the sellers) entered into a gas sales agreement on 12 April 2009 for the sale to EGPC of gas produced from the East Abu Khadra development lease in accordance with the El Mansoura Concession Agreement (the "**East Abu Khadra GSA**") in the quantities set out below:

Date	Daily production quantity (MMcfpd)
Starting from the Start-Up Date	8.00
Starting from January 1, 2010	6.60

20.3.18 South Zarqa Gas Sales Agreement

EGPC and Melrose El Mansoura (collectively the sellers) entered into a gas sales agreement on 26 January 2009 for the sale to EGPC of gas produced from the South Zarqa development lease in accordance with the El Mansoura Concession Agreement (the "**South Zarqa GSA**") in the quantities set out below:

Date	Daily production quantity (MMcfpd)
Starting from the Start-Up Date	12.00
Starting from January 1, 2010	9.80
Starting from January 1, 2011	8.10
Starting from January 1, 2012	6.60
Starting from January 1, 2013	5.40
Starting from January 1, 2014	4.40
Starting from January 1, 2015	3.60
Starting from January 1, 2016	3.00
Starting from January 1, 2017	2.50
Starting from January 1, 2018	2.00
Starting from January 1, 2019	1.70
Starting from January 1, 2020	1.40
Starting from January 1, 2021	1.10

The remaining provisions are the same as under the South Khilala GSA.

20.3.19 North East Abu Zahra Gas Sales Agreement

EGPC and Melrose El Mansoura entered into a gas sales agreement on 26 January 2009 for the sale to EGPC of the gas produced from the North East Abu Zahra development lease in accordance with the El Mansoura Concession Agreement (the "**North East Abu Zahra GSA**") in the quantities set out below.

Date	Daily production quantity (MMcfpd)
Starting from the Start-Up Date	15.00
Starting from January 1, 2010	10.30
Starting from January 1, 2011	7.00
Starting from January 1, 2012	3.50
Starting from January 1, 2013	2.50
Starting from January 1, 2014	2.30
Starting from January 1, 2015	1.60

The remaining provisions are the same as under the South Khilala GSA.

South East El Mansoura

20.3.20 South East El Mansoura Concession Agreement

ARE, EGPC, Melrose Petroleum (South East El Mansoura) Company (formerly known as Merlon Petroleum Company and now a wholly owned subsidiary of Melrose ("**Melrose South East EI Mansoura**") and Melrose entered into a concession agreement on 26 July 2005 for the exploration and exploitation of petroleum in the South East El Mansoura area of the Nile Delta in Egypt ("**South East El Mansoura Concession Agreement**").

Melrose and Melrose South East El Mansoura are nominated as the "**Contractor**" under the agreement. An initial period of three years shall be set aside for exploration; this period can be extended two successive three year extensions. After three years and six years, on each occasion 25 per cent of the original area for which a development lease has not been granted shall be relinquished. After nine years all of the area for which a development lease has not be granted shall be relinquished.

Whether a commercial discovery of oil or gas in the concession area has been made is to be mutually agreed between the Contractor and EGPC. Upon making a commercial discovery of oil or gas, the area capable of production is to be mutually agreed between the parties. Upon such agreement, the area is converted into a development lease with: (i) in the case of a commercial discovery of oil, a 20 year term from the date of discovery (subject to extension by the period of five years at the election of the Contractor); or (ii) in the case of a commercial discovery of gas, a 20 year term from the date of first delivery of gas locally or for export (subject to extension by the period of five years at the election of the Contractor).

If gas is subsequently discovered in a development lease based on an initial oil discovery, or oil is subsequently discovered in a development lease based on a gas discovery, a new term would apply in relation to such subsequent discovery but subject to a 35 year longstop date from the date of the original discovery that gave rise to the development lease (unless otherwise agreed upon between EGPC and the Contractor and subject to the approval of the Minister of Petroleum).

A royalty of 10 per cent of the total quantity of petroleum produced and saved from the area is paid by EGPC to the Egyptian government. The agreement also provides that a minimum of US$3 million be spent by the contractor on exploration operations during the initial 3 year period. For the first and second three year extension periods a further US$5 million must be committed by the contractor during each extension. Bonuses are payable to EGPC by the Contractor on (i) the effective date, (ii) on the approval of a development lease and (iii) at such time as the average daily production exceeds certain prescribed levels.

ARE may requisition the production from the area, the oil and/or gas field itself and, if necessary, related facilities in case of national emergency due to war or imminent expectation of war or internal causes however ARE must indemnify EGPC and the Contractor for any subsequent loss.

The non-performance or delay in performance by EGPC and/or the Contractor of any obligation under the agreement shall be excused if and to the extent that such non-performance or delay is caused by force majeure. Force majeure shall be any act of god, insurrection, riot, war, strike and other labour disturbance, fires, floods or any cause not due to the fault or negligence of EGPC and/or the Contractor, provided that any such cause is beyond their reasonable control.

The South East El Mansoura Concession Agreement is governed by the laws of ARE. The South East El Mansoura Concession Agreement is governed by the laws of are any dispute or claim arising between ARE and the parties shall be referred to the jurisdiction of the appropriate ARE court and shall be finally settled by such court. Any dispute or claim between EGPC and the Contractor shall be settled by arbitration in accordance with the Arbitration Rules of the Cairo Regional Center for International Commercial Arbitration.

Damas

20.3.21 Damas development lease

Melrose South East El Mansoura and EGPC obtained approval on 9 October 2008 from the Minister of Petroleum to convert the two development blocks comprising the gas discovery of Damas-1 well into the Damas development lease via an operating company pursuant to the South East El Mansoura Concession Agreement. The total area of the Damas lease is approximately 5.8 km². Under the terms of the Damas development lease, the parties agreed that the date of the gas commercial discovery was 10 June 2008 and agreed a proposed development plan. The parties also agreed to review the development blocks periodically every three years with the objective of mutually agreeing in writing to drop any blocks not producing or contributing to production.

20.3.22 South Damas development lease

Melrose South East El Mansoura and EGPC obtained on 29 June 2010 approval from the Minister of Petroleum to convert the five development blocks comprising the gas discovery of the South Damas-1 well into the South Damas development lease via an operating company pursuant to the South East El Mansoura Concession Agreement. The total area of the South Damas lease is approximately 15 km². Under the terms of the development lease, the parties agreed a proposed development plan.

20.3.23 Al Rawdah development lease

Melrose South East El Mansoura and EGPC obtained approval on 23 November 2006 from the Minister of Petroleum to convert the two development blocks comprising the gas discovery of Al Rawdah-1 well into the Al Rawdah development lease via an operating company pursuant to the South East El Mansoura Concession Agreement. The total area of the Al Rawdah lease is approximately 5.8 km². Under the terms of the development lease, the parties agreed a proposed development plan.

20.3.24 Damas Gas Sales Agreement

EGPC and Melrose Petroleum South East El Mansoura Company entered into a gas sales agreement on 26 January 2009 for the sale to EGPC of gas produced from the Damas development lease in accordance with the South East El Mansoura Concession Agreement (the "**Damas GSA**") in the quantities set out below:

Date	Daily production quantity (MMcfpd)
Starting from the Start-Up Date	6.00
Starting from January 1, 2010	4.30
Starting from January 1, 2011	6.00
Starting from January 1, 2012	2.70

The sellers shall not be required to make available for delivery more than 110 per cent of the DCQ. However, if EGPC wishes to take and purchase gas in excess of that amount, it may notify the sellers of this requirement and the sellers shall (if they have such excess available) use all reasonable endeavours to meet such requirements.

The sellers are required to inform EGPC of the last determined recoverable reserves upon which the DCQ may be increased or decreased, with such changes being approved by EGPC within three (3) months from receipt of such notice (such approval not to be unreasonably withheld). Within thirty (30) days of issuing such approval EGPC shall notify the sellers when the date of the new DCQ shall come into force. The minimum take is not less than 75 per cent of the ACQ.

If there is a sellers' shortfall, then EGPC shall, in the subsequent contract year, have the right to take a quantity equal to the difference between the calculated quantity and the quantity actually delivered by the sellers in the previous contract year at a price equal to 90 per cent of the gas price. There will be a shortfall if the sellers fail to deliver 75 per cent of the DCQ multiplied by the number of days in each relevant contract year, less the aggregate of all quantities that have not been made available due to force majeure, pipeline shut-down, maintenance or other operational requirements.

If in any contract year EGPC has paid for, but not taken, any quantity of gas, EGPC shall accrue a make-up gas right to such quantity that shall be recorded in a separate account called the "Take-or-Pay Account". If EGPC has taken a quantity of gas in excess of 75 per cent of the ACQ then such excess shall be set against and reduce quantities of gas in the Take-or-Pay Account to the extent thereof and, to that extent, no payment shall be due for such gas. Upon termination of the Damas GSA, the sellers shall have no obligation to deliver such make-up gas and EGPC shall have no right to any cash refund for any quantity of gas recorded in the Take-or-Pay Account.

Quantities of gas taken in excess of the ACQ in any contract year shall be carried forward and used to reduce the quantities of gas required to be taken up by EGPC to meet the minimum take during subsequent contract years. The maximum amount of carry forward gas which may be counted against the ACQ shall be 20 per cent of the ACQ for that said contract year.

The gas price shall be calculated according to the following formula: PG = F x H, where:

- PG = the value of the gas in US$ per thousand cubic feet;
- H = the number of million British Thermal Units per thousand cubic feet of gas; and
- F = the value of the gas in US$ per million British Thermal Units determined according to the table set out at clause 6 of the Damas GSA.

EGPC may pay the Contractor either in cash or in kind by giving notice in writing at least ninety (90) days prior to the commencement of each calendar quarter. Should EGPC fail to make payment in cash or in kind of any undisputed amount hereunder when said payment is due, then such unpaid amount shall incur interest charges equal to LIBOR plus 2.5 per cent from the date when such amount would have been due and payable.

The Damas GSA shall remain in force and effect until the production of gas is no longer economically sustainable or until the date of expiration of the Contractor's rights under the South East El Mansoura Concession Agreement, whichever first occurs.

The force majeure provision of the South East El Mansoura Concession Agreement shall apply to the Damas GSA. However, lack of gas market outlets or failure by the buyer's customers to take contracted quantities, though not constituting a force majeure under the South East El Mansoura Concession Agreement, shall be treated as a force majeure for EGPC as buyer under the Damas GSA, if such event(s) are (i) beyond the reasonable control of EGPC and (ii) materially adversely affect multiple customers of EGPC, and (iii) beyond the reasonable control of said multiple customers by reason of the force majeure.

The assignment provisions of the South East El Mansoura Concession Agreement shall apply to the Damas GSA.

The Damas GSA is governed by the laws of ARE. Any dispute or claim arising out of the Damas GSA shall be settled in accordance with the provisions of the South East El Mansoura Concession Agreement.

20.3.25 Al Rawdah Gas Sales Agreement

EGPC and Melrose South East El Mansoura (collectively the sellers) entered into a gas sales agreement on 14 August 2007 for the sale to EGPC of gas produced from the Al Rawdah development lease in accordance with the South East El Mansoura Concession Agreement (the "**Al Rawdah GSA**") in the quantities set out below.

Date	Daily production quantity (MMcfpd)
Starting from the Start-Up Date	7.00
Starting from January 1, 2008	7.00
Starting from January 1, 2009	7.00
Starting from January 1, 2010	3.00

The remaining provisions are the same as under the Damas GSA.

Mesaha Concession

20.3.26 Mesaha Concession Agreement

On 9 October 2007, ARE, GANOPE, Melrose Egypt Mesaha Limited ("**Melrose Mesaha**"), KEC (Egypt) Limited (formerly known as Oil Search (Egypt) Limited) ("**KEC**") and Hellenic Petroleum SA ("**Hellenic**") entered into a concession agreement for the exploration and exploitation of petroleum in the Mesaha area of the Western Desert in Egypt (the "**Mesaha Concession Agreement**").

The Mesaha Concession Agreement received the approval of the Egyptian government on 9 October 2007. Melrose Mesaha, KEC and Hellenic were nominated as the "**Contractor**" under the Mesaha Concession Agreement. An initial period of four years shall be set aside for exploration; this period can be extended twice for a further three year period successive and a further two year period. After four years and seven years, on each occasion 25 per cent of the original area for which a development lease has not been granted shall be relinquished. After nine years all of the area for which a development lease has not been granted shall be relinquished.

Whether a commercial discovery of oil or gas in the concession area has been made is to be mutually agreed between the Contractor and GANOPE. Upon making a commercial discovery of oil or gas, the area capable of production is to be mutually agreed between the parties. Upon such agreement, the area is converted into a development lease with: (i) in the case of a commercial discovery of oil, a 20 year term from the date of discovery (subject to extension by the period of five years at the election of the Contractor); or (ii) in the case of a commercial discovery of gas, a 20 year term from the date of first delivery of gas locally or for export (subject to extension by the period of five years at the election of the Contractor).

If gas is subsequently discovered in a development lease based on an initial oil discovery, or oil is subsequently discovered in a development lease based on a gas discovery, a new term would apply in relation to such subsequent discovery but subject to a 35 year longstop date from the date of the original discovery that gave rise to the development lease (unless otherwise agreed upon between GANOPE and the Contractor and subject to the approval of the Minister of Petroleum).

A royalty of 10 per cent of the total quantity of petroleum produced and saved from the area is paid by GANOPE (and not the Contractor) to ARE. The Mesaha Concession Agreement also provides that a minimum of US$14.3 million shall be spent by the Contractor on the exploration operations. If the exploration period is extended, a further US$10 million must be committed by the Contractor during that first extension period and a further US$10 million in the second extension period. Bonuses are payable to GANOPE by the Contractor on: (i) the effective date, (ii) on the approval of a development lease; and (iii) at such time as the average daily production exceeds certain prescribed levels.

ARE may requisition the production from the area, the oil and/or gas field itself and, if necessary, related facilities in case of national emergency due to war or imminent expectation of war or internal causes however ARE must indemnify EGPC and the Contractor for any subsequent loss.

The non-performance or delay in performance by EGPC and/or the Contractor of any obligation under the agreement shall be excused if and to the extent that such non-performance or delay is caused by force majeure. Force majeure shall be any act of god, insurrection, riot, war, strike and other labour disturbance, fires, floods or any cause not due to the fault or negligence of EGPC and/or the Contractor, provided that any such cause is beyond their reasonable control.

The Mesaha Concession Agreement is governed by the laws of ARE. The Mesaha Concession Agreement is governed by the laws of ARE. Any dispute or claim arising between ARE and the parties shall be referred to the jurisdiction of the appropriate ARE court and shall be finally settled by such court. Any dispute or claim between EGPC and the Contractor shall be settled by arbitration in accordance with the Arbitration Rules of the Cairo Regional Center for International Commercial Arbitration.

20.3.27 Mesaha JOA

A joint operating agreement was entered into on 9 October 2007 between Melrose Mesaha, Hellenic and KEC to define the parties' rights and obligations under the Mesaha Concession Agreement (the "**Mesaha JOA**"). The Mesaha JOA runs until the Mesaha Concession Agreement is terminated, all materials, equipment and personal property used in connection with the joint operations under the Mesaha Concession Agreement (the "**Joint Operations**") have been disposed of or removed and final settlement has been made.

The parties participating interests in the Mesaha Concession Agreement are split as follows:

- Melrose Mesaha 40 per cent
- Hellenic 30 per cent
- KEC 30 per cent

KEC's interest is subject to a farm-in agreement for 50 per cent of its participating interest, but such farm-in agreement is subject to execution and completion.

Melrose Mesaha is designated as "operator" under the Mesaha JOA which means that it shall exercise all rights and perform and discharge all of the functions and duties of the "Contractor" under the Mesaha Concession Agreement and shall have exclusive charge of, and shall conduct, all operations and activities to be carried out under the Mesaha JOA. An operating committee is constituted by one representative of each party and approval by two parties having at least 65 per cent of the participating interests is required to approve proposals for the Joint Operations.

The joint operations to be performed under the Mesaha JOA are detailed in a work programme and budget produced by the operator each year, which is then approved by the operating committee. The work plan includes the minimum work and expenditure obligations specified under the Mesaha Concession Agreement that must be performed in order to satisfy the conditions of the Mesaha Concession Agreement.

Exclusive operations, being operations and activities carried out pursuant to the Mesaha JOA, the costs of which are chargeable to the account of less than all of the parties, may also be carried out under the Mesaha JOA but must not conflict with the Joint Operations.

All costs of the Joint Operations are chargeable to all of the parties. The obligations of the parties under the Mesaha Concession Agreement and all liabilities and expenses incurred by Melrose Mesaha in connection with the Joint Operations are chargeable to the joint account maintained by Melrose Mesaha (as operator) and all credits to the joint account are shared by all parties in accordance with their participating interests. Each party shall pay when due its participating interest share of joint account expenses, including cash advances and interest.

Any party that fails to pay when due its share of the joint account expenses shall be in default. During the default period (being the period from which defaulting party receives the default notice until the default is remedied in full) the defaulting party has limited rights in relation to various provisions under the agreement.

The default notice to each non-defaulting party shall include a statement of the sum of money that the non-defaulting party has to pay as its portion of joint account expenses which the defaulting party has failed to pay (excluding any interest owed on such amount). The obligations for which the defaulting party is in default shall be satisfied by the non-defaulting parties in proportion to the ratio that each non-defaulting party's participating interest bears to the participating interest of all non-defaulting parties. During the default period, the defaulting party shall not have any right to its share in the quantity of hydrocarbons under the Mesaha JOA, which shall vest in and be the property of the non-defaulting parties. Melrose Mesaha, as operator, be authorised to sell such entitlement on an arm's length sale, and to pay the net proceeds of such sale to the non-defaulting parties in proportion to the amounts they are owed by the defaulting party.

A decision to plug and abandon any well which has been drilled as a Joint Operation requires the approval of the operating committee. Any well plugged and abandoned must be plugged and abandoned in accordance with the laws and regulations of ARE governing the activities under the Mesaha Concession Agreement and at the cost, risk and expense of the parties who participated in the cost of drilling such well.

Any sale, assignment, encumbrance or other disposition by a party of any participating interest or rights or obligations derived from the Mesaha Concession Agreement or the Mesaha JOA (including its participating interest) other than its entitlement to hydrocarbons and its rights to any credits, refunds or payments under the agreement ("**Transfer**") is subject to the pre-emption rights of the other parties.

Except in the case of a party transferring all of its participating interest, no Transfer shall be made by any party which results in the transferor or transferee holding a participating interest of less than 10 per cent or any interest other than a participating interest in the Mesaha Concession Agreement and the Mesaha JOA.

Melrose Mesaha, as operator, shall remain operator following a Transfer of a portion of its participating interest. In the event of a Transfer of all of its participating interest, except to an affiliate, the party serving as operator shall be deemed to have resigned as operator, effective on the date the Transfer becomes effective, in which event a successor operator shall be appointed. If the operator Transfers all of its participating interest to an affiliate, the affiliate will automatically become operator, provided that the transferring operator shall remain liable for its affiliate's performance of its obligations.

Any party to the Mesaha JOA subject to a change of control shall obtain approval from the Egyptian government as necessary. In addition, the party subject to a change of control must provide evidence to the other parties that following the change of control such party shall have the financial capability to satisfy its payment obligations under the Mesaha Concession Agreement.

The rights, duties, obligations and liabilities of the parties under the Mesaha JOA shall be individual, not joint or collective

The Mesaha JOA is governed by the laws of England. The dispute resolution mechanisms are first, negotiation between senior executives of the parties, secondly mediation pursuant to the ICC ADR Rules of the International Chamber of Commerce and failing that, arbitration in London pursuant to the International Chamber of Commerce Arbitration Rules.

Qantara Concession

20.3.28 Qantara Concession Agreement

A concession agreement was entered into on 22 June 1998 between the ARE, EGPC, and Odyssey Petroleum (Qantara) Limited and Melrose Petroleum (Qantara) Company ("**Melrose Qantara**", formerly known as Merlon Petroleum Qantara Company) (as "**Contractor**") for the exploration and exploitation of petroleum in the Qantara area (the "**Qantara Concession Agreement**").

The exploration period set out in the Qantara Concession Agreement has expired. Accordingly, exploration areas not converted into development lease(s) have been relinquished in accordance with the terms of the Qantara Concession Agreement.

The ARE is entitled to a royalty of 10 per cent of the petroleum produced and saved from the concession area during the development period. Such royalty is payable by EGPC (and not the Contractors) under the terms of the Qantara Concession Agreement. Bonuses are payable to EGPC by the Contractor on (i) the effective date and (ii) such time as the average daily production exceeds certain prescribed levels.

Whether a commercial discovery of oil or gas in the concession area has been made is to be mutually agreed between the Contractor and EGPC. Upon the making of a commercial discovery of oil or gas, the area capable of production is to be mutually agreed between the Contractor, EGPC and the ARE. Upon such agreement, the area is converted into a development lease with: (i) in the case of a commercial discovery of oil, a 20 year term from the date of discovery (subject to extension for a period of five years at the election of the Contractor); or (ii) in the case of a commercial discovery of gas, a 20 year term from the date of first delivery of gas locally or for export (subject to extension for a period of five years at the election of the Contractor).

If gas is subsequently discovered in a development lease based on an initial oil discovery, or oil is subsequently discovered in a development lease based on a gas discovery, a new term would apply in relation to such subsequent discovery but subject to a 35 year longstop from the date of the original discovery that gave rise to the development lease (unless otherwise agreed upon between EGPC and the Contractor, subject to approval of the Minister of Petroleum).

If commercial production of oil in regular shipments is not established in a development block within four years from the date of commercial discovery of the oil, the development block is deemed relinquished (unless there is a commercial gas discovery within the development lease). If commercial production of gas is not established in accordance with an agreement between EGPC and the Contractor for the supply of gas to EGPC, the relevant development lease is deemed relinquished.

On commercial discovery, the Contractor and EGPC agree to form an Egyptian private company (the charter of which is prescribed by the Qantara Concession Agreement) to be owned on a 50:50 basis. Under the terms of the charter, the operating company is to act as the agent of the Contractor and EGPC only, and is not to own any direct interest in the development activities or assets on its own behalf.

The Contractor is entitled to recover, on a quarterly basis, exploration, development and certain operating costs out of 35 per cent of petroleum produced and saved from the development leases and not used in petroleum operations ("**Cost Recovery Petroleum**"). If such costs are not recovered from the Cost Recovery Petroleum in a particular tax year, the excess cost can be carried forward until fully recovered (up to termination of the Qantara Concession Agreement). If the value of the Cost Recovery Petroleum exceeds the recoverable costs (including carried forward costs) in a particular quarter, the value of such excess is split between EGPC and the Contractor in the same proportions as the production share. EGPC can elect to receive its share of such excess in the form of crude oil (i.e. in kind rather than in cash).

The remaining 65 per cent of the petroleum shall be divided between EGPC and the Contractor in various proportions depending on amount of petroleum that is produced ("**Production Sharing Petroleum**"). EGPC is granted preferential rights to purchase oil and gas from the Contractor. EGPC can elect to pay for gas and LPG in crude oil (i.e. in kind), rather than in cash.

EGPC becomes the owner of all assets acquired by the Contractor which are subsequently charged to the cost recovery process under the Qantara Concession Agreement by the Contractor and, in the case of certain operational assets not charged to the cost recovery process, upon termination of the Qantara Concession Agreement.

The Contractor is solely liable to third parties for any damage caused by the Contractor's operations and the Contractor indemnify ARE and EGPC against all damages for which they may be held liable on account of the Contractors' operations.

In the case of national emergency due to war or imminent expectation of war or internal causes, the ARE reserves the right to requisition all or part of the production from the concession area, including any oil and/or gas fields and any related facilities.

The non-performance or delay in performance by EGPC and/or the Contractor of any obligation under the agreement shall be excused if and to the extent that such non-performance or delay is caused by force majeure. Force majeure shall be any order, regulation or direction of ARE, or the governments of Bermuda or Cayman Islands with respect to the Contractor whether in the form of a law or otherwise or any act of god, insurrection, riot, war, strike and other labour disturbance, fires, floods or any cause not due to the fault or negligence of EGPC and/or the Contractor, provided that any such cause is beyond their reasonable control.

Assignment of the rights or obligations arising under the Qantara Concession Agreement by the Contractor or EGPC requires the written consent of the ARE, save that the Contractor may assign the Qantara Concession Agreement to an affiliated company without consent.

ARE has the right to cancel the Qantara Concession Agreement with respect to a Contractor if the Contractor:

- knowingly has submitted any material false statements to the ARE;
- assigns any interest to the Qantara Concession Agreement to another party, without the ARE's consent;
- is adjudicated bankrupt;

- does not comply with a court decision obtained in accordance with the terms of the Qantara Concession Agreement;
- intentionally extracts any mineral other than petroleum; or
- commits a material breach of the Qantara Concession Agreement or certain Egyptian laws.

Disputes relating to the Qantara Concession Agreement between the ARE and the other parties are to be determined by the Egyptian courts. Any other disputes are to be determined by international arbitration. The Qantara Concession Agreement is governed by Egyptian law.

The Contractor is obliged to give priority to local contractors, sub-contractors, materials and equipment provided that their performance and quality is comparable with internationally available alternatives and provided that they are less than 10 per cent more costly than such alternatives.

20.3.29 Qantara Joint Operating Agreement

On 17 April 1998, Odyssey Petroleum (Qantara) Ltd. and Melrose Qantara entered into a joint operating agreement to establish and clarify their respective rights and obligations as Contractor members in relation to the Qantara Concession. Both companies are now wholly owned subsidiaries of Melrose. Under the terms of the joint operating agreement, the companies granted in favour of Stratton Corporation an overriding royalty interest equal to three per cent of the Contractor's share of petroleum saved and sold from the Qantara area as excess cost recovery petroleum and as production sharing petroleum and such overriding royalty interest continues to be paid by the companies.

20.3.30 Qantara development lease

Melrose Qantara and EGPC obtained approval on 12 September 1999 from the Minister of Petroleum to convert the gas discovery of the Qantara-1, 2 and 3 wells into the Qantara development lease via an operating company pursuant to the Qantara Concession Agreement. The total area of the Qantara lease is approximately 150 km².

20.3.31 Qantara Gas Sales Agreement

EGPC, Melrose Qantara, Odyssey Petroleum (Qantara) Ltd, and Global Oilfield and Mining Services (as "**Contractor**") (together the sellers) entered into a gas sales agreement on 19 October 1999 for sale to EGPC of the gas produced from the Qantara development area in accordance with the Qantara Concession Agreement (the "**Qantara GSA**") in the quantities set out below:

Date	Daily production quantity (MMcfpd)
Starting from May 2000	6.00
Starting from January 1, 2001	6.00
Starting from January 1, 2002	6.00
Starting from January 1, 2003	3.00
Starting from January 1, 2004	1.00

The sellers shall not be required to make available for delivery more than 110 per cent of the DCQ. However, if EGPC wishes to take and purchase gas in excess of that amount, it may notify the sellers of this requirement and the sellers shall (if they have such excess available) use all reasonable endeavours to meet such requirements.

The sellers are required to inform EGPC of the last determined recoverable reserves upon which the DCQ may be increased or decreased, with such changes being approved by EGPC within three (3) months from receipt of such notice (such approval not to be unreasonably withheld). Within 30 days of issuing such approval EGPC shall notify the sellers when the date of the new DCQ shall come into force. The minimum take is not less than 75 per cent of the ACQ.

If in any contract year EGPC has paid for, but not taken, any quantity of gas, EGPC shall accrue a make-up gas right to such quantity that shall be recorded in a separate account called the "Take-or-Pay Account". If EGPC has taken a quantity of gas in excess of 75 per cent of the ACQ then such excess shall be set against and reduce quantities of gas in the Take-or-Pay Account to the extent thereof and, to that extent, no payment shall be due for such gas. Upon termination of the Qantara GSA, the sellers shall have no obligation to deliver such make-up gas and EGPC shall have no right to any cash refund for any quantity of gas recorded in the Take-or-Pay Account.

Quantities of gas taken in excess of the ACQ in any contract year shall be carried forward and used to reduce the quantities of gas required to be taken up by EGPC to meet the minimum take during subsequent contract years. The maximum amount of carry forward gas which may be counted against the ACQ shall be 20 per cent of the ACQ for that said contract year.

All gas shall be valued at a price determined in accordance with the Qantara Concession Agreement.

EGPC may pay the Contractor either in cash or in kind by giving notice in writing at least 90 days prior to the commencement of each calendar quarter. Should EGPC fail to make payment in cash or in kind of any undisputed amount hereunder when said payment is due, then such unpaid amount shall incur interest charges equal to LIBOR plus 2.5 per cent from the date when such amount would have been due and payable.

The Qantara GSA shall remain in force and effect until the production of gas is no longer economically sustainable or until the date of expiration of the Contractor's rights under the Qantara Concession Agreement, whichever first occurs.

The force majeure provision of the Qantara Concession Agreement shall apply to the Qantara GSA. However, lack of gas market outlets or failure by the buyer's customers to take contracted quantities, though not constituting force majeure under the Qantara Concession Agreement, shall be treated as a force majeure for EGPC as buyer under the Qantara GSA, if such event(s) are: (i) beyond the reasonable control of EGPC (ii) materially adversely affect multiple customers of EGPC; and (iii) beyond the reasonable control of said multiple customers by reason of the force majeure.

The assignment provisions the Qantara Concession Agreement shall apply to the Qantara GSA. However, each party will have the right to freely assign partly or fully its rights and obligations under the Qantara GSA to any of its affiliated companies, subject to the prior written notification to the other parties. The assignor party shall remain jointly liable with the assignee for the full performance of its obligations under the Qantara GSA until the deed of assignment has been approved by EGPC and the Egyptian Government.

The Qantara GSA is governed by the laws of the ARE. Any dispute or claim arising out of the Qantara GSA shall be settled in accordance with the provisions of the Qantara Concession Agreement.

Bulgaria

Galata Field

20.3.32 Galata Field Concession Agreement

A concession agreement for the development and production of natural gas from the Galata Field, offshore Bulgaria was entered into between the Council of Ministers of the Republic of Bulgaria, represented by the Chairman of the State Agency on Energy and Energy Resources, Ivan Shiliashky (the "**Government of Bulgaria**"); Melrose Resources S.A.R.L. (formerly Melrose Bulgaria Petreco S.A.R.L.) ("**Melrose S.A.R.L.**"); and Melrose Bulgaria Eood (formerly Petreco Bulgaria Eood) ("**Melrose Bulgaria**") contracting jointly and severally, (together the "**Concessionaires**" dated 16 May 2001 (the "**Galata Field Concession Agreement**"). The concession area covers $19km^2$. The term of the agreement is 25 years from the date of the Galata Field Concession Agreement, which can be further extended by 10 years if there is commercial production.

The parties participation rights in the Galata Field Concession Agreement are split as follows:

- Melrose S.A.R.L. -$48^{1/3}$ per cent
- Melrose Bulgaria Eood -$51^{2/3}$ per cent

The Concessionaires are jointly liable under the Galata Field Concession Agreement.

The scope of the Galata Field Concession Agreement is to carry out the production (i.e. the extraction, injection, stimulation, treatment, transportation to the delivery point etc) of natural gas from the Galata Field within the concession area. The Galata Field Concession Agreement does not provide the Concessionaires ownership rights over natural gas in situ in the concession area. However, the Concessionaires have the right to receive in kind, dispose of and export the natural gas from the concession area in accordance with the promulgated Bulgarian laws. Title and risk of the natural gas passes to the Concessionaires at the well-head of any well producing commercial quantities of natural gas within the concession area.

The activities conducted by the Concessionaires shall be insured at all times where the insurance shall at least cover damage to installations (covering replacement value) including removal of wreck and clean-up after possible accidents, pollution damage and other liabilities towards third parties for not less than US$5 million for any occurrence and statutory workmen's compensation and insurance for the Concessionaires' own employees that are engaged in the activities.

The Concessionaires will indemnify the Government of Bulgaria in respect of any claims or losses of any person (including the Government of Bulgaria) which may arise out of the performance or failure to perform any obligation of the Concessionaires under the Galata Field Concession Agreement.

Upon termination, the Government of Bulgaria has a right to take over, free of charge, any permanent installations and their accessories. Should the Government of Bulgaria not wish to take over the installations and their accessories, it may require the owner of the installations at the time to wholly or partly remove the installations.

The Concessionaires have an obligation to pay royalties and bonuses. The royalty will be calculated using the "R-factor" which is calculated using the following formula:

R-factor = CumRev/CumCosts

Where:

CumRev	=	total cumulative revenue from the activity related to the Galata Field Concession Agreement for all reported periods minus concession fees (royalty) paid;
Cumcosts	=	total cumulative costs from the activity related to the Galata Field Concession Agreement (exploration, appraisal, development and operating costs and bonuses) for all reported periods.

R factor	Royalty
<1.50	2.50 per cent
1.50 – 1.75	5.00 per cent
1.75 – 2.00	7.50 per cent
2.00 – 2.50	10.00 per cent
2.50 – 3.00	12.50 per cent
>3.00	25.00 per cent

Bonuses are payable to the Government of Bulgaria on first commercial production and at such time as the daily production exceeds certain levels.

The Concessionaires shall, at their sole discretion, provide either an irrevocable annual bank guarantee or an annual monetary guarantee for the amount equal to 20 per cent of the concession fee paid for the entire preceding year to guarantee the fulfilment of their obligations to make the concession fee payment for the upcoming year.

Each Concessionaire has the right, subject to permission from the Government of Bulgaria, which shall not be unreasonably withheld, to transfer entirely or partially its rights and obligations under the Galata Field Concession Agreement at any time, provided the new participant can guarantee to pay its proportionate share of the costs and possesses the required technical and managerial skills to carry out the concession activities and undertakes to be bound by the terms and conditions of the Galata Field Concession Agreement. All costs pertaining to such transfer are to be borne by the transferring Concessionaire.

By mutual agreement between the Government of Bulgaria, Melrose S.A.R.L. and Melrose Bulgaria, the production from the Galata Field may be terminated before the gas field is depleted and before expiry of the term of the Galata Field Concession Agreement, with the objective to transform the gas field into a gas storage facility.

The Galata Field Concession Agreement will be terminated:

- upon expiry of the term;
- in case of termination of production for a period longer than six months or termination of production because of Galata field depletion, whichever occurs first;
- in case of an objective failure to perform the activities under the Galata Field Concession Agreement;
- in the event of insolvency of the Concessionaires;
- on the grounds of a mutual agreement between all the parties;
- on the grounds of a court or arbitration ruling; or
- in case of a threat to national security or the environment and territories protected by law.

The Government of Bulgaria suspends the Galata Field Concession Agreement if the Concessionaires perform illegal activities or perform activities in violation of the Galata Field Concession Agreement. The suspension will be notified to the Concessionaires in writing by the Government of Bulgaria. The suspended Galata Field Concession Agreement resumes if the Concessionaires rectify the reasons which caused the suspension within a given time period. The period of suspension does not extend the term of the Galata Concession Agreement. The Concessionaires are not entitled for compensation for loss of profits during the suspension.

The Government of Bulgaria has the right to terminate the Galata Field Concession Agreement if the Concessionaires fail to make any monetary payment required by law or under the Galata Field Concession Agreement, or if they fail to fulfil their obligations under the Galata Field Concession Agreement, or if they:

- conduct activities which are in contradiction with Bulgarian legislation;
- have otherwise committed a material breach of the terms and conditions of the Galata Field Concession Agreement and the concession;
- fail to comply with lawful acts, regulations, orders or instructions issued by the government;
- become bankrupt, or go into liquidation because of insolvency or make composition with their creditors; or
- fail to comply with a determination of a sole expert.

At termination of the Galata Field Concession Agreement, full ownership of geological and technical documentation, which during the contract's life are co-property of the Government of Bulgaria and Concessionaires, becomes the sole property of the Government of Bulgaria.

The Galata Field Concession Agreement is governed by Bulgarian laws and international conventions to which Bulgaria is a party and generally accepted principles of international law.

A dispute will be determined by an expert and will be binding on all parties. If the parties disagree as to whether a dispute concerns technical matters, such dispute will be submitted to a board of three arbitrators. Arbitration proceedings shall take place in Geneva, Switzerland, and shall be conducted in English and in accordance with ICC Rules of Arbitration and Swiss substantive law.

20.3.33 Net Profits Interest Agreement

A net profits interest agreement dated 29 March 2007 was entered into between Melrose S.A.R.L. and Melrose Bulgaria; and Orbis Holding Limited ("**Orbis**") relating to the Galata Field Concession Agreement dated 16 May 2001 ("**NPI Agreement**"). Melrose is now the sole ultimate owner of both Melrose S.A.R.L. and Melrose Bulgaria. Under the terms of the NPI Agreement, the companies granted in favour of Orbis a net profits interest equal to three per cent of all net revenue during the term of the Galata Field Concession Agreement and such net profits interest continues to be paid by the companies. If the parties cannot agree on the amount to be payable to Orbis, any party may refer the dispute to an expert for determination. The decision of the expert will be binding. The expert will act as an expert and not as an arbiter. Melrose S.A.R.L. and Melrose Bulgaria have agreed not to sell their shares in whole or in part, nor sell or dispose of all or any part of their participating interest unless neither is in breach of any of their obligations under the NPI Agreement and a transferee will have to agree in writing to be bound by the provisions of the NPI Agreement and is acceptable under the terms of the Galata Field Concession Agreement. Except as provided above under the transfer of interests, neither Melrose S.A.R.L. nor Melrose Bulgaria will be entitled to assign their obligations under the NPI Agreement without the prior written consent of Orbis, which cannot be unreasonably withheld or delayed.

The NPI Agreement is governed by the laws of Scotland and the parties agree to the non-exclusive jurisdictions of the Scottish courts.

20.3.34 Galata Block Permit

An agreement for prospecting and exploration for oil and natural gas in the Galata Block, under the permit awarded with decision number 848 by the Council of Ministers of Bulgaria dated 19 December 2007 was entered into between the Minister of the Environment and Water, Dzhevdet Chakarov (the "**Minister**"); and Melrose Resources (the "**Permit Holder**") dated 4 February 2008 (the "**Galata Block Permit**").

The Galata Block is situated in on the continental shelf and economic zone of the Republic of Bulgaria in the Black Sea and was originally), over an area of 1,910 km² (but has subsequently been decreased by way of supplemental agreements in relation to an area forming a commercial discovery (being the Kavarna and Kaliakra gas fields) and in accordance with the latest supplemental agreement dated 4 February 2011, the size of the Galata Block is now 1,786.86km².

The term of the Galata Block Permit is three years from 4 February 2008, with two possible extensions, up to two years each, subject to completion of a minimum work programme (the "**MWP**"). Further extension of up to a year is possible subject to making a discovery that needs to be appraised. The MWP consists of eight wells with a commitment of US$73.5 million (initial phase) which is to be implemented upon discovery of a successful well. Such actualisation was made by virtue of Galata Block Permit Supplements No. 3/15.06.2010 approved by Decision No 414 of the Council of Ministers dated 10 June 2011 and the Galata Block Permit was extended by a following two years effective 4 February 2011. Commercial discovery registered within the term of Galata Block Permit allows for the direct awarding of a production concession to the Permit Holder.

At termination of Galata Block Permit the Minister has a right to full ownership of geological and technical documentation, which during the Galata Block Permit's life are shared property of the Minister and Permit Holder. The Minister may also impose penalties if the Permit Holder fails to perform its obligations under the Galata Block Permit, and a penalty of US$1 million is due if the Permit Holder fails to fully or partially fulfil its obligations under the Galata Block Permit. In addition, in case of late payment of the first year fee, the Permit Holder will incur a penalty to the value of 5 per cent of the due amount to the Minister and will incur a penalty of US$5,000 if it fails to submit an annual report. A late final penalty also exists at a value of the lowest estimate of the report preparation fee.

The Permit Holder is required to pay an annual fee for the Galata Block of Bulgarian Lev 30 per km² supported by a parent company guarantee which has increased to Bulgarian Leva 45 per km² under the terms of the supplemental agreement dated 4 February 2011. The performance of the Permit Holder is supported by a parent company guarantee which will extend for 6 months after the extension of the term of the permit.

The Minister may suspend the Galata Block Permit when the Permit Holder performs illegal activities or performs activities in violation of the Galata Block Permit.

The Permit Holder may partially or entirely transfer its rights and obligations to a third party with the approval of the Council of Ministers. Ministerial approval will be provided within one month after the Permit Holder makes a written application, with evidence of the assignee having technical, managerial and financial capability and the assignee accepting the rights and obligations of the Permit Holder, including the parent company guarantee.

Termination of the Galata Block Permit will take place in the following circumstances:

- on expiry of the term of the Galata Block Permit or its extension;
- if it is no longer possible to perform activities under the Galata Block Permit;
- upon dissolution or bankruptcy of the Permit Holder;

- by court decision or arbitration award;
- by mutual consent (with three months' notice);
- by the Permit Holder, subject to a payment of 100 per cent of any unfulfilled MWP for the initial period;
- by the Minister:
  - if the annual fee or parent company guarantee is late by more than thirty (30) days;
  - if the reasons for any suspension have not been rectified by the Permit Holder; or
  - for reasons of national security or defence.

In the case of a dispute, the parties shall reach a settlement through negotiations and all disputes shall be settled according to the Civil Procedure Code. If a technical dispute arises, an independent expert will be appointed by both parties. In the event that no agreement is reached within thirty days, then each party can address the dispute to the Centre of Technical Expertise at the International Chamber of Commerce in Paris.

20.3.35 Kaliakra Concession Agreement

A concession agreement was entered into for the production of natural gas from the Kaliakra Field, located in the continental shelf and the exclusive economic zone of the Republic of Bulgaria in the Black Sea between the Council of Ministers of the Republic of Bulgaria, represented by the Minister of Economy, Energy and Tourism, Traycho Traykov (the "**Government of Bulgaria**"); and Melrose S.A.R.L. (the "**Concessionaire**") dated 1 November 2010 (the "**Kaliakra Concession Agreement**").

The concession area covers 18.9895 km^2 and the Kaliakra Concession Agreement is for a term of seven years from signing. The annual quantity of the gas produced for the period covering year 2011 to year 2015 shall not be less than 255 million m^3.

Under the terms of the Kaliakra Concession Agreement, the Concessionaire has the right of ownership of natural gas produced in the term of the concession and ownership of the natural gas produced will pass to the Concessionaire at the wellhead of any producing well within the concession area. The Concessionaire is obliged to provide an unconditional and irrevocable annual bank guarantee to guarantee the payment of the concession fee payment, interest payment and penalties for each respective year, at the amount of 20 per cent of the concession payment due for the preceding year but not less than US$450,000.

The rights and obligations under the Kaliakra Concession Agreement cannot be transferred to any third party except with the written consent of the Government of Bulgaria. Failure to comply is a ground for the Government of Bulgaria to unilaterally terminate the Kaliakra Concession Agreement. All costs and expenses are to be borne by the Concessionaire.

The right of ownership of the natural gas produced and the ownership of the produced natural gas quantities shall transfer to the Concessionaire at the well head of any producing well within the concession area. Upon termination, the Government of Bulgaria has a right to take over, free of charge, any permanent installations with accessories. The Concessionaire must not encumber entirely or partially the Kaliakra Field and the installations pertaining to the latter.

The Concessionaire is obliged to make a concession payment to the Government of Bulgaria regardless of the end financial result of the Concessionaire's activity. The pecuniary concession payment will be calculated on a percentage of the total revenue of the Concessionaire from the sale of the natural gas from the Kaliakra Field.

The concession fee will be calculated using the "R-factor" scale, being the ratio of total cumulative revenues (reduced by the concession fees paid) to the total costs of the activities under the concession as follows:

R factor	Royalty
<1.50	2.50 per cent
1.50 – 1.75	5.00 per cent
1.75 – 2.00	7.50 per cent to 10 per cent
2.00 – 2.50	10.00 per cent to 12.5 per cent
2.50 – 3.00	12.50 per cent to 22.5 per cent
>3.0	25.00 per cent to 30 per cent

The Concessionaire is required to make the concession payments in two instalments each year, by 31 July and 31 January.

The following penalties may have to be paid by the Concessionaire:

- if a concession payment is not made, as well as paying the payment itself, the Concessionaire is required to pay interest at the legally defined amount of interest in Bulgarian Lev;
- in the case of non-fulfilment of any non-pecuniary obligations, the Concessionaire will, as well as performance of the obligation, pay a penalty at the market value of 5,000 cubic meters of gas per day, but not more than US$20,000;
- if 255 MMcm of natural gas are not produced annually for the period 2011-2015, the Concessionaire will also have to pay a penalty equal to the amount of gas not produced. This is calculated at the price at which the Concessionaire sells the produced natural gas from the Kaliakra Field to the public supplier;
- if the Concessionaire does not make an investment for the first five year period of the term of the Kaliakra Concession Agreement, it will pay a penalty of 10 per cent of the amount of investment that has not been made for the first five year period;
- in the case of an overdue payment under the bank guarantee, the Concessionaire will pay a penalty at the legally defined amount of interest in Bulgarian Lev for each day overdue, but not more than 10 per cent of the amount of the guarantee;
- if the amount of the annual contribution guaranteeing the activities at abandonment is not paid into an escrow account, for each day of delay, the Concessionaire will pay a penalty at the legally defined amount of interest on the overdue payment;
- if the Concessionaire does not secure remaining quantities of gas needed for the preservation of the reservoir into a national gas storage facility, it will have to pay a penalty at double the amount of the price at which it would have sold the remaining quantities to a public supplier;
- should the Concessionaire insure the onshore/offshore operations and equipment for not less than US$5 million, it will pay a penalty of US$200,000; or
- should any obligation be non-fulfilled, the Government of Bulgaria may send the Concessionaire a written request for voluntary fulfilment. If that has not been performed within the requisite time period, the Government of Bulgaria has the right to suspend the Kaliakra Concession Agreement.

If the Concessionaire breaches the terms of the Kaliakra Concession Agreement or fails to observe the effective legislation, the Government of Bulgaria is entitled to suspend the Kaliakra Concession Agreement and if the reasons which caused the suspension are not rectified within a given time period, the Government of Bulgaria may terminate the Kaliakra Concession Agreement. The Concessionaire may be liable for damages to the Government of Bulgaria and benefits forfeited as result of the termination.

The Government of Bulgaria may unilaterally terminate the Kaliakra Concession Agreement if the Concessionaire fails to perform its obligations or breaches the conditions of the concession. The concession may be terminated by the Government of Bulgaria should there be a threat to national security, the environment, the population or cultural monuments. Should this occur, the Concessionaire is entitled to compensation for loses immediately and directly resulting from the termination. No compensation will be paid if the termination is caused by acts of the Concessionaire. The Kaliakra Concession Agreement may also be terminated by the Government of Bulgaria, if the Concessionaire fails to comply with requirements for environmental protection and rational use of subsoil resources and protection of subsurface.

The Kaliakra Concession Agreement will terminate:

- upon expiry of its term;
- due to it being impossible to perform the activities under the Kaliakra Concession Agreement;
- upon the Concessionaire becoming insolvent;
- upon mutual agreement between both parties;

- upon a court or arbitration ruling;
- upon dissolution of the Concessionaire;
- in the case of not fulfilling the following within one month:
- to produce 255 MMcm of natural gas annually for the period 2011-2015; or
- to place the natural gas at the disposal of the Bulgarian authorities in case of war or extraordinary circumstances;
- in case of termination of production for a period longer than six months due to a fault of the Concessionaire; or
- in case a threat occurs to national security or the environment, the public health, the legally protected areas or cultural monuments.

At termination of the Kaliakra Concession Agreement, full ownership of geological and technical documentation, which during the contract's life are shared property of the Government of Bulgaria and Concessionaire, reverts to the Government of Bulgaria.

The Kaliakra Concession Agreement is governed by Bulgarian law. All disputes will be settled by mutual agreement. Any disputes arising from the Kaliakra Concession Agreement will be forwarded for resolution to the Arbitration Court at the Bulgarian Chamber of Commerce and Industry under Bulgarian substantive law. Technical disputes will be resolved by an independent expert.

20.3.36 Kavarna Concession Agreement

A concession agreement was entered into for the production of natural gas from Kavarna Field, located in the continental shelf and the exclusive economic zone of the Republic of Bulgaria in the Black Sea between the Council of Ministers of the Republic of Bulgaria, represented by the Minister of Economy, Energy and Tourism, Traycho Traykov (the "**Government of Bulgaria**"); and Melrose S.A.R.L. (the "**Concessionaire**") dated 1 November 2010 (the "**Kavarna Concession Agreement**").

The concession area covers 4.36 km^2 and the Kavarna Concession Agreement is for a term of ten years from signing. The annual quantity of the gas produced for the period covering year 2011 to 2013 shall not be less than 145 million m^3 provided resources are available and their extraction is technologically possible.

Under the terms of the Kavarna Concession Agreement, the Concessionaire has the right of ownership of natural gas produced in the term of the concession and ownership of natural gas produced will pass to the Concessionaire at the wellhead of any producing well within the concession area.

The Concessionaire is obliged provide an unconditional and irrevocable annual bank guarantee to guarantee the payment of the concession fee payment, interest payment and penalties for each respective year at the amount of 20 per cent of the concession payment due for the preceding year but not less than US$200,000.

The rights and obligations under the Kavarna Concession Agreement cannot be transferred to any third party except with the written consent of the Government of Bulgaria. Failure to comply is a ground for the Government of Bulgaria to unilaterally terminate the Kavarna Concession Agreement. All costs and expenses are to be borne by the Concessionaire.

Title to and risk in the natural gas produced within the term of the Kavarna Concession Agreement will pass to the Concessionaire at the wellhead of any producing well within the concession area. Title of the assets resides with the Concessionaire. Upon termination, the Government of Bulgaria has a right to take over, free of charge, any permanent installations with accessories. The Concessionaire must not encumber entirely or partially the Kavarna Field and the installations pertaining to the latter.

The Concessionaire is obliged to make a concession payment to the Government of Bulgaria regardless of the end financial result of the Concessionaire's activity. The pecuniary concession payment will be calculated as a percentage of the total revenue of the Concessionaire from the sale of the natural gas from the Kavarna Field.

The concession fee will be calculated using the "R-factor" scale being the ratio of total cumulative revenues (reduced by the concession fees paid), to the total costs of the activities under the concession as follows:

R-factor = CumRev/CumCosts

R factor	Royalty
<1.50	2.50 per cent
1.50 - 1.75	5.00 per cent
1.75 – 2.00	7.50 per cent to 10.00 per cent
2.00 – 2.50	10.00 per cent to 12.50 per cent
2.50 – 3.00	12.50 per cent to 22.50 per cent
>3.0	25 per cent to 30 per cent

The Concessionaire is required make to concession payments in two instalments each year, by 31 July and 31 January.

The following penalties may have to be paid by the Concessionaire:

- if a concession payment is not made, as well as paying the payment itself, the Concessionaire is required to pay interest at the legally defined amount of interest in Bulgarian Lev;
- in the case of non-fulfilment of any non-pecuniary obligations, the Concessionaire will, as well as performance of the obligation, pay a penalty at the market value of 3 Mcmpd, but not more than US$20,000;
- if 145 MMcm of natural gas are not produced annually for the period 2011-2013, the Concessionaire will also have to pay a penalty equal to the amount of gas not produced. This is calculated at the price at which the Concessionaire sells the produced natural gas from the Kavarna Field to the public supplier;
- if the Concessionaire does not make an investment for the first five year period of the term of the Kavarna Concession Agreement, it will pay a penalty of 10 per cent of the amount of the investment that has not been made for the first five year period;
- in the case of an overdue payment under the bank guarantee, the Concessionaire will pay a penalty at the legally defined amount of interest in Bulgarian Lev for each day overdue, but not more than 10 per cent of the amount of the guarantee;
- if the amount of the annual contribution guaranteeing the activities at abandonment is not paid into an escrow account, for each day of delay the Concessionaire will pay a penalty at the legally defined amount of interest on the overdue payment;
- if the Concessionaire does not secure remaining quantities of gas needed for the preservation of the reservoir into a national gas storage facility, it will have to pay a penalty at double the amount of the price at which it would have sold the remaining quantities to a public supplier;
- should the Concessionaire insure the onshore/offshore operations and equipment for not less than US$5 million, it will pay a penalty of US$200,000; or
- should any obligation be non-fulfilled, the Government of Bulgaria may send the Concessionaire a written request for voluntary fulfilment. If that has not been performed within the requisite time period, the Government of Bulgaria has the right to suspend the Kavarna Concession Agreement.

If the Concessionaire breaches the terms of the Kavarna Concession Agreement or fails to observe the effective legislation, the Government of Bulgaria is entitled to suspend the Kavarna Concession Agreement and if the reasons which caused the suspension are not rectified within a given time period, the Government of Bulgaria may terminate the Kavarna Concession Agreement. The Concessionaire may be liable for damages to the Government of Bulgaria and benefits forfeited as result of the termination.

The Government of Bulgaria may unilaterally terminate the Kavarna Concession Agreement if the Concessionaire fails to perform its obligations or breaches the conditions of the Kavarna Concession Agreement. The Kavarna Concession Agreement may be terminated by the Government of Bulgaria should there be a threat to national security, the environment, the population or cultural monuments.

Should this occur, the Concessionaire is entitled to compensation for loses immediately and directly resulting from the termination. No compensation will be paid if the termination occurs due to acts of the Concessionaire. The Kavarna Concession Agreement may also be terminated by the Government of Bulgaria if the Concessionaire fails to comply with requirements for environmental protection and rational use of subsoil resources and protection of subsurface.

The Concession Agreement will terminate:

- upon expiry of its term;
- due to it being impossible to perform the activities under the Kavarna Concession Agreement;
- upon the Concessionaire becoming insolvent;
- upon mutual agreement between both parties;
- upon a court or arbitration ruling;
- upon dissolution of the Concessionaire;
- in the case of not fulfilling the following within one month:
  - to produce 145 MMcm of natural gas annually for the period 2011-2013;
  - to place the natural gas at the disposal of the Bulgarian authorities in case of war or extraordinary circumstances;
  - in case of termination of production for a period longer than six months due to a fault of the Concessionaire; or
  - in case a threat occurs to the national security of Bulgaria or the environment, the public health, the legally protected areas or cultural monuments.

At termination of the Kaliakra Concession Agreement, full ownership of geological and technical documentation, which during the contract's life are shared property of the Government of Bulgaria and Concessionaire, reverts to the Government of Bulgaria.

The Kavarna Concession Agreement is governed by Bulgarian law. All disputes shall be settled by mutual agreement. Any disputes arising from the Kavarna Concession Agreement will be forwarded for resolution to the Arbitration Court at the Bulgarian Chamber of Commerce and Industry under Bulgarian substantive law. Technical disputes shall be resolved by an independent expert.

20.3.37 Bulgargaz GSA

On 26 October 2010, Melrose S.A.R.L. and Bulgargaz EAD ("**Bulgargaz**") entered into a gas sales agreement under which Melrose S.A.R.L. agreed to supply natural gas to Bulgargaz (the "**Bulgargaz GSA**").

The Bulgargaz GSA is effective for an initial term of three years and may be extended for a further period by mutual agreement.

Monthly and daily volumes of natural gas to be delivered under the Bulgargaz GSA are to be agreed between the parties no later than 1 October of the year preceding supply. The annual contract volume is stated as 400 million m^3, which is equivalent to 100 million m^3 a quarter. By an amendment agreement dated 23 December 2011, the parties have agreed that the annual contract volume for 2012 shall be 285 million m^3 and the volume for 2013 shall be agreed no later than 15 September 2012. The monthly volumes to be delivered in the year 2012 are detailed in the same contract of amendment.

The contract price of the natural gas shall be expressed as a prescribed dollar value per 1Mcm depending on the time period during which the gas is supplied.

Each party agrees to hold the other party harmless from and against all losses, claims, demands, damages, interest and costs resulting from unlawful acts arising out of: (i) personal injury or death or loss of property of directors, officers, employees, agents or contractors unless caused by negligence, default or breach of statutory duty; (ii) damage to or loss of property of the parties unless caused by negligence, default or breach of statutory duty; or (iii) personal injury or death of, or damage to or loss of property of third parties to the extent caused by the performance, mis-performance or non-performance of the agreement.

The liabilities of one party to the other under the Bulgargaz GSA are limited and shall not exceed 50 per cent of the sum payable for the value of the natural gas.

Either party is entitled to assign its rights and obligations arising under Bulgargaz GSA in whole or in part with the consent in writing of the other party provided that such consent shall not be withheld if the proposed assignee has adequate financial and technical status and ability to perform under the contract. The assignment becomes effective upon provision to the other party of a certified copy of the assignment agreement (excluding the commercial terms thereof) and upon the assignor procuring that the proposed assignee to covenant directly with the non-assigning party to observe and perform all the terms and conditions of Bulgargaz GSA.

The Bulgargaz GSA will terminate in the event, inter alia, of expiry of its term delayed payments, mutual consent, insolvency or force majeure.

The Bulgargaz GSA is governed by the laws of Bulgaria and the dispute resolution mechanism is arbitration in Paris pursuant to the International Chamber of Commerce Rules of Arbitration.

20.3.38 *Agropolychim GSA*

On 1 January 2012, Melrose S.A.R.L. and Agropolychim AD ("**AAD**") entered into a gas sales agreement under which Melrose S.A.R.L. agrees to supply natural gas to AAD (the "**Agropolychim GSA**") valid until 31 December 2014. The annual volume of natural gas contracted to be delivered during 2012 is 75 MMcm and for the years 2013 and 2014 shall be 60 MMcm.

The price of natural gas is set as follows:

- end sale price of the public supplier to consumers connected to the gas transportation network, approved by the State Commission for Energy and Water Regulation ("**SCEWR**"), for the current quarter decreased by fifteen per cent; and
- further decreased by the price approved by the SCEWR for transportation of natural gas through the network owned by the transportation operator for the current quarter.

Each party agrees to hold the other party harmless from and against all losses, claims, demands, damages, interest and costs resulting from unlawful acts arising out of: (i) personal injury or death or loss of property of directors, officers, employees, agents or contractors unless caused by negligence, default or breach of statutory duty; (ii) damage to or loss of property of the parties unless caused by negligence, default or breach of statutory duty; or (iii) personal injury or death of, or damage to or loss of property of third parties to the extent caused by the performance, mis-performance or non-performance of the agreement.

Either party is entitled to assign its rights and obligations arising under Agropolychim GSA in whole or in part with the consent in writing of the other party provided that such consent shall not be withheld if the proposed assignee has adequate financial and technical status and ability to perform under the contract. The assignment becomes effective upon provision to the other party of a certified copy of the assignment agreement (excluding the commercial terms thereof) and upon the assignor procuring that the proposed assignee covenants directly with the non-assigning party to observe and perform all the terms and conditions of Agropolychim GSA.

The Agropolychim GSA will terminate in the event of, inter alia, delayed payment, mutual consent, insolvency or force majeure.

The gas sales agreement is governed by the laws of Bulgaria. Any dispute or claim arising from or in connection with the Agropolychim GSA which cannot be settled by the parties amicably within fifteen days may be referred to a competent court. Bulgarian legislation shall apply to any dispute and the court language shall be Bulgarian.

Romania

20.3.39 *Block EX-27 (Muridava) or and EX-28 (Est Cobalcescu) Concession Agreement*

On 8 March 2011, Melrose Resources Romania B.V. ("**Melrose Romania**") together with S.C. Petromar Resources S.A. ("**SCP**") entered into two petroleum concession agreements with the National Agency for Mineral Resources of Romania ("**NAMR**") for the exploration, development and production in Block EX-27 Muridava and Block EX-28 Est Cobalcescu, Romania (each a "**PCA**" and together the "**PCAs**").

The effective date of the PCAs is 24 October 2011, being the date of publication in the Romanian Official Gazette no. 743 of Government Decision no.1020 (ratifying the Block EX-27 Muridava PCA) and Government Decision no.1021 (ratifying the Block EX-28 Est Cobalcescu PCA), both Government Decisions dated 12 October 2011.

The term of each PCA is 30 years, which can be extended by up to 15 years. However, the period for exploration under the PCAs is limited to 6 years from the effective date of the PCAs as referenced above and can be extended for an additional period of up to 4 years provided that the title holder fulfilled its obligations for the previous exploration period and shall undertake to perform an additional work program during such extension that has been approved by NAMR.

Once the exploration period has expired, Melrose Romania and SCP must relinquish to NAMR, free of any encumbrances and obligations, any portions of the respective Block where no commercial fields have been discovered.

Relinquishment of the PCAs may take place at any time during their performance period by the voluntary relinquishment of Melrose Romania's and SCP's (as title holders) rights and obligations arising out of the PCAs, subject to the title holder meeting a number of conditions including, inter alia, paying to NAMR any outstanding amounts in respect of minimum work obligations and any non-perform abandonment works and making certain documentation available to NAMR.

NAMR can terminate the PCAs in the specific instances set out in Article 42 paragraph 1 of the Petroleum Law no. 238 dated 7 June 2004 including, inter alia, if the title holder fails to fulfil its obligations with respect to the commencement date of the petroleum operations, fails to comply with provisions of the technical and economical production studies, carries on petroleum operations without the authorisations required by the law, or its environmental approval/authorisation and/or the labour protection authorisations are withdrawn.

The title holder can request that a PCA is terminated in the case of a force majeure event.

NAMR may suspend a PCA for a period of up to one year if the title holder: (i) fails to abide by a court decision concerning disputes relating to the conduct of the petroleum operations under the PCA; (ii) is subject to a judicial restructuring and/or bankruptcy procedures; (iii) endangers (as a result of the manner in which it conducts the petroleum operations) the possibility of future exploitation of the fields; (iv) is in breach of the regulations concerning the protection and safe production of the fields; or (v) seriously infringes the labour, health, safety and security regulations or causes damage to the environment, with major risks to the population, health and environment.

Each PCA contains a schedule detailing a minimum work programme beginning with 2D and 3D seismic acquisitions and technology transfer and professional training in year one, followed by drilling of one new well and technology transfer and professional training in year two and, in year three drilling of two further wells to depths of 2,000 and 3,000 metres respectively and technology transfer and professional training. Both PCAs also contain details of the minimum work program obligations relating to the optional phase of exploration, containing details of 3 possible optional work programmes of 3 years duration each. The schedules also set out the estimated amounts of expenditure in connection with each obligation.

Royalties for both crude oil and natural gas are payable quarterly to the Romanian State budget as a percentage based on gross production volumes. Melrose Romania and SCP also agreed to spend a certain annual expenditure on intensive training and professional technology development programmes.

The PCAs are governed by the laws of Romania and the dispute resolution mechanism is arbitration in Paris, France pursuant to the Arbitration Rules of the International Chamber of Commerce in Paris. The number of arbitrators shall be three, appointed according to the Arbitration Rules and the language of the arbitration shall be English.

20.3.40 Block EX-27 Muridava Farm-In

On 20 March 2012, the Romanian government approved the farm-in of Midia Resources S.R.L. ("**Midia**") under the Block EX-27 PCA. Following the assignment by Melrose Romania and SCP as title holder, and the approval by the Romanian government, the new participating interests are as follows:

- Melrose Romania 40 per cent
- SCP 20 per cent
- Midia 40 per cent

Midia has entered into the Block EX-27 (Muridava) at the initial stages on so called "ground floor" terms and has not paid any consideration for its interest.

20.3.41 Block EX-28 Est Cobalescu JOA

On 5 March 2012, Melrose Romania and SCP entered into a joint operating agreement pursuant to which each party's respective rights and obligations under the Block EX-28 PCA are defined (the "**Block EX-28 JOA**").

The Block EX-28 JOA has effect until the Block EX-28 PCA is terminated, all materials, equipment and personal property used in connection with the joint operations under the Block EX-28 PCA (the "**Joint Operations**") have been disposed of or removed and final settlement has been made.

The parties' participating interests in the Block EX-28 PCA are as follows:

- Melrose Romania 70 per cent
- SCP 30 per cent

Melrose Romania is designated as "operator" under the Block EX-28 JOA which means that it shall exercise all rights and perform and discharge all of the functions and duties of the "contractor" under the Block EX-28 PCA and shall have exclusive charge of and shall conduct all operations and activities to be carried out under the Block EX-28 JOA.

The Joint Operations to be performed under the Block EX-28 JOA are detailed in a work programme and budget produced by the operator each year, which is then approved by the operating committee. The work plan includes minimum work and expenditure obligations specified under the Block EX-28 PCA that must be performed in order to satisfy the conditions of the Block EX-28 PCA.

Exclusive operations, being operations and activities carried out pursuant to the Block EX-28 JOA, the costs of which are chargeable to the account of less than all of the parties, may also be carried out under the Block EX-28 JOA but must not conflict with the Joint Operations.

All costs of the Joint Operations are chargeable to all of the parties. The obligations of the parties under the Block EX-28 PCA and all liabilities and expenses incurred by Melrose Romania in connection with the Joint Operations are chargeable to the joint account maintained by Melrose Romania (as operator) and all credits to the joint account are shared by all parties in accordance with their participating interests. Each party shall pay when due its participating interest share of joint account expenses, including cash advances and interest.

Any party that fails to pay when due its share of the joint account expenses shall be in default. During the default period (being the period from which the defaulting party receives the default notice until the default is remedied in full) the defaulting party has limited rights in relation to various provisions under the Block EX-28 JOA.

The default notice to each non-defaulting party shall include a statement of the sum of money that the non-defaulting party has to pay as its portion of joint account expenses which the defaulting party has failed to pay (excluding any interest owed on such amount). The obligations for which the defaulting party is in default shall be satisfied by the non-defaulting parties in proportion to the ratio that each non-defaulting party's participating interest bears to the participating interest of all non-defaulting parties.

A decision to plug and abandon any well which has been drilled as a Joint Operation requires the approval of the operating committee. Any well plugged and abandoned must be plugged and abandoned in accordance with the laws and regulations of Romania governing the activities under the Block EX-28 PCA and at the cost, risk and expense of the parties who participated in the cost of drilling such well.

Any sale, assignment, encumbrance or other disposition by a party of any rights or obligations derived from the Block EX-28 PCA or the Block EX-28 JOA (including its participating interest) other than its entitlement to hydrocarbons and its rights to any credits, refunds or payments under the Block EX-28 JOA ("**Transfer**") is subject to the requirements of the Block EX-28 PCA. A Transfer does not include a direct or indirect change in control of a party.

Except in the case of a party transferring all of its participating interest, no Transfer shall be made by any party which results in the transferor or transferee holding a participating interest of less than 10 per cent or any interest other than a participating interest in the Block EX-28 PCA and the Block EX-28 JOA.

Melrose Romania, as operator, shall remain operator following a Transfer of a portion of its participating interest. In the event of a Transfer of all of its participating interest, except to an affiliate, the party serving as operator shall be deemed to have resigned as operator, effective on the date the Transfer becomes effective, in which event a successor operator shall be appointed. If the operator Transfers all of its participating interest to an affiliate, the affiliate will automatically become operator, provided that the transferring operator shall remain liable for its affiliate's performance of obligations.

Any party to the Block EX-28 JOA subject to a change of control or change in control of its listed parent shall obtain approval from the Romanian government as necessary. In addition, the party subject to a change of control must provide evidence to the other parties that following the change of control such party shall have the financial capability to satisfy its payment obligations under the Block EX-28 PCA.

Any party may at its option withdraw from the Block EX-28 JOA and the Block EX-28 PCA by notice to the other parties, such withdrawal to be effective at the end of the calendar month following the calendar month in which the notice of withdrawal is given. Within 30 days of receipt of a withdrawal notice, each of the other parties may also give notice that it desires to withdraw from the Block EX-28 JOA and the Block EX-28 PCA. If all parties give notice of withdrawal, the parties shall proceed to abandon the exploration licence areas and terminate the Block EX-28 PCA and the Block EX-28 JOA. In these circumstances, the parties will be bound by the terms and conditions of the Block EX-28 JOA for so long as may be necessary to wind up the affairs of the parties with the government of Romania, to satisfy any requirements of the laws and regulations of Romania and to facilitate the sale, disposition or abandonment of property or interests held by the joint account of the parties. If fewer than all of the parties give notice of withdrawal, then the withdrawing parties shall take all steps to withdraw from the Block EX-28 PCA and the Block EX-28 JOA on the earliest possible date and execute and deliver all necessary instruments and documents to assign their participating interest (at their cost) to the parties which are not withdrawing, without compensation whatsoever. A withdrawing party remains liable for its share in a number of items set out in the agreement.

The rights, duties, obligations and liabilities of the parties under the agreement shall be individual, not joint or collective.

The Block EX-28 JOA is governed by the laws of England. The dispute resolution mechanism is arbitration in London pursuant to the Arbitration Rules of the London Court of International Arbitration.

Turkey

20.3.42 *South Mardin Exploration Licences*

On 3 September 2007, the General Directorate of Petroleum Affairs, Republic of Turkey, granted Melrose Resources Turkey Limited ("**Melrose Turkey**") and Güney Yildizi Petrol Üretim Sondaj Müteahhitlik ve Ticaret A.Ş. ("**GYP**") joint petroleum exploration licences AR/MEL-GYP/4206, 4207, 4208, 4214, 4215, 4216, 4217 and 4218 in Diyarbakir Petroleum District No XI in the South Mardin Basin, Turkey (the "**South Mardin Exploration Licences**"), with participating interests of 75 per cent and 25 per cent respectively.

The term of each of the South Mardin Exploration Licences is four years, provided that Melrose Turkey and GYP adhere to the exploration programme that they submitted for the specific exploration areas under each of the South Mardin Exploration Licences with the participating interests mentioned above, in accordance with Turkish Petroleum Law. After the initial four years the terms of the South Mardin Exploration Licences numbered AR/MEL-GYP-SEC/4207, 4208, 4215, 4216 and 4218 were extended for a further two years, 4216 was extended until 25 September 2013, the others were extended to 15 September 2013. At the time of the extension process, the parties relinquished the licences numbered 4206, 4214 and 4217 so that out of eight original licences, five remain as listed.

20.3.43 *Heads of Agreement*

On 1 June 2008, Melrose Turkey, Southwind Energy LLC ("**Southwind**"), Aladdin Middle East Ltd ("**Aladdin**") and GYP entered into a heads of agreement in respect of their co-operation on the South Mardin Exploration Licences. The heads of agreement together with the South Mardin JOA (see below) form the entire agreement between the parties in relation to the South Mardin Exploration Licences.

Under the heads of agreement, Melrose Turkey is to acquire and process approximately 500 km of 2D seismic over the South Mardin exploration blocks at Melrose Turkey's cost, and provide copies of the data to Southwind and GYP. On completion of the evaluation of the 2D seismic, Melrose Turkey is to present a proposal to the parties for a future work plan on the South Mardin Exploration Licences. If the parties agree to participate in such a work plan, each party will pay their proportionate share of all capital and operating costs of the work plan and the costs of all future operations in accordance with their participating and ownership interests in the South Mardin Exploration Licences being adjusted as follows:

- Melrose Turkey 66.67 per cent
- Southwind 26.67 per cent
- GYP 6.66 per cent

Pre-emptive rights apply in circumstances where a party wishes to transfer any part or all of its participating interest for cash, other than to a wholly owned affiliate or company owner.

20.3.44 *South Mardin JOA*

On 1 July 2008, Melrose Turkey, Southwind, Aladdin and GYP entered into a joint operating agreement governing the operations under the South Mardin Exploration Licences (the "**South Mardin JOA**"). The purpose of the South Mardin JOA was to establish the respective rights and obligations of the parties with regard to the operations under the South Mardin Exploration Licences, including the joint exploration, appraisal, development, production and disposition of hydrocarbons in the area covered by the South Mardin Exploration Licences.

The participating interests of the parties are as follows:

- Melrose Turkey 66.67 per cent
- Southwind 26.67 per cent
- Aladdin 6.66 per cent

The interests of Southwind and Aladdin are held on trust by GYP until it is possible for their interests to be assigned to each of them.

Melrose Turkey has the rights, functions and duties of operator under the South Mardin Exploration Licences, and has exclusive charge and conduct of all of the operations and activities carried out by the operator pursuant to the South Mardin JOA (the "**Joint Operations**"). Melrose Turkey may resign as operator at any time on 120 days' prior notice to the other parties.

An operating committee, composed of a representative of each party holding a participating interest, provides overall supervision and direction on the Joint Operations and each representative has a vote equal to the participating interest of the party such person represents and proposals shall be decided by the affirmative vote of two or more parties having collectively at least 65 per cent of the participating interests.

The South Mardin JOA took effect on 1 July 2008 and continues in effect until the South Mardin Exploration Licences terminate, all materials, equipment and personal property used in connection with the operations have been removed or disposed of and final settlement (including settlement in relation to any financial audit) has been made.

The proposal by any party to enter into or extend the term of any exploration or production period, or any phase of the South Mardin Exploration Licences, or a proposal to extend the term of the South Mardin Exploration Licences, must be put to the operating committee but does not require its support. However, any party not wishing to extend has the right to withdraw from the agreement.

The Joint Operations to be performed under the South Mardin JOA are detailed in a work programme and budget produced by the operator each year, which is then approved by the operating committee. The work plan includes minimum work and expenditure obligations specified under the South Mardin Exploration Licences that must be performed in order to satisfy the conditions of the South Mardin Exploration Licences.

Exclusive Operations, being operations and activities carried out pursuant to the South Mardin JOA, the costs of which are chargeable to the account of less than all of the parties, may also be carried out under the South Mardin JOA but must not conflict with the Joint Operations.

Aladdin and its affiliated companies have a preferential right to bid on any contract for drilling, side-tracking deepening, completing, recompleting, reworking or plugging back of any well to be performed under a work plan and budget.

All costs of the Joint Operations are chargeable to all of the parties. The obligations of the parties under the South Mardin Exploration Licences and all liabilities and expenses incurred by Melrose Turkey (as operator) in connection with the Joint Operations are chargeable to the joint account (the "**Joint Account**") maintained by Melrose Turkey (as operator) and all credits to the Joint Account are shared by all parties in accordance with their participating interests. Each party shall pay when due its participating interest share of joint account expenses, including cash advances and interest accrued pursuant to the South Mardin JOA.

Melrose Turkey (as operator) must pay the government of Turkey (for the joint account of the parties) all periodic payments, royalties, taxes and fees and other payment pertaining to the Joint Operations but excluding any taxes measured by the incomes of the parties.

Neither Melrose Turkey (as operator) nor any of its affiliates and their respective directors, officers and employees (the "**Indemnitees**") shall bear (except as a party to the extent of its participating interest share) any damage, loss, cost, expense or liability resulting from performing (or failing to perform) the duties and functions of operator, and the Indemnitees are released from liability to the parties (excluding Melrose Turkey) for any and all damages, losses, costs, expenses and liabilities, arising out or, incidental to or resulting from such performance or failure to perform, even though caused in whole or in part by a pre-existing defect, or the negligence (whether sole, joint or concurrent), gross negligence/wilful misconduct, strict liability or other legal fault of Melrose Turkey (or any such Indemnitee).

Any party that fails to pay when due its share of the Joint Account expenses shall be in default. During the default period (being the period from which the defaulting party receives a default notice until the default is remedied in full) the defaulting party's rights under the agreement are limited.

The default notice, which must also be sent to each non-defaulting party, shall include a statement of the sum of money that the non-defaulting party has to pay as its portion of Joint Account expenses which the defaulting party has failed to pay (excluding any interest owed on such amount). The obligations for which the defaulting party is in default shall be satisfied by the non-defaulting parties in proportion to the ratio that each non-defaulting party's participating interest bears to the participating interest of all non-defaulting parties. During the default period, the defaulting party shall not have any right to its share in the quantity of hydrocarbons under the South Mardin JOA, which shall vest in and be the property of the non-defaulting parties. Melrose Turkey, as operator, shall be authorised to sell such entitlement on an arm's length sale, and to pay the net proceeds of such sale to the non-defaulting parties in proportion to the amounts they are owed by the defaulting party.

Each party grants to the other parties the right and option to acquire all of its participating interest in the event that such party becomes a defaulting party and fails to fully remedy all of its defaults within 60 days of receiving a default notice.

A decision to plug and abandon any well which has been drilled as a Joint Operation requires the approval of the operating committee. Any well plugged and abandoned must be plugged and abandoned in accordance with the laws and regulations of Turkey governing the activities under the South Mardin Exploration Licenses and at the cost, risk and expense of the parties who participated in the cost of drilling such well.

Any sale, assignment, encumbrance or other disposition by a party of any rights or obligations derived from the South Mardin Exploration Licences or the South Mardin JOA (including its participating interest) other than its entitlement to hydrocarbons and its rights to any credits, refunds or payments under the South Mardin JOA ("**Transfer**") is subject to the requirements of the South Mardin Exploration Licences. A Transfer does not include a direct or indirect change in control of a party.

Except in the case of a party transferring all of its participating interest, no Transfer shall be made by any party which results in the transferor or transferee holding a participating interest of less than 5 per cent or any interest other than a participating interest in the South Mardin Exploration License and the South Mardin JOA.

Melrose Turkey shall remain operator following a Transfer of a portion of its participating interest. In the event of a Transfer of all of its participating interest, except to an affiliate, the Melrose Turkey shall be deemed to have resigned as operator, effective on the date the Transfer becomes effective, in which event a successor operator shall be appointed. If the operator Transfers all of its participating interest to an affiliate, the affiliate will automatically become operator, provided that the transferring operator shall remain liable for the performance by the affiliate of its obligations.

Any party may at its option withdraw from the South Mardin JOA and the South Mardin Exploration Licences by notice to the other parties, such withdrawal to be effective at the end of the calendar month following the calendar month in which the notice of withdrawal is given.

Within thirty days of receipt of a withdrawal notice, each of the other parties may also give notice that it desires to withdraw from the South Mardin JOA and the South Mardin Exploration Licences.

If all parties give notice of withdrawal, the parties shall proceed to abandon the exploration licence areas and terminate the South Mardin Exploration Licences and the South Mardin JOA. In such circumstances, the parties will be bound by the terms and conditions of the South Mardin JOA for so long as may be necessary to wind up the affairs of the parties with the government of Turkey, to satisfy any requirements of the laws and regulations of Turkey and to facilitate the sale, disposition or abandonment of property or interests held by the Joint Account of the parties.

If less that all of the parties give notice of withdrawal, then the withdrawing parties shall take all steps to withdraw from the South Mardin Exploration Licences and the South Mardin JOA on the earliest possible date and execute and deliver all necessary instruments and documents to assign their participating interest (at their cost) to the parties which are not withdrawing, without compensation whatsoever. A withdrawing party remains liable in respect of its participating interest's share in a number of costs set out in the agreement.

Any party withdrawing shall at its option withdraw from the entirety of the exploration licence areas or withdraw only from all exploration activities under the South Mardin Exploration Licences, but not from any production lease, commercial discovery, or discovery made prior to such withdrawal. Such withdrawing party will retain its rights in joint property but only insofar as it relates to any such production lease, commercial discovery or discovery, and shall abandon all other rights in joint property.

The rights, duties, obligations and liabilities of the parties under the agreement shall be individual, not joint or collective.

The agreement is governed by the laws of England. The dispute resolution mechanisms are first, negotiation between senior executives of the parties, secondly mediation pursuant to the ICC ADR Rules of the International Chamber of Commerce and failing that, arbitration in London pursuant to the International Chamber of Commerce Arbitration Rules.

USA

20.3.45 *Texas Sale and Purchase Agreement*

Melrose Petroleum Company (**"Melrose PCo"**) and Faulconer Resources 2010 Limited Partnership, LLP (**"Faulconer"**) entered into a sale and purchase agreement dated 26 October 2011 for the sale by Melrose PCo to Faulconer of the leases, contracts relating to such leases and wells owned by it in the counties of Liberty and Harris in Texas, USA (**"Texas SPA"**).

The purchase price payable by Faulconer was US $5.856 million subject to an adjustment mechanism for the period between the effective date of 1 July 2011 and completion held on or before 1 December 2011. Following such adjustments, consideration of approximately US$5.6 million was received by Melrose PCo on 1 December 2011 in relation to this disposal and other disposals of its assets in Texas.

The Texas SPA includes an express limitation of warranties by Melrose PCo in relation to title and condition of the assets sold under the Texas SPA. Melrose PCo agrees to indemnify Faulconer in relation to any and all claims in connection with the obligations of Melrose PCo prior to the effective date of 1 July 2011.

The Texas SPA is governed by the laws of the State of Texas, USA and the exclusive venue for any dispute arising out of the Texas SPA shall be in the State or Federal courts of Harris county, Texas, USA. The dispute resolution mechanism under the Texas SPA is firstly negotiation, secondly mediation appointing a mediator from the American Arbitration Association and failing that, arbitration pursuant to the International Arbitration Rules of the American Arbitration Association and shall be held in Harris county, Texas, USA.

20.3.46 *New Mexico Sale and Purchase Agreement*

Melrose Energy Company ("**Melrose ECo**") and Quantum Resources Management, LLC ("**Quantum**") entered into a sale and purchase agreement dated 19 November 2010 for the sale by Melrose ECo to Quantum of certain interests in oil and gas properties, rights and related assets ("**New Mexico SPA**").

The purchase price payable by Quantum was US $80 million subject to an adjustment mechanism for the period between the effective date of 30 June 2010 and completion held on or before 15 December 2010. Following such adjustments, consideration of approximately US$63.6 million was received in December 2010 with a further US$9.1 million remitted on 20 January 2011.

The New Mexico SPA includes an express limitation of warranties by Melrose ECo in relation to title and condition of the assets sold under the New Mexico SPA. Melrose ECo agrees to indemnify Quantum in relation to any and all claims in connection with the obligations of Melrose ECo prior to the effective date of 30 June 2010. Melrose ECo's overall liability for indemnification under the New Mexico SPA shall be limited to twenty per cent of the base purchase price of US$80 million.

The New Mexico SPA is governed by the laws of the State of Texas, USA and the exclusive venue for any dispute arising out of the New Mexico SPA shall be in the State or Federal courts of Harris county, Texas, USA. The dispute resolution mechanism under the New Mexico SPA is firstly negotiation, secondly mediation appointing a mediator from the American Arbitration Association and failing that, arbitration pursuant to the International Arbitration Rules of the American Arbitration Association and shall be held in Harris county, Texas, USA.

21. LITIGATION

Petroceltic Group

21.1 Petroceltic has not been and is not involved in any governmental, legal or arbitration proceedings in the 12 months prior to the date of this document, including any such proceedings which are pending or threatened of which Petroceltic is aware, which may have or have had in the recent past a significant effect on Petroceltic, its financial position or profitability.

Melrose Group

21.2 Save as disclosed in paragraph 21.3 below, Melrose has not been and is not involved in any governmental, legal or arbitration proceedings in the 12 months prior to the date of this document, including any such proceedings which are pending or threatened of which Melrose is aware, which may have or have had in the recent past a significant effect on Melrose, its financial position or profitability.

21.3 Melrose submitted a request to the French authorities to extend the licence term of the Rhône Maritime exploration licence, but the prescribed time for response passed without contact being made. On 9 August 2012, Melrose lodged an appeal with the French Authorities in respect of the non-extension of the licence. Melrose is considering its further legal options in relation to the licence.

22. MANDATORY BIDS AND COMPULSORY ACQUISITION RULES RELATING TO ENLARGED COMPANY SHARES

Mandatory Bids

22.1 Petroceltic is a public limited company incorporated in Ireland. The Existing Petroceltic Shares are currently (and following Readmission the Enlarged Company Shares will be) admitted to trading on AIM and ESM. As a result, Petroceltic is currently, and following the Readmission will continue to be, subject to the provisions of the Irish Takeover Rules.

22.2 Under the Irish Takeover Rules, if an acquisition of Ordinary Shares were to increase the aggregate holding of the acquirer and its concert parties to Ordinary Shares carrying 30 per cent or more of the voting rights in Petroceltic, the acquirer and, depending on the circumstances, its concert parties, would be required (except with the consent of the Irish Takeover Panel) to make a cash offer for the outstanding shares at a price not less than the highest price paid for Ordinary Shares by the acquirer or its concert parties during the previous 12 months. This requirement would also be triggered by any acquisition of Ordinary Shares by a person holding (together with its concert parties) Ordinary Shares carrying between 30 and 50 per cent of the voting rights in Petroceltic if the effect of such acquisition were to increase that person's percentage of the voting rights by 0.05 per cent or more in any 12 month period.

22.3 There have been no public takeover bids by third parties in respect of Petroceltic's equity, which have occurred during the last financial year and the current financial year.

Squeeze-out

22.4 Under the Irish Companies Acts, if an offeror were to acquire 80 per cent of the Ordinary Shares within four months of making a general offer to shareholders, it could then compulsorily acquire the remaining 20 per cent. In order to effect the compulsory acquisition, the offeror would send a notice to outstanding shareholders telling them that it would compulsorily acquire their shares. Unless determined otherwise by the High Court of Ireland, the offeror would execute a transfer of the outstanding shares in its favour after the expiry of one month. Consideration for the transfer would be paid to Petroceltic, which would hold the consideration on trust for the outstanding shareholders.

22.5 Where an offeror already owned more than 20 per cent of Petroceltic at the time that the offeror made an offer for the balance of the shares, compulsory acquisition rights would only apply if the offeror acquired at least 80 per cent of the remaining shares that also represented at least 75 per cent in number of the holders of those shares.

Buy-out

22.6 The Irish Companies Acts also give minority shareholders a right to be bought out in certain circumstances by an offeror who has made a takeover offer. If a takeover offer related to all the Ordinary Shares, and at any time before the end of the period within which the offer could be accepted, the offeror held or had agreed to acquire not less than 80 per cent of the Ordinary Shares, any holder of shares to which the offer related who had not accepted the offer could, by a written communication to the offeror, require it to acquire those shares. The offeror would be required to give any shareholders notice of their right to be bought out within one month of that right arising.

23. AUDITORS

23.1 KPMG Chartered Accountants, whose registered address is 1 Stokes Place, St. Stephen's Green, Dublin 2, a partnership whose members are Chartered Accountants, is Petroceltic's auditor and audited the accounts of Petroceltic for the financial years ended 31 December 2009, 31 December 2010 and 31 December 2011.

24. CONSENTS

24.1 Davy has given and not withdrawn its written consent to the inclusion in this document of its name and references thereto in the forms and contexts in which they appear.

24.2 KPMG has given and not withdrawn its written consent to the inclusion in this document of its name and references thereto in the forms and contexts in which they appear.

24.3 DeGolyer and MacNaughton has given and not withdrawn its written consent to the inclusion in this document of its name and references thereto in the forms and contexts in which they appear.

24.4 AGR Petroleum (ME) Limited has given and not withdrawn its written consent to the inclusion in this document of its name and references thereto in the forms and contexts in which they appear.

24.5 Senergy (GB) Limited has given and not withdrawn its written consent to the inclusion in this document of its name and references thereto in the forms and contexts in which they appear.

24.6 Merrill Lynch International has given and not withdrawn its written consent to the inclusion in this document of its name and references thereto in the forms and contexts in which they appear.

24.7 Lambert Energy Advisory has given and not withdrawn its written consent to the inclusion in this document of its name and references thereto in the forms and contexts in which they appear.

24.8 HSBC has given and not withdrawn its written consent to the inclusion in this document of its name and references thereto in the forms and contexts in which they appear.

24.9 NPlus1 Brewin has given and not withdrawn its written consent to the inclusion in this document of its name and references thereto in the forms and contexts in which they appear.

25. GENERAL

25.1 The total costs and expenses (exclusive of VAT) payable by Petroceltic and Melrose in connection with the Merger are estimated to be approximately US$8.2 million plus bank fees of US$6 million. Given the inter relationship between the Merger and the Readmission, it is not practicable to separate costs attributable solely to the Merger and to the Readmission.

25.2 Where information has been sourced from a third party this information has been accurately reproduced. So far as Petroceltic, the Directors and the Proposed 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.

25.3 Save as set out in this document, there are no patents, intellectual property rights, licences, industrial, commercial or financial contracts or new manufacturing processes which are or may be material to the Enlarged Group's business or profitability.

25.4 As far as the Directors and the Proposed Directors are aware and save as set out in this document, there are no environmental issues that may affect the Enlarged Group's utilisation of its tangible fixed assets.

25.5 Save as set out in this document, there have been no interruptions in the business of the Petroceltic Group or the Melrose Group, which may have or have had in the 12 months preceding the publication of this document a significant effect on the financial position of the Petroceltic Group or the Melrose Group or which are likely to have a material effect on the prospects of the Enlarged Group for the next 12 months.

25.6 Save as set out in this document, the Directors and the Proposed Directors are not aware of any trends, uncertainties, demands, commitments or events that are reasonably likely to have a material effect on the prospects of the Petroceltic Group or the Melrose Group or, if the Merger becomes Effective, the Enlarged Group for at least the current financial year.

25.7 Save as set out in this document, no person (excluding professional advisers otherwise disclosed in this document and trade suppliers) has:

25.7.1 received, directly or indirectly from the Petroceltic Group or Melrose Group within the 12 months preceding the date of this document; or

25.7.2 entered into any contractual arrangements (not otherwise disclosed in this document) to receive, directly or indirectly, from the Petroceltic Group, on or after Readmission, any of the following:

a) fees totalling £10,000 or €14,000 or more;

b) securities in Petroceltic where these have a value of £10,000 or €14,000 or more calculated by reference to the issue price; or

c) any other benefit with the value of £10,000 or €14,000 or more at the date of Readmission.

25.8 Except as stated in paragraph 20.3 of Part XII of this document and for the advisers named in Part IV of this document and trade suppliers, no person has received, directly or indirectly, from Melrose within the twelve months preceding the date of this document or has entered into any contractual arrangements to receive, directly or indirectly, from Melrose on or after Admission, fees totalling £10,000 or more or securities in Melrose with a value of £10,000 or more or any other benefit with a value of £10,000 or more at the date of Admission.

25.9 No payments aggregating over £10,000 have been made to any government or regulatory authority or similar body by the Petroceltic Group or the Melrose Group or on its behalf with regard to the acquisition of or maintenance of its assets.

25.10 Save as disclosed in this document, there are no investments in progress which are significant to the Petroceltic Group or the Melrose Group or, if the Merger were to become Effective, the Enlarged Group.

26. AVAILABILITY OF THIS DOCUMENT

Copies of this document will be available to the public free of charge at Petroceltic's registered office at 6th Floor, 75 St Stephen's Green, Dublin 2 during normal business hours any weekday other than Saturdays, Sundays and public holidays, for the period from the date of this document until the date of Readmission. This document will also be available for download from Petroceltic's website http://www.petroceltic.ie.

This document is dated 17 August 2012.

PART XIII

DEFINITIONS

The following definitions shall apply throughout this document unless the context requires otherwise:

"$"** or **"US$" or **"US dollars"** or **"cents"**	the lawful currency of the United States;
"£" or **"Sterling"** or **"pounds"** or **"pence"**	the lawful currency of the United Kingdom;
"€" or **"EUR"** or **"Euro"**	the currency introduced at the start of the third stage of the European economic and monetary union pursuant to the Treaty establishing the European Community as amended;
"**1983 Act**"	the Companies (Amendment) Act 1983 of Ireland (as amended);
"1990 Act"	the Companies Act 1990 of Ireland (as amended);
"2004 Share Scheme"	the Petroceltic 2004 Incentive Share Option Scheme, as amended from time to time;
"2009 Share Scheme"	the Petroceltic Share Option Plan 2009, as amended from time to time;
"AIM"	the AIM market operated by the London Stock Exchange;
"AIM Note for Mining and Oil & Gas Companies"	the AIM Note for Mining and Oil & Gas Companies as published by the London Stock Exchange from time to time;
"AIM Rules"	the AIM Rules for Companies as published by the London Stock Exchange from time to time;
"Articles of Association" or **"Articles"**	the articles of association of Petroceltic adopted by special resolution on 21 April 2010, as described in paragraph 15 of Part XII;
"BofA Merrill Lynch"	Merrill Lynch International, a company registered in England and Wales with registered number 02312079 and whose registered offices is at 2 King Edward Street, London, ECIA 1HQ;
"Bulgarian Regulatory Authority"	the Commission on Protection of Competition of the Republic of Bulgaria;
"Business Day"	a day (excluding Saturday, Sunday and public holidays) on which banks generally are open for business in the City of London and Ireland for the transaction of normal banking business;
"Central Bank"	the Central Bank of Ireland;
"Company" or **"Petroceltic"**	Petroceltic International plc, a company incorporated and registered in Ireland with registered number 101176 whose registered office is at 6th Floor, 75 St. Stephen's Green, Dublin 2, Ireland;
"Co-operation Agreement"	the agreement entered into between Petroceltic and Melrose dated 16 August 2012, and as described further in paragraph 20.1.5 of Part XII of this document;
"Court"	Her Majesty's High Court of Justice in England and Wales;
"Court Meeting" or **"Melrose Court Meeting"**	the meeting of Scheme Shareholders convened by order of the Court under Part 26 of the UK Companies Act to consider and, if thought fit, approve the Scheme (with or without amendment), and any adjournment thereof;
"Court Order(s)"	the Scheme Court Order and the Reduction Court Order;

"CREST"	the system of paperless settlement of trades in securities and the holding of uncertificated securities operated by CRESTCo in accordance with the Uncertificated Securities Regulations;
"CRESTCo"	CRESTCo Limited, a company incorporated and registered in England and Wales (registered number 06179984), whose registered office is at 33 Cannon Street, London, EC4M 5SB, United Kingdom, and which is the operator of CREST;
"CREST Regulations"	the Companies Act 1990 (Uncertificated Securities) Regulations 1996 (S.1.68 of 1996) of Ireland (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;
"Deferred Shares"	the deferred shares of nominal value €0.114276427 in the capital of Petroceltic;
"Declaration of Commerciality" or **"DOC"**	the formal declaration of commerciality relating to Petroceltic's Ain Tsila field, as announced on 9 August 2012;
"Directors"	the directors of Petroceltic, being at the date of this document Robert Arnott, Brian O'Cathain, Tom Hickey, Andrew Bostock, Con Casey and Hugh McCutcheon, or the directors of Petroceltic from time to time, as the context may require;
"Document" or "Admission Document"	this admission document;
"Enel"	Enel Trade S.p.A., a company established and existing under the laws of Italy;
"Effective"	in the context of the Merger: (i) if the Merger is implemented by way of the Scheme, the Scheme having become effective pursuant to its terms; or (ii) if the Merger is implemented by way of an Offer, such Offer having been declared or becoming unconditional in all respects in accordance with its terms;
"Effective Date"	the date on which the Merger becomes Effective;
"EGAS"	the Egyptian National Gas Holding Company, a company existing and incorporated under the laws of Egypt;
"EGPC"	the Egyptian General Petroleum Corporation;
"Enlarged Company"	Petroceltic as enlarged by Melrose following the Merger becoming Effective and the issue and allotment of the New Petroceltic Shares;
"Enlarged Company Audit Committee"	the audit committee established by the Enlarged Company Board to monitor financial risks in the Enlarged Company's businesses, as described in paragraph 11 of Part XII;
"Enlarged Company Board"	the board of directors of the Enlarged Company upon Readmission;
"Enlarged Company Chief Executive"	the Chief Executive of the Enlarged Company, from time to time;
"Enlarged Company Directors"	the directors of the Enlarged Company upon Readmission, as described in paragraph 6 of Part XII;

"Enlarged Company Executive Directors"	the executive Enlarged Company Directors, from time to time;
"Enlarged Company Shareholders"	the holders of the Enlarged Company Shares;
"Enlarged Company Shares"	the Existing Petroceltic Shares and the New Petroceltic Shares;
"Enlarged Company Nominations Committee"	the nominations committee established by the Enlarged Company Board to consider and make recommendations to the Enlarged Company Board concerning the composition of the Enlarged Company Board, as described in paragraph 11 of Part XII;
"Enlarged Company Remuneration Committee"	the remuneration committee established by the Enlarged Company Board to consider and make recommendations to the Enlarged Company Board as to the remuneration of Enlarged Company's directors and senior executives, as described in paragraph 11 of Part XII;
"Enlarged Group"	the Enlarged Company and its subsidiary undertakings (as defined in the European Communities (Companies : Group Accounts) Regulations 1992 of Ireland) from time to time;
"ENI"	ENI S.p.A., a company established and existing under the laws of Italy;
"Enlarged Issued Share Capital"	the Existing Petroceltic Shares together with the New Petroceltic Shares in issue upon Readmission;
"ESM"	the Enterprise Securities Market, a market regulated by the Irish Stock Exchange;
"ESM Rules"	the rules for ESM companies and their ESM advisers issued by the Irish Stock Exchange in relation to ESM traded securities;
"EU"	the European Union;
"Exchange Ratio"	17.6 New Petroceltic Shares for every Melrose Share held;
"Executive Director"	an executive Director;
"Existing Petroceltic Shares"	the 2,369,605,049 Ordinary Shares in issue as at the Latest Practicable Date;
"Existing Petroceltic Shareholders"	the holders of the Existing Petroceltic Shares;
"Extraordinary General Meeting" or **"EGM"**	the extraordinary general meeting of Petroceltic to be held at The Westin Dublin, College Green, Dublin 2, Ireland on 20 September 2012 at 12.30 p.m., notice of which is given in the Notice of Extraordinary General Meeting set out at the end of this document;
"Form of Proxy" or **" Petroceltic Form of Proxy"**	the form of proxy enclosed with this document for use by the Existing Petroceltic Shareholders in connection with the EGM;
"FSA"	the Financial Services Authority acting in its capacity as the competent authority for listing in the UK for the purposes of part VI of FSMA;
"FSMA"	the UK Financial Services and Markets Act 2000 (as amended);
"GANOPE"	Ganoub El Wadi Holding Petroleum Company, a company existing and incorporated under the laws of Egypt;

"GDP"	gross domestic product;
"Gemini"	Gemini Oil & Gas Fund II, L.P., a company existing and incorporated under the laws of Jersey;
"Hess"	Hess Middle East New Ventures, a company established and existing under the laws of the Cayman Islands;
"HM Revenue and Customs"	Her Majesty's Revenue and Customs;
"HSBC"	HSBC Bank plc;
"HSBC Senior Secured Facility"	the US$300m facility provided to Melrose by HSBC, to which Petroceltic will accede on the Merger becoming Effective, and is described further in paragraph 20.1.6 of Part XII of this document;
"HSE"	health, safety and environment;
"IFRS"	International Financial Reporting Standards as adopted by the EU;
"Independent Petroceltic Shareholders"	all Existing Petroceltic Shareholders other than Robert Adair and Skye and those persons considered to be acting in concert with them for the purposes of the UK Takeover Code;
"Ireland"	the island of Ireland excluding Northern Ireland, and the word "Irish" shall be construed accordingly;
"**Irish Companies Acts**"	the Companies Acts 1963 to 2012 of Ireland;
"Irish Prospectus Regulations"	the Prospectus (Directive 2003/71 EC) Regulations 2005 of Ireland as amended by the Prospectus (Directive 2003/71/EC) (Amendment) Regulations 2012;
"Irish Stock Exchange"	the Irish Stock Exchange Limited;
"Irish Takeover Panel"	the Irish Takeover Panel, established under the Irish Takeover Panel Act 1997 (as amended);
"**Irish Takeover Rules**"	the Irish Takeover Panel Act 1997, Takeover Rules 2007 to 2008 (as may be amended from time to time);
"ISIN"	International Security Identification Number;
"KRG"	the Kurdistan Regional Government of Iraq;
"Lambert Energy Advisory"	Lambert Energy Advisory Limited;
"Latest Practicable Date"	16 August 2012, being the latest practicable date prior to the publication of this document;
"London Stock Exchange" or "LSE"	London Stock Exchange plc, a company incorporated and registered in England and Wales (registered number 05369106) and whose registered office is at 10 Paternoster Square, London, EC4M 7LS;
"Melrose"	Melrose Resources Plc, a company incorporated and registered in England and Wales with registered number 3210072 whose registered office is at No. 1 Portland Place, London, W1B 1PN;
"Melrose Competent Person"	Senergy (GB) Limited (as to Egyptian and Bulgarian assets);

"Melrose Competent Person's Report"	the Competent Person's Report dated 15 August 2012 issued by Senergy (GB) Limited in respect of Melrose's international oil and gas assets and contained in Appendix IV to this document;
"Melrose Directors"	the directors of Melrose, being at the date of this document: Robert F M Adair, James D Agnew, David F Archer, Diane M V Fraser, Ahmed L Kebaili, Alan J Parsley, Anthony E Richmond-Watson, David H Thomas and William P Wyatt;
"Melrose Form of Proxy"	the Melrose form of proxy or form of direction for use by Scheme Shareholders in relation to the Court Meeting;
"Melrose General Meeting"	the general meeting of Melrose Shareholders to be convened for the purpose of considering, and if thought fit, approving the Scheme;
"Melrose Group"	Melrose together with its subsidiary undertakings (as defined in the UK Companies Act);
"Melrose Shareholders"	the holders of the Melrose Shares;
"Melrose Shares"	(i) prior to the Reduction Record Time, Melrose Ordinary Shares; and (ii) after the Reduction Record Time, the shares in the capital of Melrose as issued under the terms of the Scheme;
"Melrose Ordinary Share(s)"	the ordinary shares of 10 pence each in the capital of Melrose;
"Melrose Share Plans"	the Melrose Approved Share Option Scheme and Melrose Performance Share Plan;
"Merger"	the proposed Merger of Petroceltic with Melrose, to be effected by means of the Scheme (or should Petroceltic elect by means of an Offer);
"Mutual Confidentiality Agreement"	the agreement entered into between Petroceltic and Melrose dated 7 February 2012 and as described further in paragraph 20.1.1 of Part XII of this document;
"New Petroceltic Shares"	the Ordinary Shares to be issued to the Melrose Shareholders pursuant to the Merger;
"Non-Executive Director"	a non-executive Director;
"Notice of Extraordinary General Meeting"	the notice of the Extraordinary General Meeting to be held at The Westin Dublin, College Green, Westmoreland Street, Dublin 2, Ireland on 20 September 2012, at 12.30 p.m. as set out at the end of this document;
"NPlus1 Brewin"	NPlus1 Brewin LLP;
"Orca"	Orca Exploration Group Inc., a company established and existing under the laws of the British Virgin Islands;
"Offer"	a takeover offer (as that term is defined in section 974 of the UK Companies Act) under the UK Takeover Code;
"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;
"Ordinary Resolutions"	resolutions 1, 2 and 3 to be proposed at the Extraordinary General Meeting, as set out in the Notice of Extraordinary General Meeting;
"Ordinary Shares" or **"Petroceltic Shares"**	the ordinary shares of nominal value €0.0125 in the capital of Petroceltic including, if the context requires, the New Petroceltic Shares;

"Petroceltic Audit Committee"	the audit committee established by the Petroceltic Board to monitor financial risks in Petroceltic's businesses, as described in paragraph 5 of Part VII;
"Petroceltic Board" or **"Board"**	the board of directors of Petroceltic from time to time;
"Petroceltic Competent Persons"	DeGolyer and MacNaughton (as to Kurdistan Region Iraq and Italian assets) and AGR Petroleum (ME) Ltd (as to Algerian and Elsa Discovery assets);
"Petroceltic Competent Person's Report"	the Competent Person's Reports issued by the Petroceltic Competent Persons on Petroceltic's international oil and gas assets contained in Appendix I, II and III to this document;
"Petroceltic Group"	Petroceltic and its subsidiary undertakings (as defined in the European Communities (Companies : Group Accounts) Regulations 1992 of Ireland;
"Petroceltic Italia"	Petroceltic Italia S.r.l., a company existing and incorporated under the laws of Italy and a wholly owned subsidiary of Petroceltic;
"Petroceltic Nominations Committee"	the director nominations committee established by the Petroceltic Board to consider and make recommendations to the Petroceltic Board concerning the composition of the Petroceltic Board, as described in paragraph 5 of Part VII;
"Petroceltic Remuneration Committee"	the remuneration committee established by the Petroceltic Board to consider and make recommendations to the Petroceltic Board as to the remuneration of the Directors and senior executives, as described in paragraph 5 of Part VII;
"Petroceltic Shareholders" or **"Shareholders"**	the holders of Ordinary Shares;
"Proposed Directors"	the directors who, upon the Merger becoming Effective, will join the Enlarged Company Board, as set out in paragraph 6 of Part XII;
"PSC or **"Production Sharing Contract"**	a contract signed between a host government and an oil and gas exploration company, regulating how much of the oil and gas produced from a production concession each will receive;
"Readmission"	the admission of the Enlarged Company Shares to AIM and ESM in accordance with the AIM Rules and ESM Rules, as the context so requires;
"Reduction Court Order"	the order of the Court confirming the Reduction of Capital under section 648 of the UK Companies Act;
"Reduction of Capital"	the proposed reduction of the share capital of Melrose pursuant to the Scheme;
"Reduction Record Time"	6.00 p.m. on the Business Day immediately preceding the date on which the Reduction Court Order is made;
"Registrars"	Petroceltic's registrars, being Computershare Investor Services (Ireland) Limited, at Heron House, Corrig Road, Sandyford Industrial Estate, Dublin 18;
"Relationship Agreement"	the agreement between Petroceltic, Robert Adair and Skye dated 16 August 2012, as further described in paragraph 20.1.2 of Part XII of this document;
"Reporting Accountants"	KPMG, 1 Stokes Place, St. Stephen's Green, Dublin 2;
"Resolutions"	the Ordinary Resolutions and the Special Resolution;

"reverse takeover"	has the meaning given to such a term by the AIM Rules and ESM Rules;
"Rule 2.7 Announcement"	the announcement made by Petroceltic and Melrose on 17 August 2012 announcing Petroceltic's offer to acquire the entire issued and to be issued share capital of Melrose;
"Scheme" or "Melrose Scheme"	the scheme of arrangement under part 26 of the UK Companies Act proposed to be made between Melrose and the Scheme Shareholders set out in the Scheme Circular;
"Scheme Circular"	the document to be sent to Melrose Shareholders setting out, amongst other things, the Scheme and notices convening the Melrose Court Meeting and the Melrose General Meeting;
"Scheme Court Hearing" or **"Melrose Scheme Court Hearing"**	the hearing by the Court to sanction the Scheme and confirm the Reduction of Capital;
"Scheme Court Order"	the order of the Court sanctioning the Scheme under Part 26 of the UK Companies Act;
"Scheme Share(s)"	Melrose Ordinary Shares: (i) in issue at the date of the Scheme Circular; (ii) (if any) issued after the date of the Scheme Circular and prior to the Scheme Voting Record Time; and (iii) (if any) issued on or after the Scheme Voting Record Time and before the Reduction Record Time, on terms that the original or any subsequent holders thereof are, or shall have agreed in writing to be, bound by the Scheme, in each case, excluding Melrose Ordinary Shares (if any) registered in the name of or beneficially owned by any member of the Petroceltic Group;
"Scheme Shareholders"	the registered holders of Scheme Shares;
"Scheme Voting Record Time"	6.00 p.m. on the day which is two days before the date of the Court Meeting or, if the Court Meeting is adjourned, 6.00 p.m. on the day which is two days before the date set for the adjourned Court Meeting;
"Skye"	Skye Investments Ltd, a company incorporated in England and Wales with company number 03340923 and whose registered address is High Leases Farm, Westfield, Richmond, North Yorkshire DL10 4SB;
"Sonatrach"	Société Nationale pour la Recherche, la Production, le Transport, la Transformation, et la Commercialisation des Hydrocarbures s.p.a., an Algerian government owned company formed to exploit the hybocarbon resources of Algeria;
"Special Dividend"	a special dividend of 4.7 pence per Melrose Share payable by Melrose to Melrose Shareholders who are on Melrose's register of members at the Reduction Record Time within 14 days of the Effective Date, payable subject to, and with effect from, the Effective Date
"Special Resolution"	resolution 4 to be proposed at the Extraordinary General Meeting, as set out in the Notice of Extraordinary General Meeting;

"UK Bribery Act"	the United Kingdom Bribery Act 2010;
"**UK Companies Act**"	the Companies Act 2006 of the United Kingdom (as amended);
"UK Listing Authority" or "UKLA"	the United Kingdom Listing Authority, being the FSA acting as the competent authority for the purposes of Part VI of the FSMA;
"UK Takeover 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;
"Uncertificated Securities Regulations"	the Uncertificated Securities Regulations 2001 (SI 2001/3755);
"United Kingdom" or "UK"	the United Kingdom of Great Britain and Northern Ireland;
"United States" or "US"	the United States of America, its territories and possessions, any state of the United States of America, the District of Columbia;
"VAT" or "Value Added Tax"	value added tax;
"Vega"	Vega Oil S.p.A., a company established and existing under the laws of Italy;

For the purpose of this document, references to one gender include the other gender.

Any references to any provision of any legislation or regulation shall include any amendment, modification, re-enactment or extension thereof.

PART XIV

GLOSSARY OF TECHNICAL TERMS AND ABBREVIATIONS

The glossary below contains selected technical terms and abbreviations related to the exploration for and production of crude oil and/or natural gas along with certain abbreviations used in the oil and gas industry.

"2C"	Denotes best estimate scenario of contingent resources.
"2D seismic data"	A vertical section of seismic data consisting of numerous adjacent traces acquired sequentially.
"2D"	Two dimensional.
"2P"	Taken to be equivalent to the sum of proved plus probable reserves; denotes best estimate scenario of reserves.
"3D seismic data"	A set of numerous closely-spaced seismic lines that provide a high spatially sampled measure of subsurface reflectivity. 3D seismic data provide detailed information about fault distribution and subsurface structures.
"3D"	Three dimensional.
"3P"	Taken to be equivalent to the sum of proved plus probable plus possible reserves; denotes high estimate scenario of reserves.
"anticline"	An arch-shaped fold in rock in which rock layers are upwardly convex. The oldest rock layers form the core of the fold, and outward from the core progressively younger rocks occur.
"API gravity"	A specific gravity scale developed by the API for measuring the relative density of various petroleum liquids.
"appraisal well"	A well drilled to evaluate an oil or gas deposit that has already been discovered.
"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.
"bbl"	Abbreviation for barrel of oil, condensate or natural gas liquids.
"bblpd"	Abbreviation for barrel of oil, condensate or natural gas liquids per day.
"BCF" or "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
"Bcm"	Abbreviation for billion cubic metres of gas.
"beneficial working interest"	Same as a working interest except it may not be recognised by other parties in an agreement.
"boe"	Abbreviation for barrel of oil equivalent.
"boepd"	Abbreviation for barrel of oil equivalent per day.

"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).
"cap rock"	A relatively impermeable rock, commonly shale, anhydrite or salt, forming a barrier or seal above and around reservoir rock so that fluids cannot migrate beyond the reservoir.
"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 and system, covering the time period between 359 and 299 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 mm in size.
"completion"	A generic term used to describe the procedures that are undertaken to prepare a well for production of oil or natural gas. Procedures may include perforation of the casing that separates the wellbore and the potential producing zone and the assembly the equipment required to enable safe and efficient production from the well.
"condensate"	A natural gas liquid with a low vapour pressure compared with natural gasoline and liquefied petroleum gas. Condensate is mainly composed of propane, butane, pentane and heavier fractions.
"consolidated"	Pertaining to sediments that have been compacted and cemented to the degree that they become coherent, relatively solid rock.
"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.
"cost oil"	The amount of production allocated to costs and expenses under a PSC.
"Cretaceous"	A geological time period and system, covering the time between 145 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"	An area of deposition or the deposit formed by a flowing sediment-laden current as it enters an open or standing body of water. As a river enters a body of water, its velocity drops and its ability to carry sediment diminishes, leading to deposition.

"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 and system, covering the time between 416 and 359 million years ago.
"Dead weight tonnage" or "DWT"	A measure of how much cargo a ship is carrying or safely carry.
"downstream"	A general term which designates the sector of the oil and gas industry focused on transportation and refining of oil or natural gas and the marketing of by-products such as gasoline (petrol).
"dry gas"	Natural gas that occurs in the absence of condensate or other liquid hydrocarbons.
"Eocene"	A geological time period and system, covering the time period between 56 and 34 million years ago.
"exploration"	The initial phase in petroleum operations that includes generation of a prospect or play or both, and drilling of an exploration well. Appraisal, development and production phases follow successful exploration.
"exploration block", or "block"	A grant extended by a government to permit a company to explore for and produce 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 where no known oil or gas exists.
"farm-in"	An agreement whereby one oil operator acquires an interest in a concession owned by another operator.
"farmor"	The party that originally owns the leasehold interest and assigns the farm-out.
"farm-out"	A contractual agreement with an owner who holds a working interest in an oil and gas lease to assign all or part of that interest to another party in exchange for fulfilling contractually specified conditions.
"fault trap"	A type of structural hydrocarbon trap in which closure is controlled by the presence of at least one fault surface.
"fault"	A break or planar surface in brittle rock across which there is observable displacement.
"field"	An accumulation, pool, or group of pools of hydrocarbons or other mineral resources in the subsurface. A hydrocarbon field consists of a reservoir in a shape that will trap hydrocarbons and that is covered by an impermeable, sealing rock. Typically, the term "field" implies that the accumulation is commercial.
"fold"	A wave-like geologic structure that forms when rocks deform by bending instead of breaking under compressional stress.

“formation”

The fundamental unit of lithostratigraphy. A body of rock that is sufficiently distinctive and continuous that it can be mapped. In stratigraphy, a formation is a body of strata of predominantly one type or combination of types.

Also, a general term for the rock around the borehole. In the context of formation evaluation, the term refers to the volume of rock seen by a measurement made in the borehole, as in a log or a well test.

“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 prone”

The quality of a source rock that makes it more likely to generate gas than oil. The nature of the organic matter in source rocks can vary from coals, found in terrestrial source rocks to algal or other marine material that makes up marine source rocks. Terrestrial source rocks (such as coal) tend to be gas prone.

“gas water contact” (GWC)

A bounding surface in a reservoir above which predominantly gas occurs and below which predominantly water occurs.

“gas”

A naturally occurring mixture of hydrocarbon gases that is highly compressible and expansible – same as natural gas

“geological map”

A map showing the type and spatial distribution of rocks at the surface of the Earth.

“geology”

The study of the history, structure and composition of the Earth and the processes that continue to change it.

“geophysicist”

A scientist trained in the study of the physics of the Earth, particularly its electrical, gravitational and magnetic fields and propagation of seismic waves within it. In the petroleum industry, geophysicists perform a variety of functions, chiefly the processing and interpretation of seismic data and generation of subsurface maps on the basis of seismic data. Such interpretations enhance understanding of subsurface geology.

“geophysics”

The study of the physics of the Earth, especially its electrical, gravitational and magnetic fields and propagation of seismic waves within it. Geophysics plays a critical role in the oil and gas industry because geophysical data are used by exploration and development personnel to make predictions about the presence, nature and size of subsurface hydrocarbon accumulations.

“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. Often the same success case outcome is uncertain and is described by parameters such as the P10, P50, P90 of a probabilistic range.

“gravity”

The Earth’s gravitational field, or the attractive force produced by the mass of the Earth.

“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.

“hydrocarbon”	Naturally organic compounds comprising hydrogen and carbon. The least complex hydrocarbons compounds are created through the heating of organic carbon material at high pressure. The least complex hydrocarbon, called methane (CH_4), consists of one carbon atom and four hydrogen atoms. Methane has high energy content and is the most abundant component of natural gas. More complex compounds of carbon and hydrogen create hydrocarbon chains with the weight of the chain and the type of hydrocarbon being dependent upon the length of the chain. Hydrocarbons may be divided into five main categories: dry gas, wet gas, condensate, light oil and heavy oil.
“impermeable”	Pertaining to a rock that is incapable of transmitting fluids because of low permeability. Shale has a high porosity, but its pores are small and disconnected, so it is relatively impermeable. Impermeable rocks are desirable sealing rocks or cap rocks for reservoirs because hydrocarbons cannot pass through them readily.
“in situ”	In the original location or position. Tests can be performed in situ in a reservoir to determine its pressure and temperature.
“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.
“JOA”	Joint operating agreement.
“Jurassic”	A geological time period and system, covering the time between 200 to 145 million years ago.
“JV”	Joint venture (incorporated or unincorporated).
“light crude oil”	Crude oil that has a high API gravity, usually more than 40°.
“liquid hydrocarbons”	Liquid compounds such as propanes, butanes, pentanes and heavier products extracted from the gas flowstream.
“LNG”	Liquefied natural gas. Natural gas, mainly methane and ethane, which has been liquefied.
“logging”	Pertaining to a wireline log. Logging while drilling is the measurement of formation properties during the excavation of the hole, or shortly thereafter, through the use of tools integrated into the bottomhole assembly.
“LPG”	Liquid petroleum gas.
“Mbbl”	Abbreviation for thousand barrels of oil condensate or natural gas liquids.
“Mboe”	Abbreviation for thousand barrels of oil equivalent.
“Mboepd”	Abbreviation for thousand barrels of oil equivalent per day.
“Mbopd”	Abbreviation for thousand barrels of oil per day.
“Mcf”	Abbreviation for thousand cubic feet of gas.
“Mcfe”	Abbreviation for thousand cubic feet of gas equivalent.
“Mcfpd”	Abbreviation for thousand cubic feet of gas per day.

"Mcm"	Abbreviation for thousand cubic metres, a measurement of natural gas.
"Mcmh"	Abbreviation for thousand cubic metres per hour, a measure of pipeline capacity.
"methane"	The lightest, least complex and most abundant of the hydrocarbon gases and the principal component of natural gas. Methane (CH_4) 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 time period and system, covering the time period between 23 and 5.3 million years ago.
"MMbbl"	Abbreviation for million barrels of oil, condensate or natural gas liquids.
"MMboe"	Abbreviation for million barrels of oil equivalent.
"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.
"MMcm"	Abbreviation for thousand cubic metres of gas.
"natural gas liquids" or "NGL"	Components of natural gas which are liquid at surface in field facilities or in gas-processing plants. May be condensate, natural gasoline and liquefied petroleum gas.
"natural gas"	A naturally occurring mixture of hydrocarbon gases that is highly compressible and expansible.
"net gas production"	The volume of gas produced less gas injected.
"net oil production"	The volume of oil produced less oil injected. In hydraulic pumping, the oil injected is known as power oil.
"net profits interest"	A share of net proceeds from production paid solely from the working interest owner's share.
"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.
"normal fault"	A type of fault in which the hanging wall moves down relative to the footwall, and the fault surface dips steeply, commonly from 50° to 90°.
"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. Typically, industry professionals use the term "oilfield" with an implied assumption of economic viability.
"oil pool"	A subsurface oil accumulation. An oil field can consist of one or more oil pools or distinct reservoirs within a single large trap. The term "pool" can create the false impression that oil fields are immense caverns filled with oil, instead of rock filled with small oil-filled pores.

"oil water contact" (OWC)	A bounding surface in a reservoir above which predominantly oil occurs and below which predominantly water occurs.
"oil well"	A producing well with oil as its primary commercial product. Oil wells almost always produce some gas and frequently produce water. Most oil wells eventually produce mostly gas or water.
"OPEC"	Organisation of the Petroleum Exporting Countries.
"Ordovician"	A geological time period and system, covering the time between 488 to 444 million years ago.
"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"	A reservoir or portion of a reservoir that contains economically producible hydrocarbons.
"permeability"	The ability of a rock to transmit fluids.
"petroleum"	A naturally occurring mixture consisting predominantly of hydrocarbons in the gaseous, liquid or solid phase.
"pinch-out"	A type of stratigraphic trap. The termination by thinning or tapering out ("pinching out") of a reservoir against a nonporous sealing rock creates a favourable geometry to trap hydrocarbons.
"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"	An area in which potential hydrocarbon accumulations or prospects of a given type occur.
"Pliocene"	A geological time period and system, covering the time between 5.3 and 2.6 million years ago.
"porosity"	The percentage of pore volume or void space, or that volume within rock that can contain fluids.
"possible reserves"	An incremental category of estimated recoverable volumes associated with a defined degree of uncertainty. Possible reserves are those additional reserves that analysis of geoscience and engineering data suggest are less likely to be recoverable than probable reserves. The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P), which is equivalent to the high estimate scenario. When probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate.
"pressure"	The force distributed over a surface, usually measured in pounds force per square inch (lbf/in^2), or p.s.i., in US oilfield units.

“probable reserves”

An incremental category of estimated recoverable volumes associated with a defined degree of uncertainty. Probable reserves are those additional reserves that are less likely to be recovered than proved reserves but more certain to be recovered than possible reserves. It is equally likely that actual remaining quantities recovered will be greater or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, where probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate.

“production sharing contract” or “PSC”

A contract signed between a host government and an oil and gas exploration company, regulating how much of the oil and gas produced from a production concession each will receive.

“production”

The phase that occurs after successful exploration and development and during which hydrocarbons are drained from an oil or gas field.

“profit oil”

The amount of production, after deducting cost oil production, which is divided between the participating parties and the host government under a PSC.

“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% of the median potential production area be located within the block or licence area of interest.

“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% probability that the quantities actually recovered will equal or exceed the estimate. Often referred to as 1P, also as “Proven”.

“reflection”

Generally, the return or rebound of particles or energy from the interface between two media. Reflection seismic surveys are useful for mapping geologic structures in the subsurface and evaluating potential hydrocarbon accumulations.

“relinquishment”

The return of part or all of a lease or concession to a lessor, farmor or host government. The return may be voluntary or compelled contractually.

“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"	A subsurface body of rock having sufficient porosity and permeability to store and transmit fluids.
"resources"	In the context of this document, "resources" are potential oil and gas assets that are not yet producing.
"royalty"	A percentage share of production, or the value derived from production, paid from a producing well.
"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"	A clastic sedimentary rock whose grains are predominantly of sand size. The term is commonly used to imply consolidated sand or a rock made of predominantly quartz sand, although sandstones often contain other mineral grains held together with silica or another type of cement. The relatively high porosity and permeability of sandstones make them good reservoir rocks.
"sedimentary"	One of the three main classes of rock (igneous, metamorphic and sedimentary). Sedimentary rocks are formed at the Earth's surface through deposition of sediments derived from weathered rocks, biogenic activity or precipitation from solution. Clastic sedimentary rocks such as conglomerates, sandstones, siltstones and shales form as older rocks weather and erode, and their particles accumulate and lithify, or harden, as they are compacted and cemented. Biogenic sedimentary rocks form as a result of activity by organisms, including coral reefs that become limestone. Precipitates, such as the vaporate minerals halite (salt) and gypsum can form vast thicknesses of rock as seawater evaporates. Sedimentary rocks can include a wide variety of minerals, but quartz, feldspar, calcite, dolomite and vaporate group and clay group minerals are most common because of their greater stability at the Earth's surface than many minerals that comprise igneous and metamorphic 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 fine-grained, impermeable, sedimentary rock composed of clays and other minerals, usually with a high percentage of quartz. Shale is the most common, and certainly the most troublesome, rock type that must be drilled in order to reach oil and gas deposits.
"Silurian"	A geological time period and system, covering the time between 444 and 416 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.
"stimulation"	A treatment performed to restore or enhance the productivity of a well.
"strata"	Layers of sedimentary rock that form beds.

"stratigraphic trap"	A variety of sealed geologic container capable of retaining hydrocarbons. Generally formed by changes in rock type or pinch-outs, unconformities, or sedimentary features such as reefs.
"stratigraphy"	The study of the history, composition, relative ages and distribution of strata, and the interpretation of strata to elucidate Earth history. The comparison, or correlation, of separated strata can include study of their composition, fossil content, and relative or absolute age.
"structure"	A geological feature produced by deformation of the Earth's crust. Most structures in oil and gas exploration are either anticlines or synclines.
"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. An anticline is the opposite type of fold, having upwardly-convex layers with old rocks in the core.
"Tcf"	Abbreviation for trillion cubic feet of gas.
"Tcfe"	Abbreviation for trillion cubic feet of gas equivalent.
"Tcm"	Abbreviation for trillion cubic metres of gas.
"Tertiary Deltaic"	Sediments that were deposited in a deltaic environment at some point during the Tertiary period. A geological time period and system, covering the time between 65 and 1.8 million years ago.
"trend"	A general area in which subsurface geology is expected to be similar and in which hydrocarbons are expected to occur.
"Triassic"	A geological time period and system, covering the time between 251 to 200 million years ago.
"upstream"	A general term which designates the sector of the oil and gas industry focused on exploration, development and production of hydrocarbons.
"wellbore"	The wellbore 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.
"wellhead"	The system of spools, valves and assorted adapters that provide pressure control of a production well.
"wet gas"	Natural gas from which no liquids have been removed prior to the reference point. Contains less methane (typically less than 85% methane) and more ethane and other more complex hydrocarbons.
"wireline log"	A continuous measurement of formation properties with electrically powered instruments to infer properties and make decisions about drilling and production operations. The record of the measurements, typically a long strip of paper, is also called a log. The most common measurements include electrical properties (resistivity and conductivity), sonic properties, active and passive nuclear measurements and dimensional measurements of the wellbore. Equipment lowered into a well on a wire line is also used for fluid sampling, pressure measurements and for sidewall coring.

"working interest"	A percentage of ownership in an oil and gas lease granting its owner the right to explore, drill and produce oil and gas from a defined area. Working interest owners are obligated to pay a corresponding percentage of the cost of exploration, drilling, production and any related activities. After royalties are paid, the working interest also entitles its owner to share in production revenues with other working interest owners.
"workover"	The repair or stimulation of an existing production well for the purpose of restoring, prolonging or enhancing the production of hydrocarbons.
"zone"	Reservoir rock which is bounded above and below by impermeable rock.

The Directors
Petroceltic International PLC
75 St. Stephen's Green
Dublin 2
Ireland

and

The Directors
Davy
Davy House,
49 Dawson St.
Dublin 2
Ireland

17 August 2012

Petroceltic International PLC ("Petroceltic")
Competent Person's Report
Algeria Isarene Permit (Ain Tsila Field)

Dear Sirs

We have been contracted by Petroceltic and J&E Davy to prepare a competent person's report on the Algeria Isarene Permit, Ain Tsila Field (the "Competent Person's Report") that will be included in an admission document prepared in accordance with the AIM Rules of the London Stock Exchange plc and the ESM Rules of the Irish Stock Exchange Limited (the "Admission Document"). The Competent Person's Report has been prepared in accordance with Competent Person's Report scope and content guidelines set out in the AIM Note for Mining, Oil and Gas Companies - June 2009 published by the London Stock Exchange plc ("the AIM Note for Mining, Oil and Gas Companies"). The Competent Person's Report relates solely to the defined licences and is based on various geologic and economic assumptions as detailed in the Competent Person's Report. Therefore, the Competent Person's Report must be read in its entirety.

Qualifications.
AGR was founded in 2005 and, following amalgamation of a number of long-established consultancies including TRACS International Ltd in the UK in 2008, currently has over 100 petroleum engineers, geoscientists and petroleum economists working from seven office locations. AGR has extensive

AGR Petroleum (ME) Ltd
802 Saba Tower 1, PO Box 346097, Jumeirah Lakes Towers, Dubai, UAE
Tel: +971 4 450 9811 Fax: +971 4 450 9810

reserves and asset valuation experience and are recognised as industry reserve, risk and valuation experts.
The reports have been prepared by senior AGR staff members, each with more than 15 years experience in the oil and gas industry. The principal reporter, Mr. Jerry Hadwin has previously reviewed the technical work performed for Petroceltic during 2010, holds a Master of Engineering degree in petroleum engineering and has extensive reserves evaluation experience.
No AGR personnel have any substantive financial interest (past or present) in the Isarene Permit or in Petroceltic International plc.

Opinion
The evaluation presented in the Competent Person's Report reflects our informed judgment based on accepted standards of professional investigation. The evaluation has been conducted within our understanding of relevant legislation, taxation and all other regulations that currently applies to these interests.

Consent
We hereby consent to the inclusion of the Competent Person's Report and to the use of our name in the Admission Document in the form and context in which they respectively appear.

Correct Extraction
We have reviewed the relevant sections of the Admission Document which relate to information contained in the Competent Person's Report and confirm that the information presented is accurate, balanced and complete and not inconsistent with the Competent Person's Report. In particular we confirm that the information in the Admission Document, where extracted from the Competent Person's Report, is extracted directly and presented in a manner which is not misleading or inconsistent with the Competent Person's Report and provides a balanced view of the Competent Person's Report.

Responsibility
We accept responsibility for the Competent Person's Report contained in the Admission Document for the purposes of a competent person's report under the AIM Note for Mining, Oil and Gas Companies. The Competent Person's Report is complete up to and including information available in May 2012. To the best of our knowledge and belief, after having taken all reasonable care to ensure that such is the case, the information contained in the Competent Person's Report is in accordance with the facts and does not omit anything likely to affect the import of such information.

No Material Change
To the best of our knowledge and belief, after having taken all reasonable care to ensure that such is the case, no material change has occurred from May 2012 to the date hereof that would require any amendment to the Competent Person's Report.

Independence
We are independent of Petroceltic, the directors and senior management of Petroceltic and its other advisors. The Competent Person's Report is prepared in return for professional fees based upon agreed commercial rates and the payment of these fees is in no way contingent on the results of the Competent Person's Report, the admission of Petroceltic's shares to trading on AIM or the ESM or the value of Petroceltic.

Yours faithfully,

Jerry Hadwin
AGR Petroleum (ME) Ltd

17 August 2012

AGR Petroleum (ME) Ltd
802 Saba Tower 1, PO Box 346097, Jumeirah Lakes Towers, Dubai, UAE
Tel: +971 4 450 9811 Fax: +971 4 450 9810

Competent Person's Report

Ain Tsila, Isarene Permit, Algeria

for

Petroceltic International plc

Jerry Hadwin

August 2012

This report was prepared in accordance with standard geological and engineering methods generally accepted by the oil and gas industry. Estimates of hydrocarbon reserves/resources should be regarded only as estimates that may change as further information become available. Not only are reserves estimates based on the information currently available, but are also subject to uncertainties inherent in the application of judgemental factors in interpreting such information. AGR Petroleum (ME) Ltd. shall have no liability arising out of or related to the use of the report.

No Political or Country Risk have been accounted for in this evaluation.

Report Author Jerry Hadwin

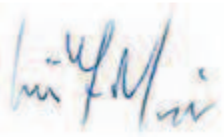
(Director of Reservoir Management, Middle East)

Signed

Approved by

(Director, Middle East) Iain Morrison

Signed



Report status FINAL

Qualification

AGR was founded in 2005 and, following amalgamation of a number of long-established consultancies including TRACS International Ltd in the UK in 2008, currently has over 100 petroleum engineers, geoscientists and petroleum economists working from three office locations. AGR has extensive reserves and asset valuation experience and are recognised as industry reserve, risk and valuation experts.

The Isarene Ordovician discovery evaluation and report was prepared by senior AGR staff members (refer Appendix 2), each with more than 20 years experience in the oil and gas industry. The principal reporter has previously reviewed the technical work performed for Petroceltic during 2010, holds a Master of Engineering degree in petroleum engineering and has extensive reserves evaluation experience.

No AGR personnel have any substantive financial interest (past or present) in the Isarene Permit or in Petroceltic International plc.

This assessment has been conducted within the context of AGR’s understanding of the effects of petroleum legislation, taxation, and other regulations that currently apply to the Isarene Permit. However, AGR is not in a position to attest to property title, financial interest relationships or encumbrances thereon for any part of the appraised properties.

It should be understood that any determination of reserve and resource volumes and corresponding values, particularly involving petroleum developments, may be subject to significant variations over short periods of time as new information becomes available and perceptions change. This is particularly relevant to exploration activities which by their nature involve a high degree of uncertainty.

Yours Sincerely,

AGR

Iain Morrison

Director, Middle East

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The Directors
Petroceltic plc
75 St Stephen's Green
Dublin 2
Ireland

and

The Directors
Davy
Davy House
49 Dawson St.
Dublin
Ireland

Competent Person's Report for Petroceltic International plc

Ain Tsila Field

Executive Summary

This Competent Person's Report concerns Petroceltic International's participation in the Ain Tsila, Cambro-Ordovician Gas-Condensate Reservoir Discovery in the Isarene Block (Block 228-229) in Algeria. Petroceltic International plc ("Petroceltic") is operator of the permit and is in joint-venture partnership in the Block with Enel and the national oil company, Sonatrach S.p.A. Petroceltic presently hold a 56.625% interest; Sonatrach interest is 25% and the remainder is held by Enel Trade S.p.A. ("Enel").

The Reservoir is currently in a pre-development phase, following recent completion of a "Delineation Period", which was the final phase of the "Exploration Stage" as defined in the Production Sharing Agreement (PSA).

Petroceltic (and Enel) filed a "Final Discovery Report" on Ain Tsila in April 2012, and entered into a period of discussion with Sonatrach on the commercialisation options for the gas. These discussions concluded in August 2012 with a unanimous Declaration of Commerciality by the PSA Management Council, and the execution of an "Accord Cadre" (Heads of Terms) between Petroceltic, Enel and Sonatrach which fixes the key commercial terms (price, volumes) for Sonatrach to market the Ain Tsila gas on behalf of the parties. The parties will now draft and execute a gas sales contract honouring those terms.

Sonatrach has now submitted the Ain Tsila commerciality dossier to the Algerian competent authorities, National Agency For Hydrocarbons Valorisation (ALNAFT), who have 60 days to examine it and endorse the declaration of commerciality, expected in the fourth quarter of 2012. Thereafter the field moves into an exploitation phase through the grant of a 30-year "Operating Licence" by the competent authorities, with first commercial gas expected in October 2017.

AGR Petroleum (ME) Limited
Office 207, Golden Falcon Tower, Hamdan Street, Abu Dhabi, UAE
Tel: +971 2 635 3522 Fax: +971 2 635 3577 www.agr.com
Registered in Abu Dhabi

Property Interests Evaluated

Asset	*Operator*	*Interest*	*Status*	*PSC Award Date*	*Phase Expiry Date*	*Licence Area*	*Comments*
Ain Tsila Field (Isarene Permit, Blocks 228, 229A))	Petroceltic International plc	56.625%	Exploration Permit	April 2005	Exploration Stage: Q1 2012 (see comments)	2,564.796 km^2	Final Discovery Report has been submitted, Declaration of Commerciality has been made; it is expected that the licence will be extended to a 30 year Operating Licence.

The Isarene Block is located in the SW of the Palaeozoic *Illizi Basin*, in the SE of Algeria. Whilst a number of discoveries have been made and appraised, the only accumulation deemed to be commercial is the Ain Tsila gas-condensate field. To date, fourteen wells have been drilled on this structure. The nine most recent wells were drilled by Petroceltic with six wells drilled during the Delineation Period which have sufficiently appraised the reservoir to remove remaining subsurface project risk and allow development to move forward subject to the agreement of all partners. Any remaining project risk is therefore related to commercialisation, requiring ALNAFT's approval of the Declaration of Commerciality and the granting of an Operating Licence; this risk is now considered small.

A substantial amount of technical work has been carried out by Petroceltic in parallel with the appraisal programme and is fully documented in the Final Discovery Report ("FDR"). This document presents a full technical description of the reservoir and proposed development scheme. Following an in-depth review of the assumptions and techniques used, the FDR forms the basis of the volumes presented in this document. A full economic evaluation has been conducted by Petroceltic and this shows the proposed development scheme to be commercial; no further economic evaluation has been conducted as part of this CPR.

No Reserves are defined for the Ain Tsila Field whilst negotiations for commercialisation of the gas are ongoing and prior to the granting of an Operating Licence. The producible volumes are therefore classified as Contingent Resources, with probability of success estimated to be 90%.

Contingent Resources Summary (Gross)

Gross Contingent Resources		*1C*	*2C*	*3C*	*Probability of Success*
Isarene Ain Tsila	**Gas (Bscf)**	1,181	2,174	3,124	***90%***
	Condensate (MMbbl)	34.4	70.2	97.7	
	LPG (MMbbl)	61.5	113.0	162.6	
	Total (MMboe)	289.0	538.0	770.4	

Contingent Resources Summary (Net Working Interest)

Gross Contingent Resources		*1C*	*2C*	*3C*	*Probability of Success*
Isarene Ain Tsila	**Gas (Bscf)**	669	1,231	1,769	***90%***
	Condensate (MMbbl)	19.5	39.7	55.3	
	LPG (MMbbl)	34.8	64.0	92.1	
	Total (MMboe)	163.7	304.6	436.2	

1. Introduction

AGR Petroleum (ME) Ltd ("AGR") was commissioned by Petroceltic International plc ("Petroceltic") to complete a Competent Person's Report assessing the resource potential of the Ain Tsila gas discovery in the Isarene Permit in southern Algeria. The relevant reservoirs are contained within the glacial clastics of the Ordovician Unit IV. The Devonian Isarene prospects and discoveries are not presently deemed to be commercial and are not included in this report.

Property Interests Evaluated

Asset	*Operator*	*Interest*	*Status*	*PSC Award Date*	*Phase Expiry Date*	*Licence Area*	*Comments*
Ain Tsila Field (Isarene Permit, Blocks 228, 229A))	Petroceltic International plc	56.625%	Exploration Permit	April 2005	Exploration Stage: Q1 2012 (see comments)	2,564.796 km^2	Final Discovery Report has been submitted, Declaration of Commerciality has been made; it is expected that the licence will be extended to a 30 year Operating Licence.

All volumetric calculations are based on 3D reservoir modelling carried out by Petroceltic for the Final Discovery Report (FDR) based on well data available up to, but not including, the AT-9 delineation well, including core data.

The Ordovician Unit IV is characterised by low matrix porosity and permeability and generally requires favourable facies and/or the presence of fractures to achieve substantial flow rates. Sector models tuned to productivity tests have been used to estimate recoverable volumes.

The resource estimates presented in this report have been prepared in accordance with reserves definitions presented in the SPE's Petroleum Resources Management System ("SPE-PRMS", Appendix 4), and the risking of contingent resources has been done in accordance with the LSE/AIM Guidance note for Mining, Oil and Gas Companies ("LSE/AIM Guidelines").

Estimates of petroleum reserves and contingent and prospective resources should be regarded only as estimates that may change as additional information becomes available. Not only are such reserve and resource estimates based on that information which is currently available, but such estimates are also subject to the uncertainties inherent in the application of judgement factors in interpreting such information.

No site visit was considered necessary as there are no active wells or production facilities currently in the licence.

The evaluation was performed by senior AGR staff as detailed in Appendix 2.

2. Overview of Regions, Locations and Assets

The 2,564.796 km^2*Isarene* block (or *Isarene Field* (*Blocks 228, 229A)* as designated by Sonatrach) is located in the SW of the Palaeozoic *Illizi Basin*, in the SE of Algeria (Figure 2-1). The effective date of the Isarene Production Sharing Contract is the 26th April 2005 and 30% of the permit was relinquished, in April 2008, at the end of the First Exploration Period. The Second Exploration Period, which allowed for the drilling of wells AT-1, -2 and -3 and discovery of the Ain Tsila structure by the present joint venture partners, ended in April 2010.

The Ain Tsila reservoir was then subject to a two-year Delineation Period of focused appraisal, including the drilling, evaluation and testing of six additional wells. A Final Discovery Report, completed in April 2012, consolidates subsurface data from all the exploration/delineation periods and includes the proposed development plan for the field.

The centre of the block, when taken as the position of the *Irarraren-1* (*IR-1*) wildcat, is located:

- 1,100 km SSE of Algiers and 160 km NW of Illizi, the head town of the namesake "wilaya", the main territorial and administrative subdivision of Algeria,
- 105 km from the nearest gas pipeline in the Repsol operated *Tin Fouye Tabankort* oil and gas field (TFT) and
- 55 km from the Repsol operated *Tifernine* oil field

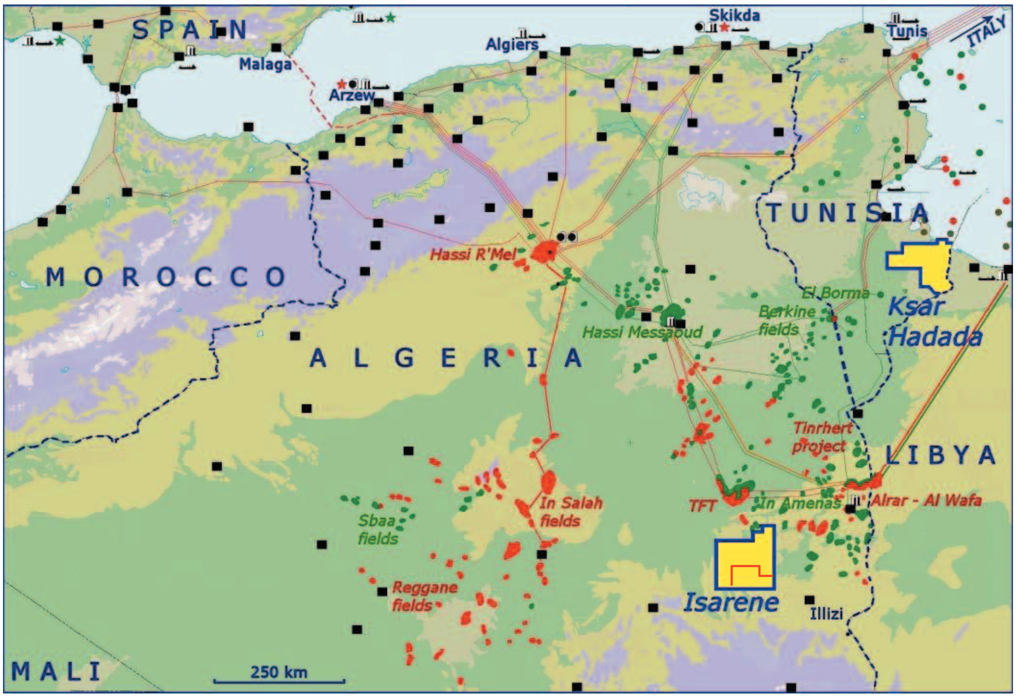


Figure 2-1: Isarene Block Location in Algeria

The Block lies in a desert area covered with dune cordons in the 50 to 100 m range, with the SE corner being more exposed with outcrops and a few isolated small barkhans (croissant dunes). An abrupt escarpment lies 60 km to the north on the proposed evacuation route to the TFT pipeline system.

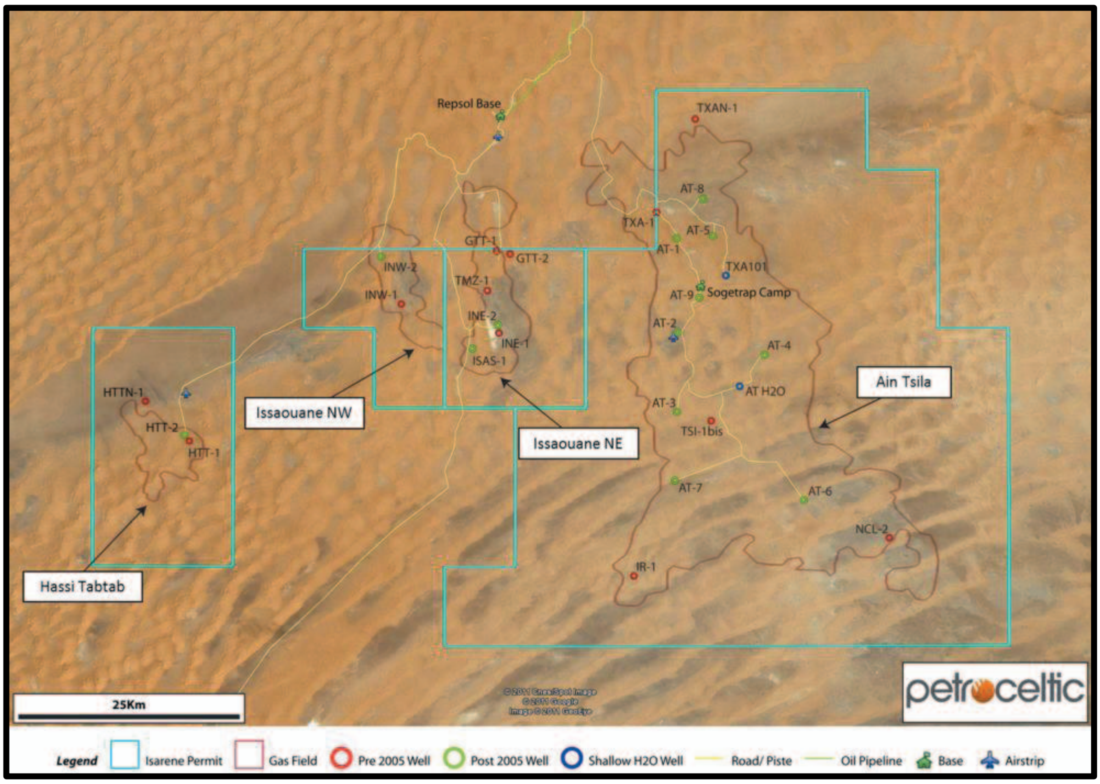


Figure 2-2: **A satellite view of the Isarene block – showing the location of all exploration and delineation wells up to AT-9.**

15 wells have been drilled in and around the Ain Tsila structure, penetrating the Ordovician: AT-1 to 9, TXA-1, TXAN-1, TSI-1bis, NCL-2, CLR-1 and IR-1. Although the latter five wells were drilled first, AT-1, drilled by the Petroceltic-Sonatrach association in 2009, was officially designated the discovery well. Of the 15 wells, 12 produced gas to surface and the remaining three showed hydrocarbon indications over the Ordovician. The wells prefixed 'AT' are those that were part of the Petroceltic-Sonatrach drilling programme.

Based on the information provided by the drilling and seismic programme and the interpretation thereof, an Exploitation Permit Perimeter, the potential development area, has been proposed. This area extends to the lesser of the limits of the 228/229a Blocks and a distance 1 km from the mapped spill point depth (shown in brown in Figure 2-2).

Hydrocarbon resources have been encountered in Devonian and Carboniferous reservoirs in the Exploration Block, but these have been deemed not to be commercial at this point in time and have not been reviewed as part of this CPR. Additional hydrocarbon resources that were encountered in shallower reservoirs directly overlying the Ain Tsila structure were not fully evaluated as the Joint Venture has no entitlement to these resources at the present time. This CPR specifically evaluates the Ordovician resources of the Ain Tsila structure.

3. Technical Evaluation

3.1. Introduction

The technical evaluation upon which this CPR is based has been carried out by Petroceltic up to the filing of the Final Discovery Report in April 2012, on the basis of data from wells up to and including well AT-8. Whilst AT-9 was a successful horizontal well which produced at high gas rates from natural fractures without a programme of hydraulic fracturing, the AT-9 well data were obtained too late for integration into the FDR.

The Ain Tsila discovery is a large structural closure extending up to 1800 km^2 (approx. 65 by 30 km). It is covered by 3D seismic in the north and an extensive grid of reprocessed 2D seismic in the south. The tie between the 3D and 2D data is considered to be excellent thus giving confidence to the extent of this large structure.

Isochore mapping and structural restoration (flattening of seismic lines) indicate that the Ain Tsila structure was initially formed during the Silurian. Although the morphology of the structure has changed through time, the isochores indicate that a closure was likely to have been present on the Ain Tsila structure during the period of initial hydrocarbon (oil) charge in the Tournaisian. During subsequent tilting of the Illizi Basin to the north, the Ain Tsila structure continued to maintain closure at Ordovician level and is therefore considered to be filled to spill to at least the currently mapped closing contour of -1970 mBSRD (metres below seismic reference datum) in the P50 case, with hydrocarbons observed below this depth not presently included in volumetric estimates.

The principle productive interval is the Ordovician Unit IV sandstone, with a net thickness of approximately 110 m at the AT-1 Discovery Well location. Porosity is low, averaging 6% in the net sand and matrix permeability, measured from extensive core recovery, is very low; in the range of microdarcies (μD) and below. In three wells, AT-1, AT-8 and AT-9, a higher porosity and permeability unit up to 9 m thick is encountered within the Unit IV-3, with permeability values measured in hundreds of mD and up to 700 mD. Occasional higher permeability streaks are observed in other wells but these are not thought to be extensive. This high permeability facies in Unit IV-3 is also known in nearby analogue fields, such as TFT and Ohanet.

A very large GIIP has been proven by the delineation drilling, however the key to commercial success in this reservoir is well productivity. Productivity is believed to be governed by natural fracturing and the presence of the high permeability facies, but flow rates can be substantially enhanced by hydraulic fracture treatments.

Most of the wells drilled during the Second Exploration Stage and the Delineation Period show some evidence of natural fractures; either simply through well productivity greater than what is theoretically possible for the observed matrix permeability, core observations, drilling (mud-loss) observations or qualitative productivity behaviour (e.g. water production through a fracture network extending below the GWC). Quantification of the production enhancement due to fractures has been carried out by single well simulation modelling. The data are generally supportive of a model whereby fracture 'swarms', located in the damage zones of identified faults, provide enhanced productivity, which lessens away from the faulted areas.

Productivity has been shown to be significantly improved in a number of wells through hydraulic fracture stimulation and where open-hole multistage completion techniques have been employed. The technique has mostly been successful but there are exceptions and there is a large variation in well productivity achieved in the appraisal wells. Open-hole completion techniques were first deployed on the horizontal sidetrack AT-5ZST. The first vertical well where an open-hole completion was permitted to be deployed was AT-7. Prior to that, a cemented liner completion had been used, the performance of which has been significantly impairing the production potential as no conventional perforation techniques could be employed.

3.2. Geological setting

The regional setting of the Ordovician petroleum system in Algeria is well-described in the literature and summarised in a number of Petroceltic documents (e.g. Petroceltic's Isarene Prospectivity Report; Pre-drilling assessment, February 2006, Isarene Core Atlas, March 2008 and Isarene Stratigraphical and Sedimentological Study, August 2008).

The Ordovician IV reservoir interval comprises a mixed clastic assemblage deposited during deglaciation of a late Ordovician (Hirnantian) ice sheet. Reservoir distribution is strongly influenced by the interplay of proglacial and marine deposition upon a prominent sub-glacial topography. Analogous reservoirs are present in the Tiguentourine and Tin Fouye Tabankort Fields.

The assumption of how the accepted regional setting plays out over the Ain Tsila discovery has a significant impact on reservoir characterisation and derivation of field-scale volumetrics Ordovician IV Reservoir Framework.

3.2.1. Ordovician IV Reservoir Framework

Seismic interpretation (on both 2D and 3D data) confirms the presence of strongly incised N-S trending valley features running through the Ain Tsila field area. Individual valleys are 5-12 km in width and display U-shaped valley floors with up to 350 m of relief, locally incised into shales and sandstones of outer to inner shelf origin within the Ordovician III. The valleys show a general convergence in a northerly direction.

These valley features represent sub-glacial valleys that have been enlarged by glacial erosion and sub-glacial fluvial channels. It is noted that the predominant NNW-SSE valley direction is comparable to the N-S and NW-SE Cambro-Ordovician fault pattern mapped from seismic. It is likely therefore that many of the valley features may have initially formed in response to this fabric (as well as the overall palaeogeographic setting with ice sheets expanding from the south) and then been enlarged through glacial growth and retreat.

Whilst the Ordovician IV reservoir interval is bounded by prominent seismic reflectors, it lacks consistent internal reflectivity so it has been sub-divided on the basis of core-calibrated log picks and geologically constrained isochores. The adopted reservoir correlation is lithostratigraphic in foundation and records the progressive filling and reorganisation of the valley features during and following waxing and waning, then final retreat of the ice sheet.

Three principal sub-units are recognised within the Ordovician IV of the study area comprising, from the base, the IV-1 the IV-2 and the IV-3.

3.2.2. Depositional Model

The current reservoir description is based upon sedimentological analysis of core and image logs acquired by Petroceltic in their AT wells and integrates the 384 m of core from the pre-AT wells. The only Petroceltic well not cored was AT-9 though image logs were obtained. Core material is heavily weighted towards the IV-3 and IV-2 units, with IV-1 the least represented.

Core observations from outwith Ain Tsila plus log character suggest Unit IV-1 comprises stacked sub-glacial moraines and tillites and possibly mass-flow deposits (IV-1a) passing upwards into pro-glacial mass-flow sands (IV-1b).

Unit IV-2 represents a further transition into pro-glacial high and low-density turbidite deposits. The IV-2a is sand-rich whilst the IV-2b is mudstone dominated by only thin sands and evidence of glacial dropstones suggesting increasing relative sea-level causing progressively limited glacial input to this part of the basin. Unit IV-2 is absent in the northern part of Ain Tsila structure, either through non-deposition or erosion. In this area, Unit IV-3 lies directly on Unit IV-1.

Unit IV-3 represents a significant shift of shorelines and shallowing of water depth due to (post-glacial) isostatic rebound in the north. The presence of shallow marine trace fossil assemblages and occasional tidal features suggest deposition of Unit IV-3 sands in an inner shelf setting. Palaeocurrent indicators in Unit IV-3 are complex but onlap of seismic reflectors within the overlying Silurian shales suggest deposition of Unit IV-3 from the north whereas the sub-glacial Unit IV-1 was deposited from the south.

These environmental interpretations are consistent with established models for the (Upper) Ordovician within North Africa.

3.2.2.1. Reservoir Unit IV-1

Unit IV-1 comprises the majority of the Ordovician IV interval and dominates the section of those wells drilled within the valley features. The Unit is recognised on logs as a blocky assemblage with occasional shale inter-beds. The base is penetrated only in those wells drilled away from the deepest part of the valleys.

The thickness maps produced show that the IV-1a can be up to 300 m thick but is restricted entirely to the mapping valley features whilst the IV-1b, although thinner, is slightly more widespread – indicative of gradual over-filling of the valleys.

3.2.2.2. Reservoir Unit IV-2

Unit IV-2 is much thinner than Unit IV-1 (ranging from 20 to 70 m in wells) but shows a slightly more widespread distribution. The base is penetrated in most of the field wells with the boundary to the IV-1 typically picked at a prominent shale.

Whilst the sand-rich IV-2a is again thickest within the valley features, the IV-2b is thickest outwith or on the immediate flanks of the valleys. Unit IV-2 is absent in the northern part of Ain Tsila structure, either through non-deposition or, more likely, erosion. In this area, Unit IV-3 lies directly on Unit IV-1.

3.2.2.3. Reservoir Unit IV-3

Unit IV-3 is recognised on logs as a clean to cleaning-upwards sandstone interval, typically around 10 m thick (exceptionally 37 m in AT-7) sitting on shales of the IV-2b, where present, and abruptly overlain by high Gamma Ray shales of the Silurian. The base of the IV-3 represents a significant unconformity and is associated with absence (erosion) of the IV-2b in the north of the field area.

The best matrix porosity-permeability of the Ordovician IV proven from core to date is typically associated with thin coarser-grained to granular beds towards the top of unit IV-3. This is interpreted to represent reworking and incorporation of older glacial outwash deposits being progressively uplifted to the north of the field area.

The isochore of IV-3 differs from the underlying IV-1 and IV-2a units in not following the underlying glacial valleys.

3.2.2.4. Further Observations

The lack of IV-2 in the north of the field area is most obviously taken to represent sub IV-3 erosion - ravinement associated with transgression of the previous pro-glacial setting.

Similar such erosional surfaces are not explicitly defined within the individual reservoir units but may be expected. A sequence stratigraphic model in which key stratal surfaces linked to periods of both erosion and deposition may be possible to establish during future development when a greater well stock is available. Such a model will provide a more predictive basis for facies (and reservoir quality) distribution but is not considered an issue for field-wide volumetric evaluations.

3.3. Wells

The following wells have been drilled on and around the Ain Tsila structure with locations shown in Figure 3-1:

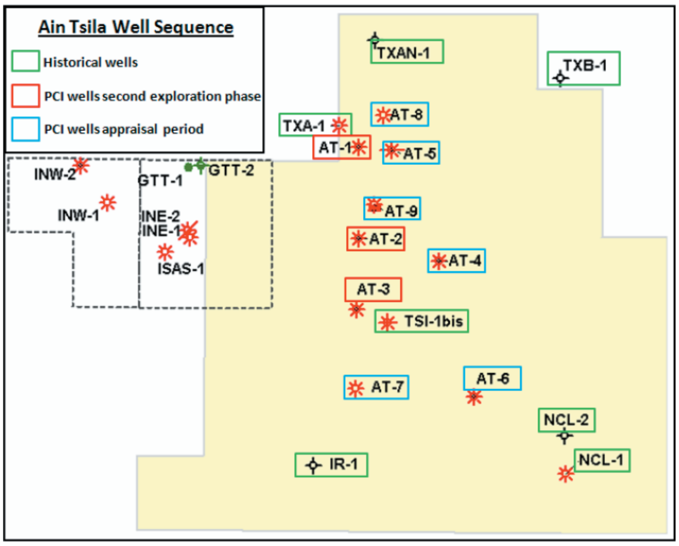


Figure 3-1 Relative Location of the Isarene / Ain Tsila Wells

Couloir-1 (CLR-1)

This well, drilled by CREPS in 1958, is not shown on Figure 3-1 because it is due south of NCL-1 and outside the Delineation Area. However, it has a historical importance as the first well in the Isarene area and reached Total Depth (TD) in the Cambrian at 2,133 mBRT. The Cambro-Ordovician was not tested, but high resistivity sandstones at the top of the Ordovician sequence may represent bypassed hydrocarbons.

Tihigaline A-1 (TXA-1)

TXA-1 was drilled by CFP(A) in 1963 and reached TD in the Ordovician Unit III at 2454.2 mBRT. *TXA-1* encountered a glacial valley in Unit IV of 330 m which tested aggregated 0.53 MMscf/d gas with traces of condensate. Based upon shows, numerous tests and open-hole logs, the Ordovician Unit IV is interpreted to have a hydrocarbon column of 84 m (1909-1993 mBRT). Saline water (40.3 g/l) was tested below this level and may represent a water leg or locally moveable water.

Irarraren-1 (IR-1)

IR-1 was drilled by SAFREP in 1963 and reached TD in the Ordovician Unit III at 2160 mBRT. The test of the uppermost Ordovician section was dry, although some gas was observed bubbling from a core of this upper unit. Maximum permeability from core from the Unit IV-3 was 159 mD (from a small interval) in what are described as fine-to-coarse grained sands. The IR-1 core was re-sampled by Petroceltic and confirmed the occurrence of occasional higher permeability streaks. A small volume of mud and saline water was recovered from the open-hole test.

Ain Tsila-1bis (TSI-1bis)

This is an important data point, being near to the crest of the Ain Tsila structure. Drilled by Sonatrach in 1986, the original well (*TSI-1*) was abandoned at the Visean level and was not able to run further down hole because of excess gas in the hole. The re-spudded *TSI-1bis* well reached TD in basement at 2461 mBRT and tested 0.167 MMscf/d from the top Ordovician Unit IV-3. The testing procedure was inconclusive as both packers may have leaked on test and the test covered a large interval of open hole. However, gas production and good gas shows confirmed the presence of gas charge.

Nord Couloir-2 (NCL-2)

NCL-2 was drilled by Sonatrach in 1988 and reached TD in the basement at 2599 mBRT, having encountered a glacial valley in the Lower Ordovician with hydrocarbon shows and a thin (5.5 m) Unit IV-3 at the top. Testing of the Ordovician, open-hole over all intervals, encountered a weak gas flow and recovered gassy mud.

Tihigaline A Nord-1 (TXAN-1)

Repsol drilled TXAN-1 in 1997 to 2140 mBRT as an ***oil*** appraisal well north of *TXA-1*. The well was drilled downdip from *TXA-1* to assess the accumulation that had been encountered in the Ordovician reservoir in *TXA-1 (*with potential for down-dip oil). The well had good yellow fluorescence from the top of the Ordovician Unit IV down to 1,981 mbRT. Repsol ran an MDT with one of the 3 sample chambers, but this only yielded mud filtrate. In their re-evaluation of this well, Petroceltic found that the Repsol conductivity log was incorrectly labelled and was, in fact, a resistivity log. When correctly interpreted the well contains a significant gas column. *TXAN-1* is considered to be only just within the currently mapped structural closure of Ain Tsila Prospect. However, the apparently deeper gas column and associated GWC is consistent with the Petroceltic saturation model which requires a theoretical free-water level, derived from capillary pressure data, at -1680 mss. Also, variations in contact are feasible due to stratigraphic or hydrodynamic trapping, as in the Tin Fouye Tabankort (TFT) Field. Permeabilities in Unit IV were found as high as 11.3 – 24.9 mD. No conventional tests were run on this well before it was abandoned due to tools being stuck in the hole.

Ain Tsila-1 (*AT-1*)

This is the first well drill on Ain Tsila structure by the Petroceltic-Sonatrach Joint Venture. It was drilled at a location approximately 3.5 km SE of TXA-1 in 2009 and reached TD in the Ordovician IV-1a at 2,118 mBRT, after 26 days drilling. It was the first well of the second Exploration Phase and all subsequent wells have been drilled by Petroceltic. The Ordovician Unit IV unit was encountered at 1915 mBRT and an extensive open-hole logging suite confirmed the presence of gas at *AT-1* with a log interpreted gas down to of 2,001 mBRT. Two cores were cut (27 m each), confirming the presence of reservoir quality sandstones in the Ordovician, with maximum measured permeability of 775 mD. The well was perforated from 1915-1919 mBRT and tested hydrocarbons at a rate of 7.75 MMscf/d of gas and 233 bbl/d of condensate, with a flowing wellhead pressure of 1,456 psi on a 32/64" choke. The well was tested under natural flow but because of a high mechanical skin it was considered a candidate for fracturing. Post fracture the well tested 12.5 MMscf/d gas and 368 bbl/d condensate on a 32/64" choke with a wellhead pressure of 2296 psig, but gas rates as high as 33.8 MMscf/d were achieved on a 80/64" choke. The discovery declaration was made on 22 September 2009.

Ain Tsila-2 *(AT-2)*

Also drilled in 2009, AT-2 reached TD in the Ordovician Unit IV-1a at 2075 m, approximately 11.4 km south of AT-1, after 33 days of drilling. The Ordovician Unit IV was encountered at 1914 mbRT. A limited quantity of core was recovered with maximum measured permeability of 0.4 mD. Wireline logging indicated a gas column in excess of eighty metres. The well was perforated and fractured from 1920 mBRT to 1922 mBRT and tested hydrocarbons at a maximum rate of 4.8 MMscf/d + 42 bbl/d condensate with a flowing wellhead pressure of 885 psi on a 32/64" choke. The pressure analysis confirms that the well is in the same hydrostatic pressure regime as the AT-1 well.

Ain Tsila-3 *(AT-3)*

The final well drilled in 2009, AT-3, reached TD in the Ordovician at 2045 m after 27 days of drilling. The top of the Ordovician Unit IV was encountered at 1897 mBRT. One core was cut from 1894.0 to 1921.3 mBRT, with a maximum measured permeability of 1.5 mD. Wireline logging indicates a gas column in line with previous wells but hydrocarbon shows were weak. The well was perforated from 1931 to 1933 mBRT but an attempt to propagate a hydraulic fracture could not be completed as significantly higher *in situ* rock stresses were encountered at this location than at the AT-1 or AT-2 locations, and only a small proportion of the required proppant could be pumped into the formation. Nevertheless, pressures derived from a precursory Diagnostic Fracture Injection Test (DFIT), indicate that the AT-3 gas column is in the same pressure regime as the gas columns in AT-1 and AT-2. In addition, a small flow of gas, equivalent to 75,000 scf/d, was achieved.

Ain Tsila-4 *(AT-4)*

This is the first well of the 2010-2011 Delineation Period by the Petroceltic-Sonatrach Joint Venture. The objective was to appraise the reservoir in the previously undrilled eastern margin outside the main glacial valley trend. Top Ordovician was encountered at 1920.5 mBRT and the well reached TD in the Ordovician Unit III-3 at 2142 mBRT after 32 days drilling. Extensive coring was conducted, with 48.8 m recovered; permeability up to 83 mD was measured. As planned prior to drilling, no pre-frac test was conducted and the vertically extensive gas zone was hydraulically fractured twice, once in the Unit III-3 and then the Unit IV-1b having temporarily isolated the lower fracture. The well produced a significant amount of water (in addition to achieving a maximum gas rate of 1.3 MMscf/d) even with the lower fracture isolated. This is interpreted to show a connected natural fracture network, enhanced by the induced fracture treatment, extending below the GWC.

Ain Tsila-5 *(AT-5)*

This well and all subsequent wells up to AT-9 were drilled by Petroceltic in 2011. Targeting a large "pop-up" feature, approximately 1.5 km in diameter identified from the seismic, AT-5 is located approximately 4.2 km east of AT-1. In order to optimise the drilling of the planned horizontal sidetrack from the approved surface location, the pilot well, AT-5, was drilled as a slightly deviated hole to be followed by horizontal sidetracking as AT-5Z. Due to a momentary power failure resulting in collapse of the Silurian shale hole section, the initial attempt to drill the sidetrack resulted in stuck pipe close to the top of the reservoir. Success was achieved on the second attempt with AT-5ZST. However, the new horizontal drain was oriented to optimise drilling parameters and was not optimal for intersecting natural fractures.

TD in the pilot hole was 2049 mBRT in the Unit IV-1a, having encountered top Ordovician at 1961.5 mBRT and taking significant mud-losses. Logging was carried out by LWD but subsequent pipe-conveyed logging failed. 31 m of core was cut (77% recovery) across the top of the reservoir (starting in the Silurian hot shale, down through Units IV-3 and IV-2 and into IV-1b). Core and image logs indicate significant open natural fractures at the pilot well location. Maximum permeability measured was 1.2 mD, which showed that the high-permeability sand was not present at this location (important to know during interpretation of subsequent well testing).

The pilot hole was not production tested and could not have been tested due to the well and completion design which was optimised for testing the horizontal drain. The successful sidetrack, AT-5ZST, was drilled at approximately 84° and reached a TD of 2421 mBRT (377 m horizontal length) in the upper reservoir, Unit IV-3. Due to ledging a short distance into the reservoir, no logs could be run. Nevertheless, a four-stage, selective packer completion (uncemented) was run to allow hydraulic fracturing and testing of a number of potential productive zones.

Prior to fracture treatments, the well flowed at a maximum rate of 1.3 MMscf/d with 30 bbl/d of condensate from the upper port only. Despite sub-optimal performance of the completion (only three fractures out of four were successfully placed) and preferential production from one completion port at the heel of the well, a post-fracture rate of 3.4 MMscf/d with 29 bbl/d of condensate was achieved. The well has been suspended to allow for future production.

Ain Tsila-6 *(AT-6)*

The first well to be drilled by Petroceltic outside the 3D seismic area, AT-6 was located approximately 14.2 km southeast of TSI-1bis, 18.2 km southeast of AT-3 and 17.5 km south-southeast of AT-4. The well was drilled to delineate and test the productivity in the south of the field, targeting a broad culmination in the southeastern leg of the glacial valley. Top Ordovician was encountered at 1951.5 mBRT and TD was in the Unit IV-1a at 2117 mBRT after 26 days of drilling. 37 m of core was recovered, with evidence of hydrocarbons and some flushing and analysis showed permeability up to 0.7 mD. Gas readings during drilling were generally low. The well was perforated and successfully fractured but failed to flow on test. Reasons for this failure are anomalous based on previous well results. Comparisons with offset poorer reservoir quality wells which were successfully tested suggest similar reservoir quality at AT-6. This was the last well drilled by Petroceltic to use a conventional cemented liner completion. It is considered that this is likely a local phenomenon and that regions in the south of the field will ultimately be developed with improved completion and stimulation technology.

Ain Tsila-7 *(AT-7)*

AT-7 was also drilled outside the 3D area in the south of the field, but this time to appraise the southwestern leg of the main glacial valley, 14.8 km west of AT-6 and 10 km south of AT-3. The well encountered the top Ordovician at 1935 mBRT and reached TD at 2142 m BRT in the Unit IV-1a after 25 drilling days. Two cores were cut from the top of the reservoir achieving a total recovery of 37 m. Maximum measured permeability was 0.18 mD and a hydrocarbon fluorescing fracture was observed at 1943 mBRT. The well did not flow prior to fracture treatment. Following hydraulic fracturing, using a multistage open-hole packer completion, a maximum rate of 5.4 MMscf/d of gas was achieved.

Ain Tsila-8 *(AT-8)*

AT-8 is a vertical appraisal well inside the 3D seismic area, 5.1 km to the northeast of AT-1, 4.5 km to the north-northwest of AT-5, 5.6 km east of TXA-1 and 9.3 km south of TXAN-1. It was drilled as a vertical well to appraise the damage zone of a major fault system associated with a structural pop-up feature. Based on the geological model, it was also designed to test for the high-permeability sand found in well AT-1.

Top Ordovician was found at 1960.4 mBRT and TD was reached at 2122 mBRT in Unit III-3 after 34 days of drilling. A single 13.5 m core was cut with high recovery. The core exhibited a strong hydrocarbon odour and the measured permeability ranged up to 146 mD (confirming the presence of the high-permeability sand). The reservoir was completed with a multistage open-hole packer completion. The well was tested prior to and following hydraulic fracturing. The pre-frac test was conducted in intervals, with maximum rates of 2.4 MMscf/d with 120 bbl/d condensate (Unit IV-1b), 4.8 MMscf/d with 129 bbl/d condensate (IV-2a), 5.8 MMscf/d with 214 bbl/d condensate (IV-3 / IV-2a) and 5 MMscf/d with 114 bbl/d condensate (IV-3). The final IV-3 zone was fractured and the well produced a maximum rate of 38.6 MMscf/d from this completion port alone. The well has been suspended for production.

Ain Tsila-9 *(AT-9)*

This was the final well drilled during the Delineation phase by Petroceltic. The reservoir was drilled horizontally (87°) with no pilot hole at a location 4.3 km northeast of AT-2, 7.8 km south-southeast of AT-1 and 7.5 km south-southwest of AT-5. The objective was to find and test production from open natural fractures associated with a mapped 'pop-up' feature with different structural character to those observed at AT-1, AT-5 and AT-8 and within the main glacial valley. The well was spudded on 12 September 2011, encountered top Ordovician at 2089 mBRT and reached a TD of 2494 mBRT on 24 October 2011 in Unit IV-3. Core was not taken in this well. Gas readings were high and there was evidence of micro-fracturing during drilling from micro-loss measurements. Log analysis showed the presence of a 9 m (TVT) thick high porosity unit within Unit IV-3 and the subsequent test results confirmed the presence of the depositional high permeability unit at this location. Average permeability over this interval is calculated from log data to be about 95 mD. This result was unexpected and extended the range of the high permeability sand further south than previously thought. The well was completed with a multistage open-hole packer completion and tested prior to a possible fracture treatment. Individual stage tests were conducted from two ports; the first flowed at a gas rate of 6.7 MMscf/d with 197 bbl/d condensate and the second produced at 11.9 MMscf/d gas with 295 bbl/d condensate and also achieved a very high maximum rate of approximately 66 MMscf/d of gas. As the rates were surface facility constrained it was not deemed to be of any benefit to hydraulically fracture the well.

In summary, and most importantly in the context of this CPR, the AT-1 to AT-9 wells confirm the presence of a large, probably continuous gas accumulation within the Ain Tsila Ordovician reservoir over the drilled area and beyond. Although principally a structural closure, some stratigraphic control on the presence of gas is also recognised. This is largely due to variations in the (generally low) rock quality and hence capillarity. Using the SCAL and log-interpreted best-fit GWC (approximately 1570 mTVSS), the Ain Tsila-1 discovery is considered to include the areas drilled by TXA-1, and TXAN-1 (Tihigaline) in the north to NCL-2 (Nord Couloir), and IR-1 in the south. It has been proven that open natural fractures exist and are productive. Completion and stimulation techniques, whilst still requiring some optimisation, have been sufficiently established to allow reliable (multistage) hydraulic fractures to be placed. The high permeability sand encountered at AT-1 has been shown to occur in other wells and, as further wells are drilled during the development phase, a reliable way of predicting the distribution will undoubtedly be developed.

3.4. Formation Properties

3.4.1. Available Data

With the exception of certain logs on AT-5 (operational issues) the evaluation data acquired on wells AT-1 to AT-9 is considered to be of good quality. This data is supplemented by core data and results of both routine and special core analysis studies. All wells within the Ain Tsila accumulation have been evaluated petrophysically and a consistent suite of property curves has been calculated.

3.4.2. Workflow

V_{clay} was derived from GR using linear interpolation between chosen end points.

Porosity was derived using the density logs only, but calibrated to core where available, with a good match of datasets being observed.

Core investigation reveals that despite the range of depositional facies identified, the effects of diagenesis apparently limit the distinction of reservoir rock on the basis of its initial depositional environment or grain size. The most reliable discriminator of reservoir rock type is considered to be pore system type with three end-members identified (from SEM and thin-section).

The distinction between these three rock-types using logs in turn allowed their discrimination in uncored sections and so provided a basis for prediction of permeability through facies specific porosity-permeability relationships.

The resulting petrophysical averages show that the porosity of the Ordovician IV as a whole ranges from 5% to 6.8% across the analysed wells with high values noted in the AT-6 and NCL-2 wells of the southern field area. It would be expected that the quantification of porosity in such low porosity reservoirs may be subject to large uncertainty. However the strength of the calibration to core (and also to alternative porosity calculations, such as that from sonic) as well as the good agreement in average porosity across all wells, indicates a robust characterisation of this parameter.

Average permeabilities are everywhere very low (typically in the order of 0.1 mD) the exception being in those wells, such as AT-1, with local high permeability lenses that result in Unit average values of more than 1 mD and high values in 100s of mD.

Saturation was determined using an Archie model, with 'a' and 'm' based directly upon core experiments and the water salinity of 156 kppm derived from the AT-8 well-test.

3.4.3. Fractures

High resolution resistivity images, combined with reference to detailed core logging, were used to evaluate the presence and style of fractures within the Ordovician IV reservoir. For all wells, the majority of fractures identified on logs are considered to be drilling-related but generations of older fracture sets (both open and filled) were also noted. Images of core material showing fracturing (in multiple wells) are shown in Figure 3-2.

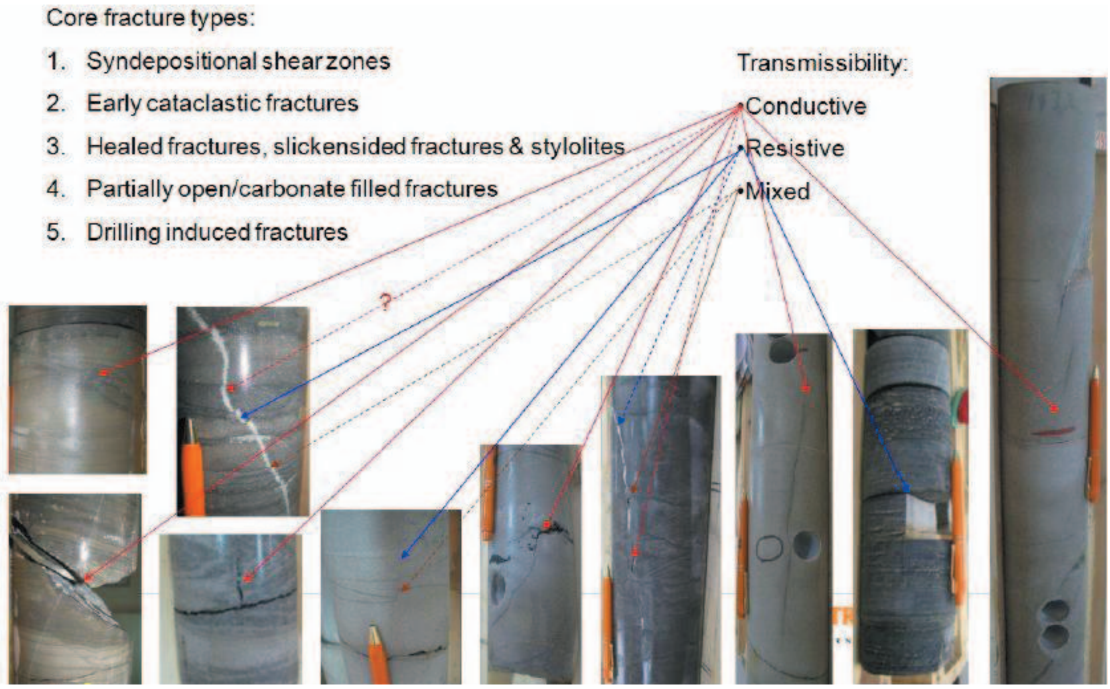


Figure 3-2 Ain Tsila Core Fracture Types

Fracture density is generally observed to be low, but with occasional zones of more intense fracturing (e.g. in AT-5, with more than 10 fractures/m) interpreted as corresponding to fault-related fracture corridors. Interpretation of natural fracture contributions to productivity also requires calibration and interpretation of well test data which confirms the importance of natural fracture networks to the overall producibility of the Ain Tsila reservoir (see Sections 3.7 and 3.8).

Fracture orientation was typically variable but populations trending both NW-SE and N-S could be distinguished – notably parallel to the seismically mapped faults. In general, the natural fracture systems are consistent with the regional stress regime, confirmed during the 2011 Delineation drilling, with the maximum horizontal stress oriented approximately NW-SE, the regional trend. The only exception to this was at AT-3 where an orientation close to N-S was observed. This has not been explained and may be a tool calibration error or due to a local anomaly in the stress field.

3.5. Seismic interpretation

3.5.1. Seismic data

The north of the Ain Tsila Field is covered by the 892 square km Isarene 3D seismic dataset which was acquired in Jan-August 2008 using vibroseis. The data was processed in 2008/09. The rest of the Isarene permit is covered by 2D seismic lines acquired from the 1970s to the 2000s and reprocessed in 2005-2010 (Figure 3-3); there is higher uncertainty in the structural interpretation outside the 3D seismic area.

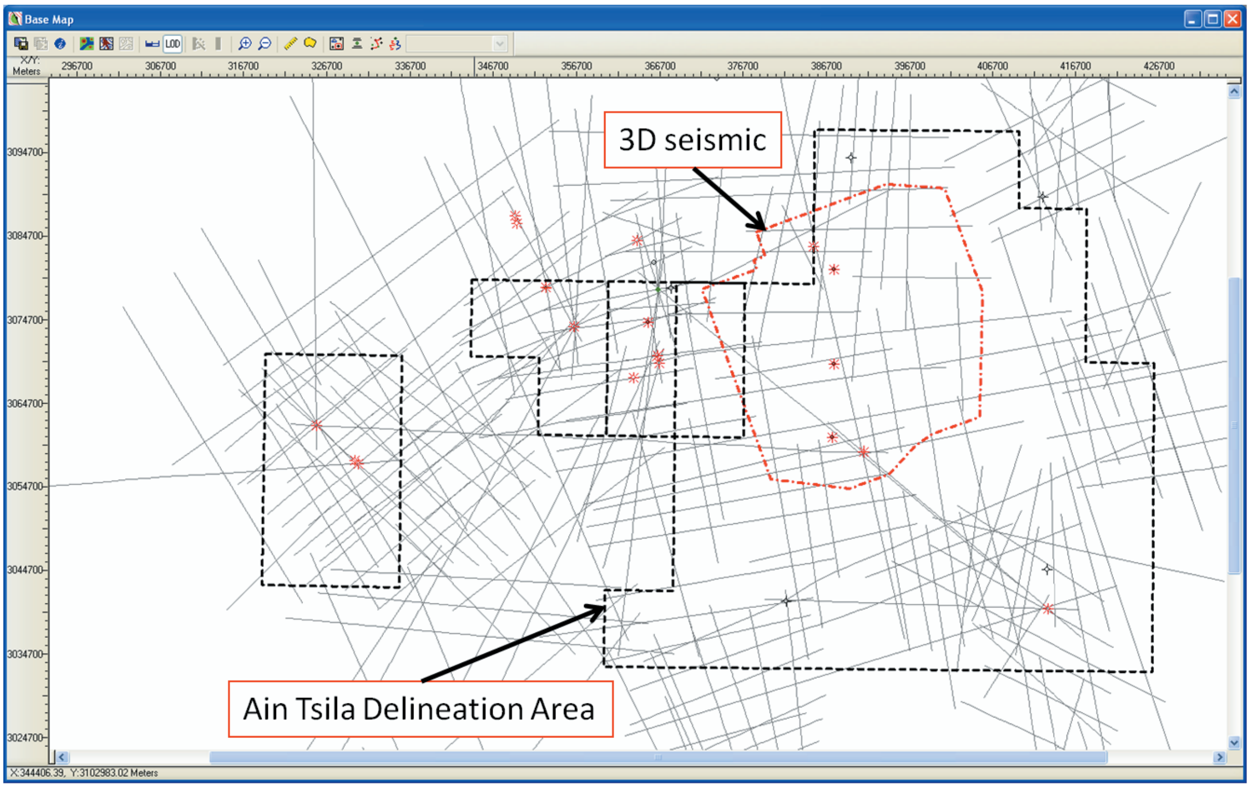


Figure 3-3 Seismic data map

3.5.2. Seismic horizons

Nine main seismic horizons were interpreted initially on both the 3D and the 2D seismic (Figure 3-4):

> Visean C, Visean B, top Tournaisian, Devonian F2, near MPR 'hot' shale, Frasnian unconformity, Devonian F6C3, Silurian Gotlandian shales, and Top Ordovician.

Further horizons were interpreted below Top Ordovician on the 3D only, in particular a Base Glacial Valley (Top Unit III-3) and a Basement. The 2D seismic imaging quality was not of sufficient quality to interpret these horizons with confidence. Instead, indications of Glacial Valley presence were observed by change of 2D seismic quality, and these have been used to constrain the extent of the Glacial Valley during reservoir modelling.

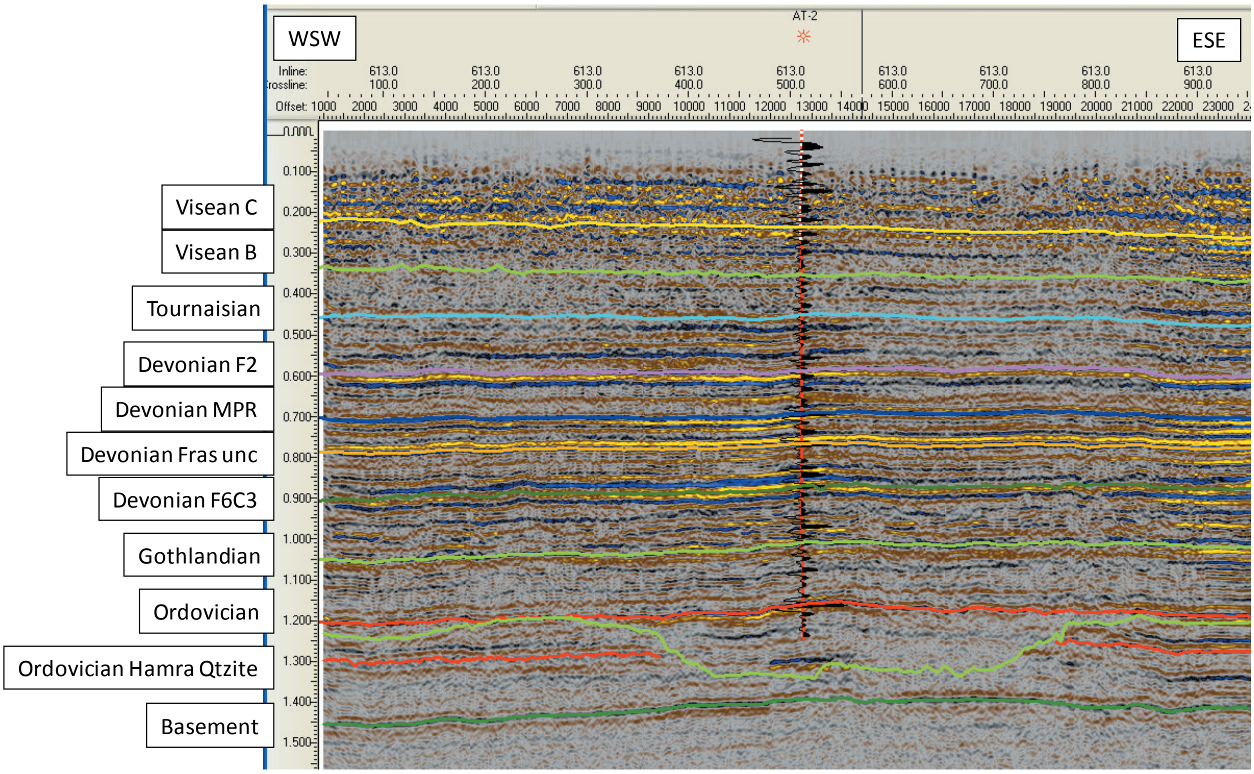


Figure 3-4 Seismic inline 613 through the AT-2 well location

3.5.3. Seismic faults

A combined approach to the classification of seismic lineaments by their extent and their throw has been taken. Faults were firstly identified that had clear throw at Top Ordovician over a lateral extent of at least 2.5 km (an approximate 2D seismic line spacing) on both 2D and 3D seismic. Then seismic lineaments in the 3D area only were interpreted from seismic attributes such as coherency, dip and curvature. Finally elevated pop-ups were interpreted by picking laterally high-frequency anomalies against a smoothed regional background Top Ordovician horizon.

In total over 700 faults were identified in this way, this figure being distilled down to a more manageable 191 by amalgamating faults of similar alignment and omitting the smallest features (typically less than 1 km long). NW-SE faults are most common although the largest faults are typically seen to be approximately N-S oriented. The resulting fault framework also shows a strong areal bias (partly inherited from the 2D versus 3D datasets) with the area north of AT-9 showing greatest fault density – associated with the common pop-up structures identified there. Note that despite the number of faults identified, very few fault cuts have been picked within the Ordovician III-IV section. The exception is at AT-8 which targeted a mapped fault zone. Elsewhere, interpretation of possible faults from logs is difficult given the lithologically monotonous nature of the reservoir and the high-angle nature of the fault planes.

The identified faults were transferred to the reservoir model, where structural lineaments and connectors were added to create a self-consistent horizon-fault network.

3.5.4. Depth conversion

Several methods of depth conversion have been explored, the addition of extra well penetrations within the Ain Tsila accumulation providing better spatial coverage.

The base case depth conversion utilised apparent velocity with residuals at wells tied through convergent gridding. Within the southern part of the field area (including the more recently drilled AT6 and AT-7) the average velocity data shows a prominent N-S trend- caused by variation in the overburden.

A composite depth conversion was thus used to create depth horizons for modelling, with average velocity utilised in the central and northern area and a trended apparent velocity in the southern area. This provided a top Ordovician closure in the SE of the field close to 1970 mBSRD (1570 mTVDSS).

3.6. Fluid data

Representative fluid samples for analysis have been gathered at surface during testing of wells AT-1 and AT-8. Samples collected from other wells, such as AT-2 and -3 are not considered to be reliable as they were taken at bottom hole flowing pressures much lower than the established dew point.

The fluid is a lean gas-condensate with retrograde behaviour, as shown by analysis of the samples collected from AT-1. The initial condensate-gas ratio is approximately 30 bbl/MMscf based on a simple separation process. A Constant Mass experiment shows the dew point to be 2783 psia compared to an initial reservoir pressure of approximately 2900 psia. Figure 3-5 shows the phase envelope, indicating mild retrograde behaviour with a maximum liquid drop-out expected to occupy a pore volume fraction of 1%.

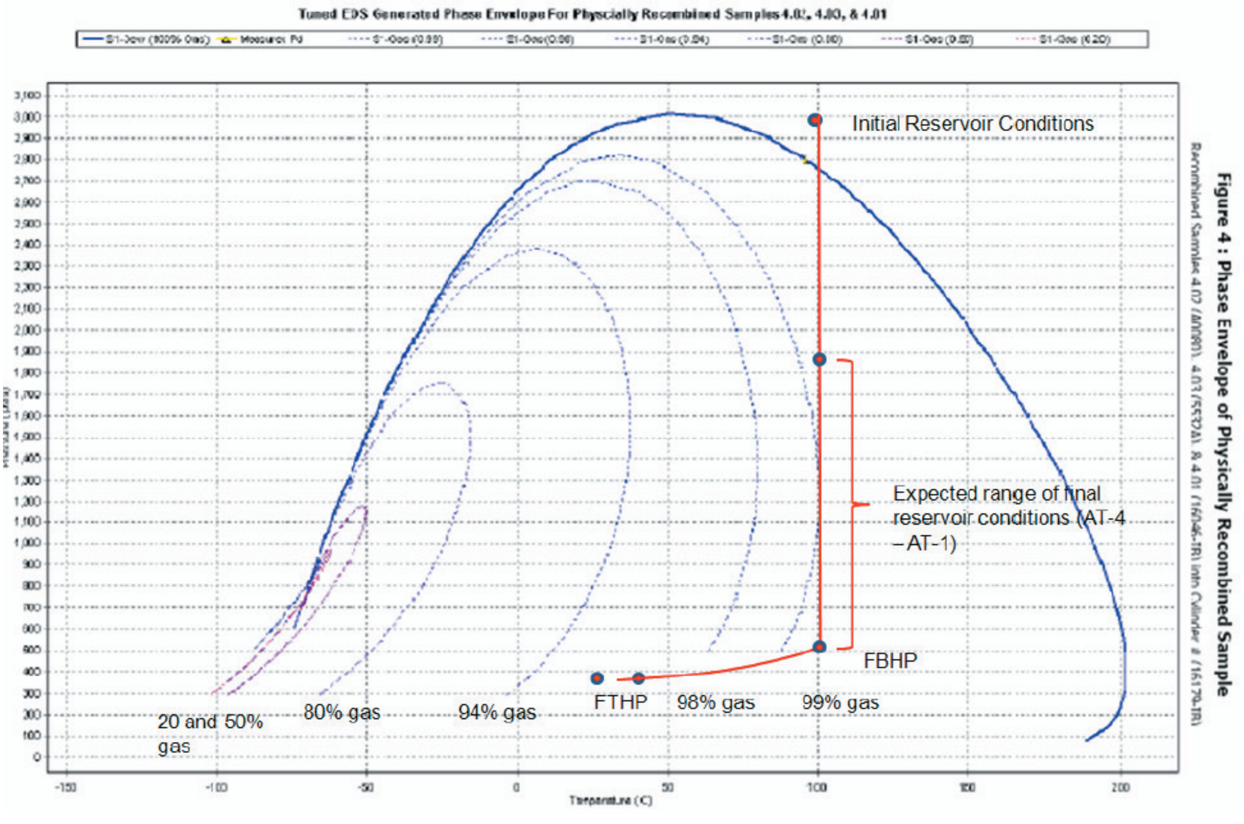


Figure 3-5 AT-1 Phase Envelope showing mild retrograde behaviour

The gas is relatively free of contaminants with just 1.82% CO_2 and 1.92% of N_2, with no H_2S detected. Methane content is high at approximately 78%.

The sample from AT-1 has been characterised using an equation of state (EOS) to allow use in simulation and reservoir recovery calculations. To forecast liquids (condensate and Liquid

Petroleum Gas, LPG, recovery), a process simulation has been carried out based on the proposed development scheme. A reservoir depletion (constant-volume depletion, CVD) process is applied to allow prediction of the prevailing liquid-to-gas ratios at different reservoir pressures. This model predicts an initial condensate-gas ratio of 32.2 bbl/MMscf, which declines at abandonment conditions (685 psia) to 18.2 bbl/MMscf. LPG recovery, assuming 97.5% recovery of C_3 and C_4 varies little during reservoir depletion as these fractions remain in the gaseous phase and a recovery of 48.2 bbl/MMscf is predicted by the model. Gas shrinkage associated with the liquid recovery at initial conditions is 89.8% and the wet gas expansion factor is 187.4 scf/rcf.

Analysis of samples from AT-8, including a Constant Volume Depletion experiment, is presently being carried out.

3.7. Production testing

A wealth of production testing data is available following the delineation appraisal campaign. Including early information from the pre-discovery wells (i.e. before AT-1), TXA-1 and TSI-1bis, production data (of varying quality) are available from a total of 11 wells. As will be discussed in Section 3.8 on recovery, this allows a synthesis with geological data to provide a coherent understanding of the factors controlling well deliverability and, within the limits of the geological uncertainty, the distribution of well productivity.

Although some flow has been achieved from early wells, the main results from production testing on the Ain Tsila Ridge are from the Petroceltic-Sonatrach wells AT-1 to -9. The results are summarised in Table 3-1.

Well	***Test***	***Date***	***Depth (mMD)***	***Interval (m)***	***Maximum Gas Rate (MMscf/d)***	***Kh (mD.ft)***	***Skin***	***Comments***
AT-1	Pre-frac	Sep-09	1917-1919 1915-1919	2 4	8.7 10.9	- 2900	- 140	High k sand in IV-3 dominated flow
	Post-frac	Oct-09	1915-1919 Abrasijet perfs, fracced	Est. Frac Height 67m	33.8	2500	-3.7	Frac reduced skin
AT-2	Pre-frac	Sep-09	Open Hole 1917-2000	83	0.23 (est)	N/A	N/A	No stable flow
	Post-frac	Nov-09	1920-1922 Abrasijet perfs, fracced	Est. Frac Height 47m	4.9	22	N/A	Up to 195 bwpd
AT-3	Pre-frac	not tested	-	-	-	-	-	-
	Post-frac	Dec-09 Jan-11	1936-1938 Abrasijet perfs, fracced	2	not measured 0.075 (est)			Early screen out of frac
AT-4	Pre-frac	not tested	-	-	-	-	-	-

Well	Test	Date	Depth (mMD)	Interval (m)	Maximum Gas Rate (MMscf/d)	Kh (mD.ft)	Skin	Comments
	Post-frac	Feb-11	1946-1947.2 2085.8-2087 (Abrasiject) both fracced	Upper 112m X_f 119m lower 104m X_f 221m	1.3	0.2		up to 500 bwpd
AT-5	Pre-Frac	Jul-11	2046 – 2404 (open hole multi-packer 4-interval completion)	N/A	1.4	40	15	Horizontal well. Three natural fractures interpreted. Acidisation carried out. Most flow from top interval (Port 4) from MPLT
	Post Frac	Aug-11	As above	3 fracs; est. length 40, 31, 32 m, height 69, 55, 47 m	3.6	32.8	N/A	Successful staged fracs in 3 of 4 ported intervals. Natural fractures interpreted in lower intervals, induced fracs more important in upper interval (Port 4), with highest production
AT-6	Pre-frac	not tested	1975 – 1977 (Surgijet)	-	-	-	-	-
	Post-frac	Aug-11	1975 – 1977, 1971 – 1973 & 1951.5 - 1953 (Surgijet)	Estimated X_f 74 m , height 57 m	-	0.5	-	Well was fracced but no flow observed. Low kh from DFIT analysis (0.03 mD) Estimated net flowing height 25m
AT-7	Pre-frac	Oct-11	Multi-stage openhole packer completion (3 ports)	Open-hole interval	-	-	-	No measurable gas at surface
	Post-frac	Nov-11	Multi-stage openhole packer completion (3 ports)	Estimated X_f 130 m, height 51 m	5.4	7	0.3	up to 216 bwpd
AT-8	Pre-frac	Sep-11	Multi-stage openhole packer completion (3 ports)	Open-hole interval	7.5	Port 1: 142 Port 3 (&2): 1660 - 2000	Port 1: 23 Port 3 (&2): 146 - 177	Tested individually on each completion port interval showing good contribution from each but probable communication between upper and middle zones
	Post-frac	Sep-11	Multi-stage openhole packer completion (3 ports)	Estimated X_f 53 m, height 51 m	38.6	2300	-3.5	up to 240 bwpd

Table 3-1: Well Test Summary

The table shows the wide range in productivity of the wells drilled to date. Values for permeability-thickness (kh) and skin are based on particular interpretations to show the variability and demonstrate the high values of permeability that can be present when fracture networks have been encountered. The quality of the pressure data for transient analysis is mixed and alternative reservoir models may be applied to many of the tests. However, the values interpreted are generally supported by several interpretation techniques (classic analytical transient analysis, fracture injection test (DFIT) analysis and matching with single well sector simulation models. The effect of the fractures is demonstrated by observations of linear flow and dual porosity type responses.

Thus, at the end of the delineation drilling and testing campaign, the range of well productivity behaviour is still large. However, some important concepts have been proven up in the process:

1. Natural fractures are shown to be present in most of the wells and contribute to the achievement of commercial rates; overall productivity in many of the wells cannot be explained by matrix permeability only. Wells drilled close to faults identified from seismic have shown to be the most productive (even without stimulation). This is consistent with observations in local analogue fields such as Tin Fouye Tabankort and Ohanet (see Figure 3-6 and Figure 3-7 for TFT).

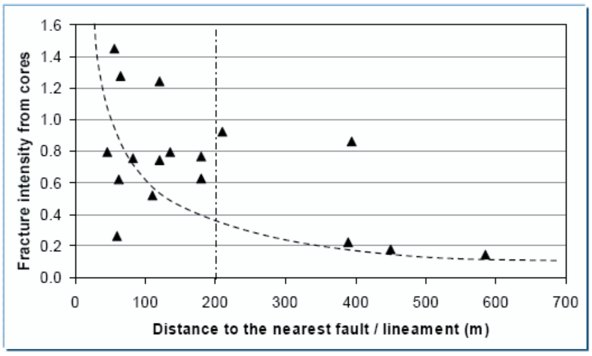


Figure 3-6 TFT Reservoir Core Fracture Intensity vs. Proximity to Faults

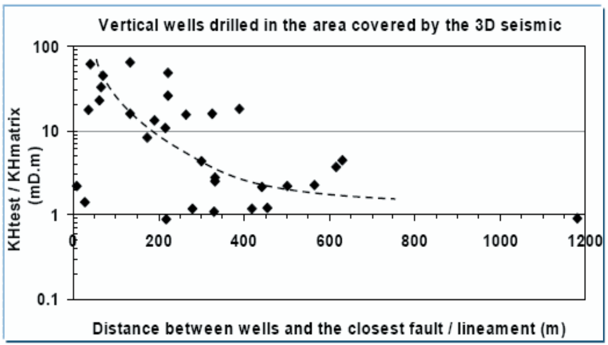


Figure 3-7 TFT Reservoir Well Test kh / Matrix kh vs. Proximity to Faults

2. Natural fractures (potentially enhanced by hydraulic fractures) have the ability to connect to productive water volumes below the GWC. This concept has only been tested in a short-term test (AT-4) and it is possible that once available water-filled fractures have been depleted, this phenomenon may reduce. Hydraulic fractures should nevertheless be designed to avoid fracturing close to the GWC.

3. The high permeability sand facies has been shown to be present in wells other than the original observation in AT-1. Although it is now clear, from Ain Tsila well data and nearby field analogues, that this facies is a primary depositional facies, the exact geological factors controlling its distribution in Ain Tsila are still uncertain. It is difficult to predict occurrence and to distinguish productivity increase due to the sand from that due to fractures when no other information (e.g. core permeability measurements) is available.

4. Hydraulic fracturing is a viable and valuable technique for improving productivity from the Ain Tsila wells. Multistage open-hole packer completions allow optimal fracture treatments and can potentially allow water-producing zones to be isolated.

5. Horizontal wells can be drilled and increase the chance of encountering open fractures. However, it is shown that vertical wells can as also be productive if sufficiently dense fracture zones can be penetrated and hydraulic fracturing can ensure connection to fracture networks.

6. A plot showing all of the interpreted build-up pressures from the well tests shows (within measurement and interpretation error) that all the wells tested lie in the same pressure regime (Figure 3-8).

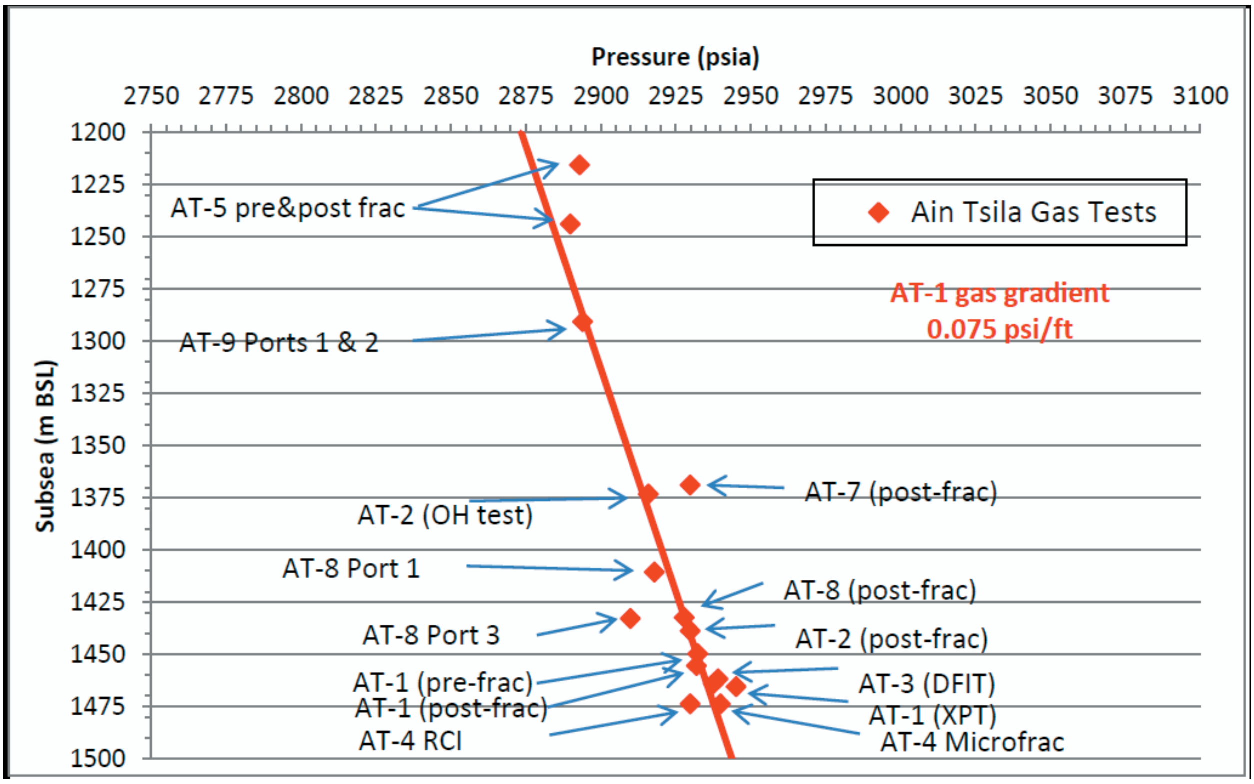


Figure 3-8 AT Well Test Build-up Pressure vs. Depth Plot

3.8. Reservoir modelling

3.8.1.1. Static Model

The geocellular model constructed over the Ain Tsila field area incorporated all available well data and consolidated the reservoir unit mapping and geological concepts proposed from integration of the field specific and regional sedimentological studies. Core and log data were initially used to define both a sand (vs. shale) log and then a sand quality electrofacies log that were in turn upscaled at each well. The electrofacies definition was initially derived from petrographic considerations backed up by SEM but then extrapolated on the basis of log character.

The geocellular model was then prepared along the following workflow:

- Sand 'trend maps' defined for the key sand-rich units IV-3, IV-2a and IV-1 were used to guide population of sand away from the wells. This matched gross sand presence in the model to that expected from the thickness and depositional environment observations.
- The electrofacies were then distributed accordingly within the gross sand facies to honour any observed vertical and lateral trends, such as the general cleaning-up of the facies in IV-3 Unit. Whilst image log data has allowed estimation of palaeo-currents in certain reservoir units such information has limited confidence and has not been used to further guide electrofacies distribution.
- The reservoir properties were then populated within the model stochastically according to the relationships identified from data analysis of that property (e.g. porosity or permeability) and the differing electrofacies. Conditioning of the modelling process ensured that net electrofacies were attributed to gross sand facies only.

Low case gross sand properties (increased percentage of shale) and high case electrofacies properties were also developed to capture uncertainty in reservoir definition.

3.8.1.2. Definition of Net

Extensive core data recovered from the Ain Tsila Ordovician IV reservoir confirm that although the sands are typically quite clean, reservoir porosity is predominantly less than 8% though individual units may locally average up to 12%. The choice of a 4% porosity net cut-off pushes up the average porosity but may also remove some sand that, albeit of low quality, may contain moveable gas.

Alternative net flags were also explored: an upside case in which the 4% porosity cut-off was not used (relying on V_{shale} alone) and an alternative mid-case in which the 4% porosity cut-off was supplemented by a 50% Sw cut-off.

3.8.1.3. Saturation Model

Hydrocarbon (gas) saturation has been modelled within the geocellular model using a saturation-height function derived from drainage (mercury injection) SCAL capillary pressure data and incorporating the log derived permeability. Saturation functions were compared to the Archie derived water saturation (S_w) profile at each well and the saturation-height parameters were then iteratively adjusted to obtain acceptable match. The best overall fit of saturation profiles (above the adopted GWC of 1570 mTVDSS) was achieved using a FWL of 1680 mTVDSS – acknowledging that in such low quality matrix there may be gas present below the GWC.

3.8.1.4. DFN Modelling

Preliminary DFN models are being constructed which will allow the properties from alternative conceptual models, tuned to well observations, to be tested in the dynamic models.

3.8.2. Dynamic Modelling

Recovery efficiency has been assessed by making a series of Eclipse (single-well) sector models to cover the range of potential reservoir characteristics, as defined by the production tests from the delineation wells. Specific models have been built and matched to well test data for wells AT-1, -2, -4 and -8. These, with some variations, are considered to represent the range of potential reservoir/well type configurations that will be encountered in the Ain Tsila reservoir. The reservoir behaviour at wells AT-7 (reservoir similar to AT-2) and AT-9 (reservoir similar to AT-8) are considered to be covered by these models.

The sector model grids measured 200 m by 200 m areally (20 by 20 cells, varying dimensions to allow for explicit fracture modelling as required) with variable numbers of layers in the vertical direction, depending on the gross thickness of reservoir encountered by the well. Properties and grids were exported from the Petrel model with constant properties as defined at the well locations, for this purpose assumed to be areally constant. The grids used for the AT-2 well test and AT-4 well test matches are shown in Figure 3-9 and Figure 3-10. The fine gridding in the centre of the model allows explicit modelling of hydraulic fractures.

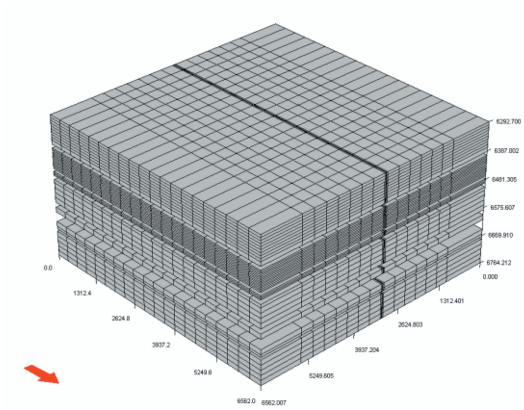


Figure 3-9 AT-2 Well Test Sector Model Grid

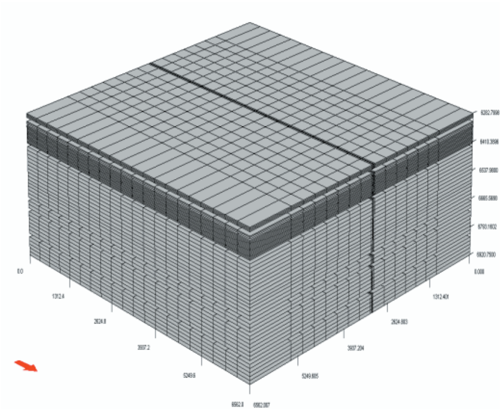


Figure 3-10 AT-4 Well Test Sector Model Grid

The size of the models is more than adequate to cover the radius of investigation of the well tests and is considered to be a reasonable size to represent the drainage radius of a development well – in fact for the poorer quality sectors the drainage area may be less. It is shown that including additional wells in the 200 m by 200 m sectors improves recovery up to a total well count of six. This could represent an alternative (higher recovery but more costly) development which can be optimised following initial development results. Conversely, it is also possible that an extensive fracture network will allow drainage of a greater area, which may be considered an upside, requiring less wells for a given recovery.

The intensity of the fracturing in the damaged zones close to the faults is expected to be high (this is confirmed by core material) and in this case, the open fractures can be considered to effectively enhance the overall permeability with no significant dual porosity effects caused by the slower response of the matrix feeding into the fractures. Hence single porosity simulation models have been used to match the well tests.

The well test matches were achieved by changing the permeability of the model (average of matrix and fractures) and the skin factor. Gas rate, water rate and bottom-hole pressure were matched and the overall quality of the matches is good although precise matches of the log pressure plots was not attempted (and should not be expected from a relatively coarse grid numerical simulator). An example, for the AT-2 test, is shown in Figure 3-11.

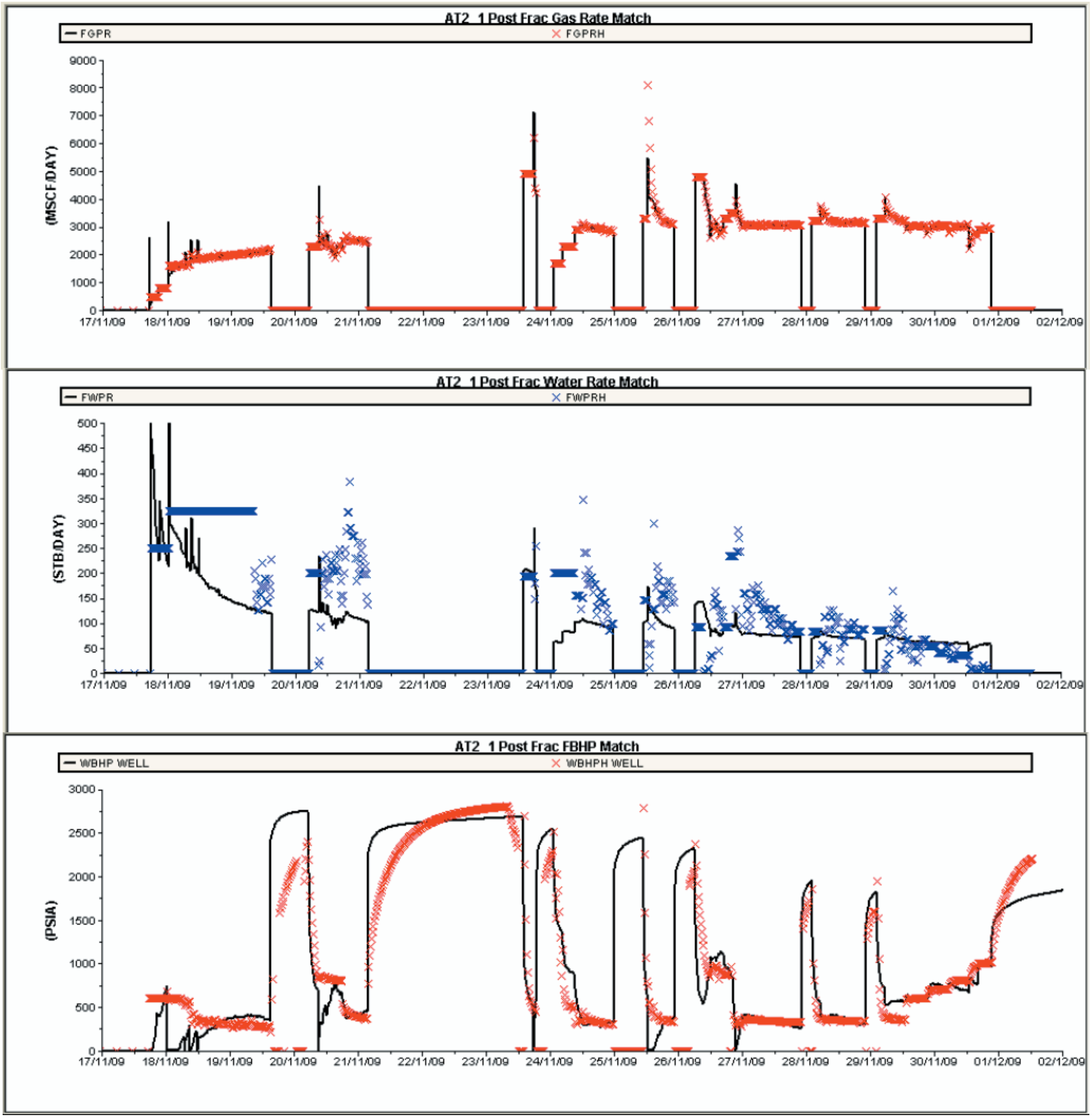


Figure 3-11 AT-2 Sector Model History Match Plots; Gas (Upper), Water (Middle) and BHP (Lower)

Permeability multiples of between 5 and 440 were applied for different well sector matches and the resultant ‘kh’ (permeability-thickness) values conformed well to the analytical well test results. A table showing the multipliers used in each of the models is shown below.

Well	Permeability x	Comments
AT-1	50 24	Low-perm, not sensitive to match as hi-k dominates, estimated High-perm layer
AT-2	100	AT-2 is considered to be representative of large areas, away from direct influence of faults
AT-4	5	Eastern Flank well
AT-8	190 440	Lower Zone, Port 1 Upper Zones

Table 3-2 Well test sector history match permeability multipliers

3.8.2.1. Vertical Lift Performance

Petroleum Experts’ PROSPER vertical lift modelling application was used to match well test data (rate, bhp and thp) to generate models that could then be used to determine the optimum tubing size for the wells and to predict the abandonment pressure for the sector models. The forecasting models assumed that the tubing would be changed over field life to achieve optimum recovery.

3.8.2.2. Forecasts

Having history-matched the wells, the sector models, including the vertical lift tables, were used to make prediction runs to provide input to full-field forecasting. For a final flowing tubing-head pressure (FTHP) of 450 psia, the following recoveries were calculated.

Well	Number of wells	Ultimate Recovery Factor (%)	Comments
AT-1	1	86.4	High-perm layer extensive over entire model allows access to all GIIP, assuming vertical connectivity
AT-2	1 2 4 6	22.9 37.2 58.2 60.7	Increasing numbers of wells shows improvement in recovery factor with diminishing gains. The two well sector is regarded as a useful scenario to take to development planning
AT-4	1 2 4	6.2 11.7 22.6	Increasing numbers of wells shows improvement in recovery factor. For less-fractured areas this may be required.
AT-8	1	81.6	Intensely fractured region shows high RF

Table 3-3 Well test sector recovery factors

The above recovery factors are based on a 30 year limit (AT-2 and AT-4) or a cut-off rate of 0.25 MMscf/d (AT-1 and AT-8), as has been used for the full field profile.

3.9. Field development plan

A central gas-processing facility (CPF) is proposed with pipeline export to TFT, to a tie-in approximately 110 km away to the north. Three cases have been generated, based on the "low", "mid" and "high" gas recovery cases. The magnitude of the plateau rates is based on the plateau (facilities throughput) rate of 355 MMscf/d of wet gas, with various subsurface depletion plans for the low, mid and high cases respectively (as described in Section 4.3).

Wells will be pre-drilled to allow the facilities capacity to be fully utilised from first gas. The initial wells will include six suspended appraisal wells. Continuous drilling of twelve wells per year will be required to maintain capacity. Wells are planned to be drilled on individual pads with infield flowlines connecting to manifolds positioned throughout the field.

The plateau rate was subject to some optimisation based on economics, ability to achieve the plateau for an extended duration within the range of potential subsurface outcomes and discussions with Sonatrach. The plateau rate chosen results in a 4.5% depletion of the reserves per year and gives a 14-year plateau length in the Best Estimate case. For the low and high cases, the same plateau capacity is achieved but percentage offtake changes to 8.3% and 2.5% respectively. The plateau length for the Low Case is six years and the High Case results in a plateau lasting to the end of the 30-year licence period.

The considerable export back-pressure means that individual well decline rates are high and in order to achieve continuity of productivity, compression will be required at an early stage. It has been assumed that export gas compression, allowing the lowering of wellhead pressure from 1030 psia to 450 psia, will be beneficial from the start of production. Some economic optimisation may still be possible based on the deliverability of wells drilled prior to first gas.

LPG extraction facilities will be provided at the CPF as well as refining facilities and condensate treatment and stabilisation.

A project schedule has been prepared by Petroceltic (Figure 3-12). Design and installation of the facilities is expected to take five years, pursuant to the issue of an Operating Licence.

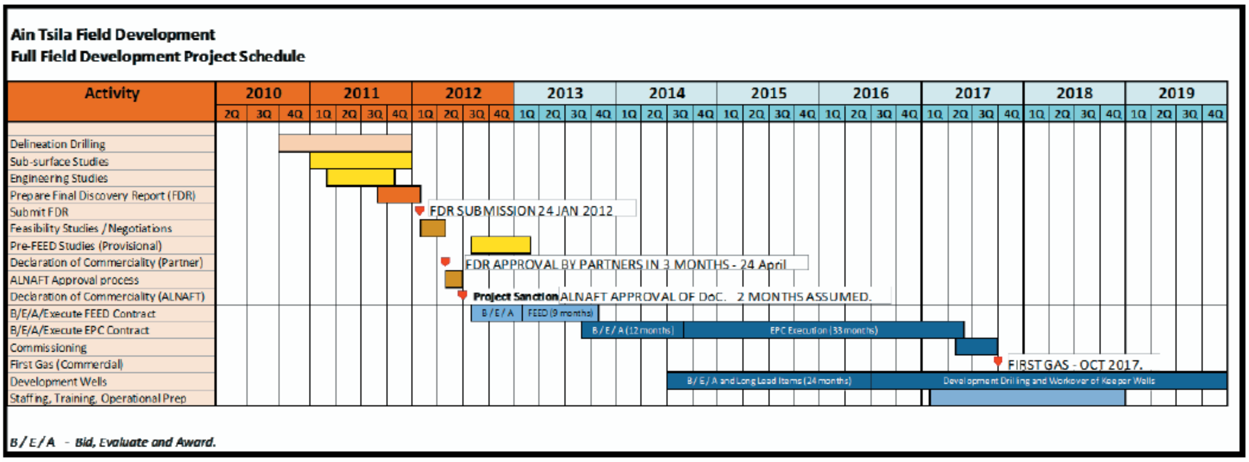


Figure 3-12 AT Development Project Schedule

The FDR was approved by Sonatrach in the second quarter of 2012.

3.10. Facilities and Costs

Detailed conceptual engineering has been carried out for the proposed development, including process simulation modelling (with infield flowline modelling) to optimise the drilling sequence and development plan.

Ain Tsila will be developed through a single Central Processing Facility (CPF), tying in to existing and planned regional infrastructure. First gas from Ain Tsila is envisaged towards the latter part of 2017 (October 2017); the current project schedule is presented above in Figure 3-12. This schedule allows for a 33 month period for the Engineering, Procurement and Construction (EPC) activities.

The conceptual design study has been conducted for the Joint Venture by G3baxi who have carried out the detailed process and cost engineering. Arup have conducted the gathering system and pipeline design. It is important to note that technical evaluation of both reservoir and facilities is ongoing and the exact details are subject to change.

The Ain Tsila development will include a gathering system, comprising individual well flow lines and field headers, bringing produced wet gas from the estimated total of 124 wells, to the CPF in the north of the field for processing and conditioning.

Wet gas from the wells will arrive at the plant inlet facilities initially at pressures from 375 psig and will require processing to meet the export specifications on water content, hydrocarbon dew point and heating value.

The inlet facilities, as currently planned, will primarily comprise a manifold and a slug catcher/separator along with the pig receiving facility. Gas will then be compressed to 1060 psia and dehydrated with a molecular sieve unit. The dehydrated gas will be routed to a turbo expander for dew point control and LPG recovery targeting 87% C_3 recovery. The gas is then compressed for fiscal metering and evacuation.

In summary, processing of the gas at the CPF will comprise water removal and disposal, dew point control to sales specification, gas compression and liquids recovery including LPG recovery. Figure 3-13 below shows the Process Flow Diagram for the Ain Tsila CPF.

It has been assumed that the treated gas, meeting the export specifications, will be evacuated to Tin Fouye Tabankort (TFT), a Sonatrach gas boosting and condensate hub 100 km to the northwest. This involves the construction of pipeline beyond the Isarene perimeter.

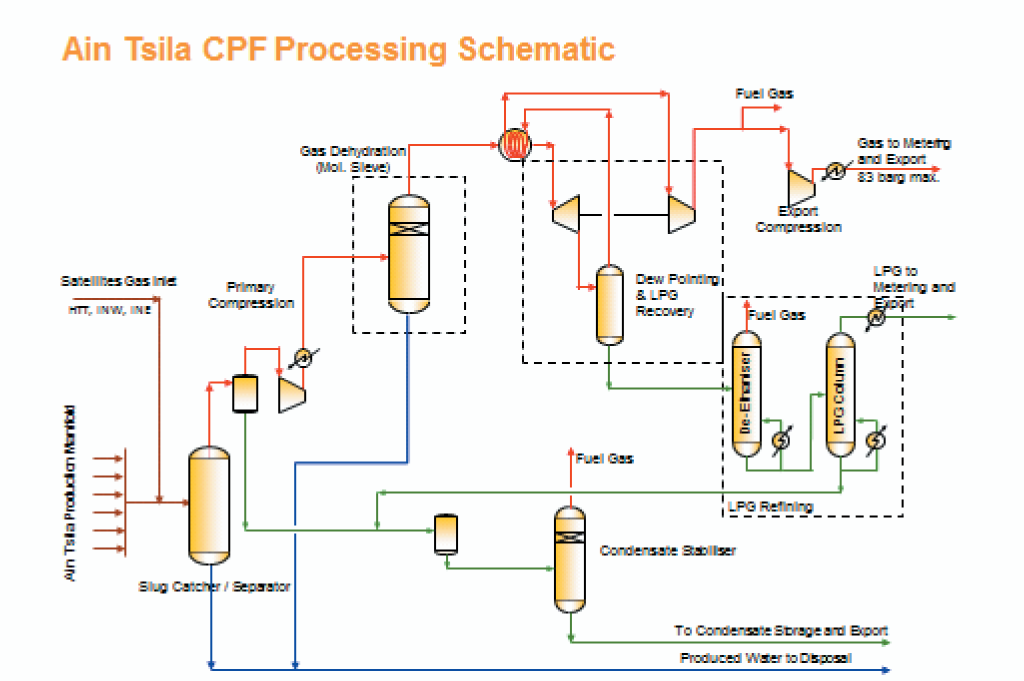


Figure 3-13 Planned AT CPF Processing Schematic

A 110 km gas evacuation pipeline plus condensate and liquid petroleum gas (LPG) pipelines will be required to transport gas to the evacuation hub at TFT. 10 km of the evacuation pipelines will be within the Licence boundary, with the remaining 100 km being external to the licence boundary.

Table 3-4 below provides a breakdown of the Capex estimate.

Ain Tsila Capex (US$ million, 2012 real)	***Sunk E&A***	***Development***	***Contingency***	***Development + Contingency***
Historic (to end 2011)	272.85			
2012 Budget Spent	4.43			
Pre-FEED, FEED		15.05	20%	18.06
Development Seismic		25.00		25.00
Capitalised Opex		27.66		27.66
Facilities (inc. hook-ups)		1,164.00	20%	1,396.80
Pipelines (Internal)		16.89	20%	20.26
Owner's Costs		72.49		72.49
Drilling (118 wells + 6 re-entries)		645.23	15%	742.01
Drilling start-up		12.36	15%	14.21
Other drilling		72.92	15%	83.86
Mid-life Investment		35.25	20%	42.30
Total	277.28	2,086.85		2,442.66

Table 3-4 AT Development CAPEX Summary

The field life Opex estimate, for the operation of the AT field, is US $1,129.90 million. The estimate for the total cost of abandonment is US $190 million; this is inclusive of $42 million for the well abandonments.

3.11. HSE

A baseline Environmental Impact Assessment (EIA) study has been undertaken to establish the existing environmental status and identify sensitivities of the AT area to the operation of the gas processing facilities. A further EIA study shall be undertaken during early stages of front end engineering and design (FEED) to make a thorough assessment of the proposed project's impact on the surrounding physical, biological and human environment. This study will be based on the final engineering concept selected for the development of the AT field.

Petroceltic International operates an HSE Management System and, whilst not having developed and operated a producing asset before, it has access to relevant, experienced staff members and has already started actively considering the risk management process. A comprehensive process has already started, identifying hazards along with mitigation and control measures.

Drilling and testing in the Ain Tsila area have been conducted to date with no major incidents.

4. Reserves and Resources assessment

4.1. Uncertainty

The Ain Tsila Ordovician discovery is a tight gas-condensate reservoir. The uncertainty range in terms of both reservoir distribution and deliverability remains significant prior to initial development drilling. The development plan described in the FDR has been approved by Sonatrach and is based on a developable area defined by the data gathered during the delineation. Development awaits approval and the grant of an Operating Licence. The estimated recoverable volumes are presently considered to be Contingent Resources.

The recent appraisal wells were designed to test reservoir distribution and productivity, and the development is now considered to carry only manageable subsurface risk. The key remaining uncertainties are as listed below:

- Distribution of productive natural fractures,
- Distribution of the high permeability sand facies
- Localised uncertainty in stress regimes relating to effectiveness of hydraulic fracturing

These factors have been taken into account in preparing the subsurface realisations used to represent the Low, Best and High Cases for defining production profiles and recoverable volumes.

The total probability of commercial success is evaluated at 90% (10% failure possibility) which is based on awaiting the approval of the competent authorities (ALNAFT) of the Declaration of Commerciality and the granting of an Operating Licence.

While awaiting the grant of an Operating Licence based on the agreed development plan and a final gas sales agreement, the recoverable volumes associated with this planned development have been classified as Contingent Resources in line with the definitions in the SPE-PRMS. Discussions between the operator and Sonatrach have been completed with a unanimous declaration of commerciality and the execution of a heads of terms covering gas sales via Sonatrach, and it is highly likely that the Exploitation Permit will be granted in the fourth quarter of 2012.

The volumes quoted in the sections below are unrisked Contingent Resources (low-best-high) in the event of a favourable commercial outcome of the commercial negotiations.

4.2. HCIIP Volumetrics

The volumetric range is based on deterministic realisations created using the Petrel model described in Section 3.8.1.1. Extensive probabilistic modelling has also been carried out; however it is considered that without a sufficiently narrowly defined statistical range for the input parameters (from the well data), choosing deterministic conceptual alternatives (still within the probabilistic range) is more suitable to represent upsides and downsides for in-place volumes.

The principal uncertainty in the in-place volumes is the distribution of hydrocarbons, mainly associated with the definition of the Free-Water Level (FWL) and associated Gas-Water Contact (GWC). Evaluation of the saturation profiles is challenging in such a tight and heterogeneous reservoir and there is uncertainty associated both with the interpretation of measurements and with the conceptual model based on these; saturation is stratigraphically controlled with high (100%) water saturations observed above gas-saturated zones because of the high capillarity of the tighter, water-saturated rock.

A conservative base case is proposed for the GWC, at 1570 mss, which coincides with the seismically-mapped spill point, well test results and fairly consistent observations of gas saturation in the wells, see Figure 4-1. Gas is certainly present at deeper levels, as evidenced by electric and mud logs, but this gas has not been considered developable in the study work carried out to date.

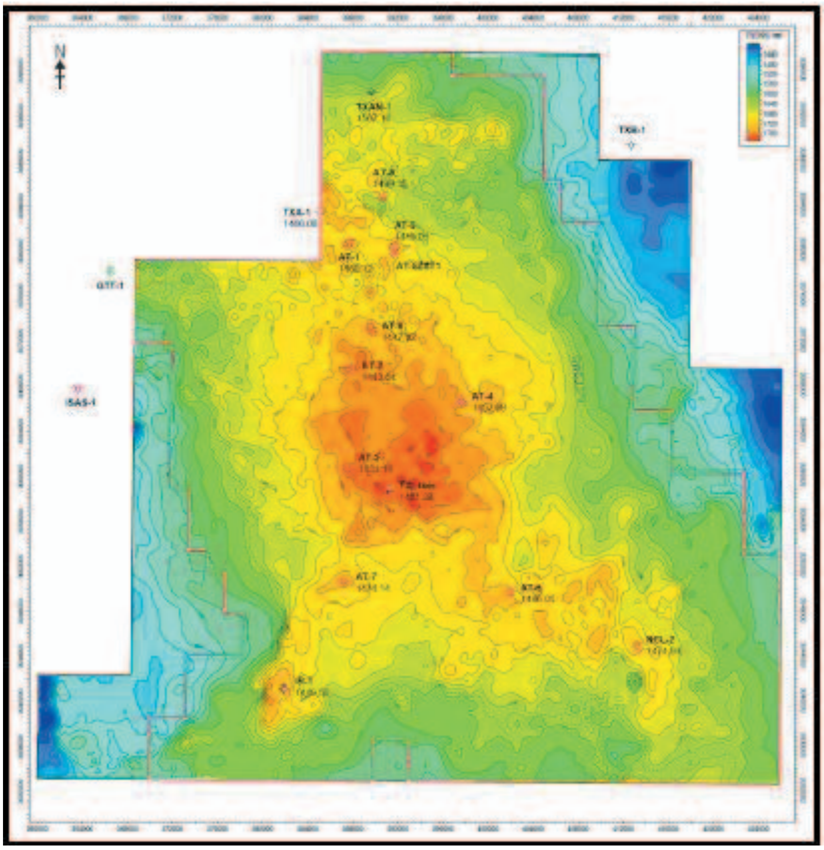


Figure 4-1 Top Ordovician IV-3 with Best Estimate GWC (Blue Line) for HCIIP Determination

A High Case is differentiated from the Best Estimate by assuming a deeper FWL (with the same GWC). When this is used in conjunction with the saturation-height function (Section 3.4), it results in higher gas saturations in the reservoir above the GWC and this provides a reasonable upside to the saturation evaluation uncertainty.

A conservative approach to gas saturations has been defined for the Low Case, whereby an observed deepest level of consistently high gas saturations in each well has been contoured in the model (with a maximum value of 1570 mss) to produce an irregular surface (effectively as a proxy for rock type variation) for the GWC termed the "Base of High Gas Saturation" (BHGS).

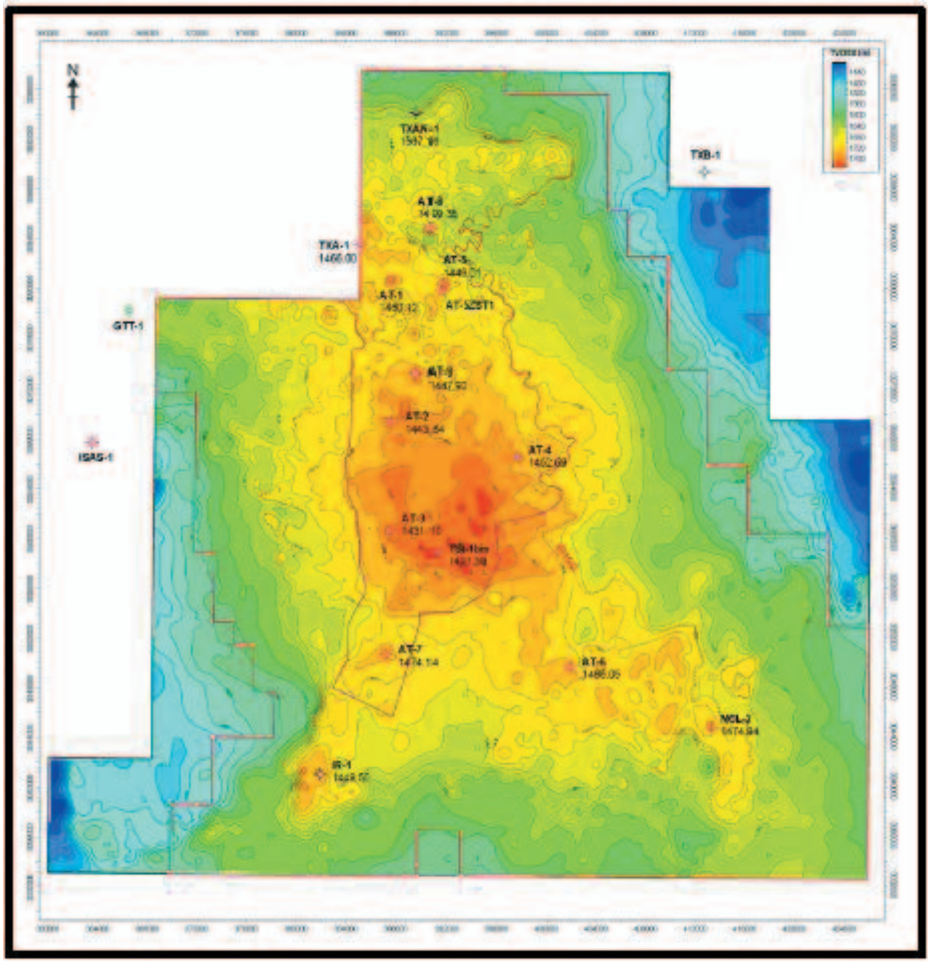


Figure 4-2 Top Ordovician IV-3 with Low Case GWC (BHGS, Red Line) for HCIIP Determination

In addition to the saturation range, uncertainty in rock properties was considered. Although there is broad geological understanding of the depositional setting of the sands, proven by the delineation programme, diagenesis also plays a role and both (1) sand presence and (2) sand quality away from the wells carry uncertainty.

Two cases for the net-to-gross fraction were defined, based on the V_{clay} cut-off; given that the wells have targeted likely sand-rich areas there is a reasonable chance that they have oversampled the sand distribution and therefore no further upside is considered for this parameter.

It is considered that the uncertainty in the top structure is less important than the factors discussed above and is, in any case, included to some extent in the variation of the GWC/FWL. The three factors described above were then used to define three cases for calculation of GIIP, as shown in Table 4-1 below:

Case	Sand Distribution	Net Sand	Saturation	
			GWC (mss)	FWL (mss)
Low	Low Sand	Expected Net	BHGS Surface	1680
Best	Expected Sand	Expected Net	1570	1680
High	Expected Sand	High Net	1570	1730

Table 4-1 HCIIP Cases

The fluid properties are defined in Section 3.6 where the Gas Expansion Factor and Condensate-Gas Ratio are defined. No range of uncertainty was considered for these parameters as the impact is considered to be negligible compared to the influence of the geological factors.

GIIP is calculated below as wet gas, with no shrinkage for liquids accounted for. Based on the three cases defined in Table 4-1, the following ranges of HCIIP are calculated (Table 4-2):

Fluid	Low	Best	High
Wet GIIP (Tscf)	2.63	10.12	12.49
CIIP (MMstb)	84.8	325.8	402.3

Table 4-2 HCIIP Ranges

The distribution is significantly skewed; the mean value lies between the Low Case and the Best Estimate. Whilst there is an expectation that the gas reservoir is relatively continuous, this is a model-driven value and the downside is more supportable as a proven value.

The above GIIP range is also broken down by reservoir unit in Table 4-3 below.

GIIP (Tscf)	Low	Best	High
Unit IV-3	1.11	3.16	3.49
Unit IV-2	1.18	3.72	4.00
Unit IV-1	0.35	3.23	4.99

Table 4-3 HCIIP Ranges by Unit

The relative volumetric uncertainty in the different units can be seen, which is greatly related to the GWC assumptions, with Unit IV-1 carrying the greatest range and becoming more dominant in the High Case.

4.3. Recoverable volumes

The estimation of recoverable gas and liquids is made using sector simulation models. As described in Section 3.8.2, recoverable volumes have been calculated for specific reservoir types or configurations, which are defined by the delineation-well test results. The specific wells analysed were AT-1, -2, -4 and -8 and these well tests have been matched in Eclipse simulation sector models. Together with two variations in the AT-2 sector model (increased fracture density, consistent with the geological model and the same sector with two wells producing), this suite of sector models was considered adequate to cover the range of reservoir characteristics and behaviours observed. The reservoir configuration and responses of wells AT-7 and -9 are also covered by these well types by analogy. These then form the basis of the estimates for field production profiles and recoverable volumes.

The sector models were run with appropriate vertical lift models and an assumed tubing head pressure constraint of 450 psia, consistent with installation of surface compression from the beginning of field life with a downstream plant intake pressure of 390 psia (375 psig).

4.3.1. Base Case (Best Estimate)

A Base Case (Best Estimate) forecasting model has been built from the available data, which describes the distribution of reservoir (or sector model well types) across the defined gas-bearing area. This distribution takes into account likely variability in sand distribution (high-permeability sand) and fractures (associated with faults). Production profiles are then built up by accumulating the appropriate number of sector model types defined by the reservoir distribution model, with sequencing based on a drilling schedule. The number of wells required to develop any given area is defined by the size of the sectors which are all 2 km by 2 km. This size was originally guided by approximate well test investigation distances although modelling indicates that the overall recovery factor could in some situations be significantly increased by drilling at a greater well density. Nevertheless, experience from nearby fields such as Tin Fouye Tabankort (TFT) and Ohanet suggests that connectivity (through fracture or high permeability sand) is adequate at a two kilometre well spacing.

The distribution of expected reservoir characteristics (as defined by well test behaviour, but guided by a deterministic geologic conceptual model) is shown in Figure 4-3. It can be seen that the reservoir has been divided, for convenience, into five regions (delineated by the dashed lines in the Figure and named in red text). Region 3 contains the largest GIIP; however productivity has shown to be better in the north (AT-8 well type), in line with the interpretation of fracture (fault) distribution and the likelihood of encountering the high permeability sand facies. The area is also constrained by the column height at the edges of the developable area such that at least a 30 m column is available for hydraulic fracturing and production; all wells are thus located within the 1540 m tvss depth contour.

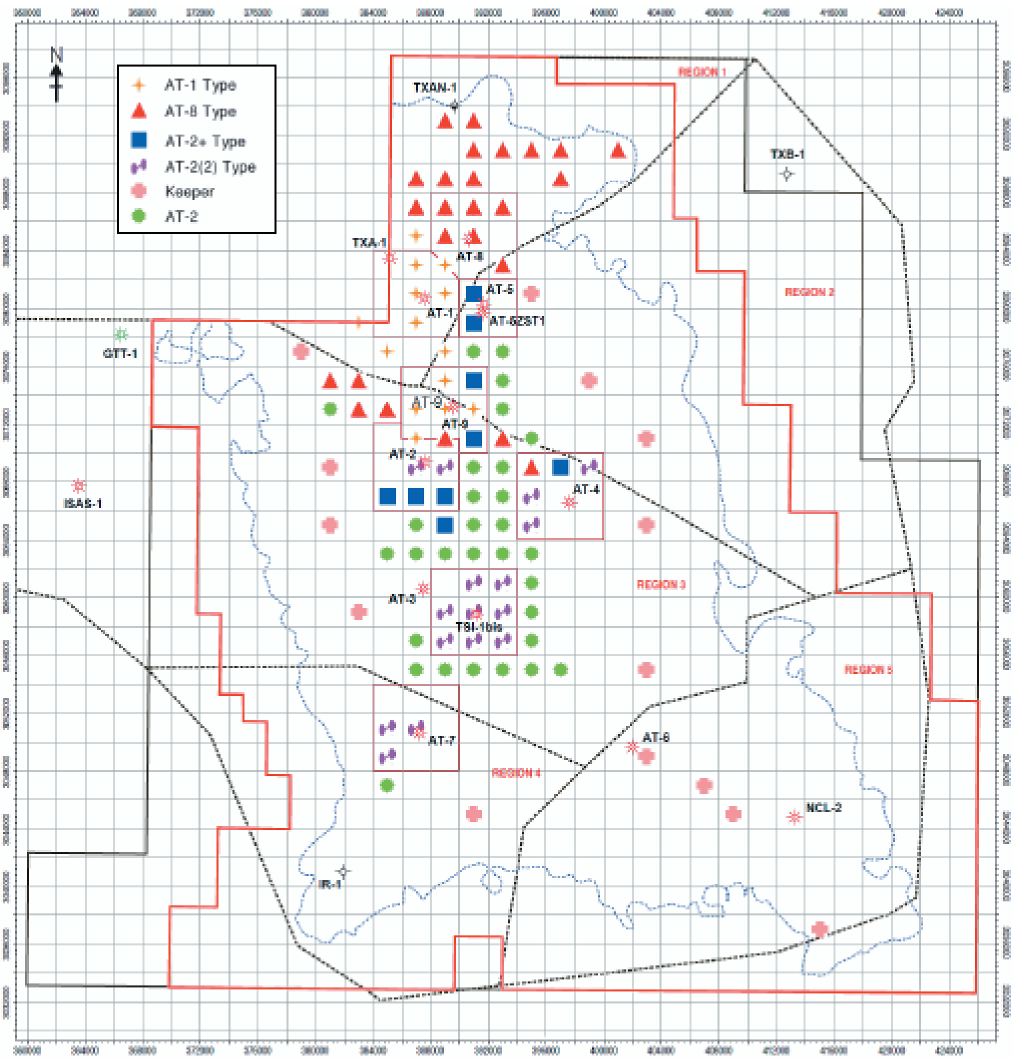


Figure 4-3 AT Base Case Development Region and Well Type Distribution

The range in recovery factors that might be achievable from this reservoir is still large (sector model recovery factors range from 6% to 85%, although the former could be significantly increased by prudently reducing well spacing) and it is important to capture this in the low and high cases. The delineation programme has proven up the occurrence of natural fractures and the ability to improve productivity through induced fracture treatments. Importantly, the concept of productive fractures associated with fault damage zones, as observed in nearby reservoirs, is shown to be true, if not fully calibrated, also for Ain Tsila.

4.3.2. Low Case

Overall sand distribution is well established through proving up the depositional concepts and the presence of the high-permeability sand has now been demonstrated beyond its original occurrence in AT-1. Nevertheless, anomalies remain, such as the locally-altered stress and fracture regime encountered at AT-3 (between the proven productive wells AT-2 and AT-4) and the apparent lack of productivity at AT-6, following hydraulic fracturing.

A deterministic low (proven) case has therefore been developed that only considers production from the areas near to the successfully producing wells to date. Whilst there is a good chance that reasonable productivity exists close to most of the identified faults in the northern part of the field (north of AT-3), in order to create a reasonable low case, areas of 6 km by 6 km (i.e. nine 2 km by 2 km sector models) around the successful wells have been used (with sector properties guided by the geological modelling). Coincidentally, the GIIP represented by the sector areas thus selected is very close the Low Case GIIP established in Section 4.2, partly on account of the sector models not being clipped to the BHGS (Base of High Gas Saturation) surface but being more areally confined.

The Low Case developable areas and well types are shown in Figure 4-4.

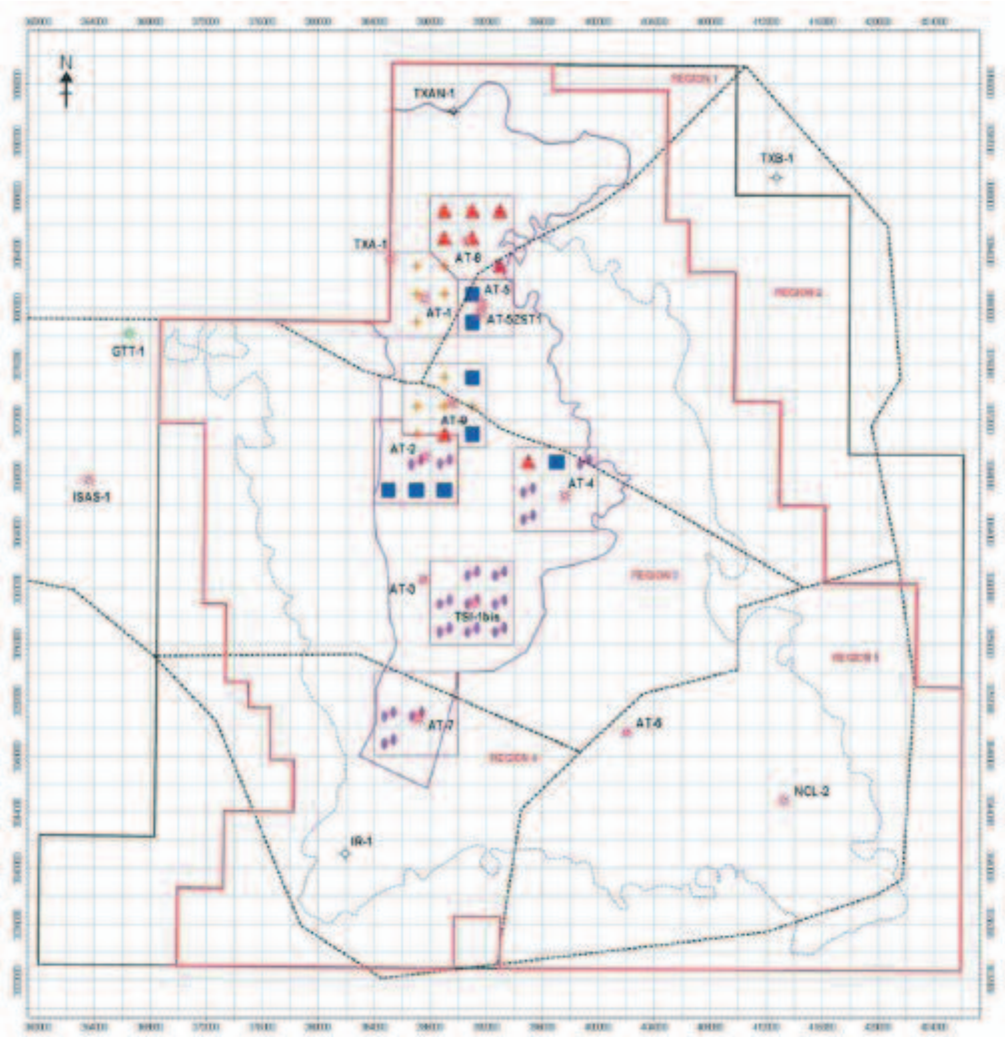


Figure 4-4 Low Case Development Areas with Well Sector Types

Note that all the sectors are within the BHGS contour which is marked on the map as a maroon-coloured polygon and also that the full nine-by-nine sector patterns do not include wells where the low case geological model does not predict a successful outcome (e.g. where there is a limited gas column height).

However, included as "successful wells" are:

1. TSI-1bis (close to AT-3, but which produced gas at a similar low rate to the later exploration and appraisal wells which were then subsequently successfully hydraulically fractured and produced at commercial rates) and
2. AT-4 which was designed to fracture deep to test productivity close to the GWC with the known risk of water production. The well was shown to be productive but was

hindered by water production. This could be avoided by changing the fracture design on the basis of the learning from this well.

It is unlikely that these latter two areas would be developed up front in any actual development; it is far more likely that the initial wells will be drilled to target maximum deliverability in the northern part of the field where maximum open fracture density is interpreted (see Figure 4-5).

Figure 4-5 Seismically & structurally interpreted fault pattern with 100 m & 500 m fracture corridors

Nevertheless, the Low Case is considered to be a reasonable, albeit conservative, proxy for a downside subsurface development drilling plan and resultant production profiles.

4.3.3. High Case

The High Case recoverable volume estimate is developed in a similar manner to the Low Case and Base Case, allowing for the upside realisation in the static distribution of gas saturation and volumes. All gas down to the 1570 m tvss contour is presumed to be accessed. This still does not include gas saturations observed in wells below this depth but allows for the fact that water production has been observed in wells that have accessed deeper intervals (e.g. AT-4). It is assumed that there is good continuity between the proven gas producing areas, which except for occasional anomalies, is a reasonable assumption. It is expected that the development will initially concentrate on the known productive areas and move out to fill in the intervening areas as development proceeds; the High Case is certainly a plausible representation of this.

In addition to accessing additional hydrocarbon volumes, the High Case also considers the value of a tighter well spacing in the mid-reservoir area (AT-2 type properties), which has been shown to be advantageous by the dynamic sector modelling The assumed well drilling pattern is shown in Figure 4-6.

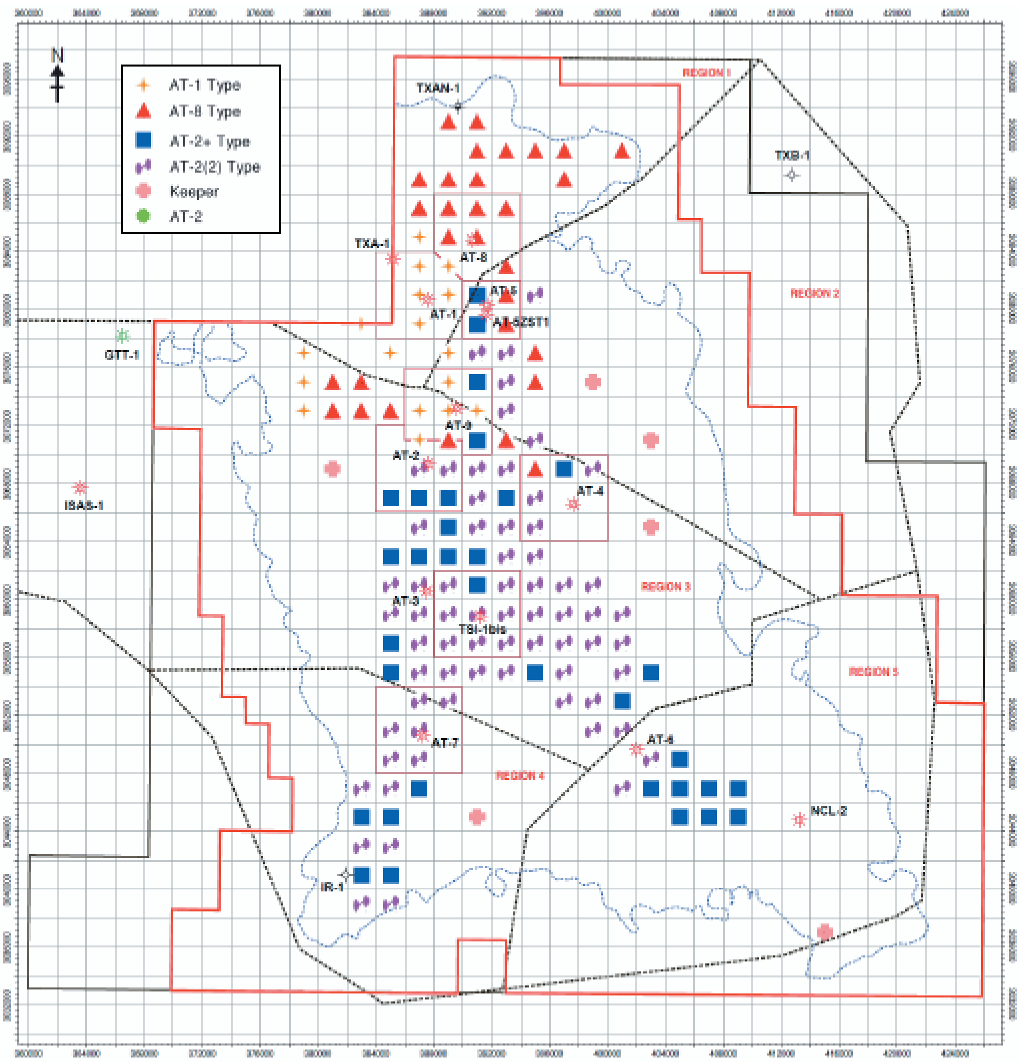


Figure 4-6 High Case Development Area with Well Sector Type Distribution

As can be seen in the above figure, large areas of the reservoir remain undeveloped also in the deterministic High Case.

4.3.4. Resource volumes

The profiles for each sector from simulation were concatenated, based on a drilling sequence, to achieve a 355 MMscf/d wet gas plateau rate from first gas (requiring pre-drilling of wells) and to maintain this for as long as achievable with the well sectors available for the given case. Wells AT-1, -2, -5, -7, -8 and -9 have been suspended and are supposed to be available at first gas.

The length of the Operating Licence is defined in the PSA as 30 years from the initial grant of the licence (expected third quarter 2012). It is expected to take four years to design and build the production plant and drill the initial development wells. First gas is expected in third quarter 2016, with commercial gas in October 2017. The production profiles thus generated are shown in Figure 4-7 (sales gas), Figure 4-8 (condensate) and Figure 4-10 (LPG). The 2C production forecast is given in Appendix 5.

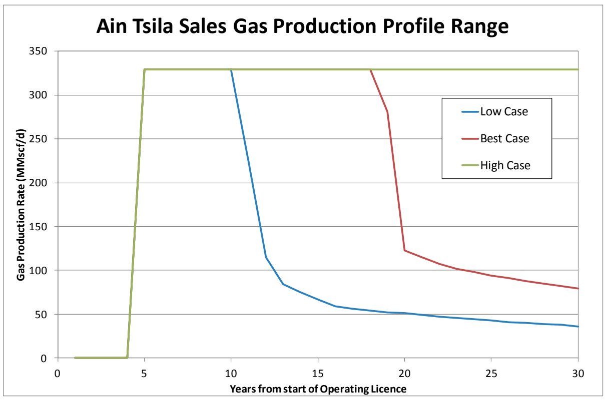


Figure 4-7 AT Gas Profile Range

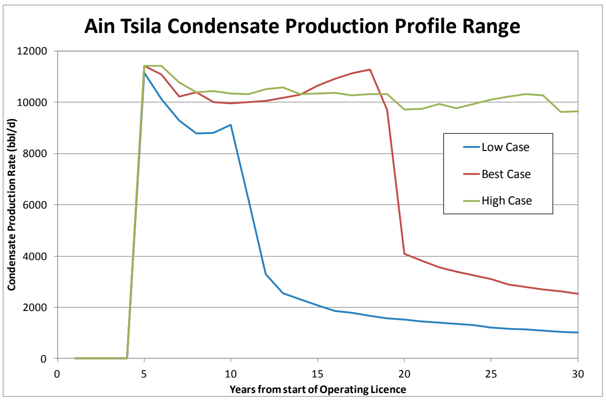


Figure 4-8 AT Condensate Profile Range

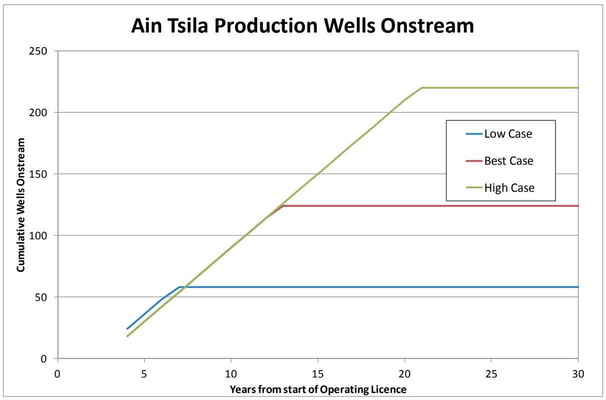


Figure 4-9 AT Profiles, Wells Onstream

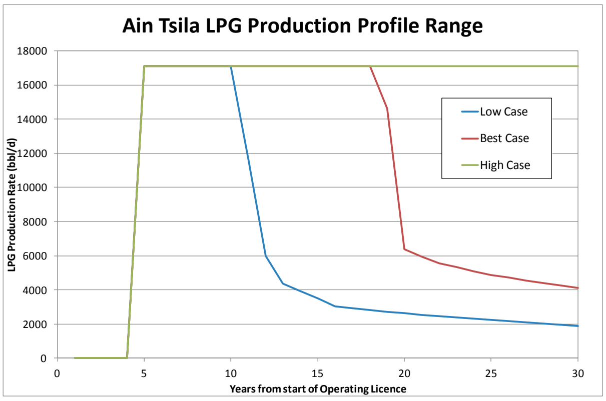


Figure 4-10 AT LPG Profile Range

The Base Case (Best Estimate) plateau is sustained for a 14-year period, compared to the Low Case plateau of 6 years and the High Case plateau which is sustainable to the end of the Licence period.

LPG is recovered with identical profiles to the gas (ratioed appropriately) as this product is recovered from the gaseous phase. The condensate profiles are affected by dropout and loss of liquids in the reservoir. Each sector depletes independently which explains the irregular profiles, with sectors brought onstream later in field life starting at initial pressure and therefore at initial CGR. The drop in gas rate is more severe in the low case because the sectors developed are mostly the high productivity sectors associated with high fracture density, higher pressure depletion and higher associated recovery factor from a lower developed GIIP. The other two cases include progressively more low productivity sectors which do not rapidly deplete and have lower recovery factors per sector (albeit with better properties and more developable sectors in the high case). The average gas recovery factors at the end of the 30-year licence period for the three cases are; Low 43%, Best (Base) 22% and High 25%.

More wells are required initially in the Low Case since the sector models are proportionally reduced in volume (on average) because of clipping to the BHGS surface (i.e. faster depletion for a given offtake rate). More wells are required in the other cases later on to develop the much larger GIIP and area. Total wells required in each case are; Low 58, Best (Base) 112 and High 220.

Recoverable volumes from the three cases evaluated are shown in Table 4-4 below.

	1C (Low)	2C (Best)	3C (High)
Gas (Tcf)	1.181	2.174	3.124
Condensate (MMbbl)	34.40	70.18	97.72
LPG (MMbbl)	61.46	113.04	162.61

Table 4-4: Recoverable Volumes

The volumes are expressed in barrels of oil equivalents in the following table, factors of 0.873 boe/bbl, 0.621 boe/bbl and 5.349 Mscf/boe were used for the conversion:

	1C (Low)	2C (Best)	3C (High)
Gas (MMboe)	220.78	406.41	584.00
Condensate (MMboe)	30.05	61.29	85.35
LPG (MMboe)	38.20	70.25	101.06
Total (MMboe)	289.02	537.95	770.41

Table 4-5: Recoverable Volumes Expressed in Oil Equivalents

It can be seen that the recoverable volume range is much more symmetrical (still with a large spread of approximately +/-50%) than the in-place volume range. This highlights the fact that the recovery from this reservoir is very much tied to the developable areas defined by reasonable productivity, afforded by fracture enhancement and, to a lesser degree, the occurrence of high permeability sands.

4.4. Valuation of Resources

The Ain Tsila Ordovician resources have been not been valued for this CPR, however an overview of the Fiscal Terms associated with the contract with Sonatrach are shown below.

4.4.1. Overview of PSC terms

The Isarene Block was awarded to Petroceltic in the 5th Algerian International Licensing Round of 2004. Prior to the award, 15 wells had been drilled on the permit, resulting in eight hydrocarbon discoveries. However, no discovery was considered commercial and all fields remained undeveloped. Petroceltic carry Sonatrach through the exploration phase and Sonatrach has the option to buy back into any subsequent commercial development with up to 25% participation.

Petroceltic have fulfilled all their current obligations under the PSC with a development plan approved by Sonatrach. The Ain Tsila field was unanimously declared commercial by all the parties to the PSC in August 2012. Petroceltic are currently awaiting the issue of an

Operating Licence for development by the Algerian competent authorities. The duration of the Operating Licence is 30 Years.

Remuneration to Petroceltic (the Investor) is made on the basis of a production multiplier, where the Investor's percentage share is based on the formula:

$$Pi = K*a - b$$

Where:

Pi is the percentage share

K is "Production Multiplier" bid by Petroceltic to win the licence with a value of 0.739.

"a" is a sliding scale percentage, decreasing in increments of oil equivalent production.

"b" is a percentage ratio of total revenues to investment for the duration of the contract.

A tax is levied on the investors taxable remuneration.

The full details of the PSA have been reviewed by AGR in order to ensure the commercial viability of the project.

Appendix 1 Gas and Liquids Contingent Resource Summary Ain Tsila

	Gross			***Net Working Interest***			***Risk Factor***	***Operator***
	Low Estimate	***Best Estimate***	***High Estimate***	***Low Estimate***	***Best Estimate***	***High Estimate***		
Gas (Tscf)	1.181	2.174	3.124	0.669	1.231	1.769	90%	Petroceltic
Oil (MMbbl)	-	-	-	-	-	-		
Condensate (MMbbl)	34.404	70.175	97.721	19.481	39.737	55.335		
LPG (MMbbl)	61.464	113.042	162.609	34.804	64.010	92.077		

Appendix 2 Personnel

Senior Petroleum Engineer

Jerry Hadwin

Jerry Hadwin has 27 years of petroleum/reservoir engineering experience, 13 with Shell International in the UK, Netherlands and Oman and 14 with TRACS International. He is a highly competent reservoir engineer with experience in asset evaluations, simulation, PVT and well test analysis and has a proven track record as a subsurface/field development project co-ordinator. He is a specialist in technical and economic screening of greenfield and brownfield development concepts and has extensive experience in reserves estimation and production forecasting. Jerry was a senior partner in TRACS and is now a senior manager in AGR Petroleum Services, which fully owns TRACS International.

Senior Geologist

Tim Salter

Tim Salter has 20 years of experience as a geologist working in the North Sea as well as Australasia and the Middle East. A sedimentologist by training he specialises in reservoir description, reservoir model building and the integration of geological data in an operational forum as well as execution of horizontal wells. In addition to experience with BP and Talisman he has provided asset review and integrated studies for a range small and mid-size operating companies. He has worked for AGR since 2011.

Appendix 3 Glossary

List of key abbreviations used in this report.

AIM	Alternative Investment Market
B	Billion (10^9)
BRT	Reference depth Below Rotary Table
bbl	Barrels
stb	Stock tank barrels
bopd	Barrels oil per day
Tscf	Trillion (10^{12}) standard cubic feet
BS&W	Bottom sediment and water
CGR	Condensate Gas Ratio
CPR	Competent Person's Report
GDT	Gas Down To
GIIP	Gas initially in place
GWC	Gas Water Contact
km	Kilometres
km^2	Square kilometres
m	Metres
mBRT	Metres below rotary table
mTVSS	Metres true vertical sub-sea
m^3	Cubic metres
mD	Permeability in millidarcies
M	Thousand (10^3)
MM	Million (10^6)
MD	Measured Depth
PI	Productivity Index
psi	Pounds per square inch
psig	Pounds per square inch gauge
RF	Recovery Factor
scf	Standard Cubic Feet
scf/d	Standard Cubic Feet per day
SPE	Society of Petroleum Engineers
SS	Subsea
SW	Water Saturation
Tcf	Trillion cubic feet of gas
TD	Total depth
TVDSS	True Vertical Depth Subsea
bSRD	below Seismic Reference Datum
WPC	World Petroleum Congresses

2D	Two-dimensional
3D	Three-dimensional
%	Percentage

Appendix 4 Petroleum Reserves Definitions

SOCIETY OF PETROLEUM ENGINEERS (SPE)

AND

WORLD PETROLEUM CONGRESSES (WPC)

DEFINITIONS

Reserves are those quantities of petroleum1 which are anticipated to be commercially recovered from known accumulations from a given date forward. All reserve estimates involve some degree of uncertainty. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability.

The intent of the SPE and WPC in approving additional classifications beyond proved reserves is to facilitate consistency among professionals using such terms. In presenting these definitions, neither organization is recommending public disclosure of reserves classified as unproved. Public disclosure of the quantities classified as unproved reserves is left to the discretion of the countries or companies involved.

Estimation of reserves is done under conditions of uncertainty. The method of estimation is called deterministic if a single best estimate of reserves is made based on known geological, engineering, and economic data. The method of estimation is called probabilistic when the known geological, engineering, and economic data are used to generate a range of estimates and their associated probabilities. Identifying reserves as proved, probable, and possible has been the most frequent classification method and gives an indication of the probability of recovery. Because of potential differences in uncertainty, caution should be exercised when aggregating reserves of different classifications.

Reserves estimates will generally be revised as additional geologic or engineering data becomes available or as economic conditions change. Reserves do not include quantities of petroleum being held in inventory, and may be reduced for usage or processing losses if required for financial reporting.

Reserves may be attributed to either natural energy or improved recovery methods. Improved recovery methods include all methods for supplementing natural energy or altering natural forces in the reservoir to increase ultimate recovery. Examples of such methods are pressure maintenance, cycling, waterflooding, thermal methods, chemical flooding, and the use of miscible and immiscible displacement fluids. Other improved recovery methods may be developed in the future as petroleum technology continues to evolve.

1. PETROLEUM: For the purpose of these definitions, the term petroleum refers to naturally occurring liquids and gases which are predominately comprised of hydrocarbon compounds. Petroleum may also contain non-hydrocarbon compounds in which sulphur, oxygen, and/or nitrogen atoms are combined with carbon and hydrogen. Common examples of non-hydrocarbons found in petroleum are nitrogen, carbon dioxide and hydrogen sulphide.

PROVED RESERVES

Proved reserves are those quantities of petroleum which, by analysis of geological and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under current economic conditions, operating methods, and government regulations. Proved reserves can be categorized as developed or undeveloped.

If deterministic methods are used, the term reasonable certainty is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate.

Establishment of current economic conditions should include relevant historical petroleum prices and associated costs and may involve an averaging period that is consistent with the purpose of the reserve estimate, appropriate contract obligations, corporate procedures, and government regulations involved in reporting these reserves.

In general, reserves are considered proved if the commercial producibility of the reservoir is supported by actual production or formation tests. In this context, the term proved refers to the actual quantities of petroleum reserves and not just the productivity of the well or reservoir. In certain cases, proved reserves may be assigned on the basis of well logs and/or core analysis that indicate the subject reservoir is hydrocarbon bearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation tests.

The area of the reservoir considered as proved includes (1) the area delineated by drilling and defined by fluid contacts, if any, and (2) the undrilled portions of the reservoir that can reasonably be judged as commercially productive on the basis of available geological and engineering data. In the absence of data on fluid contacts, the lowest known occurrence of hydrocarbons controls the proved limit unless otherwise indicated by definitive geological, engineering or performance data.

Reserves may be classified as proved if facilities to process and transport those reserves to market are operational at the time of the estimate or there is a reasonable expectation that such facilities will be installed. Reserves in undeveloped locations may be classified as proved undeveloped provided (1) the locations are direct offsets to wells that have indicated commercial production in the objective formation, (2) it is reasonably certain such locations are within the known proved productive limits of the objective formation, (3) the locations conform to existing well spacing regulations where applicable, and (4) it is reasonably certain the locations will be developed. Reserves from other locations are categorized as proved undeveloped only where interpretations of geological and engineering data from wells indicate with reasonable certainty that the objective formation is laterally continuous and contains commercially recoverable petroleum at locations beyond direct offsets.

Reserves which are to be produced through the application of established improved recovery methods are included in the proved classification when (1) successful testing by a pilot project or favourable response of an installed program in the same or an analogous reservoir with similar rock and fluid properties provides support for the analysis on which the project was based, and, (2) it is reasonably certain that the project will proceed. Reserves to be recovered by improved recovery methods that have yet to be established through commercially successful applications are included in the proved classification only (1) after a favourable production response from the subject reservoir from either (a) a representative pilot or (b) an installed program where the response provides support for the analysis on which the project is based and (2) it is reasonably certain the project will proceed.

UNPROVED RESERVES

Unproved reserves are based on geologic and/or engineering data similar to that used in estimates of proved reserves; but technical, contractual, economic, or regulatory uncertainties preclude such reserves being classified as proved. Unproved reserves may be further classified as probable reserves and possible reserves.

Unproved reserves may be estimated assuming future economic conditions different from those prevailing at the time of the estimate. The effect of possible future improvements in economic conditions and technological developments can be expressed by allocating appropriate quantities of reserves to the probable and possible classifications.

PROBABLE RESERVES

Probable reserves are those unproved reserves which analysis of geological and engineering data suggests are more likely than not to be recoverable. In this context, when probabilistic methods are used, there should be at least a 50% probability that the quantities actually recovered will equal or exceed the sum of estimated proved plus probable reserves.

In general, probable reserves may include (1) reserves anticipated to be proved by normal step-out drilling where sub-surface control is inadequate to classify these reserves as proved, (2) reserves in formations that appear to be productive based on well log characteristics but lack core data or definitive tests and which are not analogous to producing or proved reservoirs in the area, (3) incremental reserves attributable to infill drilling that could have been classified as proved if closer statutory spacing had been approved at the time of the estimate, (4) reserves attributable to improved recovery methods that have been established by repeated commercially successful applications when (a) a project or pilot is planned but not in operation and (b) rock, fluid, and reservoir characteristics appear favourable for commercial application, (5) reserves in an area of the formation that appears to be separated from the proved area by faulting and the geologic interpretation indicates the subject area is structurally higher than the proved area, (6) reserves attributable to a future workover, treatment, re-treatment, change of equipment, or other mechanical procedures, where such procedure has not been proved successful in wells which exhibit similar behaviour in analogous reservoirs, and (7) incremental reserves in proved reservoirs where an alternative interpretation of performance or volumetric data indicates more reserves than can be classified as proved.

POSSIBLE RESERVES

Possible reserves are those unproved reserves which analysis of geological and engineering data suggests are less likely to be recoverable than probable reserves. In this context, when probabilistic methods are used, there should be at least a 10% probability that the quantities actually recovered will equal or exceed the sum of estimated proved plus probable plus possible reserves.

In general, possible reserves may include (1) reserves which, based on geological interpretations, could possibly exist beyond areas classified as probable, (2) reserves in formations that appear to be petroleum bearing based on log and core analysis but may not be productive at commercial rates, (3) incremental reserves attributed to infill drilling that are subject to technical uncertainty, (4) reserves attributed to improved recovery methods when (a) a project or pilot is planned but not in operation and (b) rock, fluid and reservoir characteristics are such that a reasonable doubt exists that the project will be commercial, and (5) reserves in an area of the formation that appears to be separated from the proved area by faulting and geological interpretation indicates the subject area is structurally lower than the proved area.

RESERVE STATUS CATEGORIES

Reserve status categories define the development and producing status of wells and reservoirs.

Developed: Developed reserves are expected to be recovered from existing wells including reserves behind pipe. Improved recovery reserves are considered developed only after the necessary equipment has been installed, or when the costs to do so are relatively minor. Developed reserves may be sub-categorized as producing or non-producing.

Producing: Reserves subcategorized as producing are expected to be recovered from completion intervals which are open and producing at the time of the estimate. Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Non-producing: Reserves subcategorized as non-producing include shut-in and behind-pipe reserves. Shut-in reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe reserves are expected to be recovered from zones in existing wells, which will required additional completion work or future recompletion prior to the start of production.

Undeveloped Reserves: Undeveloped reserves are expected to be recovered: (1) from new wells on undrilled acreage, (2) from deepening existing wells to a different reservoir, or (3) where a relatively large expenditure is required to (a) recomplete an existing well or (b) install production or transportation facilities for primary or improved recovery projects.

Approved by the Board of Directors, Society of Petroleum Engineers (SPE), Inc., and

the Executive Board, World Petroleum Congresses (WPC), March 1997.

PETROLEUM RESOURCES CLASSIFICATION AND DEFINITIONS

SOCIETY OF PETROLEUM ENGINEERS (SPE)

WORLD PETROLEUM CONGRESSES (WPC)

AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS (AAPG)

In March 1997, the Society of Petroleum Engineers (SPE) and the World Petroleum Congresses (WPC) approved a set of petroleum□* reserves definitions which represented a major step forward in their mutual desire to improve the level of consistency in reserves estimation and reporting on a worldwide basis. As a further development, the SPE and WPC recognized the potential benefits to be obtained by supplementing those definitions to cover the entire resource base, including those quantities of Petroleum contained in accumulations that are currently sub-commercial or that have yet to be discovered. These other resources represent potential future additions to reserves and are therefore important to both countries and companies for planning and portfolio management purposes. In addition, the American Association of Petroleum Geologists (AAPG) participated in the development of these definitions and joined SPE and WPC as a sponsoring organization.

In 1987, the WPC published its report "Classification and Nomenclature Systems for Petroleum and Petroleum Reserves", which included definitions for all categories of resources. The WPC report, together with definitions by other industry organizations and recognition of current industry practice, provided the basis for the system outlined here.

Nothing in the following resource definitions should be construed as modifying the existing definitions for petroleum reserves as approved by the SPE/WPC in March 1997.

As with unproved (i.e. probable and possible) reserves, the intent of the SPE and WPC in approving additional classifications beyond proved reserves is to facilitate consistency among professionals using such terms. In presenting these definitions, neither organization is recommending public disclosure of quantities classified as resources. Such disclosure is left to the discretion of the countries or companies involved.

Estimates derived under these definitions rely on the integrity, skill, and judgement of the evaluator and are affected by the geological complexity, stage of exploration or development, degree of depletion of the reservoirs, and amount of available data. Use of the definitions should sharpen the distinction between various classifications and provide more consistent resources reporting.

DEFINITIONS

The resource classification system is summarized in Figure 1 and the relevant definitions are given below. Elsewhere, resources have been defined as including all quantities of petroleum which are estimated to be initially-in-place; however, some users consider only the estimated recoverable portion to constitute a resource. In these definitions, the quantities estimated to be initially-in-place are defined as Total Petroleum-initially-in-place, Discovered Petroleum-initially-in-place and Undiscovered Petroleum-initially-in-place, and the recoverable portions are defined separately as Reserves, Contingent Resources and Prospective Resources. In any event, it should be understood that reserves constitute a subset of resources, being those quantities that are discovered (i.e. in known accumulations), recoverable, commercial and remaining.

TOTAL PETROLEUM-INITIALLY-IN-PLACE

Total Petroleum-initially-in-place is that quantity of petroleum which is estimated to exist originally in naturally occurring accumulations. Total Petroleum-initially-in-place is, therefore, that quantity of petroleum which is estimated, on a given date, to be contained in known accumulations, plus those quantities already produced therefrom, plus those estimated quantities in accumulations yet to be discovered. Total Petroleum-initially-in-place may be subdivided into Discovered Petroleum-initially-in-place and Undiscovered Petroleum-initially-in-place, with Discovered Petroleum-initially-in-place being limited to known accumulations.

It is recognized that all Petroleum-initially-in-place quantities may constitute potentially recoverable resources since the estimation of the proportion which may be recoverable can be subject to significant uncertainty and will change with variations in commercial circumstances, technological developments and data availability. A portion of those quantities classified as Unrecoverable may become recoverable resources in the future as commercial circumstances change, technological developments occur, or additional data are acquired.

□ For the purpose of these definitions, the term "petroleum" refers to naturally occurring liquids and gases that are predominantly comprised of hydrocarbon compounds. Petroleum may also contain non-hydrocarbon compounds in which sulphur, oxygen, and/or nitrogen atoms are combined with carbon and hydrogen. Common examples of non-hydrocarbons found in petroleum are nitrogen, carbon dioxide, and hydrogen sulphide.

DISCOVERED PETROLEUM-INITIALLY-IN-PLACE

Discovered Petroleum-initially-in-place is that quantity of petroleum which is estimated, on a given date, to be contained in known accumulations, plus those quantities already produced therefrom. Discovered Petroleum-initially-in-place may be subdivided into Commercial and Sub-commercial categories, with the estimated potentially recoverable portion being classified as Reserves and Contingent Resources respectively, as defined below.

RESERVES

Reserves are defined as those quantities of petroleum which are anticipated to be commercially recovered from known accumulations from a given date forward. Reference should be made to the full SPE/WPC Petroleum Reserves Definitions for the complete definitions and guidelines.

Estimated recoverable quantities from known accumulations which do not fulfil the requirement of commerciality should be classified as Contingent Resources, as defined below. The definition of commerciality for an accumulation will vary according to local conditions and circumstances and is left to the discretion of the country or company concerned. However, reserves must still be categorized according to the specific criteria of the SPE/WPC definitions and therefore proved reserves will be limited to those quantities that are commercial under current economic conditions, while probable and possible reserves may be based on future economic conditions. In general, quantities should not be classified as reserves unless there is an expectation that the accumulation will be developed and placed on production within a reasonable timeframe.

In certain circumstances, reserves may be assigned even though development may not occur for some time. An example of this would be where fields are dedicated to a long-term supply contract and will only be developed as and when they are required to satisfy that contract.

CONTINGENT RESOURCES

Contingent Resources are those quantities of petroleum which are estimated, on a given date, to be potentially recoverable from known accumulations, but which are not currently considered to be commercially recoverable.

It is recognized that some ambiguity may exist between the definitions of contingent resources and unproved reserves. This is a reflection of variations in current industry practice. It is recommended that if the degree of commitment is not such that the accumulation is expected to be developed and placed on production within a reasonable timeframe, the estimated recoverable volumes for the accumulation be classified as contingent resources.

Contingent Resources may include, for example, accumulations for which there is currently no viable market, or where commercial recovery is dependent on the development of new technology, or where evaluation of the accumulation is still at an early stage.

UNDISCOVERED PETROLEUM-INITIALLY-IN-PLACE

Undiscovered Petroleum-initially-in-place is that quantity of petroleum which is estimated, on a given date, to be contained in accumulations yet to be discovered. The estimated potentially recoverable portion of Undiscovered Petroleum-initially-in-place is classified as Prospective Resources, as defined below.

PROSPECTIVE RESOURCES

Prospective Resources are those quantities of petroleum which are estimated, on a given date, to be potentially recoverable from undiscovered accumulations.

ESTIMATED ULTIMATE RECOVERY

Estimated Ultimate Recovery (EUR) is not a resource category as such, but a term which may be applied to an individual accumulation of any status/maturity (discovered or undiscovered). Estimated Ultimate Recovery is defined as those quantities of petroleum which are estimated, on a given date, to be potentially recoverable from an accumulation, plus those quantities already produced therefrom.

AGGREGATION

Petroleum quantities classified as Reserves, Contingent Resources or Prospective Resources should not be aggregated with each other without due consideration of the significant differences in the criteria associated with their classification. In particular, there may be a significant risk that accumulations containing Contingent Resources or Prospective Resources will not achieve commercial production.

RANGE OF UNCERTAINTY

The Range of Uncertainty, as shown in Figure 1, reflects a reasonable range of estimated potentially recoverable volumes for an individual accumulation. Any estimation of resource quantities for an accumulation is subject to both technical and commercial uncertainties, and should, in general, be quoted as a range. In the case of reserves, and where appropriate, this range of uncertainty can be reflected in estimates for Proved Reserves (1P), Proved plus Probable Reserves (2P) and Proved plus Probable plus Possible Reserves (3P) scenarios. For other resource categories, the terms Low Estimate, Best Estimate and High Estimate are recommended.

The term "Best Estimate" is used here as a generic expression for the estimate considered to be the closest to the quantity that will actually be recovered from the accumulation between the date of the estimate and the time of abandonment. If probabilistic methods are used, this term would generally be a measure of central tendency of the uncertainty distribution (most likely/mode, median/P50 or mean). The terms "Low Estimate" and "High Estimate" should provide a reasonable assessment of the range of uncertainty in the Best Estimate.

For undiscovered accumulations (Prospective Resources) the range will, in general, be substantially greater than the ranges for discovered accumulations. In all cases, however, the actual range will be dependent on the amount and quality of data (both technical and commercial) which is available for that accumulation. As more data become available for a specific accumulation (e.g. additional wells, reservoir performance data) the range of uncertainty in EUR for that accumulation should be reduced.

RESOURCES CLASSIFICATION SYSTEM

Graphical Representation

Figure 1 is a graphical representation of the definitions. The horizontal axis represents the range of uncertainty in the estimated potentially recoverable volume for an accumulation, whereas the vertical axis represents the level of status/maturity of the accumulation. Many organizations choose to further sub-divide each resource category using the vertical axis to classify accumulations on the basis of the commercial decisions required to move an accumulation towards production.

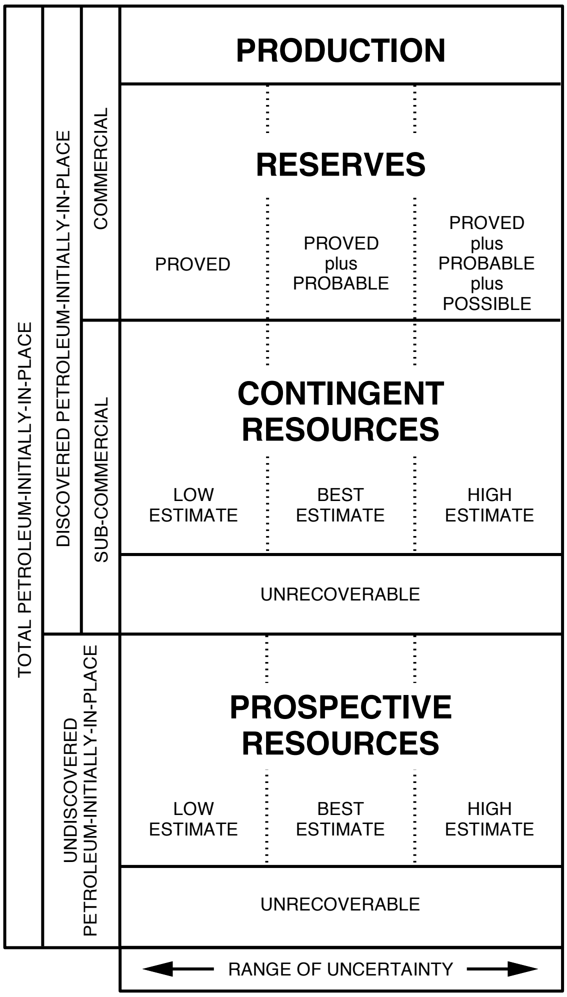
As indicated in Figure 1, the Low, Best and High Estimates of potentially recoverable volumes should reflect some comparability with the reserves categories of Proved, Proved plus Probable and Proved plus Probable plus Possible, respectively. While there may be a significant risk that sub-commercial or undiscovered accumulations will not achieve commercial production, it is useful to consider the range of potentially recoverable volumes independently of such a risk.

If probabilistic methods are used, these estimated quantities should be based on methodologies analogous to those applicable to the definitions of reserves; therefore, in general, there should be at least a 90% probability that, assuming the accumulation is developed, the quantities actually recovered will equal or exceed the Low Estimate. In addition, an equivalent probability value of 10% should, in general, be used for the High Estimate. Where deterministic methods are used, a similar analogy to the reserves definitions should be followed.

As one possible example, consider an accumulation that is currently not commercial due solely to the lack of a market. The estimated recoverable volumes are classified as Contingent Resources, with Low, Best and High estimates. Where a market is subsequently developed, and in the absence of any new technical data, the accumulation moves up into the Reserves category and the Proved Reserves estimate would be expected to approximate the previous Low Estimate.

Approved by the Board of Directors, Society of Petroleum Engineers (SPE), Inc., the Executive Board, World Petroleum Congresses (WPC), and the Executive Committee, American Association of Petroleum Geologists (AAPG), February, 2000.

FIGURE 1 - RESOURCES CLASSIFICATION SYSTEM



Not to scale

Appendix 5 Ain Tsila 2C Production Profile

Year	Sales Gas mmscf/d	Condensate bpd	LPG bpd
1	0	0	0
2	0	0	0
3	0	0	0
4	0	0	0
5	329	11,428	17,117
6	329	11,095	17,117
7	329	10,237	17,117
8	329	10,382	17,117
9	329	10,018	17,117
10	329	9,964	17,117
11	329	10,019	17,117
12	329	10,066	17,117
13	329	10,168	17,117
14	329	10,299	17,117
15	329	10,668	17,117
16	329	10,928	17,117
17	329	11,141	17,117
18	329	11,285	17,117
19	281	9,704	14,629
20	123	4,087	6,386
21	115	3,818	5,966
22	107	3,561	5,563
23	102	3,391	5,322
24	98	3,233	5,071
25	94	3,109	4,877
26	91	2,890	4,710
27	88	2,793	4,551
28	85	2,701	4,400
29	82	2,614	4,258
30	79	2,531	4,122

DEGOLYER AND MACNAUGHTON
5001 SPRING VALLEY ROAD
SUITE 800 EAST
DALLAS, TEXAS 75244

August 17, 2012

The Directors
Petroceltic International PLC
75 St Stephen's Green
Dublin 2
Ireland

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

Dear Sirs:

We have been contracted by Petroceltic International PLC (Petroceltic) and J&E Davy to prepare a competent person's report on the extent and potential volumes of the prospective resources, as of June 30, 2012, for the Shakrok, Pelewan, Shireen, Chinara, and Bradost prospects in Kurdistan and the Carpignano Sesia, Case Cerano, Desana Deep, Rosso Channels, and Arborio prospects in Italy. (the Competent Person's Report) that will be included in an admission document prepared in accordance with the AIM Rules of the London Stock Exchange plc and the ESM Rules of the Irish Stock Exchange Limited (the Admission Document).

The Competent Person's Report has been prepared in accordance with Competent Person's Report scope and content guidelines set out in the AIM Note for Mining, Oil and Gas Companies – June 2009 published by the London Stock Exchange plc ("the AIM Note for Mining, Oil and Gas Companies"). The Competent Person's Report relates solely to the defined licenses and is based on various geologic and economic assumptions as detailed in the Competent Person's Report. Therefore, the Competent Person's Report must be read in its entirety.

DeGolyer and MacNaughton is a Delaware Corporation with offices at 5001 Spring Valley Road Suite 800 East, Dallas, Texas 75244, U.S.A. The firm has been providing petroleum consulting services throughout the world since 1936. The firm's professional engineers, geologists, geophysicists, petrophysicists, and economists are engaged in the independent appraisal of oil and gas properties, evaluation of hydrocarbon and other mineral prospects, basin evaluations, comprehensive field studies, equity studies, and studies of supply and economics related to the energy industry. Except for the provision of professional services on a fee basis, DeGolyer and MacNaughton has no commercial arrangement with any other person or company involved in the interests which are the subject of this report.

The evaluation presented in the Competent Person's Report reflects our informed judgment based on accepted standards of professional investigation. The evaluation has been conducted within our understanding of relevant legislation, taxation, and all other regulations that currently applies to these interests.

We hereby consent to the inclusion of the Competent Person's Report and to the use of the name DeGolyer and MacNaughton in the Admission Document in the form and context in which they respectively appear.

We have reviewed the relevant sections of the Admission Document which relate to information contained in the Competent Person's Report and confirm that the information presented is accurate, balanced, and complete and not inconsistent with the Competent Person's Report. In particular we confirm that the information in the Admission Document, where extracted from the Competent Person's Report, is extracted directly and presented in a manner which is not misleading or inconsistent with the Competent Person's Report and provides a balanced view of the Competent Person's Report.

We accept responsibility for the Competent Person's Report contained in the Admission Document for the purposes of a competent person's report under the AIM Note for Mining, Oil and Gas Companies. The Competent Person's Report is complete up to and including June 30, 2012. To the best of our knowledge and belief, after having taken all reasonable care to ensure that such is the case, the information contained in the Competent Person's Report is in accordance with the facts and does not omit anything likely to affect the import of such information.

We are not aware of any material changes to Petroceltic's estimated prospective resources since the effective date of the Competent Person's Report. No representations can be made as to whether any events of which we are not aware may have occurred subsequent to June 30, 2012, which could materially affect the conclusions presented in the Competent Person's Report.

We are independent of Petroceltic, the directors, and senior management of Petroceltic and its other advisors. The Competent Person's Report is prepared in return for professional fees based upon agreed commercial rates, and the payment of these fees is in no way contingent on the results of the Competent Person's Report, the admission of Petroceltic's shares to trading on AIM, or the ESM, or the value of Petroceltic.

Very truly yours,

DeGolyer and MacNaughton

DeGOLYER and MacNAUGHTON
Texas Registered Engineering Firm F-7

DeGolyer and MacNaughton
5001 Spring Valley Road
Suite 800 East
Dallas, Texas 75244

July 24, 2012

Directors
Petroceltic International PLC
75 St. Stephen's Green
Dublin 2, Ireland

Directors
DAVY
49 Dawson Street
Dublin 2, Ireland

Dear Sirs:

Pursuant to the request of Petroceltic International PLC. (Petroceltic) and DAVY, we have conducted an independent evaluation, as of June 30, 2012, of the extent and potential volumes of the prospective resources for the Shakrok, Pelewan, Shireen, Chinara, and Bradost prospects in Kurdistan and the Carpignano Sesia, Case Cerano, Desana Deep, Rosso Channels, and Arborio prospects in Italy. Petroceltic represents that it currently owns a 20-percent working interest in the Kurdistan prospects and various ownership interests in the Italian prospects (Table P1 and P2). There has been no material change from June 30, 2012, to the as-of date of the report. Site visits to the prospects evaluated herein were not made by DeGolyer and MacNaughton.

The prospective resources estimates presented in this report have been prepared in accordance with the Petroleum Resources Management System (PRMS) approved in March 2007 by the Society of Petroleum Engineers, the World Petroleum Council, the American Association of Petroleum Geologists, and the Society of Petroleum Evaluation Engineers. The PRMS standard is a referenced standard in published guidance of the Alternative Investment Market (AIM) of the London Stock Exchange.

Petroceltic has represented that it intends to proceed with development and operation of any commercially viable discovered prospect. Based on these representations, we have included as prospective resources certain quantities that, if discovered, may potentially be produced under the terms of the relevant license agreements.

The prospective resources estimated herein are expressed as gross and net prospective resources. Gross prospective resources are defined as the total estimated petroleum that is potentially recoverable after June 30, 2012. Net prospective resources are defined as the product of the gross prospective resources and Petroceltic's gross working interest.

The prospective resources estimated herein are those quantities of petroleum that are potentially recoverable from accumulations yet to be discovered. Because of the uncertainty of commerciality and the lack of sufficient exploration drilling, the prospective resources estimated herein cannot be classified as contingent resources or reserves. The prospective resources estimates in this report are not provided as a means of comparison to contingent resources or reserves.

Information used in the preparation of this report was obtained from Petroceltic. All figures in this report are provided by Petroceltic. In the preparation of this report, we have relied upon information furnished by Petroceltic with respect to the property interests evaluated, and these data were accepted as represented. Although there is no independent verification of certain information, the information provided by Petroceltic appears reasonable in the context of the venue and known circumstances from general experience. Petroceltic represents that its technical staff adhere to generally accepted industry practices and appear to be experienced and technically competent in their fields of expertise. Site visits to the prospects evaluated herein were not made by DeGolyer and MacNaughton, as existing information from the public domain in this known producing venue was considered adequate.

Executive Summary

Petroceltic is an Ireland-based oil and gas company that owns various working interests in several license areas in Kurdistan and Italy (Figures 1 and 4). Petroceltic owns a 20-percent working interest in the Shakrok and Dinarta license blocks in the Zagros-Arabian foreland basin of Kurdistan. Petroceltic also owns various working interests in the Po Valley of Italy (Carisio and Ronsecco license blocks). The assessed prospects and their relevant license, exploration, and ownership information are summarized in Tables P1 and P2, and further described in the Exploration Overview section.

	Summary of Prospect Particulars							
Prospect	**Country**	**Basin**	**License Block**	**Operator**	**Working Interest**	**Status**	**License Expiration (mo./yr.)**	**License Area (km^2)**
Shakrok	Kurdistan	Zagros-Arabian	Shakrok	Hess	0.200 [a]	Exploration	07/2016[b]	418
Pelewan	Kurdistan	Zagros-Arabian	Shakrok	Hess	0.200 [a]	Exploration	07/2016[b]	418
Shireen	Kurdistan	Zagros-Arabian	Dinarta	Hess	0.200 [a]	Exploration	07/2016[b]	1,319
Chinara	Kurdistan	Zagros-Arabian	Dinarta	Hess	0.200 [a]	Exploration	07/2016[b]	1,319
Bradost	Kurdistan	Zagros-Arabian	Dinarta	Hess	0.200 [a]	Exploration	07/2016[b]	1,319
Carpignano Sesia	Italy	Po Valley	Carisio	ENI	0.475	Exploration	12/2012[c,d]	728
Case Cerano	Italy	Po Valley	Ronsecco	Petroceltic	1.000	Exploration	11/2016[c]	746
Desana Deep	Italy	Po Valley	Ronsecco	Petroceltic	1.000	Exploration	11/2016[c]	746
Rosso Channels	Italy	Po Valley	Carisio	ENI	0.475	Exploration	12/2012[c,d]	728
Arborio	Italy	Po Valley	Carisio	ENI	0.475	Exploration	12/2012[c,d]	728

Notes:
[a] The Kurdistan Regional Government (KRG) has a 20-percent carried interest, net of which Petroceltic will have a 16-percent participating interest.
[b] End Base Exploration Term (5 years).
[c] End of 1st Exploration Period (6 years).
[d] Application for extension under review.

Prospective resources for 10 prospects (30 targeted potential reservoirs) have been estimated as of June 30, 2012. The portfolio statistical aggregate probability of geologic success (P_g) for all the oil prospects in Shakrok, Dinarta, Carisio, and Ronsecco license blocks is 0.238 (gross). The portfolio statistical aggregate P_g for all gas prospects in Ronsecco and Carisio license blocks is 0.222 (gross).

The estimated gross and net prospective oil, raw natural gas, and condensate resources in various license blocks in Kurdistan and Italy evaluated herein are summarized as follows, expressed in thousands of barrels (10^3bbl) and millions of cubic feet (10^6ft^3):

	Gross and Net Prospective Resources			
	Low Estimate	**Best Estimate**	**High Estimate**	**Mean Estimate**
Gross Prospective Resources				
Gross Prospective Oil Resources, 10^3bbl	2,282,560	3,324,988	4,843,768	3,471,389
Gross Prospective Raw Natural Gas Resources, 10^6ft^3	563,107	820,273	1,194,956	856,391
Gross Prospective Condensate Resources, 10^3bbl	19,735	73,027	257,403	103,626
Net Prospective Resources				
Net Prospective Oil Resources, 10^3bbl	605,925	979,746	1,583,737	1,061,095
Net Prospective Raw Natural Gas Resources, 10^6ft^3	469,945	722,708	1,091,560	767,609
Net Prospective Condensate Resources, 10^3bbl	19,735	73,027	257,403	103,626

Notes:
1. Low, best, and high estimates in this table are P_{90}, P_{50}, and P_{10}, respectively.
2. P_g has not been applied to the volumes in this table.
3. Application of any geological or economic chance factor does not equate prospective resources with contingent resources or reserves.
4. Recovery efficiency is applied to prospective resources in this table.
5. The prospective resources presented above are based on the statistical aggregation method.
6. Net interest prospective resources are defined as the product of the gross prospective resources and Petroceltic's working interest, summarized in Tables P1 and P2.
7. There is no certainty that any portion of the prospective resources estimated herein will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources evaluated.

The gross and net P_g-adjusted mean estimate prospective oil, raw natural gas, and condensate resources, should these prospects result in successful discoveries and development, as of June 30, 2012, are summarized as follows, expressed in English units in thousands of barrels (10^3bbl) and millions of cubic feet (10^6ft^3):

	Mean Estimate
Gross P_g-Adjusted Prospective Resources	
Gross P_g-Adjusted Prospective Oil Resources, 10^3bbl	824,601
Gross P_g-Adjusted Prospective Raw Natural Gas Resources, 10^6ft^3	190,260
Gross P_g-Adjusted Prospective Condensate Resources, 10^3bbl	24,482
Net P_g-Adjusted Prospective Resources	
Net P_g-Adjusted Prospective Oil Resources, 10^3bbl	230,348
Net P_g-Adjusted Prospective Raw Natural Gas Resources, 10^6ft^3	175,618
Net P_g-Adjusted Prospective Condensate Resources, 10^3bbl	24,482

Notes:
1. Application of any geological and economic chance factor does not equate prospective resources to contingent resources or reserves.
2. Recovery efficiency is applied to prospective resources in this table.
3. The prospective resources presented above are based on the statistical aggregation method.
4. Net interest prospective resources are defined as the product of the gross prospective resources and Petroceltic's working interest, summarized in Tables P1 and P2.
5. There is no certainty that any portion of the prospective resources estimated herein will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources evaluated.

Definition of Prospective Resources

Petroleum resources included in this report are classified as prospective resources and have been prepared in accordance with the PRMS approved in March 2007 by the Society of Petroleum Engineers, the World Petroleum Council, the American Association of Petroleum Geologists, and the Society of Petroleum Evaluation Engineers. Because of the lack of commerciality or sufficient drilling, the prospective resources estimated herein cannot be classified as contingent resources or reserves. The petroleum resources are classified as follows:

> *Prospective Resources* – Those quantities of petroleum that are estimated, as of a given date, to be potentially recoverable from

undiscovered accumulations by application of future development projects.

The estimation of resources quantities for a prospect is subject to both technical and commercial uncertainties and, in general, may be quoted as a range. The range of uncertainty reflects a reasonable range of estimated potentially recoverable quantities. In all cases, the range of uncertainty is dependent on the amount and quality of both technical and commercial data that are available and may change as more data become available.

Low, Best, High, and Mean Estimates – Estimates of petroleum resources in this report are expressed using the terms low estimate, best estimate, high estimate, and mean estimate to reflect the range of uncertainty.

A detailed explanation of the probabilistic terms used herein and identified with an asterisk (*) is included in the Glossary of Probabilistic Terms bound with this report. For probabilistic estimates of petroleum resources, the low estimate reported herein is the P_{90}* quantity derived from probabilistic analysis. This means that there is at least a 90-percent probability that, assuming the prospect is discovered and developed, the quantities actually recovered will equal or exceed the low estimate. The best (median) estimate is the P_{50}* quantity derived from probabilistic analysis. This means that there is at least a 50-percent probability that, assuming the prospect is discovered and developed, the quantities actually recovered will equal or exceed the best (median) estimate. The high estimate is the P_{10}* quantity derived from probabilistic analysis. This means that there is at least a 10-percent probability that, assuming the prospect is discovered and developed, the quantities actually recovered will equal or exceed the high estimate. The expected value* (EV), an outcome of the probabilistic analysis, is the mean estimate.

Uncertainties Related to Prospective Resources – The quantity of petroleum discovered by exploration drilling depends on the number of prospects that are successful as well as the quantity that each success contains. Reliable forecasts of these quantities are, therefore, dependent on accurate predictions of the number of discoveries that are likely to be made if the entire portfolio of prospects is drilled. The accuracy of this forecast depends on the portfolio size, and an accurate assessment of the probability of geologic success* (P_g).

Probability of Geologic Success (P_g) – P_g is defined as the probability of discovering reservoirs that flow petroleum at a measurable rate. P_g is estimated by quantifying the probability of each of the following individual geologic factors: trap, source, reservoir, and migration. The product of these four probabilities or chance factors is computed as P_g.

In this report estimates of prospective resources are presented both before and after adjustment for P_g. Total prospective resources estimates are based on the probabilistic summation of the quantities for the total inventory of prospects.

Application of P_g to estimate the P_g-adjusted prospective resources quantities does not equate prospective resources with reserves or contingent resources. P_g-adjusted prospective resources quantities cannot be compared directly to or aggregated with either reserves or contingent resources. Estimates of P_g are interpretive and are dependent on the quality and quantity of data currently made available. Future data acquisition, such as additional drilling or seismic acquisition, can have a significant effect on P_g estimation. These additional data are not confined to the study area, but also include data from similar geologic settings or technological advancements that could affect the estimation of P_g.

Predictability versus Portfolio Size (PPS) – The accuracy of forecasts of the number of discoveries that are likely to be made is constrained by the number of prospects in the exploration portfolio. The size of the portfolio and P_g together are helpful in gauging the limits on the reliability of these forecasts. A high P_g, which indicates a high chance of discovering measurable petroleum, may not require a large portfolio to ensure that at least one discovery will be made (assuming the P_g does not change during drilling of some of the prospects). By contrast, a low P_g, which indicates a low chance of discovering measurable petroleum, could require a large number of prospects to ensure a high confidence level of making even a single discovery. The relationship between portfolio size, P_g, and the probability of a fully unsuccessful drilling program that results in a series of wells not encountering measurable hydrocarbons is referred to herein as the predictability versus portfolio size relationship* (PPS). It is critical to be aware of PPS, because an unsuccessful drilling program, which results in a series of wells that do not encounter measurable hydrocarbons, can adversely affect any exploration effort, resulting in a negative present worth.

For a large prospect portfolio, the P_g-adjusted mean estimate of the prospective resources quantity should be a reasonable estimate of the recoverable petroleum quantities found if all prospects are drilled. When the number of prospects in the portfolio is small and the P_g is low, the recoverable petroleum actually found may be considerably smaller than the P_g-adjusted mean estimate would indicate. It follows that the probability that all of the prospects will be unsuccessful is smaller when a large inventory of prospects exist.

Prospect Technical Evaluation Stage – A prospect can often be subcategorized based on its current stage of technical evaluation. The different stages of technical evaluation relate to the amount of geologic, geophysical, engineering, and petrophysical data as well as the quality of available data.

Prospect – A prospect is a potential accumulation that is sufficiently well defined to be a viable drilling target. For a prospect, sufficient data and analyses exist to identify and quantify the technical uncertainties, to determine reasonable ranges of geologic chance factors and engineering and petrophysical parameters, and to estimate prospective resources.

Lead – A lead is less well defined and requires additional data and/or evaluation to be classified as a prospect. An example would be a poorly defined closure mapped using sparse regional seismic data in a basin containing favorable source and reservoir(s). A lead may or may not be elevated to prospect status depending on the results of additional technical work. A lead must have a P_g equal to or less than 0.05 to reflect the inherent technical uncertainty.

Play – A project associated with a prospective trend of potential prospects, but which requires more data acquisition and/or evaluation in order to define specific leads or prospects.

Estimation of Prospective Resources

Estimates of prospective resources were prepared by the use of standard geological and engineering methods generally accepted by the petroleum industry. The method or combination of methods used in the analysis of the reservoirs was tempered by experience with similar reservoirs, stage of development, and quality and completeness of basic data.

The probabilistic analysis of the prospective resources in this study considered the uncertainty in the amount of petroleum that may be discovered and the P_g. The uncertainty analysis addresses the range of possibilities for any given volumetric parameter. Low, best, high, and mean estimates of prospective resources were estimated to address this uncertainty. The P_g analysis addresses the probability that the identified prospect will contain petroleum that flows at a measurable rate.

Standard probabilistic methods were used in the uncertainty analysis. Probability distributions were estimated from representations of porosity, petroleum saturation, net hydrocarbon thickness, geometric correction factor, recovery efficiency, fluid properties, and productive area for each prospect. These representations were prepared based on known data, analogy, and other standard estimation methods including experience. Statistical measures describing the probability distributions of these representations were identified and input to a Monte Carlo simulation to produce low estimate, best estimate, high estimate, and mean estimate prospective resources for each prospect. The gross and net prospective resources estimated herein are tabulated in Tables 1 through 8.

Nonassociated gas is gas at initial reservoir conditions with no crude oil present in the reservoir. Gas-cap gas is gas at initial reservoir conditions and is in communication with an underlying oil zone. Solution gas is gas dissolved in crude oil at initial reservoir conditions. In known accumulations, solution gas and gas-cap gas are sometimes produced together, and as a whole, referred to as associated gas. Prospective raw natural gas quantities (nonassociated and associated) included herein are defined as the total gas potentially producible from the prospective reservoirs before any reduction for shrinkage for potential field and/or platform handling, separation, processing, fuel usage, flaring, reinjection, and/or pipeline losses. Prospective sales-gas quantities included herein are defined as the total gas to be produced from the reservoirs, measured at the point of delivery, after reduction for fuel usage, flare, and shrinkage resulting from field separation and processing.

However, it is not certain whether prospective reservoirs will be gas bearing, oil bearing, or water bearing. Prospective resources volumes in this report are identified herein as oil, raw natural gas, and condensate.

In this report gas quantities are expressed at a temperature base of 60 degrees Fahrenheit (°F) and at a pressure base of 14.7 pounds per square inch absolute (psia).

Quantitative Risk Assessment and the Application of P_g

Minimum, modal, and maximum representations of potential area were interpreted from maps, available seismic data, and/or analogy. Low, mean, and high representations for the petrophysical parameters (porosity, petroleum saturation, and net hydrocarbon thickness) and engineering parameters (recovery efficiency and fluid properties) were also made based on available well data, regional data, analog field data, and global experience. Individual probability distributions for net rock volume and petrophysical and engineering parameters were produced from these representations and are summarized in Tables 7 and 8.

The distributions for the variables were derived from (1) scenario-based interpretations, (2) the geologic, geophysical, petrophysical, and engineering data available, (3) local, regional, and global knowledge, and (4) field and case studies in the literature. The parameters used to model the potential recoverable quantities were productive area, net hydrocarbon thickness, geometric correction factor, porosity, petroleum saturation, formation volume factor, and recovery efficiency. Minimum, mean, and maximum representations were used to statistically model and shape the input P_{90}, P_{50}, and P_{10} parameters. Productive area and net hydrocarbon thickness were modeled using truncated lognormal distributions. Truncated normal and triangular distributions were used to model geometric correction factor, formation volume factor, and recovery efficiency. Porosity and petroleum saturation were modeled using truncated normal distributions. Latin hypercube sampling was used to better represent the tails of the distributions.

Each individual volumetric parameter was investigated using a probabilistic approach with attention to variability. Deterministic data were used to anchor and shape the various distributions. The net rock volume parameters had the greatest range of variability, and therefore, had the greatest impact on the uncertainty of the simulation. The volumetric parameter variability was based on the structural and stratigraphic uncertainties due to the depositional environment and quality of the seismic data. Analog field data were statistically incorporated to derive uncertainty limits and constraints on the net pore volume. Uncertainty associated with the depth conversion, seismic interpretation, gross sand thickness mapping, and net hydrocarbon thickness assumptions were also derived from studies of analogous reservoirs, multiple interpretative scenarios, and sensitivity analyses.

A P_g analysis was applied to estimate the quantities that may actually result from drilling these prospects. In the P_g analysis, the P_g estimates were made for each prospect from the product of the probabilities of the four geologic chance factors: trap, reservoir, migration, and source.

Estimates of gross and net prospective resources and the P_g estimates, as of June 30, 2012, evaluated herein are shown in Tables 1 through 6. The P_g-adjusted mean estimate of the prospective resources was then made by the probabilistic product of P_g and the resources distributions for the prospect. These results were then stochastically summed (zero dependency) to produce the total P_g-adjusted mean estimate prospective resources.

Application of the P_g factor to estimate the P_g-adjusted prospective resources quantities does not equate prospective resources with reserves or contingent resources. P_g-adjusted estimates of prospective resources quantities cannot be compared directly to or aggregated with either reserves or contingent resources. Estimates of P_g are interpretive and are dependent on the quality and quantity of data currently available. Future data acquisition, such as additional drilling or seismic acquisition can have a significant effect on P_g estimation. These additional data are not confined to the area of study, but also include data from similar geologic settings or from technological advancements that could affect the estimation of P_g.

There is no certainty that any portion of the prospective resources summarized herein will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources estimated herein.

A summary of the gross prospective oil, raw natural gas, and condensate resources in various license blocks in Kurdistan and Italy estimated herein are shown in the following tables, expressed in thousands of barrels (10^3bbl) and millions of cubic feet (10^6ft^3):

Gross Prospective Oil Resources Summary

Prospect	Country	Low Estimate (10^3bbl)	Best Estimate (10^3bbl)	High Estimate (10^3bbl)	Mean Estimate (10^3bbl)	Probability of Geologic Success, P_g (decimal)	P_g-Adjusted Mean Estimate (10^3bbl)
Shakrok	Kurdistan	402,244	649,714	1,060,956	707,074	0.245	173,233
Pelewan	Kurdistan	117,529	216,854	370,791	232,290	0.245	56,911
Shireen	Kurdistan	385,435	660,197	1,067,226	706,042	0.245	172,980
Chinara	Kurdistan	331,164	566,628	962,796	621,589	0.245	152,289
Bradost	Kurdistan	303,958	533,362	926,401	590,417	0.245	144,652
Arithmetic Summation:							
Kurdistan		1,540,330	2,626,754	4,388,170	2,857,414	0.245	700,066
Carpignano Sesia	Italy	43,216	161,730	510,845	236,882	0.275	65,143
Case Cerano	Italy	124,938	311,180	715,438	377,093	0.158	59,392
Arithmetic Summation:							
Italy		168,154	472,910	1,226,283	613,976	0.203	124,535
Statistical Aggregate		**2,282,560**	**3,324,988**	**4,843,768**	**3,471,389**	**0.238**	**824,601**
Arithmetic Summation:							
Portfolio		1,708,483	3,099,664	5,614,453	3,471,389	0.238	824,601

Notes:

1. Low, best, high, and mean estimates follow the PRMS guidelines for prospective resources.
2. Low, best, high, and mean estimates in this table are P_{90}, P_{50}, and P_{10}, and mean, respectively.
3. P_g is defined as the probability of discovering reservoirs which flow petroleum at a measurable rate.
4. P_g has been rounded for presentation purposes. Multiplication using this presented P_g may yield imprecise results. Dividing the P_g-adjusted mean estimate by the mean estimate yields the precise P_g.
5. Application of any geological and economic chance factor does not equate prospective resources to contingent resources or reserves.
6. Recovery efficiency is applied to prospective resources in this table.
7. Arithmetic summation of probabilistic estimates produces invalid results except for the mean estimate. Arithmetic summation of the portfolio probabilistic estimates is presented in this table in compliance with PRMS guidelines.
8. Summations may vary from those shown here due to rounding.
9. There is no certainty that any portion of the prospective resources estimated herein will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources evaluated.

Gross Prospective Raw Natural Gas Resources Summary

Prospect	Low Estimate (10^6ft^3)	Best Estimate (10^6ft^3)	High Estimate (10^6ft^3)	Mean Estimate (10^6ft^3)	Probability of Geologic Success, P_g (decimal)	P_g-Adjusted Mean Estimate (10^6ft^3)
Desana Deep	195,204	542,231	1,333,580	687,282	0.236	162,370
Rosso Channels	77,339	127,053	195,026	132,283	0.113	15,001
Arborio	12,480	31,777	68,140	36,826	0.350	12,889
Statistical Aggregate	**563,107**	**820,273**	**1,194,956**	**856,391**	**0.222**	**190,260**
Arithmetic Summation:						
Portfolio	285,023	701,061	1,596,746	856,391	0.222	190,260

Notes:
1. Low, best, high, and mean estimates follow the PRMS guidelines for prospective resources.
2. Low, best, high, and mean estimates in this table are P_{90}, P_{50}, and P_{10}, and mean, respectively.
3. P_g is defined as the probability of discovering reservoirs which flow petroleum at a measurable rate.
4. P_g has been rounded for presentation purposes. Multiplication using this presented P_g may yield imprecise results. Dividing the P_g-adjusted mean estimate by the mean estimate yields the precise P_g.
5. Application of any geological and economic chance factor does not equate prospective resources to contingent resources or reserves.
6. Recovery efficiency is applied to prospective resources in this table.
7. Arithmetic summation of probabilistic estimates produces invalid results except for the mean estimate. Arithmetic summation of the portfolio probabilistic estimates is presented in this table in compliance with PRMS guidelines.
8. Summations may vary from those shown here due to rounding.
9. There is no certainty that any portion of the prospective resources estimated herein will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources evaluated.

Gross Prospective Condensate Resources Summary

Prospect	Low Estimate (10^3bbl)	Best Estimate (10^3bbl)	High Estimate (10^3bbl)	Mean Estimate (10^3bbl)	Probability of Geologic Success, P_g (decimal)	P_g-Adjusted Mean Estimate (10^3bbl)
Desana Deep	19,735	73,027	257,403	103,626	0.236	24,482
Statistical Aggregate	**19,735**	**73,027**	**257,403**	**103,626**	**0.236**	**24,482**
Arithmetic Summation:						
Portfolio	19,735	73,027	257,403	103,626	0.236	24,482

Notes:
1. Low, best, high, and mean estimates follow the PRMS guidelines for prospective resources.
2. Low, best, high, and mean estimates in this table are P_{90}, P_{50}, and P_{10}, and mean, respectively.
3. P_g is defined as the probability of discovering reservoirs which flow petroleum at a measurable rate.
4. P_g has been rounded for presentation purposes. Multiplication using this presented P_g may yield imprecise results. Dividing the P_g-adjusted mean estimate by the mean estimate yields the precise P_g.
5. Application of any geological and economic chance factor does not equate prospective resources to contingent resources or reserves.
6. Recovery efficiency is applied to prospective resources in this table.
7. Arithmetic summation of probabilistic estimates produces invalid results except for the mean estimate. Arithmetic summation of the portfolio probabilistic estimates is presented in this table in compliance with PRMS guidelines.
8. Summations may vary from those shown here due to rounding.
9. There is no certainty that any portion of the prospective resources estimated herein will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources evaluated.

A summary of the net prospective oil, raw natural gas, and condensate resources in various license blocks in Kurdistan and Italy estimated herein are shown in the following tables, expressed in thousands of barrels (10^3bbl) and millions of cubic feet (10^6ft^3).

		Net Prospective Oil Resources Summary					
Prospect	**Country**	**Low Estimate (10^3bbl)**	**Best Estimate (10^3bbl)**	**High Estimate (10^3bbl)**	**Mean Estimate (10^3bbl)**	**Probability of Geologic Success, P_g (decimal)**	**P_g-Adjusted Mean Estimate (10^3bbl)**
Shakrok	Kurdistan	80,449	129,943	212,191	141,415	0.245	34,647
Pelewan	Kurdistan	23,506	43,371	74,158	46,458	0.245	11,382
Shireen	Kurdistan	77,087	132,039	213,445	141,208	0.245	34,596
Chinara	Kurdistan	66,233	113,326	192,559	124,318	0.245	30,458
Bradost	Kurdistan	60,792	106,672	185,280	118,083	0.245	28,930
Arithmetic Summation:							
Kurdistan		308,066	525,351	877,634	571,483	0.245	140,013
Carpignano Sesia	Italy	20,527	76,822	242,651	112,519	0.275	30,943
Case Cerano	Italy	124,938	311,180	715,438	377,093	0.158	59,392
Arithmetic Summation:							
Italy		145,465	388,001	958,089	489,612	0.185	90,335
Statistical Aggregate		**605,925**	**979,746**	**1,583,737**	**1,061,095**	**0.217**	**230,348**
Arithmetic Summation:							
Portfolio		453,531	913,352	1,835,724	1,061,095	0.217	230,348

Notes:
1. Low, best, high, and mean estimates follow the PRMS guidelines for prospective resources.
2. Low, best, high, and mean estimates in this table are P_{90}, P_{50}, and P_{10}, and mean, respectively.
3. P_g is defined as the probability of discovering reservoirs which flow petroleum at a measurable rate.
4. P_g has been rounded for presentation purposes. Multiplication using this presented P_g may yield imprecise results. Dividing the P_g-adjusted mean estimate by the mean estimate yields the precise P_g.
5. Application of any geological and economic chance factor does not equate prospective resources to contingent resources or reserves.
6. Recovery efficiency is applied to prospective resources in this table.
7. Arithmetic summation of probabilistic estimates produces invalid results except for the mean estimate. Arithmetic summation of the portfolio probabilistic estimates is presented in this table in compliance with PRMS guidelines.
8. Summations may vary from those shown here due to rounding.
9. Net interest prospective resources are defined as the product of the gross prospective resources and Petroceltic's working interest, summarized in Tables P1 and P2.
10. There is no certainty that any portion of the prospective resources estimated herein will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources evaluated.

Prospect	Low Estimate (10^6ft^3)	Best Estimate (10^6ft^3)	High Estimate (10^6ft^3)	Mean Estimate (10^6ft^3)	Probability of Geologic Success, P_g (decimal)	P_g-Adjusted Mean Estimate (10^6ft^3)
	Net Prospective Raw Natural Gas Resources Summary					
Desana Deep	195,204	542,231	1,333,580	687,282	0.236	162,370
Rosso Channels	36,736	60,350	92,637	62,834	0.113	7,125
Arborio	5,928	15,094	32,367	17,492	0.350	6,122
Statistical Aggregate	**469,945**	**722,708**	**1,091,560**	**767,609**	**0.229**	**175,618**
Arithmetic Summation:						
Portfolio	237,868	617,675	1,458,584	767,609	0.229	175,618

Notes:

1. Low, best, high, and mean estimates follow the PRMS guidelines for prospective resources.
2. Low, best, high, and mean estimates in this table are P_{90}, P_{50}, and P_{10}, and mean, respectively.
3. P_g is defined as the probability of discovering reservoirs which flow petroleum at a measurable rate.
4. P_g has been rounded for presentation purposes. Multiplication using this presented P_g may yield imprecise results. Dividing the P_g-adjusted mean estimate by the mean estimate yields the precise P_g.
5. Application of any geological and economic chance factor does not equate prospective resources to contingent resources or reserves.
6. Recovery efficiency is applied to prospective resources in this table.
7. Arithmetic summation of probabilistic estimates produces invalid results except for the mean estimate. Arithmetic summation of the portfolio probabilistic estimates is presented in this table in compliance with PRMS guidelines.
8. Summations may vary from those shown here due to rounding.
9. Net interest prospective resources are defined as the product of the gross prospective resources and Petroceltic's working interest, summarized in Tables P1 and P2.
10. There is no certainty that any portion of the prospective resources estimated herein will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources evaluated.

Prospect	Low Estimate (10^3bbl)	Best Estimate (10^3bbl)	High Estimate (10^3bbl)	Mean Estimate (10^3bbl)	Probability of Geologic Success, P_g (decimal)	P_g-Adjusted Mean Estimate (10^3bbl)
	Net Prospective Condensate Resources Summary					
Desana Deep	19,735	73,027	257,403	103,626	0.236	24,482
Statistical Aggregate	**19,735**	**73,027**	**257,403**	**103,626**	**0.236**	**24,482**
Arithmetic Summation:						
Portfolio	19,735	73,027	257,403	103,626	0.236	24,482

Notes:
1. Low, best, high, and mean estimates follow the PRMS guidelines for prospective resources.
2. Low, best, high, and mean estimates in this table are P_{90}, P_{50}, and P_{10}, and mean, respectively.
3. P_g is defined as the probability of discovering reservoirs which flow petroleum at a measurable rate.
4. P_g has been rounded for presentation purposes. Multiplication using this presented P_g may yield imprecise results. Dividing the P_g-adjusted mean estimate by the mean estimate yields the precise P_g.
5. Application of any geological and economic chance factor does not equate prospective resources to contingent resources or reserves.
6. Recovery efficiency is applied to prospective resources in this table.
7. Arithmetic summation of probabilistic estimates produces invalid results except for the mean estimate. Arithmetic summation of the portfolio probabilistic estimates is presented in this table in compliance with PRMS guidelines.
8. Summations may vary from those shown here due to rounding.
9. Net interest prospective resources are defined as the product of the gross prospective resources and Petroceltic's working interest, summarized in Tables P1 and P2.
10. There is no certainty that any portion of the prospective resources estimated herein will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources evaluated.

Kurdistan Petroleum Geology

Exploration History: Overview

Exploration in the Kurdistan Region of Iraq is in its nascent stage, and fewer than 10 exploration wells were drilled in this region pre-2002. This was probably in large part due to the geo-political uncertainty associated with the area. By the end of 2011, 49 wells had been drilled and 35 block licenses had been issued. Four major discoveries have been announced. The petroleum system is now proven and could be quite prolific. Several significant discoveries have been made in the Mesozoic carbonates in the subsurface: The Shaikan, Taq Taq, Tawke, Atrush, Swara Tika, and Barda Rash are now undergoing subsurface exploitation and development. What is more, a number of exploration companies have significant efforts ongoing in the Kurdistan exploration fairway: ExxonMobil, Marathon, Sinopec, Repsol, Murphy, Hess, DNO, MOL, Genel Energy, Afren, Gulf Keystone, KNOC, Heritage Oil, Talisman, and Petroceltic.

The potential size of some of these newly discovered accumulations has been interpreted to be large. The Shaikan field, a faulted and fractured Mesozoic carbonate, has been interpreted to hold several billion barrels, with cumulative tested rates from Shaikan-1 and Shaikan-4 exceeding 20,000 barrels of oil per day (BOPD).

Wells can take up to 6 months to drill due to lithofacies variance (hard carbonates, shales, highly fractured reservoirs) and subsurface pressure variability. Targeted reservoirs are typically found between 500 and 3,500 meters true vertical depth.

Infrastructure is developing at a pace limited only by the political difficulties in the region. Pipeline construction is ongoing, and oil field service companies are growing in number and breadth of services offered to the region, especially given the recent flurry of subsurface activity and company interest in the hydrocarbon potential. Export routes through Turkey are available and potentially more secure than through southern Iraq.

Petroceltic, in partnership with Hess Corporation as operator, was awarded two production sharing contracts (PSC) in the Kurdistan Region of Iraq in July 2011 (Figure 1). Hess and Petroceltic have gross working interests of 80 percent and 20 percent, respectively, in each block, and the Kurdistan Regional Government (KRG) has a 20-percent carried interest in both PSCs. The Petroceltic blocks, namely Dinarta and Shakrok, are within the Mesozoic carbonate play fairway. The effective date of these PSCs is July 26, 2011. The work program commitment for the initial 3-year exploration period consists of three components: (1) geologic fieldwork, (2) acquisition of a minimum of 750 kilometers of two-dimensional (2–D) seismic data, and (3) the drilling of two exploration wells. One exploration well will be drilled in the Dinarta block and one exploration well will be drilled in the Shakrok block.

Field work is currently in progress, and the seismic tendering process was also completed in December 2011. Separate seismic acquisition crews are being deployed at Shakrok and Dinarta. Seismic acquisition has commenced at Shakrok, and geophysical work will continue throughout 2012. It is anticipated that the first exploration well will be spudded in the third quarter of 2013.

The Petroceltic program has focused on the geological, geophysical, petrophysical, and engineering evaluation of petroleum potential of these two license blocks. Petroceltic has initiated extensive acquisition of geological data to facilitate this evaluation. High quality surface mapping and remote sensing has been utilized to map the potential traps, which are easily recognizable on surface geologic maps. The active petroleum system in the region is capable of charging the structural prospects mapped on these license blocks. Potential productive carbonate reservoirs of Cretaceous, Jurassic, and Triassic age have been confirmed in the nearby fields and accumulations. Petroceltic has interpreted the potential fluid type to be a light crude oil in its targeted potential reservoirs. Moreover, if fractured carbonates are discovered, these types of reservoirs should result in economic flow rates and production. The location of the Kurdistan prospects is shown in Figure 1.

Petroleum System: Kurdistan

Structural Geology

The Zagros-Arabian basin lies on the northeastern margin of the Arabian plate. This region was generally characterized by an eastwards-facing and tectonically stable passive margin throughout much of the Paleozoic and the Mesozoic, punctuated by regional Caledonian compression in the Middle-Late Devonian, and by Tethyan rifting during the Permian and Triassic. This period of relative tectonic quiescence ended in the Cenozoic due to the convergence and eventual collision of the Arabian plate and the Eurasian plate, which occurred as part of the broader Alpine-Himalayan orogenic system. This compressional phase culminated in the formation of the Zagros fold and thrust belt during the Late Miocene and Pliocene. The Zagros fold and thrust belt is a seismically active orogen that extends over 2,000 kilometers, from the Taurus thrust zone in southeast Turkey to the Straits of Hormuz in Iran. The Zagros fold and thrust belt in the Kurdistan Region of Iraq is characterized by long and linear northwest/southeast- to east/west-trending, doubly plunging folds that can verge in either a northeasterly or a southwesterly direction. Thrust faulting is observed only at surface in the northern part of the fold and thrust belt, but it is probable that most surface anticlines are carried by deeper compressional faults. Surface anticlines are generally well defined on the surface by ribs of resistant carbonates of Eocene and Cretaceous age, and the majority of fields discovered to date in the Kurdistan Region of Iraq have been drilled on surface anticlines. Individual anticlines can vary in length from 25 to 120 kilometers, and can be as much as 5 kilometers in width. Significant erosion has occurred along these uplifted anticlines, resulting in progressive erosion to deeper stratigraphic levels towards the northeast within the Zagros fold and thrust belt.

The Dinarta and Shakrok blocks are located within Zagros fold and thrust belt, which runs along the northeastern flank of the Zagros-Arabian sedimentary basin. This basin encompasses an area of some 200,000 square kilometers and contains some of the largest oil fields in the world, including the Ghawar field and the Kirkuk field, which is located about 100 kilometers to the southwest of the Shakrok license block.

The five prospects located in these two license blocks in Kurdistan are large surface anticlines that have an obvious topographic expression (Figures 2 and 3). All five prospects are interpreted to have four-way dip closures. The length to width ratios of these anticlines exceeds 3:1, and significant fracture potential exists due to the flexure and folding of the brittle lithologies of the targeted potential reservoirs. The anticlines plunge in a northwest-southeast direction. Variable erosion has occurred on all five prospective anticlines, with the Cretaceous section at surface on the Shireen, Bradost and Shakrok structures, and with the Middle-Upper Jurassic at surface on the Chinara and Pelewan structures.

Stratigraphy and Sedimentation: Reservoirs – Seals – Source Rocks

A petroleum systems chart for the area of interest is shown in Figure 12.

During the Mesozoic and early Cenozoic, following the opening of the Neo-Tethys ocean, sedimentation on the northeastern passive margin of the Arabian plate was controlled by local tectonics, eustatic sea-level changes, and climate variations. This paleogeographic setting was conducive to alternating carbonate and evaporate sedimentation, with occasional deposition of organic-rich layers during local anoxic events. The net result of this alternating sequence is that the Zagros-Arabian basin is characterized by a series of independent and stacked petroleum systems, with recent discoveries occurring within Tertiary, Cretaceous, Jurassic, and Triassic reservoirs in the Kurdistan Region of Iraq. The Permian is also a productive reservoir in neighboring Iran. Due to the level of erosion from the crests of the anticlinal structures, the primary targeted potential reservoirs in Dinarta and Shakrok are Mesozoic and upper Permian carbonates: Lower Jurassic (Butmah), Triassic (Kurra Chine A, B, and C), and the Upper Permian. Upside potential could exist in shallower reservoirs of the Middle-Upper Jurassic (Barsarin, Sargelu, Alan, Mus) in the Shireen, Shakrok, and Bradost prospects. The targets have porosity which ranges from 5 to 16 percent, with a central tendency range of 10 to 12 percent. They can be fractured, and may have secondary porosity development associated with karstification. The current interpretation of the depositional environment of the targeted potential reservoir carbonates ranges from deepwater mudstones-wackestones, shallow water packstones-grainstones, supratidal mudstones-grainstones, and anhydrites. Net pay thickness in these targets is interpreted to vary from 30 to more than 300 feet. The critical geologic chance factor of the petroleum system is reservoir. Reservoir porosity development in the basin is quite variable. Moreover, fracturing has been shown to be critical for permeability development and porosity enhancement, which contributes to the economic viability of the potential accumulations.

The primary regional source rocks are interpreted to be the Middle Jurassic Sargelu and Naokelekan Formations, which have original total organic carbon contents of up to 30 percent. Additionally, the Cretaceous-age Chia Gara Formation, organic-rich zones within the Triassic Kurra Chine Formation, and the Lower Silurian Akkas Formation are all interpreted to be potential source rocks for this basin.

The major recent phase of hydrocarbon generation and migration in the Zagros fold and thrust belt began during Neogene folding and faulting, and hydrocarbon generation may still be active today in synclinal lows that have not been uplifted, and in the relatively undeformed foreland to the south. Faults and fractures developed during this period are interpreted to have created vertical migration paths for hydrocarbons, and also may have resulted in some leakage of hydrocarbon via breached traps. The Mesozoic and Cenozoic stratigraphy may be amenable to extensive lateral migration from the source/kitchen upwards into existing structural highs and potential hydrocarbon traps.

In summary, the exploration model targets potential fractured dolomite reservoirs top-sealed by evaporates, which are sourced from organic rich source rocks interbedded within the reservoir-seal pairs. This exploration model has proven successful at the Shaikan field. The Shaikan field produced light oil (36 to 42 °API) and condensate from Triassic dolomites with rates from individual zones sometimes exceeding 4,000 BOPD. Another local discovery has been reported at the Swara Tika-1 well, 30 kilometers along strike from the Chinara prospect in the Dinarta block. This well is interpreted to be an Upper Triassic discovery, testing light oil (38 °API) from three different zones at a cumulative rate of 7,000 BOPD.

Prospect Summaries: Kurdistan

Shakrok

The oil prospect has a potential reservoir thickness of between 30 and more than 300 feet in five zones: Lower Jurassic (Butmah), Triassic (Kurre Chine A), Triassic (Kurra Chine B), and Triassic (Kurra Chine C), and the Upper Permian. The P_{10} potential productive area is approximately 28,000 acres (113 square kilometers) (Figure 2). Upside potential may exist in the shallower Middle-Late Jurassic reservoirs (Barsarin, Sargelu, Alan, Mus) that are productive in the region (Figure 12).

The evidence of an active hydrocarbon system and a four-way dip closure provides a rationale for excellent trap, source, and migration geologic chance factors. The overall geologic chance factor for the Shakrok prospect is 0.245.

Pelewan

The oil prospect has a potential reservoir thickness of between 30 and more than 300 feet in four zones: Triassic (Kurre Chine A), Triassic (Kurra Chine B), Triassic (Kurra Chine C), and the Upper Permian. The P_{10} potential productive area is approximately 15,000 acres (61 square kilometers) (Figure 2).

The evidence of an active hydrocarbon system and a four-way dip closure provides a rationale for excellent trap, source, and migration geologic chance factors. The overall geologic chance factor for the Pelewan prospect is 0.245.

Shireen

The oil prospect has a potential reservoir thickness of between 30 and more than 300 feet in five zones: Lower Jurassic (Butmah), Triassic (Kurre Chine A), Triassic (Kurra Chine B), and Triassic (Kurra Chine C), and the Upper Permian. The P_{10} potential productive area is approximately 28,000 acres (113 square kilometers) (Figure 3). Upside potential may exist in the shallower Middle-Late Jurassic reservoirs (Barsarin, Sargelu, Alan, Mus) that are productive in the region (Figure 12).

The evidence of an active hydrocarbon system and a four-way dip closure provides a rationale for excellent trap, source, and migration geologic chance factors. The overall geologic chance factor for the Shireen prospect is 0.245.

Chinara

The oil prospect has a potential reservoir thickness of between 30 and more than 300 feet in four zones: Triassic (Kurre Chine A), Triassic (Kurra Chine B), Triassic (Kurra Chine C), and the Upper Permian. The P_{10} potential productive area is approximately 41,000 acres (166 square kilometers) (Figure 3).

The evidence of an active hydrocarbon system and a four-way dip closure provides a rationale for excellent trap, source, and migration geologic chance factors. The overall geologic chance factor for the Chinara prospect is 0.245.

Bradost

The oil prospect targets a potential reservoir thickness of between 30 and more than 300 feet in four zones: Triassic: (Kurre Chine A), Triassic (Kurra Chine B), Triassic (Kurra Chine C), and the Upper Permian. The P_{10} potential productive area is approximately 39,000 acres (158 square kilometers) (Figure 3). Upside potential may exist in the shallower Jurassic reservoirs (Barsarin, Sargelu, Alan, Mus, Butmah) that are productive in the region (Figure 12).

The evidence of an active hydrocarbon system and a four-way dip closure provides a rationale for excellent trap, source, and migration geologic chance factors. The overall geologic chance factor for the Bradost prospect is 0.245.

Petroleum Geology: Italy

Exploration History – Overview: Po Valley

Exploration in the Po Valley region of Italy has traditionally focused on two primary plays: a shallow, clastic, Mio-Pliocene gas play, which is in a mature stage with respect to petroleum exploration, and a deep Mesozoic carbonate oil and gas condensate play, which is relatively underexplored. Sub-thrust seismic imaging of the deeper carbonate reservoirs is one of the main challenges for exploration of the deeper Mesozoic play in the Po Valley Basin. At the end of 2011, nine exploration wells had been drilled in the Ronsecco license block and three exploration wells had been drilled in the Carisio license block. None of these wells have tested the deeper Mesozoic carbonate reservoirs.

Four Mesozoic carbonate oil/gas-condensate discoveries have been drilled east of the Petroceltic Po Valley license blocks and prospects: (1) Malossa, (2) Villafortuna-Trecate, (3) Gaggiano, and (4) Lacchiarella. The petroleum system in the basin is proven and could be quite prolific. The majority of these discoveries were made more than two decades ago and have been substantially developed and depleted at this time. The Villafortuna-Trecate field has an estimated ultimate recoverable of 235 million barrels of light oil (35 to 42 °API) and is situated less than 30 kilometers to the east of Petroceltic's license blocks. The Mesozoic discoveries to date are associated with Alpine compressional structures and with Mesozoic extensional structures variably reactivated during Alpine compression. The primary Mesozoic reservoirs are Triassic carbonates (dolomites), which have secondary porosity development through the processes of fracturing, karstification, hydrothermal alteration, and dolomitization. These reservoirs have been well studied in outcrops in Italy and have served as a subsurface exploration model analog for global plays.

Deep Mesozoic targeted wells can take up to a year or more to drill due to target depth and lithology (hard-slow drilling carbonates). Targeted reservoirs are typically found between 3,500 and 6,500 meters true vertical depth.

Discovered hydrocarbons would be delivered to local markets and cities in Italy. Facility and pipeline construction could be easily built given the local industry, vendors, and service companies in country.

Geophysical and geological interpretation work is currently in progress, and various vintages of 2–D seismic have been acquired, processed and interpreted. It is anticipated that the first exploration well will be spudded in 2013.

The Petroceltic program has focused on the geological, geophysical, petrophysical, and engineering evaluation of petroleum potential of these two license blocks. Petroceltic has initiated extensive acquisition of geological and geophysical data to facilitate this evaluation. High quality subsurface mapping and geologic modeling has been utilized to map the potential traps, which are visible on the current seismic data sets. The petroleum system in the region is capable of charging the structural prospects mapped on these license blocks. Potential productive reservoirs of the Mesozoic carbonates and Neogene clastics are confirmed in the nearby accumulations. The location of the Italian prospects is shown in Figure 4. Petroceltic has mapped two Mesozoic carbonate oil prospects (Carpignano Sesia and Case Cerano) and three gas prospects (Desana Deep, Rosso Channels, and Arborio) in the Po Valley area of interest.

Petroleum System: Po Valley, Italy

Structural Geology

The present-day structural framework of the Po Valley basin resulted from an initial Mesozoic extensional tectonic phase dominated by carbonate deposition and a subsequent Tertiary compressional tectonic phase dominated by siliciclastic deposition.

Rifting during the Middle-Late Triassic resulted in a depositional environment that was articulated into carbonate platforms and intra-platform basins filled with mixed siliciclastics and carbonate sediments. These Triassic carbonate platforms were drowned during Late Hettangian-Sinemurian time, with deepening-upward pelagic to hemipelagic sequences being deposited in the western Po Valley throughout the Jurassic as the Ligurian ocean opened to the west. During the next major tectonic phase, the Po Valley basin developed as a Late Cretaceous to Tertiary foreland basin to the Alpine orogen to the north. During this time, the northern margin of the Po Valley basin was deformed in south-verging compressional structures of the Southern Alps. This deformational event involved both the Mesozoic carbonates and the overlying syntectonic Tertiary siliciclastics; Alpine deformation had largely ceased by Messinian time. Finally, during Pliocene time, the southern margin of the western Po Valley was involved in Appenninic deformation, which produced north-verging compressional structures. Potential trapping mechanisms for prospects in the western Po Valley are variable due to the interplay between extensional structures in the Mesozoic and compressional structures in the Tertiary. Stratigraphic traps are also possible targets within the Miocene gas play where channelised sands onlap onto the depositional slope. The current exploration model explores for faulted four-way dip closures in either hanging wall or footwall blocks, where Triassic dolomites are likely to be fractured and have enhanced porosity.

Stratigraphy and Sedimentation: Reservoirs – Seals – Source Rocks

A Triassic petroleum systems chart for the area of interest is shown in Figure 11.

The targeted potential reservoirs in the Western Po Valley include Triassic-age shallow marine carbonates and Neogene-age slope-channel clastics.

The Middle Triassic (Monte San Giorgio, San Salvatore dolomites) and Upper Triassic (Dolomia Principale, Campo di Fiori, Dolomia a Conchodon) carbonates are interpreted to have been deposited in a shallow marine setting. The Middle Triassic carbonates were deposited along north/south-trending horsts within the broader Meride basin, while the Upper Triassic platform carbonates generally have a broader and more widespread distribution. The lithofacies interpretation is variable and includes carbonate mudstones, carbonate pack-wackestone, and carbonate grainstones. These potential reservoirs typically undergo extensive diagenesis in the Po Valley exploration fairway: hydrothermal alteration, multi-staged dolomitization, karstification, fracturing (tectonic and karst related), karst and tectonic associated brecciation, and secondary porosity development via dissolution/leaching. Porosity ranges between 2 and 12 percent. Net pay thickness in these targets is interpreted to vary from 30 to more than 300 feet. The critical geologic chance factor of the petroleum system is reservoir. Reservoir porosity development is the critical geologic chance factor. Moreover, fracturing will be critical for permeability development, which should contribute to the economic viability of any discovery.

The main reservoir targets in the Miocene gas play are found in the Gonfolite Group, which consists of Middle-Late Miocene aged slope channel systems deposited within the finer-grained Gallare (Marl) Group. They are typically quartz arenites to lithic subarenites with porosity ranging from 10 to 20 percent. Depth of burial, compaction, and diagenesis are the main processes associated with porosity occlusion.

The Middle Triassic reservoirs are sealed by the Carnian Pizzella Marls and San Giovanni Bianco shales and evaporates, which overlie the regional Carnian Unconformity. This seal is proven within some fault compartments of the Villafortuna-Trecate field. The Upper Triassic reservoirs are sealed by Liassic basinal limestones of the Medolo Formation. This is a proven seal in the Villafortuna-Trecate field. These facies are laterally extensive and thick and, therefore, could provide ample hydrocarbon seals.

The proven Triassic source rocks in the western Po Valley are the Ladinian Meride limestone and Besano shale. Total organic carbon averages over 2 percent in the Meride limestone and averages greater than 10 percent in the Besano shale. These source rocks are predominantly Type II kerogen and are thought to have developed in restricted mini-basins associated with the Triassic paleogeography.

The major phase of hydrocarbon generation and migration in the prospect fairway is interpreted to begin in the Oligo-Miocene. The stratigraphy may be amenable to lateral migration; however, the most likely migration pathway should be along major and minor faults and fractures. Source-kitchen to reservoir pathway length is interpreted to be short. The mini-basins would source the nearby three-way and four-way dip-faulted traps.

In summary, the exploration models targets: (1) potential fractured dolomite reservoirs top-sealed by marls-shales, trapped in four-way and dip-fault closures, which are interpreted to be sourced from the Ladinian-age organic rich Type II source rocks and (2) potential Neogene marine clastics top-sealed by shales, trapped in dip-fault closures or lithofacies pinchouts and sourced from interbedded Tertiary shales.

Prospect Summaries: Po Valley, Italy

Carpignano Sesia

The oil prospect has a potential reservoir thickness of between 100 and more than 600 feet in the Triassic. The P_{10} potential productive area is approximately 17,000 acres (69 square kilometers) (Figure 5).

The evidence of an active hydrocarbon system and a faulted four-way dip closure provides a rationale for good trap, source, and migration geologic chance factors. The overall geologic chance factor for the Carpignano Sesia prospect is 0.275.

Case Cerano

The oil prospect has a potential reservoir thickness of between 100 and 400 feet in two Triassic zones. The P_{10} potential productive area is approximately 30,000 acres (121 square kilometers) (Figure 6).

The evidence of an active hydrocarbon system and a faulted four-way dip closure provides a rationale for fair trap, source, reservoir, and migration geologic chance factors. The overall geologic chance factor for the Case Cerano prospect is 0.158.

Desana Deep

The gas prospect has a potential reservoir thickness of between 200 and more than 400 feet in the Triassic. The P_{10} potential productive area is approximately 9,000 acres (36 square kilometers) (Figure 7).

The evidence of an active hydrocarbon system and a faulted four-way dip closure provides a rationale for good trap, source, and migration geologic chance factors. The overall geologic chance factor for the Desana Deep prospect is 0.236.

Rosso Channels

The gas prospect has a potential reservoir thickness of between 50 and more than 100 feet in three stacked Neogene zones. The P_{10} potential productive area is approximately 3,000 acres (12 square kilometers) (Figure 8).

The evidence of an active hydrocarbon system and a stratigraphic-lithofacies trap provides a rationale for fair source, reservoir, and migration geologic chance factors. The overall geologic chance factor for the Rosso Channels prospect is 0.113.

Arborio

The gas prospect has a potential reservoir thickness of between 50 and more than 100 feet in the Lower Miocene – Oligocene. The P_{10} potential productive area is approximately 900 acres (4 square kilometers) (Figure 9).

The evidence of an active hydrocarbon system and a four-way dip closure provides a rationale for good trap, source, reservoir, and migration geologic chance factors. The overall geologic chance factor for the Arborio prospect is 0.350.

Predictability versus Portfolio Size (PPS), Portfolio Expectancy

An estimation of PPS quantifies the inherent uncertainties associated with the probability that none of the prospects within the portfolio will result in successful discovery. The likely probability (0.90) of at least one success suggests drilling all 10 of the prospects in the current portfolio. Moreover, the current set of geologic chance factors and probabilities of geologic successes in the portfolio result in an estimated mean number of geologic discoveries of two. This estimate assumes drilling all 10 prospects in the current portfolio and that the critical risk factors as interpreted do not significantly change due to future exploratory drilling and the resulting geologic data.

Summary and Conclusions

The estimated gross and net prospective oil, raw natural gas, and condensate resources in various license blocks in Kurdistan and Italy evaluated herein are summarized as follows, expressed in thousands of barrels (10^3bbl) and millions of cubic feet (10^6ft^3):

	Gross and Net Prospective Resources			
	Low Estimate	Best Estimate	High Estimate	Mean Estimate
Gross Prospective Resources				
Gross Prospective Oil Resources, 10^3bbl	2,282,560	3,324,988	4,843,768	3,471,389
Gross Prospective Raw Natural Gas Resources, 10^6ft^3	563,107	820,273	1,194,956	856,391
Gross Prospective Condensate Resources, 10^3bbl	19,735	73,027	257,403	103,626
Net Prospective Resources				
Net Prospective Oil Resources, 10^3bbl	605,925	979,746	1,583,737	1,061,095
Net Prospective Raw Natural Gas Resources, 10^6ft^3	469,945	722,708	1,091,560	767,609
Net Prospective Condensate Resources, 10^3bbl	19,735	73,027	257,403	103,626

Notes:

1. Low, best, and high estimates in this table are P_{90}, P_{50}, and P_{10}, respectively.
2. P_g has not been applied to the volumes in this table.
3. Application of any geological or economic chance factor does not equate prospective resources with contingent resources or reserves.
4. Recovery efficiency is applied to prospective resources in this table.
5. The prospective resources presented above are based on the statistical aggregation method.
6. Net interest prospective resources are defined as the product of the gross prospective resources and Petroceltic's working interest, summarized in Tables P1 and P2.
7. There is no certainty that any portion of the prospective resources estimated herein will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources evaluated.

The gross and net P_g-adjusted mean estimate prospective oil, raw natural gas, and condensate resources, should these prospects result in successful discoveries and development, as of June 30, 2012, are summarized as follows, expressed in English units in thousands of barrels (10^3bbl) and millions of cubic feet (10^6ft^3):

	Mean Estimate
Gross P_g-Adjusted Prospective Resources	
Gross P_g-Adjusted Prospective Oil Resources, 10^3bbl	824,601
Gross P_g-Adjusted Prospective Raw Natural Gas Resources, 10^6ft^3	190,260
Gross P_g-Adjusted Prospective Condensate Resources, 10^3bbl	24,482
Net P_g-Adjusted Prospective Resources	
Net P_g-Adjusted Prospective Oil Resources, 10^3bbl	230,348
Net P_g-Adjusted Prospective Raw Natural Gas Resources, 10^6ft^3	175,618
Net P_g-Adjusted Prospective Condensate Resources, 10^3bbl	24,482

Notes:
1. Application of any geological and economic chance factor does not equate prospective resources to contingent resources or reserves.
2. Recovery efficiency is applied to prospective resources in this table.
3. The prospective resources presented above are based on the statistical aggregation method.
4. Net interest prospective resources are defined as the product of the gross prospective resources and Petroceltic's working interest, summarized in Tables P1 and P2.
5. There is no certainty that any portion of the prospective resources estimated herein will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources evaluated.

Professional Qualifications

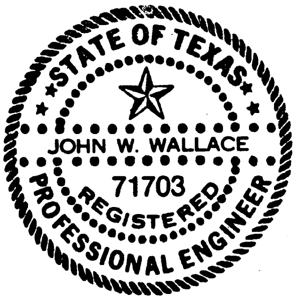
DeGolyer and MacNaughton is a Delaware corporation with offices at 5001 Spring Valley Road, Suite 800 East, Dallas, Texas 75244, U.S.A. The firm has been providing petroleum consulting services throughout the world since 1936. The firm's professional engineers, geologists, geophysicists, petrophysicists, and economists are engaged in the independent appraisal of oil and gas properties, evaluation of hydrocarbon and other mineral prospects, basin evaluations, comprehensive field studies, equity studies, and studies of supply and economics related to the energy industry. Except for the provision of professional services on a fee basis, DeGolyer and MacNaughton has no commercial arrangement with any other person or company involved in the interests which are the subject of this report.

The evaluation has been supervised by Mr. John Wallace. Mr. Wallace is an Executive Vice President with DeGolyer and MacNaughton, a registered professional engineer in the State of Texas. He has over 30 years of oil and gas industry experience.

Submitted,

DeGolyer and MacNaughton

DeGOLYER and MacNAUGHTON
Texas Registered Engineering Firm F-716



John W. Wallace

John W. Wallace, P.E.
Executive Vice President
DeGolyer and MacNaughton

Glossary of Probabilistic Terms

1C – Denotes low estimate scenario of contingent resources.

2C – Denotes best estimate scenario of contingent resources.

3C – Denotes high estimate scenario of contingent resources.

Accumulation – The term accumulation is used to identify an individual body of moveable petroleum. A known accumulation (one determined to contain reserves or contingent resources) must have been penetrated by a well. The well must have clearly demonstrated the existence of moveable petroleum by flow to the surface or at least some recovery of a sample of petroleum through the well. However, log and/or core data from the well may establish an accumulation, provided there is a good analogy to a nearby and geologically comparable known accumulation.

Arithmetic Summation – The process of adding a set of numbers that represent estimates of resources quantities at the reservoir, prospect, or portfolio level and estimates of PPW_{10} at the prospect or portfolio level. Statistical aggregation yields different results.

Best (Median) Estimate – The best (median) estimate is the P_{50} quantity. P_{50} means there is a 50-percent chance that an estimated quantity, such as a prospective resources volume or associated quantity, will be equaled or exceeded.

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.

Based on assumptions regarding future conditions and their impact on ultimate economic viability, projects currently classified as Contingent Resources may be broadly divided into three groups:

Geometric Correction Factor – The geometric correction factor (GCF) is a geometry adjustment correction that takes into account the relationship of the potential fluid contact to the geometry of the reservoir and trap. Input parameters used to estimate the geometric correction factor include trap shape, length-to-width ratio, potential reservoir thickness, and the height of the potential trapping closure (potential hydrocarbon column height).

High Estimate – The high estimate is the P_{10} quantity. P_{10} means there is a 10-percent chance that an estimated quantity, such as a prospective resources volume or associated value, will be equaled or exceeded.

Lead – A lead is less well defined and requires additional data and/or evaluation to be classified as a prospect. An example would be a poorly defined closure mapped using sparse regional seismic data in a basin containing favorable source and reservoir(s). A lead may or may not be elevated to prospect status depending on the results of additional technical work. A lead must have a P_g equal to or less than 0.05 to reflect the inherent technical uncertainty.

Low Estimate – The low estimate is the P_{90} quantity. P_{90} means there is a 90-percent chance that an estimated quantity, such as a prospective resources volume or associated quantity, will be equaled or exceeded.

Mean Estimate – In accordance with petroleum industry standards, the mean estimate is the probability-weighted average, which typically has a probability in the P45 to P15 range, depending on the variance of prospective resources volume or associated quantity. Therefore, the probability of a prospect or accumulation containing the probability-weighted average volume or greater is usually between 45 and 15 percent. The mean estimate is the preferred probabilistic estimate of resources volumes.

Median – Median is the P_{50} quantity, where the P_{50} means there is a 50-percent chance that a given variable (such as prospective resources, porosity, or water saturation) is equaled or exceeded. The median of a data set is a number such that half the measurements are below the median and half are above.

The median is an acceptable, and one of the preferred, quantities to use for the best estimate in probabilistic estimations of prospective resources.

Migration Chance Factor – Migration chance factor ($P_{migration}$) is defined as the probability that a trap either predates or is coincident with petroleum migration and that there exists vertical and/or lateral migration pathways linking the source to the trap.

Mode – The mode (MO) is the quantity that occurs with the greatest frequency in the data set and therefore is the quantity that has the greatest probability of occurrence. However, the mode may not be uniquely defined, as is the case in multimodal distributions.

The mode is an acceptable, but not preferred, quantity to use for the best estimate in probabilistic estimations of prospective resources.

P_g-adjusted Mean Estimate – The P_g-adjusted mean estimate, or "geologic risk-adjusted mean estimate," is a probability-weighted average of the hydrocarbon quantities potentially recoverable if a prospect portfolio were drilled, or if a family of similar prospects were drilled. The P_g-adjusted mean estimate is a "blended" quantity. It is a mean estimation of both volumetric uncertainty and geological risk (chance). This statistical measure considers and quantifies the geological success and geological failure outcomes. Consequently, it represents the average or mean "geologic" outcome of a drilling and exploration program. The P_g-adjusted mean estimate is calculated as follows:

$$P_g\text{-adjusted mean estimate} = P_g \times \text{mean estimate}$$

P_n Nomenclature – This report uses the convention of denoting probability with a subscript representing the greater than cumulative probability distribution. As such, the notation P_n indicates the probability that there is an n-percent chance that a specific input or output quantity will be equaled or exceeded. For example, P_{90} means there is a 90-percent chance that a variable (such as prospective resources, porosity, or water saturation) is equaled or exceeded.

Play – A project associated with a prospective trend of potential prospects, but which requires more data acquisition and/or evaluation in order to define specific leads or prospects.

Probability of Geologic Success – The probability of geologic success (P_g) is defined as the probability of discovering reservoirs that flow petroleum at a measurable rate. P_g is estimated by quantifying with a probability each of the following individual geologic chance factors: trap, source, reservoir, and migration. The product of the probabilities of these four chance factors is P_g.

Prospect – A prospect is a potential accumulation that is sufficiently well defined to be a viable drilling target. For a prospect, sufficient data and analyses exist to identify and quantify the technical uncertainties, to determine reasonable ranges of geologic chance factors and engineering and petrophysical parameters, and to estimate prospective resources. In addition, a viable drilling target requires that 70 percent of the median potential production area be located within the block or license area of interest.

Prospective Resources – Those quantities of petroleum that are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects.

Raw Natural Gas – Raw natural gas is the total gas produced from the reservoir prior to processing or separation and includes all nonhydrocarbon components as well as any gas equivalent of condensate.

Reservoir Chance Factor – The reservoir chance factor ($P_{reservoir}$) is defined as the probability associated with the presence of porous and permeable reservoir quality rock.

Sales Gas – Sales Gas is defined as the total gas to be potentially produced from the reservoirs, measured at the point of delivery, after reduction for projected fuel usage, flare, and shrinkage resulting from field separation and processing.

Source Chance Factor – The source chance factor (P_{source}) is defined as the probability associated with the presence of a hydrocarbon source rock rich enough, of sufficient volume, and in the proper spatial position to charge the prospective area or areas.

Standard Deviation – Standard deviation (SD) is a measure of distribution spread. It is the positive square root of the variance. The variance is the summation of the squared distance from the mean of all possible values. Since the units of standard deviation are the same as those of the sample set, it is the most practical measure of population spread.

$$\sigma = \sqrt{\sigma^2} = \sqrt{\frac{\sum_{i=1}^{n}(x_i - \mu)^2}{n-1}}$$

where: σ = standard deviation
σ^2 = variance
n = sample size
x_i = value in data set
μ = sample set mean

Statistical Aggregation – The process of probabilistically aggregating distributions that represent estimates of resources quantities at the reservoir, prospect, or portfolio level and estimates of PPW_{10} at the prospect or portfolio level. Arithmetic summation yields different results.

Trap Chance Factor – The trap chance factor (P_{trap}) is defined as the probability associated with the presence of a structural closure and/or a stratigraphic trapping configuration with competent vertical and lateral seals, and the lack of any post migration seal integrity events or breaches.

Variance – The variance (σ^2) is a measure of how much the distribution is spread from the mean. The variance sums up the squared distance from the mean of all possible values of x. The variance has units that are the squared units of x. The use of these units limits the intuitive value of variance.

$$\sigma^2 = \frac{\sum_{i=1}^{n}(x_i - \mu)^2}{n-1}$$

where: σ^2 = variance
n = sample size
x_i = value in data set
μ = sample set mean

Working Interest – Working interest prospective resources are that portion of the gross prospective resources to be potentially produced from the properties attributable to the interests owned by "Company" before deduction of any associated royalty burdens, net profits payable or government profit share. Working interest is a percentage of ownership in an oil and gas lease granting its owner the right to explore, drill and produce oil and gas from a tract of property. Working interest owners are obligated to pay a corresponding percentage of the cost of leasing, drilling, producing and operating a well or unit. The working interest also entitles its owner to share in production revenues with other working interest owners, based on the percentage of working interest owned.

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Texas Registered Engineering Firm

TABLE P1
PROSPECT PORTFOLIO SUMMARY
as of
JUNE 30, 2012
for
PETROCELTIC INTERNATIONAL PLC
in
CERTAIN PROSPECTS
VARIOUS LICENSE BLOCKS
KURDISTAN AND ITALY

Prospect	Country	Basin	License/Block	License Type	Working Interest (decimal)	Spud Date (year)	Operator	License area (km^2)	License expiration (mth/year)	Prospect Potential Fluid
Shakrok	Kurdistan	Zagros-Arabian	Shakrok	PSC	0.200[a]	2013	Hess	418	07/2016[b]	Oil
Pelewan	Kurdistan	Zagros-Arabian	Shakrok	PSC	0.200[a]	2014	Hess	418	07/2016[b]	Oil
Shireen	Kurdistan	Zagros-Arabian	Dinarta	PSC	0.200[a]	2013	Hess	1,319	07/2016[b]	Oil
Chinara	Kurdistan	Zagros-Arabian	Dinarta	PSC	0.200[a]	2014	Hess	1,319	07/2016[b]	Oil
Bradost	Kurdistan	Zagros-Arabian	Dinarta	PSC	0.200[a]	2015	Hess	1,319	07/2016[b]	Oil
Carpignano Sesia	Italy	Po Valley	Carisio	Concession	0.475	2012	ENI	728	12/2012[c,d]	Oil
Case Cerano	Italy	Po Valley	Ronsecco	Concession	1.000	2014	Petroceltic	746	11/2016[c]	Oil
Desana Deep	Italy	Po Valley	Ronsecco	Concession	1.000	2016	Petroceltic	746	11/2016[c]	Gas
Rosso Channels	Italy	Po Valley	Carisio	Concession	0.475	2015	ENI	728	12/2012[c,d]	Gas
Arborio	Italy	Po Valley	Carisio	Concession	0.475	2015	ENI	728	12/2012[c,d]	Gas

Notes:
[a]The Kurdistan Regional Government (KRG) have a 20 percent carried interest, net of which Petroceltic will have a 16% participating interest.
[b]End Base Exploration Term (5 years).
[c]End of 1st Exploration Period (6 years).
[d]Application for extension under review.

These data accompany the report of DeGolyer and MacNaughton and are subject to its specific conditions.

DeGolyer and MacNaughton
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TEXAS REGISTERED ENGINEERING FIRM

TABLE P2
SUMMARY OF PROSPECT PARTICULARS
as of
JUNE 30, 2012
for
PETROCELTIC INTERNATIONAL PLC
in
CERTAIN PROSPECTS
VARIOUS LICENSE BLOCKS
KURDISTAN AND ITALY

Prospect	Country	Basin	License/Block	Operator	Working Interest (decimal)	Status	License expiration (mth/year)	License area (km^2)
Shakrok	Kurdistan	Zagros-Arabian	Shakrok	Hess	0.200[a]	Exploration	07/2016[b]	418
Pelewan	Kurdistan	Zagros-Arabian	Shakrok	Hess	0.200[a]	Exploration	07/2016[b]	418
Shireen	Kurdistan	Zagros-Arabian	Dinarta	Hess	0.200[a]	Exploration	07/2016[b]	1,319
Chinara	Kurdistan	Zagros-Arabian	Dinarta	Hess	0.200[a]	Exploration	07/2016[b]	1,319
Bradost	Kurdistan	Zagros-Arabian	Dinarta	Hess	0.200[a]	Exploration	07/2016[b]	1,319
Carpignano Sesia	Italy	Po Valley	Carisio	ENI	0.475	Exploration	12/2012[c,d]	728
Case Cerano	Italy	Po Valley	Ronsecco	Petroceltic	1.000	Exploration	11/2016[c]	746
Desana Deep	Italy	Po Valley	Ronsecco	Petroceltic	1.000	Exploration	11/2016[c]	746
Rosso Channels	Italy	Po Valley	Carisio	ENI	0.475	Exploration	12/2012[c,d]	728
Arborio	Italy	Po Valley	Carisio	ENI	0.475	Exploration	12/2012[c,d]	728

Notes:
[a]The Kurdistan Regional Government (KRG) have a 20 percent carried interest, net of which Petroceltic will have a 16% participating interest.
[b]End Base Exploration Term (5 years).
[c]End of 1st Exploration Period (6 years).
[d]Application for extension under review.

These data accompany the report of DeGolyer and MacNaughton and are subject to its specific conditions.

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TABLE 1
ESTIMATE of the GROSS PROSPECTIVE OIL RESOURCES
as of
JUNE 30, 2012
for
PETROCELTIC INTERNATIONAL PLC
in
CERTAIN OIL PROSPECTS
VARIOUS LICENSE BLOCKS
KURDISTAN AND ITALY

				Gross Prospective Oil Resources Summary					
Prospect	Country	Basin	License/Block	Low Estimate (10^3bbl)	Best Estimate (10^3bbl)	High Estimate (10^3bbl)	Mean Estimate (10^3bbl)	Probability of Geologic Success, P_g (decimal)	P_g-Adjusted Mean Estimate (10^3bbl)
Shakrok	Kurdistan	Zagros-Arabian	Shakrok	402,244	649,714	1,060,956	707,074	0.245	173,233
Pelewan	Kurdistan	Zagros-Arabian	Shakrok	117,529	216,854	370,791	232,290	0.245	56,911
Shireen	Kurdistan	Zagros-Arabian	Dinarta	385,435	660,197	1,067,226	706,042	0.245	172,980
Chinara	Kurdistan	Zagros-Arabian	Dinarta	331,164	566,628	962,796	621,589	0.245	152,289
Bradost	Kurdistan	Zagros-Arabian	Dinarta	303,958	533,362	926,401	590,417	0.245	144,652
Arithmetic Summation: Kurdistan				1,540,330	2,626,754	4,388,170	2,857,414	0.245	700,066
Carpignano Sesia	Italy	Po Valley	Carisio	43,216	161,730	510,845	236,882	0.275	65,143
Case Cerano	Italy	Po Valley	Ronsecco	124,938	311,180	715,438	377,093	0.158	59,392
Arithmetic Summation: Italy				168,154	472,910	1,226,283	613,976	0.203	124,535
Statistical Aggregate				**2,282,560**	**3,324,988**	**4,843,768**	**3,471,389**	**0.238**	**824,601**
Arithmetic Summation: Portfolio				1,708,483	3,099,664	5,614,453	3,471,389	0.238	824,601

Notes:

1. Low, best, high, and mean estimates follow the PRMS guidelines for prospective resources.
2. Low, best, high, and mean estimates in this table are P_{90}, P_{50}, P_{10}, and mean respectively.
3. P_g is defined as the probability of discovering reservoirs which flow petroleum at a measurable rate.
4. P_g has been rounded for presentation purposes. Multiplication using this presented P_g may yield imprecise results. Dividing the P_g-adjusted mean estimate by the mean estimate yields the precise P_g.
5. Application of any geological and economic chance factor does not equate prospective resources to contingent resources or reserves.
6. Recovery efficiency is applied to prospective resources in this table.
7. Arithmetic summation of probabilistic estimates produces invalid results except for the mean estimate. Arithmetic summation of the portfolio probabilistic estimates is presented in this table in compliance with PRMS guidelines.
8. Summations may vary from those shown here due to rounding.
9. There is no certainty that any portion of the prospective resources estimated herein will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources evaluated.

These data accompany the report of DeGolyer and MacNaughton and are subject to its specific conditions.

DEGOLYER AND MACNAUGHTON
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TABLE 2
ESTIMATE of the NET PROSPECTIVE OIL RESOURCES
as of
JUNE 30, 2012
for
PETROCELTIC INTERNATIONAL PLC
in
CERTAIN OIL PROSPECTS
VARIOUS LICENSE BLOCKS
KURDISTAN AND ITALY

				Net Prospective Oil Resources Summary					
Prospect	**Country**	**Basin**	**License/Block**	**Low Estimate (10^3bbl)**	**Best Estimate (10^3bbl)**	**High Estimate (10^3bbl)**	**Mean Estimate (10^3bbl)**	**Probability of Geologic Success, P_g (decimal)**	**P_g-Adjusted Mean Estimate (10^3bbl)**
Shakrok	Kurdistan	Zagros-Arabian	Shakrok	80,449	129,943	212,191	141,415	0.245	34,647
Pelewan	Kurdistan	Zagros-Arabian	Shakrok	23,506	43,371	74,158	46,458	0.245	11,382
Shireen	Kurdistan	Zagros-Arabian	Dinarta	77,087	132,039	213,445	141,208	0.245	34,596
Chinara	Kurdistan	Zagros-Arabian	Dinarta	66,233	113,326	192,559	124,318	0.245	30,458
Bradost	Kurdistan	Zagros-Arabian	Dinarta	60,792	106,672	185,280	118,083	0.245	28,930
Arithmetic Summation: Kurdistan				308,066	525,351	877,634	571,483	0.245	140,013
Carpignano Sesia	Italy	Po Valley	Carisio	20,527	76,822	242,651	112,519	0.275	30,943
Case Cerano	Italy	Po Valley	Ronsecco	124,938	311,180	715,438	377,093	0.158	59,392
Arithmetic Summation: Italy				145,465	388,001	958,089	489,612	0.185	90,335
Statistical Aggregate				**605,925**	**979,746**	**1,583,737**	**1,061,095**	**0.217**	**230,348**
Arithmetic Summation: Portfolio				453,531	913,352	1,835,724	1,061,095	0.217	230,348

Notes:

1. Low, best, high, and mean estimates follow the PRMS guidelines for prospective resources.
2. Low, best, high, and mean estimates in this table are P_{90}, P_{50}, P_{10}, and mean respectively.
3. P_g is defined as the probability of discovering reservoirs which flow petroleum at a measurable rate.
4. P_g has been rounded for presentation purposes. Multiplication using this presented P_g may yield imprecise results. Dividing the P_g-adjusted mean estimate by the mean estimate yields the precise P_g.
5. Application of any geological and economic chance factor does not equate prospective resources to contingent resources or reserves.
6. Recovery efficiency is applied to prospective resources in this table.
7. Arithmetic summation of probabilistic estimates produces invalid results except for the mean estimate. Arithmetic summation of the portfolio probabilistic estimates is presented in this table in compliance with PRMS guidelines.
8. Summations may vary from those shown here due to rounding.
9. Net interest prospective resources are defined as the product of the gross prospective resources and PLC's working interest.
10. There is no certainty that any portion of the prospective resources estimated herein will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources evaluated.

These data accompany the report of DeGolyer and MacNaughton and are subject to its specific conditions.

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TABLE 3
ESTIMATE of the GROSS PROSPECTIVE RAW NATURAL GAS RESOURCES
as of
JUNE 30, 2012
for
PETROCELTIC INTERNATIONAL PLC
in
CERTAIN GAS PROSPECTS
VARIOUS LICENSE BLOCKS
ITALY

				Gross Prospective Raw Natural Gas Resources Summary					
Prospect	Country	Basin	License/Block	Low Estimate ($10^6 ft^3$)	Best Estimate ($10^6 ft^3$)	High Estimate ($10^6 ft^3$)	Mean Estimate ($10^6 ft^3$)	Probability of Geologic Success, P_g (decimal)	P_g-Adjusted Mean Estimate ($10^6 ft^3$)
Desana Deep	Italy	Po Valley	Ronsecco	195,204	542,231	1,333,580	687,282	0.236	162,370
Rosso Channels	Italy	Po Valley	Carisio	77,339	127,053	195,026	132,283	0.113	15,001
Arborio	Italy	Po Valley	Carisio	12,480	31,777	68,140	36,826	0.350	12,889
Statistical Aggregate				**563,107**	**820,273**	**1,194,956**	**856,391**	**0.222**	**190,260**
Arithmetic Summation: Portfolio				285,023	701,061	1,596,746	856,391	0.222	190,260

Notes:
1. Low, best, high, and mean estimates follow the PRMS guidelines for prospective resources.
2. Low, best, high, and mean estimates in this table are P_{90}, P_{50}, P_{10}, and mean respectively.
3. P_g is defined as the probability of discovering reservoirs which flow petroleum at a measurable rate.
4. P_g has been rounded for presentation purposes. Multiplication using this presented P_g may yield imprecise results. Dividing the P_g-adjusted mean estimate by the mean estimate yields the precise P_g.
5. Application of any geological and economic chance factor does not equate prospective resources to contingent resources or reserves.
6. Recovery efficiency is applied to prospective resources in this table.
7. Arithmetic summation of probabilistic estimates produces invalid results except for the mean estimate. Arithmetic summation of the portfolio probabilistic estimates is presented in this table in compliance with PRMS guidelines.
8. Summations may vary from those shown here due to rounding.
9. There is no certainty that any portion of the prospective resources estimated herein will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources evaluated.

These data accompany the report of DeGolyer and MacNaughton and are subject to its specific conditions.

DeGolyer and MacNaughton
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TEXAS REGISTERED ENGINEERING FIRM

TABLE 4
ESTIMATE of the NET PROSPECTIVE RAW NATURAL GAS RESOURCES
as of
JUNE 30, 2012
for
PETROCELTIC INTERNATIONAL PLC
in
CERTAIN GAS PROSPECTS
VARIOUS LICENSE BLOCKS
ITALY

				Net Prospective Raw Natural Gas Resources Summary					
Prospect	**Country**	**Basin**	**License/Block**	**Low Estimate (10^6ft^3)**	**Best Estimate (10^6ft^3)**	**High Estimate (10^6ft^3)**	**Mean Estimate (10^6ft^3)**	**Probability of Geologic Success, P_g (decimal)**	**P_g-Adjusted Mean Estimate (10^6ft^3)**
Desana Deep	Italy	Po Valley	Ronsecco	195,204	542,231	1,333,580	687,282	0.236	162,370
Rosso Channels	Italy	Po Valley	Carisio	36,736	60,350	92,637	62,834	0.113	7,125
Arborio	Italy	Po Valley	Carisio	5,928	15,094	32,367	17,492	0.350	6,122
Statistical Aggregate				**469,945**	**722,708**	**1,091,560**	**767,609**	**0.229**	**175,618**
Arithmetic Summation: Portfolio				237,868	617,675	1,458,584	767,609	0.229	175,618

Notes:
1. Low, best, high, and mean estimates follow the PRMS guidelines for prospective resources.
2. Low, best, high, and mean estimates in this table are P_{90}, P_{50}, P_{10}, and mean respectively.
3. P_g is defined as the probability of discovering reservoirs which flow petroleum at a measurable rate.
4. P_g has been rounded for presentation purposes. Multiplication using this presented P_g may yield imprecise results. Dividing the P_g-adjusted mean estimate by the mean estimate yields the precise P_g.
5. Application of any geological and economic chance factor does not equate prospective resources to contingent resources or reserves.
6. Recovery efficiency is applied to prospective resources in this table.
7. Arithmetic summation of probabilistic estimates produces invalid results except for the mean estimate. Arithmetic summation of the portfolio probabilistic estimates is presented in this table in compliance with PRMS guidelines.
8. Summations may vary from those shown here due to rounding.
9. Net interest prospective resources are defined as the product of the gross prospective resources and PLC's working interest.
10. There is no certainty that any portion of the prospective resources estimated herein will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources evaluated.

These data accompany the report of DeGolyer and MacNaughton and are subject to its specific conditions.

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TABLE 5
ESTIMATE of the GROSS PROSPECTIVE CONDENSATE RESOURCES
as of
JUNE 30, 2012
for
PETROCELTIC INTERNATIONAL PLC
in the
DESANA DEEP GAS PROSPECT
RONSECCO LICENSE BLOCK
ITALY

				Gross Prospective Condensate Resources Summary					
Prospect	**Country**	**Basin**	**License/Block**	**Low Estimate (10^3bbl)**	**Best Estimate (10^3bbl)**	**High Estimate (10^3bbl)**	**Mean Estimate (10^3bbl)**	**Probability of Geologic Success, P_g (decimal)**	**P_g-Adjusted Mean Estimate (10^3bbl)**
Desana Deep	Italy	Po Valley	Ronsecco	19,735	73,027	257,403	103,626	0.236	24,482
Statistical Aggregate				**19,735**	**73,027**	**257,403**	**103,626**	**0.236**	**24,482**
Arithmetic Summation: Portfolio				19,735	73,027	257,403	103,626	0.236	24,482

Notes:
1. Low, best, high, and mean estimates follow the PRMS guidelines for prospective resources.
2. Low, best, high, and mean estimates in this table are P_{90}, P_{50}, P_{10}, and mean respectively.
3. P_g is defined as the probability of discovering reservoirs which flow petroleum at a measurable rate.
4. P_g has been rounded for presentation purposes. Multiplication using this presented P_g may yield imprecise results. Dividing the P_g-adjusted mean estimate by the mean estimate yields the precise P_g.
5. Application of any geological and economic chance factor does not equate prospective resources to contingent resources or reserves.
6. Recovery efficiency is applied to prospective resources in this table.
7. Arithmetic summation of probabilistic estimates produces invalid results except for the mean estimate. Arithmetic summation of the portfolio probabilistic estimates is presented in this table in compliance with PRMS guidelines.
8. Summations may vary from those shown here due to rounding.
9. There is no certainty that any portion of the prospective resources estimated herein will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources evaluated.

These data accompany the report of DeGolyer and MacNaughton and are subject to its specific conditions.

DeGolyer and MacNaughton
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TEXAS REGISTERED ENGINEERING FIRM

TABLE 6
ESTIMATE of the NET PROSPECTIVE CONDENSATE RESOURCES
as of
JUNE 30, 2012
for
PETROCELTIC INTERNATIONAL PLC
in the
DESANA DEEP GAS PROSPECT
RONSECCO LICENSE BLOCK
ITALY

				Net Prospective Condensate Resources Summary					
Prospect	**Country**	**Basin**	**License/Block**	**Low Estimate (10^3bbl)**	**Best Estimate (10^3bbl)**	**High Estimate (10^3bbl)**	**Mean Estimate (10^3bbl)**	**Probability of Geologic Success, P_g (decimal)**	**P_g-Adjusted Mean Estimate (10^3bbl)**
Desana Deep	Italy	Po Valley	Ronsecco	19,735	73,027	257,403	103,626	0.236	24,482
Statistical Aggregate				**19,735**	**73,027**	**257,403**	**103,626**	**0.236**	**24,482**
Arithmetic Summation: Portfolio				19,735	73,027	257,403	103,626	0.236	24,482

Notes:

1. Low, best, high, and mean estimates follow the PRMS guidelines for prospective resources.
2. Low, best, high, and mean estimates in this table are P_{90}, P_{50}, P_{10}, and mean respectively.
3. P_g is defined as the probability of discovering reservoirs which flow petroleum at a measurable rate.
4. P_g has been rounded for presentation purposes. Multiplication using this presented P_g may yield imprecise results. Dividing the P_g-adjusted mean estimate by the mean estimate yields the precise P_g.
5. Application of any geological and economic chance factor does not equate prospective resources to contingent resources or reserves.
6. Recovery efficiency is applied to prospective resources in this table.
7. Arithmetic summation of probabilistic estimates produces invalid results except for the mean estimate. Arithmetic summation of the portfolio probabilistic estimates is presented in this table in compliance with PRMS guidelines.
8. Summations may vary from those shown here due to rounding.
9. Net interest prospective resources are defined as the product of the gross prospective resources and PLC's working interest.
10. There is no certainty that any portion of the prospective resources estimated herein will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources evaluated.

These data accompany the report of DeGolyer and MacNaughton and are subject to its specific conditions.

DEGOLYER AND MACNAUGHTON
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TABLE 7
PROBABILITY DISTRIBUTIONS
for
MONTE CARLO SIMULATION
as of
JUNE 30, 2012
for
PETROCELTIC INTERNATIONAL PLC
in
CERTAIN OIL PROSPECTS
VARIOUS LICENSE BLOCKS
KURDISTAN AND ITALY

Prospect	Reservoir	Parameter	P_{100}	P_{90}	P_{50}	P_{10}	P_{0}	Mean
Shakrok	Jurassic: (Butmah)	Productive area, acres	2,619	5,483	13,843	28,298	35,719	15,438
		Net hydrocarbon thickness, feet	60.4	107.4	157.4	228.7	329.6	163.7
		Geometric correction factor, decimal	0.80	0.86	0.94	0.99	1.00	0.93
		Net to gross ratio, decimal	1.00	1.00	1.00	1.00	1.00	1.00
		Porosity, decimal	0.075	0.096	0.120	0.146	0.183	0.121
		Oil saturation, decimal	0.551	0.591	0.650	0.709	0.749	0.650
		Formation volume factor, Bo	1.260	1.208	1.144	1.081	1.037	1.142
		Recovery efficiency, decimal	0.096	0.147	0.224	0.299	0.357	0.224
		Prospective OOIP, barrels	124,451,200	388,875,100	1,037,574,000	2,453,000,000	6,271,883,000	1,255,338,000
		Prospective gross ultimate recovery, barrels	21,434,900	78,202,990	223,034,500	562,654,500	1,267,873,000	281,890,400
Shakrok	Triassic: (Kurre Chine A)	Productive area, acres	2,681	5,523	13,852	28,296	35,698	15,453
		Net hydrocarbon thickness, feet	33.0	50.2	89.3	162.3	317.0	99.5
		Geometric correction factor, decimal	0.81	0.86	0.94	0.99	1.00	0.93
		Net to gross ratio, decimal	1.00	1.00	1.00	1.00	1.00	1.00
		Porosity, decimal	0.053	0.071	0.095	0.121	0.157	0.096
		Oil saturation, decimal	0.550	0.591	0.650	0.709	0.749	0.650
		Formation volume factor, Bo	1.646	1.576	1.492	1.410	1.351	1.490
		Recovery efficiency, decimal	0.096	0.147	0.224	0.299	0.356	0.224
		Prospective OOIP, barrels	28,735,000	113,224,300	369,523,700	945,678,400	3,376,585,000	463,252,800
		Prospective gross ultimate recovery, barrels	6,065,815	23,519,370	80,269,540	207,771,700	1,069,743,000	103,700,300
Shakrok	Triassic: (Kurra Chine B)	Productive area, acres	2,652	5,504	13,856	28,327	35,687	15,451
		Net hydrocarbon thickness, feet	33.2	50.2	89.2	162.2	328.7	99.6
		Geometric correction factor, decimal	0.80	0.86	0.94	0.99	1.00	0.93
		Net to gross ratio, decimal	1.00	1.00	1.00	1.00	1.00	1.00
		Porosity, decimal	0.057	0.076	0.100	0.126	0.165	0.101
		Oil saturation, decimal	0.550	0.591	0.650	0.709	0.749	0.650
		Formation volume factor, Bo	1.699	1.629	1.542	1.457	1.400	1.540
		Recovery efficiency, decimal	0.101	0.151	0.229	0.306	0.365	0.229
		Prospective OOIP, barrels	40,475,220	128,094,500	362,514,100	896,319,200	3,480,387,000	467,526,800
		Prospective gross ultimate recovery, barrels	6,129,681	26,573,230	82,705,890	220,524,300	1,041,309,000	108,318,100

These data accompany the report of DeGolyer and MacNaughton and are subject to its specific conditions.

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TABLE 7 – PROBABILITY DISTRIBUTIONS – *(Continued)*

Prospect	Reservoir	Parameter	P_{100}	P_{90}	P_{50}	P_{10}	P_0	Mean
Shakrok	Triassic: (Kurra Chine C)	Productive area, acres	2,674	5,512	13,863	28,303	35,739	15,450
		Net hydrocarbon thickness, feet	33.3	50.1	89.2	162.0	321.6	99.6
		Geometric correction factor, decimal	0.80	0.86	0.94	0.99	1.00	0.93
		Net to gross ratio, decimal	1.00	1.00	1.00	1.00	1.00	1.00
		Porosity, decimal	0.057	0.076	0.100	0.126	0.162	0.101
		Oil saturation, decimal	0.600	0.641	0.700	0.759	0.800	0.700
		Formation volume factor, Bo	1.754	1.681	1.592	1.504	1.446	1.589
		Recovery efficiency, decimal	0.097	0.147	0.224	0.299	0.360	0.224
		Prospective OOIP, barrels	37,256,740	126,342,000	379,062,600	1,046,668,000	3,066,199,000	500,407,300
		Prospective gross ultimate recovery, barrels	5,896,293	26,222,850	81,210,140	236,112,400	618,115,400	110,531,800
Shakrok	Upper Permian	Productive area, acres	2,656	5,502	13,855	28,316	35,738	15,453
		Net hydrocarbon thickness, feet	33.1	50.1	89.2	162.3	322.1	99.6
		Geometric correction factor, decimal	0.81	0.86	0.94	0.99	1.00	0.93
		Net to gross ratio, decimal	1.00	1.00	1.00	1.00	1.00	1.00
		Porosity, decimal	0.057	0.076	0.100	0.126	0.163	0.101
		Oil saturation, decimal	0.550	0.591	0.650	0.709	0.750	0.650
		Formation volume factor, Bo	1.775	1.702	1.612	1.523	1.460	1.609
		Recovery efficiency, decimal	0.100	0.151	0.229	0.306	0.363	0.229
		Prospective OOIP, barrels	34,758,550	123,510,600	356,381,900	910,626,800	3,303,072,000	451,086,000
		Prospective gross ultimate recovery, barrels	6,514,145	26,039,770	75,753,370	212,851,400	786,049,300	102,633,800
Pelewan	Triassic: (Kurre Chine A)	Productive area, acres	1,508	2,997	7,487	15,243	19,204	8,340
		Net hydrocarbon thickness, feet	33.0	50.1	89.3	162.1	315.7	99.6
		Geometric correction factor, decimal	0.80	0.86	0.94	0.99	1.00	0.93
		Net to gross ratio, decimal	1.00	1.00	1.00	1.00	1.00	1.00
		Porosity, decimal	0.053	0.071	0.095	0.121	0.161	0.096
		Oil saturation, decimal	0.550	0.591	0.650	0.709	0.749	0.650
		Formation volume factor, Bo	1.644	1.576	1.492	1.410	1.351	1.490
		Recovery efficiency, decimal	0.096	0.147	0.224	0.299	0.356	0.224
		Prospective OOIP, barrels	18,965,250	69,285,460	192,088,400	523,336,100	1,581,748,000	252,181,900
		Prospective gross ultimate recovery, barrels	3,049,711	14,373,560	40,584,980	114,767,100	414,030,500	56,420,050
Pelewan	Triassic: (Kurra Chine B)	Productive area, acres	1,513	2,993	7,480	15,263	19,226	8,338
		Net hydrocarbon thickness, feet	33.3	50.2	89.2	162.2	319.8	99.6
		Geometric correction factor, decimal	0.80	0.86	0.94	0.99	1.00	0.93
		Net to gross ratio, decimal	1.00	1.00	1.00	1.00	1.00	1.00
		Porosity, decimal	0.057	0.076	0.100	0.126	0.165	0.101
		Oil saturation, decimal	0.551	0.591	0.650	0.709	0.749	0.650
		Formation volume factor, Bo	1.697	1.628	1.542	1.457	1.399	1.540
		Recovery efficiency, decimal	0.100	0.151	0.229	0.306	0.364	0.229
		Prospective OOIP, barrels	11,000,460	69,965,950	192,295,700	523,791,500	1,986,722,000	255,278,800
		Prospective gross ultimate recovery, barrels	2,394,115	14,674,710	43,687,810	126,057,200	487,990,200	58,892,690

These data accompany the report of DeGolyer and MacNaughton and are subject to its specific conditions.

TABLE 7 – PROBABILITY DISTRIBUTIONS – *(Continued)*

Prospect	Reservoir	Parameter	P_{100}	P_{90}	P_{50}	P_{10}	P_{0}	Mean
Pelewan	Triassic: (Kurra Chine C)	Productive area, acres	1,503	2,997	7,481	15,245	19,203	8,337
		Net hydrocarbon thickness, feet	33.3	50.1	89.2	162.3	324.4	99.6
		Geometric correction factor, decimal	0.80	0.86	0.94	0.99	1.00	0.93
		Net to gross ratio, decimal	1.00	1.00	1.00	1.00	1.00	1.00
		Porosity, decimal	0.057	0.076	0.100	0.126	0.161	0.101
		Oil saturation, decimal	0.600	0.641	0.700	0.759	0.799	0.700
		Formation volume factor, Bo	1.754	1.681	1.592	1.504	1.445	1.589
		Recovery efficiency, decimal	0.097	0.147	0.224	0.299	0.356	0.224
		Prospective OOIP, barrels	25,522,540	67,345,050	213,093,400	526,676,600	1,608,513,000	268,290,700
		Prospective gross ultimate recovery, barrels	3,456,869	13,957,010	44,430,770	127,523,700	415,621,000	60,382,110
Pelewan	Upper Permian	Productive area, acres	1,506	2,999	7,484	15,247	19,211	8,340
		Net hydrocarbon thickness, feet	33.2	50.1	89.3	162.2	328.0	99.6
		Geometric correction factor, decimal	0.81	0.86	0.94	0.99	1.00	0.93
		Net to gross ratio, decimal	1.00	1.00	1.00	1.00	1.00	1.00
		Porosity, decimal	0.057	0.076	0.100	0.126	0.161	0.101
		Oil saturation, decimal	0.551	0.591	0.650	0.709	0.749	0.650
		Formation volume factor, Bo	1.779	1.702	1.612	1.523	1.463	1.609
		Recovery efficiency, decimal	0.100	0.151	0.229	0.306	0.365	0.229
		Prospective OOIP, barrels	15,111,080	62,435,400	189,296,900	515,907,300	1,393,060,000	247,689,400
		Prospective gross ultimate recovery, barrels	2,508,937	13,571,460	41,274,400	118,835,200	430,407,300	56,595,350
Shireen	Jurassic: (Butmah)	Productive area, acres	2,638	5,485	13,859	28,292	35,670	15,438
		Net hydrocarbon thickness, feet	61.3	107.5	157.4	228.9	328.5	163.7
		Geometric correction factor, decimal	0.80	0.86	0.94	0.99	1.00	0.93
		Net to gross ratio, decimal	1.00	1.00	1.00	1.00	1.00	1.00
		Porosity, decimal	0.076	0.095	0.120	0.146	0.183	0.121
		Oil saturation, decimal	0.551	0.591	0.650	0.709	0.749	0.650
		Formation volume factor, Bo	1.260	1.208	1.144	1.081	1.038	1.142
		Recovery efficiency, decimal	0.097	0.147	0.224	0.299	0.359	0.224
		Prospective OOIP, barrels	138,626,500	392,620,000	1,011,929,000	2,437,421,000	6,750,965,000	1,258,104,000
		Prospective gross ultimate recovery, barrels	19,920,340	75,941,790	227,514,300	554,146,400	1,603,059,000	280,432,100
Shireen	Triassic: (Kurre Chine A)	Productive area, acres	2,667	5,515	13,869	28,329	35,713	15,452
		Net hydrocarbon thickness, feet	33.1	50.1	89.2	162.1	317.3	99.6
		Geometric correction factor, decimal	0.80	0.86	0.94	0.99	1.00	0.93
		Net to gross ratio, decimal	1.00	1.00	1.00	1.00	1.00	1.00
		Porosity, decimal	0.053	0.071	0.095	0.121	0.156	0.096
		Oil saturation, decimal	0.551	0.591	0.650	0.709	0.749	0.650
		Formation volume factor, Bo	1.643	1.576	1.492	1.410	1.353	1.490
		Recovery efficiency, decimal	0.096	0.147	0.224	0.299	0.357	0.224
		Prospective OOIP, barrels	29,259,750	121,227,200	360,110,800	912,416,100	3,367,054,000	465,564,200
		Prospective gross ultimate recovery, barrels	5,188,753	25,708,340	78,813,570	209,701,700	616,821,400	103,293,300

These data accompany the report of DeGolyer and MacNaughton and are subject to its specific conditions.

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TABLE 7 – PROBABILITY DISTRIBUTIONS – *(Continued)*

Prospect	Reservoir	Parameter	P_{100}	P_{90}	P_{50}	P_{10}	P_{0}	Mean
Shireen	Triassic: (Kurra Chine B)	Productive area, acres	2,655	5,504	13,865	28,314	35,681	15,451
		Net hydrocarbon thickness, feet	33.2	50.1	89.2	162.3	318.8	99.6
		Geometric correction factor, decimal	0.80	0.86	0.94	0.99	1.00	0.93
		Net to gross ratio, decimal	1.00	1.00	1.00	1.00	1.00	1.00
		Porosity, decimal	0.057	0.076	0.100	0.126	0.168	0.101
		Oil saturation, decimal	0.550	0.591	0.650	0.709	0.750	0.650
		Formation volume factor, Bo	1.697	1.628	1.542	1.457	1.396	1.540
		Recovery efficiency, decimal	0.100	0.151	0.229	0.306	0.363	0.229
		Prospective OOIP, barrels	43,066,550	120,090,800	364,439,200	934,281,500	3,255,056,000	473,385,500
		Prospective gross ultimate recovery, barrels	7,080,482	25,919,170	80,007,960	217,721,800	1,135,139,000	108,449,600
Shireen	Triassic: (Kurra Chine C)	Productive area, acres	2,663	5,518	13,863	28,299	35,724	15,449
		Net hydrocarbon thickness, feet	33.0	50.1	89.2	162.3	320.7	99.6
		Geometric correction factor, decimal	0.80	0.86	0.94	0.99	1.00	0.93
		Net to gross ratio, decimal	1.00	1.00	1.00	1.00	1.00	1.00
		Porosity, decimal	0.057	0.076	0.100	0.126	0.166	0.101
		Oil saturation, decimal	0.601	0.641	0.700	0.759	0.799	0.700
		Formation volume factor, Bo	1.756	1.681	1.592	1.504	1.442	1.589
		Recovery efficiency, decimal	0.097	0.147	0.224	0.299	0.355	0.224
		Prospective OOIP, barrels	29,767,760	124,622,000	386,080,500	982,531,800	2,967,855,000	495,109,000
		Prospective gross ultimate recovery, barrels	6,511,013	27,400,810	84,783,510	226,986,000	785,054,300	110,435,800
Shireen	Upper Permian	Productive area, acres	2,678	5,516	13,859	28,323	35,714	15,452
		Net hydrocarbon thickness, feet	33.0	50.1	89.2	162.3	326.9	99.6
		Geometric correction factor, decimal	0.80	0.86	0.94	0.99	1.00	0.93
		Net to gross ratio, decimal	1.00	1.00	1.00	1.00	1.00	1.00
		Porosity, decimal	0.057	0.076	0.100	0.126	0.164	0.101
		Oil saturation, decimal	0.550	0.591	0.650	0.709	0.749	0.650
		Formation volume factor, Bo	1.775	1.702	1.612	1.523	1.461	1.609
		Recovery efficiency, decimal	0.101	0.151	0.229	0.306	0.363	0.229
		Prospective OOIP, barrels	29,057,700	119,165,500	348,899,300	903,917,600	2,918,424,000	453,924,100
		Prospective gross ultimate recovery, barrels	5,197,092	25,295,090	75,720,360	214,304,800	653,223,800	103,431,600
Chinara	Triassic: (Kurre Chine A)	Productive area, acres	3,866	8,027	20,238	41,369	52,227	22,566
		Net hydrocarbon thickness, feet	33.3	50.1	89.2	162.0	317.7	99.6
		Geometric correction factor, decimal	0.81	0.86	0.94	0.99	1.00	0.93
		Net to gross ratio, decimal	1.00	1.00	1.00	1.00	1.00	1.00
		Porosity, decimal	0.053	0.071	0.095	0.121	0.162	0.096
		Oil saturation, decimal	0.550	0.591	0.650	0.709	0.749	0.650
		Formation volume factor, Bo	1.645	1.576	1.492	1.410	1.353	1.490
		Recovery efficiency, decimal	0.096	0.147	0.224	0.299	0.357	0.224
		Prospective OOIP, barrels	55,280,370	185,873,900	513,344,700	1,298,634,000	5,503,569,000	674,970,100
		Prospective gross ultimate recovery, barrels	11,748,400	36,074,180	110,927,300	316,838,100	1,427,819,000	152,231,000

TABLE 7 – PROBABILITY DISTRIBUTIONS – *(Continued)*

Prospect	Reservoir	Parameter	P_{100}	P_{90}	P_{50}	P_{10}	P_0	Mean
Chinara	Triassic: (Kurra Chine B)	Productive area, acres	3,836	8,039	20,242	41,383	52,178	22,564
		Net hydrocarbon thickness, feet	33.3	50.1	89.2	162.1	327.7	99.6
		Geometric correction factor, decimal	0.80	0.86	0.94	0.99	1.00	0.93
		Net to gross ratio, decimal	1.00	1.00	1.00	1.00	1.00	1.00
		Porosity, decimal	0.057	0.076	0.100	0.126	0.161	0.101
		Oil saturation, decimal	0.550	0.591	0.650	0.709	0.750	0.650
		Formation volume factor, Bo	1.697	1.628	1.542	1.457	1.399	1.540
		Recovery efficiency, decimal	0.100	0.151	0.229	0.306	0.367	0.229
		Prospective OOIP, barrels	65,727,540	182,018,300	534,099,300	1,398,736,000	5,529,446,000	692,637,200
		Prospective gross ultimate recovery, barrels	11,664,890	37,560,050	116,250,600	321,694,600	1,207,421,000	158,419,900
Chinara	Triassic: (Kurra Chine C)	Productive area, acres	3,833	8,038	20,223	41,359	52,234	22,563
		Net hydrocarbon thickness, feet	33.3	50.1	89.2	162.2	325.0	99.6
		Geometric correction factor, decimal	0.80	0.86	0.94	0.99	1.00	0.93
		Net to gross ratio, decimal	1.00	1.00	1.00	1.00	1.00	1.00
		Porosity, decimal	0.057	0.076	0.100	0.126	0.162	0.101
		Oil saturation, decimal	0.600	0.641	0.700	0.759	0.800	0.700
		Formation volume factor, Bo	1.759	1.681	1.592	1.504	1.446	1.589
		Recovery efficiency, decimal	0.096	0.147	0.224	0.299	0.355	0.224
		Prospective OOIP, barrels	41,969,500	189,166,300	568,190,000	1,438,317,000	3,919,898,000	718,047,600
		Prospective gross ultimate recovery, barrels	8,140,453	37,902,900	120,291,800	330,120,100	1,061,172,000	160,429,500
Chinara	Upper Permian	Productive area, acres	3,829	8,029	20,233	41,346	52,176	22,566
		Net hydrocarbon thickness, feet	33.1	50.1	89.2	162.3	318.6	99.6
		Geometric correction factor, decimal	0.80	0.86	0.94	0.99	1.00	0.93
		Net to gross ratio, decimal	1.00	1.00	1.00	1.00	1.00	1.00
		Porosity, decimal	0.057	0.076	0.100	0.126	0.162	0.101
		Oil saturation, decimal	0.550	0.591	0.650	0.709	0.749	0.650
		Formation volume factor, Bo	1.779	1.702	1.612	1.523	1.464	1.609
		Recovery efficiency, decimal	0.100	0.151	0.229	0.306	0.368	0.229
		Prospective OOIP, barrels	54,703,180	174,173,400	519,223,000	1,327,538,000	3,539,333,000	655,917,600
		Prospective gross ultimate recovery, barrels	10,663,500	35,997,360	114,245,100	310,623,900	1,040,750,000	150,509,000
Bradost	Jurassic: (Butmah)	Productive area, acres	3,644	7,600	19,172	39,184	49,457	21,381
		Net hydrocarbon thickness, feet	33.2	50.1	89.2	162.1	328.7	99.6
		Geometric correction factor, decimal	0.80	0.86	0.94	0.99	1.00	0.93
		Net to gross ratio, decimal	1.00	1.00	1.00	1.00	1.00	1.00
		Porosity, decimal	0.057	0.076	0.100	0.126	0.165	0.101
		Oil saturation, decimal	0.551	0.591	0.650	0.709	0.749	0.650
		Formation volume factor, Bo	1.775	1.702	1.612	1.523	1.460	1.609
		Recovery efficiency, decimal	0.100	0.151	0.229	0.306	0.365	0.229
		Prospective OOIP, barrels	44,927,750	163,785,200	480,486,400	1,290,911,000	4,443,699,000	627,746,800
		Prospective gross ultimate recovery, barrels	8,045,057	34,684,770	105,758,400	312,181,800	832,394,700	144,120,100

These data accompany the report of DeGolyer and MacNaughton and are subject to its specific conditions.

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TABLE 7 – PROBABILITY DISTRIBUTIONS – *(Continued)*

Prospect	Reservoir	Parameter	P_{100}	P_{90}	P_{50}	P_{10}	P_{0}	Mean
Bradost	Triassic: (Kurre Chine A)	Productive area, acres	3,654	7,623	19,165	39,172	49,428	21,380
		Net hydrocarbon thickness, feet	33.0	50.2	89.3	162.3	317.0	99.5
		Geometric correction factor, decimal	0.81	0.86	0.94	0.99	1.00	0.93
		Net to gross ratio, decimal	1.00	1.00	1.00	1.00	1.00	1.00
		Porosity, decimal	0.053	0.071	0.095	0.121	0.157	0.096
		Oil saturation, decimal	0.550	0.591	0.650	0.709	0.749	0.650
		Formation volume factor, Bo	1.646	1.576	1.492	1.410	1.351	1.490
		Recovery efficiency, decimal	0.096	0.147	0.224	0.299	0.356	0.224
		Prospective OOIP, barrels	39,499,890	156,351,600	511,339,300	1,308,983,000	4,674,607,000	640,964,500
		Prospective gross ultimate recovery, barrels	8,330,014	32,460,020	111,061,700	287,537,300	1,480,972,000	143,480,600
Bradost	Triassic: (Kurra Chine B)	Productive area, acres	3,614	7,598	19,172	39,216	49,413	21,379
		Net hydrocarbon thickness, feet	33.2	50.2	89.2	162.2	328.7	99.6
		Geometric correction factor, decimal	0.80	0.86	0.94	0.99	1.00	0.93
		Net to gross ratio, decimal	1.00	1.00	1.00	1.00	1.00	1.00
		Porosity, decimal	0.057	0.076	0.100	0.126	0.165	0.101
		Oil saturation, decimal	0.550	0.591	0.650	0.709	0.749	0.650
		Formation volume factor, Bo	1.699	1.629	1.542	1.457	1.400	1.540
		Recovery efficiency, decimal	0.101	0.151	0.229	0.306	0.365	0.229
		Prospective OOIP, barrels	55,571,030	176,779,700	501,427,100	1,240,643,000	4,818,527,000	646,888,100
		Prospective gross ultimate recovery, barrels	8,469,907	36,464,940	114,432,300	305,204,200	1,441,790,000	149,874,800
Bradost	Triassic: (Kurra Chine C)	Productive area, acres	3,646	7,609	19,181	39,181	49,484	21,378
		Net hydrocarbon thickness, feet	33.3	50.1	89.2	162.0	321.6	99.6
		Geometric correction factor, decimal	0.80	0.86	0.94	0.99	1.00	0.93
		Net to gross ratio, decimal	1.00	1.00	1.00	1.00	1.00	1.00
		Porosity, decimal	0.057	0.076	0.100	0.126	0.162	0.101
		Oil saturation, decimal	0.600	0.641	0.700	0.759	0.800	0.700
		Formation volume factor, Bo	1.754	1.681	1.592	1.504	1.446	1.589
		Recovery efficiency, decimal	0.097	0.147	0.224	0.299	0.360	0.224
		Prospective OOIP, barrels	51,403,540	174,302,500	524,413,800	1,448,249,000	4,243,676,000	692,412,900
		Prospective gross ultimate recovery, barrels	8,098,850	36,151,900	112,407,800	326,683,700	855,483,000	152,941,900
Carpignano Sesia	Triassic	Productive area, acres	1,617	3,383	8,532	17,417	21,947	9,504
		Net hydrocarbon thickness, feet	50.8	139.4	282.4	569.7	1288.1	326.7
		Geometric correction factor, decimal	0.80	0.86	0.94	0.99	1.00	0.93
		Net to gross ratio, decimal	1.00	1.00	1.00	1.00	1.00	1.00
		Porosity, decimal	0.016	0.028	0.051	0.076	0.115	0.052
		Oil saturation, decimal	0.601	0.641	0.700	0.759	0.800	0.700
		Formation volume factor, Bo	1.371	1.313	1.244	1.175	1.128	1.242
		Recovery efficiency, decimal	0.178	0.237	0.350	0.465	0.544	0.351
		Prospective OOIP, barrels	30,979,890	128,543,300	471,392,400	1,467,224,000	7,549,529,000	673,257,200
		Prospective gross ultimate recovery, barrels	8,690,952	43,215,560	161,730,100	510,845,200	3,234,339,000	236,882,300

DEGOLYER AND MACNAUGHTON
F-716
TEXAS REGISTERED ENGINEERING FIRM

TABLE 7 – PROBABILITY DISTRIBUTIONS – *(Continued)*

Prospect	Reservoir	Parameter	P_{100}	P_{90}	P_{50}	P_{10}	P_{0}	Mean
Case Cerano	Upper Dolomite: Top U. Triassic	Productive area, acres	1,534	5,590	14,719	30,398	38,461	16,414
		Net hydrocarbon thickness, feet	38.6	119.4	220.2	404.1	817.2	245.4
		Geometric correction factor, decimal	0.36	0.48	0.63	0.74	0.80	0.62
		Net to gross ratio, decimal	1.00	1.00	1.00	1.00	1.00	1.00
		Porosity, decimal	0.016	0.028	0.051	0.076	0.117	0.052
		Oil saturation, decimal	0.600	0.641	0.700	0.759	0.799	0.700
		Formation volume factor, Bo	1.446	1.387	1.313	1.241	1.190	1.311
		Recovery efficiency, decimal	0.178	0.237	0.350	0.465	0.544	0.351
		Prospective OOIP, barrels	17,936,760	114,432,600	380,186,500	1,160,164,000	4,089,263,000	536,493,700
		Prospective gross ultimate recovery, barrels	5,189,984	37,992,290	125,772,200	422,050,700	1,367,573,000	188,294,800
Case Cerano	Lower Dolomite: San Salvatore	Productive area, acres	1,591	5,581	14,733	30,373	38,412	16,415
		Net hydrocarbon thickness, feet	48.9	119.6	220.3	404.0	812.7	245.4
		Geometric correction factor, decimal	0.35	0.48	0.63	0.74	0.80	0.62
		Net to gross ratio, decimal	1.00	1.00	1.00	1.00	1.00	1.00
		Porosity, decimal	0.016	0.028	0.051	0.076	0.117	0.052
		Oil saturation, decimal	0.601	0.641	0.700	0.759	0.799	0.700
		Formation volume factor, Bo	1.446	1.387	1.313	1.241	1.192	1.311
		Recovery efficiency, decimal	0.178	0.237	0.350	0.465	0.545	0.351
		Prospective OOIP, barrels	29,235,610	109,814,200	395,463,100	1,179,914,000	6,189,796,000	542,341,800
		Prospective gross ultimate recovery, barrels	8,279,057	35,720,980	131,786,700	401,573,800	2,295,820,000	188,798,400

These data accompany the report of DeGolyer and MacNaughton and are subject to its specific conditions.

DeGolyer and MacNaughton
F-716
TEXAS REGISTERED ENGINEERING FIRM

TABLE 8
PROBABILITY DISTRIBUTIONS
for
MONTE CARLO SIMULATION
as of
JUNE 30, 2012
for
PETROCELTIC INTERNATIONAL PLC
in
CERTAIN GAS PROSPECTS
VARIOUS LICENSE BLOCKS
ITALY

Prospect	Reservoir	Parameter	P_{100}	P_{90}	P_{50}	P_{10}	P_0	Mean
Desana Deep	Jurassic-Triassic	Productive area, acres	1,008	1,786	4,321	8,736	10,977	4,811
		Net hydrocarbon thickness, feet	186.0	257.8	324.7	408.7	567.4	330.0
		Geometric Correction Factor, decimal	1.00	1.00	1.00	1.00	1.00	1.00
		Net to gross ratio, decimal	1.00	1.00	1.00	1.00	1.00	1.00
		Porosity, decimal	0.016	0.028	0.051	0.076	0.113	0.052
		Gas saturation, decimal	0.600	0.641	0.700	0.759	0.799	0.700
		Formation volume factor, Bg	293	314	342	370	391	342
		Recovery efficiency, decimal	0.629	0.704	0.800	0.896	0.968	0.800
		Prospective OGIP, cubic feet	68,034,460,000	252,406,100,000	686,883,900,000	1,697,847,000,000	3,650,700,000,000	859,792,100,000
		Prospective gross ultimate recovery, cubic feet	52,546,020,000	195,204,100,000	542,231,200,000	1,333,580,000,000	2,724,294,000,000	687,282,200,000
Rosso Channels	Messinian	Productive area, acres	300	535	1,295	2,620	3,296	1,443
		Net hydrocarbon thickness, feet	33.6	48.2	64.3	85.9	133.5	66.1
		Geometric Correction Factor, decimal	1.00	1.00	1.00	1.00	1.00	1.00
		Net to gross ratio, decimal	1.00	1.00	1.00	1.00	1.00	1.00
		Porosity, decimal	0.104	0.125	0.150	0.176	0.210	0.150
		Gas saturation, decimal	0.551	0.591	0.650	0.709	0.750	0.650
		Formation volume factor, Bg	128	138	150	162	172	150
		Recovery efficiency, decimal	0.511	0.572	0.650	0.728	0.789	0.650
		Prospective OGIP, cubic feet	9,617,155,000	20,462,920,000	51,578,870,000	113,733,100,000	253,889,100,000	60,806,060,000
		Prospective gross ultimate recovery, cubic feet	5,420,705,000	13,293,570,000	33,259,890,000	74,448,350,000	168,009,700,000	39,539,700,000
Rosso Channels	Middle Tortonian	Productive area, acres	328	580	1,403	2,838	3,572	1,563
		Net hydrocarbon thickness, feet	33.6	48.2	64.3	86.0	130.6	66.1
		Geometric Correction Factor, decimal	1.00	1.00	1.00	1.00	1.00	1.00
		Net to gross ratio, decimal	1.00	1.00	1.00	1.00	1.00	1.00
		Porosity, decimal	0.103	0.125	0.150	0.176	0.210	0.150
		Gas saturation, decimal	0.551	0.591	0.650	0.709	0.750	0.650
		Formation volume factor, Bg	128	138	150	162	172	150
		Recovery efficiency, decimal	0.510	0.572	0.650	0.728	0.787	0.650
		Prospective OGIP, cubic feet	8,086,317,000	22,065,920,000	55,484,780,000	124,974,400,000	265,758,800,000	66,633,200,000
		Prospective gross ultimate recovery, cubic feet	5,278,490,000	14,550,960,000	35,307,410,000	83,969,420,000	192,278,500,000	43,405,900,000

These data accompany the report of DeGolyer and MacNaughton and are subject to its specific conditions.

TABLE 8 – PROBABILITY DISTRIBUTIONS – *(Continued)*

Prospect	Reservoir	Parameter	P_{100}	P_{90}	P_{50}	P_{10}	P_0	Mean
Rosso Channels	Serravallian	Productive area, acres	376	669	1,619	3,276	4,122	1,804
		Net hydrocarbon thickness, feet	33.5	48.2	64.3	86.0	129.5	66.0
		Geometric Correction Factor, decimal	1.00	1.00	1.00	1.00	1.00	1.00
		Net to gross ratio, decimal	1.00	1.00	1.00	1.00	1.00	1.00
		Porosity, decimal	0.103	0.125	0.150	0.176	0.214	0.150
		Gas saturation, decimal	0.551	0.591	0.650	0.709	0.750	0.650
		Formation volume factor, Bg	128	138	150	162	172	150
		Recovery efficiency, decimal	0.512	0.572	0.650	0.728	0.788	0.650
		Prospective OGIP, cubic feet	11,311,100,000	25,719,950,000	67,319,880,000	140,302,400,000	417,624,300,000	75,759,830,000
		Prospective gross ultimate recovery, cubic feet	7,240,600,000	16,264,480,000	43,045,310,000	90,853,290,000	257,600,300,000	49,337,310,000
Arborio	L. Mio. - Oligo.	Productive area, acres	101	178	432	873	1,097	481
		Net hydrocarbon thickness, feet	36.3	58.3	80.0	109.7	191.4	82.5
		Geometric Correction Factor, decimal	1.00	1.00	1.00	1.00	1.00	1.00
		Net to gross ratio, decimal	1.00	1.00	1.00	1.00	1.00	1.00
		Porosity, decimal	0.186	0.210	0.235	0.261	0.293	0.235
		Gas saturation, decimal	0.550	0.591	0.650	0.709	0.750	0.650
		Formation volume factor, Bg	183	197	215	233	246	215
		Recovery efficiency, decimal	0.514	0.572	0.650	0.728	0.786	0.650
		Prospective OGIP, cubic feet	6,748,748,000	19,280,430,000	49,461,740,000	104,476,400,000	185,280,500,000	56,821,950,000
		Prospective gross ultimate recovery, cubic feet	4,727,981,000	12,480,200,000	31,776,510,000	68,140,060,000	139,092,200,000	36,825,530,000

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DeGolyer and MacNaughton Dallas, Texas
Texas Registered Engineering Firm F-716

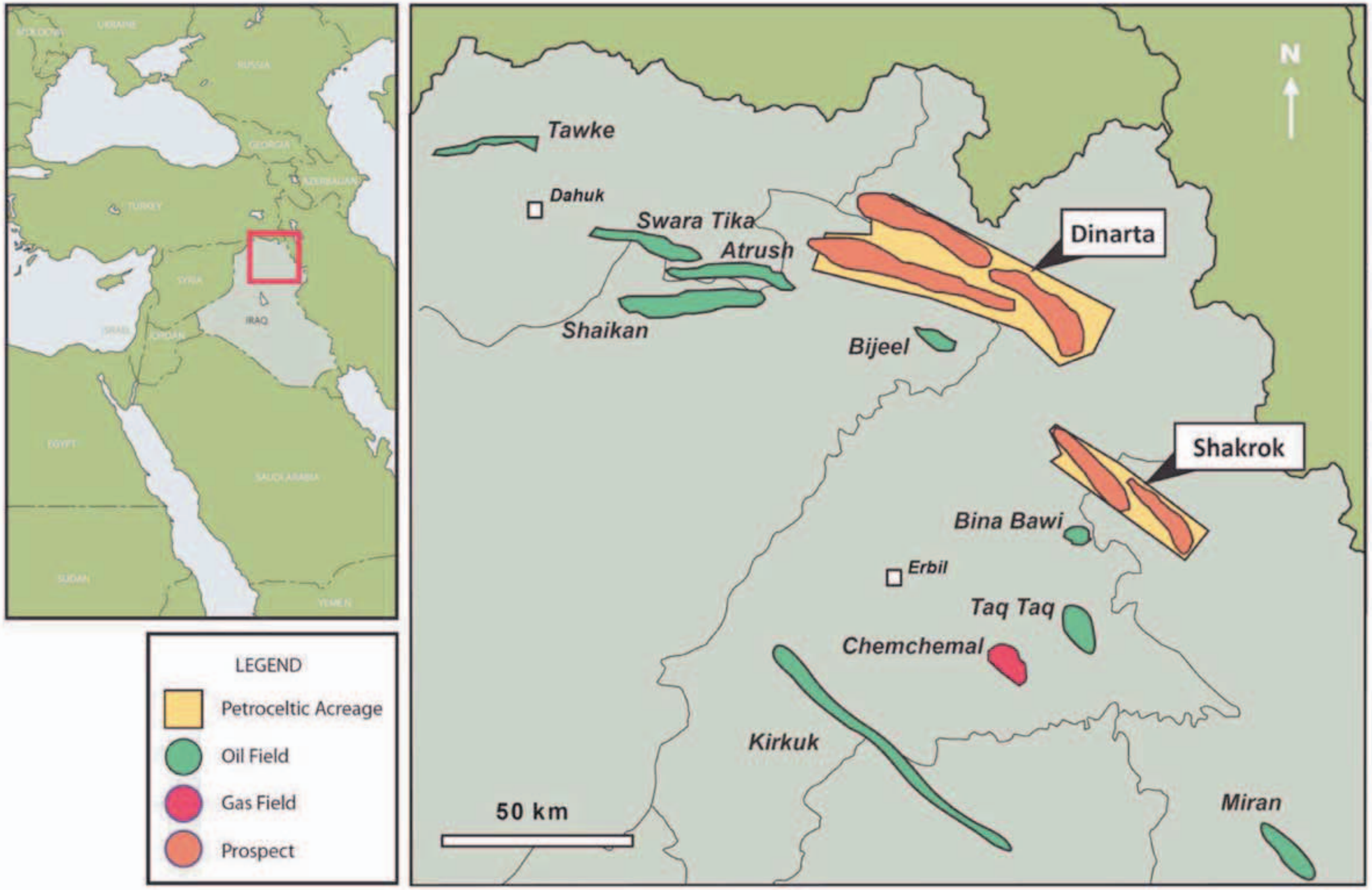


FIGURE 2
LOCATION MAP – SHAKROK and PELEWAN PROSPECTS
PROVIDED COURTESY OF PETROCELTIC
DeGolyer and MacNaughton Dallas, Texas
Texas Registered Engineering Firm F-716

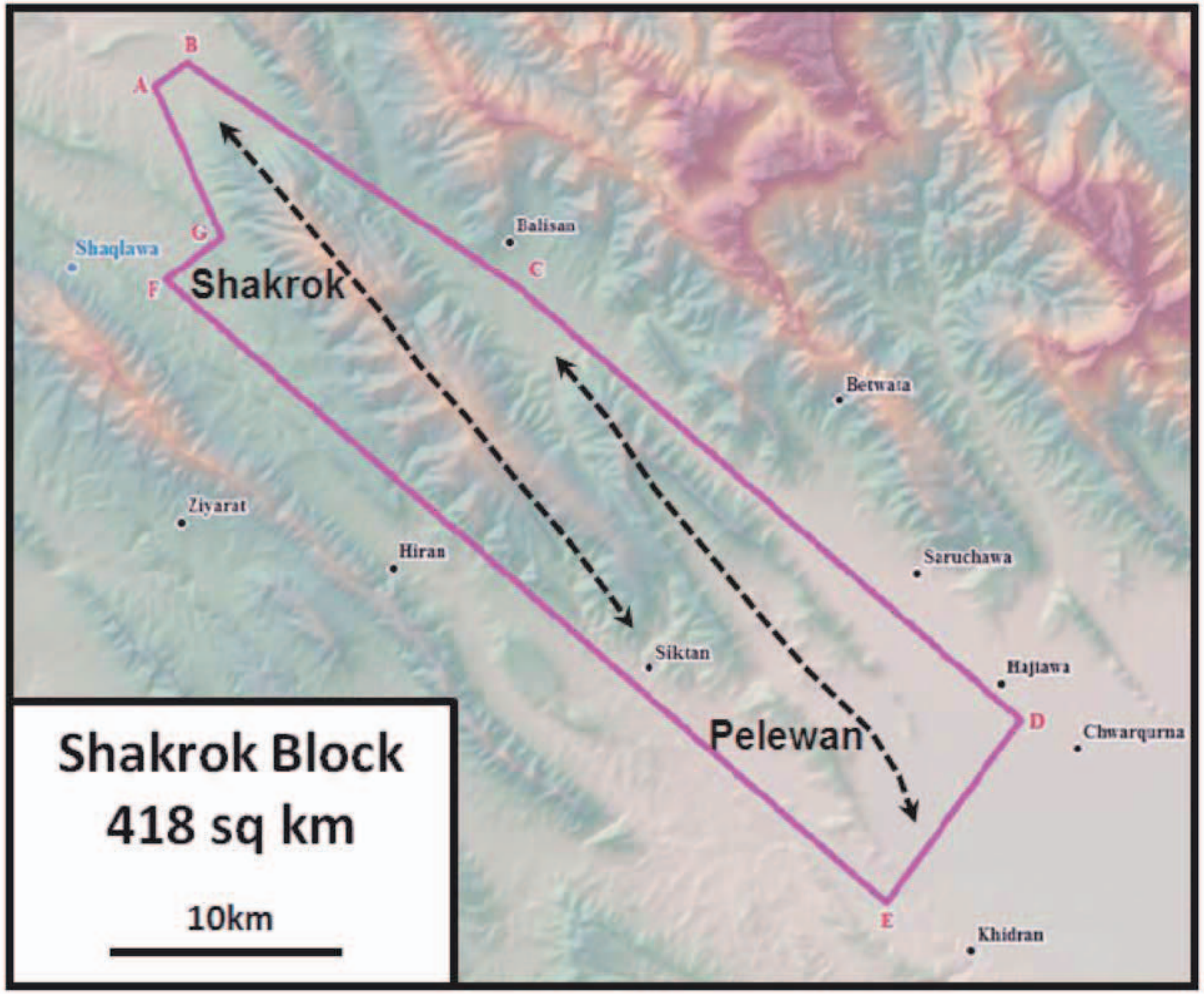


FIGURE 3
LOCATION MAP – SHIREEN, CHINARA, and BRADOST PROSPECTS
PROVIDED COURTESY OF PETROCELTIC
DeGolyer and MacNaughton Dallas, Texas
Texas Registered Engineering Firm F-716

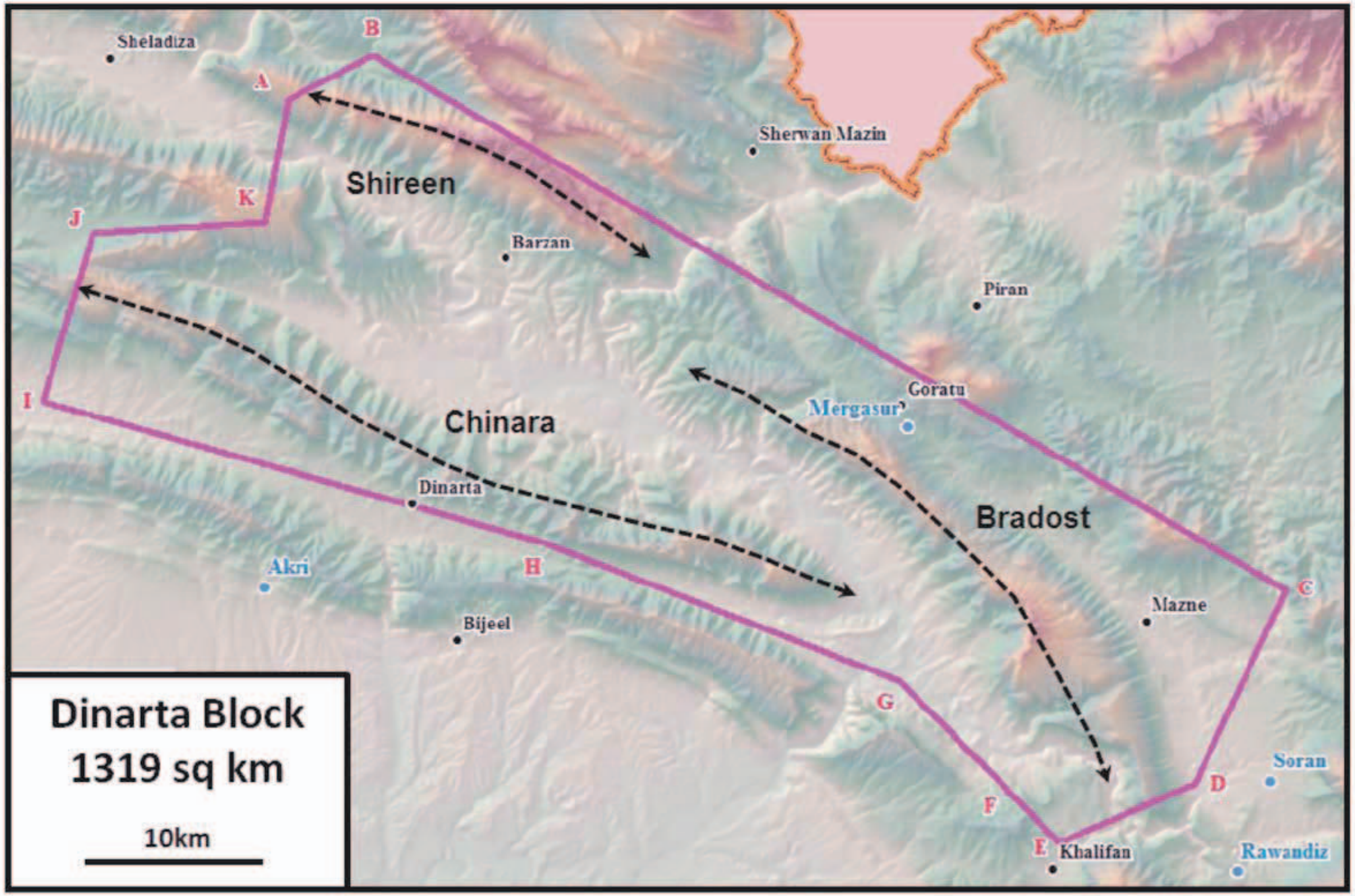
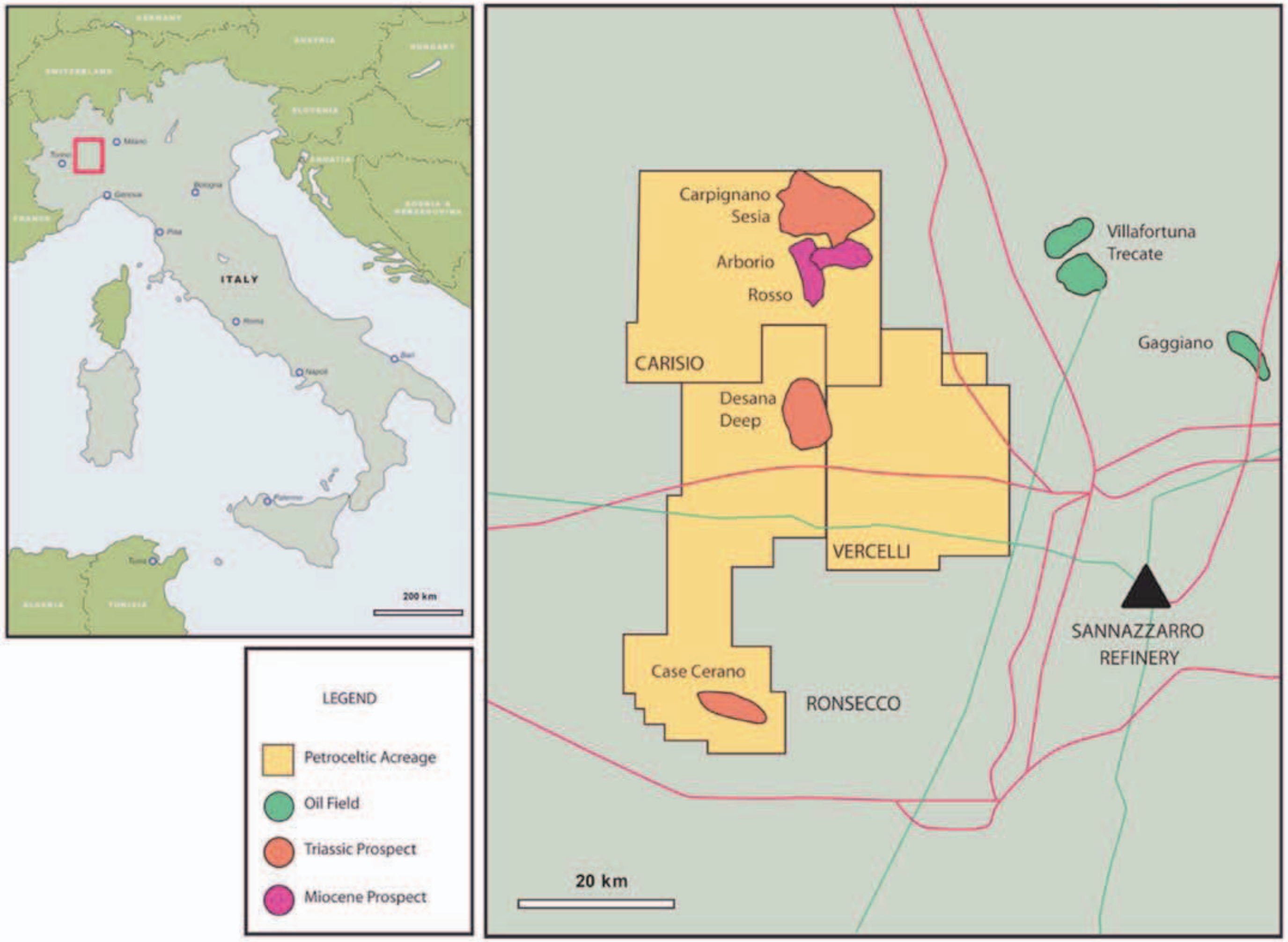


FIGURE 4
LOCATION MAP – WESTERN PO VALLEY BLOCKS and PROSPECTS
PROVIDED COURTESY OF PETROCELTIC
DeGolyer and MacNaughton   Dallas, Texas
Texas Registered Engineering Firm F-716



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LOCATION MAP, DEPTH STRUCTURE MAP, and GEO-SEISMIC CROSS-SECTION – CARPIGNANO SESIA PROSPECT
PROVIDED COURTESY OF PETROCELTIC
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Texas Registered Engineering Firm F-716

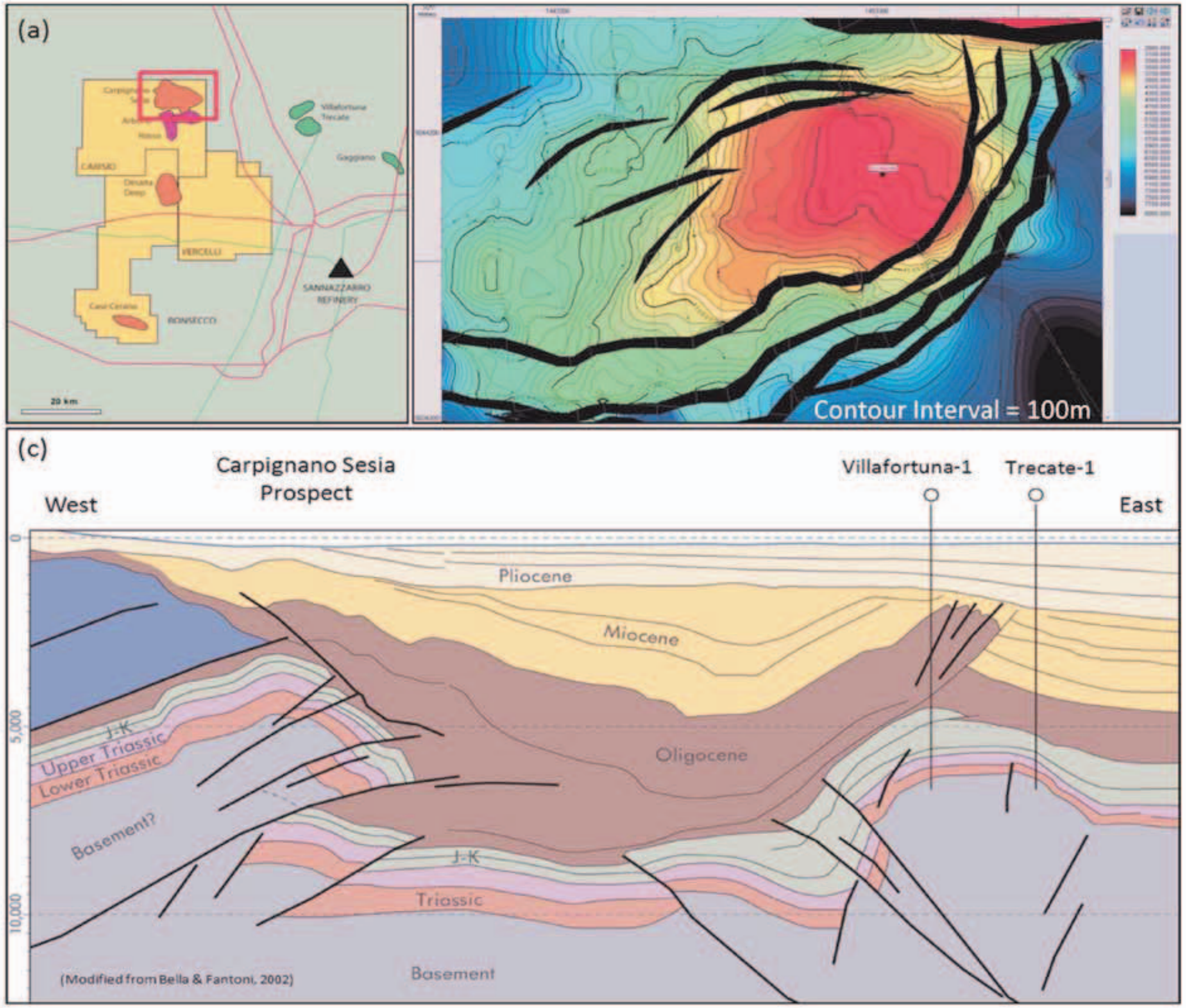

FIGURE 6
LOCATION MAP and DEPTH STRUCTURE MAP– CASE CERANO PROSPECT
PROVIDED COURTESY OF PETROCELTIC
DeGolyer and MacNaughton Dallas, Texas
Texas Registered Engineering Firm F-716

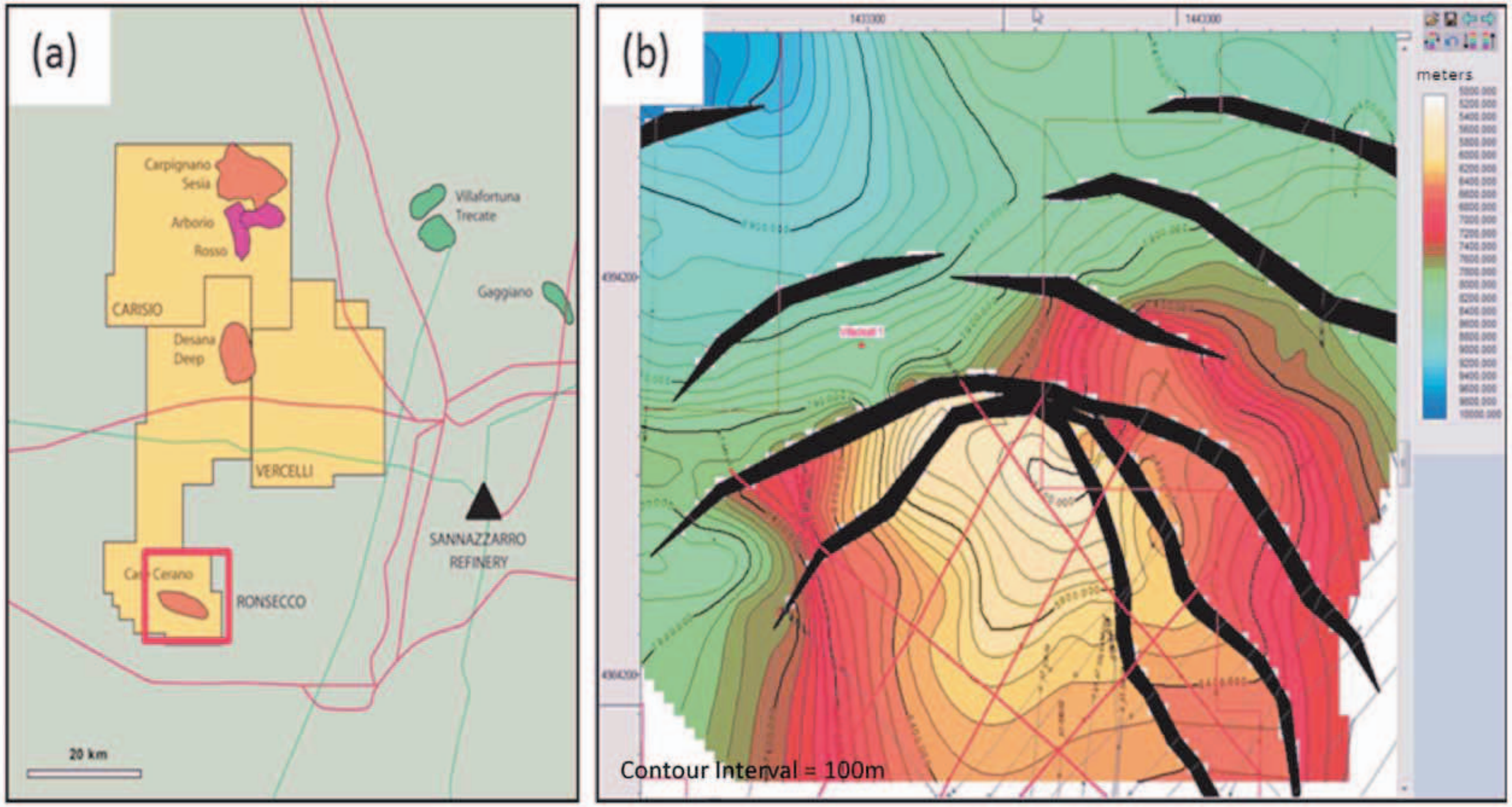

FIGURE 7
LOCATION MAP and DEPTH STRUCTURE MAP – DESANA DEEP PROSPECT
PROVIDED COURTESY OF PETROCELTIC
DeGolyer and MacNaughton Dallas, Texas
Texas Registered Engineering Firm F-716

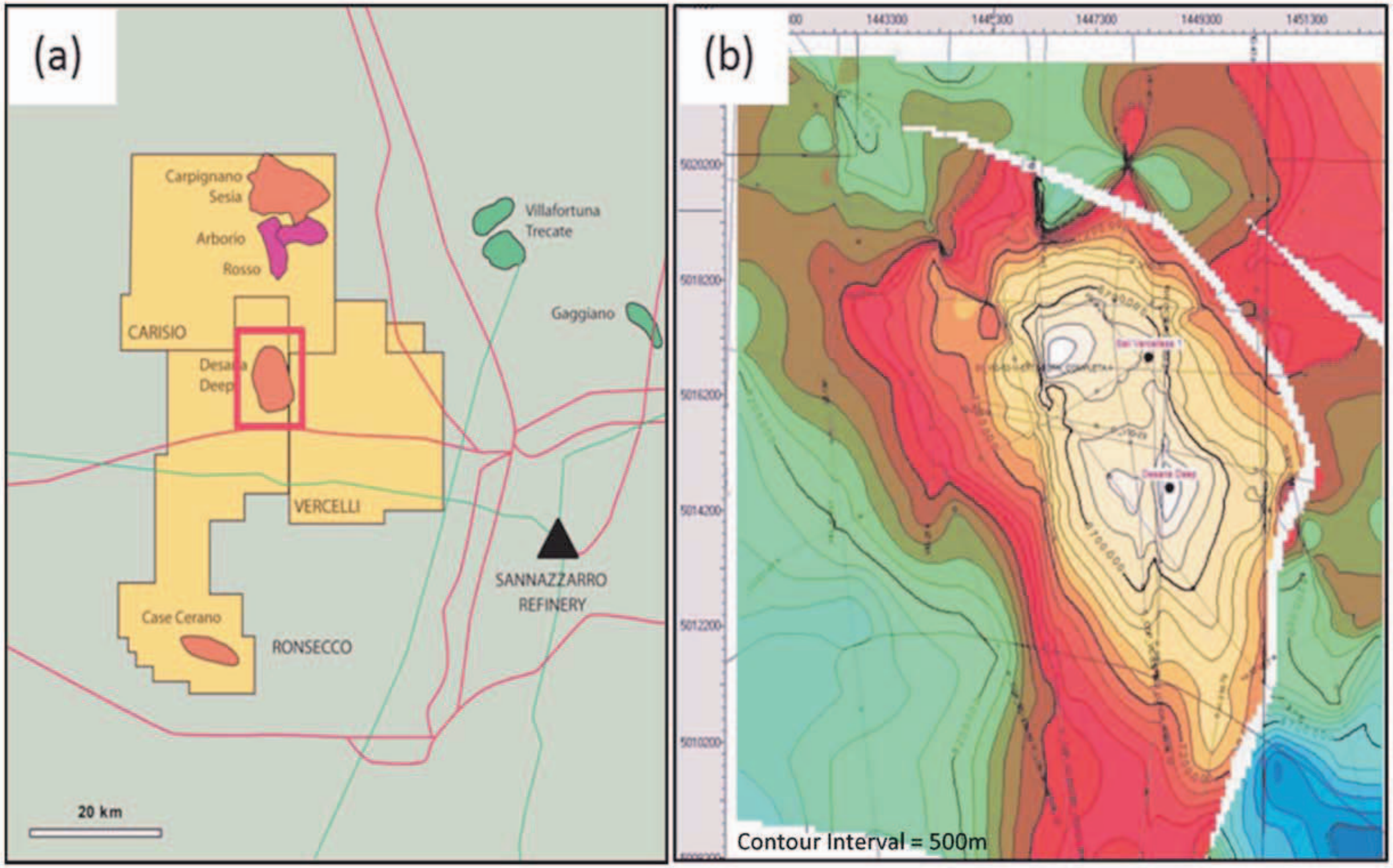

FIGURE 8
LOCATION MAP and DEPTH STRUCTURE MAP – ROSSO STACKED CHANNELS PROSPECT
PROVIDED COURTESY OF PETROCELTIC
DeGolyer and MacNaughton Dallas, Texas
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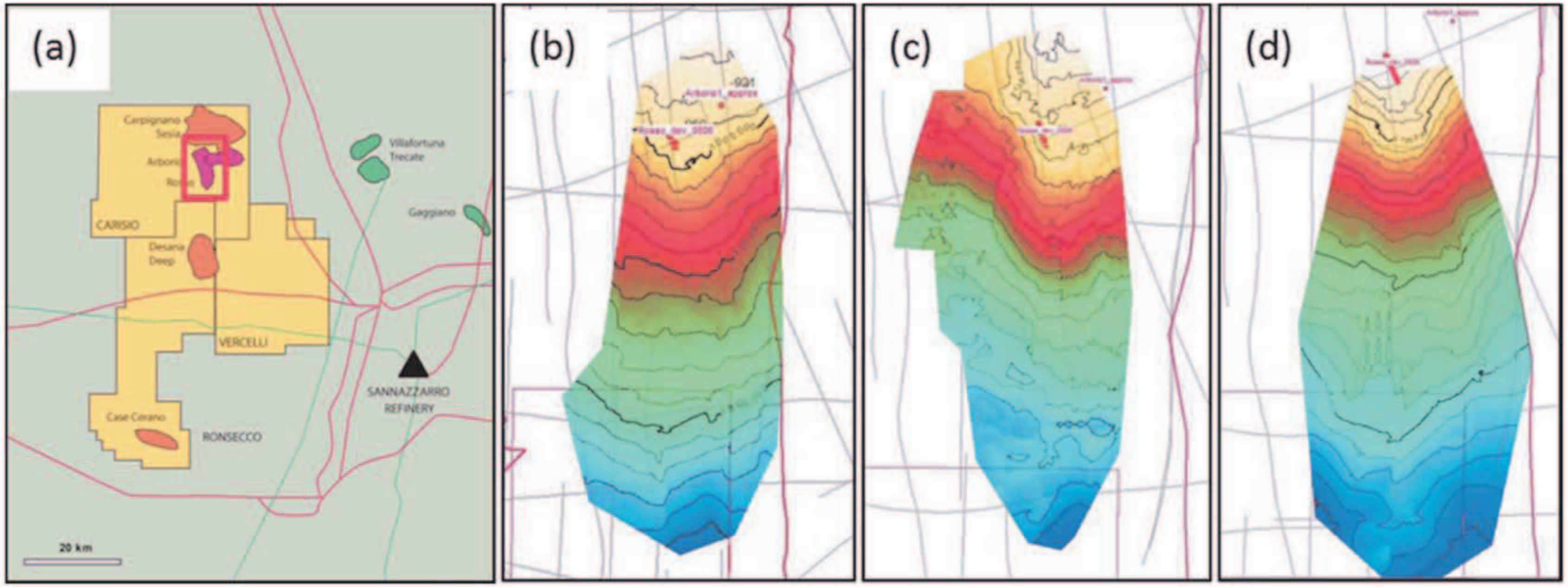


Contour Interval = 500m

FIGURE 9
LOCATION MAP and DEPTH STRUCTURE MAP – ARBORIO PROSPECT
PROVIDED COURTESY OF PETROCELTIC
DeGolyer and MacNaughton   Dallas, Texas
Texas Registered Engineering Firm F-716

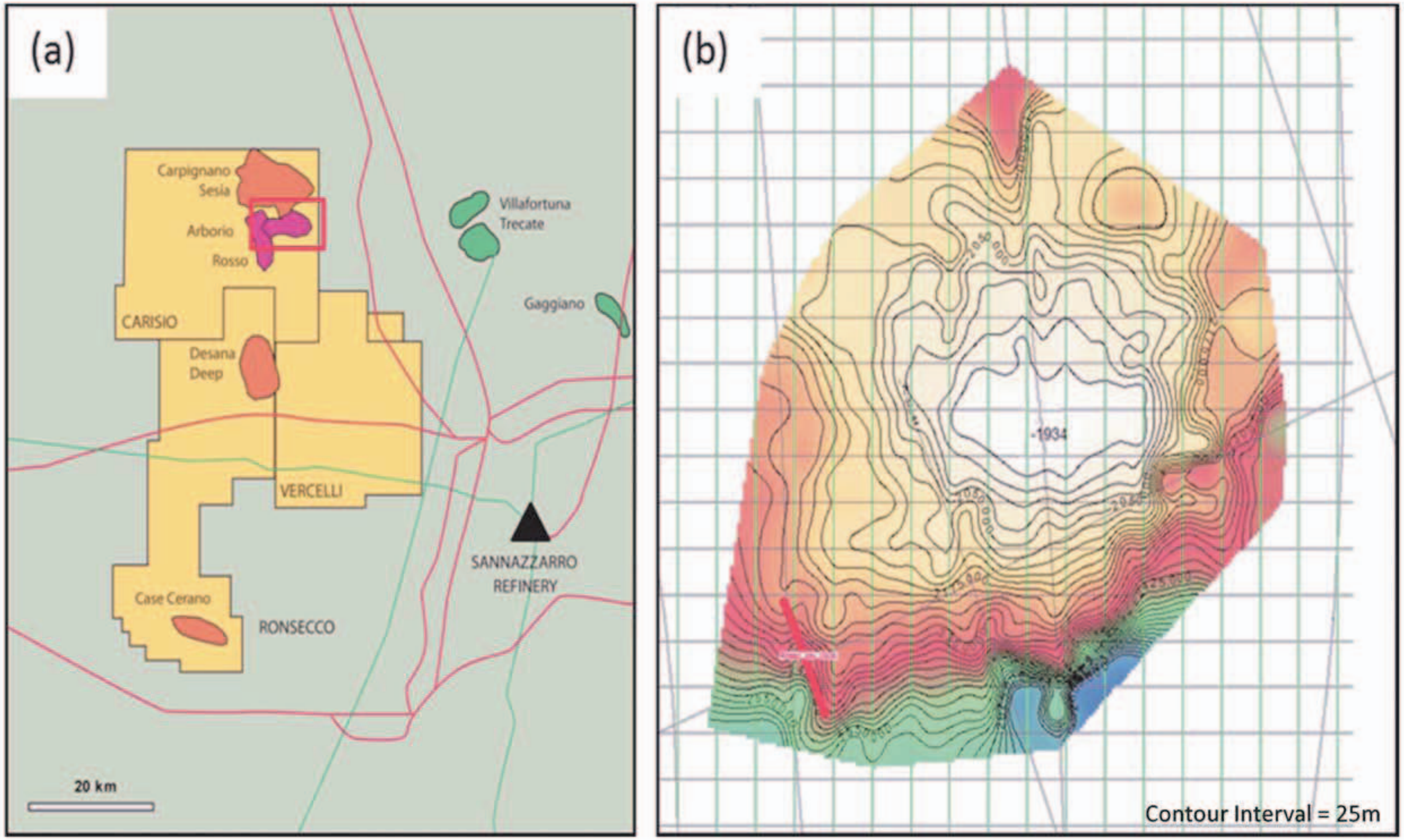


FIGURE 10

STRUCTURE MAP – TOP MESOZOIC CARBONATE, WESTERN PO VALLEY, ITALY

PROVIDED COURTESY OF PETROCELTIC

DeGolyer and MacNaughton Dallas, Texas

Texas Registered Engineering Firm F-716

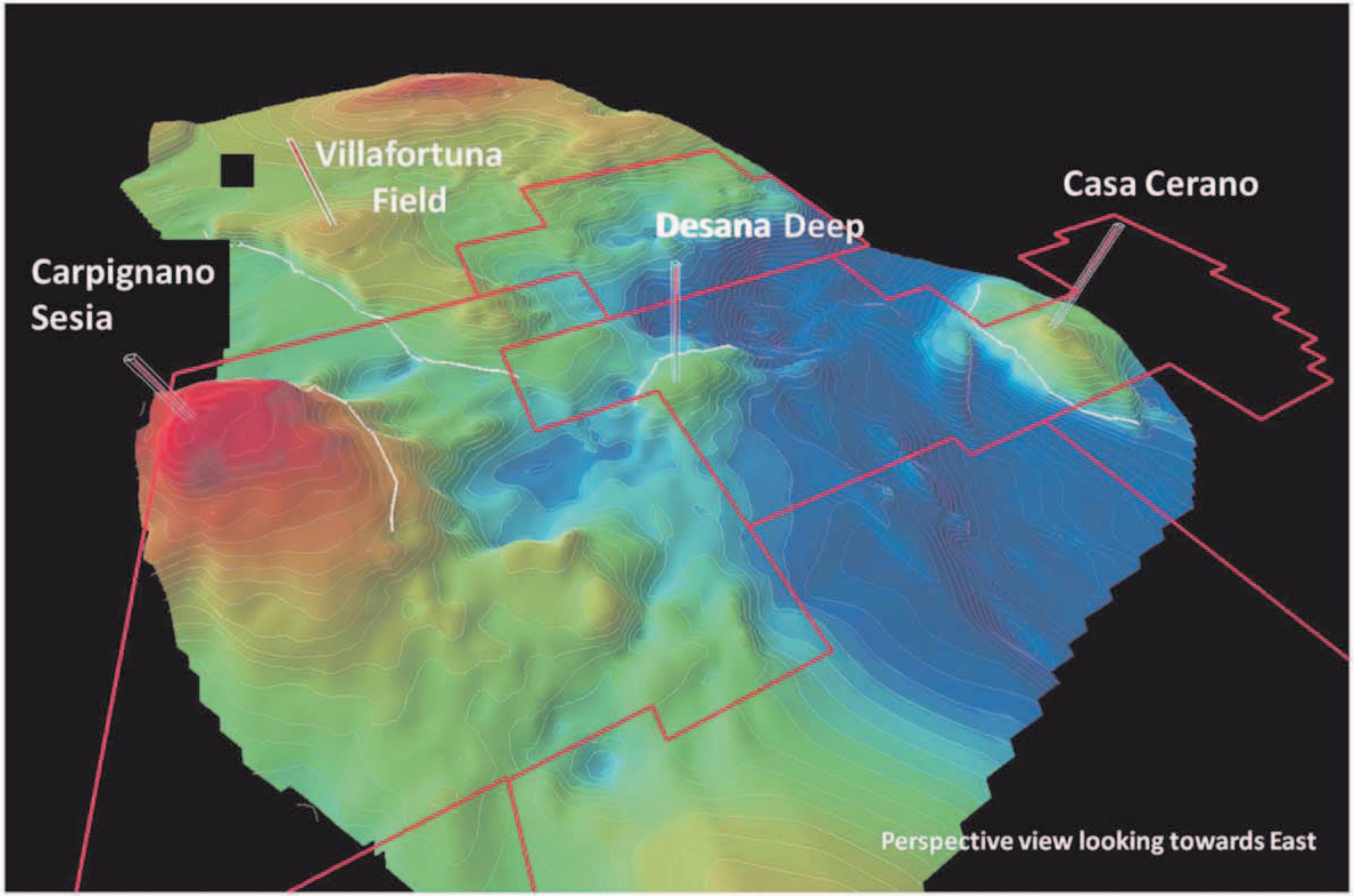


FIGURE 11
TRIASSIC PETROLEUM SYSTEMS CHART – WESTERN PO VALLEY, ITALY
PROVIDED COURTESY OF PETROCELTIC
DeGolyer and MacNaughton Dallas, Texas
Texas Registered Engineering Firm F-716

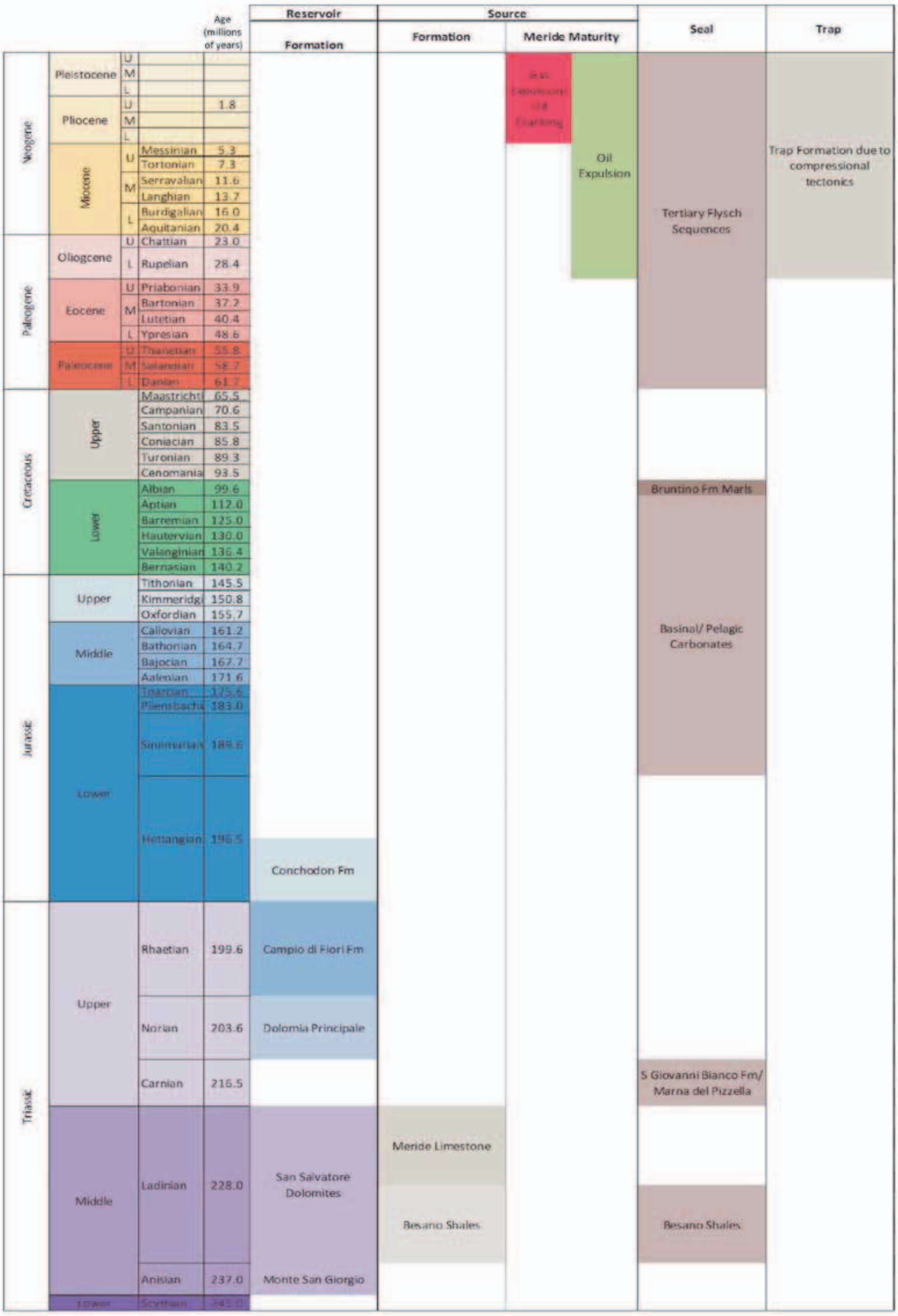
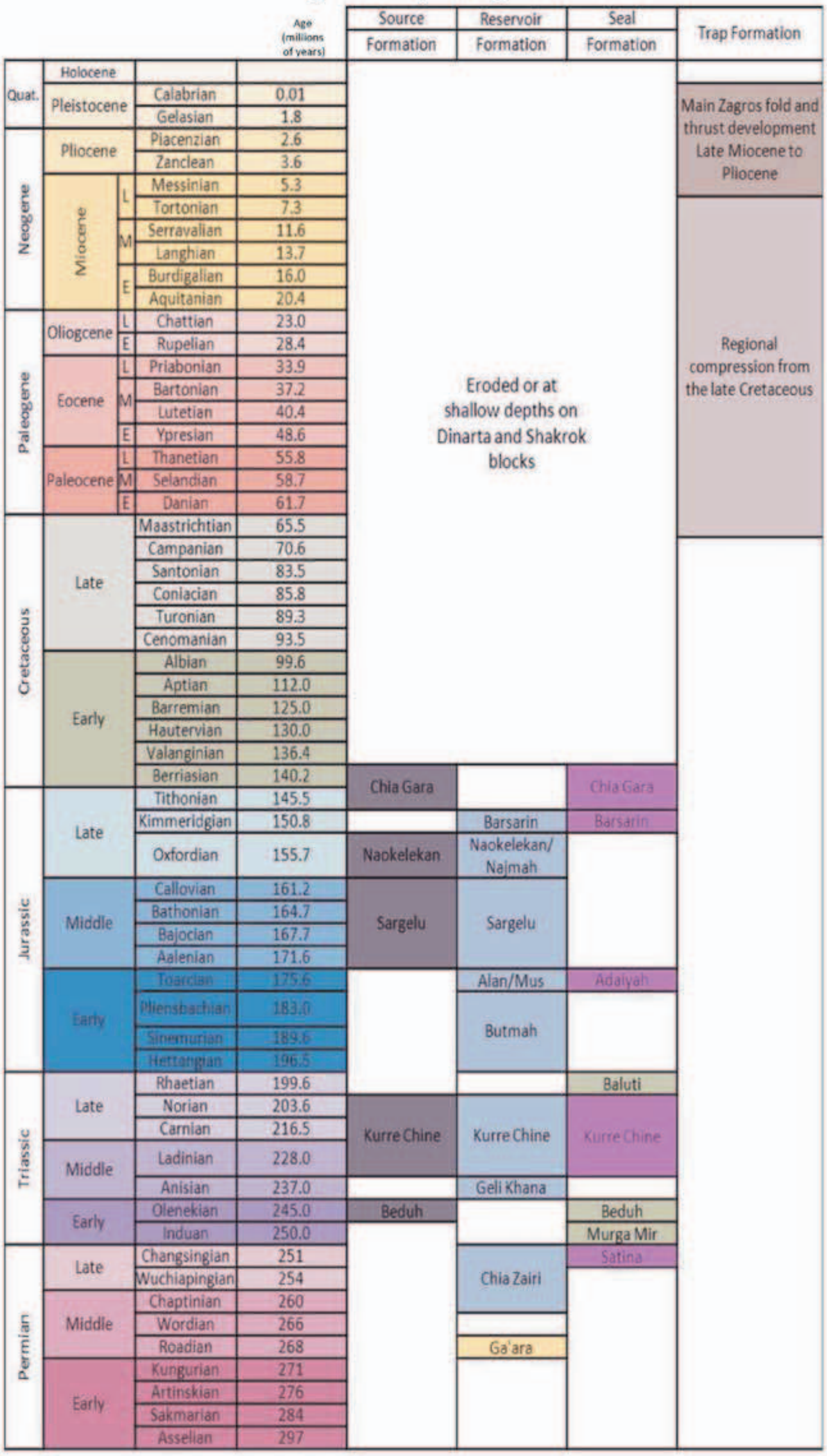


FIGURE 12
PETROLEUM SYSTEMS CHART – KURDISTAN PERMITS
PROVIDED COURTESY OF PETROCELTIC
DeGolyer and MacNaughton Dallas, Texas
Texas Registered Engineering Firm F-716



APPENDIX III

COMPETENT PERSONS REPORT ON THE B.R 268.RG PERMIT (THE ELSA DISCOVERY).

The Directors
Petroceltic International PLC
75 St. Stephen's Green
Dublin 2
Ireland

and

The Directors
Davy
Davy House,
49 Dawson St.
Dublin 2
Ireland

17 August 2012

Petroceltic International PLC ("Petroceltic")
Competent Person's Report
Italy B.R268.RG Permit

Dear Sirs

We have been contracted by Petroceltic and J&E Davy to prepare a competent person's report on the Italy B.R268.RG Permit (the "Competent Person's Report") that will be included in an admission document prepared in accordance with the AIM Rules of the London Stock Exchange plc and the ESM Rules of the Irish Stock Exchange Limited (the "Admission Document"). The Competent Person's Report has been prepared in accordance with Competent Person's Report scope and content guidelines set out in the AIM Note for Mining, Oil and Gas Companies - June 2009 published by the London Stock Exchange plc ("the AIM Note for Mining, Oil and Gas Companies"). The Competent Person's Report relates solely to the defined licences and is based on various geologic and economic assumptions as detailed in the Competent Person's Report. Therefore, the Competent Person's Report must be read in its entirety.

Qualifications.
AGR was founded in 2005 and, following amalgamation of a number of long-established consultancies including TRACS International Ltd in the UK in 2008, currently has over 100 petroleum engineers, geoscientists and petroleum economists working from seven office locations. AGR has extensive

AGR Petroleum (ME) Ltd
802 Saba Tower 1, PO Box 346097, Jumeirah Lakes Towers, Dubai, UAE
Tel: +971 4 450 9811 Fax: +971 4 450 9810

reserves and asset valuation experience and are recognised as industry reserve, risk and valuation experts.
The reports have been prepared by senior AGR staff members, each with more than 15 years experience in the oil and gas industry. The principal reporter, Mr. Jerry Hadwin has previously reviewed the technical work performed for Petroceltic during 2010, holds a Master of Engineering degree in petroleum engineering and has extensive reserves evaluation experience. No AGR personnel have any substantive financial interest (past or present) in the Isarene Permit or in Petroceltic International plc.

Opinion
The evaluation presented in the Competent Person's Report reflects our informed judgment based on accepted standards of professional investigation. The evaluation has been conducted within our understanding of relevant legislation, taxation and all other regulations that currently applies to these interests.

Consent
We hereby consent to the inclusion of the Competent Person's Report and to the use of our name in the Admission Document in the form and context in which they respectively appear.

Correct Extraction
We have reviewed the relevant sections of the Admission Document which relate to information contained in the Competent Person's Report and confirm that the information presented is accurate, balanced and complete and not inconsistent with the Competent Person's Report. In particular we confirm that the information in the Admission Document, where extracted from the Competent Person's Report, is extracted directly and presented in a manner which is not misleading or inconsistent with the Competent Person's Report and provides a balanced view of the Competent Person's Report.

Responsibility
We accept responsibility for the Competent Person's Report contained in the Admission Document for the purposes of a competent person's report under the AIM Note for Mining, Oil and Gas Companies. The Competent Person's Report is complete up to and including information available in May 2012. To the best of our knowledge and belief, after having taken all reasonable care to ensure that such is the case, the information contained in the Competent Person's Report is in accordance with the facts and does not omit anything likely to affect the import of such information.

AGR Petroleum (ME) Ltd
802 Saba Tower 1, PO Box 346097, Jumeirah Lakes Towers, Dubai, UAE
Tel: +971 4 450 9811 Fax: +971 4 450 9810

No Material Change
To the best of our knowledge and belief, after having taken all reasonable care to ensure that such is the case, no material change has occurred from May 2012 to the date hereof that would require any amendment to the Competent Person's Report.

Independence
We are independent of Petroceltic, the directors and senior management of Petroceltic and its other advisors. The Competent Person's Report is prepared in return for professional fees based upon agreed commercial rates and the payment of these fees is in no way contingent on the results of the Competent Person's Report, the admission of Petroceltic's shares to trading on AIM or the ESM or the value of Petroceltic.

Yours faithfully,

Jerry Hadwin
AGR Petroleum (ME) Ltd

17 August 2012

The Directors
Petroceltic plc
75 St Stephen's Green
Dublin 2
Ireland

and

The Directors
Davy
Davy House
49 Dawson St.
Dublin 2
Ireland

12th August, 2012

Gentlemen,

Competent Person's Report for Petroceltic International plc

B.R268.RG Permit

AGR Petroleum (ME) Ltd ("AGR") has, at the request of Petroceltic International PLC ("the Company"), conducted an independent evaluation of resources held by the Company within the B.R268.R.G. Permit, located near offshore in the Central Adriatic of Italy. As instructed, AGR has prepared a Competent Person's Report (CPR) in respect of the Company's Assets and Liabilities pertaining to the licence as of the 1st of July, 2012.

The B.R268.RG. Permit covers an area of 126.7 km^2 and currently contains one Lower Cretaceous oil discovery (Elsa) and one Lower Cretaceous prospect. Petroceltic International, through its wholly-owned subsidiary Petroceltic Italia S.R.L, currently holds a 40% interest in the Elsa exploration permit, with 60% held by Vega Oil S.p.A.

By way of the Farm-in Agreement executed on December 15th, 2009 between the two parties, Vega Oil S.p.a will assign an additional 30% interest in B.R268.RG to Petroceltic Italia S.R.L., effective upon Petroceltic spudding an exploration well. By way of a Farm-out Agreement executed on June 2nd, 2010 between Orca Exploration Italy Inc. and Petroceltic Italia S.R.L., Petroceltic will assign a 15% interest in the Elsa Permit (B.R268.RG) to Orca. From this point, Petroceltic will have a combined 55% interest in the B.R268.RG Permit. Table 0.1 below summarises the current license status.

Table 0.1 - B.R268.RG. Permit Status as of 8th August, 2012

Asset	Operator	Interest	Status	Licence expiry date	Licence area	Comments
Elsa discovery, B.R268.RG Permit, Offshore Adriatic	Petroceltic Italia S.R.L.	40% Increasing to 70%(1) Decreasing to 55%(2)	Exploration	30-Sept-2011(3)	126.7 sq. km.	One commitment well

Notes:

(1) Assignment of an additional 30% WI from Vega S.p.A. to occur in 2 steps - 10% on purchase of Long Lead Items; 20% on spudding of the Elsa-2 Appraisal Well
(2) Assignment of 15% WI to ORCA upon the completion of the Elsa-2 appraisal well
(3) The licence has been suspended pending the decision of the Abruzzo Regional Court on Petroceltic's appeal against the Ministry of the Environments rejection of the Elsa-2 VIA (Environmental Impact Assessment) on the basis of DL128/2010. The recently approved Legislative Decree 83/2012 clarifies that the restrictions imposed under Decree 128/2010 are not applicable to licences that were already in existence when DL 128/2010 was passed (June 2010). Petroceltic is in the process of commencing discussions with the relevant National and Regional institutions concerning the implications of this law for the Elsa project.

AGR has based their evaluation upon data supplied by Petroceltic and upon information available in the public domain. The conducted evaluations assume that Petroceltic Italia S.R.L will meet work program requirements and thus earn the additional 30% net interest to achieve a total 70% net interest, and furthermore, will farm out 15% of the interest to achieve a net interest of 55%.

Following independent evaluation, AGR can report that the Company has net entitlement best estimate (2C) Unrisked Contingent Resources of 52.3 MMbbls and best estimate Risked Prospective Resources of 7.8 MMbbls. Tables 0.2 and 0.3 below summarise the Contingent and Prospective Resource ranges.

Table 0.2- Summary of Contingent Resources within the B.R268RG Permit

Asset	Gross Unrisked Volumes (Oil MMbbls)			Net Attributable Unrisked Volumes (Oil MMbbls)			Risk Factor
	Low Estimate (1C)	Best Estimate (2C)	High Estimate (3C)	Low Estimate (1C)	Best Estimate (2C)	High Estimate (3C)	
Elsa Discovery	**34.2**	**95.0**	**186.5**	**18.8**	**52.3**	**102.6**	**0.75**

Notes:

(1) The Geological Chance of Success (GCoS) of Contingent Resources is 100%. "Risk Factor" for these resources means the estimated chance, or probability, that the volumes will be commercially extracted, which is contingent on successful testing of Elsa-2 appraisal well and the granting of a production licence.

Table 0.3 - Summary of Upside Prospective Resources within the B.R268RG Permit

Asset	Gross Unrisked Volumes (Oil MMbbls)			Net Attributable Unrisked Volumes (Oil MMbbls)			Risk Factor
	Low Estimate (1C)	Best Estimate (2C)	High Estimate (3C)	Low Estimate (1C)	Best Estimate (2C)	High Estimate (3C)	
West Elsa Prospect	27	54	107	15	30	59	0.26

Notes:

(1) "Risk Factor" for Prospective Resources, means the chance or probability of discovering hydrocarbons in sufficient quantity for them to be tested to the surface. This, then, is the chance or probability of the Prospective Resource maturing into a Contingent Resource.

Qualifications

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

The work was undertaken by a team of AGR professional petroleum engineers and geoscientists based on data supplied by the Petroceltic. The data comprised details of licence and acreage interests, historical reports, geological and geophysical data, interpreted data, cost estimates and technical presentations. AGR has reviewed relevant farm-in agreements and title interests from copies of original documents; though it has not spoken directly to Government or licence authorities. AGR has not conducted a site visit.

In estimating prospective resources AGR have used the standard petroleum engineering techniques. These estimates are made in accordance with the Petroleum Resources Management System (PRMS) approved in March 2007 by the Society of Petroleum Engineers (SPE), the World Petroleum Congress (WPC), the American Association of Petroleum Geologists (AAPG) and the Society of Petroleum Evaluation Engineers (SPEE).

The project was reviewed and approved by Jerry Hadwin, a AGR director. Mr. Hadwin, a petroleum engineer, has 29 years experience.

Basis of Opinion

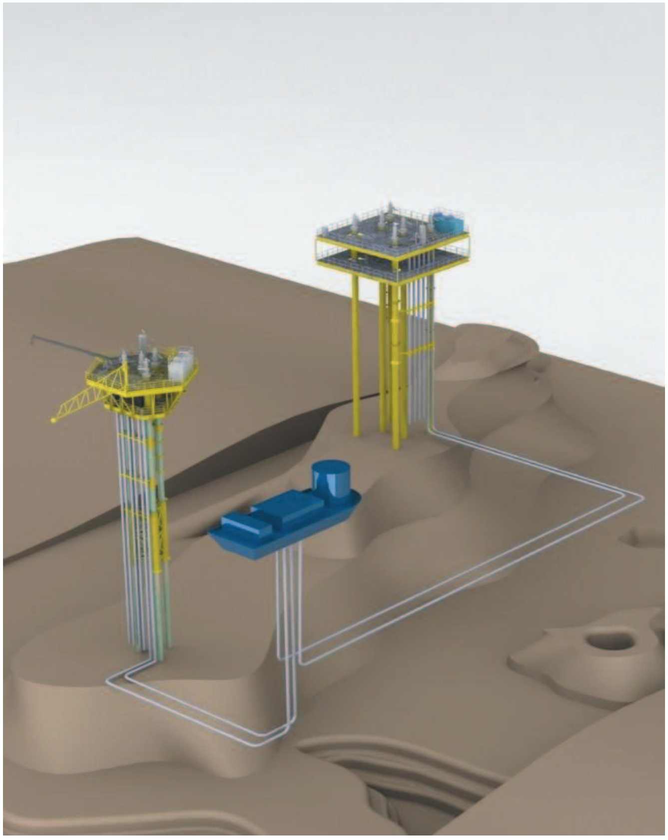
The evaluation presented in this report reflects our informed judgement based on accepted standards of professional investigation, but is subject to generally recognised uncertainties associated with the interpretation of geological, geophysical and subsurface reservoir data.

AGR have taken all reasonable care to ensure that the information contained in the Evaluation is, to the best of our knowledge, in accordance with the facts and contains no omission likely to affect its import. 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.

Competent Person's Report

B.R268.RG Permit

for
Petroceltic International plc



Jerry Hadwin

Tim Salter

August 2012

This report relates specifically and solely to the subject petroleum licence interests and is conditional upon the assumptions made therein. This report must therefore be read in its entirety.

This report was prepared in accordance with standard geological and engineering methods generally accepted by the oil and gas industry. Estimates of hydrocarbon reserves and resources should be regarded only as estimates that may change as further production history and additional information become available. Not only are reserves and resource estimates based on the information currently available, these are also subject to uncertainties inherent in the application of judgemental factors in interpreting such information. AGR Ltd. shall have no liability arising out of or related to the use of the report.

Status	**FINAL VERSION**	
Date	**August 2012**	
Issued by	**Jerry Hadwin**	
Approved by	**Iain Morrison**	

AGR Petroleum (ME) Limited

Executive Summary

This report details the results of an independent valuation conducted by AGR Petroleum (ME) Ltd. on the B.R268.RG Permit, located in a near offshore shallow water environment in the Central Adriatic of Italy. The license contains one Lower Cretaceous oil discovery named 'Elsa' and one analogous Prospect named 'West Elsa'.

Petroceltic International, through its wholly owned subsidiary Petroceltic Italia S.R.L, currently holds a 40% interest in the Elsa exploration permit, with 60% held by Vega Oil S.p.A. By way of the Farm-in Agreement executed on December 15th, 2009 between the two parties, Vega Oil S.p.A will assign an additional 30% interest in B.R268.RG to Petroceltic Italia S.R.L., effective upon Petroceltic spudding an exploration well. By way of a Farm-out Agreement executed on June 2nd, 2010 between Orca Exploration Italy Inc. and Petroceltic Italia S.R.L., Petroceltic will assign a 15% interest in the Elsa Permit (B.R268.RG) to Orca. From this point, Petroceltic will have a net 55% working interest in the B.R268.R.G Permit. Table A.1 below summaries the current license status.

Table A.1 - B.R268RG Permit asset summary

Asset	Operator	Interest	Status	Licence expiry date	Licence area	Comments
Elsa Discovery, B.R268.RG Permit, Offshore Adriatic	Petroceltic Italia S.R.L.	40% Increasing to 70%(1) Decreasing to 55%(2)	Exploration	30-Sept-2011(3)	126.7 sq. km.	One commitment well

Notes:

(1) Assignment of an additional 30% WI from Vega S.p.A. to occur in 2 steps - 10% on purchase of Long Lead Items; 20% on spudding of the Elsa-2 Appraisal Well
(2) Assignment of 15% WI to ORCA upon the completion of the Elsa-2 appraisal well
(3) The licence has been suspended pending the decision of the Abruzzo Regional Court on Petroceltic's appeal against the Ministry of the Environments rejection of the Elsa-2 VIA (Environmental Impact Assessment) on the basis of DL128/2010. The recently approved Legislative Decree 83/2012 clarifies that the restrictions imposed under Decree 128/2010 are not applicable to licences that were already in existence when DL 128/2010 was passed (June 2010). Petroceltic is in the process of commencing discussions with the relevant National and Regional institutions concerning the implications of this law for the Elsa project.

The Elsa-1 discovery well was drilled by Agip in 1992 in 34 m water depth approximately 7 km offshore, near the port of Ortona. Elsa-1 encountered a 65 m oil column in high quality reservoir within the Lower Cretaceous Maiolica formation at approximately 4,500 m. The structure is mapped as a NE-SW trending faulted anticlinal feature with a probabilistically derived in-place P90-P50-P10 volume range of 260-406-573 MMBO. Subsequent to this evaluation, AGR considers that the Contingent Resources associated with the discovery are 34-95-187 MMBO at 100% interest for the 1C-2C-3C categories, 1C and 2C recovery factors being commensurate with a heavy oil development. The evaluation criteria are defined by the 2007 Society of Petroleum Engineers (SPE) Petroleum Resource Management System (PRMS), a summary of which is shown in Inclusion 1. Table A.2 summarises the field gross and net Contingent Resources by category.

Table A.2- Summary of Contingent Resources within the B.R268RG Permit

Asset	Gross Unrisked Volumes (Oil MMbbls)			Net Attributable Unrisked Volumes (Oil MMbbls)			Risk Factor
	Low Estimate (1C)	Best Estimate (2C)	High Estimate (3C)	Low Estimate (1C)	Best Estimate (2C)	High Estimate (3C)	
Elsa Discovery	**34.2**	**95.0**	**186.5**	**18.8**	**52.3**	**102.6**	**0.75**

Notes:

(1) The Geological Chance of Success (GCoS) of Contingent Resources is 100%. "Risk Factor" for these resources means the estimated chance, or probability, that the volumes will be commercially extracted, which is contingent on successful testing of Elsa-2 appraisal well.

Although the Elsa-1 well proved the presence of a substantial oil column in high quality reservoir, it did not provide conclusive results on potential productivity and oil properties. Open hole drill stem testing was conducted on a 228 m interval which included the oil leg and water saturated formations. During testing surface flow was not established and therefore uncertainty exists with respect to the flow rate potential of the formation. Measurement of potentially contaminated dead oil samples recovered from the drill string gave a reported gravity of 13.2° API, with an uncertainty range between 12° to 15° API. Questions remain as to how representative the analysed de-gassed sample was. Uncertainty also therefore exists with respect to oil PVT properties.

Considerable upside value exists if less viscous oil is proved by Elsa-2 than currently adopted as the deterministic Low-Mid-High range for this evaluation of 12°, 15° and 20° API. Although this is not deemed to be probable, it is feasible that lighter oil is in-place as 34° API oil has been encountered in the adjacent Miglianico Field at similar depth and temperature.

It is believed most likely that further appraisal of the structure, with an appropriate casing scheme and test programme, will demonstrate commercial flow rates. Accordingly, the well test of the planned Elsa-2 appraisal well will be conducted under artificial lift conditions using an ESP. Permitting for drilling operations has commenced with submission of the VIA (Environmental Impact Assessment) to the Ministry of the Environment in July 2009 but was suspended following the enactment of D.L. 128 in June 2010, which prevented E&P operations within 5 nautical miles of the coast. Following enactment of the "Growth" Decree (D.L. 83/2012) in June 2012, and approval by both houses of parliament in August 2012, this ban no longer applies to licences in existence at the time of enactment of D.L.128 and consequently it is envisaged that the Elsa project will recommence. The Elsa-2 site survey was completed by Fugro Oceanseismica during the 2nd week of March 2010.

A number of potential Development Concepts have been reviewed within this evaluation, with the most likely development concept, at this stage, considered to be an FPSO development with conductor supported minimal facilities platforms. The final development plan will be determined based on the results of the Elsa-2 appraisal well and will be subject to technical and environmental approval by the Italian Authorities as mandated by Italian Hydrocarbon Licensing regulations

In addition to the Elsa discovery, the structural feature of 'West Elsa' has been mapped within the B.R268.RG Permit and represents potential upside. The mapped structure is located approximately 3 km to the west of the Elsa-1 well. The structure contains relatively small volumes if the same Oil Water Contact (OWC) seen in Elsa-1 is assumed. In this instance the range of Unrisked Prospective Resources is 1-3-6 MMBO at P90-P50-P10 outcome with a 0.43 chance of success (CoS). However, there is a higher risk potential for a deeper contact that would result in a much larger prospective resource as reflected in Table A.3 below (Prospective Resources shown for 100% interest and 55% net interest).

Pending the successful outcome of the Elsa-2 appraisal well, the proposed acquisition of block-wide 3D seismic data would help define the West Elsa prospect. Given the very close proximity of the mapped prospect to the Elsa discovery, considerable development synergy would exist between Elsa and West Elsa should subsequent exploration prove up the prospect.

Table A.3 - Summary of Upside Prospective Resources within the B.R268RG Permit

Asset	Gross Unrisked Volumes (Oil MMbbls)			Net Attributable Unrisked Volumes (Oil MMbbls)			Risk Factor
	Low Estimate (1C)	Best Estimate (2C)	High Estimate (3C)	Low Estimate (1C)	Best Estimate (2C)	High Estimate (3C)	
West Elsa Prospect	27	54	107	15	30	59	0.26

Notes

(1) "Risk Factor" for Prospective Resources, means the chance or probability of discovering hydrocarbons in sufficient quantity for them to be tested to the surface. This, then, is the chance or probability of the Prospective Resource maturing into a Contingent Resource.

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1. Opportunity Description

The B.R268.RG Permit is located in shallow water offshore Italy, in the Central Adriatic area (see Figure 1). The permit was awarded in March 2005 with an initial exploration period of 6 years. Petroceltic currently holds a 40% interest in the Elsa exploration permit, the balance of 60% being held by Vega Oil S.p.A.

By way of a Farm-in Agreement executed on December 15th, 2009 between Vega Oil S.p.A. and Petroceltic International PLC, Vega Oil would assign an additional 30% interest in B.R268.RG to Petroceltic Italia S.R.L., effective upon Petroceltic spudding an exploration well by October 31st, 2010 (Elsa-2). The staged assignment would have been in two parts; the first part of 10% on evidence that all long lead items required to drill the well had been ordered; and the second part of 20% to be effective upon spudding the well. From this point, Petroceltic would have had a combined 70% interest in the B.R268.RG Permit.

By way of a Farm-out Agreement executed on June 2nd, 2010 between Orca Exploration Italy Inc. and Petroceltic Italia S.R.L., Petroceltic would assign a 15% interest in the Elsa Permit (B.R268.RG) and the Adriatic Permit Applications to Orca. The assignment would have been effective on the receipt of the agreed considerations payable towards the drilling and completion of the Elsa-2 exploration well. From this point, Petroceltic would have retained a net 55% working interest in the B.R268.RG Permit.

With a letter dated October 13th, 2010 the Italian Ministry of Energy formally rejected the application for the drilling of Elsa-2 on the basis of decree 128/2010[1]. With this action, Petroceltic and its partners were prevented from fulfilling its licence obligations, namely the spudding of Elsa-2 on or before October 31st, 2010. On March 1st, 2011, a six month suspension of the licence was granted, extending the licence expiry date to September 30th, 2011. On September 20th, 2011 a further licence suspension was granted, pending the decision of the Abruzzo Regional Court on Petroceltic's appeal against the Ministry of the Environments rejection of the Elsa-2 VIA (Enivironmental Imapact Assessment). The recently published and ratified decree 83/2012[2] aims to protect exploration and production licences issued or under consideration when decree 128/2010 was put in force and it is envisaged that the Elsa project will recommence in September 2012. Given the limited remaining duration of the 1st phase of the licence, approval to proceed into the 2nd 3–year phase of the licence will be needed to enable Elsa-2 to be drilled.

For the purpose of this CPR, it has been assumed that Petroceltic will formally be granted the licence extension, and that Elsa-2 will be drilled. It has also been assumed that the above mentioned farm-in and farm-out agreements will come into effect and that Petroceltic will retain a 55% interest in the B.R268.RG Permit.

The Elsa field was discovered in 1992 with the Elsa-1 exploration well. The discovery well encountered a 65m oil column in high quality reservoir within the Lower Cretaceous Maiolica formation at ±4,500 m. The structure is mapped as a NE-SW trending faulted anticline (see Figure 2) with a probabilistically derived in place P90-P50-P10 volume range of 260-406-573 MMBO. AGR considers that the Contingent Resources associated

[1] Decree 128/2010, in force as of August 26th, 2010, bans all offshore E&P activity within five nautical miles of the coastal baseline and twelve miles adjacent to protected areas.
[2] Decree 83/2012, published on June 26th 2012 and ratified by parliament in August 2012, extends the ban to a blanket twelve nautical miles, but indicates that the restrictions under decree 128/2010 will be lifted for titles and applications and proceedings connected with such in effect when decree 128/2010 came into force.

with the discovery are 34-95-187 MMBO for the 1C-2C-3C categories at 100% interest (19-52-103 MMBO at 55% net interest). The evaluation criteria are defined by the 2007 Society of Petroleum Engineers (SPE) Petroleum Resource Management System (PRMS), a summary of which is shown in Inclusion 1.

As a consequence of an inadequately designed and executed testing programme on the discovery well Elsa-1, there is considerable uncertainty regarding the flow rate potential of the formation and the oil PVT properties. The Elsa-2 appraisal well is planned to resolve these uncertainties in order that the commerciality of the discovery can be confirmed. Work conducted associated with this report indicates that the 1C Contingent Resources will yield a positive NPV for a full development at Brent price of $90/bbl; a discount of $13.50/bbls was applied to the Brent price to account for the quality of the Elsa crude.

Considerable Upside exists if oil gravity is higher than the currently adopted 15°API base case. The proximity of nearby fields with lighter oil suggests that this is feasible.

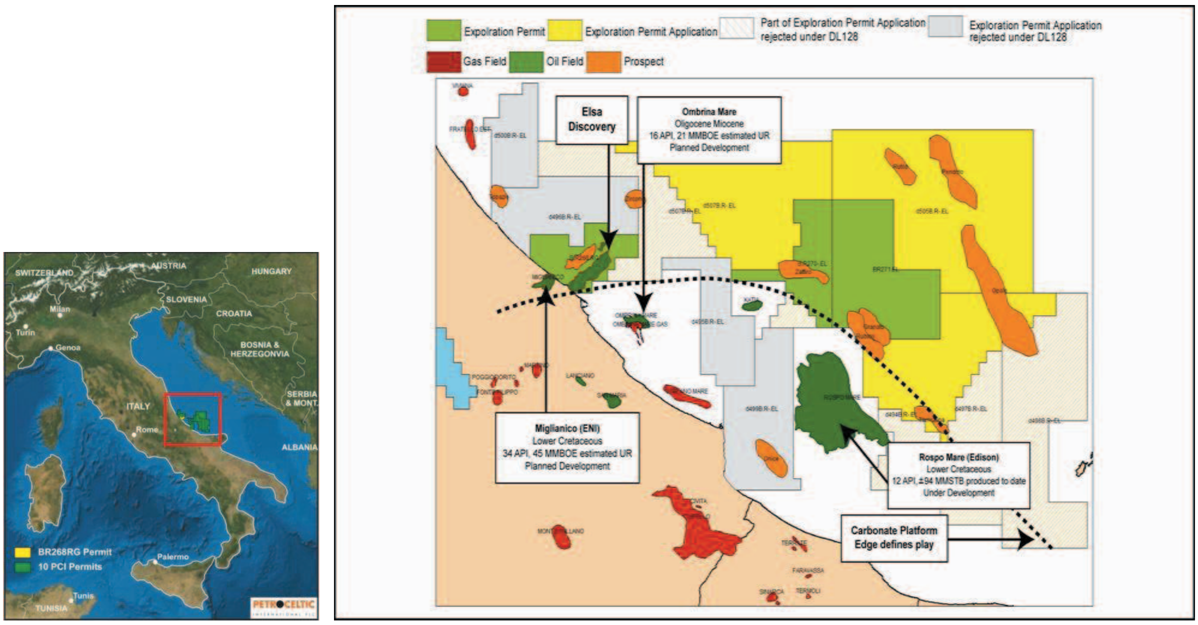


Figure 1 - Block location

Following on from the Elsa-2 appraisal it is envisaged that a 3D seismic survey will be acquired over the block (except for the coastal zone where water depth is less than 15 m). This data will be used, together with the appraisal results to conduct a full Concept Assessment and Selection study with the final development plan subject to technical and environmental approval by the Italian Authorities as mandated by Italian Hydrocarbon Licensing regulations. Should the development be sanctioned, it is envisaged that first oil could be delivered within 2-3 years with conductor supported platforms and an FPSO. If development of the Elsa field moves forward to the Development Planning stage, it is envisaged that, after 3D acquisition, exploration of the West Elsa structure will follow.

The West Elsa structure is located approximately 3 km to the west of the Elsa-1 well. The structure contains relatively small volumes if the same Oil Water Contact (OWC) seen in Elsa-1 is assumed. However, there is a higher risk potential for a deeper contact that would result in a much larger unrisked Prospective Resource of 27-54-107 MMBO at P90-P50-P10 outcome (100% interest) with a 0.23 POS. Given the very close proximity of the mapped prospect to the discovered Elsa field, considerable development synergy would exist between Elsa and West Elsa should subsequent exploration prove up the prospect.

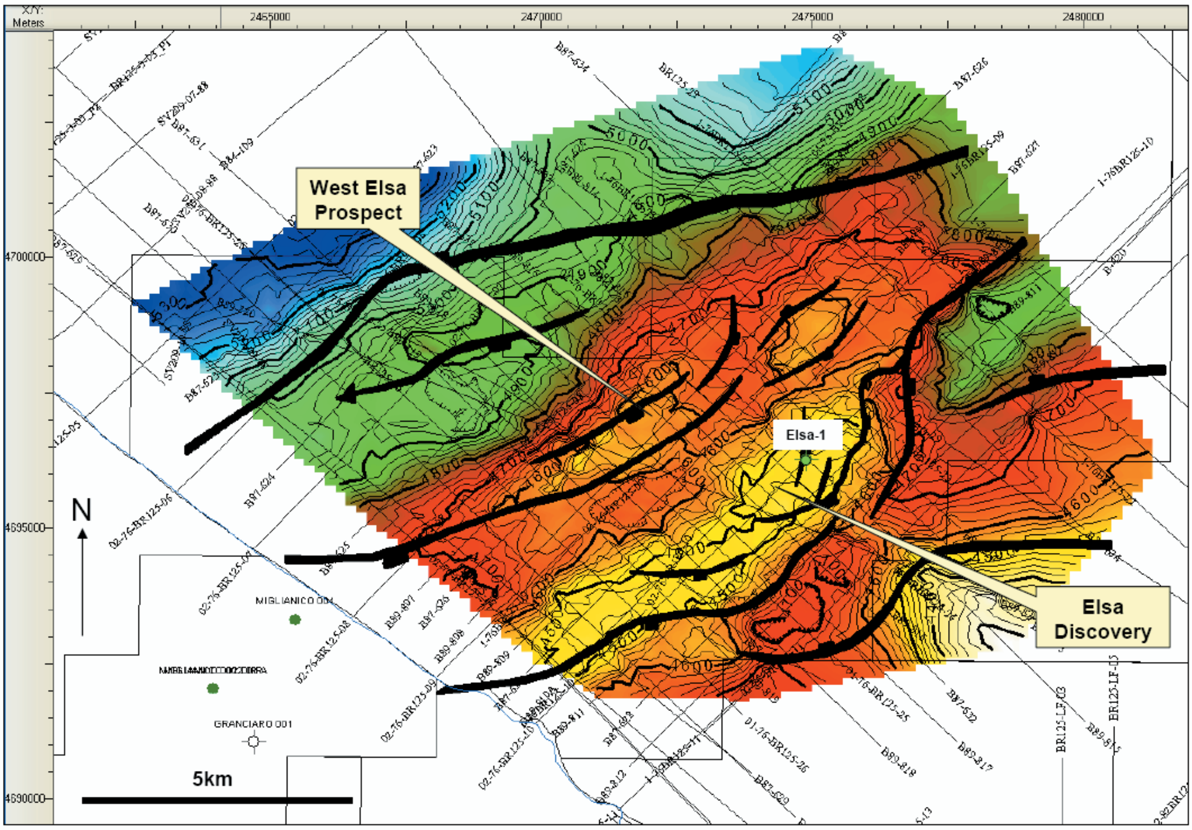


Figure 2 - Top Elsa reservoir structural depth map

In addition to its 55% equity interest in the B.R268.RG Permit, Petroceltic also holds 100% equity interest in two exploration permits and seven offshore exclusive permit applications in the Italian Central Adriatic area (see Figure 1), with Orca Exploration Italy Inc having an option to farm into these licences subsequent to their participation in the Elsa-2 well. These permits and applications provide significant upside exploration potential in the proven but underexplored Lower Cretaceous 'Maiolica' play fairway which is in the early part of the resource creaming curve for this play. There is additional hydrocarbon potential in the Cretaceous and Tertiary platform carbonates and Tertiary clastics in this region. These permits cover an area of approximately 3,100 km^2, primarily in shallow waters (30-150 m). Petroceltic report a substantial inventory of both oil and gas prospects and leads within this area; though AGR has not reviewed or confirmed such as part of this evaluation. These permits allow further exploration of the play fairway, which includes Elsa, eastwards and southwards along the Apulian Platform Margin.

1.1. Discovery Synopsis

The Elsa-1 discovery well was drilled by Agip in 1992 in 34 m water depth approximately 7 km offshore. The primary exploration target was the Jurassic Massiccio formation prognosed at approximately 4,500 m TVD ss. The well encountered the top Lower Cretaceous at 4,228 m TVD ss and subsequently discovered a 65 m oil column in good quality dolostone reservoir within the Maiolica interval at approximately 4,500 m TVD ss (original Massiccio prognosis depth). A core cut within the oil leg had porosity of 19% and permeability in the range 12-200 mD. A subsequent open-hole DST of the formation over 228 m of open hole failed to yield sustainable flow to the surface. Laboratory testing of a contaminated dead oil sample recovered via reverse circulation of the drill string indicated a gravity of 13.2°API (with a reported range of 12° to 15°API) and no H_2S. Post testing, the well was drilled ahead to 4,842 m MD where significant losses were experienced within the Massiccio Formation. Due to the inability to drill ahead without losses Elsa-1 was plugged and abandoned without further testing.

Testing operations conducted on the Maiolica interval were far from optimal for a number of key reasons, specifically; i) a 228 m open-hole interval was tested with both the oil zone and underlying/overlying water saturated intervals open to flow, ii) the carbonate formation was not acidized prior to testing despite being exposed to overbalanced mud weights for a period of four weeks, iii) no clean oil sample was collected at reservoir conditions and iv) artificial lift was not deployed. Given the aforementioned test inadequacies, drilling of Elsa-2 appraisal well is critical in order to confirm the discovery development potential. It is believed that with a suitably designed casing and test programme, commercial flow rates will be achieved from the Elsa-2 well.

Upside potential beyond the 95 MMbbl (100% interest) 2C Contingent Resource level exists if less viscous crude is found than suggested from the Elsa-1 sample. The offset field Miglianico, a discovery awaiting development, has a crude API of 34° at similar depth and pressure (see Figure 1 for location). Elsa-1 test data does not suggest that crude of similar property is contained within the Elsa structure and it is believed that the selected API (viscosity) ranges for Contingent Resource evaluation of 12°, 15° and 20° API are representative of the uncertainty range. The High (3C) outcome is reflected by matching 20° API crude with the P10 STOIIP value to give 187 MMbbl Ultimate Recovery (at 100% interest).

Figure 3 plots the field technical recovery factor versus crude specific gravity in degree API (viscosity) for the evaluated 1C-2C-3C cases (see Section 2.6), extended to include Miglianico type crude. As can be seen, presence of less viscous crude would have a significant impact on achievable field Recovery Factor and development value. Appraisal is key to resolving the uncertainty regarding fluid PVT properties.

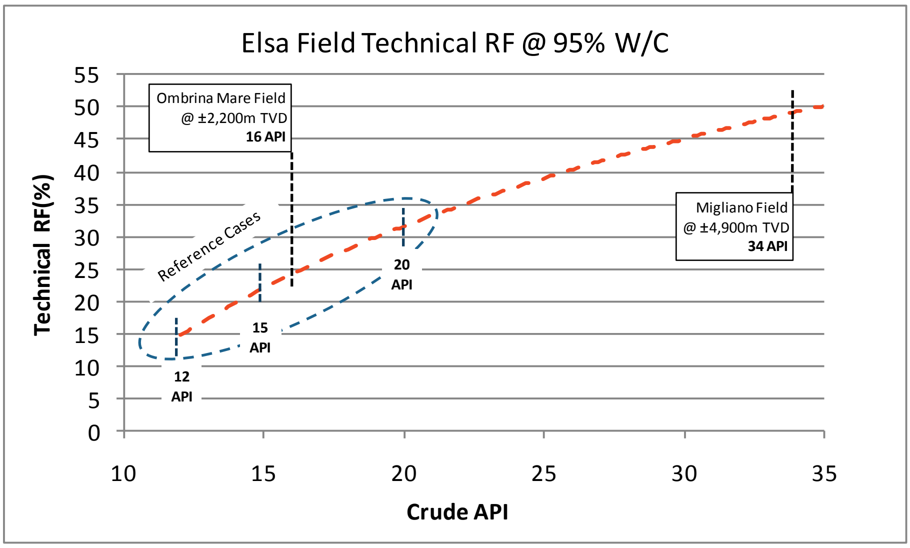


Figure 3 - Impact of oil viscosity on Technical RF for Elsa field

There are two other commercial offshore oil fields close to the B.R268.RG Permit, namely; Ombrina Mare, a discovery awaiting development, and Rospo Mare which is on production. The Ombrina Mare reservoir is at a depth of approximately 2,200 m TVss and has an oil gravity of 16°API while Rospo Mare is at approximately 1,350 TVss and has an oil gravity of 12°API.

There are also a number of producing gas discoveries in the vicinity of the Permit including Santo Stefano Mare and Fiume Trieste. The discovery well OMB-1 also tested gas within the Pliocene at rates of up to 8.5 MMscf/d. The presence of commercial gas accumulations in the province adds to upside potential within the Petroceltic held permits.

1.2. Summary of Potential Development Concepts

A range of development concepts have been evaluated for different in-place volumes and oil viscosities. The Reference Cases for the evaluation are the P90-P50-P10 STOIIP with deterministic oil gravities of 12°, 15° and 20°API. These cases in combination are referred to as Ref Case L, Ref Case M and Ref Case H respectively. These Cases represent the Low, Medium and High or 1C, 2C and 3C Contingent Resource values for the field.

A number of development concepts are technically feasible for the Elsa Field. However, the absence of infrastructure in the immediate area of the field combined with a drive to reduce the environmental footprint of any development suggests that the most likely development concept will involve an FPSO vessel and a complete offshore solution. Produced oil will be exported by shuttle tanker. All cases reviewed assume two conductor supported minimal facilities wellhead platforms (WHPs) notionally located in the central area of the field and in the North East area of the field at the proposed Elsa-2 appraisal well location; the well numbers and the injection requirements are different in the three cases.

All development wells are considered to be horizontal with drain hole lengths of between 1000 m and 2000 m. The requirement for Artificial lift (ESPs) is anticipated. All produced water is taken to be re-injected for reservoir pressure maintenance. All produced gas in excess of offshore power requirements (estimated at 6-7 MW) is considered to be disposed of via injection in dedicated disposal wells; no value is therefore attributable to the gas stream. Table 1 details the assumed number of development wells per scenario.

Table 1 - Number of assumed development wells per Scenario

	Prod Wells[1)]	WI/Disp Wells	GI Wells
Ref Case L	6	3	0
Ref Case M	8	4	1
Ref Case H	10	5	1

1) Including Elsa-2

1.3. Field Appraisal Plans

As a consequence of the sub-optimal testing and data acquisition from Elsa-1, some key uncertainties remain outstanding with regard to the commerciality of the Elsa discovery. The key geological objectives of the Elsa-2 well are to therefore to:

1. Determine the oil properties.

2. Assess the flow rate potential of the formation.

The Elsa-2 appraisal well is planned as an offset to Elsa-1. The well will be drilled vertically from a jack-up rig in a water depth of 33 m to a planned TD of 4,700 m TVss at a total cost of $37.5 million USD (excluding the Operator's G&A). The 7" casing shoe will be set at top reservoir at ± 4,500 m TVss and the reservoir section will be drilled in 6" inch hole. It is intended to cut a 27' core through the reservoir. Post log acquisition, a barefoot production test will be conducted with an ESP. The test duration is anticipated to be 24 to 48 hrs. All operations associated with the Elsa-2 well will be carried out in compliance with Petroceltic's HSSE management, as summarized in Appendix 2.

The well will be drilled by an Italian-certified zero discharge jack-up rig using water based drilling fluid in all hole sections. A number of suitable rigs with acceptable contract windows have been identified.

The Elsa-2 site survey was completed by Fugro Oceanseismica during the 2nd week of March 2010. The Environmental Impact Assessment for Elsa-2 was submitted to the Italian Ministry for the Environment in August 2009 but was rejected on the basis of decree 128/2010. The EIA will be resubmitted upon formal confirmation of the licence extension.

The well will be supported from an Operations Base, bonded warehouse and quay at the port of Ortona, which is one of the principal oilfield service centres for the Adriatic region. The anticipated well duration including DST testing and abandonment is expected to be about 116 days.

2. Field Summary

2.1. Geological Setting

The B.R268.RG Permit is situated along the northern margin of the Apulian Carbonate Platform. Degradation of this platform margin, through gravity sliding and slumping during the Late Jurassic/Early Cretaceous, resulted in the re-sedimentation of bioclastic debris and breccias onto the basin floor in the form of fan deposits. These fans, draped over Late Triassic-Jurassic extensional fault blocks, subsequently underwent pervasive dolomitization. Hydrocarbon traps are likely to be structural, related to Pliocene inversion, and stratigraphic-diagenetic in nature. The main reservoir in the Elsa-1 well is the Lower Cretaceous Maiolica Formation. Geochemical signatures from oil encountered in Mesozoic drilled sections of the Central Adriatic Basin indicate a common hydrocarbon source, identified as the Late Triassic-Early Jurassic Emma and Burano organic carbonate and evaporite sequence. These source rocks contain a mix of terrestrial and marine (Type I) organic matter and have TOC values of 1-5%. They were deposited in anoxic and hypersaline mini-basin environments in an extensional horst and graben setting. Reported analysis suggests that Elsa crude is a non-bio-degraded dead oil which has been sourced from an early mature kitchen (probably in situ).

Figure 4 shows a graphic of the Petroleum System of the B.R268.RG Permit while Figure 5 shows the Carbonate fan play depositional model. Figure 6 shows the prognosed Elsa-2 Lithological Column.

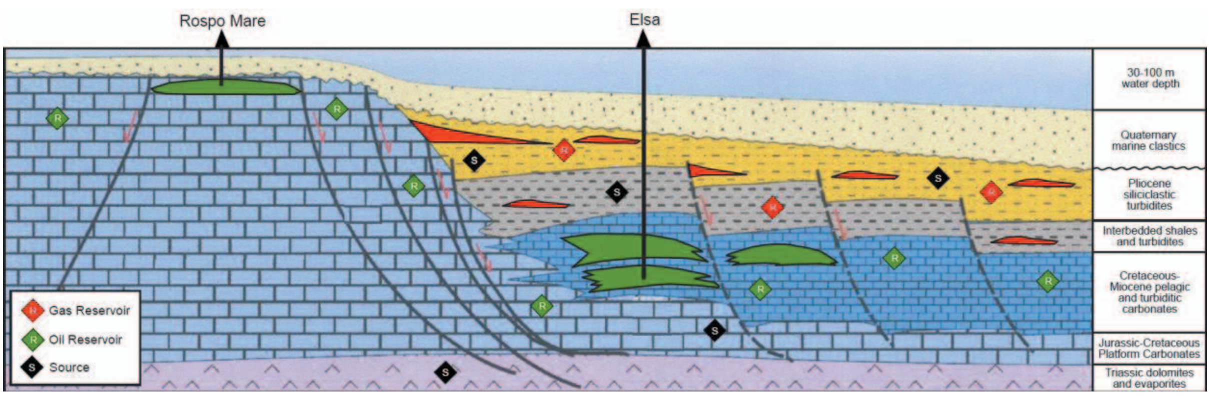


Figure 4 - Petroleum System of the B.R268RG Permit

Geological model: Bioclastic basin floor fans sourced from the platform are draped over tilted fault blocks along the Apulian Platform margin. Significant stratigraphic and structural trapping opportunity in a proven petroleum system

There are three oil fields of commercial size in the vicinity of the B.R268.RG permit, namely; Miglianico (discovery, development on hold), Ombrina Mare (discovery awaiting development) and Rospo Mare which is on production. Figure 1 shows the geographical location of these fields with respect to Elsa. In addition to the Elsa Lower Cretaceous Maiolica discovery, there is additional hydrocarbon potential in the Cretaceous and Tertiary platform carbonates and Tertiary clastics in this region.

The Miglianico discovery well was drilled by ENI in 2001 on a seismic-defined structure, with the second appraisal well Miglianico-2 drilled in 2003. The first well, Miglianico-1 tested at 890 bopd (34°API) and 1.5 MMscf/d of gas from a dolomitized Maiolica Equivalent section. The Miglianico-1 discovery was subsequently appraised with the drilling and successful testing of Miglianico-2. The Maiolica Equivalent formation can therefore be an excellent reservoir containing light gravity oil. The reservoir is comprised of dolomitized calcarenites, calcirudites and breccias which originated from the Apulian Platform carbonates through a process of turbidity currents and debris flows. These coarser sediments were deposited within a basinal sequence sealed by a sequence of tight, deep-water micrites. Miglianico carries a stated 2P reserve of 45 MMBOE. It should be noted that Miglianico produced 50,000 to 90,000 ppm H_2S during testing. Development plans for the field are currently suspended due to local legislative issues in the Abruzzo region.

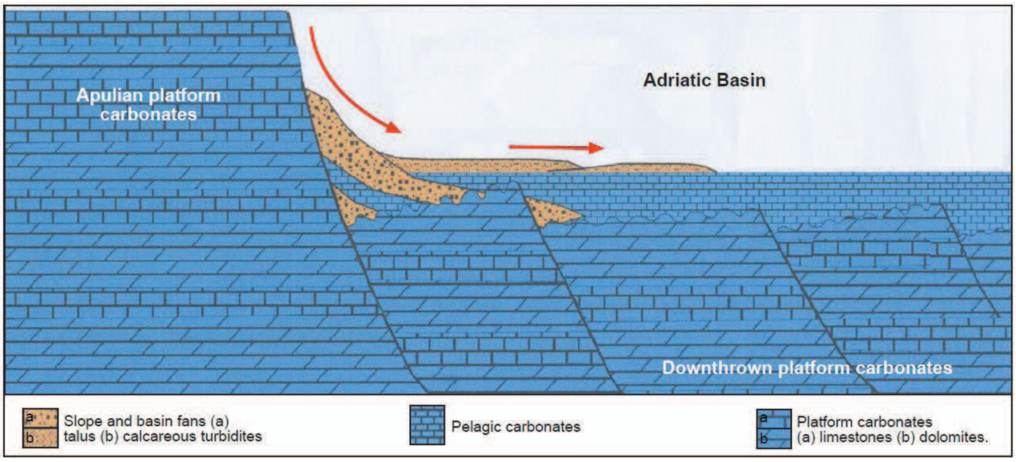


Figure 5 - Carbonate fan play depositional model

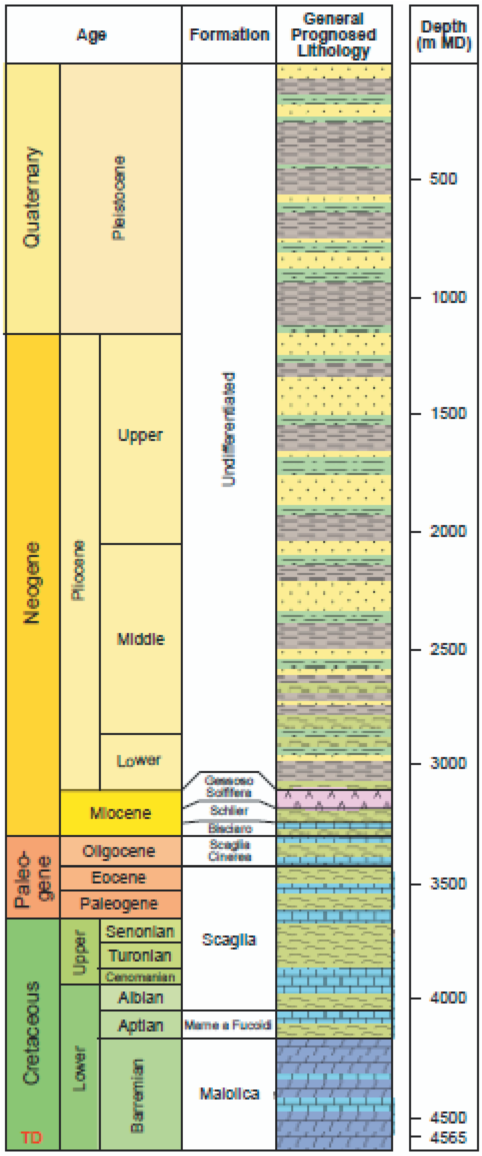


Figure 6 - Prognosed Elsa-2 Lithological Column

Platform carbonates from Jurassic to Oligo-Miocene age are seen along the length of the Apulian Platform Margin, which extends from onshore Italy across the Adriatic Sea to Albania (see Figure 1 and Figure 7). Prospects are generally in the form of extensional fault blocks, inversion and erosional truncation structures, with further potential for stratigraphic traps, particularly where karstification is identified. Hydrodynamic trapping is also possible, as shown by the dipping OWC observed at Rospo Mare, while seal is provided by Miocene evaporates or Pliocene shales. Analogues include the Rospo Mare Field, and the Ombrina Mare and Giove discoveries. Identified platform carbonate prospects/leads include the Onice (Early Cretaceous hydrodynamic trap) and Zircone (Pliocene compressional anticline) prospects.

Ombrina Mare is located 7 Km offshore in a water depth of approximately 20 m, some 13 km to the South West of Elsa. Two wells (three penetrations) have been drilled in the discovery, the first by Elf in 1987. The second well, OMB-2, was drilled in 2008 by Mediterranean Oil and Gas with a vertical pilot hole that was then plugged back and sidetracked for testing. Both wells discovered oil in the Lower Neogene limestone which unconformably overlies Lower Cretaceous limestone. The trap is sealed by overlying tight argillaceous Miocene limestone. Overlying these limestones is an interbedded series of Pliocene sandstones and shale. Gas has been discovered in a number of sandstone beds within this sequence. During an Open Hole DST on the vertical discovery well OMB-1, rates of approximately 1250 bopd were achieved on a short term flow test delivering oil with a specific gravity of 16°API. The horizontal well OMB-2 reported test rates at a similar level to those reported for OMB-1. It is likely that reported flow rates could have been improved with artificial lift. Ombrina Mare carries a stated 2P reserve of 21 MMboe.

The Rospo Mare field is located 20 km offshore in water depths of about 80 m, approximately 48 km to the South East of Elsa. In 1975 the exploration well Rospo Mare 1 discovered an oil accumulation of 12°API specific gravity at a depth of 1,350 m in Lower Cretaceous karstified Albian to Cenomanian limestone. From 1976 to 1979, two appraisal wells were drilled to delineate the field. The trap is mainly due to a hydrodynamic tilt which is explained by the low contrast between the specific gravity of oil and water. For that reason the oil column ranges from 0 to 140 m from the South West to the North East. Following a successful pilot project undertaken by an ELF-AGIP JV in 1982, full development began in 1986 initially with one platform and four horizontal producers expanding to three platforms and twenty-eight horizontal producers. To date, the field has produced a cumulative 97 MMbbl of oil. The current operator of the field is Edison.

Further play potential is represented by stacked siliciclastic turbidites that shed eastwards from the growing Apennine fold and thrust belt into the Adriatic Foredeep Basin (see Figure 1 and Figure 7). Coarse clastic influx is most likely to be found in the coastal permit applications. Prospects are compressional structures or stratigraphic traps proximal to the Apennine thrust front with the seal provided by overlying and intraformational shales. This is a biogenic gas play, with source likely to be from interformational and intraformational shales and clays, and is a widespread play in the Po Valley and Northern Adriatic Basin to the northwest of the permit applications. Many fields have been discovered which prove the potential for this play such as the Barbara Field and a number of gas fields along the Central Adriatic coast including the Santo Stefano Mare and Squalo fields. Prospects include Topazio, which is along the trend of the Fratello, Squalo and Santo Stefano Mare fields.

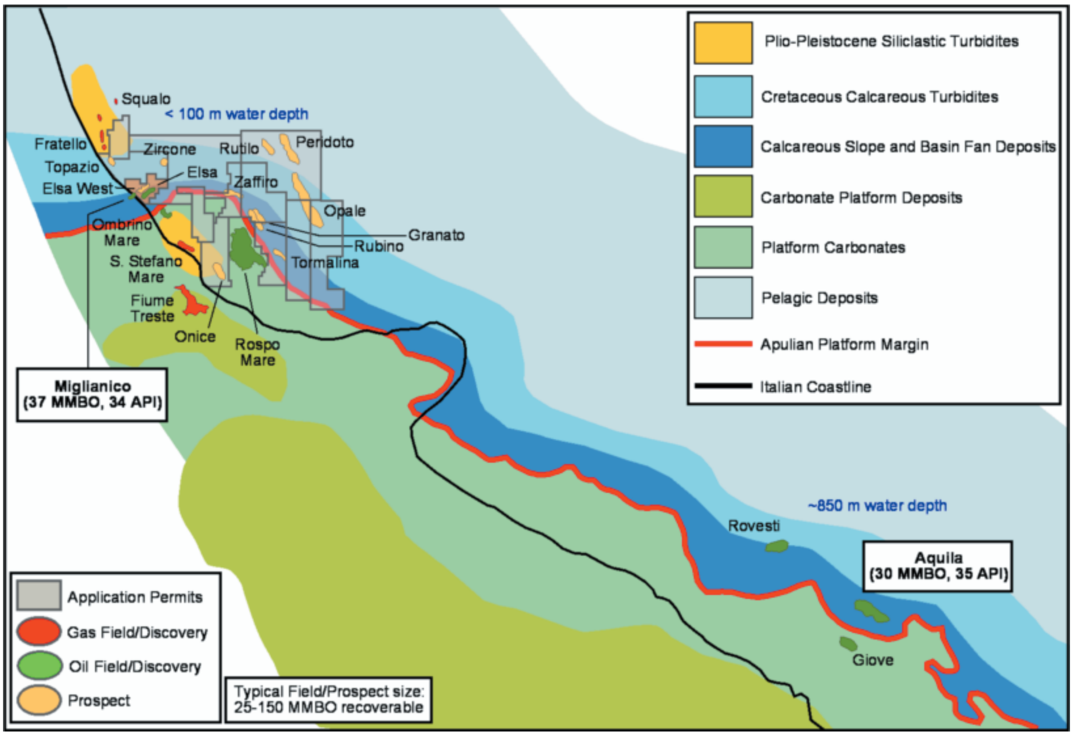


Figure 7 - Play/prospect map and Discovery Analogues for the Central Adriatic area

2.2. Seismic Interpretation

Data coverage over the B.R268.RG Permit is comprised of two 2D seismic vintages, 1976 Vaporchock and 1987-1989 Airgun. These datasets were reprocessed in 2008.

Interpretation of these datasets is complicated by a number of factors; a very noisy and low frequency content, seismic misties especially on the flanks due to migration artefacts and poor seismic imaging and resolution of the Elsa-1 top reservoir and minor faulting. The Elsa-1 structure is mapped as a northeast to southwest trending structural feature with generally steep flanks in all directions except to the South West where only low relief closure is recognised within the 2D dataset (see Figure 2). Regional geology and sparse onshore data indicate that there is likely to be there is likely to be closure to the southwest. There is the additional possibly of stratigraphic trapping in this direction. The acquisition of a 3D seismic survey is recommended to provide better trap and reservoir distribution definition; however, it is recognised that due to proximity of the coastline and environmental restrictions within 3 nautical miles of the shoreline, it is not possible to acquire data to prove southwest structural closure. Figure 8 and Figure 9 show arbitrary lines of section along and cross-strike to the structure. It is envisaged that an appraisal well on the mapped West Elsa prospect would follow a successful Elsa-2 appraisal well. A new 3D survey would be a pre-requisite to target selection.

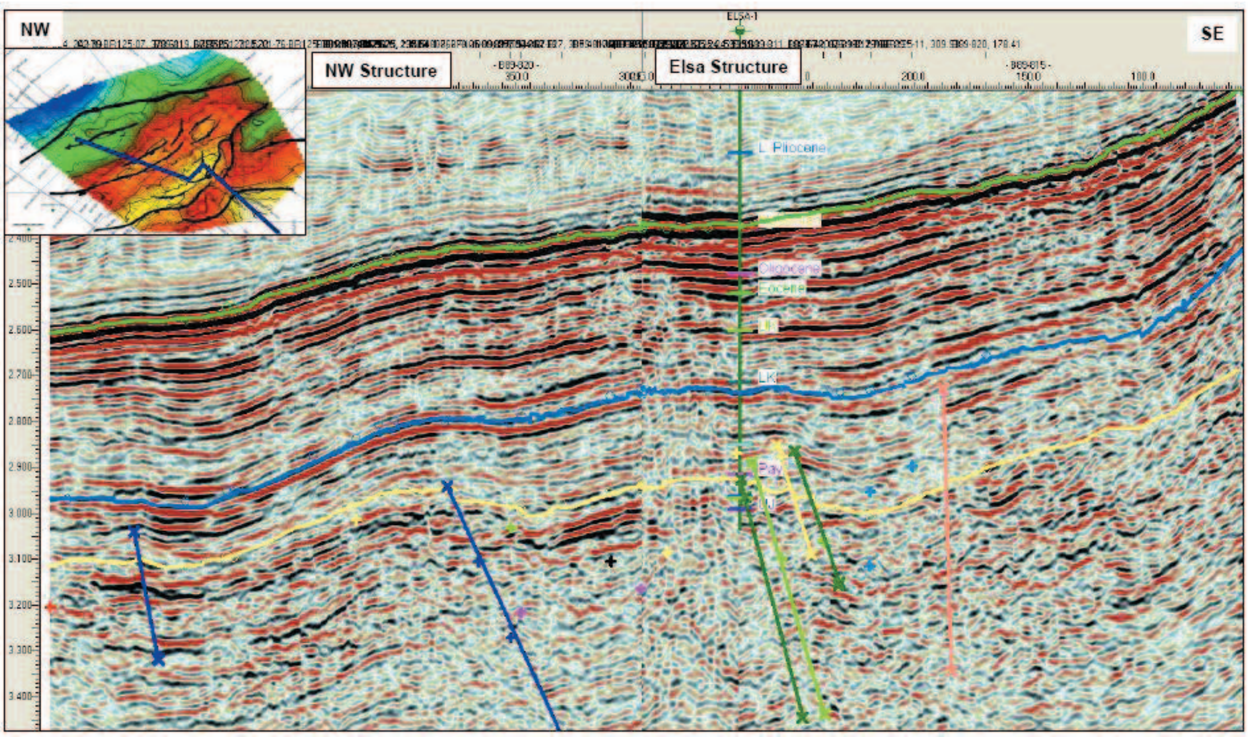


Figure 8 - Arbitrary section NW to SE through Elsa and NW Prospect

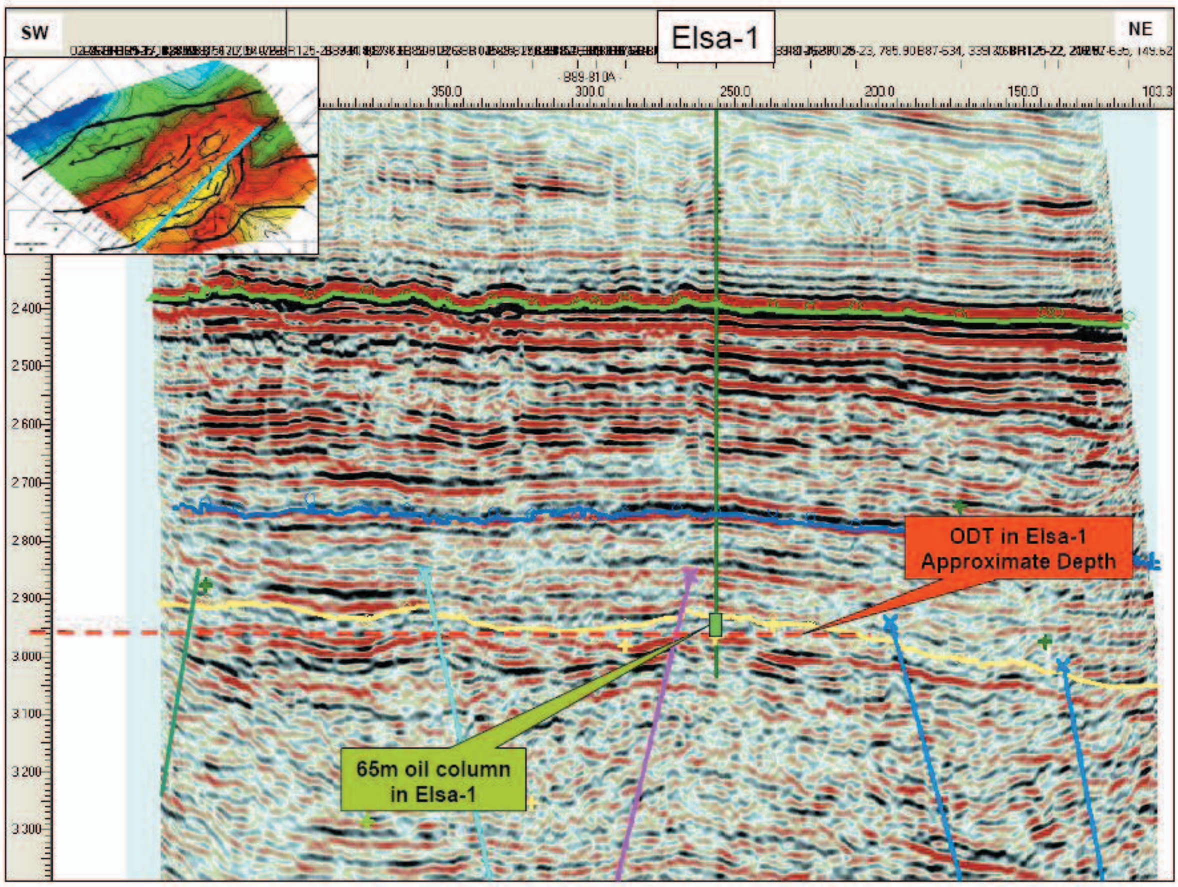


Figure 9 - Line B89-810A SW to NE along strike (Elsa)

Depth conversion to the top reservoir is based on velocity data from the Elsa-1 well only, as shown in Figure 10.

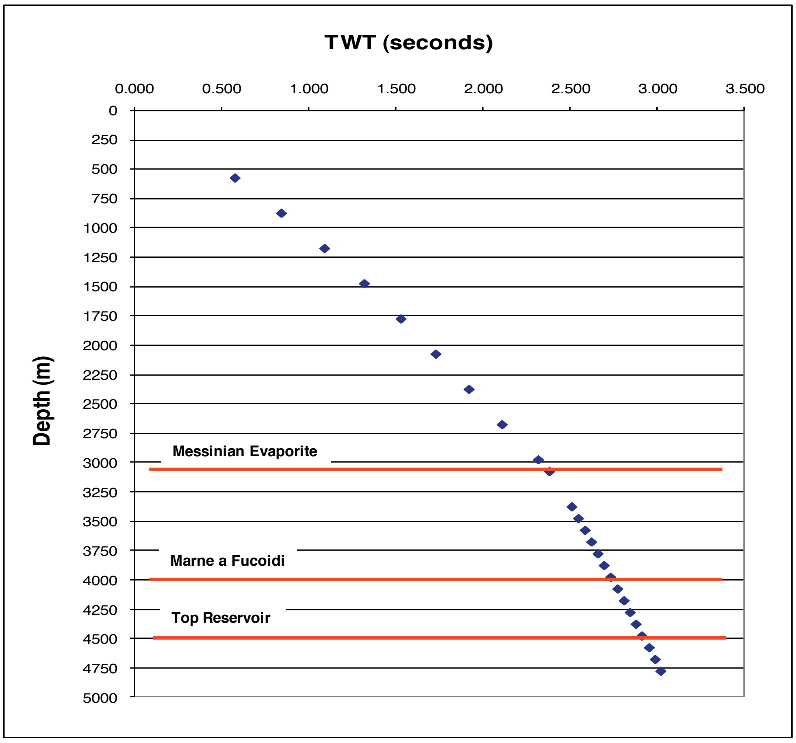


Figure 10 - Elsa-1 Time/Depth Plot

A three layer depth conversion model (Figure 10 and Figure 11) has been used to generate a top Reservoir Depth structure map (Figure 2).The three intervals used were;

1. MSL to Messinian Anhydrite
2. Messinian Anhydrite to Marne a Fucoidi
3. Marne a Fucoidi to Top Reservoir

For the interval from surface to the Messinian Evaporite event there is a clear time/depth trend which has been used to depth convert to the top Messinian Evaporite. Layers 2 and 3 were depth-converted using an interval velocity versus TWT function for each layer. The resulting Top Reservoir Depth map was tied to the well and is shown in Figure 2. This method of depth conversion is a reasonable approach given the data available i.e. just the Esla-1 well. However, there are clear limitations in using just one well not least the lack of velocity control on the deeper parts of the structure. A review of the offset wells to provide additional velocity information is recommended, assuming such data is available.

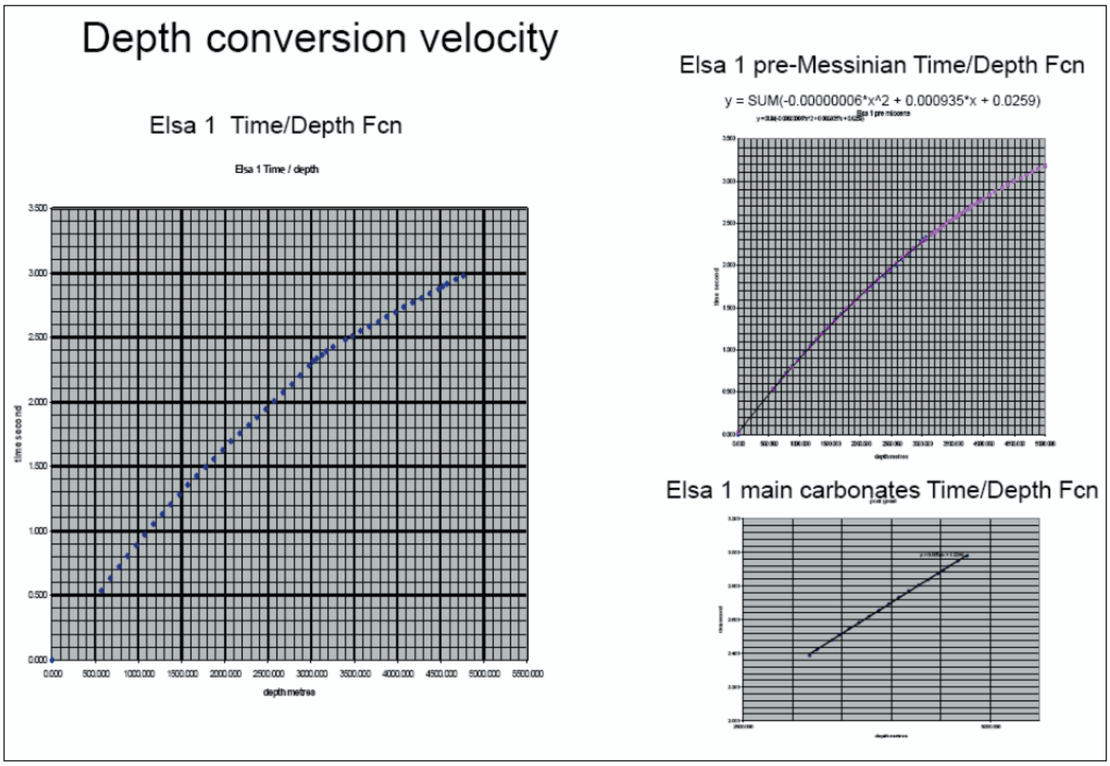


Figure 11 - Elsa-1 Time/Depth Functions used in the Depth Conversion

2.3. Field Exploration History (Elsa-1)

The Elsa-1 vertical exploration well was drilled by Agip in 1992 in the Central Adriatic Sea in Italy, in 34 m water depth and approximately 7 Km offshore. The primary target was a structure interpreted as an inverted block of Liassic Platform (Massicco Formation) sealed by sediments similar to the deep structural settings of the Aquila and Rovesti oil fields in the Southern Adriatic. The target depth of the principal objective was 4,500 m TVss. The secondary target for the well was the Cretaceous Scaglia Formation at a prognosed depth of 3,450 m TVss.

The Scaglia Formation was encountered close to prognosis at 3,422 m TVss within structural closure, but was dry as no porous resedimented intervals were present. The well then encountered the top Upper Jurassic/Lower Cretaceous Maiolica Formation at 4,228 m TVss. At approximately 4,500 m TVss a 65 m oil column was encountered within the Maiolica in good quality reservoir. Four cores were cut in the Maiolica Formation, the first three at the beginning of the oil shows (4,350 – 4355 m TVss, 4357 – 4359 m TVss, 4355 – 4357 m TVss) and one in the main hydrocarbon bearing section (4,513 – 4,520 m TVss) which had intergranular and intercrystalline porosity of 19% and permeability in the range from 12 to 200 mD. Drilling continued to some 4,800 m TVss before logging and testing the penetrated oil bearing interval. Figure 12 shows the formations, contacts and shows encountered in the 6" section.

Following log acquisition, a sand plug was placed in the well covering the lower intervals. The top of the sand was at approximately 4,550 m TVss, leaving a 50 m section of the main hydrocarbon bearing interval open. The 7" casing shoe was however, set at 4,322 m TVss, leaving a total interval of 228 m exposed during the test. The subsequent test failed to deliver sustained flow to the surface. Oil samples were, however, recovered on reverse circulation of the test string contents after each of the three in-flow periods. Laboratory analysis of recovered oil samples from the last flow period indicated an API gravity of 13.2 °API with no H_2S. From log and core analysis, the main reservoir is fully dolomitized with an average porosity of 19%, permeability ranging from tens to hundreds of millidarcies and a water saturation of less than 25%. Further details of the test results are discussed in Section 2.3.2.

After testing, the well was deepened and top Massiccio Formation was encountered at 4,808 m. Total losses were encountered however, leading to a decision to plug and abandon the well after cutting a final core from 4,840 to 4,841.5 m MD and without further testing of the Maiolica Formation.

The Elsa-1 well confirmed the exploration assumption of source rock presence etc., but showed that the reflector interpreted as top Massicco instead corresponds to an Upper Jurassic/Lower Cretaceous intra Maiolica Formation basin floor fan redeposited from the nearby platform margin/slope. This highly-porous, dolomitized, basin floor fan which forms the main reservoir at Elsa-1, is composed of calciturbidites, slumps and remobilized material coming from the Apulian Platform slope. The dolomitization distribution in Elsa-1 appears to be controlled by the characteristics of the sediments and not by the faults and fractures. The intercalation of the more dolomitic and more calcareous levels corresponds to the original layers and indicates that the more porous levels acted as fluid carrier beds allowing pervasive dolomitization.

The original Massicco Formation primary target was dry because there was no seal between the Maiolica basin floor fan and the Massicco Formation.

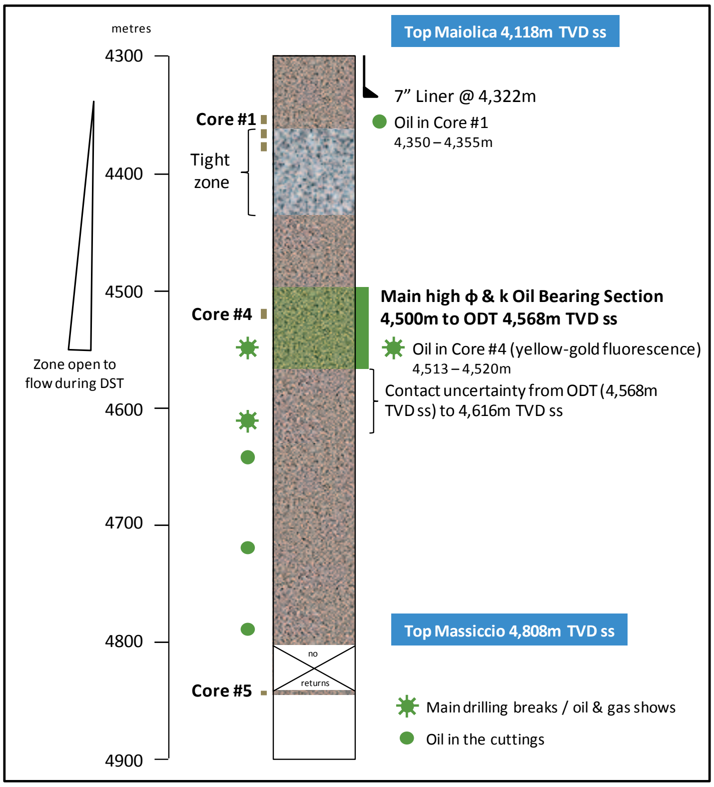


Figure 12 - Summary of the 6" hole section

2.3.1. Elsa-1 Petrophysics

Elsa-1 contains a significant thickness of dolostone interbedded with minor limestones that form the main reservoir section. A total of 85m is considered to be of reservoir quality, split into 3 distinct zones.

The well was logged in 1992 with a standard triple combo wireline suite, and sonic. The section was drilled in 6" hole and the well is within gauge throughout the reservoir section. The wireline logs are of good to excellent quality and were used within this analysis with no edits applied. Table 2 below shows the logs used in the analysis.

Table 2 - Elsa raw log audit

LOG	Type	Comments
GR	Spectral	POTA, URAN and THOR
SP		Erratic towards base of reservoir
RES	Array induction	9 depths of investigation
RES	Laterlog	3 depths of investigation
Cali		
RHOB	Density	Bulk density with density correction factor
NPHI	Neutron	
DT	Sonic	Both compressional and shear borehole compensated
PEF		Photoelectic lithology curve

A brief discussion of the results of the petrophysical analysis is shown below:

Lithology

The lithology curve was derived by cross-plotting neutron, density and PEF responses; the lithology curve is used to identify gross lithologies for input into a variable grain density porosity calculation.

The identified lithologies of limestone and dolomite have matrix density values of 2.71 g/cc and 2.85 g/cc respectively.

Volume of Clay

The clay volume (VCL) was calculated as the average of values determined from the gamma ray, neutron and density logs. In general VCL calculations are low when carbonates are encountered; however the VCL log indicates a reasonable reduction in reservoir quality with depth. This is also apparent from the total porosity calculation.

Porosity

Three porosity measurements are available; from density, neutron and sonic logs. For a reliable calculation of porosity, primary porosity is calculated from the sonic response with the density log as the preferred option for the computation of secondary porosity.

Three distinct reservoir sections are highlighted by porosity classification. Section A, from 4500 m to 4566 m MD, contains porosities in the region of 14% to 26%, Section B contains porosities from 7% to 21% and Section C contains porosities from 1% to 14%.

All log derived porosities are calibrated against the core derived porosity where available and are in good agreement.

Comparisons between the sonic (primary) and density (secondary) porosity indicates the possible presence of fractures, which may contribute to well performance or vugs which tend to be isolated and do not contribute.

The erratic nature of the micro-resistivity tool may be indicative of fractures, although it is not an uncommon response in carbonates and could be related to drilling artefacts at the borehole wall.

Permeability

Two porosity-permeability trends are apparent in the core data; the two trends represent horizontal and vertical permeability. The core measured data is shown in Figure 13. No further analysis has been undertaken on permeability.

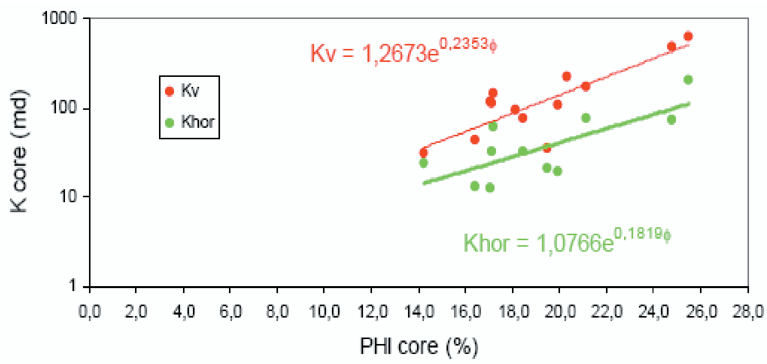


Figure 13 - Core derived K_v and K_h

Water Saturation

A simple Archie model was applied to calculate water saturation. There are a significant number of uncertainties regarding input parameters and it was felt that a simple Archie is robust in this situation.

Several sources of R_w are quoted and each give significant differences. Firstly R_w from Pickett is not recommended to be taken on its own as a reliable section of water bearing reservoir cannot be seen, however a rough approximation of Rw can be estimated. The second method of water sample analysis leads to two different Rw values based upon which samples are analysed.

The low value of Rw is calculated from a salinity of 2 kppm, this is thought to be too low and may represent drilling fluids. The second value of Rw is calculated from a measured salinity of 21 kppm, which is in broad agreement with Pickett of 0.595 Ohm-m at reservoir temperatures.

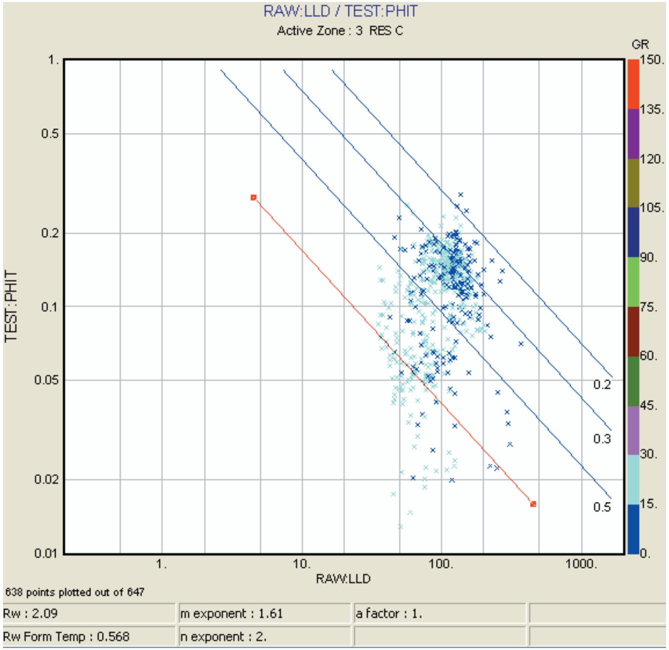


Figure 14 - Pickett plot from Maiolica formation, Section B indicating a good Rw estimate of 0.595 and an 'm' value of 1.61 fits through the log data

The value of the saturation exponent 'm' is taken directly from the Pickett plot (Figure 14) based on the best fit line through the water bearing reservoir. From this, a value of 1.61 is assumed to be representative. The cementation factor 'n' is taken to be 2.2; this is a reasonable assumption for carbonates.

Section A water saturations are relatively low, and the section contains a very high net to gross; on average Sw through this section is 27%. Section B saturations are more erratic, mostly due to reduced porosities but possibly due to the presence of the Oil Water Contact. Average saturations for this section are higher than for Section A at 39% while net to gross is significantly reduced to 38%. Section C is considered to be water wet, with significant reduced porosity.

From comparisons of Sw and Swxo the mobility of the oil appears to be poor.

Fluid Contacts

Three fluid contacts have been identified. The first at the base of Section A is defined as an Oil-Down-To (ODT) of 4566 m MD (4563 m TVss) the second is classed as an Oil-Water-Contact (OWC) and is placed at the top of a section of reservoir where the resistivity curves separate at 4580 m MD (4577 mTVss) and finally a possible OWC is seen at the top of Section C at 4619 m MD (4616 m TVss); this is based on the deepest section of porous reservoir.

Sums and Averages

Three sets of sums and averages have been derived, each with a different porosity cut-off to reflect uncertainty around oil mobility. The results are tabulated in Appendix 1.

A CPI log for the evaluation is shown as Figure 15.

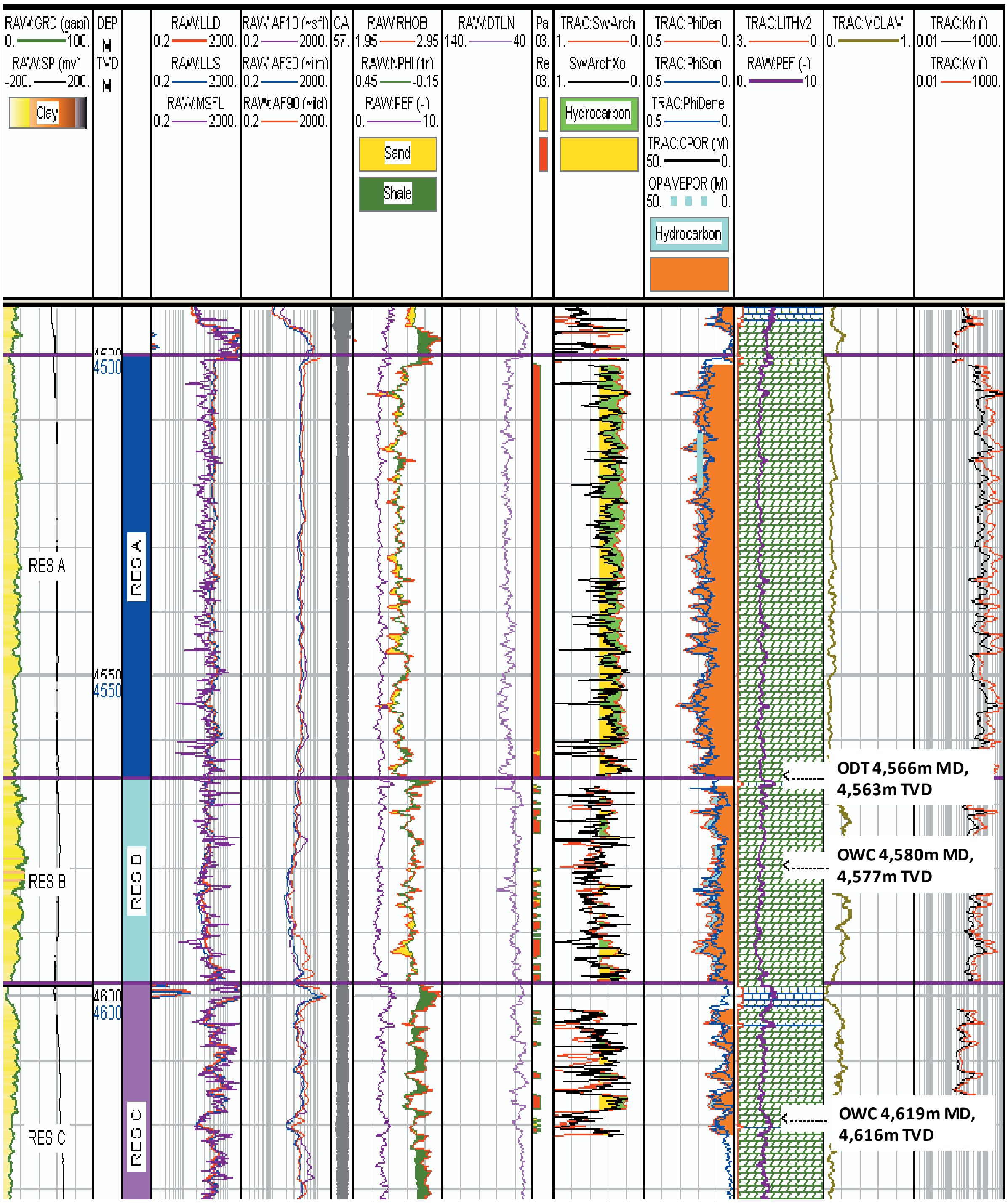


Figure 15 - CPI log for Elsa-1

2.3.2. Elsa-1 Test Results

As discussed in Section 2.3, the oil bearing interval of interest within the Maiolica Formation was tested within a significant open hole interval. Testing operations conducted on the formation were unfortunately not optimal for the following key reasons:

a. The formation of interest had been exposed to overbalanced mud weights of 1.05 SG for four weeks prior to test leading to potential formation damage. As core permeabilities were in the range 12-200 mD, skin damage was very likely. The pay section was not cleaned up with acid prior to testing.

b. No representative downhole oil sample was collected at reservoir conditions for analysis. Contaminated dead oil samples were collected at surface only on reverse circulation of drill string contents containing mixed fluids (contamination by mud, mud filtrate and/or water).

c. Underlying (and possibly overlying) water bearing zones were not isolated during the test and probably contributed to water production seen in the test (oil leg has an S_w of approximately 25%).

The drill stem test (DST) was conducted through a 3 ½" drill string with a down-hole test valve. The test packer was set inside the 7" casing at 4,302 m MD. Three tests were performed with the summary of the test results shown in Table 3. During the first two tests no flow to surface was reported. The third flow period saw decreasing water production and small volumes of oil flow to surface. Mixed fluid samples were recovered on reverse circulation of the test string contents (approximately 13.4 m^3) after each flow period. The quantity of hydrocarbons increased from 1,900 litres on the first flow to 3,400 litres on the second and 6,500 litres on the third.

A dead oil sample recovered from the third test period was analyzed by an Agip lab with the resultant report giving a measurement of 13.2 °API; with a range in possible API of 12 - 15 °API. The sample was possibly contaminated so potential may exist for the crude to have a higher API than reported. This is also suggested by drill cutting fluorescence and regional analogue. Oil and gas shows reported during drilling by EXLOG indicate yellow-gold fluorescence suggesting light oil in the range of 25° to 35° API, while Lower Cretaceous field Miglianico at ±4,900 m has a crude oil gravity of 34° API. Evaluation of the development for a low viscosity oil has not been considered within this report as Elsa-1 test data suggests that the possibility of having crude with specific gravity higher than 20° API is low. However, given the uncertainty regarding crude PVT properties, the potential for lighter crude should not be excluded as an upside. The Elsa-2 appraisal well will resolve the acknowledged PVT uncertainty.

Table 3 - DST flow results from Elsa-1 well

Test Activity	Flow Period #1	Flow Period #2	Flow Period #3
Nitrogen Lift:	From 4,000 m. Recover 12.5 m3 mud 1.03 g/lt. THP 285 Kg/cm2.	From 4,100 m. Recover 13 m3 mud 1.03 g/lt. THP 287 Kg/cm2	From 4100m. Recover 12.8 m3 mud 1.02 g/lt THP 281 Kg/cm2.
Bleed THP down[1]:	From 285 to 189 Kg/cm2	From 287 to 201 Kg/cm2	From 281 to 206 Kg/cm2
Open Test Valve for BU[2]:	189 to 238 Kg/cm2 in 14 hours	201 to 241 Kg/cm2 in ¼ hour	206 to 244 Kg/cm2 in ¼ hour
Open Choke for Flow Period:	14.75 hours flow period. Choke open with zero WHP for last 13.5 hours.	8.25 hours flow period. Choke open with zero WHP for last 6.5 hours.	5.25 hours flow period. Choke open with 0.2 Kg/cm2 WHP for last 4 hours
Flow:	No fluids at surface. Fluid level 30 m. Reverse circulation of DST string contents.	No fluids at surface. Fluid level 35 m. Reverse circulation of DST string contents.	Liquids reported to be recovered to surface. Reverse circulation of DST string contents post test.
Fluids Recovered:	1.9 m3 oil 0.975 SG 11.5 m3 water 1.03 SG	3.4 m3 oil 10 m3 water	6.5 m3 oil 0.98 SG 6.7 m3 water

[1] Test valve closed
[2] Choke closed

2.4. Reservoir Fluid Properties Ranges

Samples taken of the oil in the production string are assumed to be de-gassed with a measured density of 13.2°API, with a range of 12° to 15°API reported from the Agip lab. The GOR could not be measured because of the low flow rates. H_2S was not detected. The lack of reliable samples leaves considerable uncertainty in the fluid properties. Correlations are useful in estimating associated properties, but usually require at least the GOR or bubble point pressure to be known. The neighbouring fields of Ombrina Mare and Miglianico have properties that are differing considerably from each other and also from Elsa, as shown in Table 4. Neither is an ideal analogue and this illustrates the potential range in regional fluid properties.

Table 4 - Offset field PVT properties

Parameter	Elsa	Ombrina Mare	Miglianico
Geological Horizon	L.Cretaceous	Neogene	Jurassic / L. Cretaceous
Depth (mTVDss)	4500	2090	4800
API Gravity (°)	±13.2	16	34
Viscosity (cP)	N/A	20	0.36
GOR (scf/stb)	N/A	104	1260
FVF (rb/stb)	N/A	1.095	1.6

A range of oil gravities has been selected from which the PVT properties have been estimated. The oil gravities assumed within this evaluation are 12°, 15° and 20°API. This range is thought to be representative of the possible outcomes for the development. These cases, applied deterministically in combination with the P90-P50-P10 STOIIP, form the basis for 1C-2C-3C Contingent Resource evaluation for the field. For each case, corresponding assumptions were made on the GOR, and the resultant formation volume factors and oil viscosities were estimated using Vasquez and Beggs correlations. The resultant PVT parameters are shown in Table 5.

Table 5 - PVT assumptions

	1C	2C	3C
Parameter	BC-1	BC-2	BC-3
Oil API	12	15	20
GOR (scf / stb)	100	237	300
FVF (rb / stb)	1.06	1.1	1.16
Oil viscicity (cP)	20.2	8.74	3.11

2.5. Hydrocarbon In-Place Estimates

In-place volume estimates for the Elsa discovery have been probabilistically derived. GRV computations for input estimates were based on the Maiolica Formation reservoir depth map as shown in Figure 2. The GRV computations were based on an area-depth curve approach constrained by P90-P50-P10 reservoir thickness, OWC depths and mapping uncertainty ranges. Based upon the petrophysical interpretation results, reservoir zones 'A' and 'B' were evaluated separately as the reservoir properties appear to be different. The input ranges for the GRV calculation for zones A and B are shown in Table 6 and Table 7 respectively while the resultant GRV ranges are shown in Table 8 and Table 9 respectively.

Table 6 - Input parameters for GRV range calculation zone A

Reservoir Thickness (m)			Contacts (mTVDss)			Mapping Uncertainty (%)		
P90	P50	P10	P90	P50	P10	P90	P50	P10
30	66	75	4,537.7	4,551.6	4,590.2	85	100	115

Table 7 - Input parameters for GRV range calculation zone B

Reservoir Thickness (m)			Contacts (mTVDss)			Mapping Uncertainty (%)		
P90	P50	P10	P90	P50	P10	P90	P50	P10
20	32	40	4,537.7	4,551.6	4,590.2	85	100	115

Table 8 - Elsa discovery GRV ranges for STOIIP calculation zone A

GRV (million m3)		
P90	**P50**	**P10**
559	732	943

Table 9 - Elsa discovery GRV ranges for STOIIP calculation zone B

GRV (million m3)		
P90	**P50**	**P10**
59	119	238

Based upon the petrophysical re-interpretation of the Elsa-1 log (see Section 2.3.1), L-M-H petrophysical parameters ranges were selected for the probabilistic analysis as show in Table 10 below.

Table 10 - Petrophysically derived reservoir property ranges for STOIIP calculation

	Zone A			**Zone B**		
	L	M	H	L	M	H
N/G (%)	75	85	98	25	47	96
Por (%)	14	17	20	10.5	13	15
So (%)	50	73	80	45	60	75

For fluid properties, ranges of 12°-13.2°-15°API were adopted as P90-P50-P10 values as these are based upon the measured data from the Elsa-1 well test. A discussion of reservoir fluid properties is shown in Section 2.4 while Table 11 shows the ranges used for the probabilistic calculation.

Table 11 - Fluid property ranges for STOIIP calculation

	P90	P50	P10
Oil density, °API	12	15	20
GOR, scf/stb	100	237	360
FVF, stb/bbl	1.06	1.1	1.15

The Probabilistic STOIIP calculations were made using Crystal Ball™. The resultant distributions and in-place volume ranges are shown below for Reservoirs A and B in Figure 16 and Figure 17 respectively.

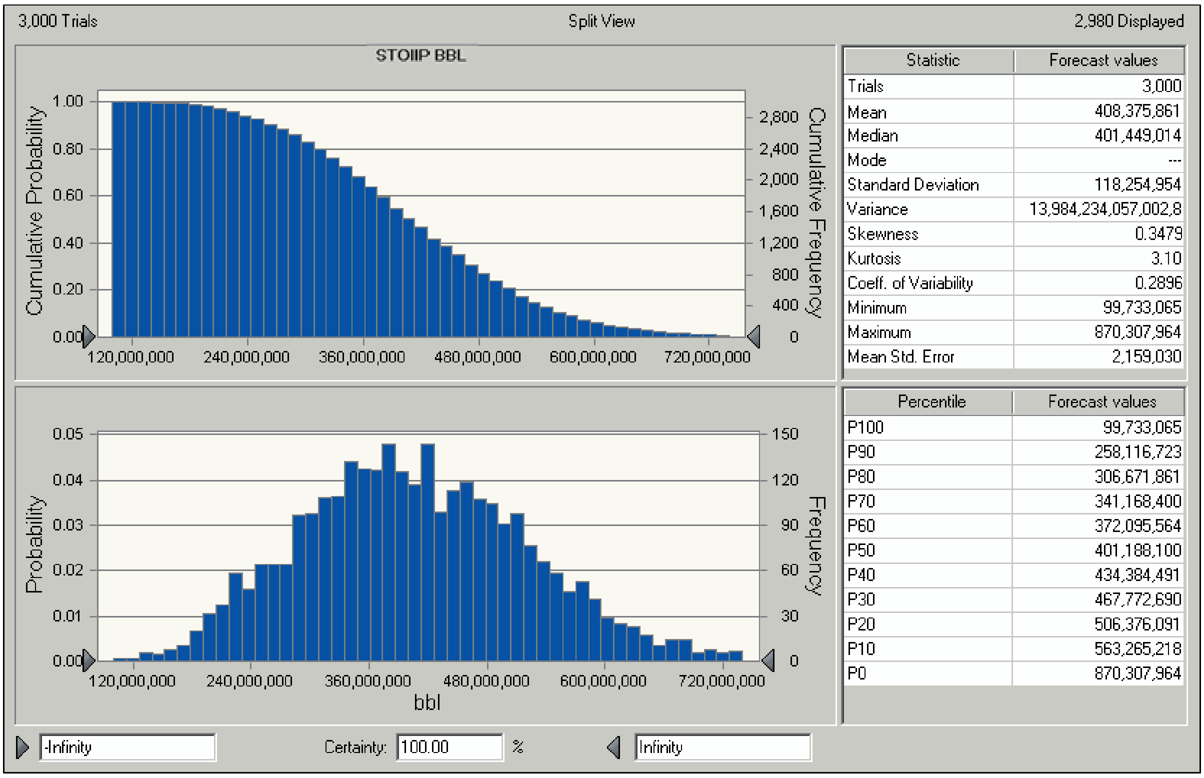
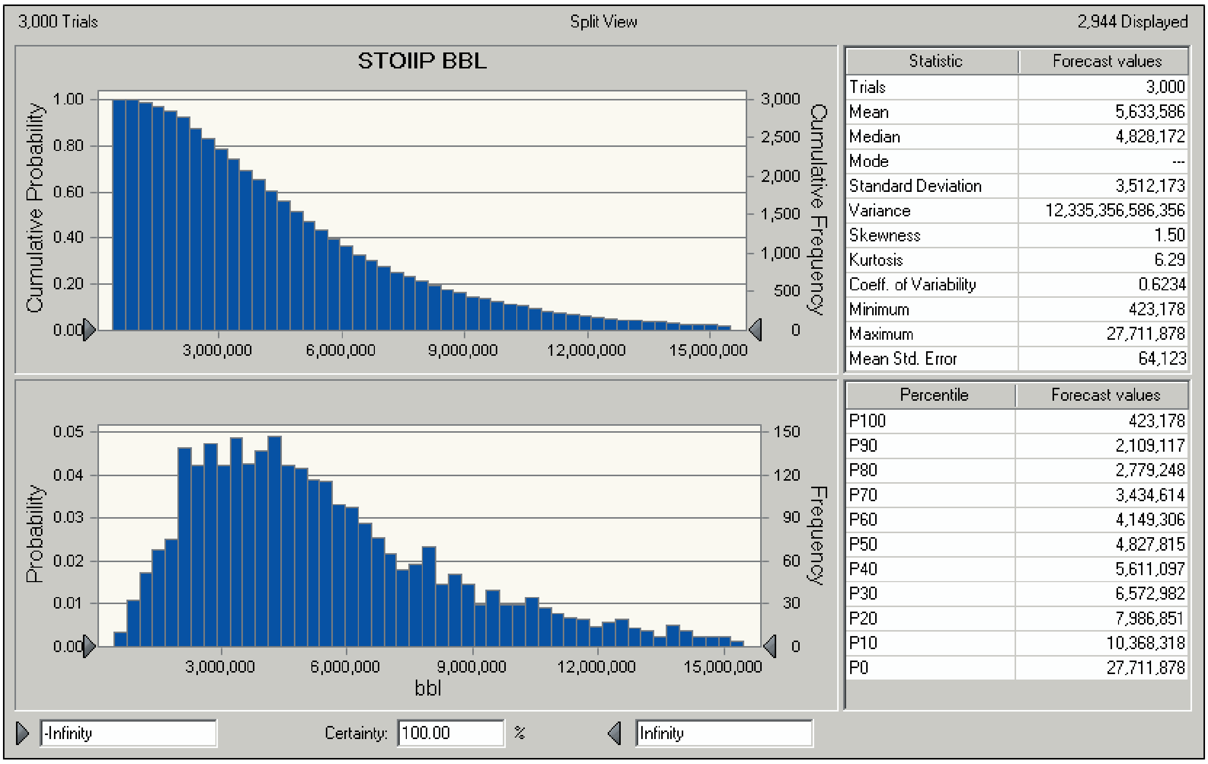


Figure 16 - Probabilistic in-place volume ranges for Elsa reservoir Zone A

A tabulated summary of volume ranges is shown for both reservoirs A and B in Table 12 below. It can be seen that the upper A zone holds the vast majority of the in-place volume. Zone A is of higher reservoir quality, has higher oil saturation, and is oil bearing throughout the entire section logged. Focus for the development evaluation has therefore been only zone A; zone B has not been considered as material within this study.

Table 12 - Summary of in-place volume ranges for Elsa

	STOIIP (MMBBL)		
	P90	**P50**	**P10**
Zone A	258	401	563
Zone B	2	5	10



Statistic	Forecast values
Trials	3,000
Mean	5,633,586
Median	4,828,172
Mode	---
Standard Deviation	3,512,173
Variance	12,335,356,586,356
Skewness	1.50
Kurtosis	6.29
Coeff. of Variability	0.6234
Minimum	423,178
Maximum	27,711,878
Mean Std. Error	64,123

Percentile	Forecast values
P100	423,178
P90	2,109,117
P80	2,779,248
P70	3,434,614
P60	4,149,306
P50	4,827,815
P40	5,611,097
P30	6,572,982
P20	7,986,851
P10	10,368,318
P0	27,711,878

Figure 17 - Probabilistic in-place volume ranges for Elsa reservoir Zone A

2.5.1. West Elsa Prospect

As well as the Elsa discovery, an additional structure has been mapped within the licence that represents potential upside. This prospect is known as West Elsa and is shown in Figure 18.

West Elsa is currently mapped deeper than the Elsa structure and, if the same OWC and rock property assumptions are assigned to the West Elsa structure, only minimal volumes are estimated in Zone A and none in Zone B. Table 13 shows the potential range of STOIIP and Resources for West Elsa based on these assumptions. The recovery factors derived for the Elsa discovery (see Table 17) have been used to determine the corresponding range of Prospective Resources in the Monte Carlo simulation. This scenario uses the dark blue polygon shown for GRV shown in Figure 18.

Table 13 - West Elsa STOIIP and Resources using Elsa OWC and Reservoir Properties

	STOIIP (MMBBL)			Resource (MMBBL)		
	P90	**P50**	**P10**	**P90**	**P50**	**P10**
Zone A	5.1	14.5	26.6	1.1	3.1	6.1

If the same OWC is assumed for the Elsa West structure, the resulting risk is relatively low. The primary geological risk for this case is the trap. As currently mapped there is no structural separation between Elsa and West Elsa so the trap cannot be adequately defined although if the OWC is the same as Elsa, structural separation is less critical.

Table 14 below provides an indication of the geological risk associated with the deep contact case for the West Elsa prospect.

Table 14 - West Elsa Geological Risk for Elsa OWC scenario

Parameter	Chance	Comments
Source	1.0	Presence of oil in Elsa and Miglianico suggests an active source and migration system is present and effective
Seal	0.80	Seal appears to be present although faulting may need to be relied on increasing the risk
Reservoir	0.80	Presence of reservoir in Elsa and Miglianico suggests reservoir presence is low risk. However, the fan geometry may add risk and the occurrence of poorer reservoir zones adds to uncertainty.
Trap	0.70	Lack of mechanism to separate West Elsa from Elsa although this is less of a risk if the OWCs are the same.
Overall	0.45	45% Chance of Success (or 1 in 2.2)

However, there is a possibility that the OWC could be deeper. The Miglianico Field which is located approximately 9 km to the South West of the Elsa-1 well has a significantly deeper contact than that seen in the Elsa discovery. It appears unlikely that the West Elsa prospect has the same OWC as Miglianico as this would require a major stratigraphic boundary between West Elsa and Elsa. A contact between the two OWCs currently identified for Miglianico and Elsa could be possible and represents a potential, albeit higher risk, upside.

Table 15 shows the range of unrisked STOIIP and Prospective Resources for this upside scenario. For GRV calculations, It has been assumed that the same range of reservoir thicknesses and reservoir properties would apply as for the Elsa discovery (refer to Table 7, Table 8, Table 10 and Table 11). An OWC of 4700 m TVss was assumed. Again, the recovery factors derived for the Elsa discovery (Table 17) have been used to determine the corresponding range of Prospective Resources in the Monte Carlo simulation.

Table 15 - West Elsa STOIIP and Resources using a 4700 m TVss OWC and Elsa Reservoir Properties (unrisked)

	STOIIP (MMBLS)			Resources (MMBLS)		
	P90	**P50**	**P10**	**P90**	**P50**	**P10**
Zone A	110	214	416	23	47	95
Zone B	20	34	54	4	7	12

This deeper contact case also allows for an additional upside scenario which includes an area to the northeast of the West Elsa prospect (shown as a pink polygon in Figure 18). This was included in order to incorporate an additional, smaller structural high but only as a P10.

The primary geological risk for this upside case is the trap. As currently mapped there is no structural separation for the deeper contact between Elsa and West Elsa so the trap cannot be adequately defined. The Table below provides an indication of the geological risk associated with the deep contact case for the West Elsa prospect.

In order to mitigate this risk, a 3D seismic survey is recommended that should improve both the imaging of the reservoir and the definition of the fault geometry leading to a better understanding of the trap.

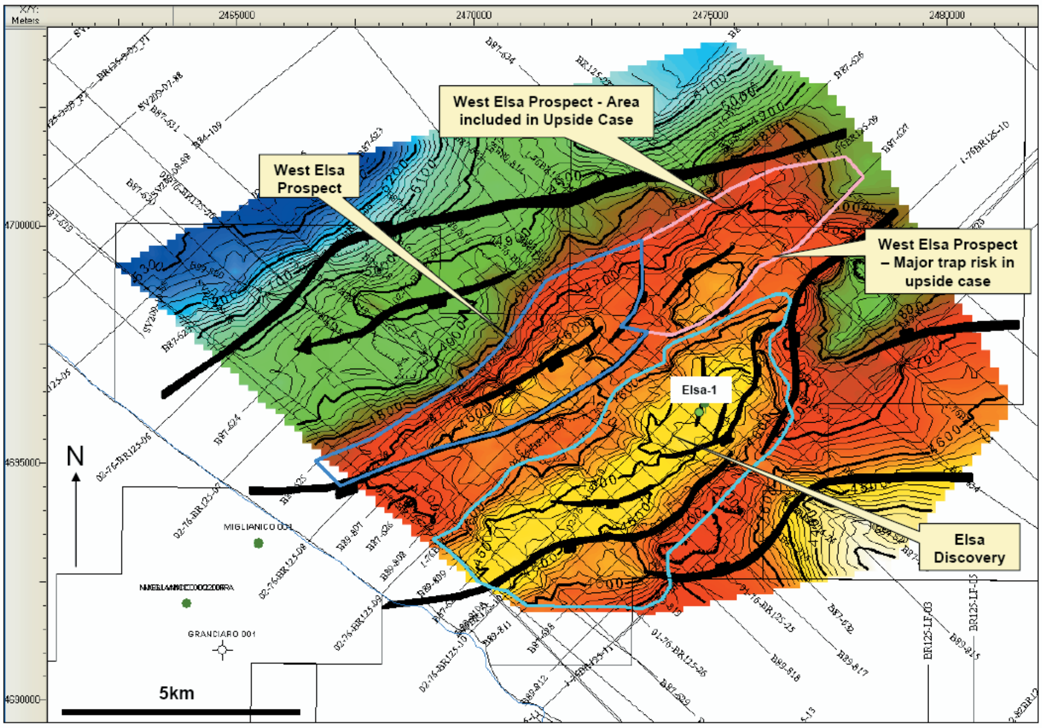


Figure 18 - Top Reservoir Depth structure map - Elsa West Prospect

Table 16 - West Elsa Geological Risk for 4,700m contact scenario

Parameter	Chance	Comments
Source	1.0	Presence of oil in Elsa and Miglianico suggests an active source and migration system is present and effective
Seal	0.80	Seal appears to be present although faulting may need to be relied on increasing the risk
Reservoir	0.80	Presence of reservoir in Elsa and Miglianico suggests reservoir presence is low risk. However, the fan geometry may add risk and the occurrence of poorer reservoir zones adds to uncertainty.
Trap	0.40	Lack of mechanism to separate West Elsa from Elsa for the deeper contact case is a major risk
Overall	0.26	26% Chance of Success (or 1 in 3.8)

The deep contact upside case (pink polygon) would carry a higher risk than the 26% shown above due to the lack of a currently mapped continuous fault to provide structural closure to the northeast, as shown in Figure 18.

2.6. Estimation of Field Recovery Factor Ranges

Recovery factors have been estimated for the three cases of 12°, 15° and 20°API. The Elsa-1 core analysis data allowed a porosity-permeability relationship to be derived (see Figure 13). This relationship was applied to the whole logged interval, giving a calculated permeability log. The range in permeabilities was then used in a Stiles model[3] to estimate the vertical sweep in a layered reservoir for each of the PVT property sets. This yielded a range in recovery factors (primarily viscosity-dependent) and, by projecting to a 95% water cut, allowed a recovery factor to be estimated. Table 17 shows the resultant technical recovery factors derived from the model while Figure 19 shows the fractional flow curves derived from the Stiles model for the three cases.

As can be seen from Table 17 and Figure 19, moving to lighter, less viscous crude has a significant impact on achievable recovery. The recovery factors in Table 17 are technical recovery factors only and are subject to economic limit testing.

[3] Wm. E. Stiles, "Use of Permeability Distributions in Water Flood Calculations", 1949

Table 17 - Calculated Technical Recovery Factors for the API ranges

	1C	2C	3C
Oil density, °API	12	15	20
RF, %	13.4	21.2	31.9

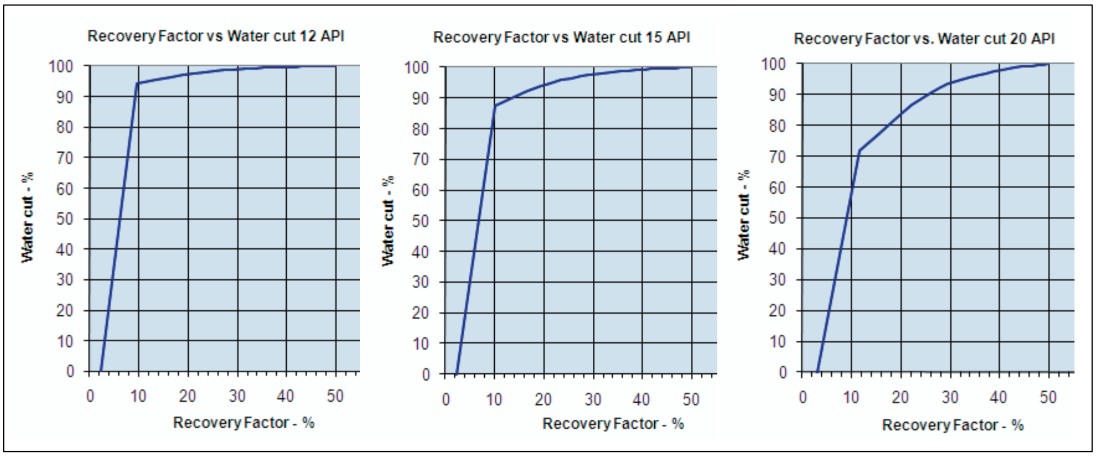


Figure 19 - Derived fractional flow curves for Base Case crudes

3. Development Concepts

In the Central Adriatic Sea there are a number of offshore developments. Santo Stefano Mare 26 km away (connected to Santo Stafano onshore at Torino di Sangro) and Rospo Mare 48 km away are both in production and are operated by Edison. Mediterranean Oil and Gas's Ombrina Mare discovery is offshore 13 km away and is in the development planning stages. The onshore discovery Miglianico (ENI) is only 11 km away but development planning for this field is currently on hold because of local legislative issues.

In the scenario of low gravity oil being produced (12°API) the oil would likely be taken direct to refinery vacuum distillation units and then further upgraded to produce light and middle distillates. Thus, the likely market outlets would be to refineries with deeper and more extensive conversion capacity. At 20°API, the oil quality would allow access to a broader and deeper range of refiners.

3.1. Identification of Development Scenarios

Given the distance to existing offshore infrastructure, tie back and tolling is not considered as a viable option. A range of technically feasible development concepts have therefore been assessed within this report, catering for the low (L), mid (M) and high (H) cases previously defined, with the most likely development concept involving an FPSO vessel and a complete offshore solution as this minimizes the environmental footprint of the Elsa development. Accordingly, produced oil will be exported by shuttle tanker.

Two conductor supported minimal facilities wellhead platforms (WHPs) have notionally been located in the central field area and in the North East area of the field at the proposed Elsa-2 appraisal well location. The final development plan will be determined based on the results of the Elsa-2 appraisal well and will be subject to technical and environmental approval by the Italian Authorities as mandated by Italian Hydrocarbon Licensing regulations. All operations associated with the Elsa project will be carried out in compliance with Petroceltic's HSSE management, as summarized in Appendix 2.

All development wells are considered to be horizontal and landed in the A reservoir zone with drain hole lengths of up to 2,000m. The requirement for artificial lift (ESPs) is anticipated. All produced gas in excess of offshore power requirements, estimated to be 6-7 MW, is to be disposed of by injection into dedicated disposal wells. Produced water will be injected down-dip for pressure maintenance. Depending on aquifer strength, make-up water may be required.

3.1.1. Sub-surface Development Concepts

A range of sub-surface development concepts has been evaluated for different in-place volumes and oil viscosities. The Reference Cases for the evaluation are the P90-P50-P10 STOIIP tied to 12-15-20 °API gravity (with corresponding viscosity assumptions). These reference cases in combination are referred to as Ref Case L, Ref Case M and Ref Case H respectively. Evaluation of these cases determine the 1C-2C-3C Contingent Resource values for the field. A conceptual sub surface development plan for each case has been constructed identifying:

- Number of producers and well offtake rates
- Production well placement on a structural map
- Number of required injectors (gas and water-cut)

In specifying conceptual sub surface developments for the individual cases, the following assumptions have been made:

1. The mapped structure extends from the North East Elsa-1 area to the South West (onshore direction) out of the seismic survey area and closes.
2. The field is not compartmentalised.
3. Reservoir rock of equivalent quality and thickness to that seen in Elsa-1 extends throughout the field (GRV distribution ranges are accounted for in probabilistic STOIIP determination but not in deterministic well rate calculations and fractional flow behaviour where a uniform 65m thickness is assumed).
4. Up to 2000 m horizontal drain length wells can be drilled and landed at ±4,550 m vertical depth with step-outs of up to ±4,000 m.
5. Wells are produced on artificial lift – assumed to be ESPs. Variable speed drives (VSDs) are available so that pump lift rate may be increased with increasing water cut and resultant changes to well productivity (resulting from relative permeability effects).
6. All produced water is injected down-dip from the withdrawal zone. Injection wells are capable of a maximum injection rate of 20,000 to 30,000 bbl/day. Each scenario carries one additional 'swing' injector to maintain capacity should an injector well be off-line.
7. In all cases where the total produced gas exceeds the power consumption requirement (>7MMSCFD), excess gas disposal via injection is assumed (i.e. no value has been attributed to produced gas). A sales gas solution may be feasible at higher GOR's. This has not been considered in this report and no gas resources have been booked.

Table 18 shows the specific development concept detail associated with each of the Reference cases.

Table 18 - Scenarios evaluated for Concept Assessment

Case	Volume (MMbbls)	Oil properties		Development wells		
		API	Viscosity (cp)	Producers[1)]	Water injectors	Gas injectors
Ref Case L	260	12	20.2	6	3	0
Ref Case M	406	15	8.74	8	4	1
Ref Case H	573	20	3.11	10	5	1

1) Including Elsa-2

3.1.1.1. Artificial Lift Selection

To effectively produce from these wells, the deployment of artificial lift will almost certainly be required, in the form of Electrical Submersible Pumps (ESPs) or Progressive Cavity Pumps (PCPs) depending on viscosity.

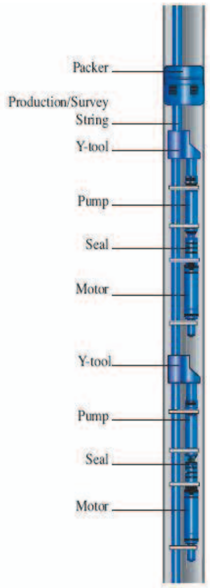
- The **Electric Submersible Pump** is an advanced multistage centrifugal pump, driven directly by a downhole electric motor. The ESPs output is more or less pre-determined by the type and number of pump stages. At significant additional cost, a variable speed drive (VSD) can be installed to allow the motor speed, and thus the flow rate, to be changed. Without installation of a VSD, changes in well productivity are hard to accommodate. This is of particular relevance for heavy oil production with increasing water cut due to relative permeability effects.

- The **Progressive Cavity Pump** consists of a rotating cork-screw like sub-surface assembly which is driven by a surface mounted motor or electric submersible motor. The flowrate achieved is mainly a function of the rotational speed of the subsurface assembly. There is in principle very little that can go wrong with progressive cavity pumps. Progressive cavity pumps excel in wells with viscous crude oils and can also handle significant quantities of produced solids.

ESPs have been used increasingly as an artificial-lift method to produce medium-to-heavy oils in deep offshore fields. In very heavy oil (e.g. 12°API), PCPs may be required.

At anticipated Elsa oil viscosities, deployment of ESPs (or PCPs) will be essential to achieve viable production in field development. Planned testing of the Elsa-2 appraisal with an ESP pump will establish rate, fluid properties and downhole conditions thus allowing appropriate pump design for the development phase.

In offshore configurations, where well intervention requires a drilling rig or support vessel, pump failure can lead to lost production, potentially for an extended period. Completion design may therefore offer redundancy through dual pump installation where, in the event of ESP failure, a back-up ESP already deployed in the well can be immediately turned on to maintain production.



A second ESP is suspended below the upper ESP with a bypass assembly. Bypass tubing provides a production path for the lower ESP. Normally the upper ESP is run first to prevent temperature affecting the backup system. The lower ESP can be appropriately sized to accommodate changes in well performance such as decreasing reservoir pressure or increasing water cut. This configuration can maintain production rates and delay expensive workovers.

Figure 20 - Dual ESP Configuration

Depending on the well condition and the characteristics of the oil and solids concentration a combination of ESP and PCP pump may be necessary. An Electric Submersible PCP (ESPCP) could be deployed in combination with a VSD. The ESP motor drives the cavity pump. This type of pump can be installed in deviated and horizontal wells have been successfully deployed in South American heavy oil fields (containing as low as 8°API oil).

Cost will be a significant factor in the pumps selected and in their manner of deployment. Dual ESPs can be prohibitively expensive depending on the alloys and steel used in their construction to compensate for reservoir and wellbore conditions. Pump design and selection will therefore add a significant cost to the overall field development; particularly where a configuration is required to reliably produce the heavy oil and associated fluids. This reliability can have a direct effect on the development's viability.

3.1.2. Surface Development Concepts

A number of surface development concepts were selected for initial, conceptual level, field development planning and costing purposes. Given a drive to minimize the environmental footprint of the Elsa development, the most likely development concept will involve an FPSO vessel and a complete offshore solution. All production is assumed to be sweet i.e. minimal levels of CO_2/H_2S.

The Floating Production, Storage and Offloading (FPSO) vessel solution has been assumed to take the following shape:

Two light-weight 4-leg WHPs, each accommodating up to ten wells (producer, water injection or gas injection) are tied back to a turret-moored FPSO. Fully stabilised crude is exported via shuttle tanker. Down-hole ESPs are required to lift well crude/water streams. All wells are assumed to be drilled (and worked-over) using a jack-up rig. All wellheads located on two remote minimum facilities conductor supported wellhead platforms (a maximum of 16 production, gas injection and water injection wells). Allowance has been made for one gas injection well (since there are likely to be gas volumes surplus to requirements here e.g. gas for power generation). Production flowlines and water/gas injection lines run between each WHP and the FPSO. All production flowlines are well insulated (for flow assurance purposes). Crude is exported via shuttle tanker.

All development wells are considered to be horizontal with drain hole lengths of between 1000 m and 2000 m. The requirement for Artificial lift (ESPs) is anticipated. All produced water is taken to be re-injected for reservoir pressure maintenance purposes. All produced gas in excess of offshore power requirements (estimated at 6-7 MW) is considered to be disposed of via injection in dedicated disposal wells, as is produced water. No value is therefore attributable to the gas stream.

3.2. Generation of Production Profiles

Production profiles were generated for each case. The maximum horizontal well offtake rates were calculated for the various oil properties using Joshi's equation[4] assuming a horizontal permeability of 31 mD, kv/kh of 0.25, a 65 m reservoir thickness and a 6" drainhole. Ref Case L assumes a 2000 m horizontal drain length and artificial lift exerting a drawdown (Δp) of 3,000 psi, Ref Case M assumes a 1500 m horizontal drain length and a Δp of 3,000 psi while Ref Case H assumes a 1000 m horizontal drain length and Δp of 2,000 psi. Furthermore, as the well water cut changes with time, so will the well productivity due to a combination of relative permeability effects and the lower viscosity of the water. These were factored into the Joshi equation so that both oil and water rates were calculated at different water cuts tied to the relevant oil viscosity.

Case specific well forecasts were generated to honour the relevant fractional flow profiles (as discussed in Section 2.6) and relative permeability effects. Well profiles were then rolled up to field level which also honoured the relevant fractional flow curve. Forecasts were run for a 30 year period and a forecast summary is shown in Table 19. ESPs are assumed to be installed with surface VSDs to allow production rate to be maximised within the imposed drawdown constraints. During regular ESP pump maintenance workovers, larger volume lift will need to be installed in later years to handle the forecast volume water.

Pre-drilling of the majority of production wells is assumed prior to first oil. With more than one WHP in each scenario, it may be necessary to have two jack-up rigs working concurrently to achieve the schedule reflected in the forecast. After drilling and testing Elsa-2, more detailed evaluation of potential development phasing will be required in the concept assessment phase.

The generated production forecasts were used to assess the recoverable volumes (Contingent Resources). All forecasts assumed 95% uptime.

Table 19 - Forecast results summary

		Peak Field Rates				Well IP[1]	Final W/C	UR	RF
	Case ID	BOPD	BWPD	BFPD	MMSCFD	(BOPD)	(%)	(MMBO)	(%)
1C	Ref Case L	13,500	38,000	40,000	1.2	2,700	95	34.2	13.2
2C	Ref Case M	29,900	97,000	100,000	7.1	5,500	97.1	95.0	23.4
3C	Ref Case H	49,150	135,000	140,000	19.2	8,000	96.3	186.5	32.6

[1]*Initial Production rate*

[4] S.D. Joshi, "Horizontal Well Technology, PennWell Books, 1991

Reference Case L

The production profile for the 1C Contingent Resource case is shown in Figure 21. Five production wells give a forecast peak oil rate of 13,500 bopd. All producers are assumed to come on-stream at the beginning of field production. One water injector is drilled pre-production with two further injectors drilled in years three and nine. During the economic project life of 23 years, 34.2 MMbbl of oil is recovered (with 205 MMbbl of produced water) at a recovery factor of 13.2% and abandonment water cut of 95%. 60% of the forecast ultimate recovery is achieved above a water cut of 50%.

Reference Case M

The production profile for the 2C Contingent Resource case is shown in Figure 22. Seven production wells give a forecast peak oil rate of 38,500 bopd. Four producers are assumed to come on-stream at the beginning of field production, with three added in month seven with tie-back of a further WHP. One water injector is drilled pre-production with three further injectors drilled in years two, five and eight. During the 30-year forecast period 95 MMbbl of oil is recovered (with 768 MMbbl of produced water) at a Recovery Factor of 23.4%. Water cut at year 30 is 97.2%. Above 50% water cut, 70% of the forecast Ultimate Recovery is achieved.

Reference Case H

The production profile for the 3C Contingent Resource case is shown in Figure 23. Nine production wells give a forecast peak oil rate of 55,000 bopd. Four producers are assumed to come on stream at the beginning of field production, with three added in month seven with tie-back of a further WHP. One water injector and one gas injector are drilled pre-production. Four further water injectors are drilled in years two, four, six and seven. During the 30 year forecast period 186.5 MMbbl of oil is recovered (with 1,098 MMbbl of produced water) at a recovery factor of 32.6%. Water cut at year 30 is 96.4%. Above 50% WC, 72% of the forecast Ultimate Recovery is achieved.

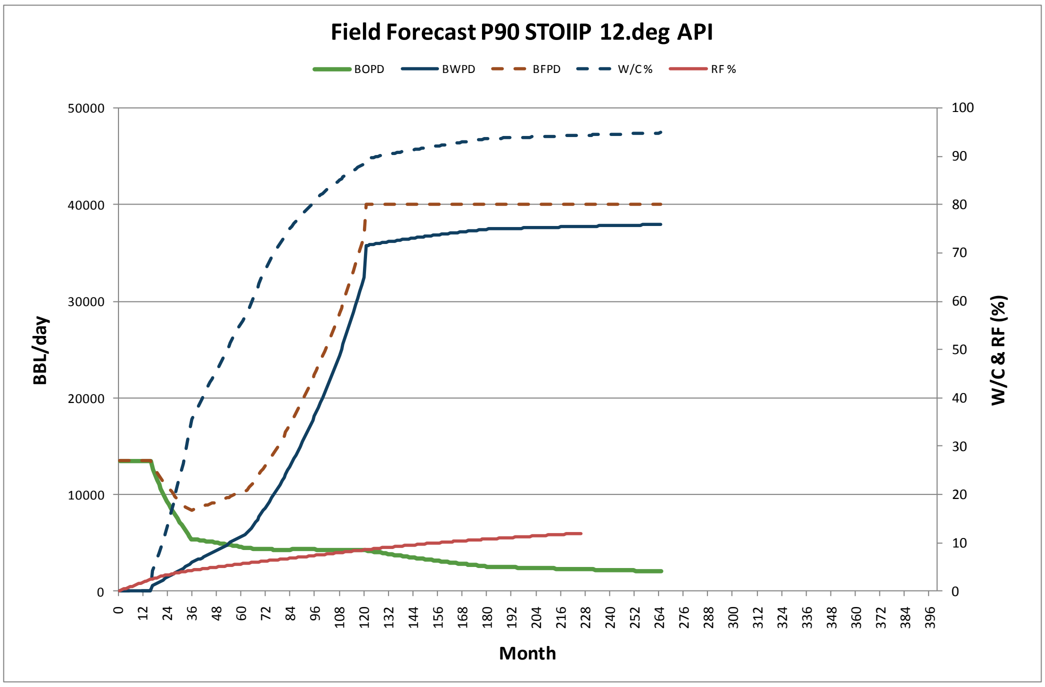


Figure 21 - P90 Forecast Reference Case L

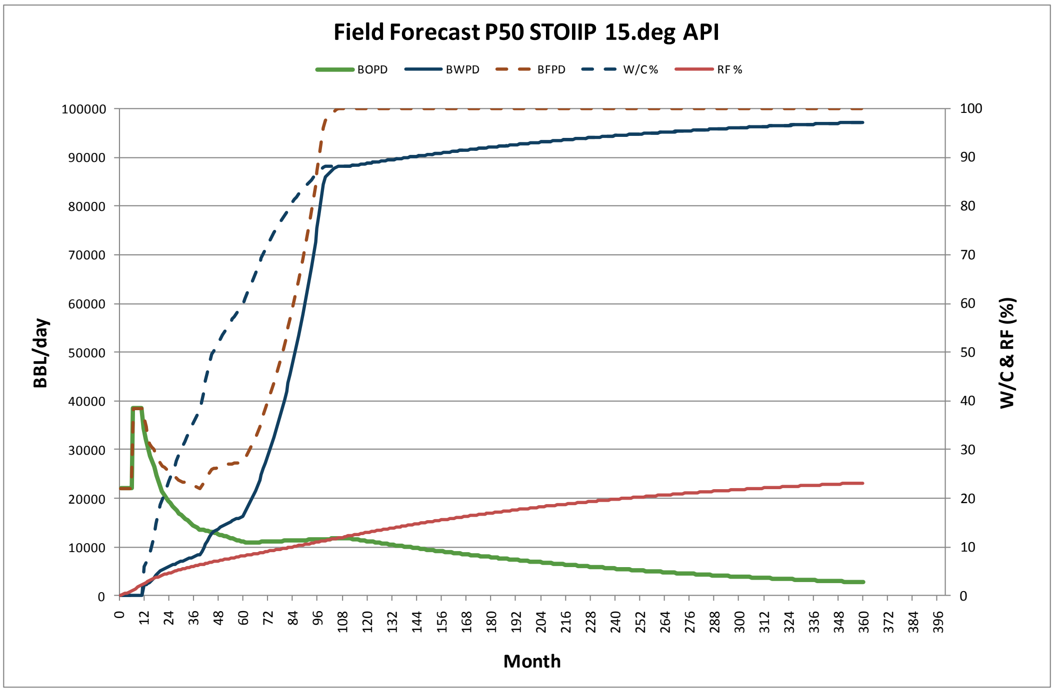


Figure 22 - P50 Forecast Reference Case M

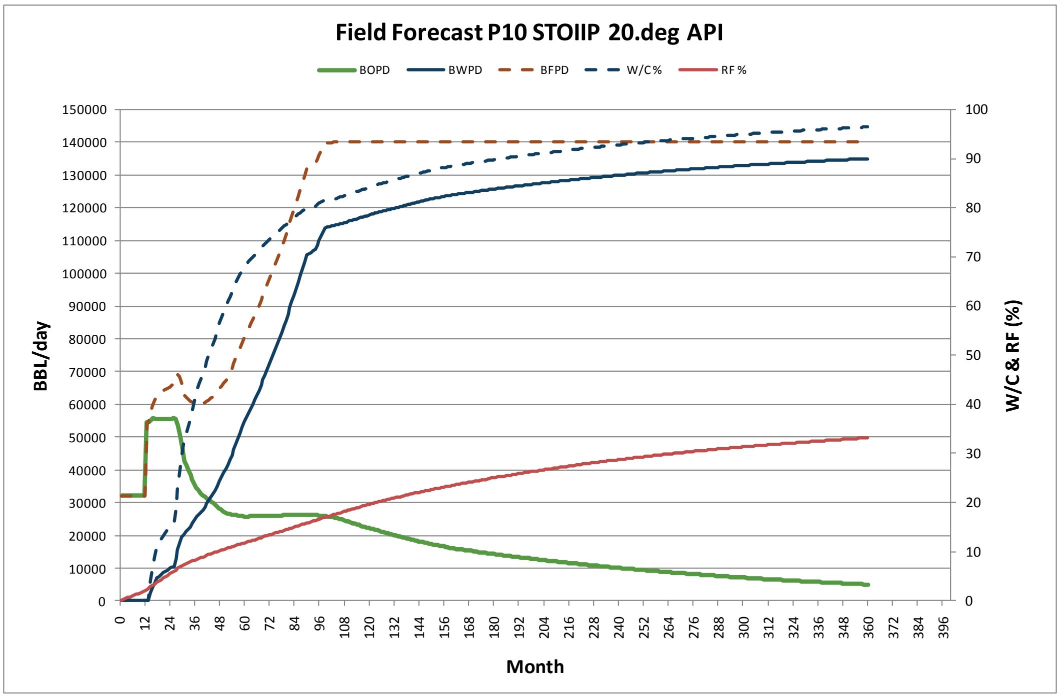


Figure 23 - P10 Forecast Reference Case H

Nomenclature

Δp	pressure differential
°API	American Petroleum Institute gravity[5]
bbl	barrel
bfpd	barrels of fluid per day
boe	barrels of oil equivalents
bopd	barrels of oil per day
bwpd	barrels of water per day
CPF	central processing facility
DST	drill stem test
dwt	deadweight tons
ESP	electric submersible pump
FPSO	floating production, storage and offload
FVF	formation volume factor
GOR	gas-oil ratio
k_h	horizontal permeability
k_v	vertical permeability
mD	millidarcy
MD	measured depth
MMbbl	million barrels
MMbo	million barrels of oil
MMboe	million barrels of oil equivalents
MMscf/d	million standard cubic feet per day
Mw	megawatt
ODT	oil-down-to
OWC	oil-water contact
Pxx	xx percent chance of being exceeded
PCP	progressive cavity pump
ppm	parts per million
psi	pounds per square inch (of pressure)
PVT	pressure, volume, temperature
RF	recovery factor
R_w	water resistivity
SG	specific gravity (air = 1.0 or water = 1.0)
scf	standard cubic foot
stb	stock tank barrel
STOIIP	stock tank oil initially in place
S_w	water saturation
S_{wxo}	water saturation of flushed zone
TVD	true vertical depth
UR	ultimate recovery
VSD	variable speed drive
WC or W/C	water cut
WHP	Wellhead platform

[5] *API gravity is a measure of how heavy or light a petroleum liquid is compared to water. If its API gravity is greater than 10, it is lighter and floats on water; if less than 10, it is heavier and sinks. API gravity is thus a measure of the relative density of a petroleum liquid and the density of water, but it is used to compare the relative densities of petroleum liquids.*

Appendix 1: Sums and averages tables

CUTOFF SUMMARY REPORT

Well : Elsa 1
Date : 11/09/2009 16:42:44

Reservoir SUMMARY

Zn #	Zone Name	Top	Bottom	Gross	Net	N/G	Av Phi	Av Sw	Av Vcl Ari	Phi*H	PhiSo*H
1	RES A	4500.00	4565.91	65.91	$$64.85	0.984	0.187	0.280	0.081	12.12	8.73
2	RES B	4565.91	4598.37	32.46	$$31.01	0.955	0.106	0.476	0.229	3.30	1.73
3	RES C	4598.37	4700.00	101.63	$$12.65	0.124	0.095	0.466	0.152	1.20	0.64
	All Zones	4500.00	4700.00	200.00	$$108.51	0.543	0.153	0.332	0.131	16.62	11.10

Pay SUMMARY

Zn #	Zone Name	Top	Bottom	Gross	Net	N/G	Av Phi	Av Sw	Av Vcl Ari	Phi*H	PhiSo*H
1	RES A	4500.00	4565.91	65.91	$$63.93	0.970	0.188	0.277	0.081	12.02	8.68
2	RES B	4565.91	4598.37	32.46	$$16.84	0.519	0.121	0.401	0.213	2.05	1.23
3	RES C	4598.37	4700.00	101.63	$$7.01	0.069	0.102	0.317	0.155	0.71	0.49
	All Zones	4500.00	4700.00	200.00	$$87.78	0.439	0.168	0.296	0.112	14.78	10.40

CUTOFFS USED

Zn #	Zone Name	Top	Bottom	Min. Height	Phi TRAC:PhiDene	Sw TRAC:SwArch	Vcl TRAC:VCLAV
	Reservoir						
1	RES A	4500.00	4565.91	0.	>= 0.05		<= 1.
2	RES B	4565.91	4598.37	0.	>= 0.05		<= 1.
3	RES C	4598.37	4700.00	0.	>= 0.05		<= 1.
	Pay						
1	RES A	4500.00	4565.91	0.	>= 0.05	<= 0.5	<= 1.
2	RES B	4565.91	4598.37	0.	>= 0.05	<= 0.5	<= 1.
3	RES C	4598.37	4700.00	0.	>= 0.05	<= 0.5	<= 1.

Depth Units : m

CUTOFF SUMMARY REPORT

Well : Elsa 1
Date : 11/09/2009 16:43:30

Reservoir SUMMARY

Zn #	Zone Name	Top	Bottom	Gross	Net	N/G	Av Phi	Av Sw	Av Vcl Ari	Phi*H	PhiSo*H
1	RES A	4500.00	4565.91	65.91	$$64.54	0.979	0.188	0.280	0.081	12.11	8.72
2	RES B	4565.91	4598.37	32.46	$$15.32	0.472	0.129	0.419	0.206	1.98	1.15
3	RES C	4598.37	4700.00	101.63	$$5.79	0.057	0.117	0.370	0.146	0.67	0.43
	All Zones	4500.00	4700.00	200.00	$$85.65	0.428	0.172	0.303	0.108	14.76	10.30

Pay SUMMARY

Zn #	Zone Name	Top	Bottom	Gross	Net	N/G	Av Phi	Av Sw	Av Vcl Ari	Phi*H	PhiSo*H
1	RES A	4500.00	4565.91	65.91	$$63.78	0.968	0.188	0.277	0.081	12.01	8.68
2	RES B	4565.91	4598.37	32.46	$$12.42	0.383	0.133	0.393	0.201	1.65	1.00
3	RES C	4598.37	4700.00	101.63	$$4.42	0.043	0.118	0.292	0.152	0.52	0.37
	All Zones	4500.00	4700.00	200.00	$$80.62	0.403	0.176	0.291	0.104	14.17	10.04

CUTOFFS USED

Zn #	Zone Name	Top	Bottom	Min. Height	Phi TRAC:PhiDene	Sw TRAC:SwArch	Vcl TRAC:VCLAV
	Reservoir						
1	RES A	4500.00	4565.91	0.	>= 0.1		<= 1.
2	RES B	4565.91	4598.37	0.	>= 0.1		<= 1.
3	RES C	4598.37	4700.00	0.	>= 0.1		<= 1.
	Pay						
1	RES A	4500.00	4565.91	0.	>= 0.1	<= 0.5	<= 1.
2	RES B	4565.91	4598.37	0.	>= 0.1	<= 0.5	<= 1.
3	RES C	4598.37	4700.00	0.	>= 0.1	<= 0.5	<= 1.

Depth Units : m

CUTOFF SUMMARY REPORT

Well : Elsa 1
Date : 11/09/2009 16:43:07

Reservoir SUMMARY

Zn #	Zone Name	Top	Bottom	Gross	Net	N/G	Av Phi	Av Sw	Av Vcl Ari	Phi*H	PhiSo*H
1	RES A	4500.00	4565.91	65.91	$$63.78	0.968	0.188	0.279	0.081	12.02	8.67
2	RES B	4565.91	4598.37	32.46	$$8.15	0.251	0.148	0.395	0.191	1.20	0.73
3	RES C	4598.37	4700.00	101.63	$$2.13	0.021	0.129	0.336	0.138	0.27	0.18
	All Zones	4500.00	4700.00	200.00	$$74.07	0.370	0.182	0.290	0.095	13.50	9.58

Pay SUMMARY

Zn #	Zone Name	Top	Bottom	Gross	Net	N/G	Av Phi	Av Sw	Av Vcl Ari	Phi*H	PhiSo*H
1	RES A	4500.00	4565.91	65.91	$$63.02	0.956	0.189	0.277	0.081	11.92	8.62
2	RES B	4565.91	4598.37	32.46	$$7.39	0.228	0.149	0.382	0.189	1.10	0.68
3	RES C	4598.37	4700.00	101.63	$$1.68	0.016	0.129	0.267	0.150	0.22	0.16
	All Zones	4500.00	4700.00	200.00	$$72.09	0.360	0.184	0.285	0.094	13.24	9.46

CUTOFFS USED

Zn #	Zone Name	Top	Bottom	Min. Height	Phi TRAC:PhiDene	Sw TRAC:SwArch	Vcl TRAC:VCLAV
	Reservoir						
1	RES A	4500.00	4565.91	0.	>= 0.12		<= 1.
2	RES B	4565.91	4598.37	0.	>= 0.12		<= 1.
3	RES C	4598.37	4700.00	0.	>= 0.12		<= 1.
	Pay						
1	RES A	4500.00	4565.91	0.	>= 0.12	<= 0.5	<= 1.
2	RES B	4565.91	4598.37	0.	>= 0.12	<= 0.5	<= 1.
3	RES C	4598.37	4700.00	0.	>= 0.12	<= 0.5	<= 1.

Depth Units : m

Appendix 2: HSSE (Health Safety Social Development Environment)

Petroceltic manages its activities through a formal HSSE management system, aimed at ensuring that all activities are carried out with diligence and integrity and that maximum attention is paid to safeguarding the environment, and the health and safety of both the company's workers and the communities within which we operate. The company is committed to carefully planning its operations to minimize the risk of incidents that could cause damage to people or to the environment and to avoiding the release of polluting substances into the environment.

All Petroceltic employees and contractors are expected to apply the Corporate HSSE policy and to identify and communicate any potential hazards within their working environment such that these may be quickly remedied. The Company monitors and reports on its HSSE performance with the aim of learning from any near misses or incidents, thereby ensuring continuous improvement of its systems and procedures.

Petroceltic employs highly experienced and qualified personnel, covering the entire spectrum of activities from exploration through to production. Petroceltic employees have worked in a wide range of challenging environments including: deepwater, high temperature-high pressure and remote locations and have experience of a wide range of geographies including: Italy, the North Sea, Australia, Canada, W Africa, Egypt, FSU, Azerbaijan, South and South-East Asia

Petroceltic is committed to working with National, Regional and Local Authorities to ensure that stakeholder interests are incorporated into project execution plans. The company is committed to establishing mutually beneficial relationships with the communities within which it operates, with the aim of positively contributing to their development. The company is committed to working in collaboration with local institutions and, where possible, to employing local people and companies.

2.1 HSSE in the Appraisal and Development Phases

The Elsa-2 well and any subsequent development activities will be carried out under Petroceltic's HSSE standards, together with the high HSE standards defined in Italian Law. A number of specific measures will be taken with the aim of minimizing the potential environmental impact of the project:

- The dimensions of drilling and production facilities will be minimized to reduce environmental footprint
- Drilling operations will be carried out during periods of the year selected to minimize impact on local flora and fauna and on tourism
- Drilling operations will be carried out utilizing a zero discharge rig with all waste material collected and disposed of onshore at licensed waste disposal sites
- Noise will be continuously monitored, and if exceeding the allowed levels, special noise reduction equipment will be installed on the rig mast and / or around the engines.
- During drilling activities, transportation of material to and from the rig will be scheduled so as to minimize ships movements.

- Well design will focus on minimizing the diameter of the wellbore to reduce energy demand and to minimize the volume of waste rock material (cuttings) generated

- Drilling will be carried out using water-based muds contained within a closed circulating system; the project will be designed to minimize any necessity for flaring

- Appropriate Emergency Response Plans & Oil Spill Response Plans will be in place prior to the commencement of operations

- Regularly scheduled inspections of drilling and production facilities and safety systems will be held to ensure their integrity and to review operating procedures

- The site will be restored following completion of Petroceltic's activities

2.2 HSSE during geophsyical data acquisition

Any geophysical data will be acquired under Petroceltic's HSSE standards, together with the high HSE standards defined in Italian Law. Before starting any geophysical acquisition, the relevant authorities will be informed, as required by law, to ensure that all nearby shipping is aware of the operations. Any operations will be conducted during periods of the year selected to minimize the impact on local flora and fauna and on tourism and the survey will be programmed to minimize duration and fuel consumption. Petroceltic will ensure that the geophysical contractor carrying out the operations follows high standards of equipment maintenance and housekeeping aimed at minimizing waste; that any discharge is compliant with the MARPOL convention; and that any solid waste is disposed of onshore at licensed waste disposal sites

Particular attention will be given to operating in a way that will minimize the impact on any Marine Mammals in the immediate vicinity of the survey:

- Animals will be alerted to the imminent start of seismic activities via a "soft start" process, so that they can autonomously move away from the survey area. This is achieved via the ramp-up protocol, where by seismic activity starts from a low level and is slowly built up to operating levels over a period of 20-40 minutes. Whenever geophysical acquisition is stopped for a period longer than 20 minutes, the ramp-up procedure is repeated.

- A safety area of 500m around the airguns will be established and will be closely monitored by experts from 30 minutes before activation of the airguns. If a Marine Mammal moves into this area then geophysical acquisition will be terminated until 30 minutes after the animal has left the safety area.

Appropriate Emergency Response Plans will be in place prior to the commencement of operations.

Inclusion 1: A Summary of Definitions and Guidelines for the Society of Petroleum Engineers 'Petroleum Resources and Management System'

The full text of the SPE PRMS Guidelines can be viewed at:

www.spe.org/industry/reserves/docs/Petroleum_Resources_Management_System_2007.pdf

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.

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 sulfide and sulfur. In rare cases, non-hydrocarbon content could be greater than 50%. The term "resources" as used herein is intended to encompass all quantities of petroleum naturally occurring on or within the Earth's crust, discovered and undiscovered (recoverable and unrecoverable), plus those quantities already produced. Further, it includes all types of petroleum whether currently considered "conventional" or "unconventional." Figure 1-1 is a graphical representation of the SPE/WPC/AAPG/SPEE resources classification system. The system defines the major recoverable resources classes: Production, Reserves, Contingent Resources, and Prospective Resources, as well as Unrecoverable petroleum.

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. 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 quantities are also measured and required to support engineering analyses based on reservoir voidage.

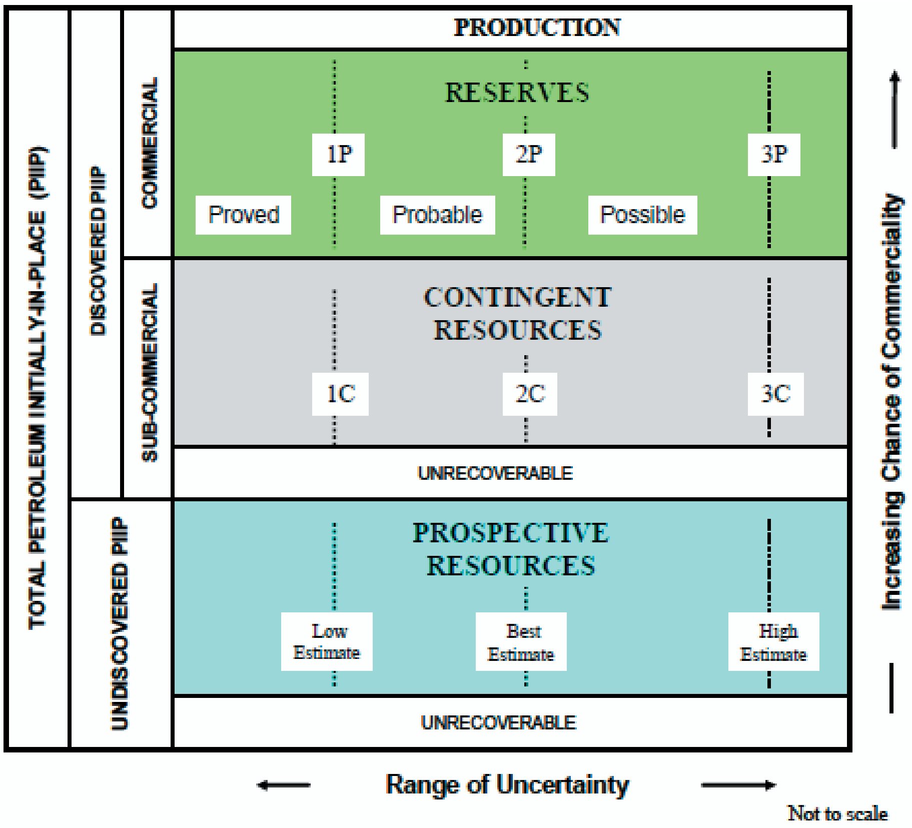


Figure 1-1: Resources Classification Framework

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.

CLASSIFICATION AND CATEGORIZATION GUIDELINES

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

Additional background information on resources classification issues can be found in Chapter 2 of the 2001 SPE/WPC/AAPG publication: "Guidelines for the Evaluation of Petroleum Reserves and Resources," hereafter referred to as the "2001 Supplemental Guidelines."

Resources Classification

The basic classification requires establishment of criteria for a petroleum discovery and thereafter the distinction between commercial and sub-commercial projects in known accumulations (and hence between Reserves and Contingent Resources).

Determination of Discovery Status

A discovery is one petroleum accumulation, or several petroleum accumulations collectively, for which one or several exploratory wells have established through testing, sampling, and/or logging the existence of a significant quantity of potentially moveable hydrocarbons. In this context, "significant" implies that there is evidence of a sufficient quantity of petroleum to justify estimating the in-place volume demonstrated by the well(s) and for evaluating the potential for economic recovery. Estimated recoverable quantities within such a discovered (known) accumulation(s) shall initially be classified as Contingent Resources pending definition of projects with sufficient chance of commercial development to reclassify all, or a portion, as Reserves. Where in-place hydrocarbons are identified but are not considered currently recoverable, such quantities may be classified as Discovered Unrecoverable, if considered appropriate for resource management purposes; a portion of these quantities may become recoverable resources in the future as commercial circumstances change or technological developments occur.

Determination of Commerciality

Discovered recoverable volumes (Contingent Resources) may be considered commercially producible, and thus Reserves, if the entity claiming commerciality has demonstrated firm intention to proceed with development and such intention is based upon all of the following criteria:

- Evidence to support a reasonable timetable for development.
- A reasonable assessment of the future economics of such development projects meeting defined investment and operating criteria.
- A reasonable expectation that there will be a market for all or at least the expected sales quantities of production required to justify development.
- Evidence that the necessary production and transportation facilities are available or can be made available:
- Evidence that legal, contractual, environmental and other social and economic concerns will allow for the actual implementation of the recovery project being evaluated.

To be included in the Reserves class, a project must be sufficiently defined to establish its commercial viability. There must be a reasonable expectation that all required internal and external approvals will be forthcoming, and there is evidence of firm intention to proceed with development within a reasonable time frame. A reasonable time frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While 5 years is recommended as a benchmark, a longer time frame could be applied where, for example, development of economic projects are deferred at the option of the producer for, among other things, market-related reasons, or to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented.

To be included in the Reserves class, there must be a high confidence in the commercial producibility of the reservoir as supported by actual production or formation tests. In certain cases, Reserves may be assigned on the basis of well logs and/or core analysis that indicate that the subject reservoir is hydrocarbon-bearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation tests.

Project Status and Commercial Risk

Evaluators have the option to establish a more detailed resources classification reporting system that can also provide the basis for portfolio management by subdividing the chance of commerciality axis according to project maturity. Such sub-classes may be characterized by standard project maturity level descriptions (qualitative) and/or by their associated chance of reaching producing status (quantitative). As a project moves to a higher level of maturity, there will be an increasing chance that the accumulation will be commercially developed. For Contingent and Prospective Resources, this can further be expressed as a quantitative chance estimate that incorporates two key underlying risk components:

- The chance that the potential accumulation will result in the discovery of petroleum. This is referred to as the "chance of discovery."
- Once discovered, the chance that the accumulation will be commercially developed is referred to as the "chance of development."

Thus, for an undiscovered accumulation, the "chance of commerciality" is the product of these two risk components. For a discovered accumulation where the "chance of discovery" is 100%, the "chance of commerciality" becomes equivalent to the "chance of development."

Project Maturity Sub-Classes

As illustrated in Figure 2-1, development projects (and their associated recoverable quantities) may be sub-classified according to project maturity levels and the associated actions (business decisions) required to move a project toward commercial production.

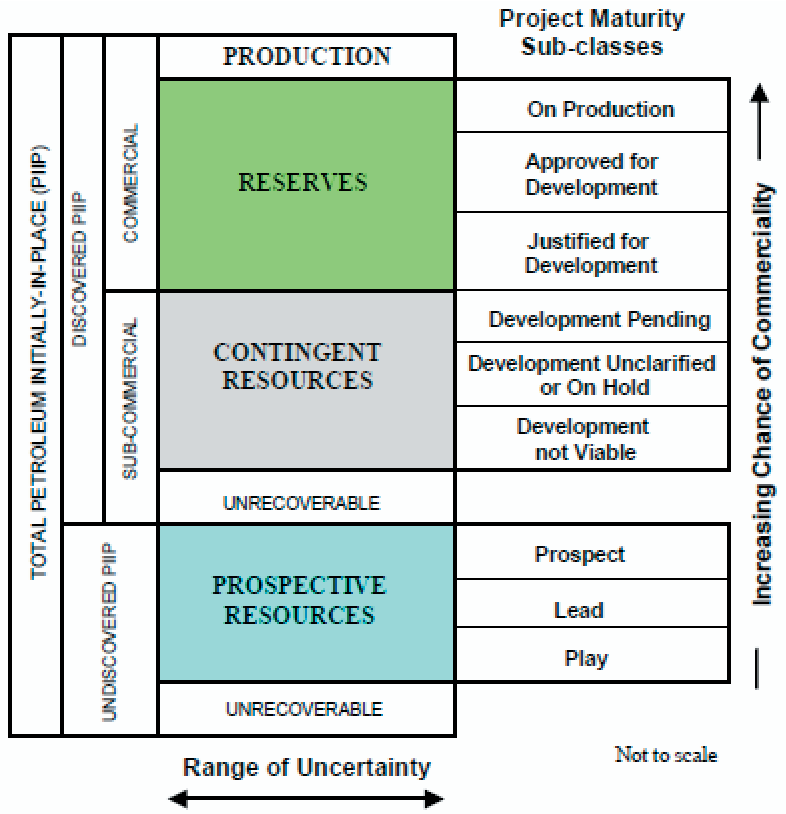


Figure 2-1: Sub-classes based on Project Maturity.

The outlined approach supports managing portfolios of opportunities at various stages of exploration and development and may be supplemented by associated quantitative estimates of chance of commerciality. The boundaries between different levels of project maturity may be referred to as "decision gates." Decisions within the Reserves class are based on those actions that progress a project through final approvals to implementation and initiation of production and product sales. For Contingent Resources, supporting analysis should focus on gathering data and performing analyses to clarify and then mitigate those key conditions, or contingencies, that prevent commercial development.

For Prospective Resources, these potential accumulations are evaluated according to their chance of discovery and, assuming a discovery, the estimated quantities that would be recoverable under appropriate development projects. The decision at each phase is to undertake further data acquisition and/or studies designed to move the project to a level of technical and commercial maturity where a decision can be made to proceed with exploration drilling. Evaluators may adopt alternative sub-classes and project maturity modifiers, but the concept of increasing chance of commerciality should be a key enabler in applying the overall classification system and supporting portfolio management.

Reserves Status

Once projects satisfy commercial risk criteria, the associated quantities are classified as Reserves. These quantities may be allocated to the following subdivisions based on the funding and operational status of wells and associated facilities within the reservoir development plan:

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

Where Reserves remain undeveloped beyond a reasonable timeframe, or have remained undeveloped due to repeated postponements, evaluations should be critically reviewed to document reasons for the delay in initiating development and justify retaining these quantities within the Reserves class. While there are specific circumstances where a longer delay is justified, a reasonable time frame is generally considered to be less than 5 years.

Development and production status are of significant importance for project management. While Reserves Status has traditionally only been applied to Proved Reserves, the same concept of Developed and Undeveloped Status based on the funding and operational status of wells and producing facilities within the development project are applicable throughout the full range of Reserves uncertainty categories (Proved, Probable and Possible).

Quantities may be subdivided by Reserves Status independent of sub-classification by Project Maturity. If applied in combination, Developed and/or Undeveloped Reserves quantities may be identified separately within each Reserves sub-class (On Production, Approved for Development, and Justified for Development).

Economic Status

Projects may be further characterized by their Economic Status. All projects classified as Reserves must be economic under defined conditions. Based on assumptions regarding future conditions and their impact on ultimate economic viability, projects currently classified as Contingent Resources may be broadly divided into two groups:

- Marginal Contingent Resources are those quantities associated with technically feasible projects that are either currently economic or projected to be economic under reasonably forecasted improvements in commercial conditions but are not committed for development because of one or more contingencies.
- Sub-Marginal Contingent Resources are those quantities associated with discoveries for which analysis indicates that technically feasible development projects would not be economic and/or other contingencies would not be satisfied under current or reasonably forecasted

improvements in commercial conditions. These projects nonetheless should be retained in the inventory of discovered resources pending unforeseen major changes in commercial conditions.

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." Additional economic status modifiers may be applied to further characterize recoverable quantities; for example, non-sales (lease fuel, flare, and losses) may be separately identified and documented in addition to sales quantities for both production and recoverable resource estimates. Those discovered in-place volumes for which a feasible development project cannot be defined using current, or reasonably forecast improvements in, technology are classified as Unrecoverable. Economic Status may be identified independently of, or applied in combination with, Project Maturity sub-classification to more completely describe the project and its associated resources.

Resources Categorization

The horizontal axis in the Resources Classification (Figure 1.1) defines the range of uncertainty in estimates of the quantities of recoverable, or potentially recoverable, petroleum associated with a project. These estimates include both technical and commercial uncertainty components as follows:

- The total petroleum remaining within the accumulation (in-place resources).
- That portion of the in-place petroleum that can be recovered by applying a defined development project or projects.
- Variations in the commercial conditions that may impact the quantities recovered and sold (e.g., market availability, contractual changes).
- Where commercial uncertainties are such that there is significant risk that the complete project (as initially defined) will not proceed, it is advised to create a separate project classified as Contingent Resources with an appropriate chance of commerciality.

Range of Uncertainty

The range of uncertainty of the recoverable and/or potentially recoverable volumes may be represented by either deterministic scenarios or by a probability distribution. When the range of uncertainty is represented by a probability distribution, a low, best, and high estimate shall be provided such that:

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

When using the deterministic scenario method, typically there should also be low, best, and high estimates, where such estimates are based on qualitative assessments of relative uncertainty using consistent interpretation guidelines. Under the deterministic incremental (risk-based) approach, quantities at each level of uncertainty are estimated discretely and separately. These same approaches to describing uncertainty may be applied to Reserves, Contingent Resources, and Prospective Resources. While there may be significant risk that sub-commercial and undiscovered accumulations will not achieve commercial production, it useful to consider the range of potentially recoverable quantities independently of such a risk or consideration of the resource class to which the quantities will be assigned.

Category Definitions and Guidelines

Evaluators may assess recoverable quantities and categorize results by uncertainty using the deterministic incremental (risk-based) approach, the deterministic scenario (cumulative) approach, or probabilistic methods. In many cases, a combination of approaches is used. Use of consistent terminology (Figure 1.1) promotes clarity in communication of evaluation results. For Reserves, the general cumulative terms low/best/high estimates are denoted as 1P/2P/3P, respectively. The associated incremental quantities are termed Proved, Probable and Possible. Reserves are a subset of, and must be viewed within context of, the complete resources classification system. While the categorization criteria are proposed specifically for Reserves, in most cases, they can be equally applied to Contingent and Prospective Resources conditional upon their satisfying the criteria for discovery and/or development.

For Contingent Resources, the general cumulative terms low/best/high estimates are denoted as 1C/2C/3C respectively. For Prospective Resources, the general cumulative terms low/best/high estimates still apply. No specific terms are defined for incremental quantities within Contingent and Prospective Resources.

Without new technical information, there should be no change in the distribution of technically recoverable volumes and their categorization boundaries when conditions are satisfied sufficiently to reclassify a project from Contingent Resources to Reserves. All evaluations require application of a consistent set of forecast conditions, including assumed future costs and prices, for both classification of projects and categorization of estimated quantities recovered by each project. The following summarizes the definitions for each Reserves category in terms of both the deterministic incremental approach and scenario approach and also provides the probability criteria if probabilistic methods are applied.

- **Proved Reserves** are those quantities of petroleum, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods, and government regulations. If deterministic methods are used, the term reasonable certainty is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate.
- **Probable Reserves** are those additional Reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves. It is equally

likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate.

- **Possible Reserves** are those additional reserves which analysis of geoscience and engineering data suggest are less likely to be recoverable than Probable Reserves. The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P) Reserves, which is equivalent to the high estimate scenario. In this context, when probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate. Based on additional data and updated interpretations that indicate increased certainty, portions of Possible and Probable Reserves may be re-categorized as Probable and Proved Reserves.

Uncertainty in resource estimates is best communicated by reporting a range of potential results. However, if it is required to report a single representative result, the "best estimate" is considered the most realistic assessment of recoverable quantities. It is generally considered to represent the sum of Proved and Probable estimates (2P) when using the deterministic scenario or the probabilistic assessment methods. It should be noted that under the deterministic incremental (risk-based) approach, discrete estimates are made for each category, and they should not be aggregated without due consideration of their associated risk.

Incremental Projects

The initial resource assessment is based on application of a defined initial development project. Incremental projects are designed to increase recovery efficiency and/or to accelerate production through making changes to wells or facilities, infill drilling, or improved recovery. Such projects should be classified according to the same criteria as initial projects. Related incremental quantities are similarly categorized on certainty of recovery. The projected increased recovery can be included in estimated Reserves if the degree of commitment is such that the project will be developed and placed on production within a reasonable timeframe. Circumstances where development will be significantly delayed should be clearly documented. If there is significant project risk, forecast incremental recoveries may be similarly categorized but should be classified as Contingent Resources.

Unconventional Resources

Two types of petroleum resources have been defined that may require different approaches for their evaluations:

- Conventional resources exist in discrete petroleum accumulations related to a localized geological structural feature and/or stratigraphic condition, typically with each accumulation bounded by a downdip contact with an aquifer, and which is significantly affected by hydrodynamic influences such as buoyancy of petroleum in water. The petroleum is recovered through wellbores and typically requires minimal processing prior to sale.

- Unconventional resources exist in petroleum accumulations that are pervasive throughout a large area and that are not significantly affected by hydrodynamic influences (also called "continuous-type deposits"). Examples include coalbed methane (CBM), basin-centered gas, shale gas, gas hydrates, natural bitumen, and oil shale deposits. Typically, such accumulations require specialized extraction technology (e.g., dewatering of CBM, massive fracturing programs for shale gas, steam and/or solvents to mobilize bitumen for in-situ recovery, and, in some cases, mining activities). Moreover, the extracted petroleum may require significant processing prior to sale (e.g., bitumen upgraders).

For these petroleum accumulations that are not significantly affected by hydrodynamic influences, reliance on continuous water contacts and pressure gradient analysis to interpret the extent of recoverable petroleum may not be possible. Thus, there typically is a need for increased sampling density to define uncertainty of in-place volumes, variations in quality of reservoir and hydrocarbons, and their detailed spatial distribution to support detailed design of specialized mining or in-situ extraction programs.

It is intended that the resources definitions, together with the classification system, will be appropriate for all types of petroleum accumulations regardless of their in-place characteristics, extraction method applied, or degree of processing required.

Similar to improved recovery projects applied to conventional reservoirs, successful pilots or operating projects in the subject reservoir or successful projects in analogous reservoirs may be required to establish a distribution of recovery efficiencies for non-conventional accumulations. Such pilot projects may evaluate both extraction efficiency and the efficiency of unconventional processing facilities to derive sales products prior to custody transfer.

senergy
oil & gas

The Directors
Petroceltic International PLC
6th Floor
75 St. Stephen's Green
Dublin 2
Ireland

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

17 August 2012

Petroceltic International PLC ("Petroceltic")
Competent Person's Report
Reserves and Prospective Resources attributable to Melrose Resources plc in various Egyptian and Bulgarian concessions

Dear Sirs,

We have been contracted by Petroceltic and J&E Davy to prepare a competent person's report on the future gross reserves, net reserves and prospective resources attributable to Melrose Resources plc (Melrose) in various Egyptian and Bulgarian concessions at 31st December 2011 (the "Competent Person's Report") that will be included in an admission document prepared in accordance with the AIM Rules of the London Stock Exchange plc and the ESM Rules of the Irish Stock Exchange Limited (the "Admission Document").

SENERGY (GB) LIMITED
39 CHARING CROSS ROAD LONDON WC2H 0AR UNITED KINGDOM
T: +44 20 7025 6750 F: +44 20 7025 6751 E: info.uk@senergyworld.com
REGISTERED IN SCOTLAND SC 125513 REGISTERED OFFICE: 15 BON ACCORD CRESCENT ABERDEEN AB11 6DE
Senergy (GB) Limited is also registered to OHSAS 18001
www.senergyworld.com

The Competent Person's Report has been prepared in accordance with Competent Person's Report scope and content guidelines set out in the AIM Note for Mining, Oil and Gas Companies - June 2009 published by the London Stock Exchange plc ("the AIM Note for Mining, Oil and Gas Companies"). The Competent Person's Report relates solely to the defined licences and is based on various geologic and economic assumptions as detailed in the Competent Person's Report. Therefore, the Competent Person's Report must be read in its entirety.

Qualifications.

Senergy (GB) Limited is a privately owned independent consulting company established in 1990, with offices in Aberdeen, Banchory, London, Guildford, Stavanger, Kuala Lumpur and Abu Dhabi. The company specialises in petroleum reservoir engineering, geology, geophysics and petroleum economics. All of these services are supplied under an accredited ISO9001 quality assurance system. The authors of this report are Competent Persons. Brief biographies of the main contributors to this report have been provided in Appendix A of the CPR.

Opinion

The evaluation presented in the Competent Person's Report reflects our informed judgment based on accepted standards of professional investigation. The evaluation has been conducted within our understanding of relevant legislation, taxation and all other regulations that currently applies to these interests.

Consent

We hereby consent to the inclusion of the Competent Person's Report and to the use of our name in the Admission Document in the form and context in which they respectively appear.

Correct Extraction

We have reviewed the relevant sections of the Admission Document which relate to information contained in the Competent Person's Report and confirm that the information presented is accurate, balanced and complete and not inconsistent with the Competent Person's Report. In particular we confirm that the information in the Admission Document, where extracted from the Competent Person's Report, is extracted directly and presented in a manner which is not misleading or inconsistent with the Competent Person's Report and provides a balanced view of the Competent Person's Report.

Responsibility

We accept responsibility for the Competent Person's Report contained in the Admission Document for the purposes of a competent person's report under the AIM Note for Mining, Oil and Gas Companies. The Competent Person's Report is complete up to and including 15 August 2012. To the best of our knowledge and belief, after having taken all reasonable care to ensure that such is the case, the information contained in the Competent Person's Report is in accordance with the facts and does not omit anything likely to affect the import of such information.

No Material Change
To the best of our knowledge and belief, after having taken all reasonable care to ensure that such is the case, no material change has occurred from last January 2012 to the date hereof that would require any amendment to the Competent Person's Report.

Independence
We are independent of Petroceltic, the directors and senior management of Petroceltic and its other advisors. The Competent Person's Report is prepared in return for professional fees based upon agreed commercial rates and the payment of these fees is in no way contingent on the results of the Competent Person's Report, the admission of Petroceltic's shares to trading on AIM or the ESM or the value of Petroceltic.

Yours sincerely

For and on behalf of Senergy (GB) Limited

Egyptian and Bulgarian Reserves and Resources CPR 2012

Conducted for

Petroceltic International PLC

By

Barry Squire, Martin Eales, Peter Aquilina, John Kendal,

Stephen Sanderson, Bob Harrison, Chris De Goey

Final

K12MEL022L

August 2012

BS EN ISO 9001

Certificate No. FS 33084

BS EN ISO 14001

Certificate No. EMS 518923

INVESTOR IN PEOPLE

SENERGY (GB) LIMITED
39 CHARING CROSS ROAD LONDON WC2H 0AR UNITED KINGDOM
T: +44 20 7025 6750 F: +44 20 7025 6751 E: info.uk@senergyworld.com
REGISTERED IN SCOTLAND SC 125513 REGISTERED OFFICE: 15 BON ACCORD CRESCENT ABERDEEN AB11 6DE
Senergy (GB) Limited is also registered to OHSAS 18001

www.senergyworld.com

Authors	Barry Squire, John Kendal, Chris de Goey
Technical Audit	Bob Harrison, Stephen Sanderson, Martin Eales, Peter Aquilina
Quality Audit	Jennifer Ives
Release to Client	
Date Released	15th August 2012

Senergy has made every effort to ensure that the interpretations, conclusions and recommendations presented herein are accurate and reliable in accordance with good industry practice and its own quality management procedures. Senergy does not, however, guarantee the correctness of any such interpretations and shall not be liable or responsible for any loss, costs, damages or expenses incurred or sustained by anyone resulting from any interpretation or recommendation made by any of its officers, agents or employees.

The Directors
Petroceltic International PLC
6th Floor
75 St. Stephen's Green
Dublin 2
Ireland

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

15th August 2012

Dear Sirs

In accordance with your instructions Senergy (GB) Limited (Senergy) has prepared an estimate of the future gross reserves, net reserves and prospective resources attributable to Melrose Resources plc (Melrose) in various Egyptian and Bulgarian concessions at 31st December 2011. The assets evaluated are listed in the Executive Summary under "Assets Included in This Evaluation".

We were requested to provide an independent evaluation of the recoverable hydrocarbons expected for each asset categorised in accordance with the 2007 Petroleum Resources Management System prepared by the Oil and Gas Reserves Committee of the Society of Petroleum Engineers (SPE) and reviewed and jointly sponsored by the World Petroleum Council (WPC), the American Association of Petroleum Geologists (AAPG) and the Society of Petroleum Evaluation Engineers (SPEE). The report has been prepared in accordance with the AIM Note for Mining, Oil and Gas Companies published by the London Stock Exchange and is to be included in an admission document.

The technically recoverable volumes presented in this report are based on a review of the independent interpretations conducted on the assets and where appropriate on an assessment of historic production trends; an independent economic review was also conducted on the interests. Reserves and resources are reported at estimated economic or technical cut-off rates agreed with Melrose and are otherwise derived according to the above definitions. For the purposes of these definitions, present producing methods are limited to primary depletion or secondary recovery by water or gas injection and do not include enhanced petroleum recovery techniques.

Recoverable volumes are expressed as gross and / or net technical reserves or resources. Gross reserves or resources are defined as the total estimated petroleum to be produced from the fields evaluated from 1st January 2012. Net reserves or resources are defined as that portion of the gross reserves or resources attributable to the interests owned by Melrose. Net Present Values (NPVs) are calculated as net attributable to Melrose. Upon completion of the transaction between Petrocelctic International PLC (Petroceltic) and Melrose, Petroceltic will own 100% of the net attributable assets to Melrose.

In conducting this review we have utilised information supplied directly or indirectly by Melrose, comprising basic engineering data, technical reports, development plans and economic models. We have reviewed the information provided and modified assumptions where we considered appropriate. Site visits were not considered necessary for the purposes of this report. We have not verified the entitlement of Petroceltic or Melrose to the interests stated in this report as this is outside the remit of the evaluation.

Standard geological and engineering techniques accepted by the petroleum industry were used in estimating recoverable hydrocarbons. These techniques rely on engineering and geo-scientific interpretation and judgement; hence the resources included in this evaluation are estimates only and should not be construed to be exact quantities. It should be recognised that such estimates of hydrocarbon resources may increase or decrease in future if there are changes to the technical interpretation, economic criteria or regulatory requirements. As far as Senergy is aware there are no special factors that would affect the operation of the assets and which would require additional information for their proper appraisal.

The tables overleaf contain Senergy's view of the reserves and resources in each class according to the defined classification system.

Executive Summary

Senergy (GB) Limited (Senergy) was requested to provide an assessment of interests that Petroceltic holds through Melrose Resources plc (Melrose) in Egypt under a Production Sharing Contract (PSC) and in Bulgaria through Melrose's wholly-owned subsidiary, Petreco SARL. This current report is based on an earlier Competent Person's Report (CPR) by Senergy on Melrose's Reserves in Bulgaria and Egypt, dated February 2012, on an earlier CPR by Senergy on Melrose's Prospective Resources in Bulgaria, dated June 2012 and on a new assessment on Melrose's Prospective Resources in Egypt.

Assets Included in This Report

The assets reviewed in this report are held in four areas covered by permits and concessions, three in Egypt and one in Bulgaria. The assets include producing fields and developments in Egypt and Bulgaria, as well as a number of selected prospects that have been interpreted and which are undergoing further work in preparation for exploration and appraisal in the next years. Other prospects and leads in the concessions are not included in this report. Nor are Melrose's interests in the Mesaha concession in southern Egypt, nor its interests in France, Romania and Turkey included in this report.

The main Egyptian concession, El Mansoura, has been and continues to be a prolific exploration area with growing production. South Damas gas field, discovered and brought onto production in 2010, has extended the life of the South-East El Mansoura concession. In Bulgaria, Kavarna and Kaliakra have continued production through the existing Galata platform; Kavarna East, discovered in 2010, is scheduled to be developed in the same way in 2013.

Egypt

El Mansoura, South-East El Mansoura and Qantara are located in the East Nile Delta (**Figure 1.1**) and are operated by Melrose. Operations are conducted under PSC terms. Gas is sold on contract to the Egyptian Gas Holding Company (EGAS), and oil is sold in the open market. Export is through local processing plants into third party pipeline systems. In addition to the concessions, there are thirteen active development leases contained within the areas of the two Mansoura concessions. El Mansoura development leases have been awarded for a minimum 20 year term and fully cover the forecast production period. Melrose has relinquished the Qantara exploration concession; however, the development lease is retained.

Bulgaria

In Bulgaria, Melrose owns a 100% interest in Block Galata (formerly Block III) located in the Black Sea approximately 30 km south-east of Varna (**Figure 1.2**). The block is operated under the "Oil and Gas Prospecting and Exploration Permit for Block Galata" by the Melrose subsidiary, Petreco SARL, under Tax and Royalty terms. There are also three "Concession(s) for Production of Natural Gas" from Galata (field), Kavarna and Kaliakra. Gas produced from these concessions is transported via an 85 km pipeline to an onshore gas processing plant where the majority is sold under contract to Bulgargaz, the Bulgarian state-owned gas utility company, and the balance is sold to a local industrial user.

Portfolio interests are as follows:

Concession / Permit	Melrose Interest	Date awarded	Expiry
El Mansoura	100%	1997	Exploration 2012, Production various
South-East El Mansoura	100%	2005	Exploration 2014 Production various
Qantara	100%	1997	Production 2019 or later[1]
Block Galata	100%	2001	Exploration 2015 Production various

[1] Qantara has been converted to a development lease.

The two following tables summarise the gross and net Proved (1P), Proved plus Probable (2P) and Proved plus Probable plus Possible (3P) Reserves and NPV10% for the basins in which Melrose holds an interest. A breakdown of the individual net asset volumes within the appropriate 1P, 2P and 3P Reserves and Low, Best and High Prospective Resources categories in each of the basins is given in **Tables 1.2 to 1.9**.

Gross reserves for Egypt and Bulgaria are shown in the following table.

Country	Category	Gross Reserves at 31st December 2011			
		Oil (MMbbl)	Condensate and LPG (MMbbl)	Gas (Bscf)	Total (Bscfe*)
Egypt	Proved (Developed and Undeveloped)	3.9	4.6	245.2	294.8
	Probable (Developed and Undeveloped)	3.0	1.6	111.1	137.5
	Proved plus Probable	6.9	6.2	356.3	432.3
	Proved plus Probable plus Possible	11.5	8.1	465.6	578.8
Bulgaria	Proved (Developed and Undeveloped)	0.0	0.0	48.0	48.0
	Probable (Developed and Undeveloped)	0.0	0.0	22.3	22.3
	Proved plus Probable	0.0	0.0	55.9	55.9
	Proved plus Probable plus Possible	0.0	0.0	70.4	70.4
Total	Proved (Developed and Undeveloped)	3.9	4.6	293.2	342.8
	Probable (Developed and Undeveloped)	3.0	1.6	133.4	159.9
	Proved plus Probable	6.9	6.2	412.1	488.2
	Proved plus Probable plus Possible	11.5	8.1	536.0	649.1

* Liquids to gas converted at 1 bbl = 5.8 Mscfe

Net reserves and NPV for Egypt and Bulgaria are shown in the table below.

Country	As at 31st December 2011	Net Reserves			Net Present Value @10% (US$ 000)
		Oil, LPG and Condensate (MMstb)	Gas (Bscf)	Total (Bscfe)	
Egypt	Proved	3.6	92.7	113.5	238,505
	Proved plus Probable	4.8	121.2	148.7	330,785
	Proved plus Probable plus Possible	5.8	136.9	170.5	423,111
Bulgaria	Proved	-	48.0	48.0	239,363
	Proved plus Probable	-	55.9	55.8	271,348
	Proved plus Probable plus Possible	-	70.3	70.3	334,818
Total	**Proved**	**3.6**	**140.7**	**161.5**	**477,868**
	Proved plus Probable	**4.8**	**177.1**	**204.6**	**602,133**
	Proved plus Probable plus Possible	**5.8**	**207.2**	**240.8**	**757,929**

Gross prospective resources for Bulgaria are shown in the following table

Gross Un-Risked Prospective Resources (Bscf)				
Prospect	**Low Estimate**	**Best Estimate**	**High Estimate**	**Best Estimate Net Present Value @10% (US$ MM)**
Chaika NW	9.5	18.4	39.9	34.3
Chaika NE	5.0	8.2	12.3	15.0
Chaika S	9.4	18.9	38.1	39.7
Kamchia	16.6	27.0	41.2	72.5
Prospect A	5.0	8.2	12.4	13.4
Prospect E	14.5	23.6	36.2	58.5
Prospect F	2.4	4.5	7.6	N/A
Prospect H	7.2	12.4	21.8	22.9
Total Gas (stochastic aggregation)	**103.6**	**129.2**	**164.2**	**256.3**

Gross prospective resources for Egypt are shown in the following two tables.

Gross Un-Risked Prospective Resources (Mstb)				
Prospect	**Low Estimate**	**Best Estimate**	**High Estimate**	**Best Estimate Net Present Value @10% (US$ MM)**[1]
Mit Hadid	407	1,009	2,089	7.4
Mustafa	926	1,904	3,457	17.4
NW Zahayra	319	863	1818	9.8
SW Tarif	383	1,501	3,626	12.2
Al Hajarisah: Kharita	501	1,464	3,631	14.0
Al Hajarisah: Barremian	1,022	2,530	5,493	
Al Hajarisah: Neocomian	595	1,753	4,438	
Kafr Saqr: Kharita	92	261	641	N/A
Kafr Saqr: Barremian	220	646	1,635	
Kafr Saqr: Neocomian	455	1,103	2,393	
Sidi Gohar: Kharita	216	939	2,550	7.5
Sidi Gohar: Barremian	681	1,836	4,473	
Sidi Gohar: Neocomian	629.	1,794	4,501	
Sinbelaywan: Kharita	592	1,512	3,656	19.5
Sinbelaywan: Barremian	631	3,446	11,440	
Sinbelaywan: Neocomian	832	3,693	10,800	
Total Liquids (stochastic aggregation)	**23,600**	**31,900**	**43,500**	**87.9**

[1] NPV is calculated for the total of the gas and liquids and on a field basis rather than per reservoir, as these will be developed in combination.

Gross Un-Risked Prospective Resources (Bscf)			
Prospect	**Low Estimate**	**Best Estimate**	**High Estimate**
Mit Hadid	3.0	7.4	14.9
Mustafa	7.9	15.8	27.4
NW Zahayra	3.9	10.3	20.9
SW Tarif	2.8	11.1	26.1
Al Hajarisah: Kharita	0.5	1.5	3.9
Al Hajarisah: Barremian	5.7	14.5	33.2
Al Hajarisah: Neocomian	0.6	1.7	4.4
Kafr Saqr: Kharita	0.1	0.3	0.7
Kafr Saqr: Barremian	1.2	3.7	9.7
Kafr Saqr: Neocomian	2.5	6.3	14.4
Sidi Gohar: Kharita	0.2	1.0	2.7
Sidi Gohar: Barremian	0.7	1.9	4.7
Sidi Gohar: Neocomian	0.6	1.8	4.5
Sinbelaywan: Kharita	0.6	1.6	3.9
Sinbelaywan: Barremian	0.6	3.6	12.3
Sinbelaywan: Neocomian	0.8	3.8	11.4
Total Gas (stochastic aggregation)	**76.1**	**100.0**	**131.0**

Conclusions

Senergy has performed an audit of the materials presented to it by Petroceltic on Melrose's assets and concludes that the volumes presented in this report, together with the related risk factors, provide a fair view of the current understanding of the assets.

Professional Qualifications

Senergy (GB) Limited is a privately owned independent consulting company established in 1990, with offices in Aberdeen, Banchory, London, Guildford, Stavanger, Kuala Lumpur and Abu Dhabi. The company specialises in petroleum reservoir engineering, geology, geophysics and petroleum economics. All of these services are supplied under an accredited ISO9001 quality assurance system. The authors of this report are Competent Persons. Brief biographies of the main contributors to this report have been provided in Appendix A. Except for the provision of professional services on a fee basis, Senergy has no commercial arrangement with any person or company involved in the interest that is the subject of this report.

Yours faithfully,

For and on behalf of Senergy (GB) Limited

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1 Introduction

This report was prepared by Senergy (GB) Limited (Senergy) in Q3 2012 at the request of the Directors of Petroceltic International PLC (Petroceltic) in support of a transaction between Petroceltic and Melrose Resources plc (Melrose). The report consists of an evaluation of the interests that Petroceltic will hold through Melrose post transaction completion in licences in Bulgaria and Egypt. These licences are operated by Melrose or its country subsidiary **(Figures 1.1 to 1.3).** The data available for review varied depending on the asset and is noted in the body of the report for each asset.

Senergy was requested to provide an independent evaluation of the recoverable hydrocarbons expected for each asset. This report merges two earlier CPRs by Senergy (Reference 1 and 2) with a new assessment of Egypt prospective resources. The report details the concession interests (**Table 1.1**), the reserves and prospective resources attributable to the assets (**Tables 1.2 to 1.9**) and Proved plus Probable Production forecasts updated by Melrose[2] (**Table 1.10**).

1.1 Evaluation Methodology

Standard geological and engineering techniques accepted by the petroleum industry were used in estimating recoverable hydrocarbons. These techniques rely on engineering and geo-scientific interpretation and judgement; hence the resources included in this evaluation are estimates only and should not be construed to be exact quantities. It should be recognised that such estimates of hydrocarbon resources may increase or decrease in future if there are changes to the technical interpretation, economic criteria or regulatory requirements.

Senergy was requested to provide an independent evaluation of the recoverable hydrocarbons expected for the asset. The starting point in making an assessment of reserves or resources is an estimate of hydrocarbons-initially-in-place (HIIP). There are various methods that can be used. In this report, the quoted low, base and high HIIP volumes are probabilistic estimates calculated by Senergy. The specific method used for calculating HIIP is based on good industry practice but it should be emphasised that there is no single universally accepted method in use within the industry.

For probabilistic estimates the low is P_{90}, base is P_{50} and high is P_{10}. The probabilistic estimates are generated using a "Monte Carlo" statistical approach. A resource size distribution is determined by the parameter input size ranges and their nature (e.g. whether normal, lognormal or other). The size of the distribution is particularly sensitive to the choice of "end member" P_{90} and P_{10} (i.e. 90% and 10% probability) input parameters especially for the key inputs of assumed hydrocarbon contact depth and reservoir thickness. Senergy's base recoverable volumes (i.e. 2P, 2C and Best Estimate cases) are based on the derived mean value of the stochastic distributions, unless otherwise explained in the text.

Senergy has used the existing interpretations (depth maps and log interpretations) and conducted independent interpretations where considered necessary to perform probabilistic HIIP volumetric distribution estimates. The resource volumes can also be estimated using a variety of methods. In this report prospective resources are based on the application of a

[2] See Section 1.6 below

recovery factor range to the estimated HIIP volumes. In this report, gas volumes are reported in billions of standard cubic feet (Bscf), condensate and oil volumes in either thousands or millions of stock tank barrels (Mstb, MMstb).

The risk factor for prospective resources is the geological chance of success (COS) and is usually the product of the four components of trap, seal, reservoir and hydrocarbon charge. Risk values are assigned to each of these elements for each defined prospect and these are multiplied together to give an overall COS. The AIM definition of exploration COS is the chance to find a sufficient volume of hydrocarbons to test to the surface. Senergy ensured that the assigned value is appropriate to the quoted size distribution[3]. The AIM definition of Risk Factor for contingent resources is the estimated chance, or probability, that the volumes will be commercially extracted.

1.2 Sources of Information

In conducting this review, we have utilised information and interpretations supplied by Melrose, comprising geological, geophysical, engineering and other data presented to us. We have reviewed the information provided and modified assumptions where we considered this to be appropriate. We have accepted, without independent verification, the accuracy and completeness of this data.

Senergy has had access to a set of interpreted data and has not attempted a systematic review of raw data (either well logs or seismic) but has performed a critical assessment of the existing interpretation work supplied in the database. These interpreted data included time and depth maps for the near top reservoir horizons, offset well log petrophysical interpretations, and hydrocarbon-in-place estimates.

The database available for each asset is described in more detail in the field description sections of this report.

1.3 Concession Details

The assets are located in Bulgaria and Egypt (**Figures 1.1** to **1.3**). The licences were awarded between 1998 and 2010. **Table 1.1** provides details of the licences held by Melrose.

1.4 Requirements

In accordance with your instructions to us we confirm that:

- We are professionally qualified and a member in good standing of a self-regulatory organisation of engineers and / or geoscientists;
- We have at least five years relevant experience in the estimation, assessment and evaluation of oil and gas assets;
- We are independent of Petroceltic, its directors, senior management and advisers;
- We will be remunerated by way of a time-based fee and not by way of a fee that is linked to the value of Petroceltic;

[3] Note that as per the PRMS guidelines, for Prospective Resources the total commercial risk is the product of the COS and the Development Risk

- We are not a sole practitioner;
- We have the relevant and appropriate qualifications, experience and technical knowledge to appraise professionally and independently the assets, being all assets, concessions, joint ventures or other arrangements owned by Melrose 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 Melrose' work programme and Assets ("Liabilities").

1.5 Standards Applied

In compiling this report we have used the definitions and guidelines set out in the 2007 Petroleum Resources Management System prepared by the Oil and Gas Reserves Committee of the Society of Petroleum Engineers (SPE) and reviewed and jointly sponsored by the World Petroleum Council (WPC), the American Association of Petroleum Geologists (AAPG) and the Society of Petroleum Evaluation Engineers (SPEE). The results of this work have been presented in accordance with the requirements of AIM, a Market operated by the London Stock Exchange, in particular as described in the "Note for Mining and Oil and Gas Companies - June 2009".

1.6 No Material Change

Senergy confirms that to its knowledge there has been no material change of circumstances or available information since the February and June 2012 reports were compiled and we are not aware of any significant matters arising from our evaluation that are not covered within this report which might be of a material nature with respect to the proposed transaction other than that specified in the following paragraph.

Melrose has informed Senergy that it has considered its offtake strategies for certain fields, in particular West Dikirnis, Egypt and Galata, Bulgaria. Melrose has updated the production forecasts (Table 1.10) taking into account slightly slower offtake from those fields than was assumed in the February 2012 report (Reference 1). Senergy has not reviewed these changes in detail but considers that the revised forecasts are not inconsistent with those of the February 2012 report given the changes in assumptions notified by Melrose. In this report, the calculated net attributable reserves volumes and NPVs for these fields are still based on the Senergy February 2012 slightly more aggressive production forecasts.

1.7 Site Visit

No site visits have been conducted for this report.

1.8 Liability

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

1.9 Consent

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

- The inclusion of this report, and a summary of portions of this report, in documents prepared by Petroceltic and its advisers;
- The filing of this report with any stock exchange and other regulatory authority;
- The electronic publication of this report on websites accessible by the public, including a website of Petroceltic; and
- The inclusion of our name in documents prepared in connection commercial or financial activities.

The report relates specifically and solely to the subject assets and is conditional upon various assumptions that are described herein. The report must therefore be read in its entirety. This report was provided for the sole use of Petroceltic on a fee basis. Except with permission from Senergy this report may not be reproduced or redistributed, in whole or in part, to any other person or published, in whole or in part, for any other purpose without the express written consent of Senergy.

2 El Mansoura (and South-East El Mansoura)

2.1 Introduction

Gas was first discovered on the El Mansoura concession in December 2001. By end 2011, forty-eight wells had discovered hydrocarbons, and twenty-five wells were on production, one well was being used as a gas injector and two as water disposal wells. Eleven of these wells tap oil accumulations and the balance are gas wells with associated condensate. During 2011, gross production from the two concessions averaged 129 MMscf/d gas and 4,555 bbl/d of liquids, compared with 190 MMscf/d gas and 6,300 bbl/d of liquids in 2010.

Log and seismic data demonstrate that the area is complex with fault compartmentalised, multiple pay zones. Each of the main reservoir intervals has a distinctive seismic character, accompanied by amplitude anomalies in the hydrocarbon-bearing sections. Seismic data have been used to map the reservoir distribution and to plan the development well locations.

2.2 Geological Description

Multiple pay zones occur in the El Mansoura development area.

2.2.1 Kafr El Sheikh Reservoir, Pliocene Age

This shallow sandstone objective is typically 50 ft thick and presents a stratigraphic play within the Pliocene sequence. In El Mansoura, the Kafr El Sheikh lies between 4,000 and 7,000 ft tvdss.

Kafr El Sheikh original reservoir pressures lie between 2,000 and 3,500 psia. The gas is 99% methane with negligible condensate yield. Geologically, the fields are channelised and are showing similar connectivity and water-cut behaviour to the Abu Madi reservoir.

2.2.2 Abu Madi Reservoir, Miocene Age

The lower Abu Madi Formation consists mainly of fluvio-marine sandstones with siltstone and shale interbeds. The sands can generally be subdivided into three main units, based on lithological and sedimentological characteristics, although only two sand pay zones of Level II and III have been encountered in the South Batra area. Levels II and III have good porosity and permeability characteristics (in excess of 20% and 200 mD respectively), and are the most common gas bearing intervals in the Nile Delta Region. In El Mansoura, the Abu Madi is gas bearing and lies between 7,000 and 10,000 ft tvdss. The individual sand units are typically 50 to 150 ft thick.

The older Abu Madi fields have now been on production for seven years and, in general, are showing limited well connectivity and increasing water-cut. However, the large West Khilala field is of a different character with much better performance. Abu Madi original reservoir pressures are between 3,400 and 4,700 psi. The gas is predominantly methane-rich with less than 1 mol% carbon dioxide and nitrogen, giving condensate yields of circa 20 bbl/MMscf for most fields except in West Khilala and South Khilala, which contain dry gas with a Condensate Gas Ratio (CGR) of about 2 bbl/MMscf.

2.2.3 Qawasim and Sidi Salim Reservoirs

Recent discoveries have been made in these stratigraphically deeper horizons comprising variable sequences of interbedded marine sandstones, mudstones, and shales with minor limestones indicative of local shallow marine 'reefal' environments. Typical plays are combination structural and stratigraphic traps in eroded, tilted fault blocks sub-cropping against overstepping sealing Pliocene shales. The formations can be in excess of 2,000 ft thick, and typically lie below 4,000 to 5,000 ft tvdss. Reservoir properties can be excellent with porosities of 25% and permeabilities of 500 mD.

2.3 Asset Overview

Senergy has concentrated its review on the accumulations according to size and where recent drilling has occurred, based on data supplied by Melrose. These recent fields were generally drilled on the basis of seismic indicators, and further leads and prospects have been identified using the same methodology.

On the basis of meetings with Melrose technical staff, we believe they are familiar with the assets and Melrose has the technical expertise required to manage them. A campaign of continuous drilling continues, and results from recent and future wells, evolving field performance and new seismic acquisition mean that there is a considerable volume of new data to consider and interpret. Evaluation of these data by Melrose is ongoing.

El Mansoura Concession

2.3.1 West Khilala

West Khilala is a producing gas field located in the north-west of the El Mansoura concession, comprising a large, tilted fault block lying within the Abu Madi Formation, which consists mainly of fluvio-marine sandstones with siltstone and shale interbeds. Reservoir quality is good with porosities and permeabilities in excess of 20% and 200 mD respectively. The West Khilala initial reservoir pressure was about 4,680 psig. West Khilala contains methane-rich gas with less than 1% carbon dioxide and nitrogen, with a low CGR of less than 2 bbl/MMscf.

The field was put on production on 5th February 2007 with the West Khilala-1 well. Wells West Khilala-2, -4, -3, -6A and -5 were subsequently drilled during 2007, allowing production to be ramped up to around 95 MMscf/d by year end. West Khilala offtake rate was increased in 2008 to a plateau production of between 100 and 105 MMscf/d, and average gas production for 2008, 2009 and 2010 was 101 MMscf/d, 102 MMscf/d and 92 MMscf/d, respectively. During 2011 West Khilala average gas production dropped to 69 MMscf/d due to revised reservoir management strategy in view of sand and water production and some down-time for mechanical work-overs on three wells. Approximately 160 Bscf of gas had been produced by year end 2011. The observed CGR is about 1.3 bbl/MMscf.

Modular formation Dynamics Tester (MDT) logs and Reservoir Saturation Tester (RST) logs run in 2007 and 2008 showed no movement of the Gas-Water Contact (GWC) in wells West Khilala-1, -3, -4 and -6ST, and only a slight movement of GWC in well West Khilala-5, indicating a very weak aquifer. Pressure Build-Up surveys were conducted in each of the West Khilala wells in November and December 2009, and in wells West Khilala-2 and -5 in November 2011. The results were used to update material balance estimates and continue to support an interpretation of a weak aquifer. Nevertheless, West Khilala-3 experienced increasing formation water production through 2011 and ceased flowing in November; some water production is also being seen in West Khilala-2 and -4. Accordingly, rates and ultimate recovery factors have been downgraded since last year. Melrose now plans two new, high-angle wells to secure future production. The Proved plus Probable (2P) Gas Initially In Place (GIIP) has been estimated at 327 Bscf, and 2P Estimated Ultimate Recovery (EUR) at 289 Bscf.

West Khilala-1, -2 and -4 were successfully worked over during 2011 to fix tubing-to-annulus pressure communication. Drilling of a high-angle development well, West Khilala-8, is in progress and one more development well is scheduled for 2013.

Tendering for the installation of compressors has been initiated, and compressors will be installed at the end of 2012 or early in 2013.

2.3.2 South Khilala

South Khilala field was discovered in April 2009 with the drilling of the South Khilala-1 well. The well encountered Qawasim sands with dry gas similar to West Khilala. It was tied back to the West Khilala field and came on stream 16th October 2009. During 2011, the average gas rate was 14.4 MMscf/d. It is currently producing 13 MMscf/d. To date this well has not produced any sand. The water/gas ratio is less than 1.5 bbl/MMscf and produced water has a salinity of 660 ppm consistent with condensed water only.

Since the start of production, three pressure build-up surveys have been conducted on this well. Material balance shows that South Khilala-1 is connected to a GIIP of 41 to 55 Bscf. It is planned to drill a second well to maximise recovery. Approximately 12.1 Bscf of gas had been produced by year end 2011.

South Khilala shares processing facilities with West Khilala and will benefit from the compression planned for that field. With compression, wellhead pressure will eventually be lowered to 200 psi, which will lead to a high recovery factor, provided that there is no significant aquifer influx.

South Khilala-1 production performance has matched expectation, and the data collected during 2011 have given more confidence in a high recovery factor. The Proved plus Probable GIIP is estimated to be 55 Bscf and EUR to be 47 Bscf.

2.3.3 West Dikirnis

West Dikirnis is a Qawasim and Sidi Salim discovery lying in the east of the El Mansoura concession. The field has a substantial oil rim and a gas cap that yields a CGR estimated at 54 bbl/MMscf. This is a relatively large reservoir with massive stacked sands and good overall reservoir quality. However, the reservoir quality deteriorates and thins towards the north. Recent well results have indicated greater complexity and difficulty in correlating sand units within the reservoir.

The field was discovered in 2005. The lowest of three sands encountered in West Dikirnis-1 tested at 21.8 MMscf/d. The field was appraised and initially developed by the following wells:

- The West Dikirnis-2 well, which was completed in 2006, was drilled down-dip to the south of West Dikirnis-1. This well discovered a 70 ft oil column with an overlying gas cap and tested at 5,089 bbl/d with minimal drawdown.

- In late 2006, a further well, West Dikirnis-4, was drilled down-dip to the north of West Dikirnis-1 and successfully proved an oil rim of 54 ft. The well tested at 1,930 bbl/d.

- West Dikirnis-7 was drilled in February 2007, and encountered a 59 ft oil leg to the north of West Dikirnis-4, which tested at 1,572 bbl/d.

- In March 2007, West Dikirnis-3 was drilled east of West Dikirnis-2, penetrating thinner sands and a 40 ft oil column.

- In May 2007, West Dikirnis-9 was drilled to the north of West Dikirnis-3, and encountered an 85 ft oil column, which was tested at a maximum oil rate of 4,370 bbl/d.

- West Dikirnis-8, completed in August 2007, was drilled on the east flank of the field and encountered a 64 ft oil column. This well tested at a maximum oil rate of 1,875 bbl/d.

The field came on stream on 5th December 2007 with production tied back to an upgraded South Batra plant with a design capacity of 10,000 bbl/d. Production was ramped up to 6,700 bbl/d and 9 MMscf/d by the end of 2007, producing from wells WD-2, -3, -4, -8 and -9. WD-7 was put on production on 2nd January 2008. Plateau production of 10,000 bbl/d and 14 MMscf/d gas was achieved on 22nd February 2008, but field performance in 2008 was mixed. On the positive side, pressure data acquired confirmed that aquifer strength was close to the predicted level. However, gas coning into WD-2, WD-9 and WD-3 was faster than predicted. Surface sand production was observed at WD-3, and sand fill was observed in WD-3, -4, and -7. WD-8 suffered from liquid loading due to high water-cut. In order to control the gas-oil ratio (GOR) and limit sand production, wells were progressively choked back and field production had declined to 4,200 bbl/d prior to start of production from the first horizontal well.

Well WD-7 was sidetracked to become West Dikirnis's first horizontal well, WD-7 ST-4 HW. This well was put on production on 24th December 2008 and field production was increased to 6,902 bbl/d on 27th December 2008. The second horizontal well, WD-10 HW, was drilled in December 2008, and put on production in March 2009 at over 2,000 bbl/d. The third horizontal well was started as a sidetrack of well WD-4; however, the horizontal sidetrack was lost, and the well had to be re-drilled from surface as WD-12 HW. WD-12 HW came on stream 13th September 2009, producing 2,050 bbl/d. A fourth horizontal well, WD-11 HW, was drilled and completed in 2009, coming on stream 18th November 2009.

Overall field performance in 2009 was characterised by a steady increase in water-cut in those wells already flowing water, and increasing field GOR. The field was shut in for seven days at the beginning of June 2009 to prepare for tie-in of the Liquefied Petroleum Gas (LPG) Plant. Well WD-3 was unable to start naturally after the shut-in due to water-cut, but it was brought back on production after a number of days. The GOR trend increased more sharply in July 2009, and, when it became apparent that several months were still required before gas re-injection would be in operation, it was decided to choke back the wells and conduct a detailed testing exercise. This was successful in reducing the GOR of wells WD-2 and WD-7. Choke reduction on WD-10 HW appeared to have less effect, either because WD-10 HW also had a significant water-cut or because the installed inflow control devices were already controlling GOR to some extent. The water-cut of WD-8 gradually increased to a high level, and this well was shut-in on 16th September 2009. WD-9 had demonstrated more susceptibility to GOR increase until the end of 2008, but in January 2009 the well showed a very sudden increase in water-cut, and the well was temporarily shut in on 8th January. Attempts to lift in the well during 2009 were unsuccessful. Shallower perforations were added from 9,170 to 9,180 ft RKB but the well produced only water. It is now planned to convert WD-9 into a gas re-injection well.

2010 production performance can be split into pre- and post-Gas Re-Injection (GRI) periods. During the pre-GRI period, from January to mid-May, the oil rate was steadily declining, with the GOR increasing and water almost steady. In early March, most of the wells were shut in for one week to repair a leak on the main 10-inch flow-line. During March 2010, WD-8 was perforated across ‘Cycle C’ sands, which proved very successful and increased field oil production. WD-10 HW watered out and was eventually shut-in on 4th April 2010. In view of the very high water-cut from WD-3, it too was closed on 24th April 2010. Consequently, field water production was reduced from 3,500 to 900 bwpd. Gas re-injection commenced on 17th May. It continued until mid-July when it was temporarily stopped due to fouling of the gas turbine fuel injection valves. The valves were cleaned and spares ordered, and GRI recommenced on 1st September, since when it has been continuous. Since the start of GRI, oil production has been fairly stable and GOR and water-cut increases moderate.

During 2011, West Dikirnis production stayed remarkably steady. Average liquid hydrocarbon production was 3,522 stb/d, of which 1,352 stb/d is estimated to be black oil, 1,197 bbl/d is base condensate, 517 stb/d is additional condensate recovered from the LPG plant and 456 stb/d is LPG produced from the LPG fractionation unit. (Note that, although LPG is measured and sold as a separate stream, condensate is spiked into the oil storage tanks and therefore base condensate and oil cannot be separately measured). Average gas production remained at 26 MMscf/d and average gas injection rate was 23 MMscf/d. Compared with earlier years, production decline was very modest due to gas re-injection. Condensate and LPG yield from the LPG plant remained above expectation and the decline in yield was also slower than anticipated. At the start of the year five wells (WD-2, WD-7 HW, WD-8, WD-11 HW and WD-12 HW) were on production and they kept producing throughout the year. Two new wells, WD-5 EP2 and WD-13 HW, were drilled and completed during 2011: these were put on production in May and June, respectively. Installation of the gas-lift and GRI lines was completed during 2011.

The LPG Plant started operation at the beginning of October 2009, but problems of subsidence of the storage tanks prevented any sales during 2009. LPG sales started in January 2010 and LPG production was gradually increased, performing better than expected. Melrose has now made firm plans to proceed with the further phase of the LPG project, the installation of a refrigeration unit, which is planned to be on-stream in 2013.

Melrose has previously carried out studies which showed that re-pressurisation of the field to initial pressure has the potential to increase the oil recovery factor by several per cent. Simulation and PVT studies were initiated in 2011 to further assess this potential, by considering either hydrocarbon gas or nitrogen as the additional gas to be used for re-injection. Facilities engineering studies and further subsurface studies are planned in 2012 to confirm the feasibility of this concept. Currently, no consideration of this potential increase to West Dikirnis recovery factor has been assumed in any of the reserves categories.

One horizontal well is planned for 2013, with contingency for a second. Ultimate liquid hydrocarbon recoveries are estimated to be 16.2 and 19.5 MMstb at 1P and 2P level, respectively.

2.3.4 East Dikirnis

The East Dikirnis-1 well was drilled in December 2008 and encountered a thin oil rim of around 11 ft thickness with a 38 ft gas cap. The well was sidetracked as ED-1A to delineate the structure. Melrose's median estimate of Stock Tank Oil Initially In Place (STOIIP) is 0.7 MMstb and of GIIP is 4.6 Bscf. The well has been temporarily abandoned.

Analysis of gas samples acquired with the MDT show that the gas is quite rich in pentanes, and PVT simulations indicate that a Condensate Gas Ratio (CGR) of 53 bbl/MMscf can be expected at the South Batra Plant. Melrose is now finalising a firm plan to re-enter and complete East Dikirnis-1A for the development of the field. The plan will be to complete the well over a limited perforation interval opposite the oil column and produce at a low rate for a few months to recover as much oil as possible, before blowing down the reservoir by producing the well at a higher rate. We estimate that this will recover Proved plus Probable reserves of 2.6 Bscf gas, 0.09 MMstb oil and 0.10 MMstb condensate.

2.3.5 El Tamad

The El Tamad field is a Sidi Salim Formation reservoir, located on a down-faulted structural nose in the south-east of the license. It comprises a thin, 30 ft oil rim reservoir with a free gas cap, originally lying at a reservoir pressure of 2,900 psia. It is a stratigraphic trap on one of a series of narrow tilted fault terraces, which downstep northwards along east-west oriented faults. Faults and fault terraces are all truncated by the regional Top Sidi Salim unconformity, which sets up the trapping mechanism as top seal against the overlying, overstepping Kafr el Sheikh shales.

In May 2011, well Tamad-4 was shut in, production ceasing possibly because of sand bridging. Melrose is considering intervention options, but no more reserves are currently assigned to this well. Well Tamad-7 was successfully returned to production in mid-November, and Tamad-1 in December. 1.78 MMstb of oil had been produced by year end 2011, and currently the field is producing at about 240 bbl/d from the four available producers Tamad-1, -2, -3 and -7, tied back to a small oil plant. Material balance and volumetric estimates indicate a STOIIP of about 8 MMstb. To maximise recovery from this thin oil rim field, Melrose plans to drill a further horizontal well, Tamad-6, between the Tamad-3 and -4 wells in 2013.

El Mansoura Extension

2.3.6 South Zarqa

South Zarqa is an Abu Madi Formation discovery in the El Mansoura Extension concession found by well South Zarqa-1, drilled in September 2007. It is a gas accumulation to the north of West Dikirnis at about 8,000 ft tvdss. The extent of the discovery for reserves reporting purposes is defined by the seismic structural interpretation and the limit of an amplitude anomaly, though there is no structural closure to the south. The well-defined GWC at 8,442 ft tvdss is different from the contacts seen in West Dikirnis. Reservoir quality is good and the discovery well was tested at gas rates of up to 17 MMscf/d, with a gas condensate ratio of up to 40 bbl/MMscf. The field came on stream on 20th April 2009.

Bottom hole pressure surveys were conducted in January, April and December 2010 and in May 2011. These data were used to estimate GIIP using material balance. There is no doubt that there is an aquifer actively supporting the pressure, but at this stage there is insufficient evidence to distinguish between a weak or a strong aquifer, and between a larger or a smaller GIIP, so that we maintain a relatively wide range of uncertainty on GIIP and reserves. Melrose has estimated a GIIP of 58 Bscf by material balance assuming a strong aquifer, which is consistent with volumetric estimates; and a simulation model was built to estimate the recovery factor from this well.

South Zarqa-1 is tied in to the South Batra plant along with North-East Abu Zahra via a 10-inch flow-line. In May 2011, the well began producing formation water. To remedy this, a water shut-off job was performed successfully in June 2011, isolating the lower perforations by setting a bridge plug. By year end 2011, this well had produced 16.7 MMscf gas. In view of sand and water production, another development well, South Zarqa-2, will be drilled in 2013. This well will be completed according to the recommendations of an ongoing sand control study.

Melrose has installed booster compressors ‘E’ and ‘F’ at the South Batra plant. These compressors have suction pressures of ca. 500 psi and will allow reduction of the South Zarqa Flowing Tubing-Head Pressure (FTHP) to 900 psi. Furthermore, in early 2015 a compressor with capacity of 17 MMscf/d will be installed to cope with Northern fields’ compression requirements. It will allow the FTHP of South Zarqa-1 and -2 to be reduced further to 350 psi, leading to a high recovery factor, subject to water control.

Expected ultimate recovery from South Zarqa-1 and-2 based on the simulation study is 36.5 Bscf. The recovery factor is 63%.

2.3.7 North-East Abu Zahra

North-East Abu Zahra is a Qawasim Formation discovery at about 9,600 ft tvdss, drilled in September 2007. The asset straddles the El Mansoura Extension concession boundary with the El Wastani concession, operated by Dana Gas. The estimated reserves given in this report relate to the GIIP volumes mapped within the Melrose acreage only. Dana Gas drilled El Basant-1 (formerly named Al Tawil-1) in their part of the structure in June 2008, confirming an extension of the accumulation. In December 2008, Dana Gas drilled appraisal well El Basant-2, in 2009 the El Basant-3 and El Basant-4 wells (see **Figure 2.1**), and in 2010 El Basant-5 (even further north-east). Reservoir quality diminishes to the north-east into the Dana Gas acreage. El Basant-2 is producing from a deeper, thin sand that is not connected to the main reservoir, whilst El Basant-1, -3 -4 and -5 are producing from the main reservoir. A Joint Exploitation Agreement has been negotiated between Melrose and Dana Gas, and approved by EGAS. Dana Gas has formally agreed to increase the “Preliminary GIIP” in the Exploitation Agreement from 25 to 38 Bscf.

The trap is formed by stratigraphic pinchout of sands to the east, fault closure to the north and west and a structural low to the south. Reservoir quality is moderately good with average porosity of 20%, and the discovery well, North-East Abu Zahra-1, was tested at gas rates of up to 20 MMscf/d with a condensate gas ratio of over 30 bbl/MMscf. The field came on stream on 21st April 2009. It produced steadily until December 2010, when formation water production was reported and the well was choked back accordingly. A water shut-off job was performed in June 2011 but subsequent production performance was not promising due to sand failure.

A development well, North East Abu Zahra-2, was drilled in the second half of 2011. It came in structurally deeper than the prognosis and reservoir quality was poorer than anticipated. This well was put on production on 7th December at a gas rate of 4 MMscf/d. By the end of 2011 cumulative gas production from this field was approximately 13 Bscf. Reservoir simulation modelling suggests that NEAZ-2 will recover in excess of 5.6 Bscf. However, in view of the uncertainty on sand production we have taken a cautious view and we expect ultimate gas recovery from both wells will be 16 Bscf (Proved plus Probable, Developed and Undeveloped).

2.3.8 East Abu Khadra

Well East Abu Khadra-1 was drilled in March 2008 and found a gas column in a 50 ft Miocene channel sand with a GDT at 9,805 ft tvdss and a net pay of 26.5 ft. A nearby well drilled by Petrobel to the north found a GWC at 9,945 ft tvdss. Whether this is structurally separate from East Abu Khadra depends on the depth conversion. In the axis of the channel to the south-east, where the sand thickens to over 250 ft gross, lies the East Delta field, with a GWC of between 9,860 and 9,890 ft tvdss. The East Abu Khadra structure does not close, so the sand has to pinch out to the west to create a trap. While there are seismic events near the top and base of the channel that can be mapped clearly in the thick channel axis, it becomes progressively harder to map these accurately towards the critical pinchout. The size of the accumulation also depends on depth conversion, and there are few wells, giving contradictory results, leading to uncertainty in the Gross Rock Volume (GRV). Net-to-gross (NTG) also increases into the channel axis and this needs to be accounted for in the calculation of GIIP.

By using a realistic velocity map for depth conversion, Senergy has mapped a structure for East Abu Khadra (**Figure 2.2**) that shows closure against the pinch-out edge to the west. The map also shows the recent Petrobel well in a very small independent closure which may be in communication with East Abu Khadra; the velocity map additionally ensures that the East Delta field closes to the west. The structure has potential for closure well below the GDT seen in the well. In fact, the lowest closing contour, 9,940 ft tvdss, is almost identical to the GWC seen in the Petrobel well, which may give support to this being the GWC for the East Abu Khadra accumulation. Net rock volume estimates by Senergy appear to give scope for a GIIP of up to 50 Bscf. The structure is also connected to a vast permeable reservoir extending to the north and south, with the possibility of aquifer support.

East Abu Khadra-1 was completed in Abu Madi Level-2 sands and tested to a maximum rate of 12.9 MMscf/d, with a condensate gas ratio of 14 bbl/MMscf. The well was put on production on 23rd December 2008. Performance has been steady and at the end of 2011 the well had produced 8.6 Bscf of gas and 89,000 bbl of condensate. Currently this well is producing 8.7 MMscf/d and 68 bbl/d condensate at a flowing tubing head pressure of 1,875 psi. Pressure build-up surveys conducted in May 2009 (after producing 0.9 Bscf), July 2010 (3.9 Bscf), December 2010 (5.29 Bscf) and October 2011 (7.92 Bscf) allow analysis by material balance. This analysis, combined with consideration of the FTHP trend, shows an apparent GIIP in the region of 50 Bscf if there were no aquifer support. However, such support is likely, and Senergy has estimated that the GIIP lies in the range of 32 to 46 Bscf. Melrose has calculated by material balance that the most likely GIIP is 40 Bscf assuming a moderate aquifer support, and this was adopted for the Proved plus Probable case.

Compression arrangements as described under South Zarqa (Section 2.3.6) will lead to high recovery factors. In view of the likely active aquifer, 1P and 2P recovery factors of 65 and 75%, respectively, were applied to calculate reserves.

2.3.9 West Zahayra

The West Zahayra discovery well was drilled at the end of 2007 in the central area of El Mansoura concession, 7 km west of the West Dikirnis field. It encountered 22 ft of net pay in fluvio-estuarine sands of the Qawasim Formation. The trap is formed by stratigraphic pinchout to the south-east, as delineated by seismic attributes. The well was temporarily suspended without testing. In the first half of 2011, the well was re-entered and completed. The re-entry well was kicked off from the $9^5/_8$-inch casing and drilled to total depth of 10,200 ft. West Zahayra-1stRE was drilled 114 ft to the south of the original well and encountered 39 ft of net oil pay with a porosity of 16%.

The well was completed with 3½-inch completion. An extended production test was conducted in August and September 2011. The flow period exhibited a steady oil production rate of 100 stb/d and 0.15 MMscf/d of associated gas. The pressure data from the build-up showed no measurable pressure depletion, and the slight decline in flowing pressure gives assurance of the minimum volume of oil contacted.

STOIIP is estimated to be 0.4 to 1.3 MMstb. We estimate that the well will recover Proved plus Probable reserves of 0.3 Bscf gas and 0.13 MMstb oil.

South-East El Mansoura Concession

2.3.10 Damas

Well Damas-1 was drilled in April 2008 and encountered three stacked pay zones within the Sidi Salim Formation. MDTs show that each of the pay zones contains wet gas. Zones 1 and 3b have GDT levels, whereas Zone 2 has a gas-water contact.

The well was completed in Zone 3b and tested to a maximum rate of 14.25 MMscf/d, with a condensate gas ratio of 7 bbl/MMscf. Interpretation of pressure decline during the test suggested a Zone 3b GIIP of about 3 Bscf. Melrose's median estimates of GIIP are 3.34 Bscf for Zone 3b and 7.2 Bscf for all three zones.

Damas-1 was put on production on 7th July 2009. It produced 1.8 Bscf gas and 17,205 bbl condensate up until 12th August 2010. At that time the well was temporarily shut-in to allow South Damas-1 to be produced at a higher rate and provide a sufficient volume for material balance analysis on South Damas by year-end.

It was planned to restart Damas-1 production in the first quarter of 2011; however, South Damas-1 GIIP turned out to be larger than previously estimated. In view of this, Melrose decided to defer production from Damas-1 until the end of 2014 to equalise flowing tubing head pressures from both the fields.

Ultimate recovery predicted from decline curve analysis is 3.0 Bscf (Zone 3b). After depleting Zone 3b, Melrose may perforate shallower Zones 1 and 2, but Senergy's opinion is that the risk of early water influx in Zone 2 means that no reserves can be assigned to these two zones at this time.

2.3.11 South Damas

South Damas lies about 6.5 km south-south-west of the Damas field. The South Damas-1 well was drilled in December 2009 through February 2010 and discovered gas. The well was completed, and it was tested on 14th and 15th February. The producing formation is the Qawasim (Messinian), and the logs show a clean, high net-to-gross, largely homogeneous sand with a number of thin shale beds. MDT pressure data show a clear free water level at 4,372 ft tvdss.

The accumulation at South Damas is dip-closed to the south-west, north-west and north-east, and sealed to the south-east by an erosion channel filled by shales above the Base Kes unconformity. **Figure 2.3** shows the mapped gas-water contact intersecting the top reservoir depth map (the black outline). The seismic horizon for the Base Kes Formation marks the top of a strong amplitude package, making the unconformity the most straightforward, consistent seismic pick in the area of the South Damas structure. The time horizon was depth converted by Melrose and then shifted downwards to tie the “Top Pay Zone” well pick at 4,291 ft tvdss to provide a consistent structural closure at reservoir level. Also shown in **Figure 2.3** (in green and yellow) are areas of high seismic Root Mean Square (RMS) amplitude response. Although not entirely confined within the contact contour, the large area of high response in the south-east around the well (blue outline) conforms closely to the structural contours and GWC, suggesting that areas of high amplitude response conform to areas of good reservoir filled with gas. It is not clear from seismic whether the whole area contains good reservoir and is in communication with the well. For further evidence of the extent of the reservoir, pressure data were analysed.

South Damas-1 was tied into existing South Mansoura processing plant and came on stream on 2nd June 2010. The well was gradually beaned up to 13 MMscf/d by November 2010. It is currently producing steadily on a $^{38}/_{64}$-inch choke at a gas rate of 12 MMscf/d and with condensate/gas ratio of 7 bbl/MMscf. The water/gas ratio is less than 1 bbl/MMscf and is consistent with water of condensation. At the end of 2011 this well had produced 6.5 Bscf gas and 47,000 bbl of condensate.

Pressure build-up surveys conducted in December 2010 (after producing 1.9 Bscf), May 2011 (3.8 Bscf) and September 2011 (5.3 Bscf) allow analysis by material balance. Data from all the build-ups are consistent and support a GIIP of 56 to 62 Bscf. This well has a very high productivity index (the average permeability of the test interval was 1,950 mD) and pressure drawdown during all PBUs was only 7 psi; it means that coning will not be a problem.

This well will benefit from the compression facility of the South Mansoura plant and flowing tubing head pressure can be lowered to 200 psi, which will lead to high potential recovery factor. Recovery factors of 70% (Proved) and 80% (Proved plus Probable) were applied to calculate reserves of 39.2 and 49.6 Bscf, respectively.

2.4 Hydrocarbons-Initially-in-Place

Senergy has made estimates of HIIP. These estimates are based on decline or material balance calculations where production and pressure data are available, and on mapping controlled by seismic and well data. The estimates are discussed above and summarised in the “Reserves Summaries”, on a gross basis.

Material balance is used to estimate GIIP for West Khilala. There is reasonable pressure and production history to apply material balance: cumulative production is more than 48% of GIIP. The aquifer seems to be very weak and GIIP was estimated by material balance assuming weak water influx.

Proved and Proved plus Probable HIIPs for West Dikirnis were estimated based on mapping controlled by seismic and well data. The recent wells confirm the lateral presence of oil but reveal further reservoir complexity. Recent well results and another year of production were used by Melrose to update mapping and fine-tune volumetric estimates. The volumetric analysis was also refined by dividing the field into polygons for STOIIP and GIIP calculations. This resulted in the following in-place estimates: 2P STOIIP of 28.3 MMstb, and 2P GIIP of 116.6 Bscf (of which 67.6 Bscf is gas cap GIIP). We then applied a risk factor to obtain 1P in-place estimates: 1P STOIIP of 22.6 MMstb, and 1P GIIP of 93.3 Bscf (of which 54.0 Bscf gas cap GIIP). The difference between 1P and 2P in-place estimates is greater than previously estimated: this is intended to reflect the reservoir uncertainty revealed by the infill drilling program during 2011.

2.5 Recoverable Reserves and Production Profile

Reserves were generally estimated using a combination of decline curves and recovery factors from analogue fields, the latter especially in cases where the absence of sufficient production history or other data precludes more technical methods of estimating reserves. Recovery factors of 81 and 88% were calculated for the Proved and the Proved plus Probable gas recovery, respectively, from West Khilala, based on pressure and production history and RST survey results.

For the major oil-field, West Dikirnis, Melrose's simulation model was used to calculate the 2P recovery factors for oil and gas in each of the three polygons created to calculate volumetrics. Recovery factors are high for the southern good-quality sands and low for the northern area. The overall field recovery factor (black oil recovery alone) was calculated to be 32%. The Proved plus Probable (2P) recovery factor for the West Dikirnis gas blow-down case was estimated to be 82%. When considering the Proved recovery factors, the more conservative approach used for the Proven in-place volumes has to be taken into account. As a result, it is considered appropriate to assign similar Proved recovery factors, namely 33% for oil and 79% for gas. These were applied to the Proved HCIIP estimates to arrive at Proved ultimate recovery. A similar method was used in the Developed cases (1PD and 2PD), using a simulation that included no further drilling. Finally, since the LPG project will result in recovery of additional liquids in the form of incremental condensate and a new LPG stream, a review of process yield calculations was carried out to establish estimates of the additional liquid recovery to be expected; compositional simulation was used as a guide to future decline in yields.

A new approach to describing condensate and LPG in-place and recoverable volumes was taken. The current approach states the in-place volumes of condensate and LPG in the gas cap alone. Previously, the reported condensate and LPG included in-place and recoverable liquids from the associated gas evolved from the oil rim as well as liquids recovered from the gas cap gas. Due to the very volatile nature of the West Dikirnis oil, substantial volumes of condensate and LPG are recovered from the associated gas of the oil rim. In addition to this, again due to the very volatile nature of the oil, simulation and PVT studies show that a very effective vaporisation process takes place when re-injected dry gas from the refrigeration plant interacts with the remaining oil in the reservoir. These recoverable volumes are best considered as recovered from the STOIIP and treated as leading to an increase in the oil recovery factor. As a result of the above processes, the recovery of condensate and LPG from the oil rim is substantial, leading to an overall increase in the combined oil, condensate and LPG recovery factor from STOIIP over the black oil figures given above to 46% in the 1P case and 45% in the 2P.

For El Tamad, an extrapolation technique was used, based on the observed development of water-oil ratio and the decline in total liquid production. In the Proved case, a pessimistic decline was assumed, whereas in the Proved plus Probable case a most likely decline was used. The 1P cases and the 2P Developed case allowed for no further drilling; for the 2P Developed and Undeveloped case the addition of one horizontal well was allowed for in July 2013.

Elsewhere, reserves were estimated based on production decline where available. In the absence of production data, more modest gas recovery factors were applied, ranging from 50%, in cases where water ingress is a risk, to 80% in the better quality reservoirs. Available simulation models were also used on a number of fields to estimate the recovery factors.

Condensate reserves were based on gas reserves, using observed condensate yields where appropriate, or assuming a lowering of yields with time as reservoir pressure declines, as observed in many of the producing assets.

Recoverable reserves are given in Section 8, “Reserves Summaries”. Note that, where probabilistic methods have been used, values of Proved hydrocarbons-in-place are not necessarily comparable with figures for Proved reserves and ultimate recovery. In particular, it is not always valid to infer a ‘Proved recovery factor’.

The reserves given in Section 8 refer to ‘feed’ gas, i.e. before processing or fuel consumption. The corresponding deductions to be made for shrinkage and fuel are given in Section 9. In most cases the deductions were estimated as a percentage of feed gas based on historical sales/feed ratios. Additional allowances were made where incremental compression facilities are part of the development plan.

2.6 High Graded Prospect Inventory

Melrose has identified over thirty undrilled prospects and leads from its existing modern seismic 3D dataset within both the El Mansoura and South East Mansoura blocks. From the total prospect inventory Melrose have high-graded the eight most significant prospects which have each been evaluated by Senergy (**Figure 2.4**). The high-graded prospects fall into two distinct hydrocarbon play types, namely:

El Mansoura Qawasim Play:

- Mustafa, Mit Hadid, NE Zahayra and SW Tarif oil, condensate and gas prospects.

SE El Mansoura Lower Cretaceous Play:

- Al Hajarisah, Kafr Saqr, Sidi Gohar and Sinbelaywan light volatile oil and associated gas prospects.

The four Qawasim prospects are located within the El Mansoura block and are directly analogous to Melrose's proven Qawasim fields and discoveries. The prospects target the uppermost 'hard' sand member of the Qawasim Formation. Three of these prospects lie adjacent to Qawasim oil, condensate and gas fields and are categorised as near field exploration opportunities. The remaining prospect can be categorised as green field exploration.

The Lower Cretaceous prospects are located within the South East El Mansoura block and represent the identification of a possible, but as yet unproven, play analogue to the productive Lower Cretaceous of the Egyptian Western Desert oil and gas play. Each identified Lower Cretaceous prospect has three stacked vertical reservoir objectives.

As reported by Melrose no exploration drilling commitments remain in the El Mansoura block. However it is likely that should an exploration period extension be granted to Melrose this would require at least one firm well commitment. One remaining commitment exploration well has to be drilled by Melrose in South East El Mansoura.

In order to arrive at a view of Egyptian prospective resources Senergy reviewed and reality checked El Mansoura and South East El Mansoura geophysical and geological maps, selected seismic lines, petrophysical analyses, selected key well interpretations and cross sections, geological study results and other analogue field statistical information supplied by Melrose. Senergy utilised its general industry experience plus specific knowledge of Melrose's Egyptian fields and other analogous producing Egyptian assets to reality check Melrose's input data for volumetric calculations. Senergy's evaluation did not include any independent seismic interpretation, time to depth conversion or petrophysical analyses specific to each identified prospect.

From its evaluation of information provided, Senergy concludes that the subsurface analyses and interpretations undertaken by Melrose are technically valid and are consistent with industry best practice. In addition Senergy broadly concurs with Melrose's input parameters and overall assumptions used in volumetric calculations of oil and gas in place generated and can replicate results within an acceptable margin of accuracy.

Prospects are covered by modern vintage 3D seismic data of good quality. The prospects are described individually in Sections 2.6.1 and 2.6.2 below.

2.6.1 El Mansoura Qawasim Play and Prospects

2.6.1.1 Play Description, Analogue Fields and Wells

The El Mansoura prospects lie in the proven Qawasim play fairway as demonstrated by Melrose's adjacent W. Dikirnis, E. Dikirnis, West Zahayra and North-East Abu Zahra fields (see Sections 2.2.3, 2.3.3, 2.3.4. and 2.3.7 of this report).

Prospect trapping configurations are interpreted by Melrose and Senergy to be similar to Melrose's fields, being simple low-relief 4-way closures or 3-way dip and fault traps defined at the Top Qawasim/Base Kafr El Sheikh seismic horizon. Melrose's Qawasim fields demonstrate weak to moderate direct hydrocarbon indicators, usually in the form of amplitude and AVO anomalies that possess some degree of structural conformance to the known occurrence of hydrocarbons at top reservoir horizon. Melrose has undertaken fluid substitution modeling which to a reasonable degree of certainty indicates that the seismic anomalies likely result from gas, gas and condensate and/or possibly light volatile oil filled Qawasim porosity. In the case of the West Zahayra field and West Zahayra-2 dry hole, whilst the DHI conformance to structure is good, the correlation to hydrocarbons is however inconclusive. With the exception of the Mit Hadid prospect, Melrose has identified seismic amplitude and AVO anomalies in three high graded Qawasim prospects that show some degree of conformity with mapped Top Qawasim structure. The absence of an obvious DHI in the Mit Hadid prospect could indicate either a lack of charge, reservoir absence or reservoir thinning below tuning thickness. Alternatively the observed DHI's could represent false positive responses unrelated to hydrocarbon filled pore space.

Seismic quality is generally good over the mapped prospects with a high degree of confidence in the resultant Top Qawasim time horizon. Velocity data calibration for time to depth calibration over the prospects is less than optimal over the Mit Hadid, Mustafa and SW Tarif prospects due to relatively sparse well penetrations in the prospect areas. The resultant uncertainty in time to depth conversion over the Mit Hadid and Mustafa prospects results in a significant low to high case range of expected hydrocarbon column height of 95 to 140 ft with a significant effect on resultant volumetrics. Senergy utilised a Qawasim depth map in its volumetric evaluation based upon Melrose's P_{50} (most likely case) depth conversion for all prospects.

Melrose interpret the Qawasim fields to be hydrocarbon filled to mapped spill-point which, if correct, demonstrates ample hydrocarbon charge is available to fill identified prospects. Senergy concurs that this is a reasonable conclusion based upon the data made available for this evaluation. Prospects have been modelled to contain a light volatile oil rim overlain by a wet gas or wet gas and condensate cap as seen in the nearby West Dikirnis, East Dikirnis, and Tamad fields. Oil rims range from 11 ft in East Dikirnis to 85 ft in West Dikirnis or approximately 50 to 80% of GRV. Gas caps can be rich in condensate as seen in West Dikirnis with up to a 54 bbl/scf condensate to gas ratio.

As detailed in Section 2.3.3 the Qawasim reservoir is well developed in the prospect area. Whilst the Qawasim can consist of stacked fluvial-estuarine sands of over 250 ft (West Zahayra-2) prospects have been modeled assuming the development of one U. Qawasim 'hard sand' of between 50 and 120 ft with high net to gross as seen in East Dikirnis and North West Zahayra. Proven reservoir quality is good with between 17 and 22% porosity in offset wells West Zahayra-1, 1 ST1 and 1 ST2, West Zahayra 2, East Dikirnis-1, East Delta-4 and North East Abu Zahra-1. The West Dikirnis and West Zahayra field wells demonstrate that there is an element of stratigraphic trapping within the U. Qawasim due to variable sand bed thicknesses and geometries and intra-formational shale seals. Consequently it is possible that the Qawasim reservoir sequence in the prospects contains a much higher degree of complexity and thickness variation than modelled in volumetric calculations.

Top seal is provided in all prospects by the regional play seal of the Kafr El Sheikh Shale Formation.

Senergy interprets that the main exploration/prospect risk element is trap definition together with some degree of uncertainty placed upon the development of the expected Qawasim 'hard sand' reservoir thickness. Although prospects have been modeled with an oil rim and wet gas/condensate cap it is possible that traps could be filled entirely with wet gas or gas and condensate.

2.6.1.2 Prospect Descriptions

2.6.1.2.1 North West Zahayra Prospect

The prospect is a seismically well defined normal fault bounded 3-way dip footwall closure (**Figure 2.5**). North West Zahayra lies on a downthrown fault terrace segment of a larger upthrown rotated fault block complex which includes the West Zahayra field 3.5 km to the south. Maximum relief from crest at ca. 10,750 ft tvdss to mapped spill point at ca. 10,980 ft tvdss is 420 ft with a mapped maximum closure of approximately 850 acres (3.5 km^2). Melrose interpret a weak amplitude anomaly which conforms roughly to the mapped 10,750 ft closing contour, an inconclusive AVO anomaly at the crest and a 'fluid factor' anomaly which corresponds approximately to the 10,850 ft tvdss contour (**Figure 2.6**). The same DHI parameters also occur at Top Qawasim level in the West Zahayra field and W. Zahayra-2 dry hole to the south thus indicating that the DHI may not be wholly indicative of hydrocarbon presence. Melrose has assumed that the significant East - West prospect-bounding fault provides lateral seal. Although Senergy have not seen any fault juxtaposition or fault-seal analyses for this fault it seems a reasonable assumption that the overlying Kafr El Sheikh shales will provide sealing capacity. The expected reservoir case has been modeled by Melrose assuming the prospect contains a similar 119 ft thick Qawasim 'hard sand' gross reservoir as found in the West Zahayra field which is a reasonable assumption given this is the closest well control. Upside reservoir thickness of up to 250 ft is demonstrated in the W. Zahayra-2 dry well.

2.6.1.2.2 Mustafa Prospect

Mustafa is a reasonably seismically well defined simple low-relief 4-way dip closure at the top Qawasim seismic horizon (**Figure 2.7**). The crest is mapped at 7,640 ft tvdss and max spill point at 7,080 ft tvdss, a closure of ca. 1,300 acres. The structure is sensitive to time-depth conversion as time map and depth map are not totally conformable. Melrose have used three depth conversion methods to bracket possible TZ outcomes which result in a variation of possible column height of 95 to 135 ft and a resultant high moderate effect on calculated GRV. A weak DHI exists over the prospect which Melrose believes might indicate a possible thinner hydrocarbon filled reservoir than seen in East Dikirnis-1. Senergy has not reviewed this DHI work in any detail. The expected reservoir case has been modeled by Melrose assuming the prospect contains a similar 50 ft thick Qawasim 'hard sand' gross reservoir as found in the East Dikirnis field 5 km to the west which is a reasonable assumption given this is the closest well control.

2.6.1.2.3 Mit Hadid Prospect

Mit Hadid is a seismically well defined simple low-relief 4-way dip closure at the Top Qawasim seismic horizon (**Figure 2.8**). The prospect lies in the hanging wall to the East Dikirnis field 1.75 km to the south. The crest is mapped at 7,940 ft tvdss and max spill point at 8,020 ft tvdss, a closure of ca. 860 acres. The spill point is defined by the East Delta 4 well which encountered wet Qawasim at ca. 8,030 ft tvdss. Senergy observes that the maximum structural closure could extend to 8,080 ft tvdss which could indicate the trap is either not full to spill (i.e. undercharged or breached) or alternatively the map is in error. The structure is sensitive to time-depth conversion as time map and depth map are not totally conformable. A similar uncertainty in time to depth conversion as seen in the Mustafa prospect is expected. Melrose does not recognise a reliable DHI over the prospect which might reflect a thinner hydrocarbon filled reservoir than East Dikirnis or possible water filled Qawasim pore space.

Senergy has not reviewed this DHI work in any detail. The expected reservoir case has been modeled by Melrose assuming the prospect contains a similar 50 ft thick Qawasim 'hard sand' gross reservoir as found in the East Dikirnis field 1.75 km to the south which is a reasonable assumption given this is the closest well control.

2.6.1.2.4 SW Tarif Prospect

SW Tarif is a seismically well defined NE-SW trending elongate 4-way dip and fault dissected antiform at the Top Qawasim seismic horizon (**Figure 2.9**). The prospect represents the crest of a tilted NE-SW trending fault block dipping to the NW. The crest is mapped at 6,700 ft tvdss and max spill point at 6,975 ft tvdss a closure of ca. 860 acres. The structure is less sensitive to time to depth conversion than either Mustafa or Mit Hadid due to greater relief and conformity with time mapping. The prospect is partly bounded on the southern flank by NE-SW trending normal fault throwing to the south-east and requires cross fault seal to retain trap integrity. Top and lateral fault seal are thought to be provided by overlying Kafr El Sheikh shales which is a reasonable assumption.

The prospect is shown on regional seismic lines to be updip of both the South East Dikirnis 1 and South Tarif 1A Qawasim dry holes. Melrose states that the prospect displays a weak DHI at the Top Qawasim seismic horizon. Senergy has not reviewed an amplitude map to assess if the DHI conforms to mapped closure or viewed any fluid substitution modeling that might support an indication that the anomaly is indicative of hydrocarbon filled porosity. The expected reservoir case has been modeled by Melrose assuming the prospect contains a similar 50 ft thick Qawasim 'hard sand' gross reservoir as found in the East Dikirnis field 9 km to the north. Similar thicknesses are also found in the closest wells, namely South East Dikirnis and Tarif 1a which gives reasonable support to the gross reservoir model.

2.6.1.3 Hydrocarbons-Initially-In-Place: Gross Rock Volume Methodology

As the expected Base Qawasim 'hard sand' reservoir is not resolvable on seismic trap GRV has been calculated using the Top Qawasim depth surface and an expected reservoir thickness. As stated in prospect descriptions Melrose has assumed a most likely case reservoir thickness based upon the closest known field analogue, which is a reasonable approach given the relatively sparse well density. Senergy has in general concurred with Melrose's net reservoir assumptions, although it has used a slightly narrower P_{90} - P_{10} range. Senergy gross reservoir inputs are as follows:

El Mansoura Reservoir Thickness (Ft)					
Property	**Prospect**	**Mean**	**P_{90}**	**P_{50}**	**P_{10}**
Gross Reservoir	NW Zahayra	126.0	78.2	119.0	181.0
Gross Reservoir	Mustafa	49.4	38.0	48.5	62.0
Gross Reservoir	Mit Hadid	49.4	38.0	48.5	62.0
Gross Reservoir	SW Tarif	51.0	40.0	50.2	63.0

Spill point distributions assume prospects are full to spill point and generally use the lowest closing contour as a P_{10} value. Senergy concurs that this assumption is reasonable.

Melrose arrives at an input GRV distribution via three deterministic cases using $P_{90}/P_{50}/P_{10}$ closure areas from mapping then assigns a reservoir thickness to each closure case. The three outcomes are then fitted to a lognormal distribution which is then used as input into a probabilistic volumetric simulation. In Senergy's view this methodology may skew the GRV distribution towards the P_{10} assumptions and does not simulate the possible outcomes of combining the closure/spill and reservoir thickness distributions (i.e. the P_{10} GRV assumes a P_{10} reservoir only not a P_{90}/P_{50}/P_{10} reservoir distribution). Senergy's evaluation uses a stochastic simulation combining top reservoir surface, reservoir thickness and spill point distributions to arrive at a GRV distribution. In general as both the Senergy and Melrose methods utilise the same surface input and similar reservoir thickness distributions the mean and P_{50} GRV values are reasonably similar. Melrose's P_{10} GRV's are usually larger than Senergy's.

The volumetric estimates also use the assumption that the prospects will contain a light volatile oil rim under a wet gas or gas and condensate cap. This is a reasonable assumption based upon the closest Qawasim fields East and West Dikirnis and the Sid Belim Formation Tamad field (see Sections 2.3.3 to 2.3.5 and 2.6.1.1). Oil rim thickness is difficult to predict and a simplistic approach based on the percentage of GRV filled with gas is used. The distribution below is taken from Melrose's calculation of gas and oil filled GRV from Tamad, East and West Dikirnis. Senergy has not independently calculated these metrics.

Percentage (%) of GRV Filled with Gas			
	P_{90}	P_{50}	P_{10}
All EM Prospects	51	67	78

2.6.1.4 Petrophysical Parameters

Melrose's average petrophysical inputs for porosity and net to gross distributions seem reasonable although Senergy has reduced the P_{10} values in the distributions to match observed well values. Although Senergy has utilised Melrose's Sw distributions in its evaluation it believes that Melrose likely underestimates the effect on oil saturations in thin oil rims due to the presence of a transition zone. That could be a significant percentage of oil filled pore space.

NW Zahayra Reservoir Parameters					
Property	Reservoir	Mean	P_{90}	P_{50}	P_{10}
NTG (-)	Qawasim	0.76	0.28	0.37	0.93
Porosity (-)	Qawasim	0.26	0.06	0.19	0.33
Sw (-)	Qawasim	0.44	0.06	0.37	0.51

2.6.1.5 Stochastic results

Melrose's resultant probabilistic outputs for the GIIP estimates were replicated by Senergy to within a reasonable margin of error and the following aggregated reservoir volumes were adopted as tabulated below. Stochastically aggregated sums were then derived for each of the Low, Best and High cases.

Gross Liquids-Initially-In-Place (Mstb)			
Prospect	**Low Estimate**	**Best Estimate**	**High Estimate**
Mit Hadid	1,000	2,570	5,460
Mustafa	2,260	4,800	9,000
NW Zahayra	1,180	3,290	7,120
SW Tarif	942	3,750	9,390

Gross Gas-Initially-In-Place (Bscf)			
Prospect	**Low Estimate**	**Best Estimate**	**High Estimate**
Mit Hadid	4.3	10.3	20.3
Mustafa	9.7	19.5	33.5
NW Zahayra	5.6	14.6	29.2
SW Tarif	4.0	15.5	35.6

Potentially recoverable volumes were derived by application of a range of gas recovery factors normally distributed between a P_{90} of 0.75 and a P_{10} of 0.90, and the results are tabulated below.

Gross Prospective Resources (Mstb)			
Prospect	**Low Estimate**	**Best Estimate**	**High Estimate**
Mit Hadid	407	1,009	2,089
Mustafa	926	1,904	3,457
NW Zahayra	319	863	1,818
SW Tarif	383	1,501	3,626

Gross Prospective Resources (Bscf)			
Prospect	**Low Estimate**	**Best Estimate**	**High Estimate**
Mit Hadid	3.0	7.4	14.9
Mustafa	7.9	15.8	27.4
NW Zahayra	3.9	10.3	20.9
SW Tarif	2.8	11.1	26.1

2.6.1.6 Chance of Success

Melrose has assessed presence and effectiveness of Trap, Seal Reservoir and Source together with Migration and Timing. Senergy has reviewed these factors and estimated the overall COS for each prospect as tabulated below.

Prospect	Reservoir
	Qawasim
Mit Hadid	0.31
Mustafa	0.40
NW Zahayra	0.40
SW Tarif	0.42

Senergy sees the same overall COS in the El Mansoura prospects as Melrose and recognises that the main risk element is trap definition combined to a lesser extent with the presence and distribution of ample Qawasim reservoir rock.

2.6.2 Southeast El Mansoura Play and Prospects

2.6.2.1 Play Description, Play Analogue and Overall Risks

The Al Hadjarisah, Sinbelaywan, Sidi Gohar and Kafr Saqr Prospects (**Figure 2.4**) are interpreted by Melrose to lie within an unexploited Lower Cretaceous play which is analogous to the West Desert petroleum system. Each identified Lower Cretaceous prospect is modeled to contain 3 stacked vertical reservoir objectives in Albian, Barremian and Neocomian reservoirs. Melrose plans to test this concept with its remaining commitment exploration well.

The play area within the block is very lightly explored containing only three Lower Cretaceous well penetrations (Monaga-1, Sindy-1, Mit Ghamr NE-1 ST). The prospect area is covered by good quality 3D seismic and there is a good degree of confidence in time and overall depth mapping. The Top Albian and Barremian reflectors have been mapped by Melrose with reasonable confidence over the area. Prospects are generally well defined from seismic and are E-W elongate 3-way dip and fault bounded antiforms. Mapped prospects show a similar structural style at top reservoir to some fields in the West Desert, although many fields show the presence of inverted normal faults which is not evident in the mapped prospects. Senergy however concurs that to within a reasonable degree of confidence the fields provide a reasonable trap style analogue to the South East El Mansoura play.

The play lies in the southern part of the South East El Mansoura block to the south of a Neogene hinge line which delineates the southernmost limit of the known Nile Delta petroleum system. The Lower Cretaceous section in the block rises up towards the south where eventually it reaches near surface lying beneath Quaternary to recent sediments as shown by the R-69-1 well 57 km to the south of the Mit Ghamr NE-1ST well. Trapping within the play is therefore highly reliant on fault dependent closures which counter the strong regional south to north dip. Melrose is unaware of any oil/gas seeps reported in the R-69-1 well or to the south of the block in Lower Cretaceous rocks area which might confirm an active petroleum system.

Senergy have looked at generalised well CPI's and correlation sections through the three key Lower Cretaceous well within the block (Monaga-1, Sindy-1, Mit Ghamr NE-1 ST) and two wells outside of the block to the west (Shibin El Kom and Tanta-1). Melrose's petrophysical analyses, end of well report and CPI's were reviewed in more detail on the Mit Ghamr NE-1 ST well.

In Senergy's view, the well penetrations examined establish that the South East El Mansoura Lower Cretaceous section is stratigraphically analogous to the productive section in the West desert petroleum system (**Figure 2.10**). The interbedded sand, shale and carbonate Lower Cretaceous sequences observed in Mit Ghamr NE-1 ST, Shibin El Kom and Tanta-1 wells indicate that the prospects could have potential reservoir thicknesses and lithologies similar in nature to the eastern and southeastern provinces of the West Desert within stratigraphic equivalents to the Kharita (Albian), Dahab (Albian/Aptian) and the Shaltut/Betty Formations (Barremian to Neocomian age). Whilst the Bahariya Formation equivalent is developed to the west of the block in the Shibin El Kom and Tanta-1 wells the Mit Ghamr NE-1 ST, Sindy-1 and Monaga-1 likely indicate that the Bahariya time equivalent sequence is developed primarily as a carbonate and interbedded shale sequence within the prospect area and is likely to be non reservoir. The Mit Ghamr NE-1 ST, Sindy-1 and Monaga 1 clearly demonstrate that potential reservoir development risk in the prospect area is weakest in the Kharita sequence.

The Monaga-1 and Sindy-1 wells also demonstrate an overall increased reservoir presence risk in the Lower Cretaceous play towards the east and north-east of the block as the reservoir sequence is replaced by increasing volumes of carbonate and shale throughout the entire sequence. Senergy considers thus considers that as prospects lie between 7 and 20 km to the north and east from Mit Ghamr reservoir presence is a significant risk element.

There are also clear stratigraphic differences between South East El Mansoura and the West Desert. The most notable are that both the overlying Abu Roash (a regional shale seal in the West Desert) and Bahariya sequences (a reservoir and interbedded shale sequence in the West Desert) are carbonate rich rather than a regional shale seal and source sequence. The absence of a potentially thick regional shale seal in South East El Mansoura makes identified prospects at Kharita level likely reliant on local sealing horizons and sealing faults. The interbedded sand and shale sequences within the Kharita, Barremian and Neocomian section will also likely require trapping to be reliant on sealing faults due to the high probability of the juxtaposition of sand vs. sand across fault planes. Consequently trap/fault seal risk is interpreted by Senergy to be a significant risk element.

Good oil shows in the Lower Cretaceous were encountered throughout the Neocomian section in Mit Ghamr NE-1 ST together with gas readings to C4 which demonstrates some hydrocarbon charge has been delivered to the west of the prospect area. Two models have been proposed to explain possible hydrocarbon charge. The first model invokes charge either from Lower Cretaceous Aptian (Alam El Bueib) and or M. Jurassic Khatatba time equivalent shale source rocks within the prospect area. Melrose state that potential source rock quality has been encountered in the Alam El Bueib in South East El Mansoura wells but this has not been independently verified by Senergy. Burial history modelling suggests that the Lower Cretaceous is likely in a possible generative oil/gas window in only the northern most area of the block and the area north of the Neogene hinge line. The second model, which both Melrose and Senergy believe more reasonable, is that charge comes from Oligocene Tineh and/or Upper Cretaceous Khoman/Abu Roash source rocks to the north of the Nile Delta Hinge Line (**Figure 2.11**). The presence of adequate hydrocarbon charge within the play and prospect area has yet to be established and therefore remains a significant risk element.

Senergy recognises that there are clear differences in Mio-Pliocene stratigraphy, formation thicknesses and burial histories between the Western Desert and the South East El Mansoura area. Consequently related charge mechanisms and fill histories are likely different and therefore from an overall basin and charge evolution perspective Senergy does not feel that the West Desert is likely a good analogue for the El Mansoura area. However this does not rule out that prospects with West Desert time equivalent reservoirs in similar traps could be charged with hydrocarbons.

Melrose has modeled likely prospect fill to consist of light oils similar to those found in Western Desert time equivalent reservoirs. Western Desert oils are largely very low energy, low GOR crudes likely due to a series of charge pulses and possible gas bleed off with time. The Miocene Damas, South Damas and Tamad Fields to the west and north-west of El Mansoura are gas, gas condensate or light oil with a wet gas cap. Whilst Senergy believes that, due to the large range of uncertainty regarding charge, it is acceptable to model trap fill with light volatile oils there is also a significant chance that prospects could have received a gas or gas and condensate charge particularly if source from north of the Neogene Hinge Line.

2.6.2.2 Analogue Wells, Fields and Fault Seal Analysis

The Mit Ghamr NE-1 ST is the key well to help assess the Lower Cretaceous play and identified prospect risk within the block. Melrose interprets the well to have penetrated a valid significant fault and 3-way dip closure at Kharita, Barremian and Neocomian levels. The trap is similar to the undrilled prospects within the block. The well encountered good live oil shows and gas cut to C4 throughout the 977 ft Neocomian section (200 ft net reservoir in an interbedded sand, shale and carbonate sequence). Reservoir quality sands were also encountered in the Bahariya, Kharita and Neocomian but with no recorded oil/gas shows. Senergy concurs with Melrose's interpretation that the trap was likely breached by a reactivation of an E-W Miocene age trap bounding fault in the Pliocene which now reaches near surface. It cannot be ruled out that the Mit Ghamr well failed due to lack of adequate charge.

With the absence of a reliable top seal of greater thickness than trap-bounding fault throws, trapping within the play is entirely dependent on sealing faults. Sealing faults are encountered within time equivalent reservoirs within the West Desert area however there are differences in stratigraphic, tectonic and burial histories between the West Desert and South East El Mansoura that may render a direct fault seal analogue to be incorrect. Melrose has addressed the fault seal play risk element via model driven clay-gouge ratio fault seal analysis using the stratigraphic sequence found in the Mit Ghamr NE-1 ST well. The method relies on the Bretan equation to predict possible hydrocarbon column height which is empirically derived and is uncalibrated to local pressure regimes in the prospect area. Clay gouge ratios of between 20 and 40% within the Lower Cretaceous have been calculated along Mit Ghamr trap bounding fault planes (**Figure 2.12**). Melrose state that as a rule of thumb a 20% clay-gouge ratio is critical level and threshold between leak and seal. Computed sealing capacity is lowest in the Kharita due to the increased carbonate content and highest in the Alam El Buieb (Barremian/Neocomian). Within the limits of the model assumptions and calibration the clay gouge ratios calculated from modelling are reasonably indicative that there is potential to seal predicted hydrocarbon columns assuming clay gouge acts as a cross fault seal.

However as model calibration is limited to one well with no core and severe hole wash outs plus the top and base of each reservoir sand cannot be reliably interpreted from seismic to precisely model cross fault juxtapositions, the results do not prove fault seal only that it is possible. Thus in Senergy's view fault seal remains possibly the most significant risk element for each prospect.

Statistics showing reservoir properties, reservoir thickness and column heights for stratigraphically analogous reservoirs and traps from thirty-eight wells in thirteen fields in the West Desert were provided to Senergy by Melrose. These metrics have been used to help guide and reality check prospect volumetrics. Data used is as follows:

Alam El Bueib Prospect Statistics			
Property	**Minimum**	**Mean**	**Maximum**
Net Thickness (ft)	6.9	20.84	54.0
Porosity (%)	10.0	16.29	25.0
Sw (%)	14.2	25.14	50.0
Column Height (ft)	9.0	56.91	323.0
RF (%)	5.0	25.97	60.0
STOIIP (MMstb)	1.503	9.57	47.113

Kharita Prospect Statistics			
Property	**Minimum**	**Mean**	**Maximum**
Net Thickness (ft)	11.5	22.25	33.0
Porosity (%)	15.0	16.05	17.1
Sw (%)	10.0	22.35	34.7
Column Height (ft)	28.0	51.50	75.0
RF (%)	25.0	32.50	40.0
STOIIP (MMstb)	1.321	19.26	37.2

Bhariya Prospect Statistics			
Property	**Minimum**	**Mean**	**Maximum**
Net Thickness (ft)	8.9	27.08	45.4
Porosity (%)	19.0	22.17	26
Sw (%)	15.0	38.55	56
Column Height (ft)	20.0	189.91	778
RF (%)	1.58	13.29	36
STOIIP (MMstb)	5.9	39.09	113.5

2.6.2.3 Prospect Descriptions

Senergy concurs with Melrose that all prospects exhibit the potential for three stacked pay objectives at Kharita, Barremian and Neocomian horizons. Structural trap configurations are conformable from the Kharita downwards through to the Neocomian. Whilst it is possible to encounter pay in all three objective horizons a more likely outcome per prospect is one to two stacked pay zones as evidenced in Western desert time equivalent reservoirs and as reflected by Neocomian shows only in the Mit Ghamr NE- 1ST well. All prospects are dependent on sealing faults within the objective Lower Cretaceous section.

2.6.2.3.1 Al Hajarisah Prospect

The prospect is seismically well defined at top Barremian reservoir sequence and Top Aptian horizon on seismic. Al Hajarisah is a high relief E-W trending 3-way dip and Miocene age footwall fault trap with a possible column height range assuming fault seal of ca. 150 to 500 ft and a range of closure from ca. 200 to 1,300 acres (**Figures 2.13** to **2.15**). The trap exhibits some degree of 4-way dip closure at max spill point. In Melrose's interpretation there is no evidence of late stage Pliocene faulting reaching surface to breach trap top seal. Maximum spill point is limited by possible spill into the Kafr Saqr prospect to the West. Fault seal analysis on the main prospect fault indicates a reasonable possibility that sealing faults could exist particularly in the Neocomian and Barremian where clay gouge ratios are 30 to 40%. Lower fault sealing potential is thought likely at Kharita level as clay gouge ratio is calculated at the lower sealing threshold of c 20%. The main fault within the closure decreases significantly in throw from 500 ft in the East to almost zero in the West creating a higher leak potential in the west of the prospect (**Figure 2.16**). Senergy considers the prospect has the lowest likely relative fault seal risk of the prospect inventory.

Reservoir presence and charge are seen as the highest risk elements as the prospect is 19 km from known reservoir and oil shows in Mit Ghamr NE-1 ST. Fault seal risk is regarded as moderate.

2.6.2.3.2 Sinbelaywan Prospect

The prospect is seismically well defined at top Barremian reservoir sequence and Top Aptian horizon on seismic. Sinbelaywan is high relief E-W trending 3-way dip and Miocene age footwall fault trap with a possible column height range assuming fault seal of ca. 100 to 400 ft and a range of possible closure from ca. 150 to 3,000 acres (**Figures 2.17** to **2.19**). The trap exhibits some degree of 4-way dip closure at max spill point. Melrose interpret that there is no evidence of late stage Pliocene faulting reaching surface to breach trap top seal. No specific fault seal analysis was conducted on the main prospect fault. Throws on the main prospect controlling fault decrease from east to west where less than 50 ft of throw is indicated. Senergy consider that fault seal risk is therefore highest at the western end of the prospect. Sinbelaywan is the northernmost prospect in the portfolio and is thus closest to possible hydrocarbon charge from the kitchen area immediately north of the Neogene Hinge Line.

Reservoir presence is seen as the highest risk element as the prospect is over 20 km from known reservoir in Mit Ghamr NE-1 ST and is within 6 km of the Sindy-1 which exhibits limited Lower Cretaceous reservoir development. The prospect exhibits the lowest charge risk relative to other prospects in the Lower Cretaceous portfolio.

2.6.2.3.3 Sidi Gohar Prospect

The prospect is seismically well defined at top Barremian reservoir sequence and Top Aptian horizon on seismic. Sidi Gohar is a moderate relief WNW-ESE trending 3-way dip and Miocene age footwall fault trap with a possible column height range assuming fault seal of ca. 150 to 500 ft and a range of possible closure from ca. 150 to 3,000 acres (**Figures 2.20** to **2.22**). Melrose interpret that there is no evidence of late stage Pliocene faulting reaching surface to breach trap top seal. The trap is entirely dependent on sealing counter-regional dip faults to counter the rise to the south and south-west towards the Mit Ghamr NE-1 ST well. The main area of spill/fault seal risk lies in the west of the prospect where fault throws decrease from over 500 ft in the east to less than 50 ft and contours spill into an updip en-echelon fault block. Fault seal analysis was conducted on the main prospect fault (**Figure 2.23**) indicating that clay gouge ratios exceed 45% in much of the Neocomian indicating good sealing fault potential if the section is as seen in the Mit Ghamr well. Clay gouge ratios are shown at 20 to 30% in both the Barremian and Kharita indicating possible but higher sealing risk.

The prospect has the highest chance of reservoir presence within the portfolio as it lies just 6 km north-east of proven reservoir in the Mit Ghamr NE 1ST. Fault seal is seen as the highest prospect risk element.

2.6.1.3.4 Kafr Saqr Prospect

The prospect is seismically well defined at top Barremian reservoir sequence and Top Aptian horizon on 3D seismic. Kafr Saqr is a moderate relief WNW-ESE trending 3-way dip and Miocene age footwall fault trap with a possible column height range assuming fault seal of ca. 100 to 300 ft and a range of possible closure from ca. 50 to 750 acres (**Figures 2.24** to **2.26**). Melrose interpret that there is no evidence of late stage Pliocene faulting reaching surface to breach trap top seal. The trap is entirely dependent on sealing counter-regional dip faults. The prospect is an en-echelon fault block to the Al Hajarisah prospect 2 to 3 km to the west. Bounding fault definition is unclear at the southeastern end of the prospect. Main spill risk area lies at the southeastern corner where the bounding fault shows a rapid decrease in throw and possible throw reversal where contours rise steeply to the south into an updip en-echelon fault block. Fault seal analysis was not conducted on the main prospect fault by Melrose.

As the prospect is 20 km from known reservoir presence in Mit Ghamr NE 1ST and the Monaga- 1 shows sands thin to the east reservoir, presence is considered high risk. Trap and fault seal risk are also seen as high due to the possibility of leakage at the southeastern limit of the closure. The prospect is considered by Senergy to have the lowest overall chance of success within the portfolio.

2.6.2.4 Hydrocarbons-Initially-In-Place: Gross Rock Volume Methodology

The prospect area is covered by good quality 3D seismic and there is a good degree of confidence in time and overall depth mapping. The Top Albian and Barremian reflectors have been mapped by Melrose with reasonable confidence over the area. Whilst the Top Barremian reservoir surface horizon is derived from a definite seismic event the Kharita and Neocomian reservoir surfaces have been constructed by adding/subtracting a regional isopach thickness from the Albian/Barremian reflectors respectively. Senergy concurs that this is an acceptable methodology, however it does introduce more volumetric uncertainty into Kharita and Neocomian prospective horizons.

Spill point distributions assume prospects are full to spill point and generally use the lowest closing contour as a P_{10} value. Senergy concurs that this assumption is reasonable. As trapping is interpreted to be dependent on the existence of sealing faults determining spill points is somewhat arbitrary base upon structural spill alone. Senergy's spill point distributions have been made by fitting a lognormal or truncated lognormal distribution to the maximum structural spill point as a P_{10} value and a minimum value at crest of structure. It should be noted that column heights modeled are towards the upper end of column height statistics supplied by Melrose seen in Kharita and Alam el Bueib fields in the West Desert.

Melrose arrive at an input GRV distribution via three deterministic cases using $P_{90}/P_{50}/P_{10}$ closure areas from mapping then assign a reservoir thickness to each closure case. The three outcomes are then fitted to a lognormal distribution which is then used as input into a probabilistic volumetric simulation. In Senergy's view, this methodology may skew the GRV distribution towards the P_{10} assumptions and does not simulate the possible outcomes of combining the closure/spill and reservoir thickness distributions (i.e. the P_{10} GRV assumes a P_{10} reservoir only not a $P_{90}/P_{50}/P_{10}$ reservoir distribution). Senergy's evaluation uses a stochastic simulation combining top reservoir surface, reservoir thickness and spill point distributions to arrive at a GRV distribution. In general, as both the Senergy and Melrose methods utilise the same surface input and similar reservoir thickness distributions the mean and P_{50} GRV values are reasonably similar. Melrose's P_{10} GRV's are usually larger than Senergy's.

As the exact expected Lower Cretaceous reservoir is not resolvable on seismic trap GRV has been calculated using the closest stratigraphic depth surface and an expected reservoir thickness. GRV's were calculated by Melrose and Senergy for each of the three prospective horizons. Senergy regards the likelihood that each prospect will contain three separate stacked pay horizons to be small as there are few fields in the West Desert with time equivalent reservoirs that have more than two proven stacked reservoirs.

Melrose's reservoir thicknesses distributions rely on an assumption that prospects contain an overall P_{90} to P_{10} pay thickness ranging from 15 to 30 ft in the Kharita to 15 to 60 ft in the Barremian and Neocomian. Whilst this assumption is somewhat arbitrary it does conform within an acceptable limit to sand body thicknesses seen in the Mit Ghamr NE 1 ST and average pay and reservoir thicknesses statistics provide by Melrose for time equivalent reservoirs in the West Desert. Senergy has utilised a slightly narrower distribution range based on its knowledge of West Desert producing fields (Kharita P_{90} to P_{10}: 12 to 30 ft, Barremian and Neocomian (P_{90} to P_{10}: 12 to 45 ft).

Southeast El Mansoura Reservoir Thickness (Feet)					
Property	**Horizon**	**Mean**	**P_{90}**	**P_{50}**	**P_{10}**
Gross Reservoir	Kharita	21	12	20	30
Gross Reservoir	Barremian	29	15	25	45
Gross Reservoir	Neocomian	29	15	25	45

Formation Volume Factors and GOR			
	P_{90}	**P_{50}**	**P_{10}**
Oil Bo vol/vol	1.6	1.7	1.8
GOR scf/bbl	800	1000	1200

As trapping is interpreted to be dependent on the existence of sealing faults determining spill points is somewhat arbitrary base upon structural spill alone. Senergy's spill point distributions have been made by fitting a lognormal or truncated lognormal distribution to the maximum structural spill point as a P_{90} value and a minimum value at crest of structure. It should be noted that column heights modeled are towards the upper end of column height statistics supplied by Melrose seen in Kharita and Alam El Bueib fields in the West Desert.

2.6.2.5 Petrophysical Parameters

Reservoir porosities have been derived from Melrose's petrophysical analysis of the Lower Cretaceous section in the Mit Ghamr NE-1 ST well. These metrics also conform within an acceptable limit to porosities and net to gross ratio statistics provided to Senergy by Melrose from time equivalent reservoir sequences in the West Desert. Senergy has reduced the overall P_{90} to P_{10} distributions to reflect that the prospects are deeper than the Mit Ghamr NE-1 ST well and reservoir quality will likely decease with depth (P_{90} to P_{10}; 12 to 20% phi). It should be noted however that due to severe hole washouts in the Lower Cretaceous section Melrose caution that Mit Ghamr petrophysical analyses could be unreliable. Identical parameters have been used for Barremian and Neocomian petrophysical distributions.

Since a Lower Cretaceous net pay distribution has been modelled net to gross has been set to 100% in volumetric models.

Although Senergy has utilised Melrose's Sw distributions in its evaluation it believes that Melrose likely underestimates the effect on oil saturations in thin oil columns in perhaps poorer quality basin margin sands due to the presence of a transition zone that could represent a significant percentage of oil filled pore space.

Senergy believes Melrose's modeled GOR to be too low for the modeled light volatile oil prospect cases as hydrocarbons are most likely to be similar to those seen in Melrose's fields to the north-west and north of the block. Senergy have utilised a P_{90} to P_{10} GOR distribution of 800 to 1,300 scf/bbl.

Kharita Reservoir Parameters					
Property	**Reservoir**	**Mean**	**P_{90}**	**P_{50}**	**P_{10}**
NTG (-)	Kharita	1.0	1.0	1.0	1.0
Porosity (-)	Kharita	0.158	0.120	0.155	0.200
Sw (-)	Kharita	0.308	0.225	0.300	0.400

Barremian and Neocomian Reservoir Parameters					
Property	**Reservoir**	**Mean**	**P_{90}**	**P_{50}**	**P_{10}**
NTG (-)	Barremian/Neocomian	1.0	1.0	1.0	1.0
Porosity (-)	Barremian/Neocomian	0.16	0.12	0.16	0.20
Sw (-)	Barremian/Neocomian	0.33	0.23	0.32	0.45

2.6.2.6 Stochastic results

Melrose's resultant probabilistic outputs for the HIIP estimates were replicated by Senergy to within a reasonable margin of error and the following aggregated reservoir volumes were adopted as tabulated below. Stochastically aggregated sums were then derived for each of the Low, Best and High cases.

Gross Liquids-Initially-In-Place (Mstb)				
Prospect	**Reservoir**	**Low Estimate**	**Best Estimate**	**High Estimate**
Al Hajarisah:	Kharita	2,300	4,130	13,900
	Barremian	4,950	10,500	20,500
	Neocomian	2,690	7,280	17,100
Kafr Saqr:	Kharita	425	1,100	2,440
	Barremian	1,040	2,700	6,220
	Neocomian	2,210	4,590	8,910
Sidi Gohar:	Kharita	988	4,010	9,740
	Barremian	3,140	7,640	17,000
	Neocomian	2,890	7,520	17,100
Sinbelaywan:	Kharita	2,760	6,280	14,000
	Barremian	2,760	14,600	45,100
	Neocomian	3,700	15,700	41,600

Potentially recoverable volumes were derived by application of a range of oil recovery factors normally distributed between a P_{90} of 0.15 and a P_{10} of 0.35, and the results are tabulated below.

Gross Prospective Resources (Mstb)				
Prospect	**Reservoir**	**Low Estimate**	**Best Estimate**	**High Estimate**
Al Hajarisah:	Kharita	500.7	1,464.0	3,631.0
	Barremian	1,022.0	2,530.0	5,493.0
	Neocomian	595.0	1,753.0	4,438.0
Kafr Saqr:	Kharita	92.4	261.0	641.3
	Barremian	219.7	646.2	1,635.0
	Neocomian	454.7	1,103.0	2,393.0
Sidi Gohar:	Kharita	215.9	938.6	2,550.0
	Barremian	680.6	1,836.0	4,473.0
	Neocomian	629.3	1,794.0	4,501.0
Sinbelaywan:	Kharita	592.2	1,512.0	3,656.0
	Barremian	630.5	3,446.0	11,440.0
	Neocomian	832.3	3,693.0	10,800.0

Gross Prospective Resources (Bscf)				
Prospect	**Reservoir**	**Low Estimate**	**Best Estimate**	**High Estimate**
Al Hajarisah:	Kharita	0.5	1.5	3.9
	Barremian	5.7	14.5	33.2
	Neocomian	0.6	1.7	4.4
Kafr Saqr:	Kharita	0.1	0.3	0.7
	Barremian	1.2	3.7	9.7
	Neocomian	2.5	6.3	14.4
Sidi Gohar:	Kharita	0.2	1.0	2.7
	Barremian	0.7	1.9	4.7
	Neocomian	0.6	1.8	4.5
Sinbelaywan:	Kharita	0.6	1.6	3.9
	Barremian	0.6	3.6	12.3
	Neocomian	0.8	3.8	11.4

2.6.2.7 Chance of Success

Melrose has assessed presence and effectiveness of Trap, Seal, Reservoir and Source together with Migration and Timing. Senergy has reviewed these factors and estimated the overall Chance of Geological Success for each prospect as tabulated below.

Prospect	Reservoir		
	Kharita	Barremian	Neocomian
Al Hajarisah	0.13	0.18	0.17
Kafr Saqr	0.13	0.09	0.09
Sidi Gohar	0.12	0.15	0.12
Sinbelaywan	0.11	0.15	0.15

Senergy assesses a lower chance of success than Melrose in all South East El Mansoura prospects due to the unproven nature of the play and the primary reliance of trap on as yet unproven sealing faults. Both charge and reservoir presence have been demonstrated in the Mit Ghamr NE1 ST as possible in the area but still have a moderate degree of associated risk. Sinbelaywan is closer to a possible hydrocarbon source kitchen than Al Hajarisah yet has a higher risk on the presence of reservoir. Fault seal risk is marginally higher in Sinbelaywan than Al Hajarisah due to the increased carbonate content in the Lower Cretaceous shown by the Sindy-1 well.

3 Qantara

3.1 Introduction

Gas was discovered in 1976. A further eight wells have been drilled on the concession with little success. The original well was tied in as a producer in 2001 but has only produced intermittently since 2003 due to high water-cut. Remedial well work is being considered.

3.2 Geological Description

The Qantara reservoir interval occurs in the Early Miocene at a depth of about 10,000 ft. The reservoir sandstones are thinly bedded and quartz-rich, with variable cement content. Rock quality is generally good with the average porosity ranging from 18 to 24% and permeability of circa 250 mD.

3.3 Asset Overview

Qantara-1 came on stream in March 2001, but has now ceased production. The reservoir contains a gas-condensate with a CGR of 265 bbl/MMscf. Original reservoir pressure was 7,200 psi. Similarly, Qantara-4 produced for a period, and was then sidetracked in July 2008. Well Qantara-4ST was tested at 7 MMscf/d with a CGR of 170 bbl/MMscf. We have regarded only the reserves associated with this sidetrack as being classifiable as Proved or Probable. Gas-in-place and production from previous wells on the asset are not included in the tables.

3.4 Gas-Initially-in-Place

Our analysis of pressure decline during the test indicates that the well is in communication with 4 to 5 Bscf of gas. The well was put on production on 13th October 2008. PLT surveys conducted in November 2008 indicated that all flow is coming from a deeper interval and the upper perforated interval is not contributing to flow. As at 31st December 2011, cumulative production from this well was 1.7 Bscf gas and 208 Mstb of condensate.

3.5 Recoverable Reserves and Production Profile

Future production was estimated from the observed decline in FTHP, allowing for future decline in performance as the water-gas ratio increases. Remaining Proved reserves were estimated to be 0.2 Bscf gas and 24 Mstb of condensate, Proved plus Probable reserves at 0.6 Bscf gas and 61 Mstb of condensate.

4 Block Galata

4.1 Introduction

Block Galata (formerly Block III) lies in the Black Sea, south-east of the Bulgarian city of Varna (see **Figure 1.2**). Petreco developed the first field, Galata, in 2003/2004 with the drilling of two production wells and the installation of 24 km of offshore pipeline, 58 km of onshore pipeline, an onshore process plant and a gas metering station. Further discoveries were made to the east of Galata in the southern part of the block on the Moesian Platform up dip from the Kamchia Trough to the south (**Figure 1.3**). The fields are small, the largest being the Kavena and Kaliakra fields, and these have been, or will be, developed as sub-sea wells tied back to the Galata field platform. Ongoing work by Melrose is focused on identification and mapping of new leads and prospects outside the main producing complex.

4.2 Geological Description

The reservoirs discovered so far in the region consist of a platform carbonate reservoir sequence comprising skeletal packstones or grainstones. Three lithostratigraphic units, the Dobrina, Kailaka and Komarevo Formations, are identified from wireline and core through the reservoir. The Kailaka Formation, which is a wackestone/packstone, is the best quality unit. The formations are late Maastrichtian to Palaeocene in age. The reservoir is of the order of 20 m thick, with a high net-to-gross ratio, porosities generally in excess of 25%, water saturation of circa 15%, and permeability in the range of 1,000 to 3,000 mD. Significant porosity variation exists (ca. 13 to 34%) with higher values recorded in the gas wells indicating preservation with hydrocarbon charge.

Regional seal is provided by the Eocene Avren Formation, a highly plastic marl, and an overlying Oligocene claystone whilst intraformational local seals are also present. Top seal is regarded as low risk and hanging wall seals likely low risk, but foot wall seals may be high risk and unpredictable.

An Oligocene source is present from the Kamchia Trough on the southern flank of the block and there are older secondary source candidates from Cretaceous and Jurassic rocks. A critical factor for prospectivity is migration into the area north of the fields currently under investigation which is underexplored, and only tested by 5 wells in an area of 1,500 km^2.

Many traps are formed by the intersection of E-W and NNE-SSW faults. All are structural traps, generally small with at least one or two way faults and, in some cases, completely reliant on faulting where located in up thrown blocks. A major risk is seal across these faults. Top seal is good but higher risk exists if the trap is reliant on intra-formational seals or sealing against up thrown faults.

Prospects are likely to be more faulted than may be defined easily on current seismic with a high probability of sub seismic faults. By analogy with producing fields to the south, this does not significantly impact production.

4.3 Asset Overview

4.3.1 Galata

Galata field lies approximately 30 km south-east of Varna. It was developed by two production wells, GP-1 and GP-2 (**Figure 4.1**).

Structurally, the reservoir is transected by faults with relatively small throws and divided into northern and southern areas by a main east-west fault of variable throw. The reservoir to the north of this fault is generally downthrown with respect to the southern reservoir section. Reservoir pressure analysis has shown that the east-west fault is fully open to flow and that the north-south fault between Galata East and Galata Main is only a partial barrier to flow.

The reservoir is of the order of 70 ft thick, with a high net-to-gross ratio, porosities in excess of 25%, water saturation of circa 15%, and permeability in the range of 1,000 to 3,000 mD.

Galata came on stream in June 2004 and production peaked at 70 MMscf/d in September 2004. The reservoir contains gas with a specific gravity of 0.567 and negligible condensate yield (no condensate reserves are reported). The initial reservoir pressure was 1,643 psia. A reduction in compression suction pressure to 90 psia was achieved during mid-November 2007. Suction pressure was maintained at, or close to, that value until the field was shut in at the end of January 2009. Melrose is currently negotiating with Bulgargaz to agree the use of the Galata field for a Gas Storage project. However, in this report, it is assumed that these negotiations will not be successful, and that Melrose will revert to a depletion of the field. Melrose anticipates that this will not commence until 2013.

Gas-Initially-in-Place

A material balance model was developed by Melrose soon after first production, and has been regularly updated with wellhead pressure trends, with MDT data from the Galata East-1 (September 2005) and Galata East-2 (November 2007) wells, and with the observation of a pressure build-up of 10 psi during a 30-day period in July 2007 when the field was shut-in to allow installation and tie-in of the second compressor. The model had two tanks (Main and East) communicating across a leaking fault.

Melrose has noted that the pressure build-up observed since shut-in has been stronger than previous modelling of the aquifer had led them to expect. This build-up is thought to be as a result of latent aquifer support caused by breaching of a pressure threshold at a subsurface fault. This suspicion was confirmed by an intervention on well GP-2 in September 2010, which found the GWC to have risen to just below mid-perforation. It is now assumed that only GP-1 can contribute to future production.

A third tank, containing only water, was added to the model to represent this effect. This tank is only allowed communication with the reservoir from late September 2008. By matching to the observed GWC in GP-2, the model can not only forecast pressures but also when the aquifer influx will start to impair production from GP-1. The latest model was reviewed and accepted by Senergy. It indicates a GIIP of 79.4 Bscf.

Recoverable Reserves and Production Profile

The field has produced around 66 Bscf of gas from two development wells to date, representing 83% of the interpreted gas-in-place. With the low pressures in the field at the end of 2008, Well GP-2 started to struggle to lift its own water of condensation under the flowing conditions. Melrose considered using Kavarna and Kaliakra gas to lift GP-1 when it comes back on production, but one side-effect of the prolonged shut-in of Galata and its re-pressurisation by the aquifer is that this will no longer be necessary.

With the successful tie-back of Kavarna and Kaliakra to the Galata production facilities, it will not now be possible to flow the GP-1 well without assistance. The higher pressure of the two new fields means that it will be necessary to fit an eductor to the GP-1 wellhead. This established technology will permit the energy from the Kavarna-2 and Kaliakra-2 wells to be used to reduce the THP of GP-1 and to allow the three fields to flow together.

The GP-1 well will be able to flow with the help of the eductor until the water/gas ratio exceeds 10 bbl/MMscf. Water breakthrough will be delayed by fitting an expandable bridge plug on slickline to shut off the lowest 10 m of the producing interval, in order to maximise reserves. Melrose assumes that production will cease when the formation water reaches the bottom of the existing perforated interval, a 33 ft stand-off from the plugged-back perforations. It should be noted that the Proved reserves of Kavarna and Kaliakra are sufficient to ensure that the eductor can still be operating when water breakthrough occurs.

Melrose's material balance model, integrated with well models, was used to project reserves with the following assumptions:

- Production from one existing development well, GP-1.
- Wellhead pressure declining from 200 to 145 psia from July 2012 to March 2013, back-calculated from an onshore compression suction pressure of about 90 psia and from the use of an eductor, which allows the GP-1 gas to combine with the high-pressure gas driving the eductor to create a pipeline entry pressure of 300 psia falling to 250 psia.
- A slickline intervention in GP-1 to fit an expandable bridge plug 10 m above bottom perforation.
- Production profile cut off at end March 2013, at which time the GP-1 well is predicted to be producing at a water/gas ratio above 10 bbl/MMscf.

This analysis gave an ultimate Proved plus Probable (2P) gas recovery of 71.4 Bscf, equivalent to a recovery factor of 90.0%. Since further production from Galata field is contingent on having the eductor and the bridge plug installed, Galata reserves are quoted only in the 'Developed and Undeveloped' categories.

4.3.2 Kavarna

The Kavarna field is located 8 km to the east of the Galata field within the Block Galata Exploration Concession.

The reservoir comprises Paleocene packstones of the Komarevo Formation overlying better quality Maastrichtian wackestones of the Kailaka and Dobrina Formations. These are directly comparable to the reservoir in the Galata field 7 km to the west. The average porosity is 28%, with a net-to-gross of 97%. The depth of the GWC is not known; a gas-down-to (GDT) at 815 m tvdss was seen in Kavarna-2.

The trap geometry is a combination of dip and fault closure. The field is divided into two fault blocks: a main block to the east and a smaller down-thrown block to the west. Senergy agrees with Melrose's view that it is highly unlikely that the western fault compartment is in complete pressure separation from the main field, given the Galata field analogue.

The field extent is defined by the mapped structural spill point at top reservoir (**Figure 4.2**), which is coincident with a pronounced direct hydrocarbon indicator (DHI) on the 3D seismic data. This DHI is expressed as a polarity reversal and is modelled and interpreted by Melrose to represent the transition from brine-filled reservoir off structure to gas-filled reservoir on structure. The lateral position of the structural spill point appears to be robust, although its depth is uncertain. This uncertainty would be reduced significantly if the depth of the GWC were known, since the extent of the DHI could be depth-calibrated with a high degree of confidence.

The Kavarna-1 and -2 wells tested the structure during the fourth quarter of 2008. Kavarna-1 was plugged and abandoned for safety reasons after encountering strong gas shows and a gas kick. However, the Kavarna-2 well confirmed the presence of a 39 m gross pay section with good reservoir properties. The well was not tested but MDT pressure and sample data confirmed a gas gradient down to the base of the reservoir with measured mobilities comparable to those noted in the Galata field. The Kavarna-2 well was completed with a 7-inch liner and 5½-inch production tubing, the whole reservoir interval perforated and a subsea tree installed. The well was tied back to the Galata Platform via a 6-inch flow-line and was officially opened to commercial production on 4th November 2010. During 2011, it produced 6.2 Bscf gas at an average rate of 17 MMscf/d. Water production has been consistent with anticipated water of condensation.

Five pressure build up surveys have been carried out since the field started production. The data obtained have been analysed by Melrose using material balance. Each of the PBUs was for a period of approximately 6 hours; where the shut-in was of a longer duration, a cut-off of 6 hours was applied. The shut-in tubing head pressure (SITHP) was converted to reservoir pressure using PVT data and gradient correlations.

For the 2P scenario Melrose assume that the reservoir is depleting in a volumetric fashion. In this scenario the MBAL model is matched with a GIIP of 30.8 Bscf. The 1P case is based on the premise that there is an active aquifer in the region of the Kaliakra and Kavarna reservoirs and that it is able to communicate with the reservoir to some extent. Whilst Melrose acknowledge that the Kavarna field may be receiving pressure support from a regional aquifer they give several reasons to believe that its impact will be limited:

- The reservoir is bounded to the south by the Blitnazi fault (**Figure 4.3**).
- The reservoir is bounded to the west by the Kaliakra fault.
- MDT data show the reservoir to be tight below the GWC in the nearby Kaliakra-2 and Kavarna East-1 wells.
- The Kaliakra reservoir, which lies approximately 6 km to the east, is acting as a pressure sink.
- The Kavarna East reservoir, which lies approximately 3 km to the east, will act as pressure sink from 2013 onwards.
- Reservoir quality in water wells in the vicinity is significantly poorer (Bogdanov East, Elizaventino and Epsilon-1).

- The Kaliakra East Well, which lies immediately to the east of the Kaliakra field, had no reservoir.
- The reservoir is delineated to the north by an east-west striking fault of approximately 200 ft displacement, so there may be limited or no pressure communication.

All of the above suggests that if an aquifer were to be modelled, it should be considered to be subtended by a rather narrow angle, be of limited thickness and have a limited permeability. Melrose have assumed that the aquifer parameters are at the upper limit of permissible values and have matched the pressure history accordingly to give a 1P estimate of GIIP. These parameters are:

- Aquifer formation volume factor of 0.08 (30 degrees).
- Permeability of 100 mD.
- Inner radius: 2,500 ft.
- Outer radius: 75,000 ft (22.6 km, the distance to the Elizaventino well).
- Aquifer height of 127 ft (Komarevo and Kailaka height in Kavarna-2 well).

Melrose matched the pressure history using the above aquifer parameters with a GIIP of 29.8 Bscf.

Senergy has reviewed and accepted the material balance estimates for the 1P and 2P GIIP of 29.8 and 30.8 Bscf, respectively. Proved and Proved plus Probable ultimate gas recoveries are estimated to be 24.6 and 26.9 Bscf, respectively using recovery factors of 82.7 and 87.4% supported by well and flow-line network modelling.

4.3.3 Kaliakra

The Kaliakra field is located 15 km to the east of the Galata field within the Block Galata Exploration Concession.

The Kaliakra gas field was discovered by well Galata East-3 in 2007, which encountered 11 m gross reservoir and a GDT. Well Kaliakra-2 was drilled in July 2009 and proved 54 m gross reservoir and a GWC at 845 m tvdss, confirming the extension of the field to the north of Galata East-3 (**Figure 4.4**). Neither well was tested, but measured mobilities were comparable with those of the Galata field reservoir.

The trapping mechanism is probably a combination of structural and stratigraphic elements, with 3-way dip closure to the north, south and west and stratigraphic closure to the east against an incised Oligocene channel, which is interpreted to be shale-plugged. However, the precise trap geometry remains uncertain. The reservoir comprises algal packstones and grainstones of the Palaeocene Komarevo/Kamen Del Formation, with an average porosity of 36% and net-to-gross of 81% in Kaliakra-2. The reservoir is split into two zones based on reservoir characteristics: Zone 1 is the upper zone with better quality reservoir than the underlying Zone 2. The gross reservoir interval thickens to the north. Melrose interpret that intra-field faulting is unlikely to cause complete pressure separation, given the Galata field analogue and we support this interpretation.

Well Kaliakra-2 was completed with 5½-inch production tubing and 7-inch liner. Only the top 11 m interval (817 to 828 m) was perforated to ensure a good balance between well productivity and reducing the risk of water coning late in field life. The well was tied back to the Galata Platform via a 10-inch flow-line and officially opened to commercial production on 4th November 2010. During 2011, it produced 9.2 Bscf gas at an average rate of 25 MMscf/d. Water production has been consistent with anticipated water of condensation.

Five pressure build up surveys have been carried out since the field started production. The data obtained have been analysed by Melrose using material balance. Each of the PBUs was for a period of approximately 6 hours; where the shut-in was of a longer duration, a cut-off of 6 hours was applied. The SITHP was converted to reservoir pressure using PVT data and gradient correlations.

For the 2P scenario Melrose assume that the reservoir is depleting in a volumetric fashion. In this scenario the MBAL model is matched with a GIIP of 38.7 Bscf. The 1P case is based on the premise that there is an active aquifer in the region of the Kaliakra and Kavarna reservoirs and that it is able to communicate with the reservoir to some extent. Whilst Melrose acknowledges that the Kaliakra field may be receiving pressure support from a regional aquifer several reasons were cited to infer that its impact will be limited. These are the same reasons, *mutatis mutandis*, as given for Kavarna in the preceding section (see **Figure 4.3**).

- The reservoir is bounded to the south by the Blitnazi fault.
- The reservoir is bounded 6 km to the west by the Kaliakra fault.
- MDT data show the reservoir to be tight below the GWC in Kaliakra-2 and in the nearby Kavarna East-1 well.
- The Kavarna reservoir, which lies approximately 6 km to the west, is acting as a pressure sink.
- The Kavarna East reservoir, which lies approximately 3 km to the west, will act as pressure sink from 2013 onwards.
- Reservoir quality in water wells in the vicinity is significantly poorer (Bogdanov East, Elizaventino and Epsilon-1).
- The Kaliakra East Well, which lies immediately to the east of the Kaliakra field, had no reservoir.
- The reservoir is delineated to the north by an east-west striking fault of approximately 200 ft displacement, so there may be limited or no pressure communication.

All of the above suggests that if an aquifer were to be modelled, it should be considered to be subtended by a rather narrow angle, be of limited thickness and have a limited permeability. Melrose have assumed that the aquifer parameters are at the upper limit of permissible values and have matched the pressure history accordingly to give a 1P estimate of GIIP. These parameters are:

- Aquifer formation volume factor of 0.08 (30 degrees).
- Permeability of 100 mD.
- Inner radius: 2,500 ft.
- Outer radius: 75,000 ft (22.6 km, the distance to the Elizaventino well).
- Aquifer height of 127 ft (Komarevo and Kailaka height in Kavarna-2 well).

Melrose matched the pressure history using the above aquifer parameters with a GIIP of 37.0 Bscf.

Senergy conducted an investigation to reconcile these indications of GIIP with our previous interpretation of geological and geophysical data. While there is no reason to review the former, we had noted considerable uncertainty in the mapping of gross rock volume. The reasons for this are as follows:

- Different seismic phase for top reservoir: at Kaliakra-2 the Top Palaeocene occurs on a seismic peak (black amplitude), a classic gas DHI; at Galata East-3 the Top Palaeocene is modelled on a seismic trough (red amplitude), although the seismic data actually show a double seismic trough. Somewhere between the wells the reservoir horizon must shift from a peak to a trough, and the point at which this is mapped has a significant effect on GRV.

- Velocity used for depth conversion: subtle differences are seen in the overburden velocity at the different wells. With the overburden consisting of a complex pattern of erosional channels, there is considerable variation likely in the velocity, and small changes can have significant volume implications. With so few wells there is a huge variety of depth conversion methods that could be used. Depth conversion is also affected by how sharply the velocity surface is flexed to tie the values at well locations.

- Limit of field to the east: in the previous Minimum case a notional closure against an (in places almost seismically invisible) Oligocene channel was used to limit the volume. A review of the seismic suggests a slightly more realistic channel can be mapped, but the uncertainty in its position still leaves volumetric uncertainty.

Senergy considered a deliberately less optimistic interpretation of the seismic data to see if structural mapping and depth conversion can provide a realistic explanation for the lower GRVs implied by pressure data. Two velocity maps were constructed from well control points, identical except for well Galata East-3, where alternative Top Palaeocene seismic picks were tested: a lower pick in the lower seismic trough of the doublet, resulting in a pseudo velocity of 1,773 m/s, and a higher pick, in the upper seismic trough, giving a faster, and therefore less optimistic, velocity of 1,794 m/s.

The less optimistic mapping (**Figure 4.5)** gives a GRV of 65.1 MM cu m for Zones 1 and 2 combined. This is a good fit with the reduced estimated volume calculated from pressure data. Note that the eastern extent of the field is based on structure contours and a seismically interpreted channel; there is no resort to an artificial barrier to provide a seal. In this version of the map there is a trough between wells Kaliakra-2 and Galata East-3 in which it is very nearly possible to divide the structure into two separate compartments with a tiny bit of blue water in between. However, a volume calculation in which only the region around well Kaliakra-2 is included gives a total GRV of 37.7 MM cu m, which is too small to explain the observed pressure data.

Senergy has, therefore, accepted the material balance estimates for the 1P and 2P GIIP at 37.0 and 38.7 Bscf, respectively.

Proved and Proved plus Probable ultimate gas recoveries are estimated to be 30.7 and 33.7 Bscf, respectively, using recovery factors of 83 and 87% supported by well and flow-line network modelling.

4.3.4 Kavarna East

The Kavarna East-1 vertical well was spudded on 7th July 2010 in 63 m water depth, approximately 11.2 km east of the Galata Platform. The well penetrated top reservoir at a depth of 841 m MD and found a gross section of 41 m with 39 m being above a GWC. Good reservoir properties were established through wireline log interpretation. The well was not tested but a gas gradient was established from MDT pressure points and two gas samples were taken, one near the top of the reservoir and the other 1 m above the GWC interpreted at 849 m tvdss. MDT mobilities were also comparable to those in Kavarna field, giving confidence in the productivity of the well. The well was suspended with a 7-inch liner for future completion and tie-back to the Galata Platform.

The field is a fault-bounded, dip-closed structure with the same Palaeocene-Maastrichtian reservoir as found in the nearby Kavarna field (**Figure 4.6**). The field extent is defined by the penetrated GWC, which extends further than the noted seismic anomaly of polarity reversal; this is consistent with fluid substitution work carried out by Melrose which suggests that 15 to 20 m of gas-charged reservoir is required to produce the anomaly and that each field will have a gas-charged 'halo' around it where the gas column is below this threshold.

Senergy produced an independent two-way time map of top reservoir. However, standard depth methods did not produce a closure of the field to the east at the known GWC. Senergy introduced a pseudo-well at the eastern edge of the field to close the field (as was done in Melrose's own analysis), where the time closure is seen forcing top reservoir to be at the GWC depth. A range of GRVs was then created by using two different methods of mapping the average velocity. Well logs indicate that the reservoir is divided into two formations: the lower, better quality Kailaka and the Upper Kamen Del. Separate GRVs were calculated for the two formations in order to refine our estimates of gas volumes in place. The Proved plus Probable volumes were taken as the average of the range, assuming a lognormal distribution. Thus the Proved GIIP was estimated to be 8.4 Bscf and the Proved plus Probable to be 11.1 Bscf.

The structure, although on a smaller scale, is similar to that of the Galata field, where there is a dip-closing horst structure with a north-south dividing fault that is not sealing. On Kavarna East, the north-south fault almost disappears at the northern margin of the field, where almost no offset of reservoir is likely, so we believe that the discovery well will be able to drain the whole in-place volume. Proved and Proved plus Probable (Undeveloped) reserves were estimated to be 5.8 and 8.2 Bscf, respectively.

Kavarna East lies just less than 3 km east of the main Kavarna field which itself is connected to the Galata platform by an 8 km 6-inch steel pipeline installed in 2010. The Kavarna East well will be completed with production equipment and a subsea production tree in a similar manner to the Kavarna and Kaliakra fields, both of which are already producing. The subsea production tree at Kavarna East will be connected to the Kavarna subsea production tree by 2.85 km of 6-inch pipeline by a 'Y-piece' manifold designed and built for the purpose. The installation of the line and subsea equipment will be completed during the summer months of 2013 ready for first production on 1st October 2013. In the initial months, the Kavarna field will be closed until the pressure in Kavarna East reservoir falls to the same pressure, after which they will be flowed together.

Kavarna East Field Development Plan has been submitted to the Bulgarian authorities.

4.4 Prospect Inventory

Melrose has identified a number of structures from the new seismic 3D dataset. The most significant are classified as prospects (**Figure 4.7**); they have been evaluated by Senergy and are described below:

Six prospects are located on the Kaliakra Hanging Wall:

- Chaika NW
- Chaika NE
- Chaika S
- Kamchia
- Prospect A
- Prospect F

Two prospects are located on Kaliakra Terraces:

- Prospect E
- Prospect H

All the prospects are combination dip and fault closures and many require at least a two-way fault trap either associated with footwall or hanging wall fault seals. In addition, many sub seismic faults are likely within the prospect areas which may further compartmentalise any accumulation. Based on analogy with the fields to the south of the concession, the smaller faults may be only partial baffles and not effective seals.

The prospects are described individually in Section 4.4.2 below.

4.4.1 Geophysics Review of Galata Area Prospects

Senergy has undertaken a review of seismic interpretation and mapping now being carried out by Melrose to the north of the Galata, Kavarna, and Kaliakra fields in their licence offshore Bulgaria approximately 30 km south-east of Varna (**Figure 1.2**). Senergy has also briefly reviewed the inputs and methodology for obtaining volumetric estimates for these new prospects.

Senergy agrees that the approach taken by Melrose is technically valid and consistent with industry best practice.

4.4.1.1 Seismic Database

Melrose has defined a number of prospects based on recent mapping of their recently acquired seismic data. The survey was acquired in 2011 and consisted of 500 km^2 of 3D data in the central part of the block to the north of the existing fields.

The data quality is good at the objective levels of the potential Lower Tertiary and Upper Cretaceous reservoirs. The data processing was to a pre-stack time migration; no depth migration was performed and a few areas indicate over-migration. However, it is not believed that this will significantly affect the quality of the interpretation.

Well control is not comprehensive over the area. Although sixteen wells lie within the limits of the 3D surveys, thirteen of these wells lie to the south mainly in the area of the discovered fields (**Figure 4.7**). Thirteen wells had sufficiently reliable data to create an average velocity map to the Top Paleocene seismic event. However, the sparse well control, especially within the area of the prospects, indicates that there is significant uncertainty in the appropriate velocity model for time depth conversion. This uncertainty is addressed in the input range to the volumetric model.

There are three wells which lie within the new 3D area (**Figure 4.8**) but only the Bogdanov North-1 well has velocity information as a VSP to permit a good tie to the seismic data. Well Elizavetino-1 has no velocity information but was used with Epsilon-1 to produce an average velocity map and to correct the depth grids.

4.4.1.2 Seismic Interpretation and Mapping

Melrose has interpreted five horizons in the area of the prospects based on the recent seismic 3D data as shown in **Figure 4.9**: Sea Bottom, Top Eocene, Top Palaeocene, Intra Cretaceous and Base Cretaceous. A synthetic was generated for the Bogdanov North -1 well which shows a good well to seismic tie and the key Top Palaeocene horizon is a well defined trough corresponding to the positive impedance contrast at the top of the reservoir interval.

Senergy has reviewed the interpretation supplied by Melrose and concluded that it is reliable within the uncertainties permitted by the data quality. The events are generally well defined on the seismic and there is a reasonably high degree of confidence in the seismic time interpretation. However, there is pervasive faulting across the area. A key uncertainty is the detailed delineation of the faults which are commonly cross cutting along near orthogonal regional trends. Sub seismic faults are also likely to exist so the structures may be more compartmentalised than shown on the horizon maps. The Palaeocene and upper Cretaceous reservoir intervals are thin and below seismic resolution so reservoir base and thickness were estimated from the regional well data.

4.4.1.3 Seismic Amplitude and AVO

The gas fields to the south of the area indicate high seismic amplitudes and polarity reversal at the level of the top reservoir corresponding to the areal extent of the gas pay. Recent modelling by Melrose indicates that fluid substitution from water to gas is not sufficient to model the amplitude changes. However, the higher porosity associated with the gas accumulations can explain the amplitude variation. It is possible that the presence of gas would have preserved porosity, resulting in enhanced reservoir quality in the pay zone and a porosity reduction within the water leg. The prospects evaluated in this report do not show clear seismic amplitude anomalies, indicating a high risk for charge and/or reservoir preservation.

4.4.1.4 Depth Conversion

The key uncertainty in estimating the potential volume of the prospects is the determination of a reliable velocity model as there are limited well data in the area. The fields to the south of the area indicate that the predicted GIIP volumes are sensitive to how the seismic time map is converted to depth.

In order to analyse the sensitivities, Melrose applied three different time to depth conversion methods to generate depth maps from the Top Palaeocene time maps:

- A gridded and smoothed pseudo-average velocity map was derived from the seismic horizon times and well depths for the Top Palaeocene. The model tends to produce the minimum case for the prospect gross rock volumes.

- Stacking velocities derived from the data processing of the 3D volume were used and then scaled by 91% to tie with the Bogdanov-1 average velocity. This velocity model tends to produce the maximum case.

- A single time to depth equation was calculated as a 2nd order polynomial fit to well checkshots/VSP of seven wells in the area. This method tends to produce the mid case volume.

A residual error map was then applied to each of three Top Palaeocene depth maps to tie exactly the wells in the area.

4.4.2 Prospect Descriptions

4.4.2.1 Chaika NW

The prospect is well defined on seismic and is a combination of dip and fault closure (**Figure 4.10**). The culmination is a 3-way dip structure, closing against a well defined west-east trending fault to the north. The spill point is also affected by subsidiary faults along the western and eastern boundaries of the structure. The structural relief is 50 to 100 m depending on the velocity model used. A small fault separates the structure from Chaika NE although it is possible, at the maximum case, that the prospects are contiguous. The structural risk is low, the trap presence is insensitive to the velocity model and the faults terminate in the thick and regionally extensive Eocene claystone.

4.4.2.2 Chaika NE

The prospect is on trend, and bounded by the same west-east trending fault as Chaika NW and divided from Chaika NW by a small graben (**Figure 4.11**). It is a well defined tilted fault block and minor north-south trending faults define the western and eastern boundaries. Structural relief is 50 to 70 m. The coherency volume indicates that the structure may be further cut by small north-south trending faults which could divide the structure or act as partial baffles. Structural risk is low; closure is robust for all the velocity models although there is a small risk associated with hanging wall seal along the northern bounding fault.

4.4.2.3 Chaika South

The trap is formed by the intersection of two major faults trending north-south and west-east (**Figure 4.12**). The core of the prospect is a 3-way fault closure formed by a north-south trending horst, a west-east fault to the south and dip closure to the north. The trap may extend to the west with a combination of low relief dip and fault closure as indicated on the depth maps. Structural relief is 50 to 120 m depending on the velocity model.

The structure may possibly be further segmented by a mapped fault and sub seismic faults as indicated from the coherency volume. The structural risk is low but with a minor risk associated with the sealing along the main fault which has a substantial throw of over 300 m over part of its length.

4.4.2.4 Kamchia

The Kamchia prospect consists of a highly faulted; three to 4-way dip closure to the southeast of the Chaika prospect area (**Figure 4.13**). The core of the structure is defined by faults formed by the intersection of a north-south and west east horst trends. The major faults lie to the north and west with a combination of dip and fault to the south and east. The structure relief is 100 to 200 m, although the eastern sector is relative low relief of 30 to 50 m. The different depth maps do not indicate a significant range of area of closure due to the strong dips and large fault throws. The coherency volume and fault mapping indicates possible compartmentalisation especially by west-east trending cross faults. Structural risk is low with a small seal risk.

4.4.2.5 Prospect A

The prospect lies to the east of the Chaika area and close to the large north-south trending Kaliakra fault in the centre part of the block (**Figure 4.14**). It is a low relief SW-NE trending, 4-way dip closure with some modification by faults, particularly along the eastern boundary. All the depth models indicate a similar area of closure but a range of structural relief between 50 and 75 m. Structural risk is low; the bounding faults terminate in the regional claystone seal but there are some indications of over migration which may accentuate structural relief.

4.4.2.6 Prospect E

The prospect lies on a north -south trending Kaliakra Terrace against the platform to the east (**Figure 4.15**). It is defined by down thrown closure against the Kaliakra Fault to the east, by dip and fault to the west and essentially dip closure to the south. The Kaliakra Fault has a significant but variable throw of the order of 100 to 300 m along the prospect depending on the velocity model applied. The throw also varies significantly along its length so that effective sealing is likely to depend on a number of different formations and lithologies associated with the Mesozoic pre-rift carbonate sequences. The potential thickness and quality of such potential seals are unknown. The relief of the structure is high in the range of 275 to 340 m. The prospect is likely to be compartmentalised by sub seismic faults and may be more complicated than mapped especially around the northern crestal area at the tip of the terrace where it is more difficult to map. The main risk is associated with the integrity of seals along the footwall of the Kaliakra fault.

4.4.2.7 Prospect F

Prospect F lies to the south of prospect E but separate from the Kaliakra Fault (**Figure 4.16**). It consists of a tilted fault with closure against a SW-NE trending fault to the west with dip closure, modified by faulting, to the east and south. The structure is relatively low relief of 25 to 55 m depending on the velocity model. The crestal area is divided into two separate culminations with a small 4-way dip closure. Structural risk is low with minor seal risk although the west fault has a substantial throw of at least 100 to 200 m.

4.4.2.8 Prospect H

Prospect H lies along a Kaliakra Terrace analogous to, and 10 km north-east of, prospect E (**Figures 4.17**). It is formed by a deflection of the Kaliakra Fault from NE to NNE, with down thrown closure against the Kaliakra Fault to the east, by fault closure to the west and essentially dip closure to the north. The relief of the structure is high in the range of 130 to 220 m depending on the velocity model. The Kaliakra fault throw is variable along the length of the prospect from less than 100 m to over 200 m so, analogous to Prospect H, effective seals will depend on a range of different formations associated with the pre-rift Mesozoic carbonates. The potential thickness and quality of such potential seals are unknown. The western bounding fault has also a substantial throw of over 400 m, especially along the southern crestal tip of the structure. The trap may be compartmentalised by small and sub seismic faults as indicated by the coherency time volume. The main structural risk is associated with the integrity of the hanging wall and footwall fault seals.

4.4.3 Gas-Initially-in-Place and Recoverable Resources

4.4.3.1 Gross Rock Volume Methodology

Melrose utilised the three depth conversion methods to generate three top reservoir depth maps and base maps. The different depth maps indicated a wide range of possible gross rock volumes and these values were input to the probabilistic GIIP calculations.

The Palaeocene and upper Cretaceous Maastrichtian reservoirs are thin and below seismic resolution so it was not possible to map the base reservoir directly from seismic. The base of the Palaeocene reservoir map was made by adding the Top Palaeocene depth map to the Palaeocene isopach derived from wells (**Figure 4.18**).

The closing contour or spill point area was taken for each prospect from each of the three depth maps and a gross rock volume calculated between the top and base reservoir within the prospect area. A P_{10} - P_{90} range of volumes could then be derived from the three depth maps. For the Upper Cretaceous reservoir, the volume was calculated by adding the total combined reservoir isopach (Palaeocene and Maastrichtian) based on wells and then subtracting the Palaeocene volume (**Figure 4.18**).

For the volumetric calculations, it is assumed that the prospects are full to spill analogous to the Kavarna and Galata Fields. A charge risk was separately assessed by considering the greater distance of each prospect from the gas kitchen compared with the discoveries to the south.

4.4.4 Petrophysical Parameters

Owing to the sparse well control in the prospective area, Melrose has not used property mapping in the volumetrics but instead reservoir property ranges have been assessed using respective petrophysical results for the Palaeocene and Maastrichtian reservoirs from the Galata, Kavarna, Kaliakra and Epsilon wells. Net-to-Gross, porosity and saturation averages obtained from these wells were used to derive the statistical mean and standard deviation measures of the normal distributions that were used as parameter inputs to the probabilistic estimates.

It has been assumed that better quality reservoir is preserved in the prospective gas accumulations as is seen in the field wells so that these averages will be representative of the rock quality likely to be encountered. Senergy believes this is a valid assumption and that the resultant statistical variations (tabulated below) should encompass the likely ranges.

Reservoir Parameters					
Property	**Reservoir**	**Mean**	**Standard Deviation**	**P_{90}**	**P_{10}**
NTG (-)	Palaeocene	0.76	0.28	0.37	0.93
	Maastrichtian	0.91	0.06	0.83	0.97
Porosity (-)	Palaeocene	0.26	0.06	0.19	0.33
	Maastrichtian	0.24	0.10	0.12	0.36
Sw (-)	Palaeocene	0.44	0.06	0.37	0.51
	Maastrichtian	0.30	0.19	0.07	0.54

Formation Volume Factor ranges were estimated for the hanging wall prospects assuming an approximate reservoir depth of 900 m and for the terrace structures at around 550 m as below.

Formation Volume Factors			
	P_{90}	**P_{50}**	**P_{10}**
Hanging wall	83.7	93.0	102.3
Terrace	54.0	60.0	45.0

4.4.5 Stochastic Results

Resultant probabilistic outputs for the GIIP estimates were replicated by Senergy to within a reasonable margin of error and Melrose' aggregated reservoir volumes were adopted as tabulated below. Stochastically aggregated sums were then derived for each of the Low, Best and High cases.

Gross Gas-Initially-In-Place (Bscf)			
Prospect	**Low Estimate**	**Best Estimate**	**High Estimate**
Chaika NW	11.6	22.3	48.2
Chaika NE	6.2	9.9	14.8
Chaika S	11.6	22.9	45.9
Kamchia	20.3	32.9	49.8
Prospect A	6.2	10.0	14.9
Prospect E	17.8	28.9	43.6
Prospect F	2.9	5.5	9.2
Prospect H	8.9	15.1	26.3
Total Gas (stochastic aggregation)	**125.8**	**156.9**	**199.3**

Potentially recoverable volumes were derived by application of a range of gas recovery factors normally distributed between a P_{90} of 0.75 and a P_{10} of 0.90, and the results are tabulated below.

Gross Prospective Resources (Bscf)			
Prospect	**Low Estimate**	**Best Estimate**	**High Estimate**
Chaika NW	9.5	18.4	39.9
Chaika NE	5.0	8.2	12.3
Chaika S	9.4	18.9	38.1
Kamchia	16.6	27.0	41.2
Prospect A	5.0	8.2	12.4
Prospect E	14.5	23.6	36.2
Prospect F	2.4	4.5	7.6
Prospect H	7.2	12.4	21.8
Total Gas (stochastic aggregation)	**103.6**	**129.2**	**164.2**

4.4.6 Chance of Success

Melrose has assessed presence and effectiveness of Trap, Reservoir and Source together with Migration and Timing. Senergy has reviewed these factors and estimated the overall COS for each prospect as tabulated below.

		Prospect			
Risk Factor		**Chaika NW**	**Chaika NE**	**Chaika S**	**Kamchia**
Trap	Presence	1.00	1.00	1.00	1.00
	Effectiveness	0.95	0.90	0.80	0.95
Reservoir	Presence	1.00	1.00	1.00	1.00
	Effectiveness	0.75	0.75	0.75	0.70
Source	Presence	1.00	1.00	1.00	1.00
	Effectiveness	1.00	1.00	1.00	1.00
	Migration	0.30	0.30	0.45	0.60
Chance of Success		**21%**	**20%**	**27%**	**40%**
		Prospect			
Risk Factor		**Prospect A**	**Prospect E**	**Prospect F**	**Prospect H**
Trap	Presence	1.00	1.00	1.00	1.00
	Effectiveness	0.95	0.40	0.90	0.40
Reservoir	Presence	1.00	1.00	1.00	1.00
	Effectiveness	0.60	0.60	0.75	0.25
Source	Presence	1.00	1.00	1.00	1.00
	Effectiveness	1.00	1.00	1.00	1.00
	Migration	0.20	0.65	0.40	0.65
Chance of Success		**11%**	**16%**	**27%**	**7%**

In summary, the Kamchia prospect is regarded as having the best chance of success with good structural expression and direct migration potential. Chaika South also has direct charge potential whilst the other Chaika prospects and Prospect F are reliant on charge from a southerly source. Prospect A and E have higher risks associated with reservoir effectiveness and migration and Prospect H suffers from a much higher risk of reservoir effectiveness.

5 Development Plans and Costs

Operator budget estimates of operating and development costs for the future development of the fields in Egypt and Bulgaria have been reviewed and are fully reflected in the economic modelling and analysis.

5.1 Capital Cost Estimate

For the El Mansoura concession, Proved plus Probable capital expenditure of $86.2 million between January 2012 and end 2018 on new facilities, drilling and well work-overs is assumed. Of this capital, approximately $40.5 million (47%) is allocated to West Dikirnis to implement the refrigeration project, and for further development drilling and flow-line repairs; $18.3 million for compression, development drilling and work-overs on West Khilala; and $7.5 million for drilling and compression on El Tamad. The remainder of the capital is allocated for drilling South Khilala-2; development drilling on South Zarqa; compression for South Zarqa, North-East Abu Zahra and East Abu Khadra; and development of East Dikirnis and West Zahayra. Development well costs are estimated to be between $4.5 million and $7.0 million each. The lower end of this range represents simpler or shallower wells, whilst the upper end represents the cost of drilling a horizontal well to a Qawasim target.

With the exception of the removal of development drilling on El Tamad, the capital expenditure to recover the Proved reserves in El Mansoura concession is the same as in the Probable case. The only other difference is in the timing of gas blow-down and therefore the requirement for compression at El Tamad.

No development expenditure is forecast for the reserves in the South East El Mansoura and Qantara concessions.

For Bulgaria, Proved plus Probable capital expenditure of $27 million is included, of which $18 million is assumed for the development of the Kavarna East discovery, with the remainder being a provision for additional compression towards the end of field life, and the cost of recommencing production from the Galata field. Melrose is understood to be in negotiations with a view to converting the Galata field to gas storage use. However, as these negotiations are not yet complete, it is not appropriate to consider that scenario for Galata in this review. Instead, a scenario of continued depletion of the field to abandonment has been assumed. To allow this to happen while Kavarna and Kaliakra are producing, some modifications at the Galata platform are required.

Capital expenditure to recover the Proved reserves in Bulgaria is the same as in the 2P case, apart from the requirement for additional compression.

The current facility expansion projects are well advanced, giving a degree of confidence in the budget estimates. However, well requirements will inevitably change as further sub-surface information comes available. These costs should be considered ‘best estimates’ at this time.

5.2 Operating Cost Estimate

For Egypt, operating costs of $13.8 million per year have been allocated across all the fields. This is in line with current running costs. These costs decline in future years commensurate with the cessation of production from depleted fields. No corporate overhead costs other than those recoverable under the PSC have been included.

In Bulgaria, operating costs of $6.3 million per year (when all fields are producing) are allocated; this is in line with current running costs.

5.3 Field Details

Senergy has adjusted the number of wells and the facility requirements as follows:

5.3.1 West Khilala

The tie-back of South Khilala to West Khilala plant allowed combined offtake from these two fields to be increased to around 112 MMscf/d and permitted the timing of compression to be deferred. The compression expenditure is estimated to be $6.8 million. Additional expenditure of $0.6 million is anticipated in 2016, when the compressors will be re-wheeled for two-stage, lower throughput service.

One additional development well, West Khilala-8, is currently drilling, and provision is made for one further development well in the second half of 2013. In addition, a work-over allowance of $3 million in 2015 has been included for production security.

5.3.2 South Khilala

South Khilala shares processing facilities with West Khilala and will benefit from compression planned to be installed by end 2012. A second well, South-Khilala-2, was successfully drilled in the first half of 2012 and results have been better than anticipated.

5.3.3 West Dikirnis

For the Undeveloped cases, it is assumed that another two horizontal wells will be added in the first half of 2013.

A combined project to provide gas re-injection to the field and to recover additional liquids in the form of LPG and incremental condensate commenced in summer 2008. The LPG project was completed in September 2009. The plant is operating as expected, and some 970 bbl/d of additional stabilised crude is currently being recovered. The gas re-injection started in May 2010 and most of the produced gas is being injected. Over the course of 2012/2013 the second part of the LPG project, the addition of a refrigeration plant, will be installed at a cost of $25.5 million. $13 million in 2013 is assumed for drilling two more horizontal wells in the field. In addition, an allowance of $2 million has been included over 2013 to 2014 for any pipeline remedial work.

5.3.4 East Dikirnis

$3.65 million will be spent in the first half of 2013 to re-enter, complete and tie back the East Dikirnis-1 well to West Dikirnis. Installation of a pipeline from the well to the West Dikirnis-3 cluster and carrying out tie-ins to West Dikirnis flow-lines are scheduled for the first half of 2013.

5.3.5 El Tamad

Senergy assumed that no more wells will be drilled in the 1PD, 1P and 2PD cases, while in the Proved plus Probable case one horizontal well (Tamad-6) will be drilled in 2013 ($4.5

million), increasing field recovery from 25% (2PD) to 27% (2P). Blow-down of the gas cap is assumed to occur in 2013 for the Proved (1PD and 1P) cases, and in 2016 (2PD) and 2019 (2P) for the other cases. An allowance of $3 million at the start of blow-down has been made for compression facilities in the Undeveloped (1P and 2P) cases.

5.3.6 South Zarqa

The South Zarqa discovery requires an additional development well in the second half of 2013, costing $6.0 million, in order to produce the Proved and the Proved plus Probable Undeveloped case reserves. South Zarqa is tied back to the South Batra plant via a 10-inch pipeline.

5.3.7 North-East Abu Zahra

NEAZ wells share the flow-line with South Zarqa. No additional capex is planned.

5.3.8 East Abu Khadra

The Proved and Probable reserves of the East Abu Khadra discovery can be developed with the existing well and no further drilling is considered necessary. Melrose has plans to install compression in 2015 at an estimated cost of $1.9 million. This compression will also assist in the recovery of gas reserves from South Zarqa and NE Abu Zahra.

5.3.9 West Zahayra

Melrose has completed West Zahayra-1 as an oil producer and is planning to commence production from July 2013. A development expenditure of $2.64 million is assumed in the first half of 2013.

5.3.10 Damas

No further development is required to produce the Proved and Probable reserves.

5.3.11 South Damas

No further development is required to produce the Proved and Probable reserves.

5.3.12 Qantara

Melrose currently has no other firm wells planned.

5.3.13 Galata

Melrose is negotiating commercial agreements and seeking authorisations to convert the Galata field to Underground Gas Storage (UGS). However, these plans are not sufficiently mature for Senergy to use as the base scenario for this reserves assessment. Meanwhile, Melrose has developed the Kavarna and Kaliakra discoveries, tying them back to shore via the Galata platform, and has similar plans for Kavarna East. Instead of considering UGS, a scenario of continued depletion for Galata has therefore been assumed, with the assumption that Galata will be producing in parallel with the new discoveries. Under that scenario, only two very minor capital investments for Galata field would be required. First, an eductor would be installed on the Galata platform to allow the GP-1 well to flow with the higher pressure

Kavarna and Kaliakra gas; second, an expandable bridge plug would be fitted as a precaution against a rising water contact. Respective capital costs of $200k and $150k have been assumed. A further $500k is allowed for the extension of existing land rights, relating to the onshore pipeline route and site of the onshore processing facility and gas metering station.

5.3.14 Kavarna

Towards the end of field life in the Proved plus Probable Undeveloped case a provision of $8 million has been included as an allowance for additional compression. The cost of this compression is shared equally between Kavarna and Kaliakra.

5.3.15 Kaliakra

See comments under Kavarna.

5.3.16 Kavarna East

This well will be tied back to the Galata platform through the existing 6-inch Kavarna pipeline. The completion and tie-in cost is assumed to be $18 million, with production starting in October 2013.

5.3.17 Bulgarian Prospects

Melrose has developed a conceptual plan on the basis that the first exploration well on the Kamchia prospect will be drilled in Q1 2013 with first gas for a development in 3Q 2014. By this time there will be sufficient ullage at the Galata facilities of more than 40 MMscf/d which should increase to the proven capacity of 70 MMscf/d by Q3 2018. New wells will be sub-sea tie-backs to Galata similarly to Kavarna and Kaliakra (**Figure 5.1**).

Eight prospects were identified and their volumes estimated (Section 4.4). The three most significant i.e. Kamchia, Chaika S and Chaika NW would each be developed as stand-alone tie-backs. The remaining five would be daisy-chained in the following arrangement (**Figure 5.2**).

- Chaika NE to Chaika NW.
- Prospects A and H to Chaika S.
- Prospects E and F to Kamchia.

5.3.18 Egyptian Prospects

Notional development plans have been developed for each of the main prospects identified in Section 2. For the four prospects in South East El Mansoura (Sinbelaywan, Sidi Gohar, Kafr Saqr and Hadjarisah) the development consists of drilling an exploration well, which, if successful, will be completed and be used as a development well. Additional development wells will be drilled as necessary and local water injection facilities will be built. For each prospect, a pipeline of length 28 to 38 km (at a cost of $19 to 31 MM depending on required pipeline diameter) will transport the oil and gas to the South Batra facility.

Based on previous experiences, the costs for a development well has been estimated at $6.6 MM (including completion and tie-in). Additional costs are related to water handling.

Opex of $100,000 pa, $200,000 pa and $400,000 pa have been estimated for the Low, Best and High cases respectively and apply to each South East El Mansoura prospect development.

For the four key prospects in El Mansoura (Mit Hadid, Mustafa, NW Zahayra and SW Tarif) it is assumed that local operations are tied back to the nearest existing facilities. The capex is therefore dedicated to wells, completions and pipelines. No water handling is expected to be required. Exploration well costs are estimated at $4.0 to 4.6 MM inclusive of completions and tie back. Additional development wells are each costed at $4.2 MM. Pipeline capex is estimated between $1 and $13 MM, depending on distance to nearest facilities and on pipeline diameter.

Opex of $100,000 pa, $150,000 pa and $250,000 pa have been estimated for the Low, Best and High cases respectively and apply to each El Mansoura prospect development.

6 Economics

The Proved and Probable reserves were valued using the economic models provided by Melrose for the El Mansoura and Qantara Areas in Egypt and for Block Galata in Bulgaria. In addition for the prospective resources in Egypt and Bulgaria, the notional development plans and related costs and production profiles were incorporated in economic models by Melrose to calculate notional unrisked NPVs. The models were audited by Senergy and we found the inputs consistent with Senergy's assumptions. The models themselves were also reviewed and found to be robust and consistent with fiscal and other commercial terms.

6.1 Fiscal Terms

The relevant Fiscal Terms are as shown below:

6.1.1 Egypt

Contractor Share	Qantara Area	El Mansoura Areas
Royalty	10% paid by state	10% paid by state
Cost Oil	35%	35%
Cost Recovery Exploration Development Operating Costs	 33.33% p.a. 33.33% p.a. 100% p.a.	 25.00% p.a. 25.00% p.a. 100% p.a.
Excess Oil	100% to Profit Oil	30%
Profit Oil	65%	65%
Profit Oil Split	0 to 2,500 bopd 15% 2,500 to 5,000 bopd 14% 5,000 to 10,000 bopd 13% 10,000 to 15,000 bopd 12% 15,000 to 25,000 bopd 11% 25,000 to 50,000 bopd 10% > than 50,000 bopd 9%	0 to 10,000 bopd 20% 10,000 to 20,000 bopd 18% 25,000 to 50,000 bopd 16% > than 50,000 bopd 15%
Bonuses Signature Commercial Bonus Production Bonus	 US$0.2 million 15,000 bopd US$2.0 million 50,000 bopd US$4.0 million	 US$0.5 million 25,000 bopd US$1.0 million 50,000 bopd US$2.0 million 100,000 bopd US$4.0 million
Taxes	All taxes including royalty paid for by Egyptian General Petroleum Corporation.	All taxes including royalty paid for by Egyptian General Petroleum Corporation.

6.1.2 Bulgaria

Contractor Share	Galata	Kavarna, Kaliakra and Kavarna East
Royalty	R-Factor based < 1.50 : 2.5% 1.50 to 1.75 : 5.0% 1.75 to 2.00 : 7.5% 2.00 to 2.50 : 10.0% 2.50 to 3.00 : 12.5% > 3.00 : 25.0%	R-Factor based < 1.50 : 2.5% 1.50 to 1.75 : 5.0% 1.75 to 1.875 : 7.5% 1.875 to 2.25 : 10.0% 2.25 to 2.75 : 12.5% 2.75 to 3.00 : 22.5% > 3.00 : 27.5%
Cost Oil	100%	100%
Bonuses Signature Commercial Bonus Production Bonus	US$3.0 million 20,000 bopd US$4.0 million 40,000 bopd US$5.0 million 80,000 bopd US$5.0 million	
Taxes	All taxes paid for by Company	All taxes paid for by Company
NPI	Melrose has to pay a 5% NPI interest to the original owners from its net cash flow from the Galata field.	

6.2 Assumptions

It was assumed that development will be carried out largely as proposed by Melrose and reported in the previous section. Total Capex for development of Proved and Probable reserves is estimated at US$86.2 million in Egypt and US$26.9 million in Bulgaria. In addition, non-field-specific costs approved in the 2012 budget, amounting to $21.1 million, were included in El Mansoura concession. This assumed exploration costs of $9.92 million, a West Khilala workover allowance of $0.8 million, development costs of $8.70 million and PLC charges of $1.68 million. Annual operating costs of $13.8 million were assumed for Egypt and $6.3 million for Bulgaria.

Stand-alone developments for the Bulgarian prospects include estimated costs of $12 MM each for installation of two pile-driven risers to carry 6-inch risers tied to the Galata platform. Only minor additions to the Hydraulic Power Unit for three additional wells are required at a cost of $0.5 MM.

The value of plant and equipment was not determined separately and is deemed to be included in the value of future net revenues derived from the reserves. Decommissioning and re-instatement costs, although not material, have been taken account of in deriving the net present value of both Egyptian and Bulgarian assets.

Production profiles were curtailed at the limit of economic production, consistent with the terms of the development leases.

A flat benchmark price of $90/bbl was assumed for oil and condensate, and $58.5/bbl for West Dikirnis LPG.

The following gas price assumptions were used for each field, based on historic averages provided by Melrose:

Field Name	Gas ($/Mscf)
Qantara	12.75
West Khilala, South Khilala	2.65
West Dikirnis	2.95
East Dikirnis	2.65
El Tamad	2.65
West Zahayra	2.65
Damas, South Damas	2.80
South Zarqa	2.95
North-East Abu Zahra	2.95
East Abu Khadra	2.95
Galata	8.30
Kavarna, Kaliakra, Kavarna East	8.30

A gas price of $2.65/Mscf was assumed for all Egyptian prospects and a $8.30/Mscf gas price for all Bulgarian prospects.

6.3 Results

Economics were carried out on a real term basis with no inflation. Estimates of the NPVs of future net revenues deriving from the Melrose share of the Proved and Proved plus Probable reserves, as of 31st December 2011, are presented below:

Net Present Value @10% (US$,000)			
Concession/ Field	Proved	Proved plus Probable	Proved plus Probable plus Possible
Qantara	983	2,495	3,191
El Mansoura	208,835	292,568	374,228
South-East El Mansoura	28,688	35,722	45,692
Galata	29,176	31,039	53,677
Kavarna	88,538	97,790	106,348
Kaliakra	107,328	116,898	133,898
Kavarna East	14,320	25,621	40,895
Total (in US$,000)	**477,868**	**602,133**	**757,929**

Unrisked NPV 10% for the best estimate prospective resources in Bulgaria are shown below.

Un-Risked Prospective Resources	
Prospect	**Net Present Value @10% (US$ MM)**
Chaika NW	34.3
Chaika NE	15.0
Chaika S	39.7
Kamchia	72.5
Prospect A	13.4
Prospect E	58.5
Prospect F	N/A
Prospect H	22.9
Total	**256.3**

Unrisked NPV 10% for the best estimate prospective resources in Egypt are shown below.

Un-Risked Prospective Resources	
Prospect	**Net Present Value @10% (US$ MM)**
El Mansoura	
Mit Hadid	7.4
Mustafa	17.4
NW Zahayra	9.8
SW Tarif	12.2
South East El Mansoura	
Sinbelaywan	19.5
Sidi Gohar	7.5
Kafr Saqr	N/A
Al Hadjarisah	14.0
Total	**87.9**

7 References

1. Senergy CPR on Bulgaria and Egypt Reserves, February 2012, authors: John Kendal, Barry Squire

2. Senergy CPR on Galata, Bulgaria Prospective Resources, June 2012, authors: Barry Squire, Martin Eales

3. "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserve Information", published by the Society of Petroleum Engineers (SPE) in June 2001, SPE website (www.spe.org).

4. "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserve Information Approved by SPE Boards June 2001 - Revision as of February 19, 2007", published by the Society of Petroleum Engineers (SPE); SPE website (www.spe.org).

5. "Petroleum Resources Management System", Sponsored by SPE, AAPG, WPC, SPEE, published 2007; SPE website (www.spe.org).

6. "Petroleum Reserves Definitions" approved by SPE and WPC March 1997; SPE website (www.spe.org).

7. "Note for Mining and Oil & Gas Companies", London Stock Exchange, AIM Guidelines, June 2009.

8 Nomenclature

Variable	Meaning
1P	Proved (Developed and Undeveloped)
1PD	Proved (Developed)
2P	Proved plus Probable (Developed and Undeveloped)
2PD	Proved plus Probable (Developed)
AVO	Amplitude Variation with Offset
bbl	U.S. barrels
Bscf	U.S. billions of standard cubic feet
Bscfe	Billions of standard cubic feet of equivalent gas (oil converted using 5.8 Mscfe/bbl)
bbl/d	Barrels per day
bopd	Barrels of oil per day
bwpd	Barrels of water per day
CGR	Condensate Gas Ratio
CIIP	Condensate Initially In Place
COS	Chance of Success
DHI	Direct Hydrocarbon Indicator
EUR	Estimated Ultimate Recovery
FTHP	Flowing Tubing-Head Pressure
GDT	Gas-Down-To
GIIP	Gas Initially In Place
GOR	Gas-Oil Ratio
GRI	Gas Re-Injection
GRV	Gross Rock Volume
GWC	Gas-Water Contact
HCIIP	Hydrocarbons Initially In Place
LPG	Liquefied Petroleum Gas
M	Thousands
mD	milliDarcies
MD	Measured Depth
MDT	Modular formation Dynamics Tester
M	Thousands
MM	Millions
MMscf/d	Millions of standard cubic feet per day
m/s	Metres per second
NPV	Net Present Value
NTG	Net-To-Gross ratio
PBU	Pressure Build-Up

PLC	Public Limited Company
PLT	Production Logging Tool
ppm	Parts per million
PSC	Production Sharing Contract
psia	Pounds per square inch (absolute)
psig	Pounds per square inch (gauge)
PVT	Pressure volume temperature
RKB	Rotary Kelly Bushing
RMS	Root Mean Square
RST	Reservoir Saturation Tester
scf	Standard Cubic Feet
SITHP	Shut-in tubing head pressure
stb	Stock tank barrels
STOIIP	Stock Tank Oil Initially In Place
THP	Tubing-Head Pressure
TVD	True Vertical Depth
TVDSS	True Vertical Depth Sub-Sea
VSP	Vertical Seismic Profile
UGS	Underground Gas Storage
UR	Ultimate Recovery
WGR	Water-Gas Ratio
$	U.S. dollar

9 Reserves Summaries

Egypt : Proved Developed Reserves, 31 Dec 2011

	Gas				Condensate and LPG				Oil			
	GIIP	UR	Produced	Reserves	CIIP	UR	Produced	Reserves	STOIIP	UR	Produced	Reserves
	Bscf	Bscf	Bscf	Bscf	Mbbl	Mbbl	Mbbl	Mbbl	Mbbl	Mbbl	Mbbl	Mbbl
El Mansoura												
West Khilala	320.0	242.0	160.0	82.0	617	278	220	59	-	-	-	-
South Khilala	41.3	31.3	12.1	19.3	97	39	22	17	-	-	-	-
El Tamad	33.3	18.6	5.2	13.4	-	-	-	-	5,470	1,825	1,781	44
East Dikirnis	-	-	-	-	-	-	-	-	-	-	-	-
West Dikirnis	93.3	53.5	20.1	33.4	6,490	3,973	1,769	2,204	22,640	9,448	6,524	2,924
El Mansoura Extension												
South Zarqa	36.7	20.2	16.7	3.4	1,652	694	579	115	-	-	-	-
North-East Abu Zahra	39.0	13.9	12.9	1.0	1,119	252	249	3	-	-	-	-
East Abu Khadra	32.0	20.8	8.6	12.2	544	170	89	81	-	-	-	-
West Zahayra	-	-	-	-	-	-	-	-	-	-	-	-
South-East El Mansoura												
Damas	3.3	2.6	1.8	0.8	32	24	17	7	-	-	-	-
South Damas	56.0	39.2	6.5	32.7	392	152	47	105	-	-	-	-
Qantara												
Qantara	3.6	2.0	1.7	0.2	644	233	208	24	-	-	-	-
Total	**658.4**	**444.2**	**245.6**	**198.6**	**11,587**	**5,816**	**3,200**	**2,616**	**28,110**	**11,274**	**8,305**	**2,968**

N.B. Proved Hydrocarbons-in-Place may not be compared with Proved Reserves.

Egypt : Proved Developed & Undeveloped Reserves, 31 Dec 2011

	Gas				Condensate and LPG				Oil			
	GIIP	UR	Produced	Reserves	CIIP	UR	Produced	Reserves	STOIIP	UR	Produced	Reserves
	Bscf	Bscf	Bscf	Bscf	Mbbl	Mbbl	Mbbl	Mbbl	Mbbl	Mbbl	Mbbl	Mbbl
El Mansoura												
West Khilala	320.0	260.1	160.0	100.1	617	289	220	69	-	-	-	-
South Khilala	41.3	36.1	12.1	24.0	97	44	22	22	-	-	-	-
El Tamad	33.3	18.6	5.2	13.4	-	-	-	-	5,470	1,825	1,781	44
East Dikirnis	3.5	1.9	-	1.9	184	72	-	72	464	56	-	56
West Dikirnis	93.3	73.6	20.1	53.6	6,490	5,810	1,769	4,041	22,640	10,351	6,524	3,827
El Mansoura Extension												
South Zarqa	36.7	22.0	16.7	5.3	1,652	753	579	174	-	-	-	-
North-East Abu Zahra	39.0	13.9	12.9	1.0	1,119	252	249	3	-	-	-	-
East Abu Khadra	32.0	20.8	8.6	12.2	544	170	89	81	-	-	-	-
West Zahayra	0.6	0.0	-	0.0	-	-	-	-	421	21	-	21
South-East El Mansoura												
Damas	3.3	2.6	1.8	0.8	32	24	17	7	-	-	-	-
South Damas	56.0	39.2	6.5	32.7	392	152	47	105	-	-	-	-
Qantara												
Qantara	3.6	2.0	1.7	0.2	644	233	208	24	-	-	-	-
Total	**662.5**	**490.8**	**245.6**	**245.2**	**11,771**	**7,799**	**3,200**	**4,599**	**28,995**	**12,253**	**8,305**	**3,948**

N.B. Proved Hydrocarbons-in-Place may not be compared with Proved Reserves.

Egypt : Proved & Probable Developed Reserves, 31 Dec 2011

	Gas				Condensate and LPG				Oil			
	GIIP	UR	Produced	Reserves	CIIP	UR	Produced	Reserves	STOIIP	UR	Produced	Reserves
	Bscf	Bscf	Bscf	Bscf	Mbbl	Mbbl	Mbbl	Mbbl	Mbbl	Mbbl	Mbbl	Mbbl
El Mansoura												
West Khilala	326.7	276.1	160.0	116.1	629	297	220	77	-	-	-	-
South Khilala	55.0	41.3	12.1	29.2	138	56	22	34	-	-	-	-
El Tamad	41.7	29.2	5.2	24.0	-	-	-	-	7,800	1,927	1,781	145
East Dikirnis	-	-	-	-	-	-	-	-	-	-	-	-
West Dikirnis	116.6	69.9	20.1	49.8	7,812	4,317	1,769	2,548	28,300	11,296	6,524	4,772
El Mansoura Extension												
South Zarqa	58.0	26.1	16.7	9.4	2,610	920	579	341	-	-	-	-
North-East Abu Zahra	40.0	14.9	12.9	2.0	1,120	257	249	8	-	-	-	-
East Abu Khadra	40.0	30.0	8.6	21.4	680	234	89	145	-	-	-	-
West Zahayra	-	-	-	-	-	-	-	-	-	-	-	-
South-East El Mansoura												
Damas	3.5	3.0	1.8	1.2	34	28	17	11	-	-	-	-
South Damas	62.0	49.6	6.5	43.1	465	225	47	178	-	-	-	-
Qantara												
Qantara	3.6	2.3	1.7	0.6	644	269	208	61	-	-	-	-
Total	**747.1**	**542.2**	**245.6**	**296.6**	**14,133**	**6,603**	**3,200**	**3,403**	**36,100**	**13,222**	**8,305**	**4,917**

Egypt : Proved & Probable Developed & Undeveloped Reserves, 31 Dec 2011

	Gas				Condensate and LPG				Oil			
	GIIP	UR	Produced	Reserves	CIIP	UR	Produced	Reserves	STOIIP	UR	Produced	Reserves
	Bscf	Bscf	Bscf	Bscf	Mbbl	Mbbl	Mbbl	Mbbl	Mbbl	Mbbl	Mbbl	Mbbl
El Mansoura												
West Khilala	326.7	288.7	160.0	128.8	629	306	220	87	-	-	-	-
South Khilala	55.0	46.7	12.1	34.7	138	64	22	41	-	-	-	-
El Tamad	41.7	31.3	5.2	26.1	-	-	-	-	7,800	2,123	1,781	341
East Dikirnis	4.6	2.6	-	2.6	244	100	-	100	716	90	-	90
West Dikirnis	116.6	95.4	20.1	75.4	7,812	6,620	1,769	4,851	28,300	12,872	6,524	6,348
El Mansoura Extension												
South Zarqa	58.0	36.5	16.7	19.8	2,610	1,294	579	715	-	-	-	-
North-East Abu Zahra	40.0	15.5	12.9	2.6	1,120	259	249	10	-	-	-	-
East Abu Khadra	40.0	30.0	8.6	21.4	680	234	89	145	-	-	-	-
West Zahayra	1.8	0.3	-	0.3	-	-	-	-	1,300	130	-	130
South-East El Mansoura												
Damas	3.5	3.0	1.8	1.2	34	28	17	11	-	-	-	-
South Damas	62.0	49.6	6.5	43.1	465	225	47	178	-	-	-	-
Qantara												
Qantara	3.6	2.3	1.7	0.6	644	269	208	61	-	-	-	-
Total	**753.5**	**601.8**	**245.6**	**356.3**	**14,376**	**9,399**	**3,200**	**6,198**	**38,116**	**15,215**	**8,305**	**6,909**

Bulgaria : Proved Developed Reserves, 31 Dec 2011

	Gas				Condensate				Oil			
	GIIP	UR	Produced	Reserves	CIIP	UR	Produced	Reserves	STOIIP	UR	Produced	Reserves
	Bscf	Bscf	Bscf	Bscf	Mbbl	Mbbl	Mbbl	Mbbl	Mbbl	Mbbl	Mbbl	Mbbl
Galata	79.4	66.0	66.0	-	-	-	-	-	-	-	-	-
Kavarna	29.8	23.3	7.5	15.8	-	-	-	-	-	-	-	-
Kaliakra	37.0	29.8	10.8	19.0	-	-	-	-	-	-	-	-
Kavarna East	-	-	-	-	-	-	-	-	-	-	-	-
Total	**146.2**	**119.1**	**84.3**	**34.8**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**

Bulgaria : Proved Developed & Undeveloped Reserves, 31 Dec 2011

	Gas				Condensate				Oil			
	GIIP	UR	Produced	Reserves	CIIP	UR	Produced	Reserves	STOIIP	UR	Produced	Reserves
	Bscf	Bscf	Bscf	Bscf	Mbbl	Mbbl	Mbbl	Mbbl	Mbbl	Mbbl	Mbbl	Mbbl
Galata	79.4	71.2	66.0	5.2	-	-	-	-	-	-	-	-
Kavarna	29.8	24.6	7.5	17.1	-	-	-	-	-	-	-	-
Kaliakra	37.0	30.7	10.8	20.0	-	-	-	-	-	-	-	-
Kavarna East	8.4	5.8	-	5.8	-	-	-	-	-	-	-	-
Total	**154.5**	**132.3**	**84.3**	**48.0**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**

N.B. Proved Hydrocarbons-in-Place may not be compared with Proved Reserves.

Bulgaria : Proved & Probable Developed Reserves, 31 Dec 2011

	Gas				Condensate				Oil			
	GIIP	UR	Produced	Reserves	CIIP	UR	Produced	Reserves	STOIIP	UR	Produced	Reserves
	Bscf	Bscf	Bscf	Bscf	Mbbl	Mbbl	Mbbl	Mbbl	Mbbl	Mbbl	Mbbl	Mbbl
Galata	79.4	66.0	66.0	-	-	-	-	-	-	-	-	-
Kavarna	30.8	26.2	7.5	18.6	-	-	-	-	-	-	-	-
Kaliakra	38.7	33.3	10.8	22.5	-	-	-	-	-	-	-	-
Kavarna East	-	-	-	-	-	-	-	-	-	-	-	-
Total	**148.9**	**125.5**	**84.3**	**41.2**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**

Bulgaria : Proved & Probable Developed & Undeveloped Reserves, 31 Dec 2011

	Gas				Condensate				Oil			
	GIIP	UR	Produced	Reserves	CIIP	UR	Produced	Reserves	STOIIP	UR	Produced	Reserves
	Bscf	Bscf	Bscf	Bscf	Mbbl	Mbbl	Mbbl	Mbbl	Mbbl	Mbbl	Mbbl	Mbbl
Galata	79.4	71.4	66.0	5.4	-	-	-	-	-	-	-	-
Kavarna	30.8	26.9	7.5	19.4	-	-	-	-	-	-	-	-
Kaliakra	38.7	33.7	10.8	22.9	-	-	-	-	-	-	-	-
Kavarna East	11.1	8.2	-	8.2	-	-	-	-	-	-	-	-
Total	**160.0**	**140.2**	**84.3**	**55.9**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**

10 Reserves Deductions for Fuel and Shrinkage

Fuel and Shrinkage, from 31 Dec 2011

	Gas			
	Proved Developed	Proved Developed & Undeveloped	Proved plus Probable Developed	Proved plus Probable Developed & Undeveloped
	Bscf	Bscf	Bscf	Bscf
El Mansoura				
West Khilala	0.2	0.8	0.3	1.1
South Khilala	0.1	0.2	0.1	0.3
El Tamad	0.5	0.5	1.0	1.0
East Dikirnis	-	0.1	-	0.1
West Dikirnis	11.5	18.2	12.6	19.6
El Mansoura Extension				
South Zarqa	0.2	0.4	0.6	1.3
North-East Abu Zahra	0.1	0.1	0.1	0.2
East Abu Khadra	0.6	0.6	1.0	1.0
West Zahayra	-	0.0	-	0.3
South East El Mansoura				
Damas	0.0	0.0	0.1	0.1
South Damas	0.7	0.7	0.9	0.9
Qantara				
Qantara	0.1	0.1	0.1	0.1
Block Galata				
Galata	-	0.3	-	0.3
Kavarna	0.5	0.8	0.5	0.8
Kaliakra	0.6	0.8	0.6	0.9
Kavarna East	-	0.3	-	0.4
Total	**15.1**	**23.9**	**18.0**	**28.5**

Appendix A – Competent Persons' Biographies

Dr. Barry Squire – Principal Geoscientist

Dr. Barry James Squire is a Principal Commercial Geoscientist employed in Senergy's London office. He is a professional petroleum production geologist with over 25 years of oil industry experience gained in major international companies, consultancies and within Senergy. He is qualified with a B.Sc. Honours degree in Geology and a Ph.D. in Sedimentary Geochemistry and has over 10 years of experience being in responsible charge of the estimation and evaluation of reserves information. He is a Fellow of the Geological Society and a member of the Petroleum Exploration Society of Great Britain.

Dr Martin Eales – Principal Geophysicist

Dr. Martin Eales is a Principal Geophysicist for Senergy (GB) Limited and was responsible for conducting the geophysical review in this evaluation. He is a professional geophysicist with over 25 years of oil industry experience gained working on a wide variety of fields and with companies including Shell, Kerr McGee, Fina, Lasmo and ENI. He is a Fellow of the Geological Society, the EAGE and a member of the Petroleum Exploration Society of Great Britain. He has a Geology degree from Cambridge University and a PhD in Geology from University of Glasgow.

Dr. John Kendal – Principal Reservoir Engineer

John Kendal is a Principal Reservoir Engineer with 30 years of energy industry experience, gained with British Gas as well as a number of reputed oil industry consultants. John has particular strengths in the areas of reserves and asset valuation, reservoir simulation and fluid characterisation. He has lead many Competent Person's Reports, including previous CPRs for Melrose Resources plc. He has a Mathematics degree from Cambridge University and a PhD in Mathematics from Stanford University, USA.

Peter Aquilina – Principal Reservoir Engineer

Peter Aquilina is a Principal Reservoir Engineer with 28 years of experience, gained with operators including Hess, FINA and Britoil, before working as a consultant. He has many years of experience with simulation, reservoir engineering, well testing, Joint Venture asset management, asset evaluation and data room analysis as well as more technical areas in his profession. He has an honours degree in Offshore Engineering from Heriot-Watt University, Edinburgh.

Melrose Licence Interests

Melrose Resources plc Summary of Assets						
Asset	**Region**	**Licence Operator**	**Participating Interest**	**Status**	**Licence Area**	**Licence Expiry Deadline**
El Mansoura	Egypt	Melrose	100%	Exploration and Production	1,058	Exploration: 21/12/2012 Production: various*
South-East El Mansoura	Egypt	Melrose	100%	Exploration and Production	1,860	Exploration: 26/07/2014 Production: various*
Qantara	Egypt	Melrose	100%	Production (Exploration Relinquished)	3	21/08/2019 or later
Block Galata	Bulgaria	Melrose	100%	Exploration and Production	1,786	Exploration: 03/02/2015 Production extended as required
Block Galata	Bulgaria	Melrose	100%	Lease Galata Field	19	Production: 16/05/2026
Block Galata	Bulgaria	Melrose	100%	Lease Kavarna Field	4	Production: 01/11/2020
Block Galata	Bulgaria	Melrose	100%	Lease Kaliakra Field	19	Production: 01/11/2020
Block Galata	Bulgaria	Melrose	100%	Lease Kavarna East Field	4	Production: [20/08/2018]**

* Development Leases covering production rights are awarded for an initial 20 years, with the option to extend for a maximum of 35 years. None of the Melrose Egyptian Assets have field production profiles that are expected to extend beyond this period."

**Kavarna East Production Concession (Lease Kavarna East Field) was awarded 1 August 2012. The effective date will run from the date of Publication of the decree, which is anticipated to be about 20th August 2012.

Table 1.1

Oil Reserves for Egypt and Bulgaria

Reserves: Egypt and Bulgaria							
Oil Reserves (Mstb)	Gross			Net Attributable to Melrose			Operator
	Proved	Proved plus Probable	Proved plus Probable plus Possible	Proved	Proved plus Probable	Proved plus Probable plus Possible	
Egypt							
El Mansoura	3927.0	6779.4	10907.0	1663.2	2484.0	3257.6	Melrose
El Mansoura Extension	21.1	130.0	543.2	8.9	47.6	162.2	
South-East El Mansoura	0.0	0.0	0.0	0.0	0.0	0.0	
Qantara	0.0	0.0	0.0	0.0	0.0	0.0	
Total Oil Egypt; Mstb	**3948.0**	**6909.4**	**11450.2**	**1672.1**	**2531.7**	**3419.9**	
Bulgaria							
Galata	0.0	0.0	0.0	0.0	0.0	0.0	
Kavarna	0.0	0.0	0.0	0.0	0.0	0.0	
Kaliakra	0.0	0.0	0.0	0.0	0.0	0.0	
Kavarna East	0.0	0.0	0.0	0.0	0.0	0.0	
Total Oil Bulgaria; Mstb	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	
Total Oil; Mstb	**3948.0**	**6909.4**	**11450.2**	**1672.1**	**2531.7**	**3419.9**	

Source: Senergy (GB) Ltd

N.b: totals may not sum exactly due to rounding to one decimal place

Table 1.2

senergy

Condensate Reserves for Egypt and Bulgaria

Reserves: Egypt and Bulgaria							
Condensate Reserves (Mstb)	Gross			Net Attributable to Melrose			Operator
	Proved	Proved plus Probable	Proved plus Probable plus Possible	Proved	Proved plus Probable	Proved plus Probable plus Possible	
Egypt							
El Mansoura	4203.9	5079.3	6064.7	1780.5	1861.1	1811.3	Melrose
El Mansoura Extension	258.9	869.5	1537.1	109.7	318.6	459.1	
South-East El Mansoura	112.0	188.6	321.7	47.4	69.1	96.1	
Qantara	24.2	60.8	132.1	10.2	22.3	39.5	
Total Condensate Egypt; Mstb	**4599.0**	**6198.3**	**8055.6**	**1947.8**	**2271.1**	**2406.0**	
Bulgaria							
Galata	0.0	0.0	0.0	0.0	0.0	0.0	
Kavarna	0.0	0.0	0.0	0.0	0.0	0.0	
Kaliakra	0.0	0.0	0.0	0.0	0.0	0.0	
Kavarna East	0.0	0.0	0.0	0.0	0.0	0.0	
Total Condensate Bulgaria; Mstb	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	
Total Condensate; Mstb	**4599.0**	**6198.3**	**8055.6**	**1947.8**	**2271.1**	**2406.0**	

Source: Senergy (GB) Ltd

N.b: totals may not sum exactly due to rounding to one decimal place

Table 1.3

Gas Reserves for Egypt and Bulgaria

Reserves: Egypt and Bulgaria							
Gas Reserves (Bscf)	Gross			Net Attributable to Melrose			Operator
	Proved	Proved plus Probable	Proved plus Probable plus Possible	Proved	Proved plus Probable	Proved plus Probable plus Possible	
Egypt							
El Mansoura	193.0	267.4	337.5	72.9	91.0	99.2	Melrose
El Mansoura Extension	18.5	44.0	67.7	7.0	15.0	19.9	
South-East El Mansoura	33.5	44.3	59.3	12.7	15.1	17.4	
Qantara	0.2	0.6	1.1	0.1	0.2	0.3	
Total Gas Egypt; Mstb	**245.2**	**356.3**	**465.6**	**92.7**	**121.2**	**136.9**	
Bulgaria							
Galata	5.2	5.4	9.4	5.2	5.4	9.4	
Kavarna	17.1	19.4	21.4	17.1	19.4	21.4	
Kaliakra	20.0	22.9	27.5	20.0	22.9	27.5	
Kavarna East	5.8	8.2	12.0	5.8	8.2	12.0	
Total Gas Bulgaria; Mstb	**48.0**	**55.9**	**70.3**	**48.0**	**55.9**	**70.3**	
Total Gas; Bscf	**293.2**	**412.1**	**536.0**	**140.7**	**177.1**	**207.2**	

Source: Senergy (GB) Ltd

N.b: totals may not sum exactly due to rounding to one decimal place

Table 1.4

Prospective Resources for Block Galata, Bulgaria

Prospective Resources: Block Galata								
Gas Resources (Bscf)	Gross on Licence			Net to Melrose			Risk Factor	Operator
	Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate		
Chaika NW	9.5	18.4	39.9	9.5	18.4	39.9	0.21	Melrose
Chaika NE	5	8.2	12.3	5.0	8.2	12.3	0.20	
Chaika S	9.4	18.9	38.1	9.4	18.9	38.1	0.27	
Kamchia	16.6	27	41.2	16.6	27.0	41.2	0.40	
Prospect A	5	8.2	12.4	5.0	8.2	12.4	0.11	
Prospect E	14.5	23.6	36.2	14.5	23.6	36.2	0.16	
Prospect F	2.4	4.5	7.6	2.4	4.5	7.6	0.27	
Prospect H	7.2	12.4	21.8	7.2	12.4	21.8	0.07	
Total Gas; Bscf (stochastic aggregation)	**103.6**	**129.2**	**164.2**	**103.6**	**129.2**	**164.2**		

Source: Senergy (GB) Ltd

"Risk Factor" (also known as COS) for Prospective Resources, means the chance or probability of discovering hydrocarbons in sufficient quantity for them to be tested to the surface. In addition Senergy assess whether this factor is appropriate to the resource size distribution and it is specifically linked to the low case volume.

NB: totals may not sum exactly due to rounding to one decimal place

Table 1.5

Prospective Resources for El Mansoura, Egypt

Prospective Resources: El Mansoura								
Liquid Resources (Mstb)	Gross on Licence			Net to Melrose			Risk Factor	Operator
	Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate		
Mit Hadid	407	1,009	2,089	148	382	757	0.31	Melrose
Mustafa	926	1,904	3,457	321	627	1,187	0.40	
NW Zahayra	319	863	1,818	114	260	580	0.40	
SW Tarif	383	1,501	3,626	153	525	1,269	0.42	
Gas Resources (Bscf)	Gross on Licence			Net to Melrose			Risk Factor	Operator
	Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate		
Mit Hadid	3.0	7.4	14.9	0.9	2.8	5.3	0.31	Melrose
Mustafa	7.9	15.8	27.4	2.4	4.6	8.7	0.40	
NW Zahayra	3.9	10.3	20.9	1.3	2.6	5.9	0.40	
SW Tarif	2.8	11.1	26.1	1.0	3.3	8.5	0.42	

Source: Senergy (GB) Ltd

"Risk Factor" (also known as COS) for Prospective Resources, means the chance or probability of discovering hydrocarbons in sufficient quantity for them to be tested to the surface. In addition Senergy assess whether this factor is appropriate to the resource size distribution and it is specifically linked to the low case volume.

Table 1.6

Prospective Resources for South East El Mansoura, Egypt - Liquids

Prospective Resources: South East El Mansoura								
Liquid Resources (Mstb)	Gross on Licence			Net to Melrose			Risk Factor	Operator
	Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate		
Al Hajarisah: Kharita	501	1,464	3,631				0.13	Melrose
Al Hajarisah: Barremian	1,022	2,530	5,493	981	2309	4260	0.18	
Al Hajarisah: Neocomian	595	1,753	4,438				0.17	
Kafr Saqr: Kharita	92	261	641				0.13	
Kafr Saqr: Barremian	220	646	1,635	355	928	1826	0.09	
Kafr Saqr: Neocomian	455	1,103	2,393				0.09	
Sidi Gohar: Kharita	216	939	2,550				0.12	
Sidi Gohar: Barremian	681	1,836	4,473	705	1933	3677	0.15	
Sidi Gohar: Neocomian	629	1,794	4,501				0.12	
Sinbelaywan: Kharita	592	1,512	3,656				0.11	
Sinbelaywan: Barremian	631	3,446	11,440	948	3447	8032	0.15	
Sinbelaywan: Neocomian	832	3,693	10,800				0.15	

Source: Senergy (GB) Ltd

“Risk Factor” (also known as COS) for Prospective Resources, means the chance or probability of discovering hydrocarbons in sufficient quantity for them to be tested to the surface. In addition Senergy assess whether this factor is appropriate to the resource size distribution and it is specifically linked to the low case volume.

Table 1.7

Prospective Resources for South East El Mansoura, Egypt - Gas

Prospective Resources: El Mansoura								
Gas Resources (Bscf)	Gross on Licence			Net to Melrose			Risk Factor	Operator
	Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate		
Al Hajarisah: Kharita	0.5	1.5	3.9				0.13	
Al Hajarisah: Barremian	5.7	14.5	33.2	3.1	6.0	11.1	0.18	
Al Hajarisah: Neocomian	0.6	1.7	4.4				0.17	
Kafr Saqr: Kharita	0.1	0.3	0.7				0.13	
Kafr Saqr: Barremian	1.2	3.7	9.7	1.8	4.8	7.8	0.09	
Kafr Saqr: Neocomian	2.5	6.3	14.4				0.09	Melrose
Sidi Gohar: Kharita	0.2	1.0	2.7				0.12	
Sidi Gohar: Barremian	0.7	1.9	4.7	0.7	1.9	3.7	0.15	
Sidi Gohar: Neocomian	0.6	1.8	4.5				0.12	
Sinbelaywan: Kharita	0.6	1.6	3.9				0.11	
Sinbelaywan: Barremian	0.6	3.6	12.3	1.0	3.5	8.4	0.15	
Sinbelaywan: Neocomian	0.8	3.8	11.4				0.15	

Source: Senergy (GB) Ltd

"Risk Factor" (also known as COS) for Prospective Resources, means the chance or probability of discovering hydrocarbons in sufficient quantity for them to be tested to the surface. In addition Senergy assess whether this factor is appropriate to the resource size distribution and it is specifically linked to the low case volume.

Table 1.8

Aggregated Prospective Resources for Egypt

Prospective Resources: El Mansoura and SE El Mansoura						
	Gross on Licence			Net to Melrose		
	Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate
Total Liquids (Mstb)	**23,600**	**31,900**	**43,500**	**3,726**	**10,412**	**21,588**
Total Gas (Bscf)	**76.1**	**100.0**	**131.0**	**12.1**	**29.4**	**59.3**

Source: Senergy (GB) Ltd

"Risk Factor" (also known as COS) for Prospective Resources, means the chance or probability of discovering hydrocarbons in sufficient quantity for them to be tested to the surface. In addition Senergy assess whether this factor is appropriate to the resource size distribution and it is specifically linked to the low case volume.

N.B. Gross total volumes are stochastically aggregated, whereas Net volumes have been calculated in the economic model per prospect and have been arithmetically summed

Table 1.9

Proved plus Probable Production Forecasts (Melrose Update)

		2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Egypt : Proved & Probable Developed & Undeveloped Production Forecast (Melrose Update)												
Total Liquids	(bpd)	3,533	3,973	4,059	3,495	3,125	2,764	2,601	2,370	2,126	1,951	1,847
Wet Gas	(MMscfpf)	104.9	108.4	106.4	83.7	66.2	53.3	48.4	58.8	47.6	40.5	31.0
Total Oil Equivalent	(boepd)	21,625	22,655	22,406	17,922	14,536	11,948	10,945	12,511	10,331	8,940	7,196
Bulgaria : Proved & Probable Developed & Undeveloped Production Forecast (Melrose Update)												
Total Oil Equivalent	(boepd)	6,400	4,326	4,400	4,103	3,318	2,062	1,768	0	0	0	0
Egypt and Bulgaria : Proved & Probable Developed & Undeveloped Production Forecast (Melrose Update)												
Total Oil Equivalent	(boepd)	28,025	26,981	26,806	22,025	17,854	14,011	12,713	12,511	10,331	8,940	7,196

Source: Melrose 2012

1) West Dikirnis production is highly dependent on the produced gas throughput. Melrose, its JV partner Mansoura, and EGAS are choosing to manage produced gas rate at its current level of below 30 MMscf/d, not increasing it to above 40 MMscf/d as Senergy had assumed in YE2011 reserves. Impact is less aggressive production in 2012 and following years, and deferral of the gas blowdown phase by some two years.

2) Galata offtake: Senergy had assumed aggressive blowdown starting 01 July 2012. Since Gas Storage negotiations are still ongoing, and this is not realistic. Reservoir monitoring has yielded very positive results for Galata, which means that high offtake rates are feasible, but Melrose choice is to start flowing Galata in 2013, and to use Galata production to provide gas nominations flexibility.

Table 1.10

senergy

Regional Location Map, Egypt

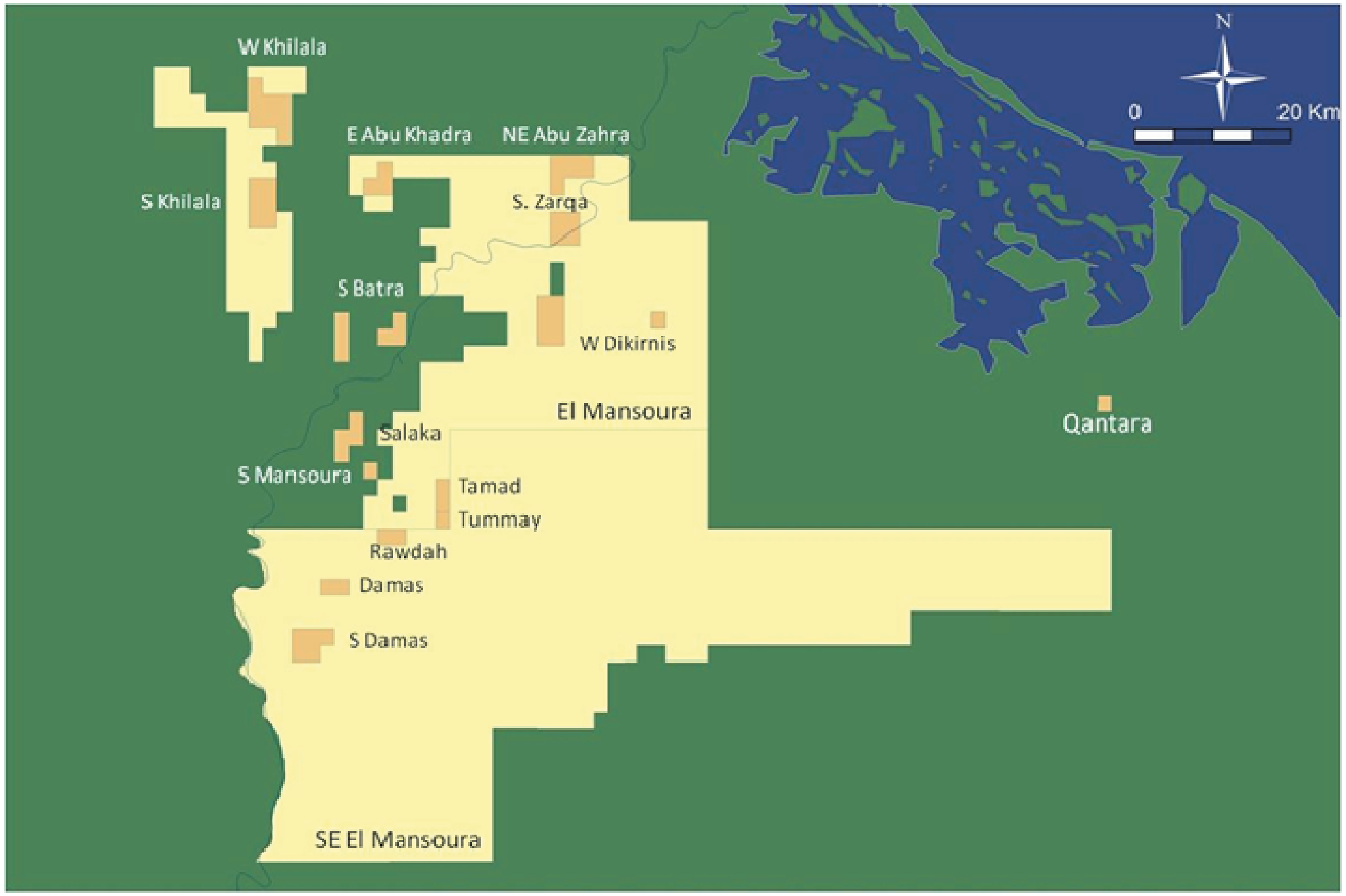
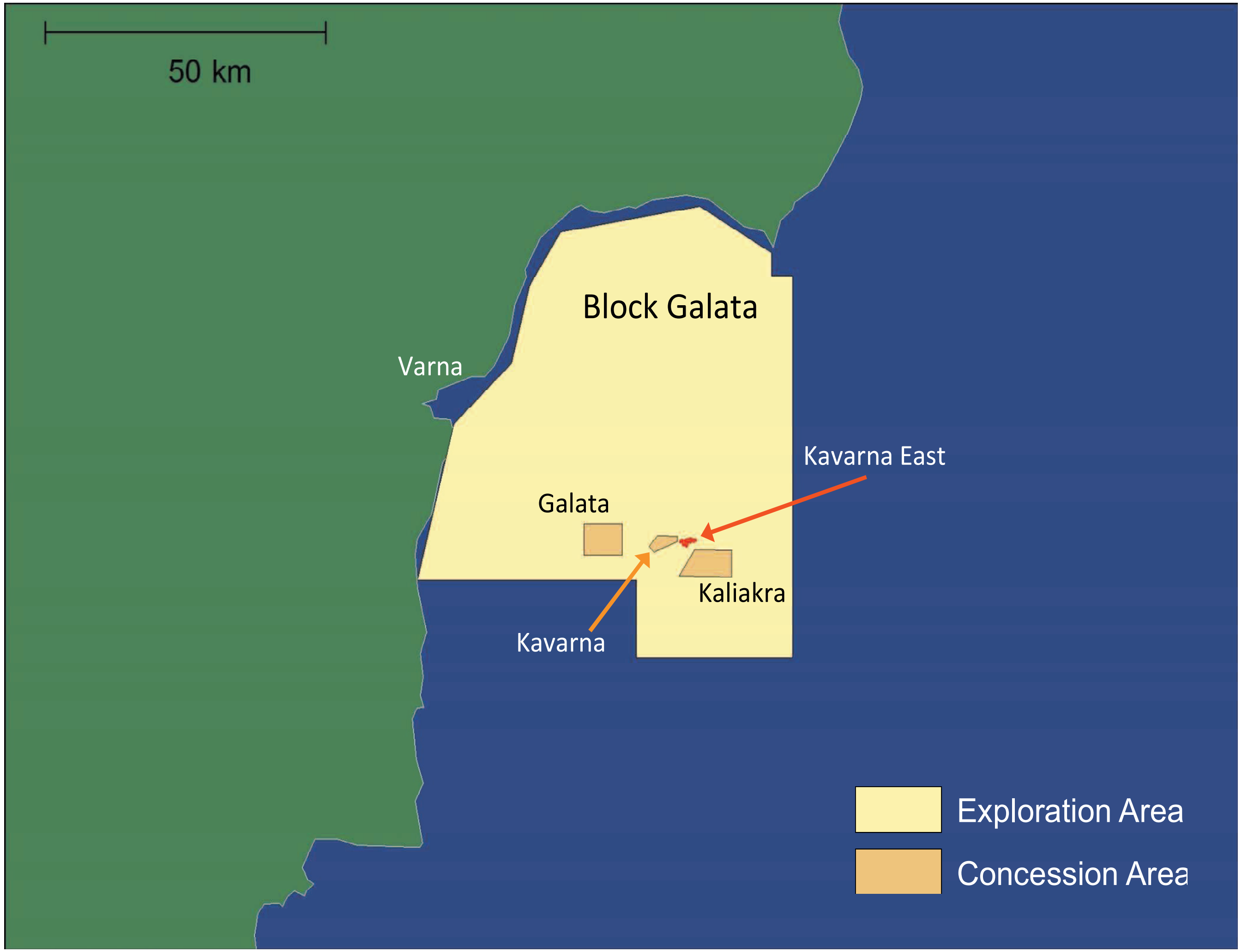


Figure 1.1

senergy

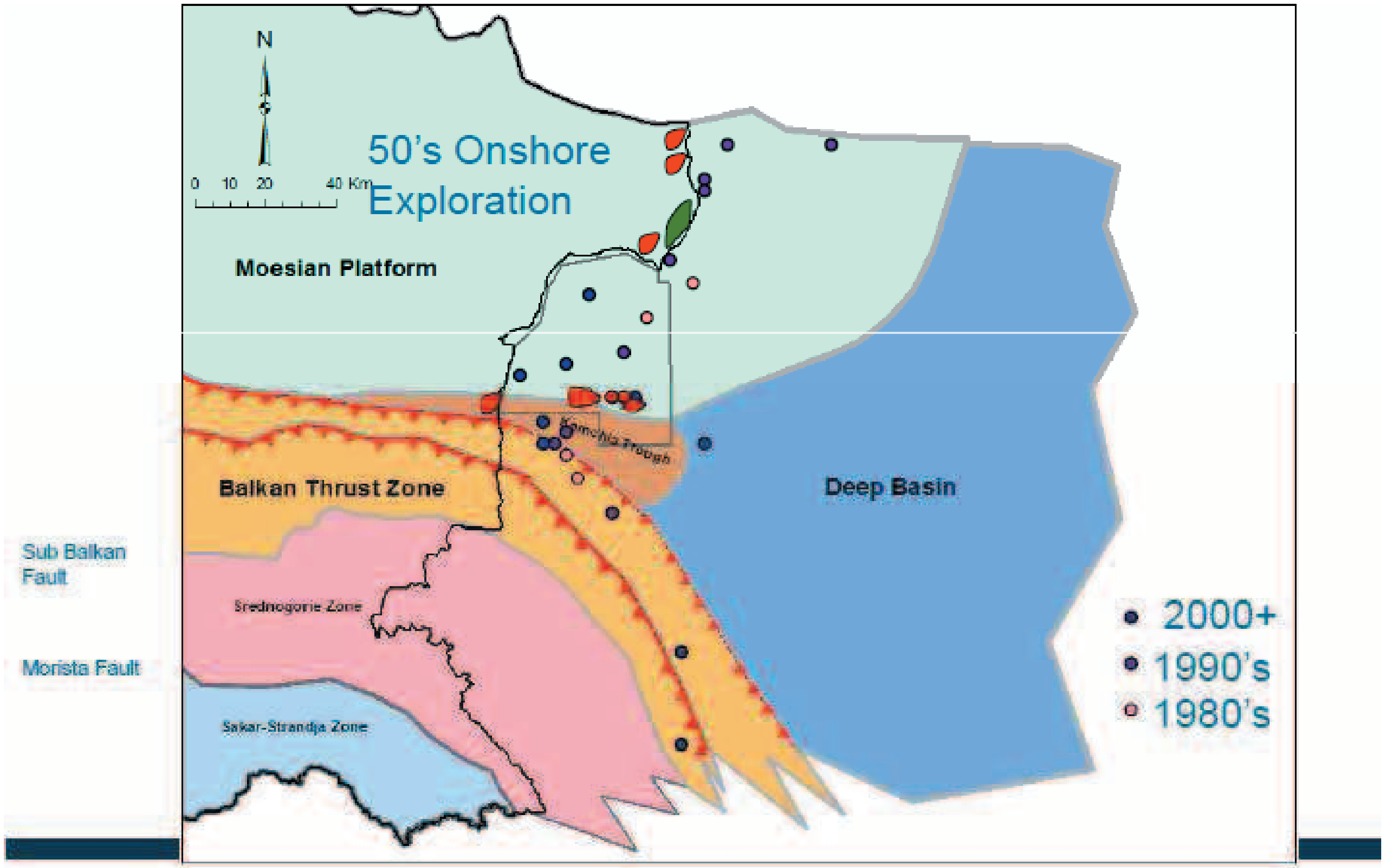
Regional Location Map, Bulgaria



Source: Melrose 2012

Figure 1.2

Structural Domains and Exploration History



Source: Melrose 2012

Figure 1.3

senergy

North-East Abu Zahra Depth Structure Map

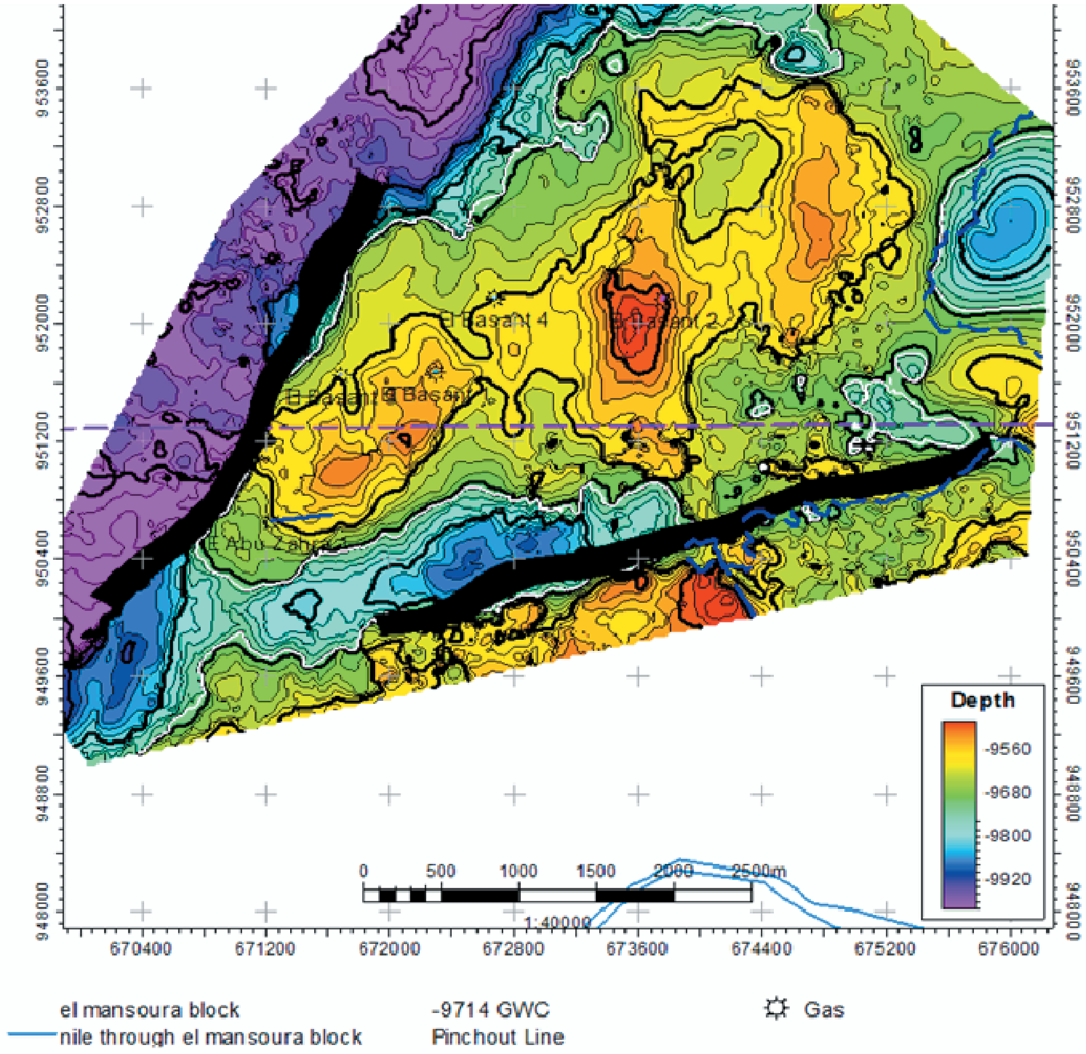
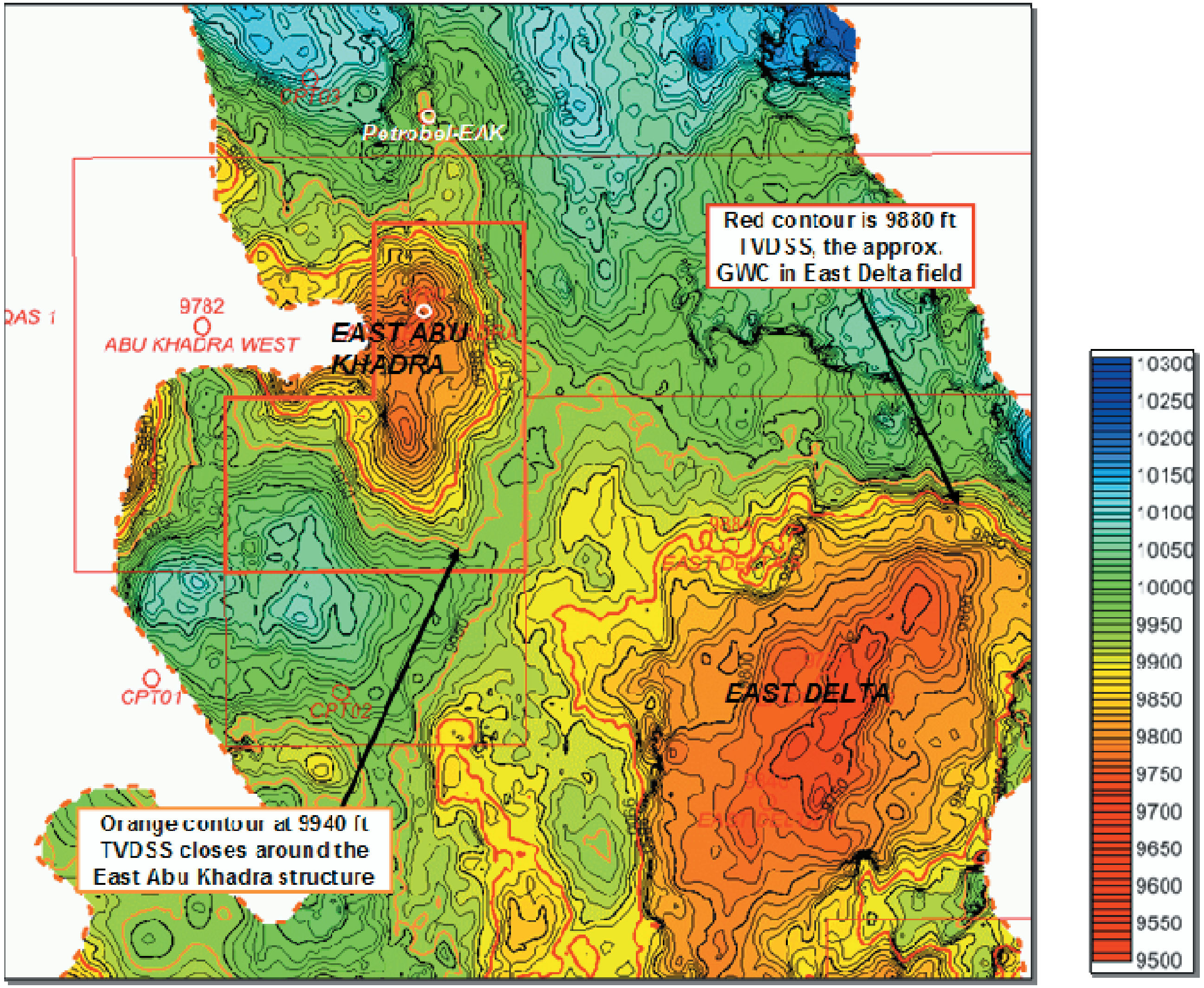


Figure 2.1

senergy

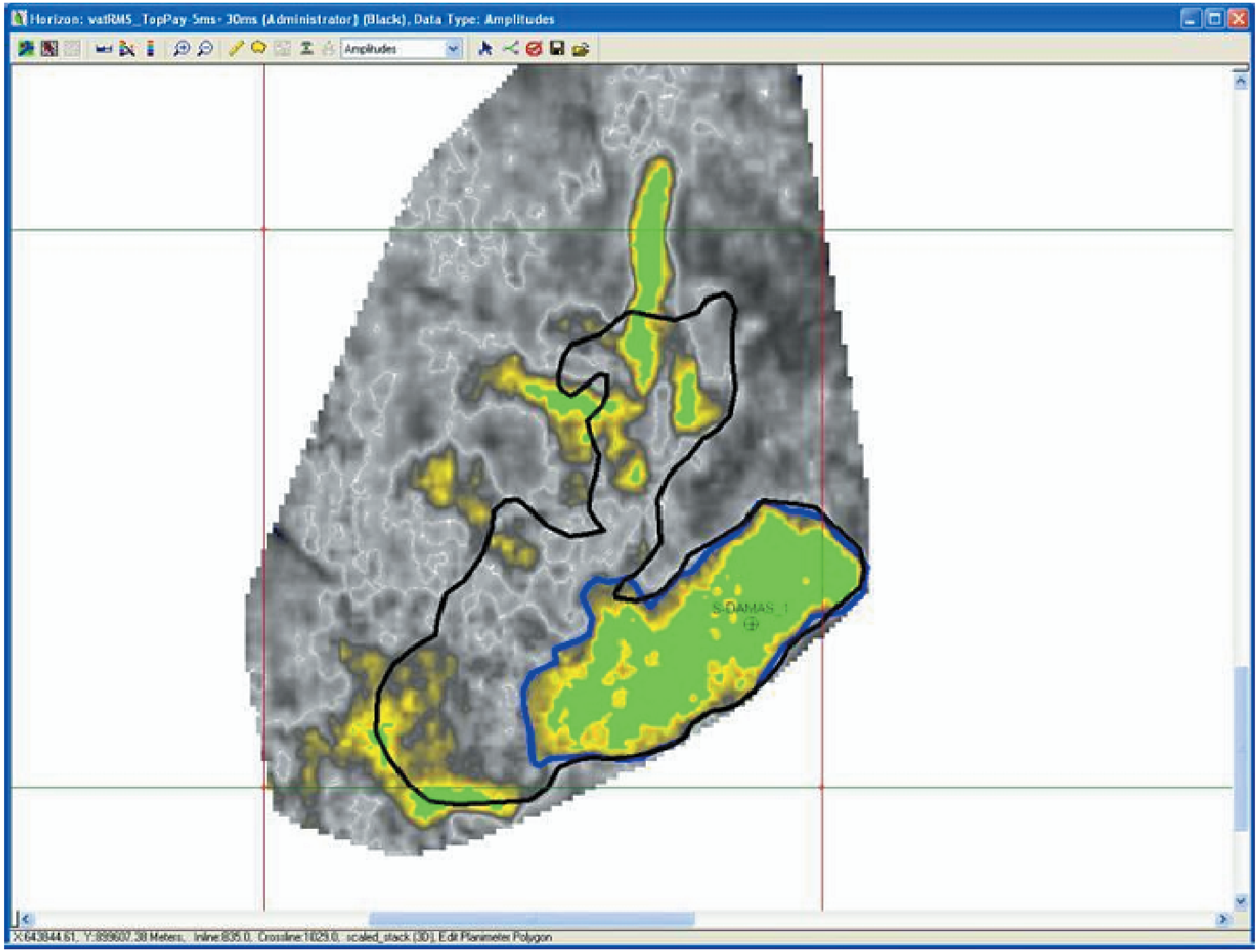
East Abu Khadra Top Reservoir Depth Map



Source: Melrose 2012

Figure 2.2

South Damas Seismic Amplitude Map

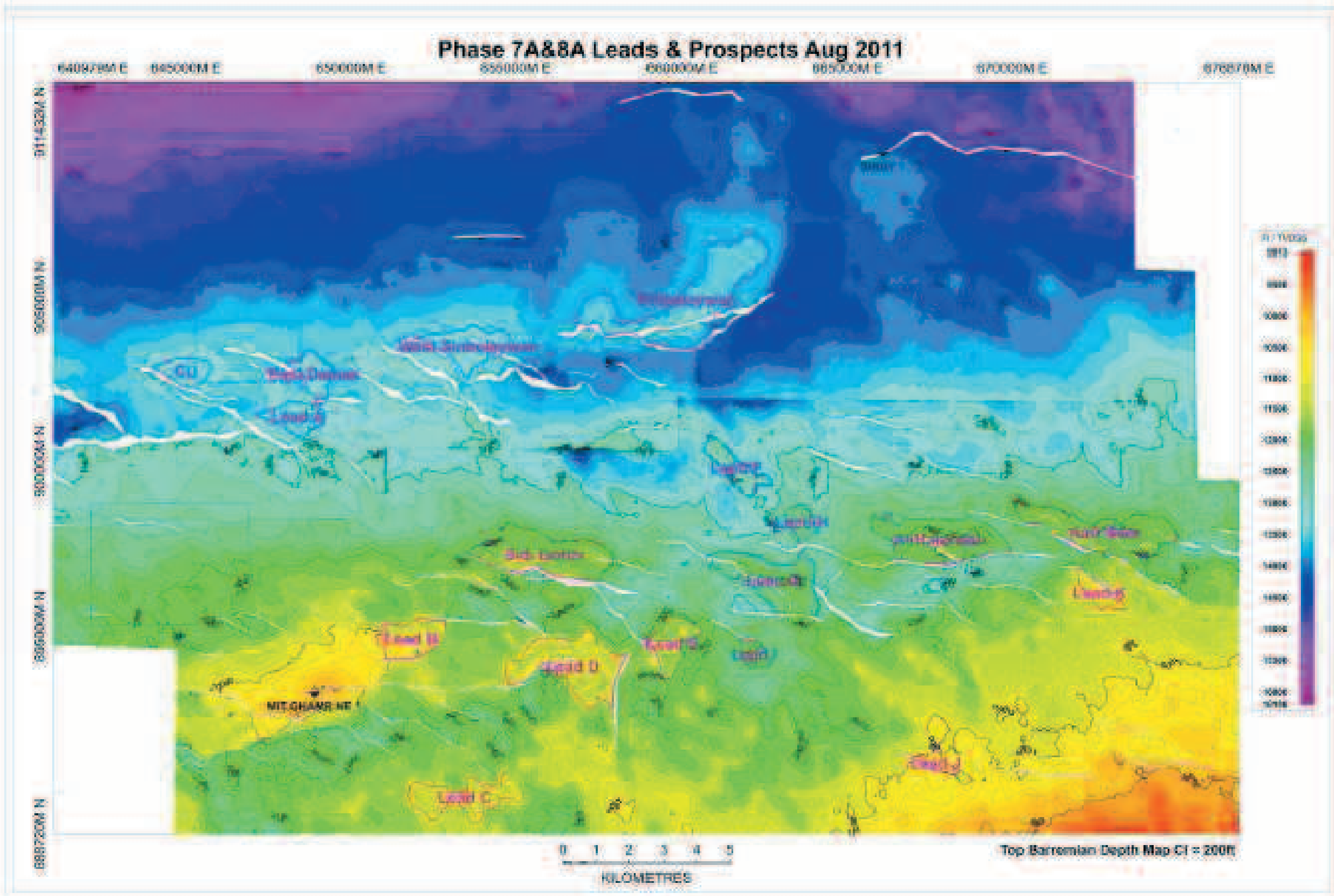


Source: Melrose 2012

Figure 2.3

senergy

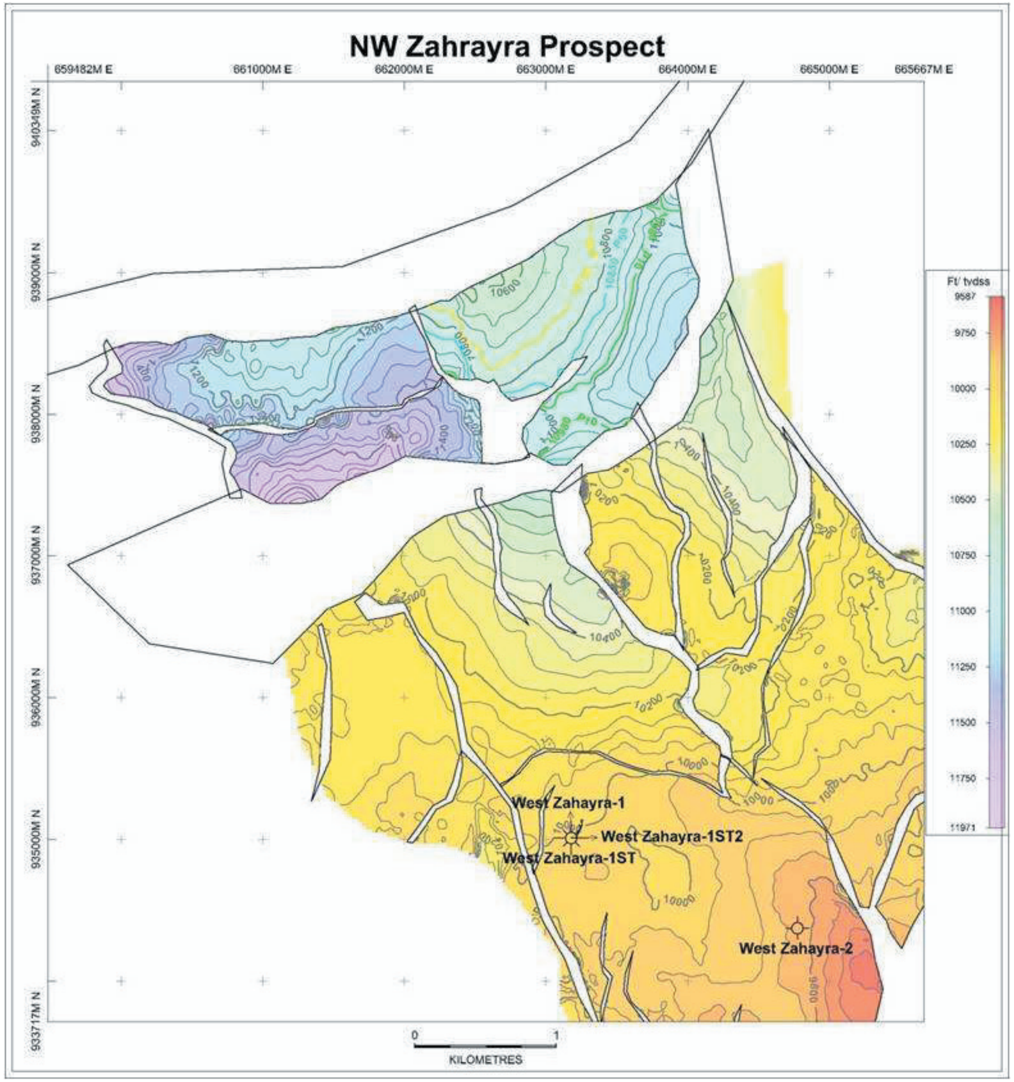
Egytian Prospectivity Location Map



Source: Melrose 2012

Figure 2.4

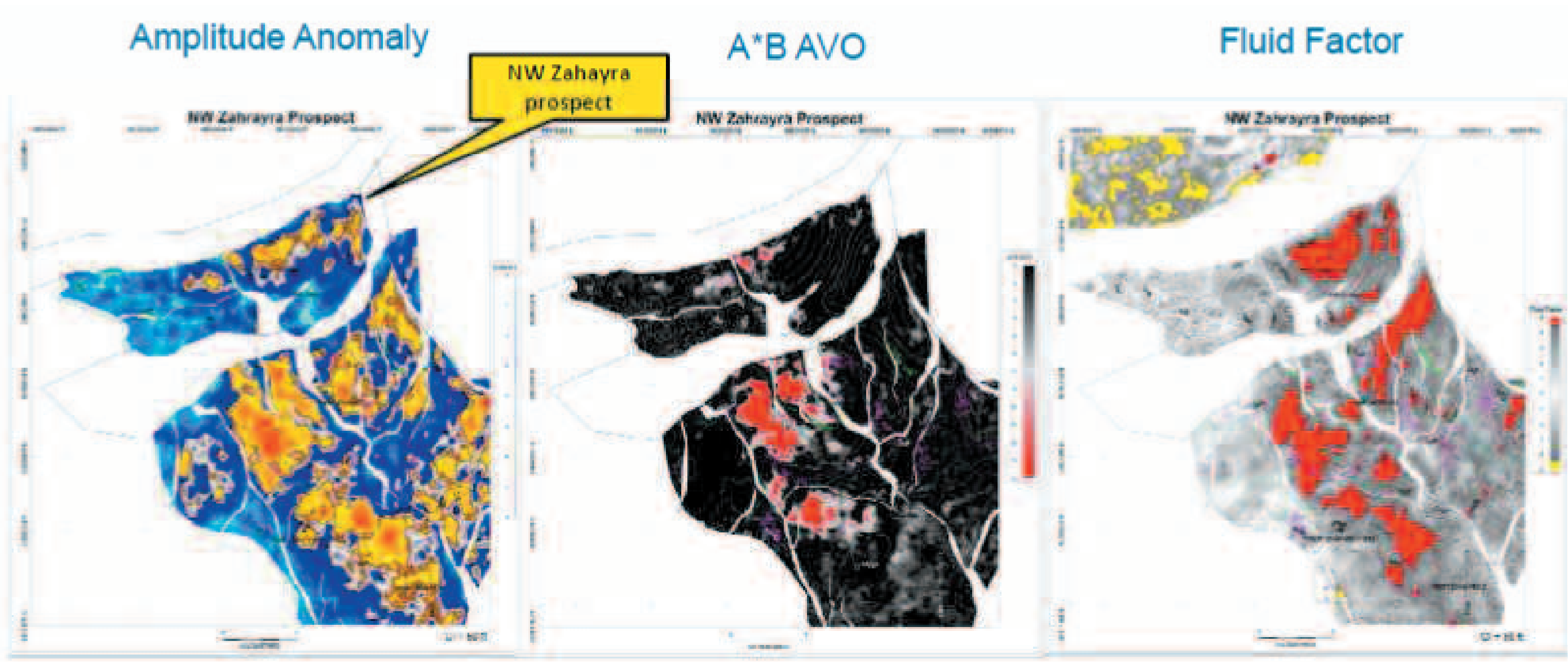
NW Zahrayra Prospect Top Qawasim Depth Map



Source: Melrose 2012

Figure 2.5

NW Zahrayra Prospect Seismic Attributes Map

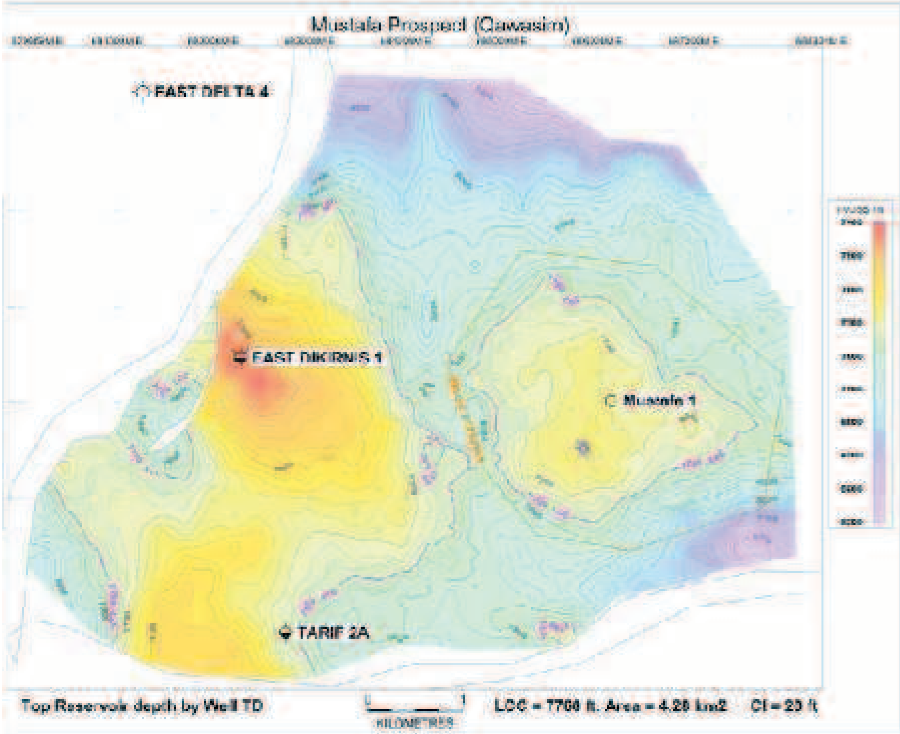


Source: Melrose 2012

Figure 2.6

senergy

Mustafa Prospect Top Qawasim Depth Map



Source: Melrose 2012

Figure 2.7

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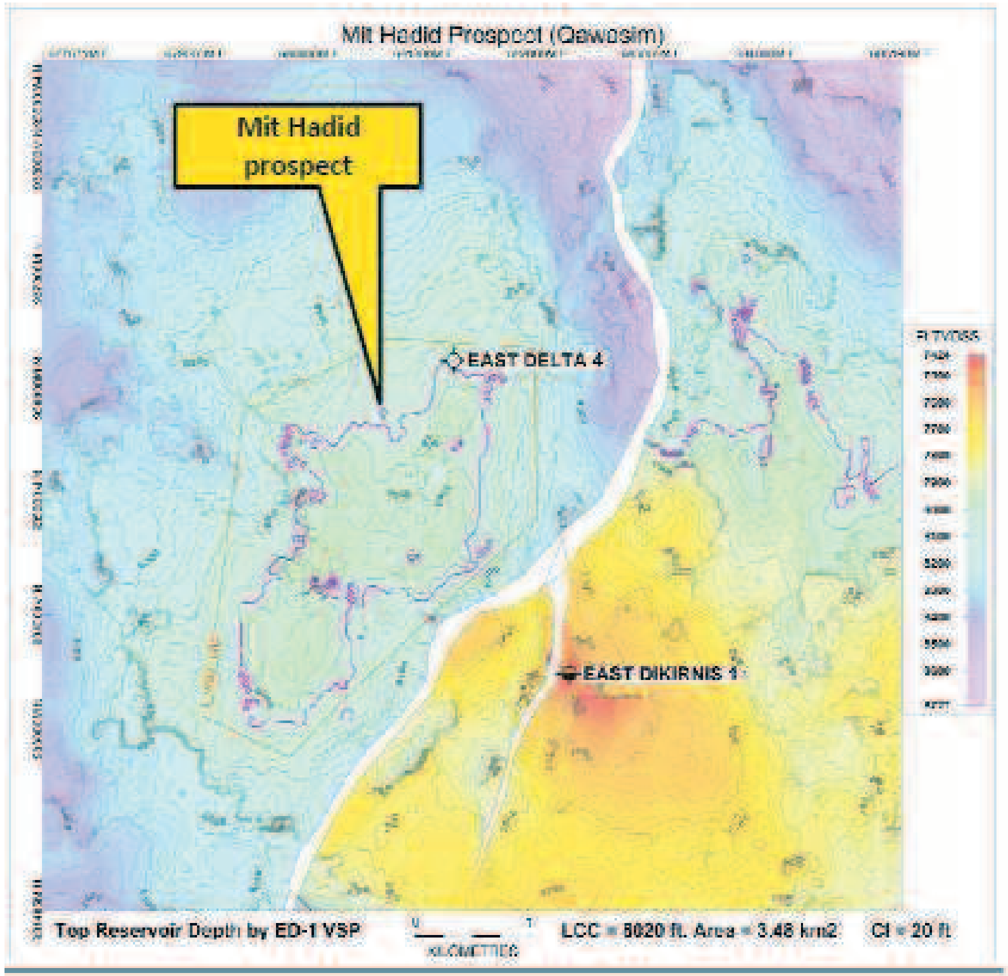
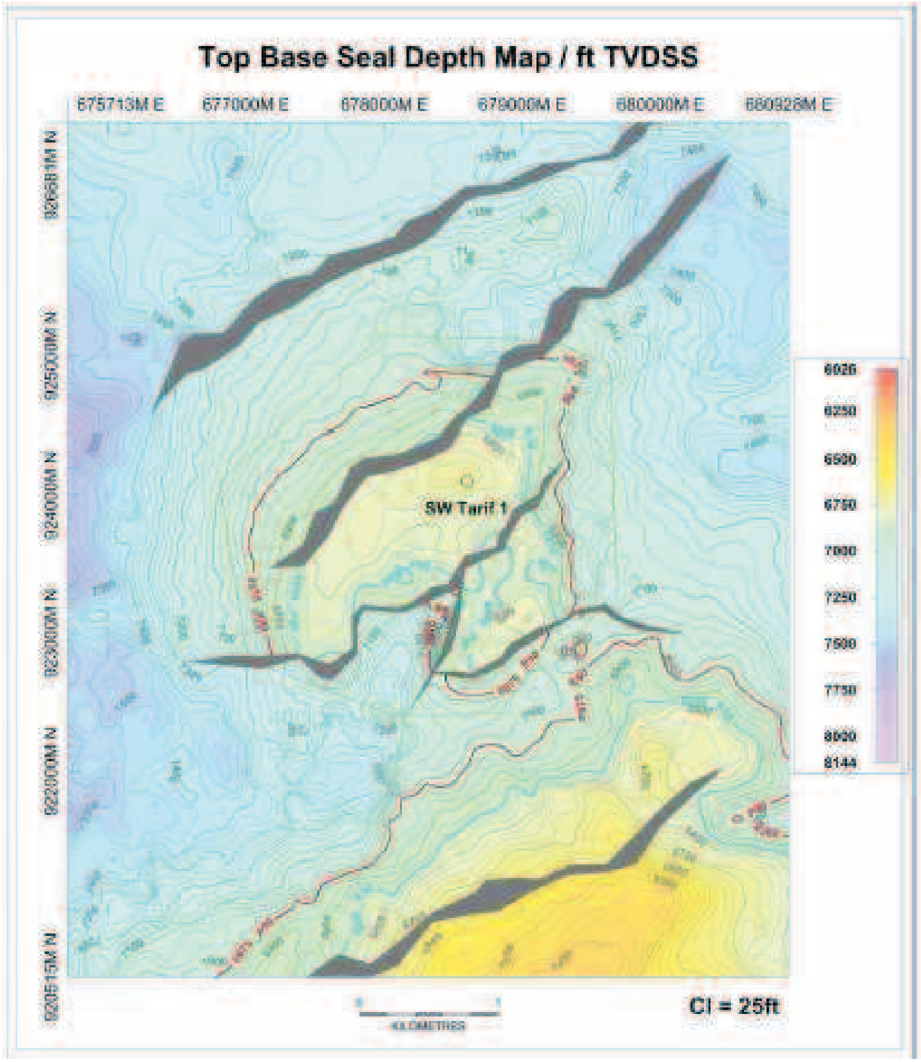
Mit Hadid Prospect Top Qawasim Depth Map



Source: Melrose 2012

Figure 2.8

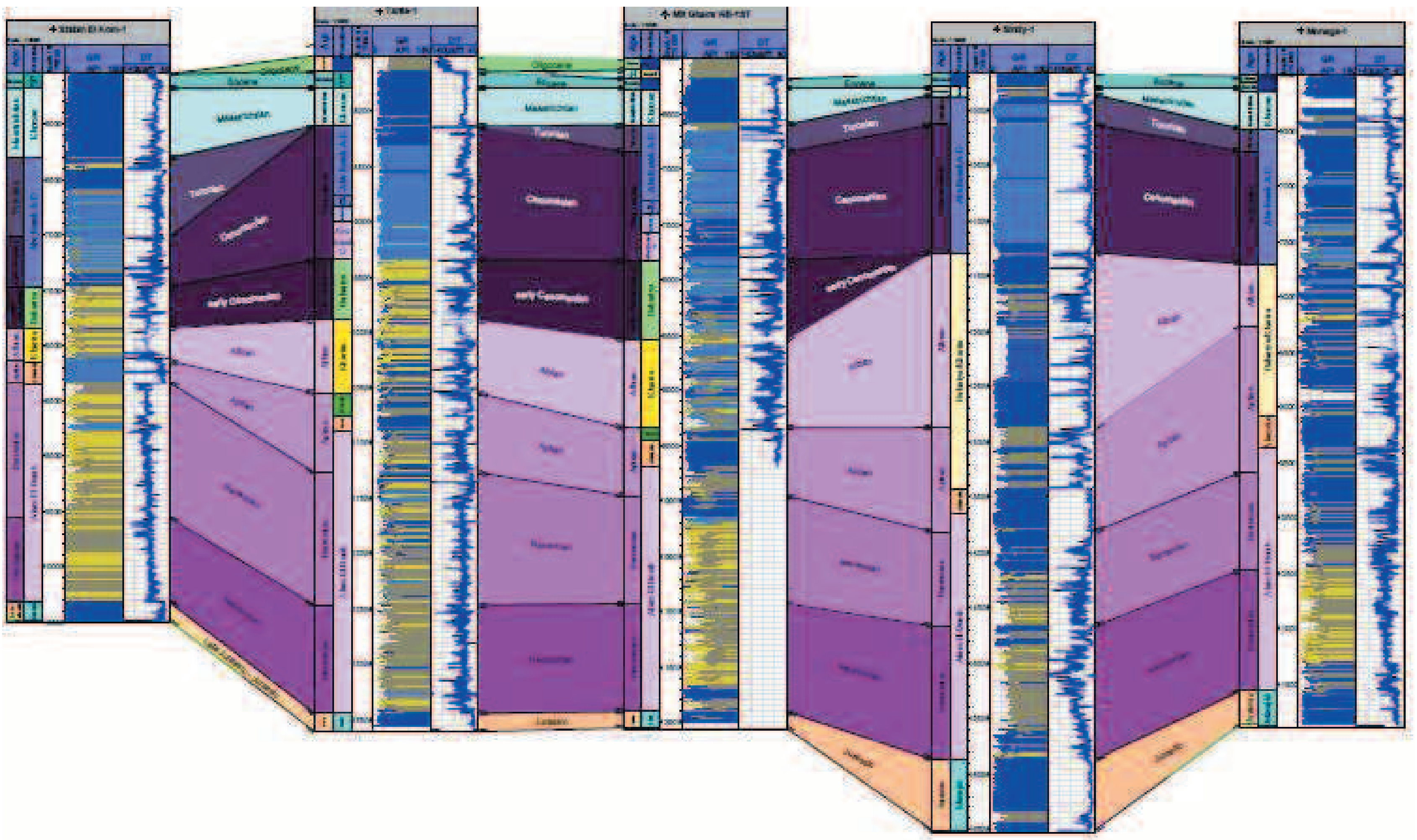
SW Tarif Prospect Top Qawasim Depth Map



Source: Melrose 2012

Figure 2.9

South East El Mansoura Cross Section Hung On Top Cretaceous



Source: Melrose 2012

Figure 2.10

Source Kitchen at Top Jurassic Map

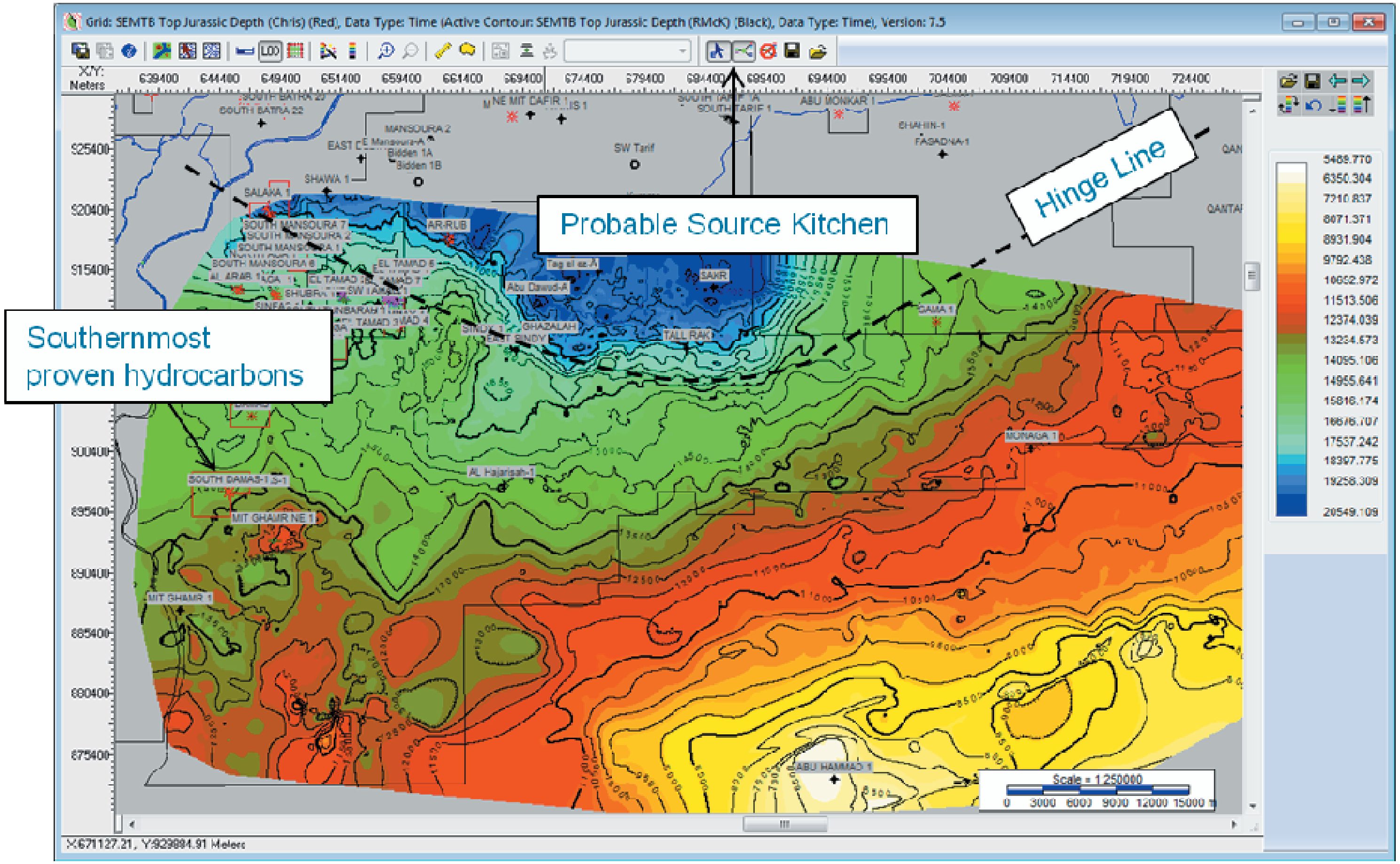


Figure 2.11

Source: Melrose 2012

Mit Ghamr Fault Seal: Shale Gouge Ratio at Sand Overlaps

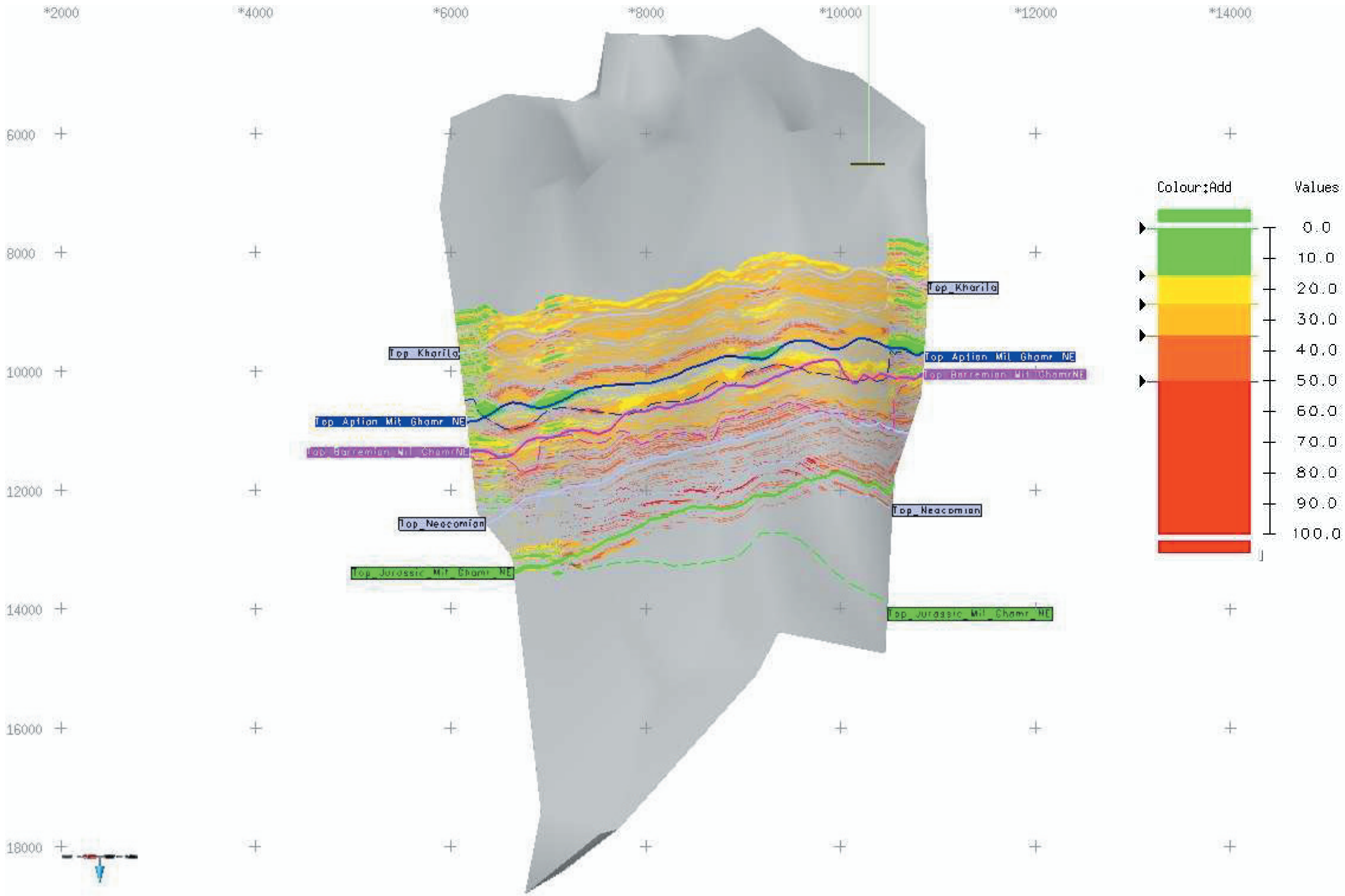
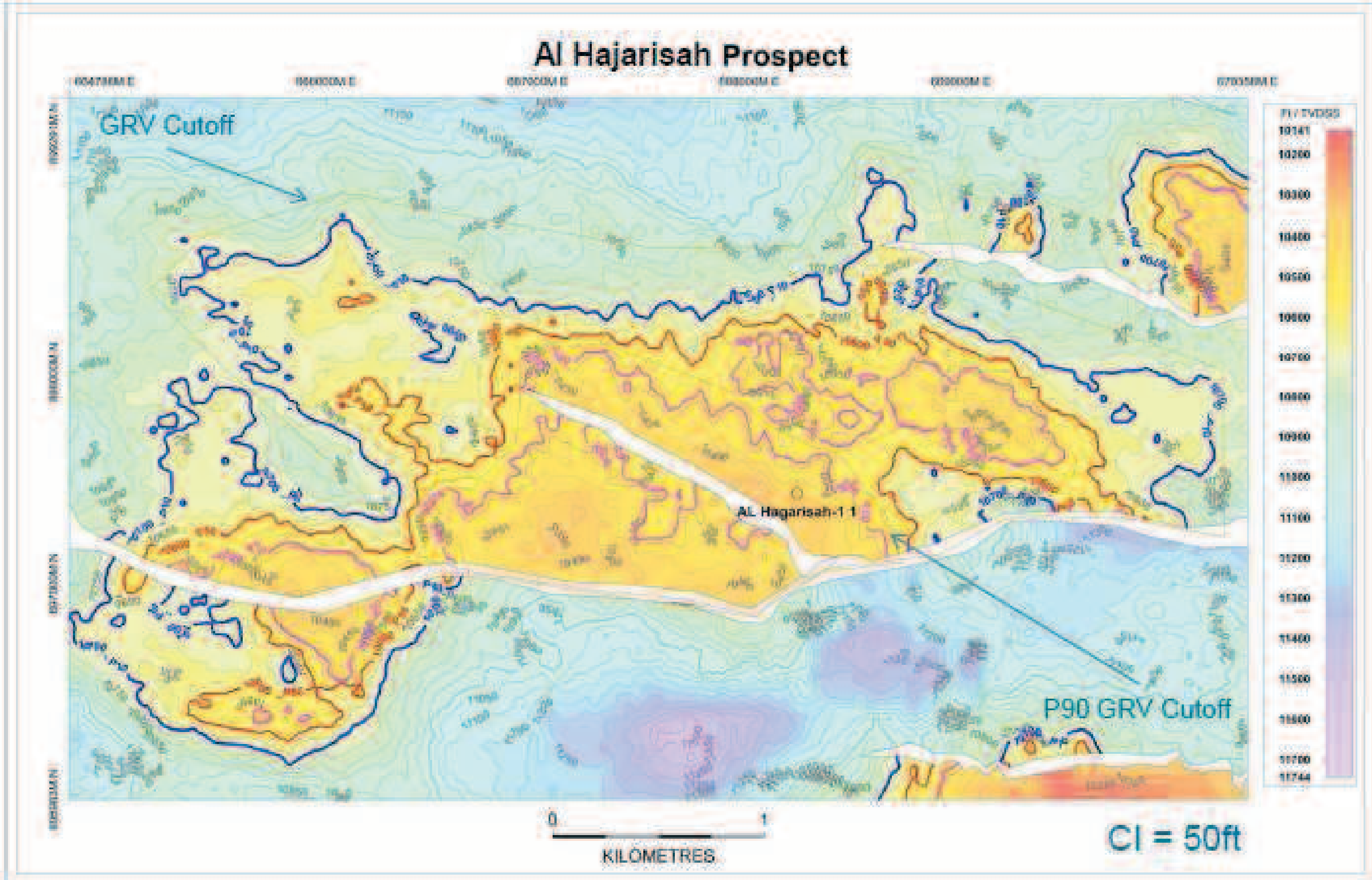


Figure 2.12

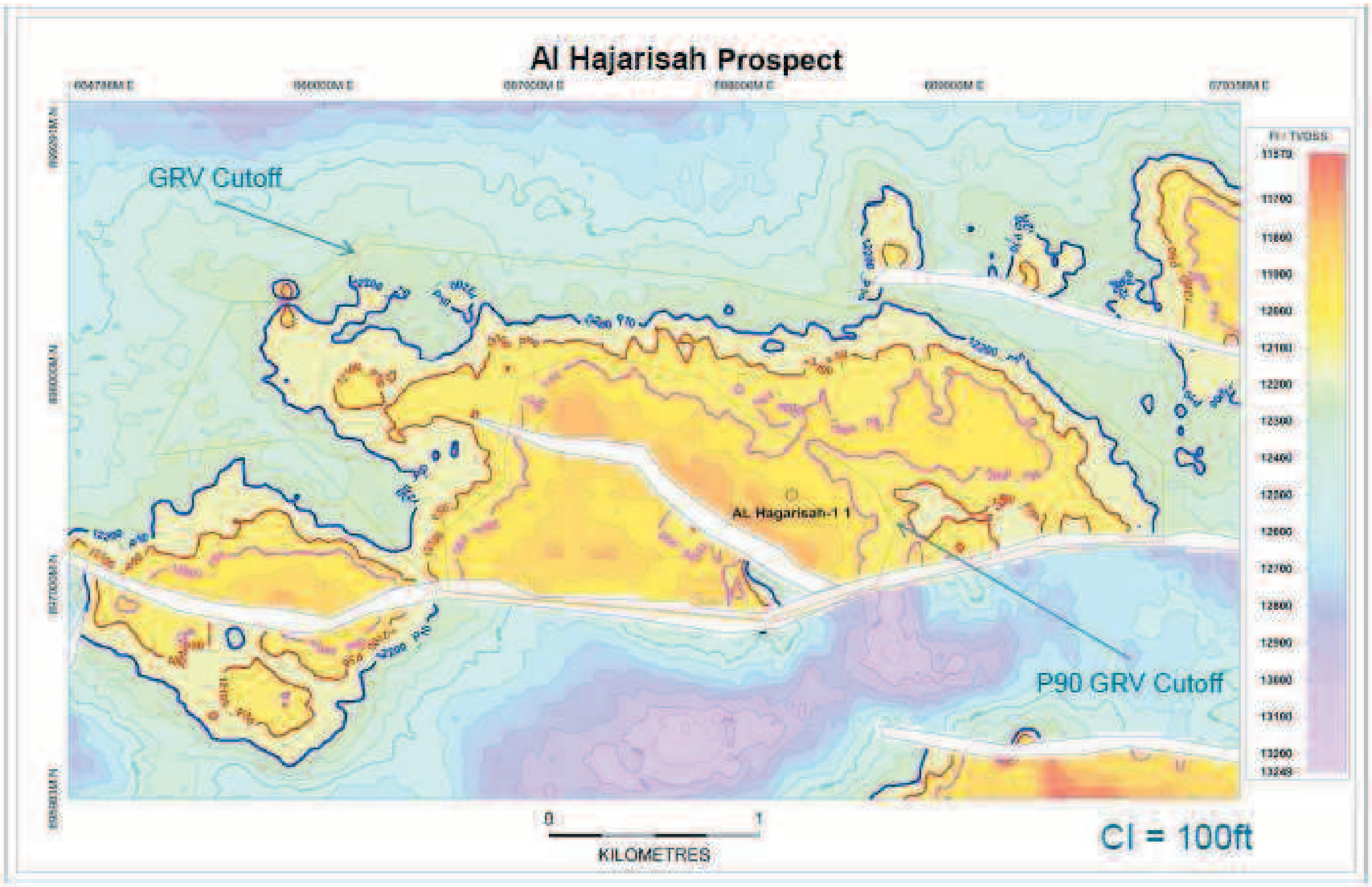
Al Hajarisah Prospect Top Kharita Depth Map



Source: Melrose 2012

Figure 2.13

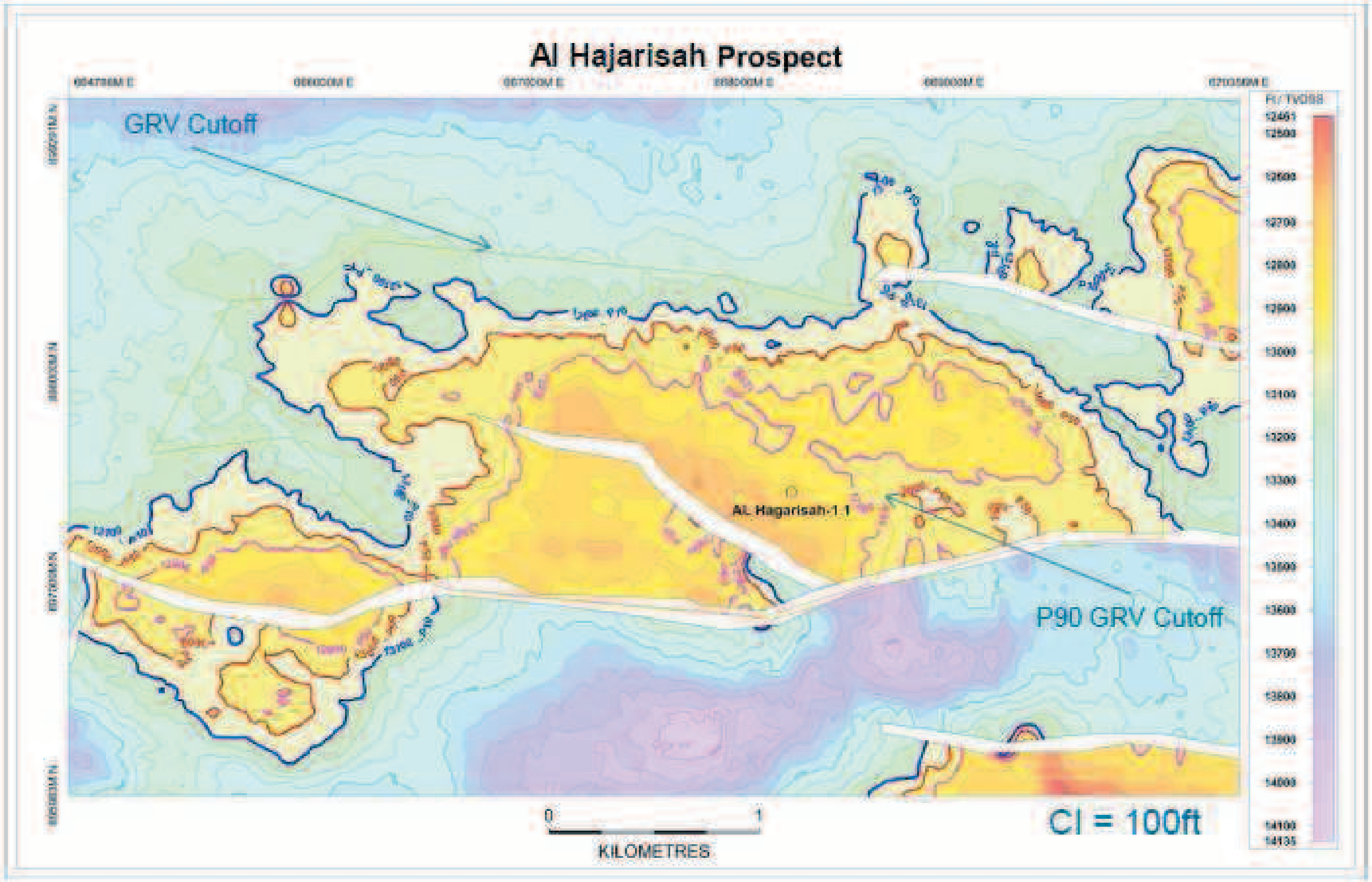
Al Hajarisah Prospect Top Barremian Depth Map



Source: Melrose 2012

Figure 2.14

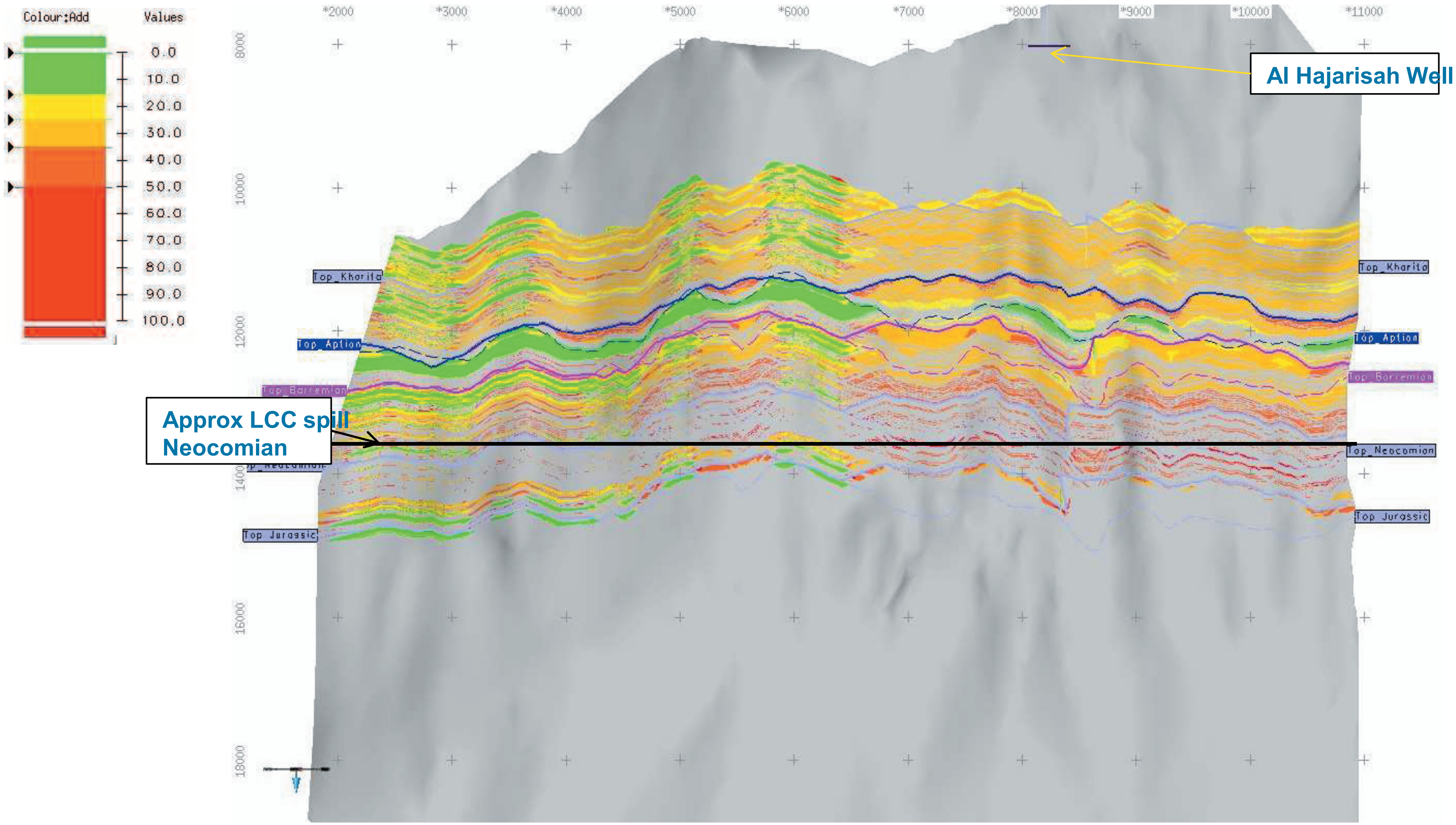
Al Hajarisah Prospect Top Neocomian Depth Map



Source: Melrose 2012

Figure 2.15

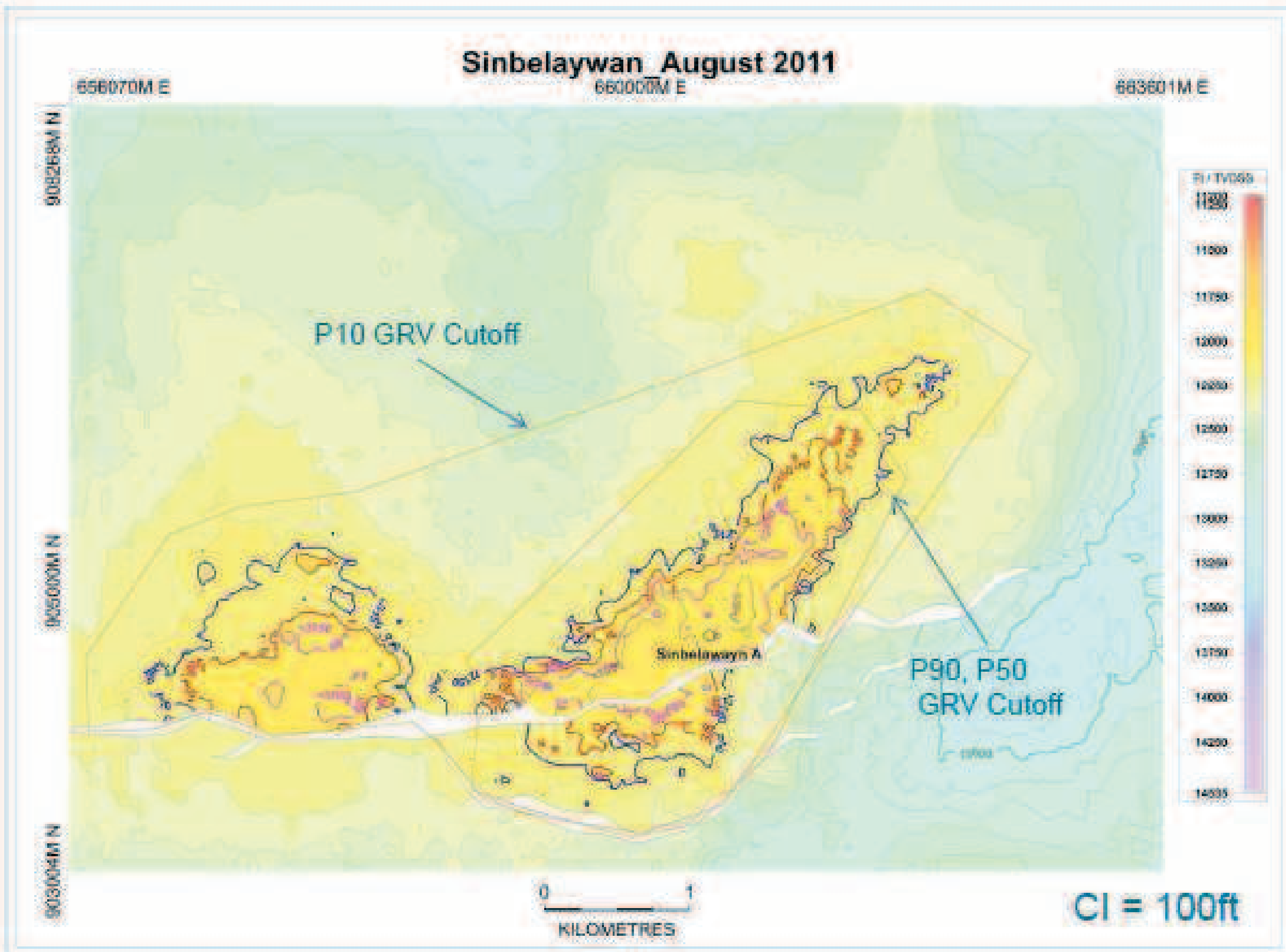
Al Hajarisah Fault Seal: Shale Gouge Ratio at Sand Overlaps



Source: Melrose 2012

Figure 2.16

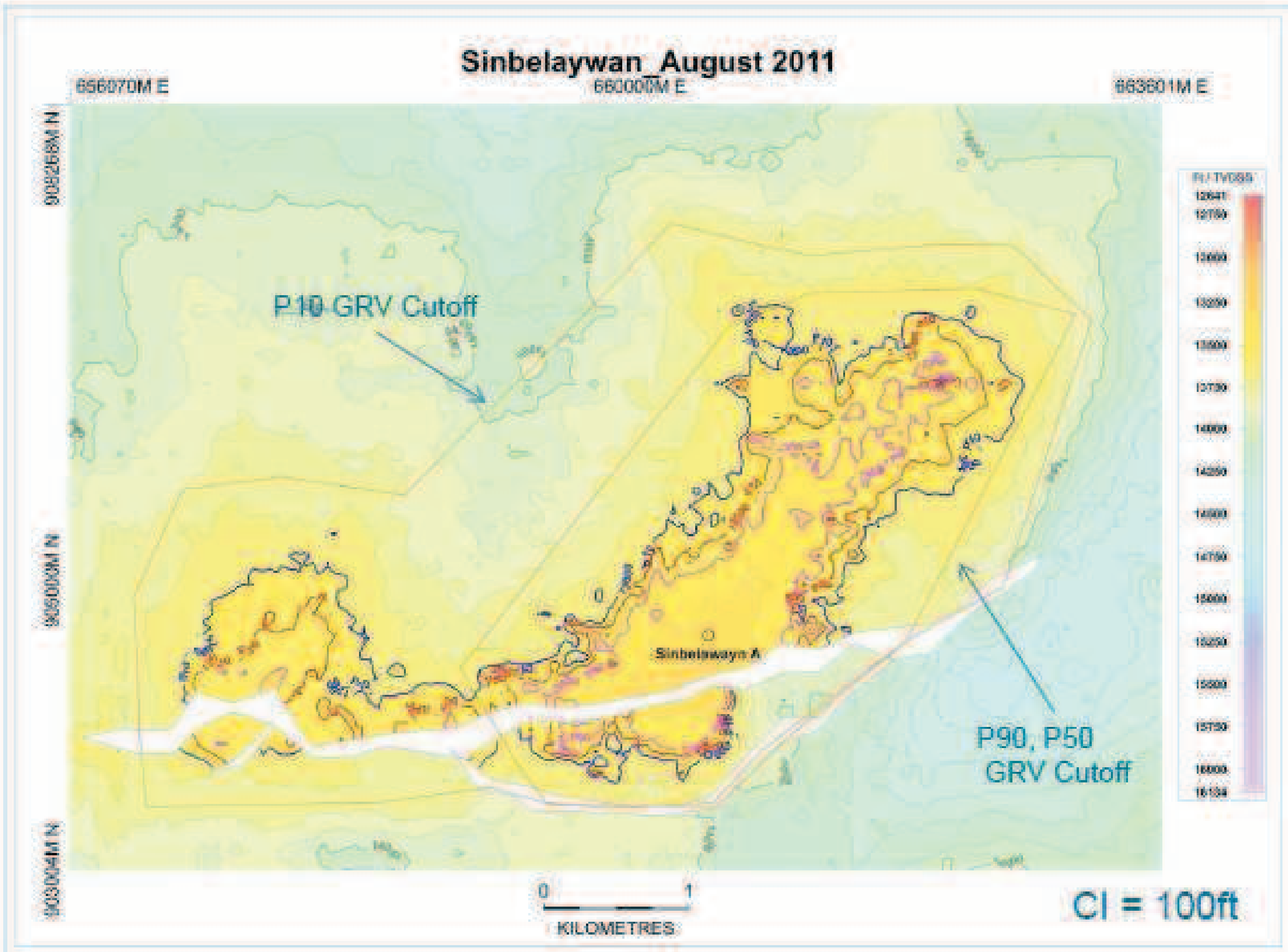
Sinbelaywan Prospect Top Kharita Depth Map



Source: Melrose 2012

Figure 2.17

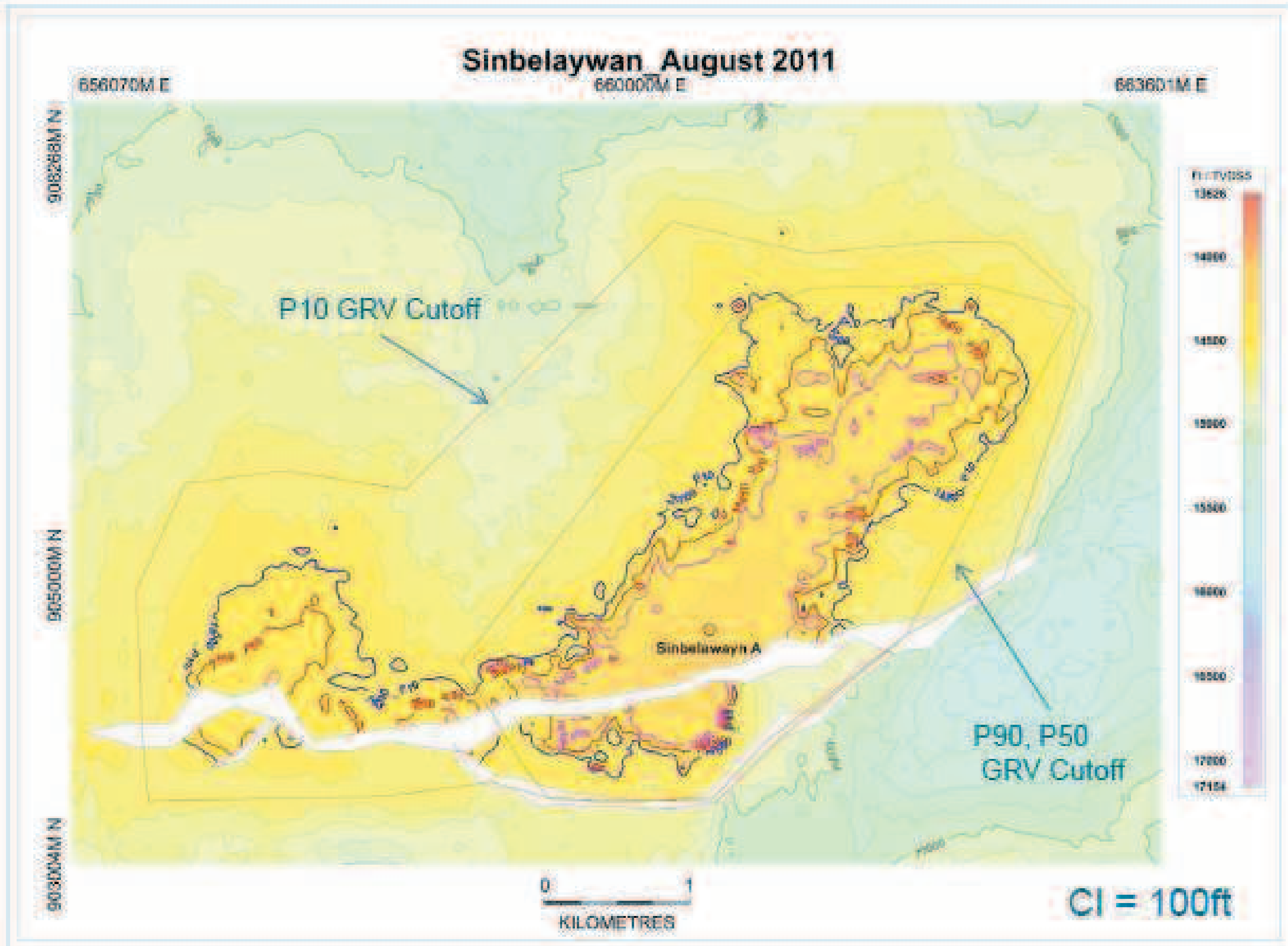
Sinbelaywan Prospect Top Barremian Depth Map



Source: Melrose 2012

Figure 2.18

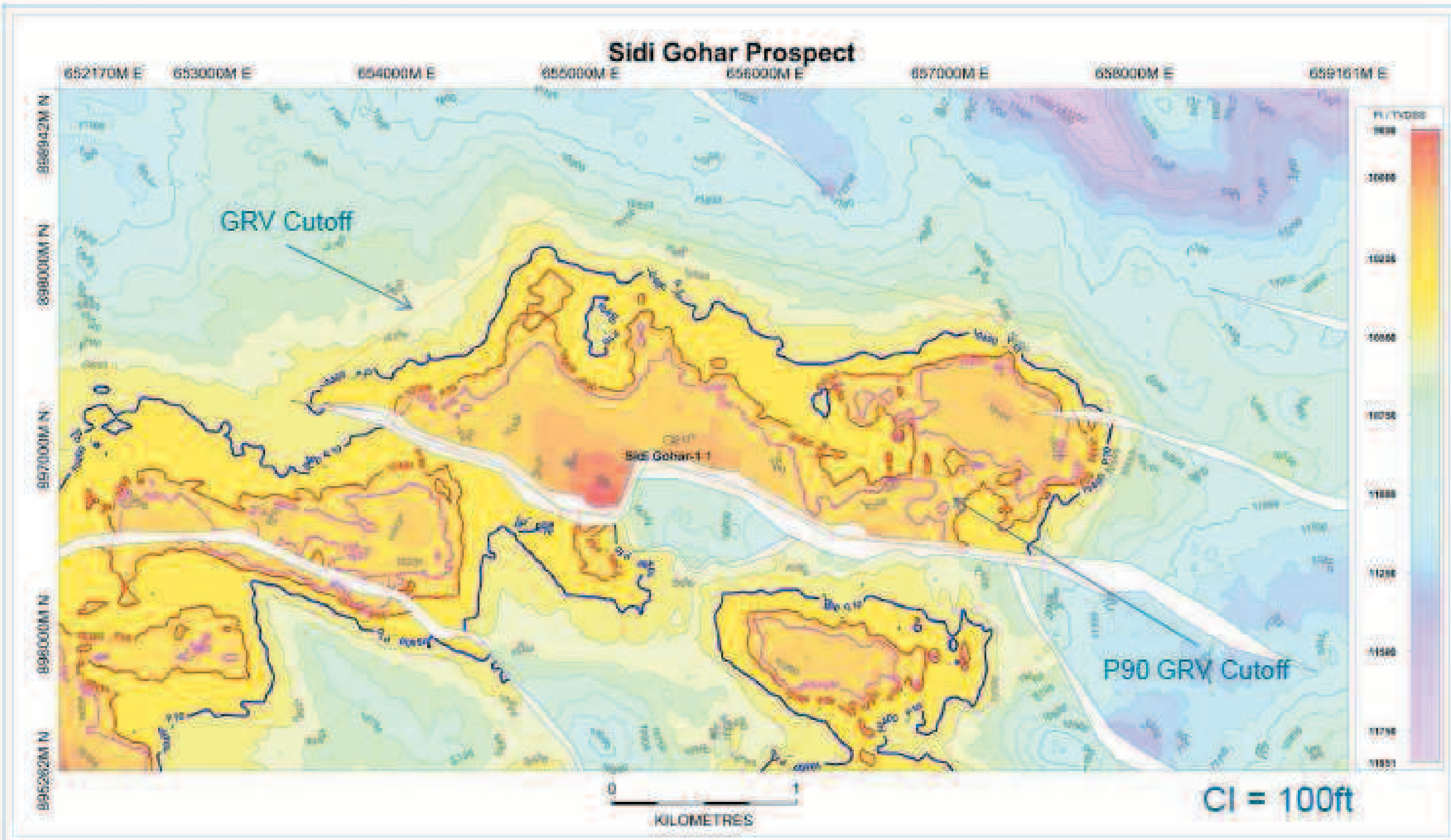
Sinbelaywan Prospect Top Neocomian Depth Map



Source: Melrose 2012

Figure 2.19

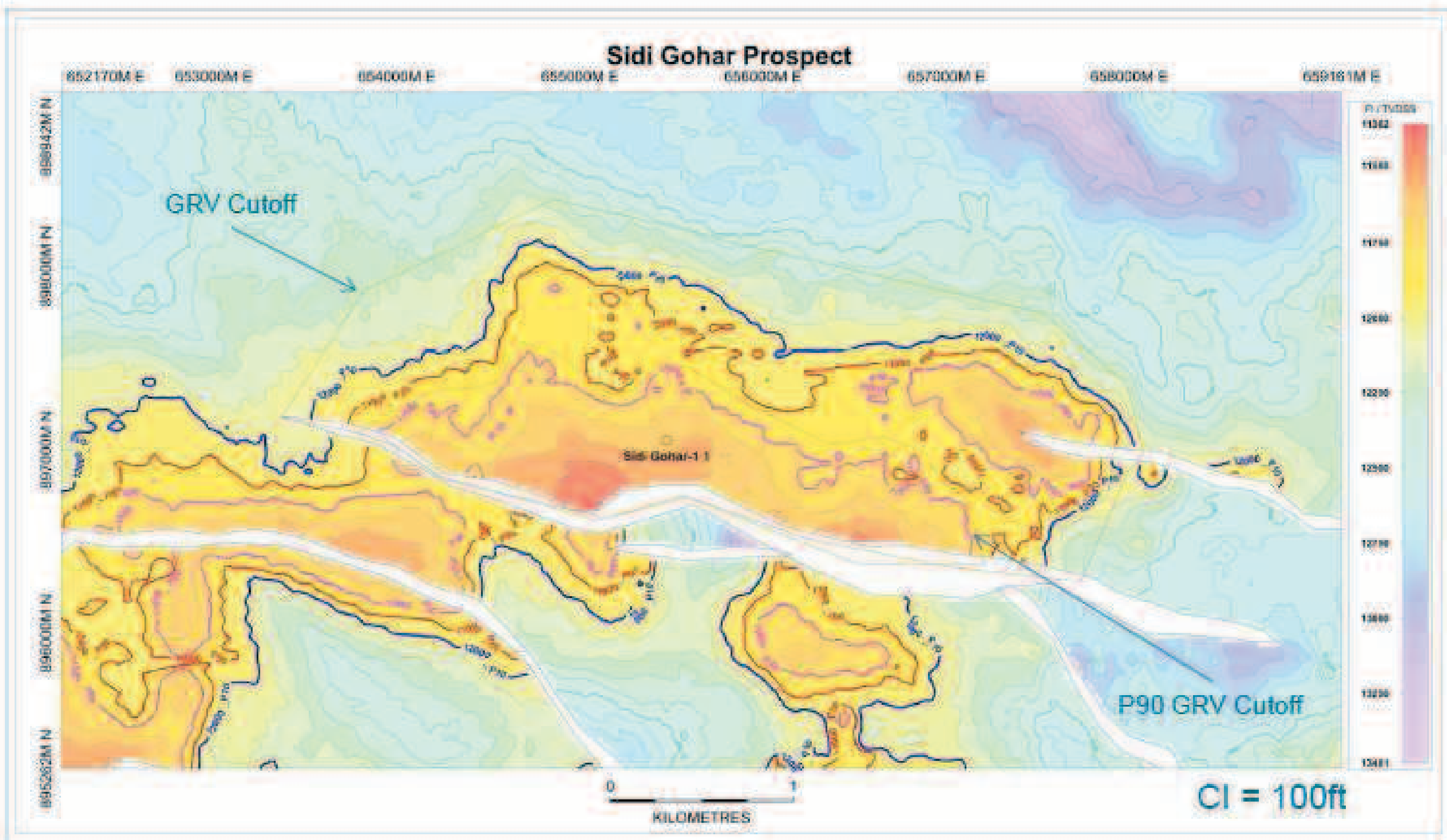
Sidi Gohar Prospect Top Kharita Depth Map



Source: Melrose 2012

Figure 2.20

Sidi Gohar Prospect Top Barremian Depth Map



Source: Melrose 2012

Figure 2.21

Sidi Gohar Prospect Top Neocomian Depth Map

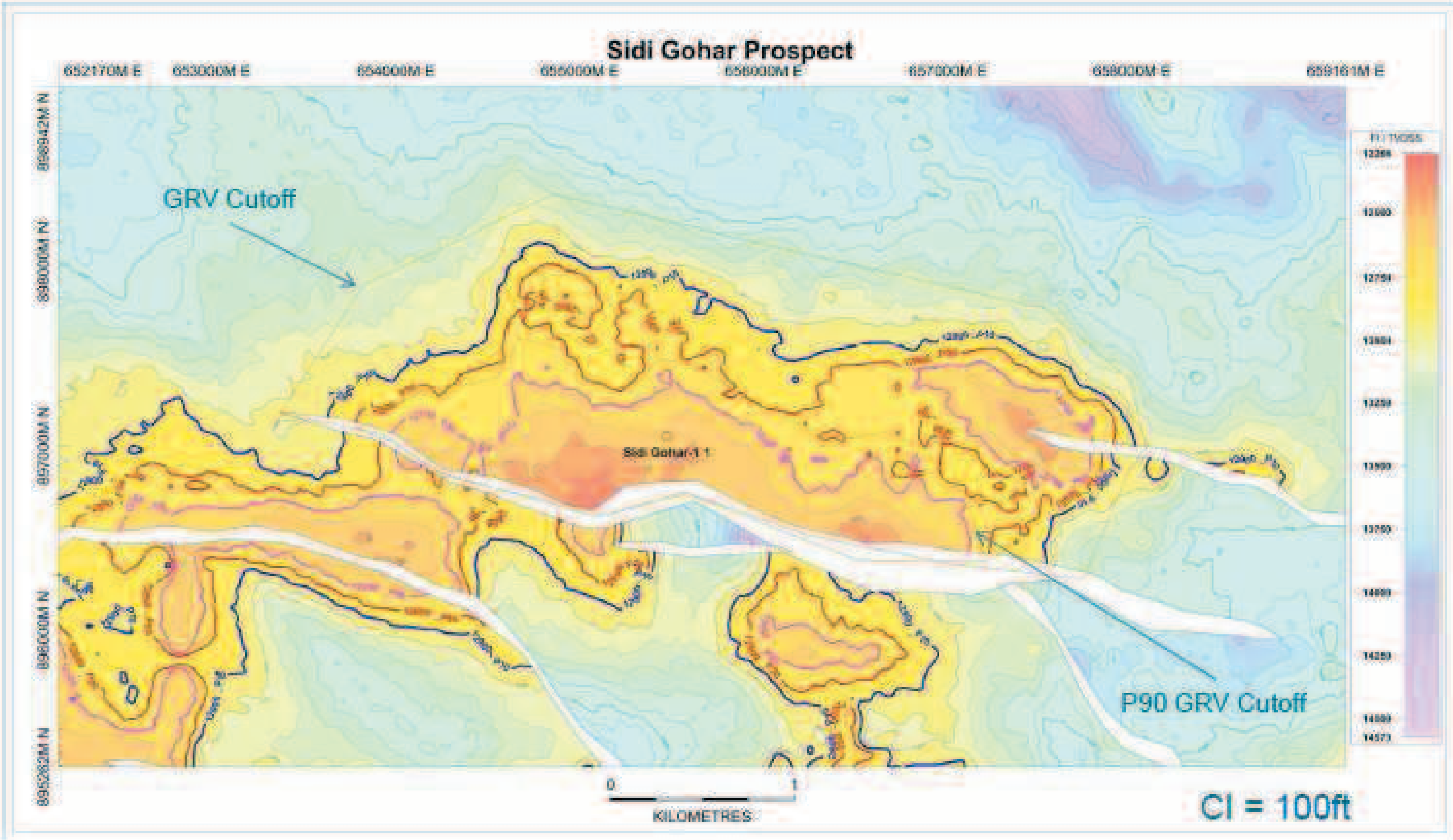
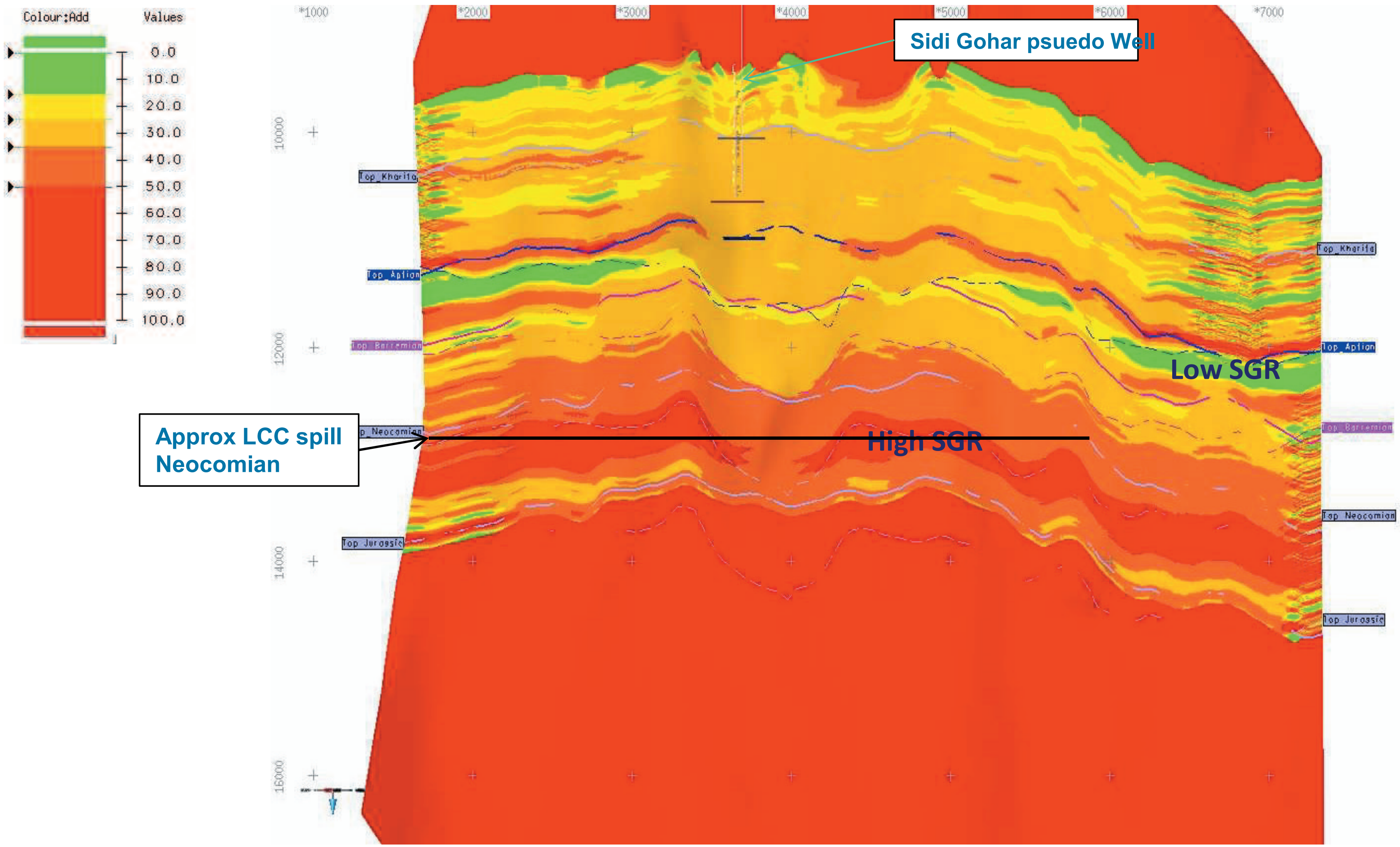


Figure 2.22

Source: Melrose 2012

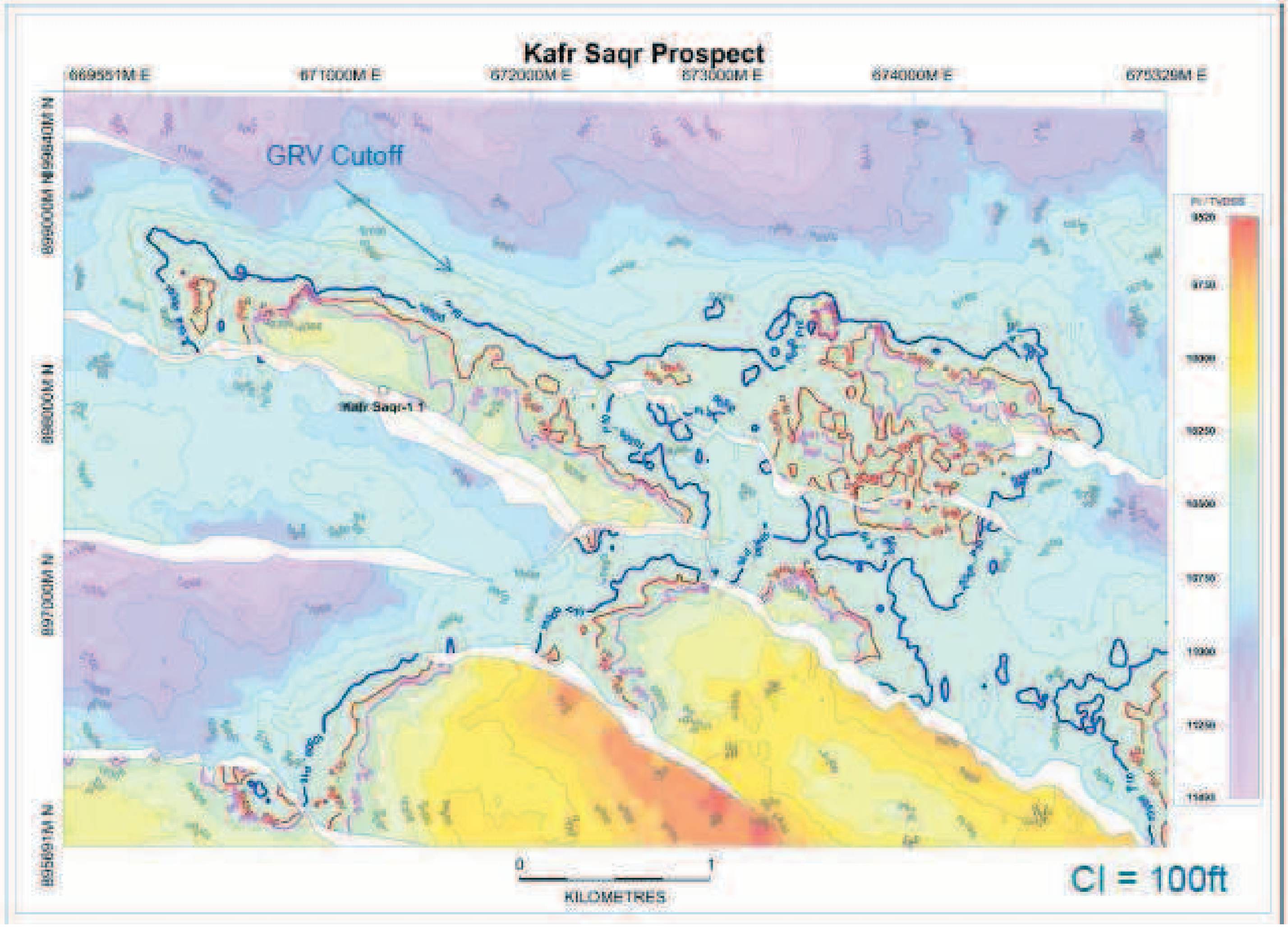
Sidi Gohar Fault Seal: Shale Gouge Ratio at Sand Overlaps



Source: Melrose 2012

Figure 2.23

Kafr Saqr Prospect Top Kharita Depth Map



Source: Melrose 2012

Figure 2.24

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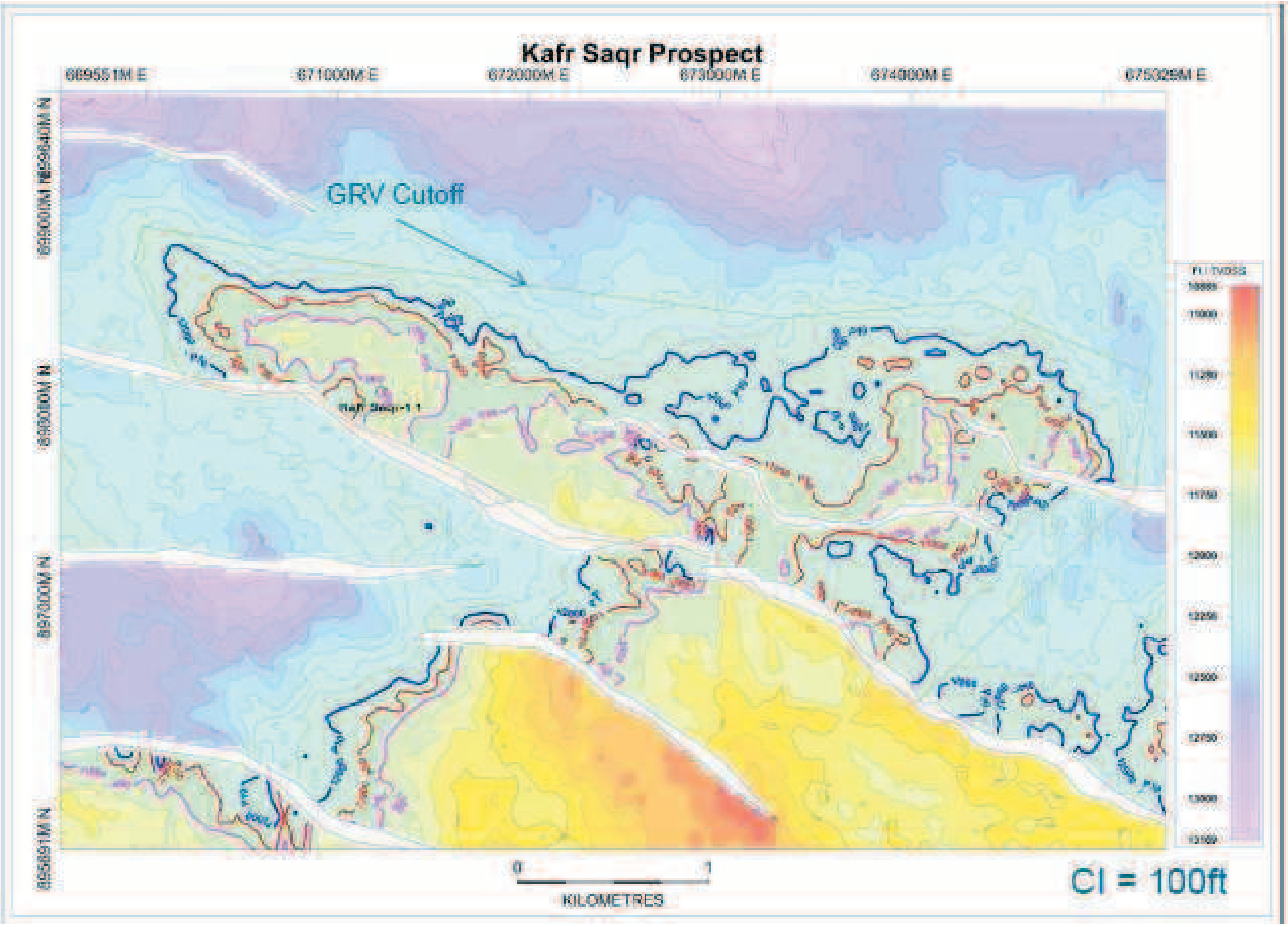
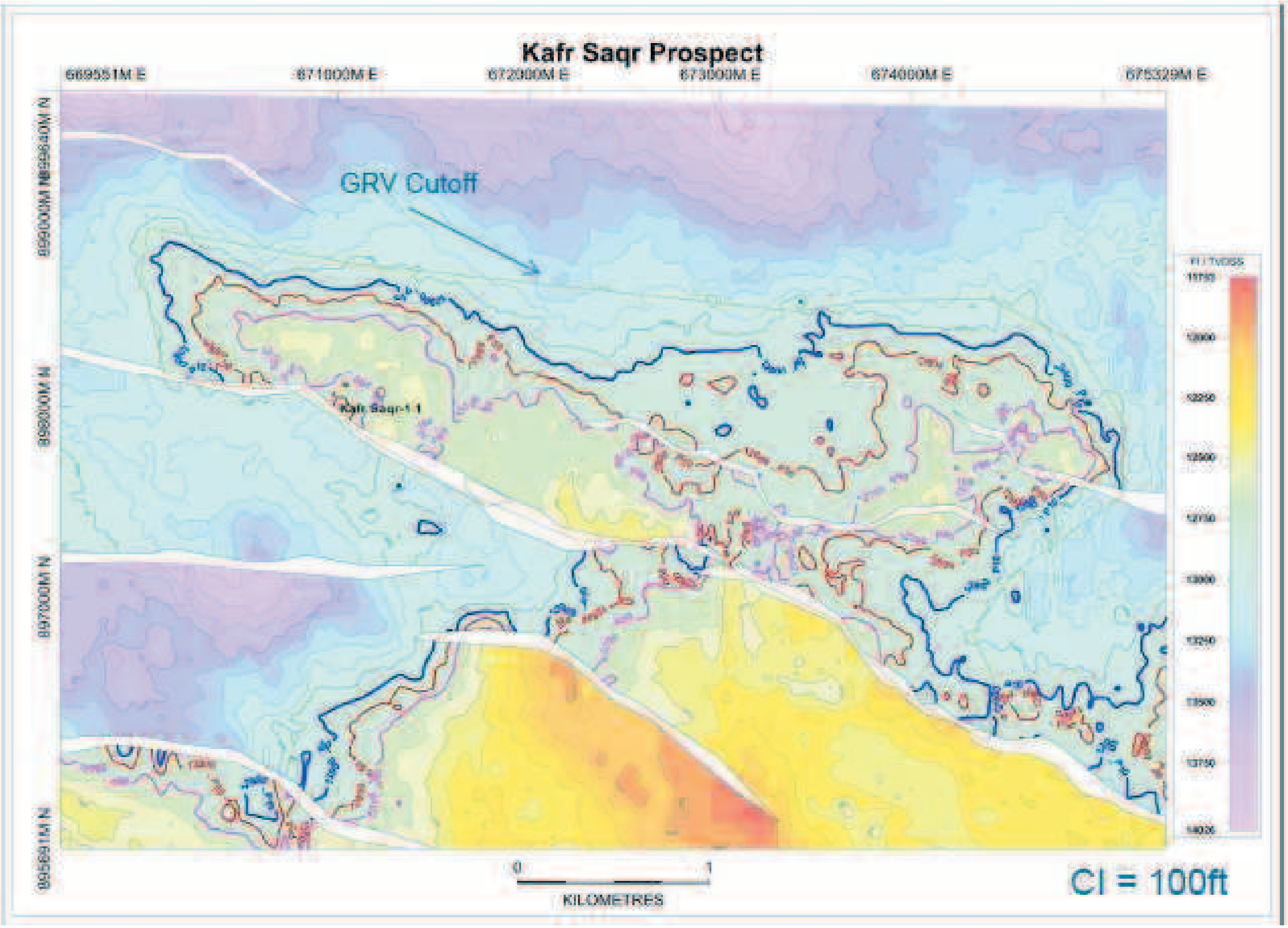
Kafr Saqr Prospect Top Barremian Depth Map



Source: Melrose 2012

Figure 2.25

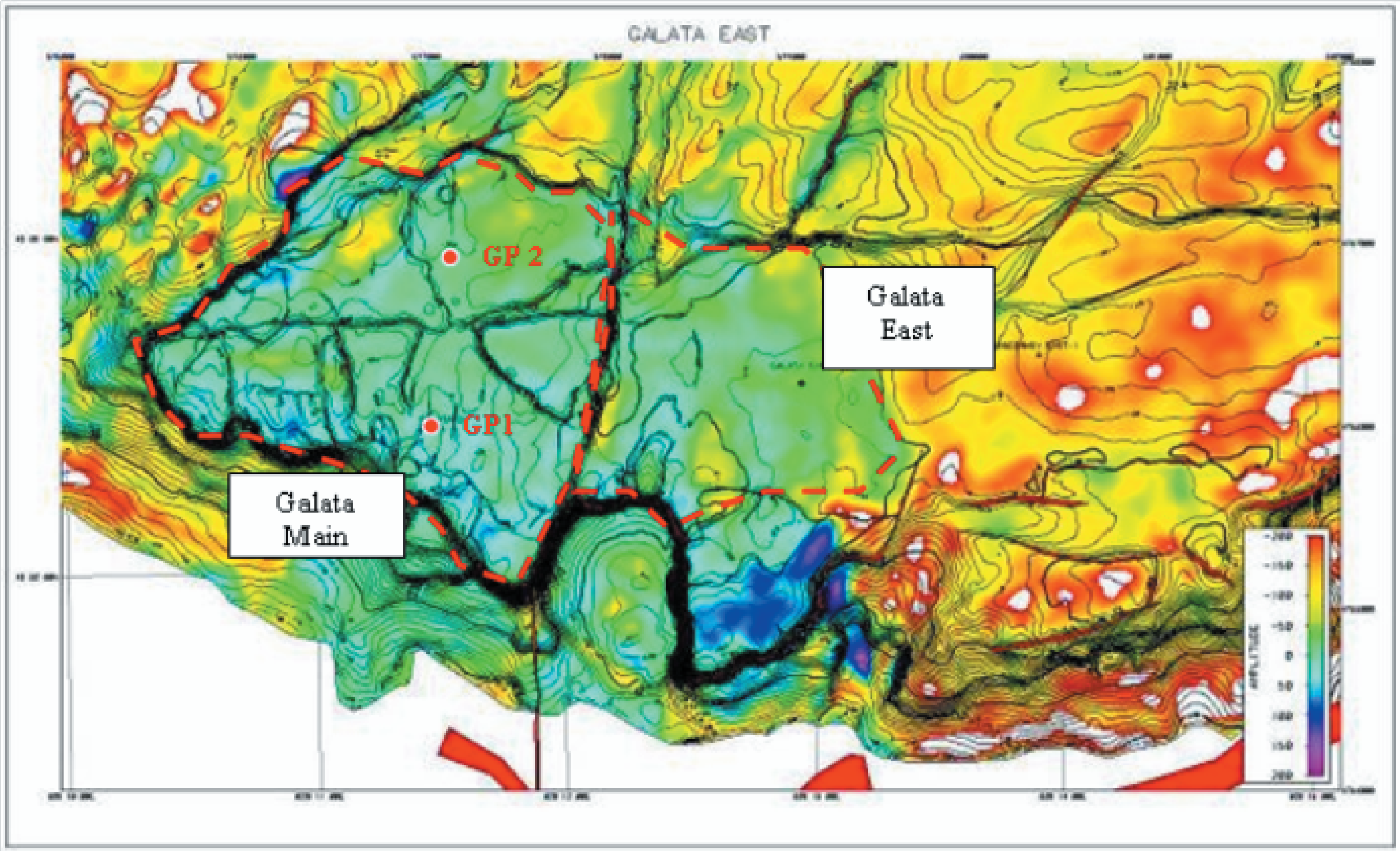
Kafr Saqr Prospect Top Neocomian Depth Map



Source: Melrose 2012

Figure 2.26

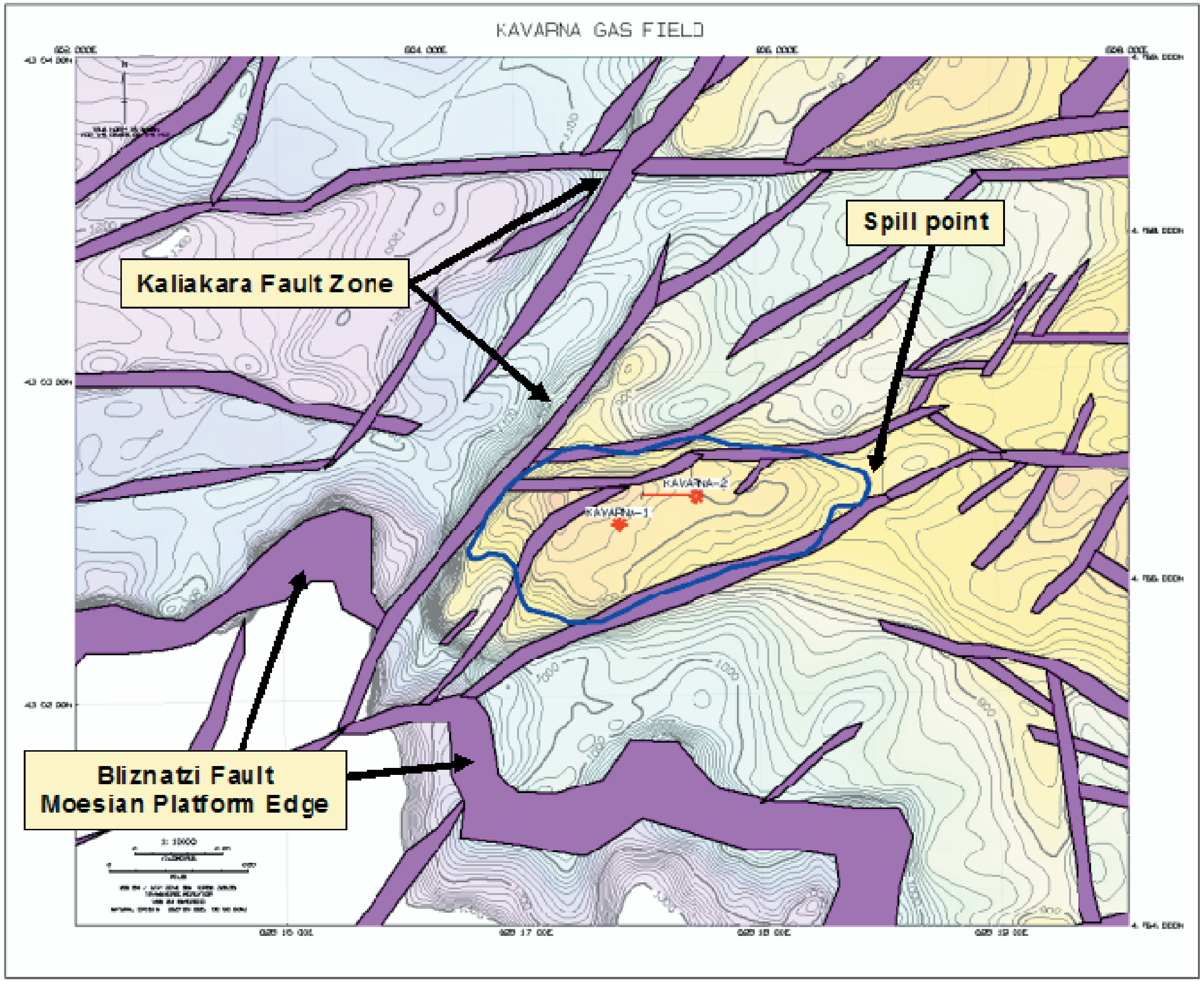
Galata Field Depth Structure Map



Source: Melrose 2012

Figure 4.1

Kavarna Field Depth Structure Map

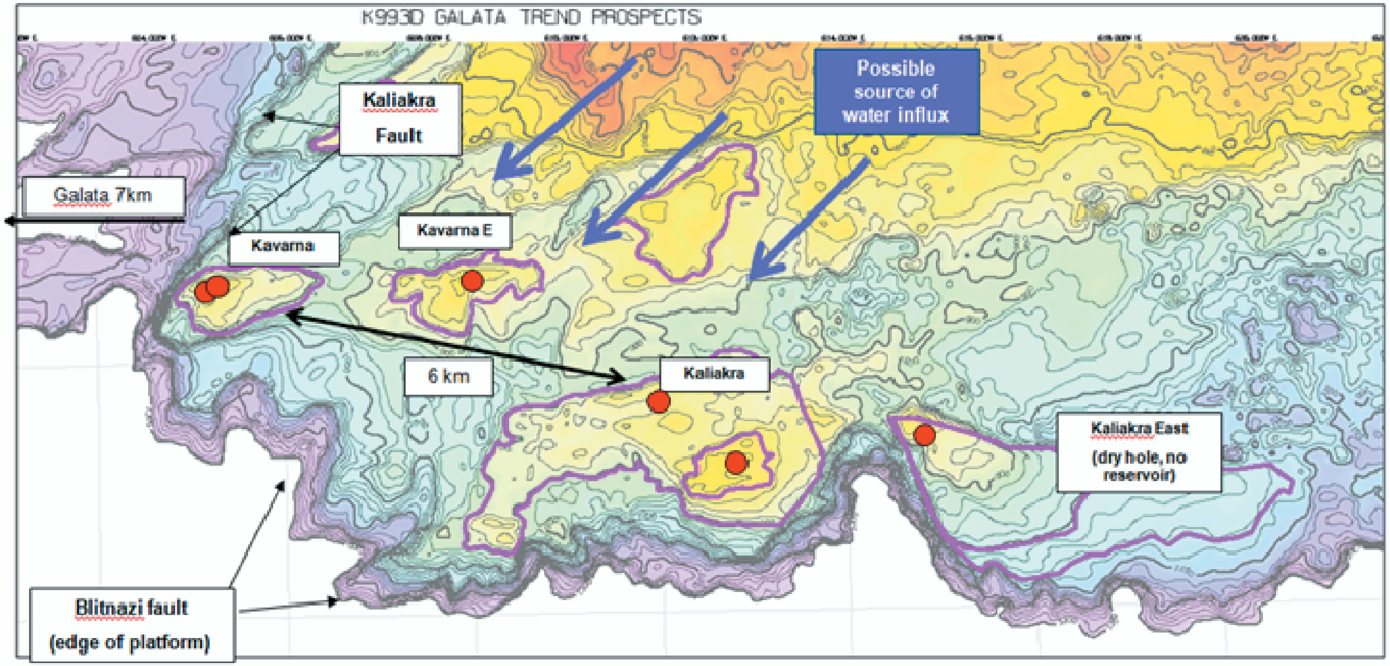


Source: Melrose 2012

Figure 4.2

senergy

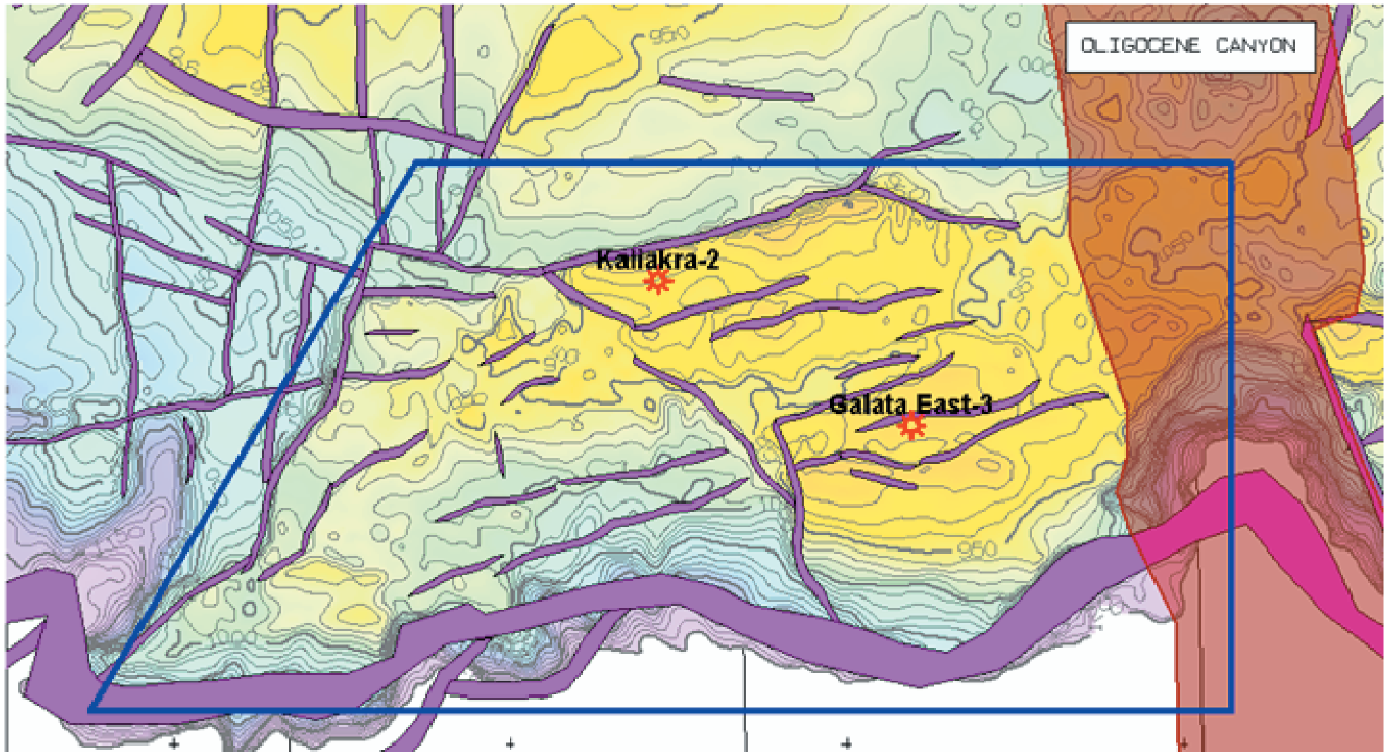
Kavarna, Kaliakra and East Kavarna FieldsTop Palaeocene Structure Map



Source: Melrose 2012

Figure 4.3

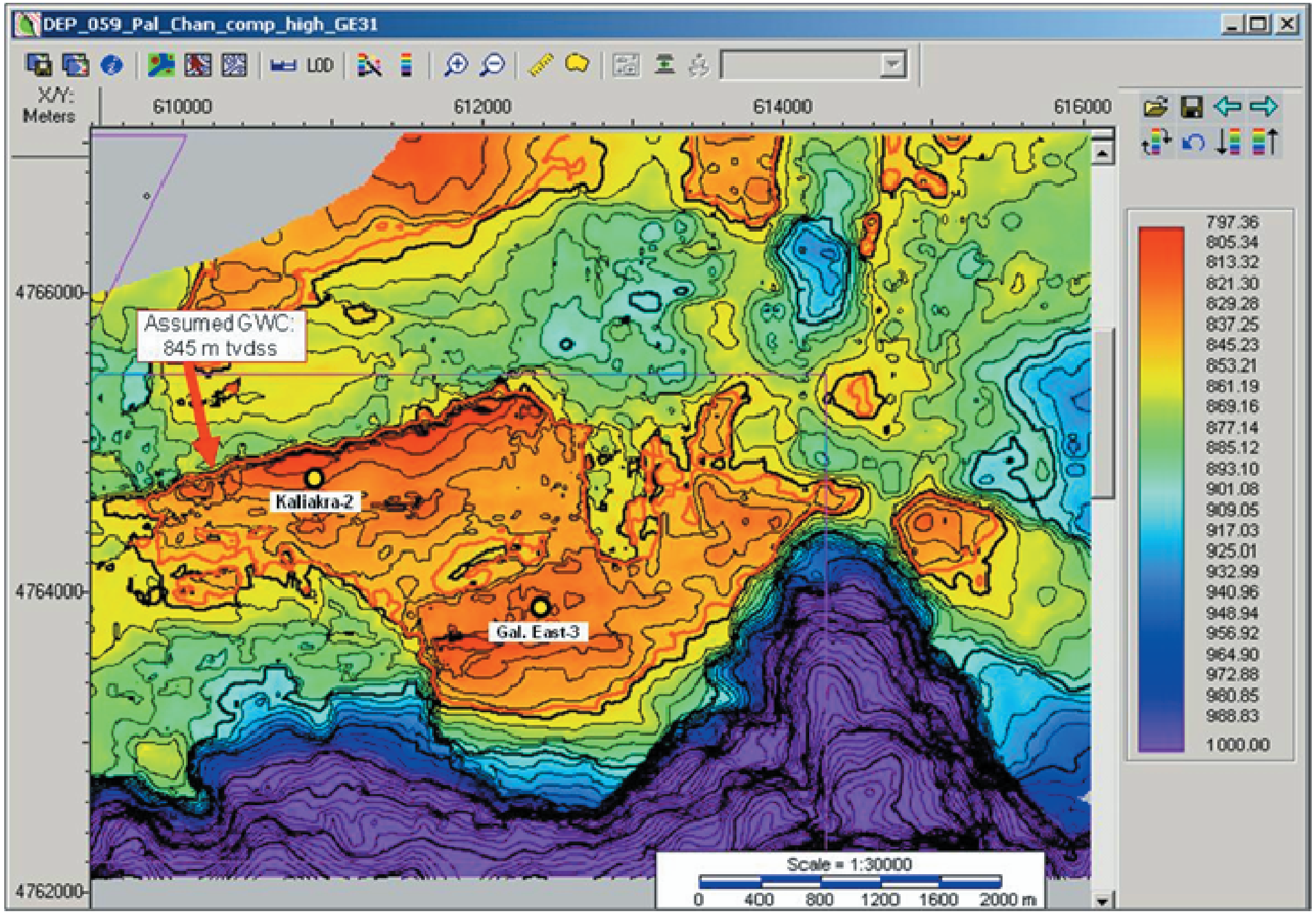
Kaliakra Field Depth Structure Map



Source: Melrose 2012

Figure 4.4

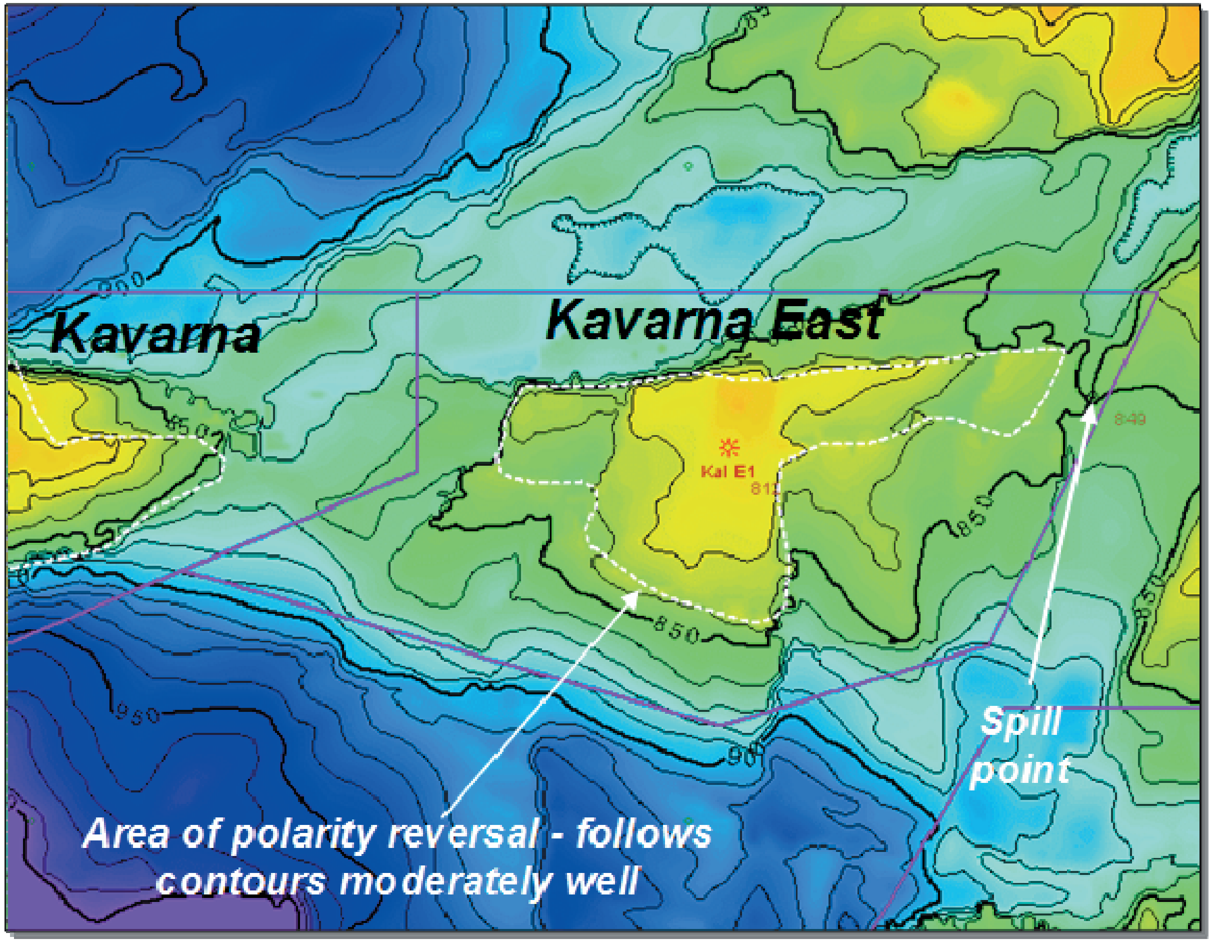
Kaliakra Field: Depth to Top Palaeocene ('High' Pick at Galata East-3)



Source: Melrose 2012

Figure 4.5

Kavarna East Field: Depth to Top Palaeocene



Source: Melrose 2012

Figure 4.6

Galata11 3D Seismic Interpretation – PreSTM

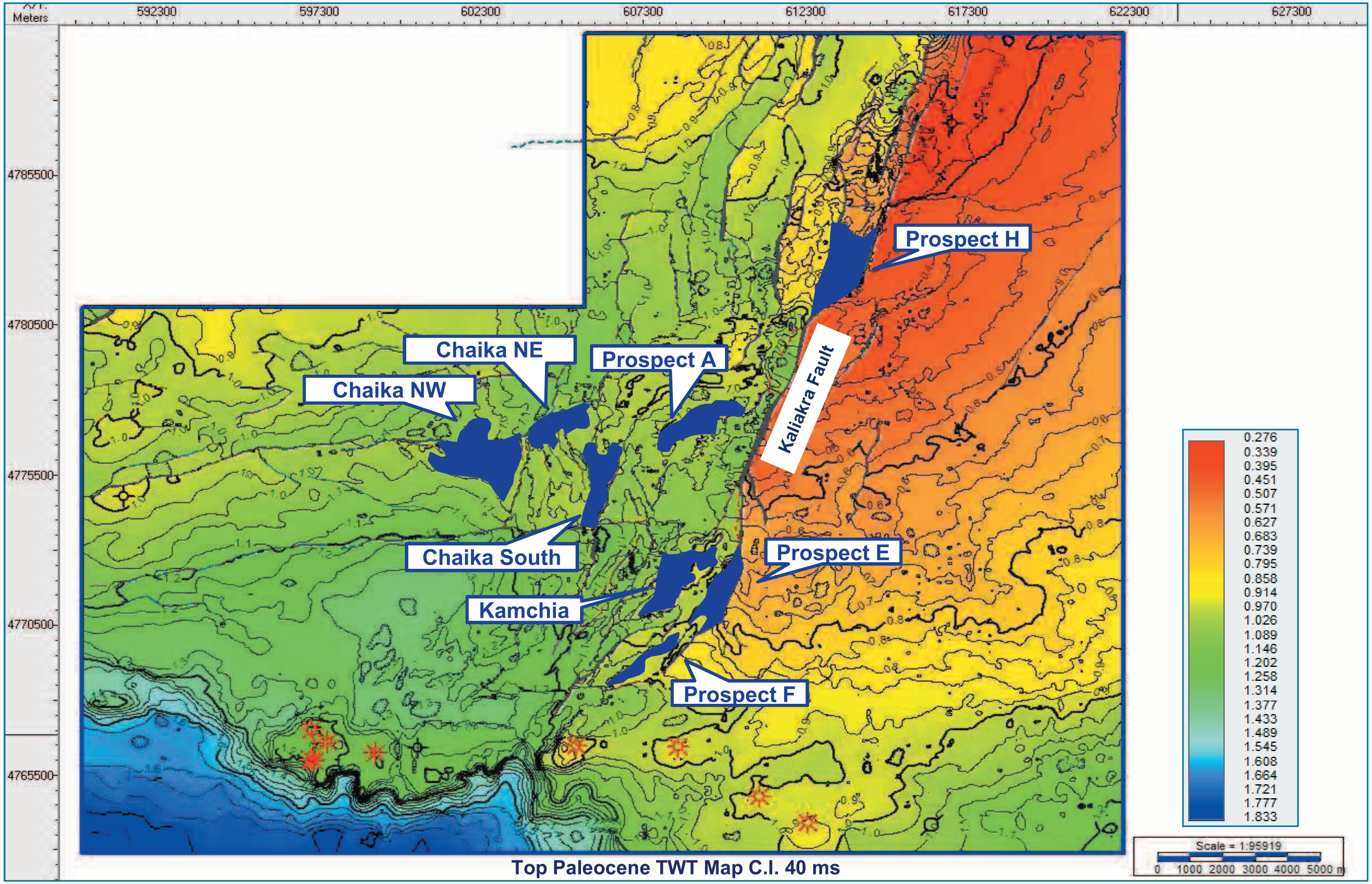


Figure 4.7

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Galata11 3D Seismic Interpretation – Well Tie

- 16 wells currently lie within the 3D limits, 13 of them in the south
- Only two of these wells have not been used for the Well-to-Seismic tie
- The remaining 13 wells were also used to create the Top Paleocene Average Velocity Map

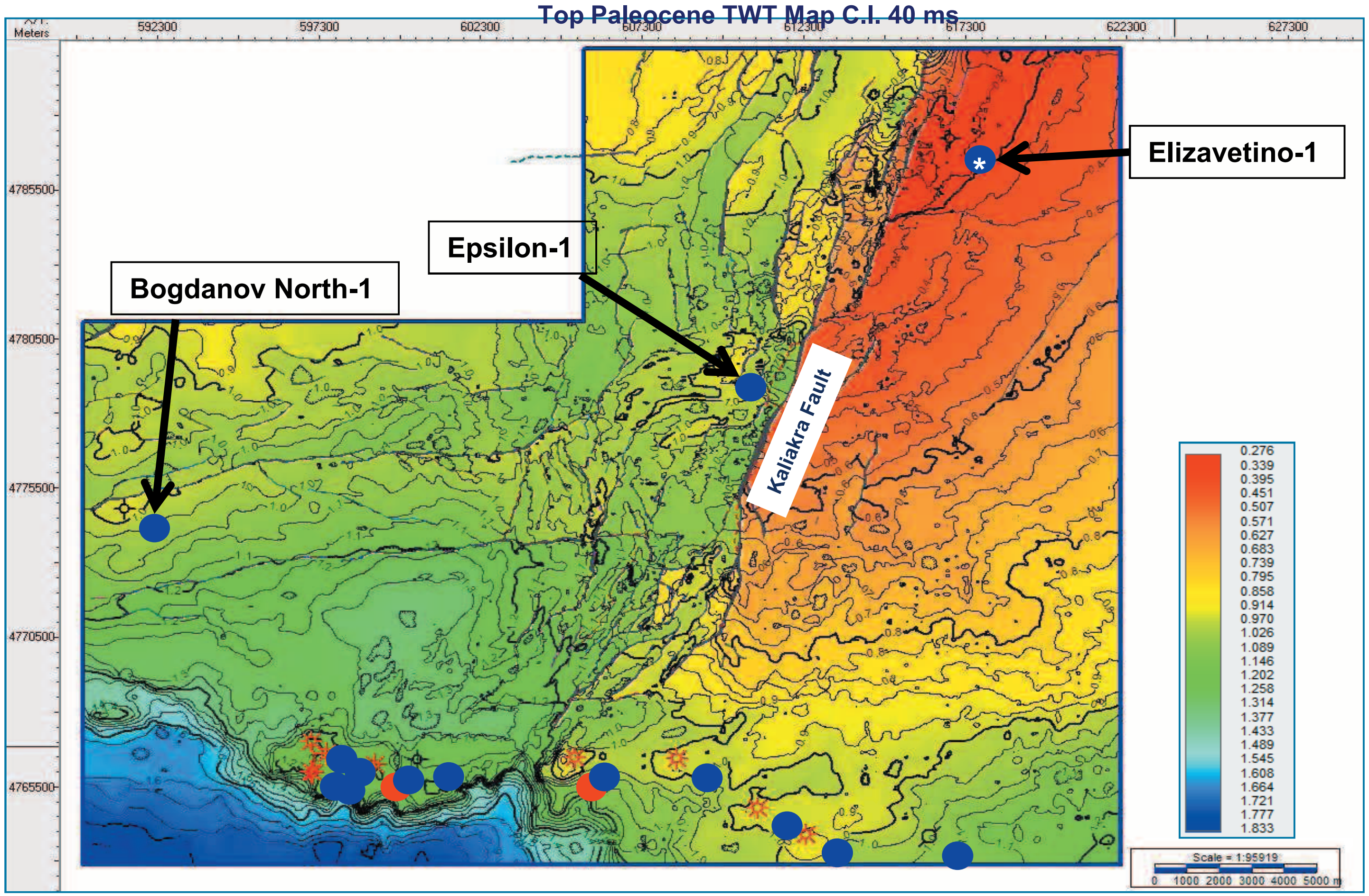


Figure 4.8

Wells used for T-D Conversion
Wells without T-D data
Wells used for T-D Conversion with T-D law imported from a similar well

Galata11 3D Seismic Interpretation – PreSTM

Five main horizons have been picked on the PreSTM so far, namely:

- Sea Bottom
- Intra Cretaceous
- Top Eocene
- Base Cretaceous
- Top Paleocene

W E

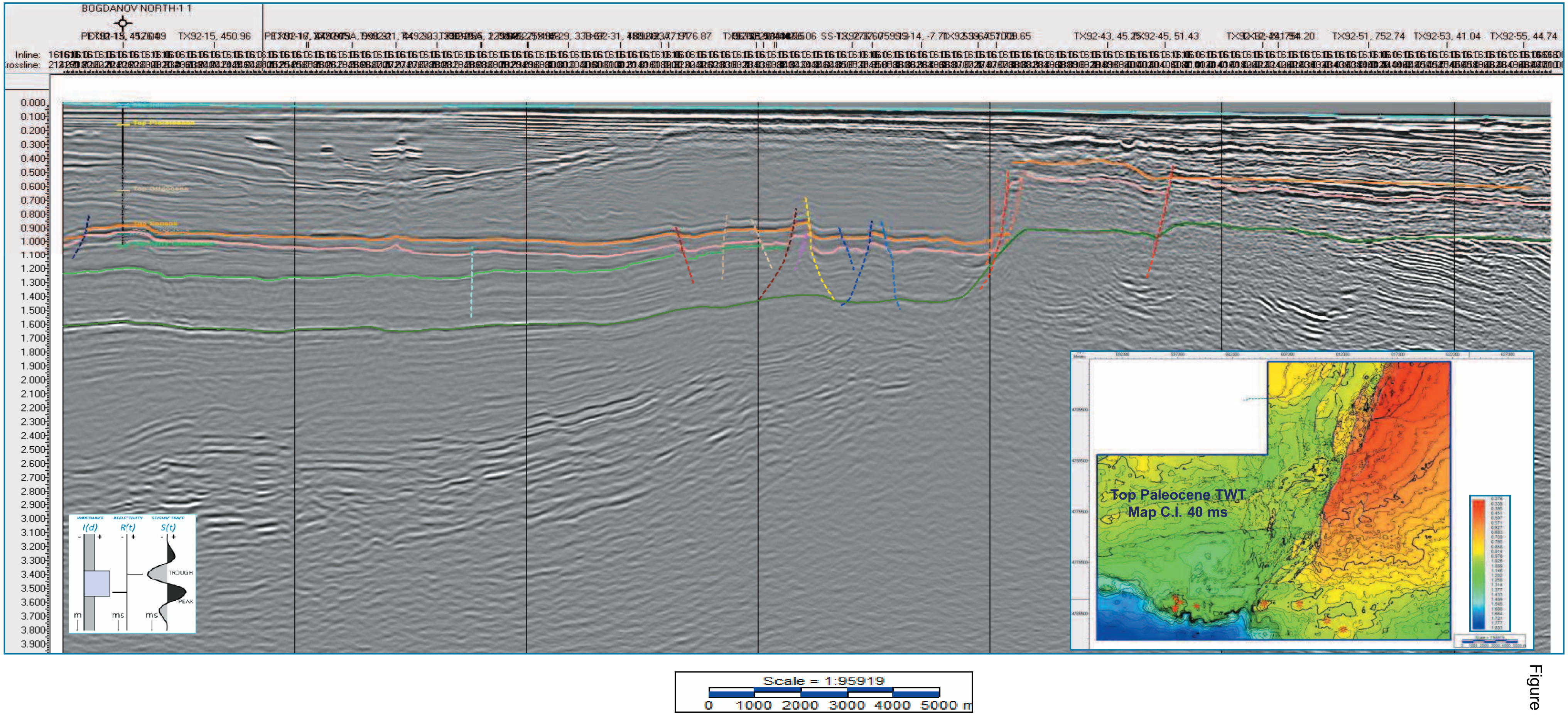


Figure 4.9

Chaika NW

Depth Maps and Seismic Line

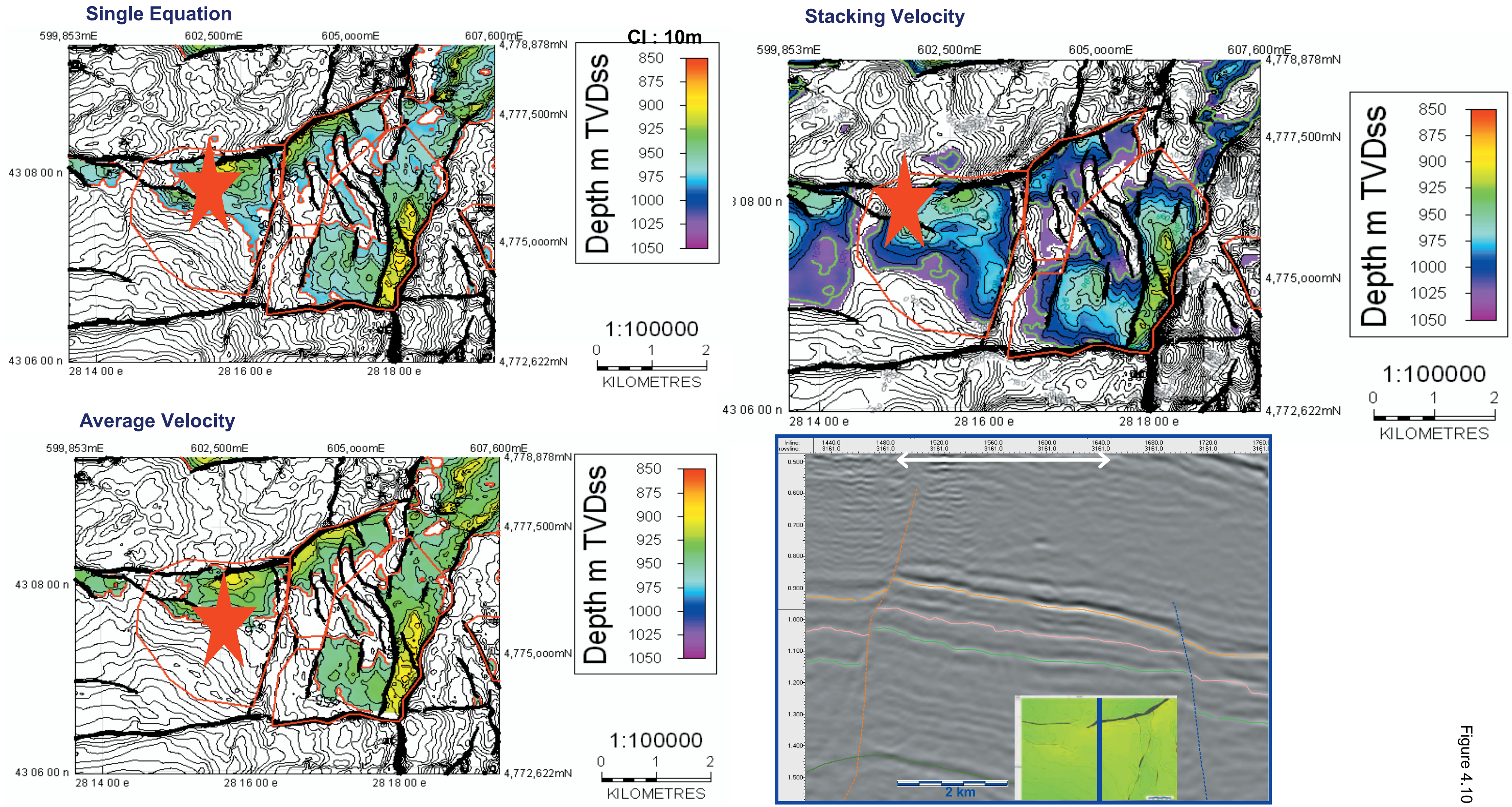


Figure 4.10

Chaika NE — Depth Maps & Seismic Line

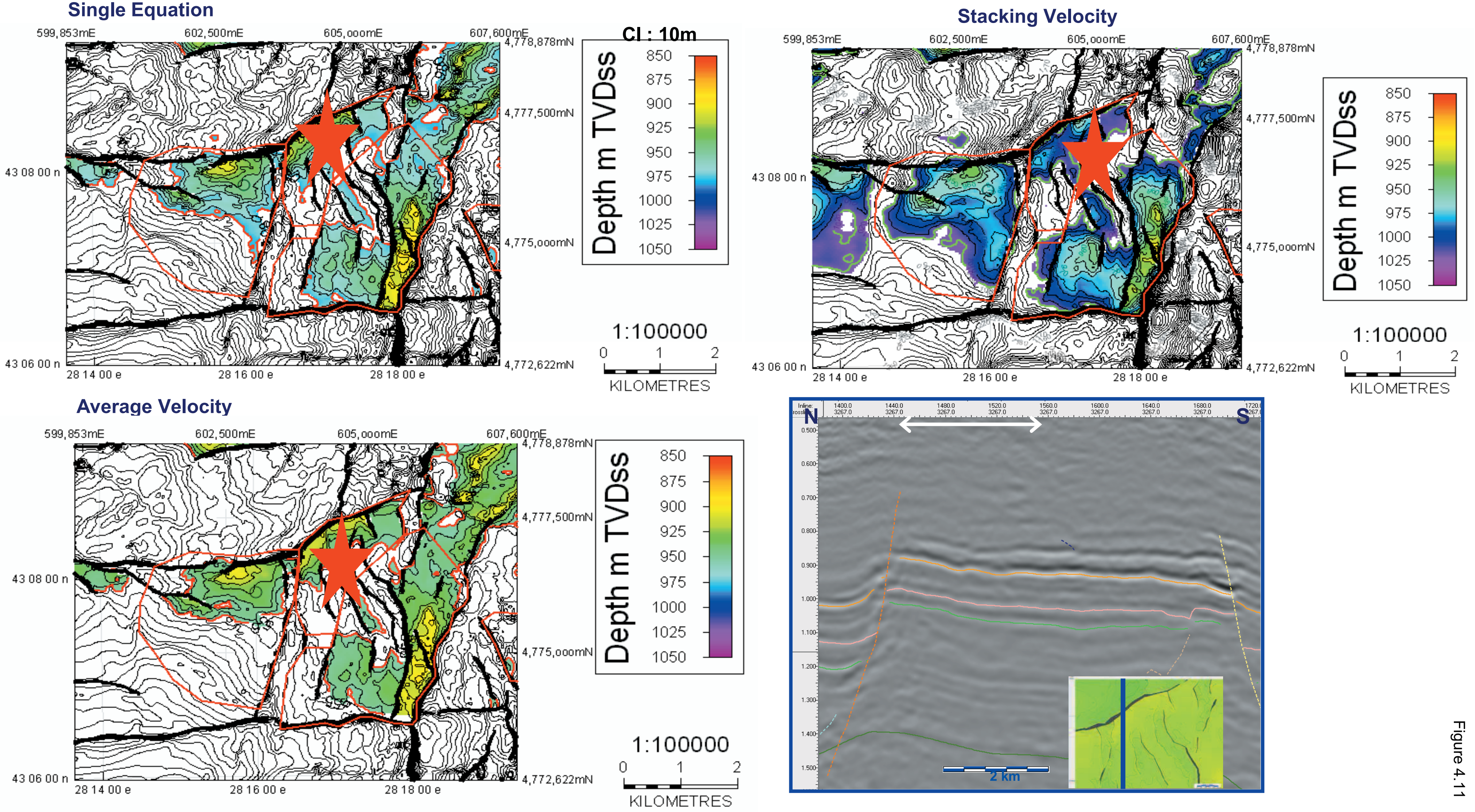


Figure 4.11

senergy

Chaika S Depth Maps & Seismic Line

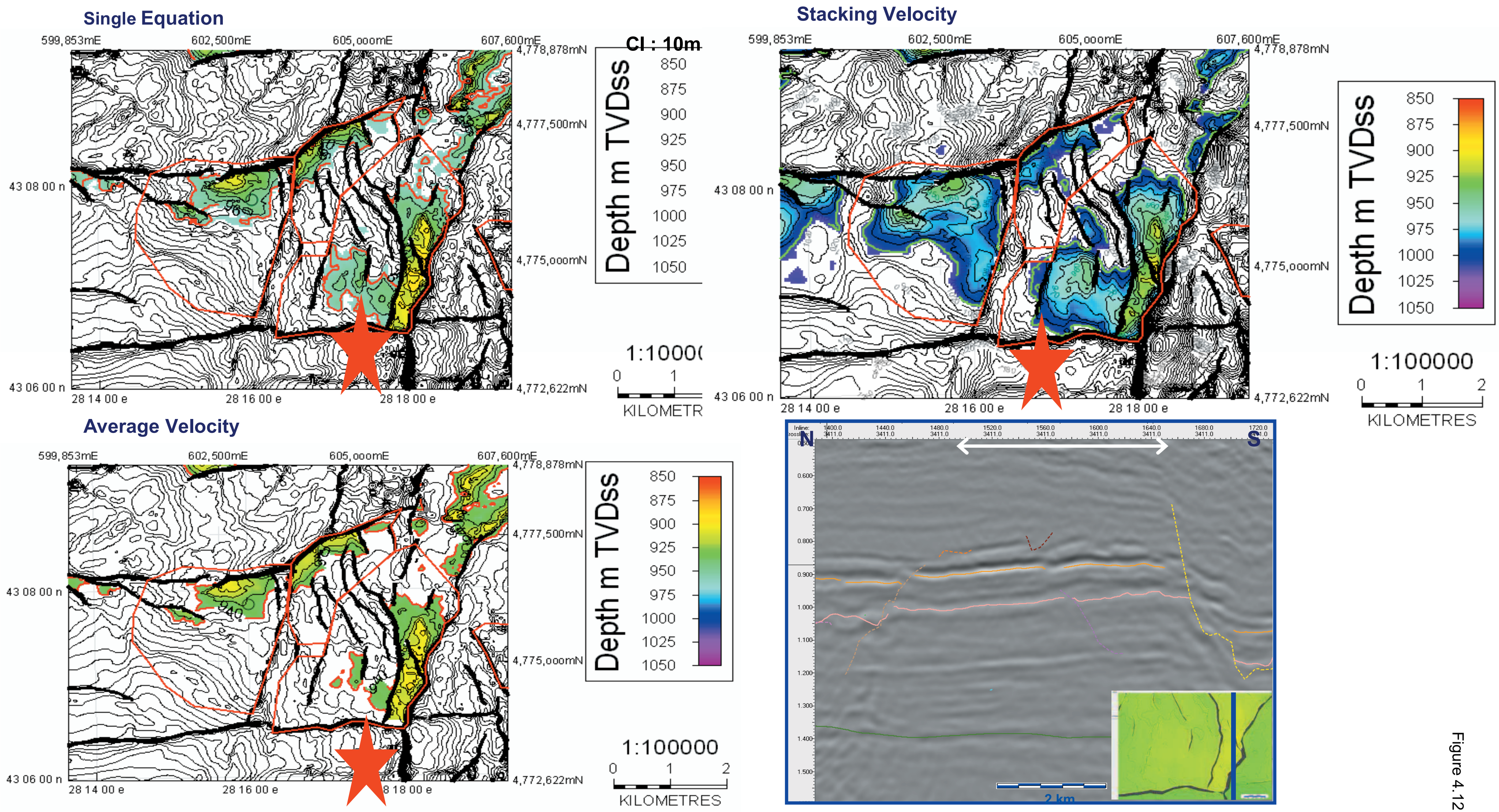


Figure 4.12

senergy

Kamchia Depth Maps & Seismic Line

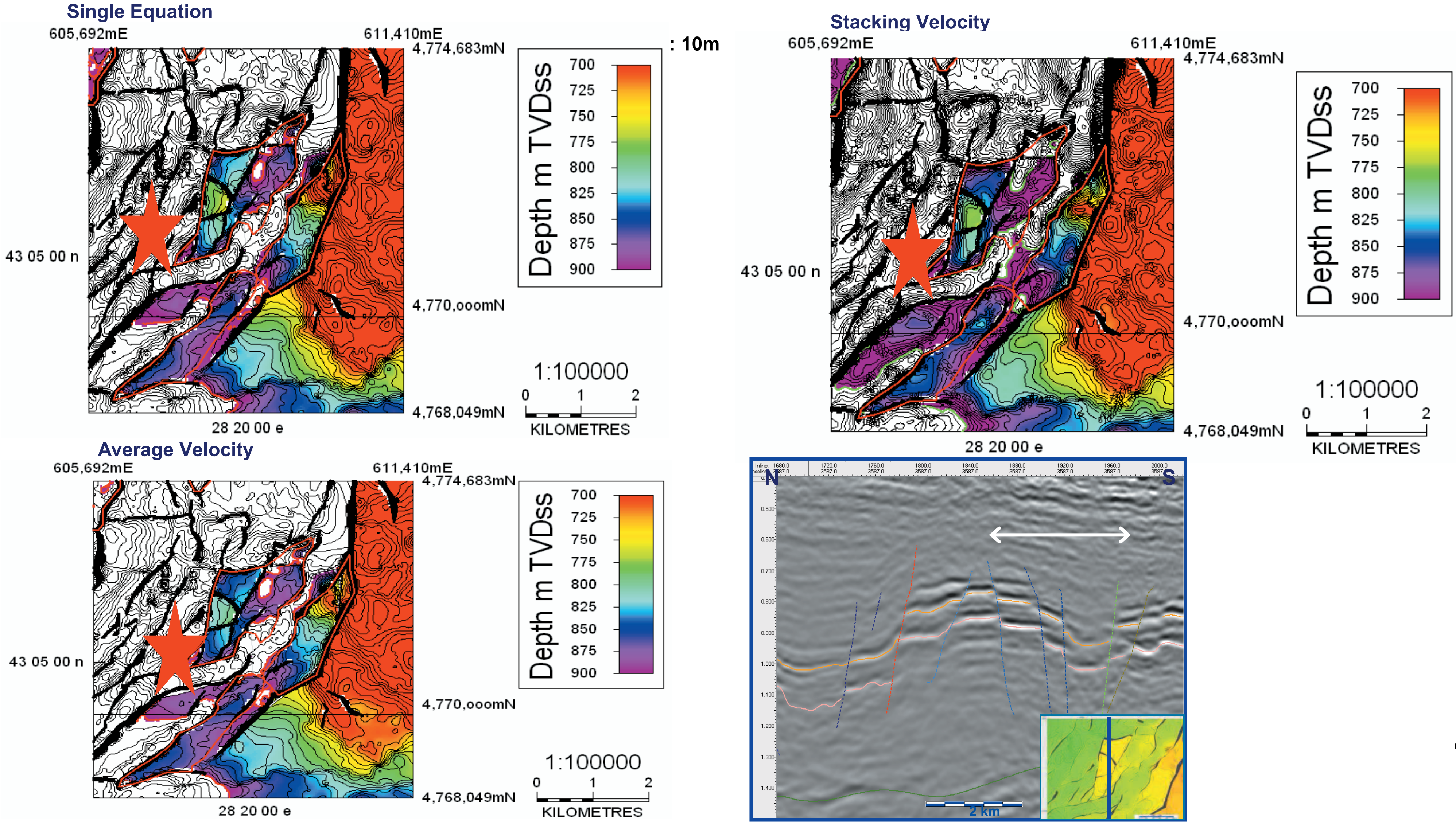


Figure 4.13

Prospect A Depth Maps & Seismic Line

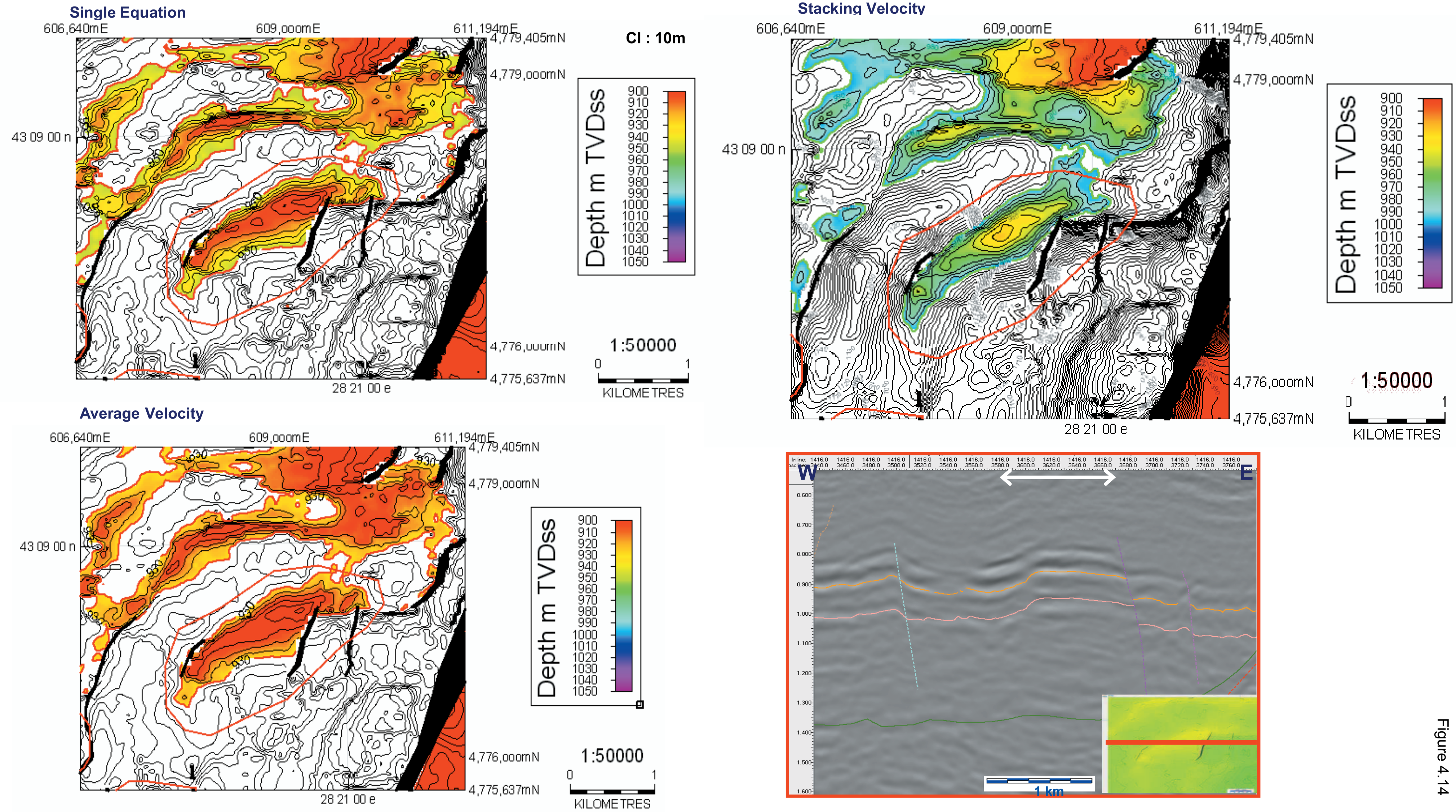
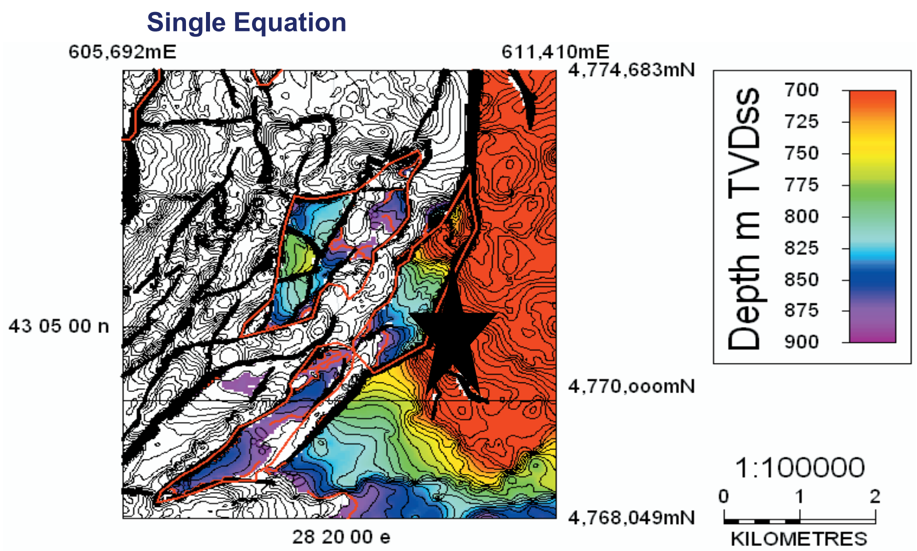
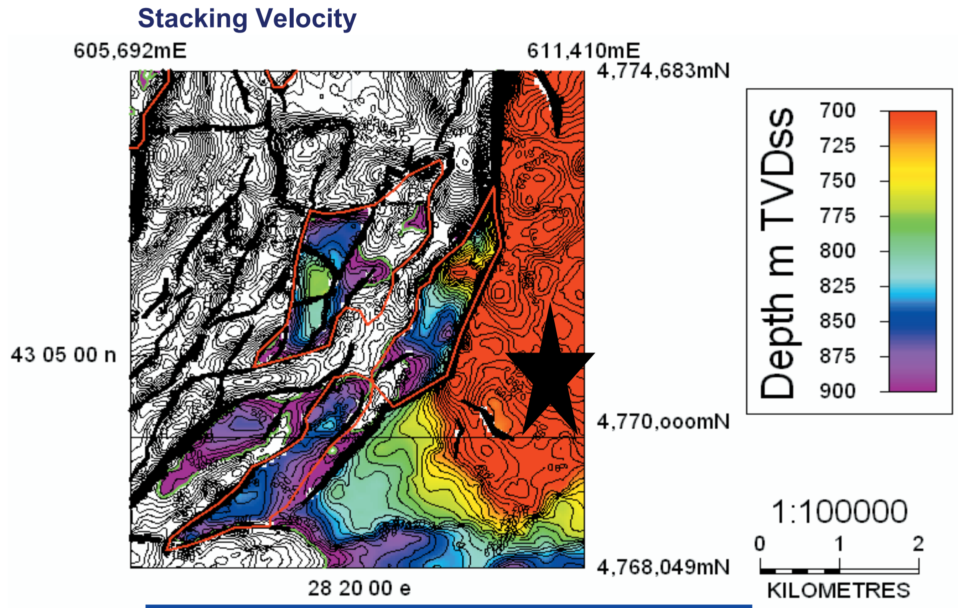
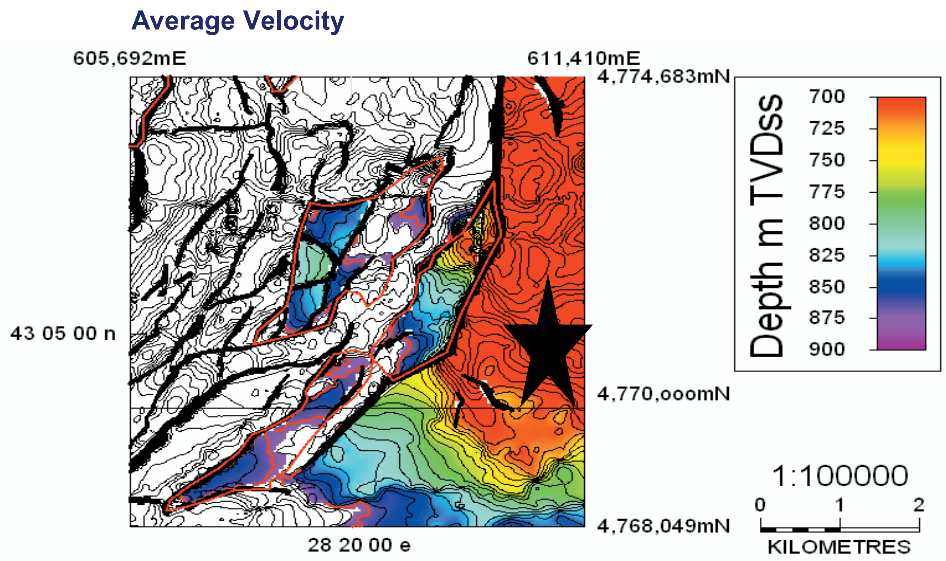


Figure 4.14

Prospect E — Depth Maps & Seismic Line







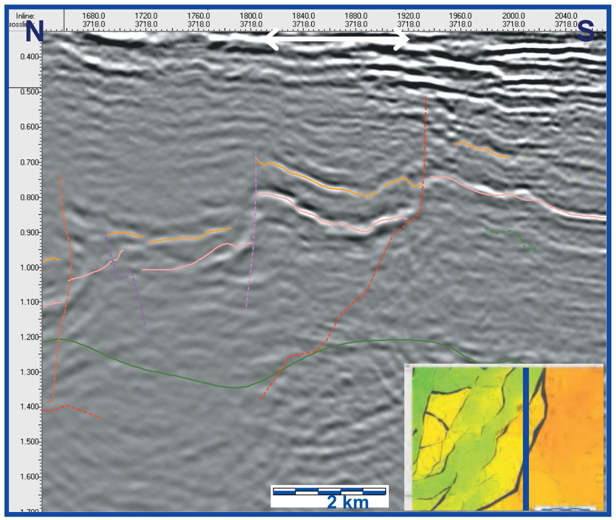


Figure 4.15

Prospect F Depth Maps & Seismic Line

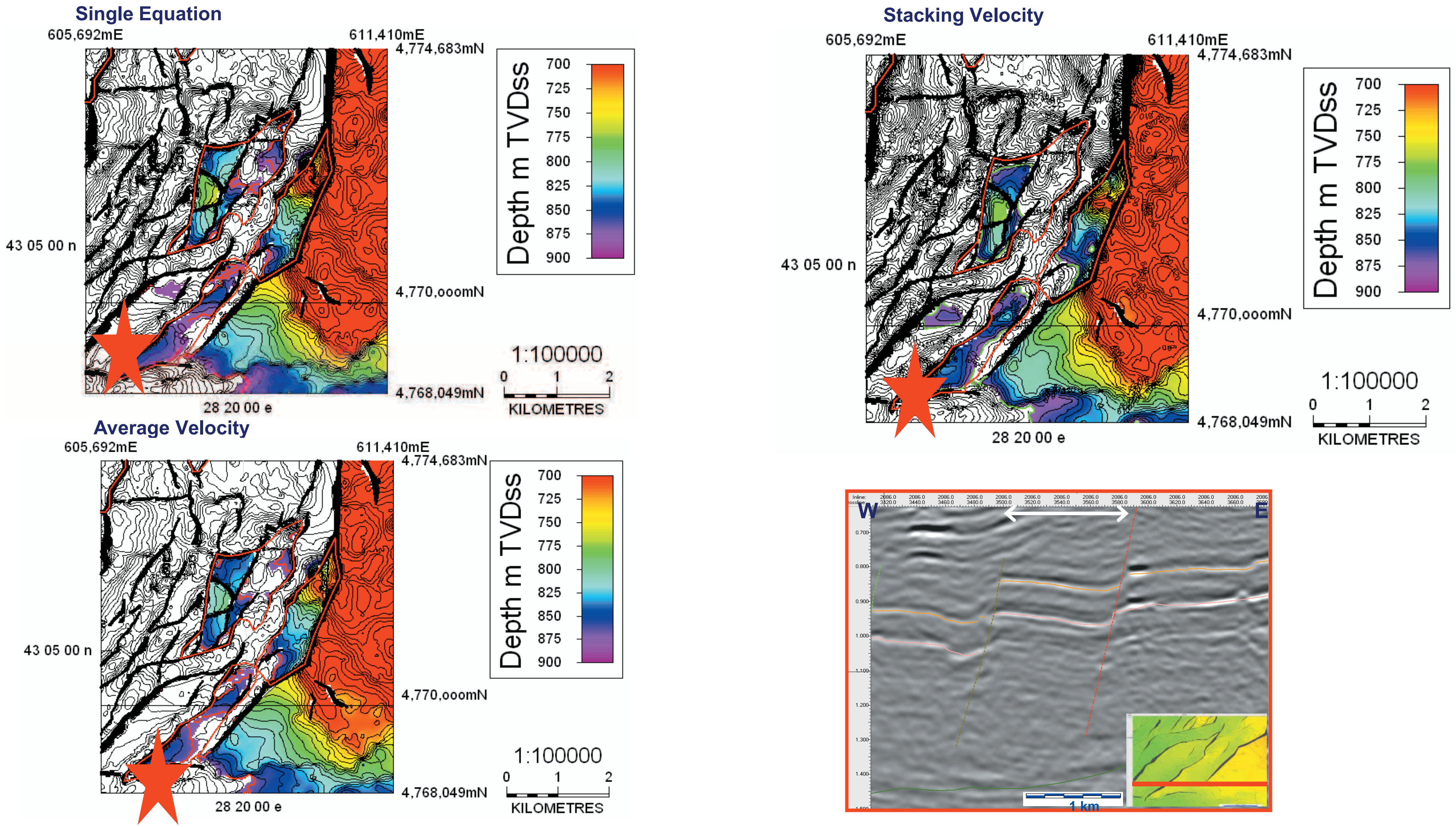


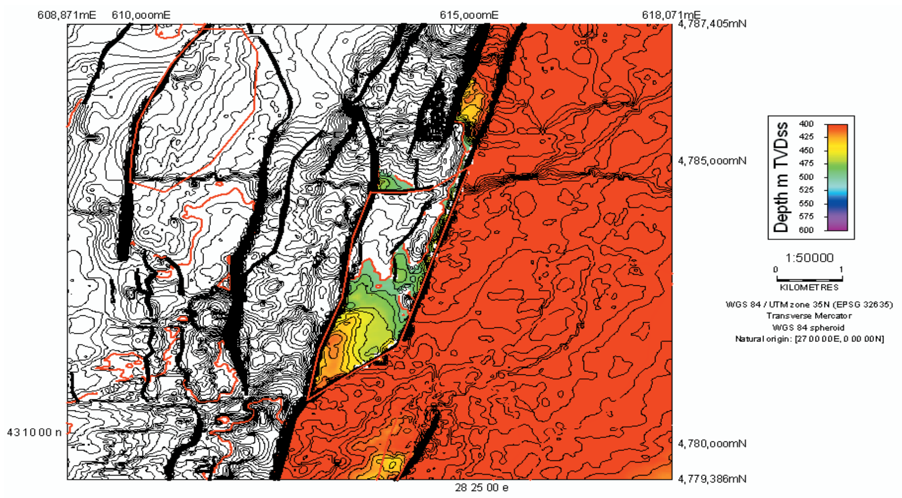
Figure 4.16

senergy

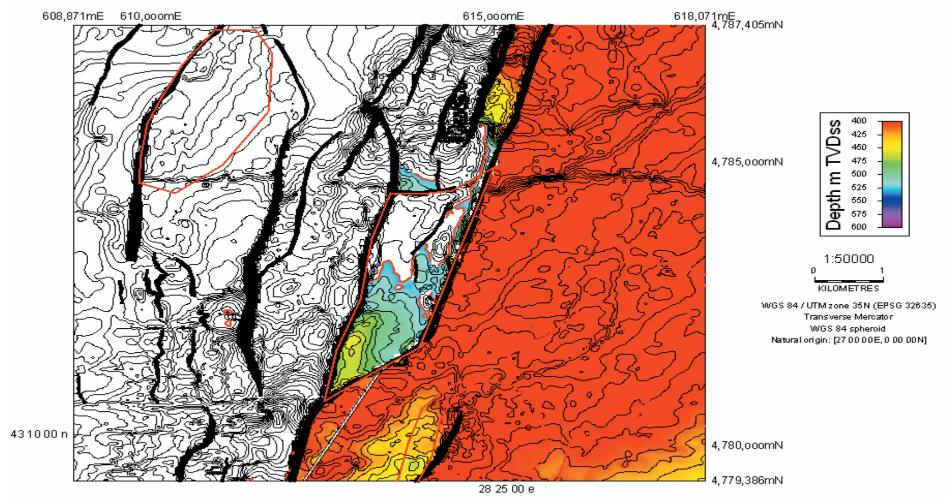
Prospect H

Depth Maps & Seismic Line

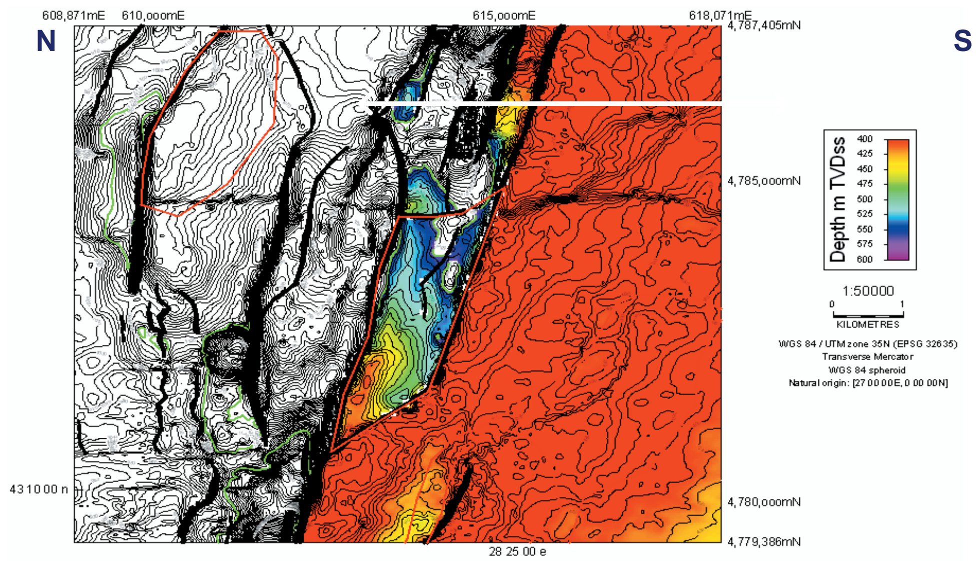
Single Equation



Average Velocity



Stacking Velocity



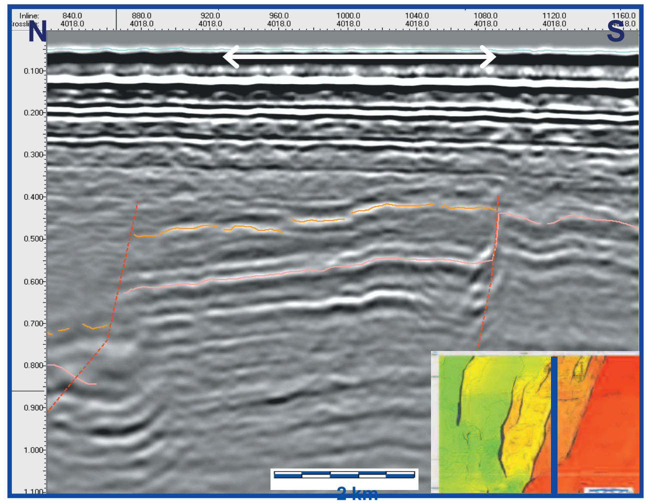
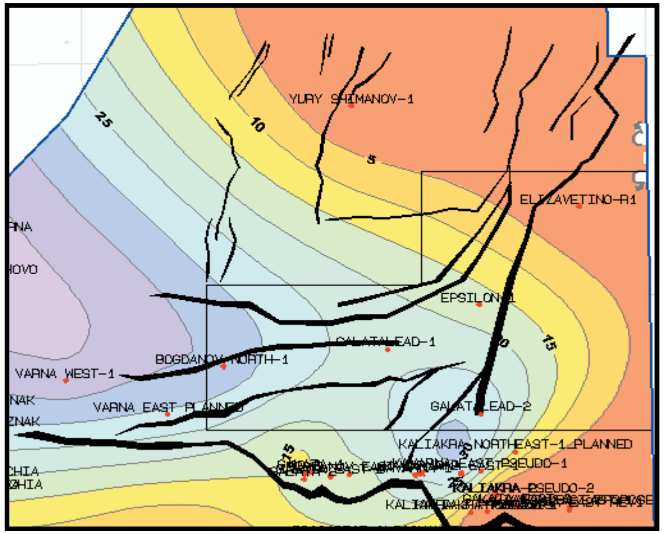
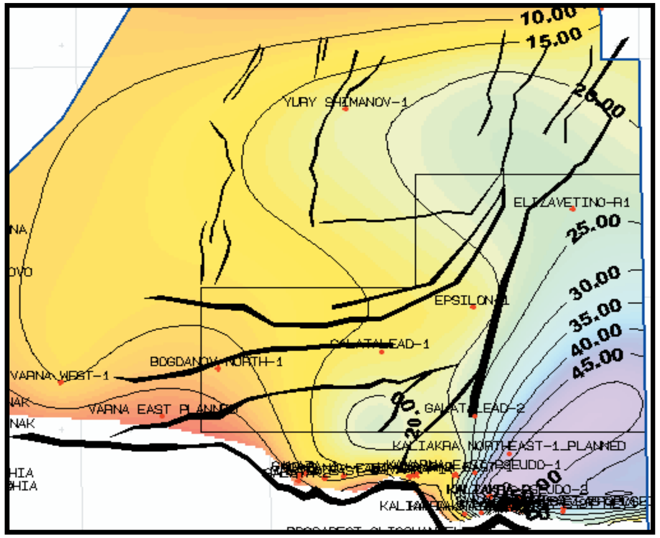


Figure 4.17

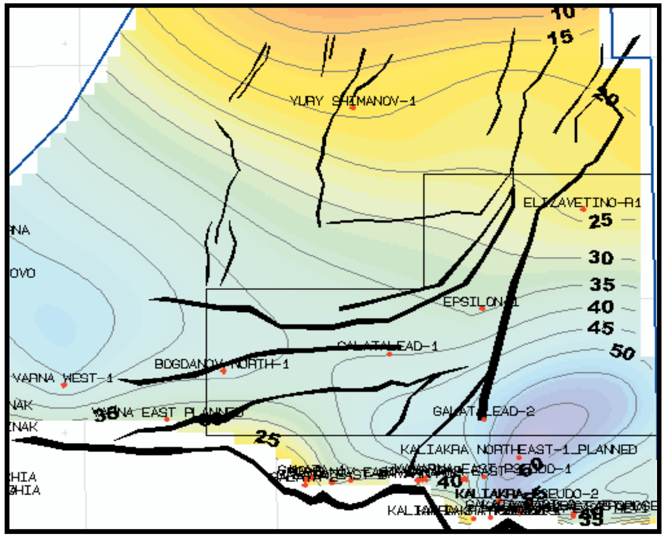
Maastrichtian Isopach



Palaeocene Isopach



Combined Reservoir Isopach



- All On Block wells used for Isopach maps
- Palaeocene GRV = Top Structure Map* + Palaeocene Isopach
- Maastrichtian GRV = (Top Structure Map* + Total Reservoir) – Palaeocene GRV

* Top Structure Map changes with different depth conversion

Figure 4.18

senergy

Block Galata Existing Infrastructure

Source: Melrose 2012

Figure 5.1

Bulgarian Prospects: Development Assumptions

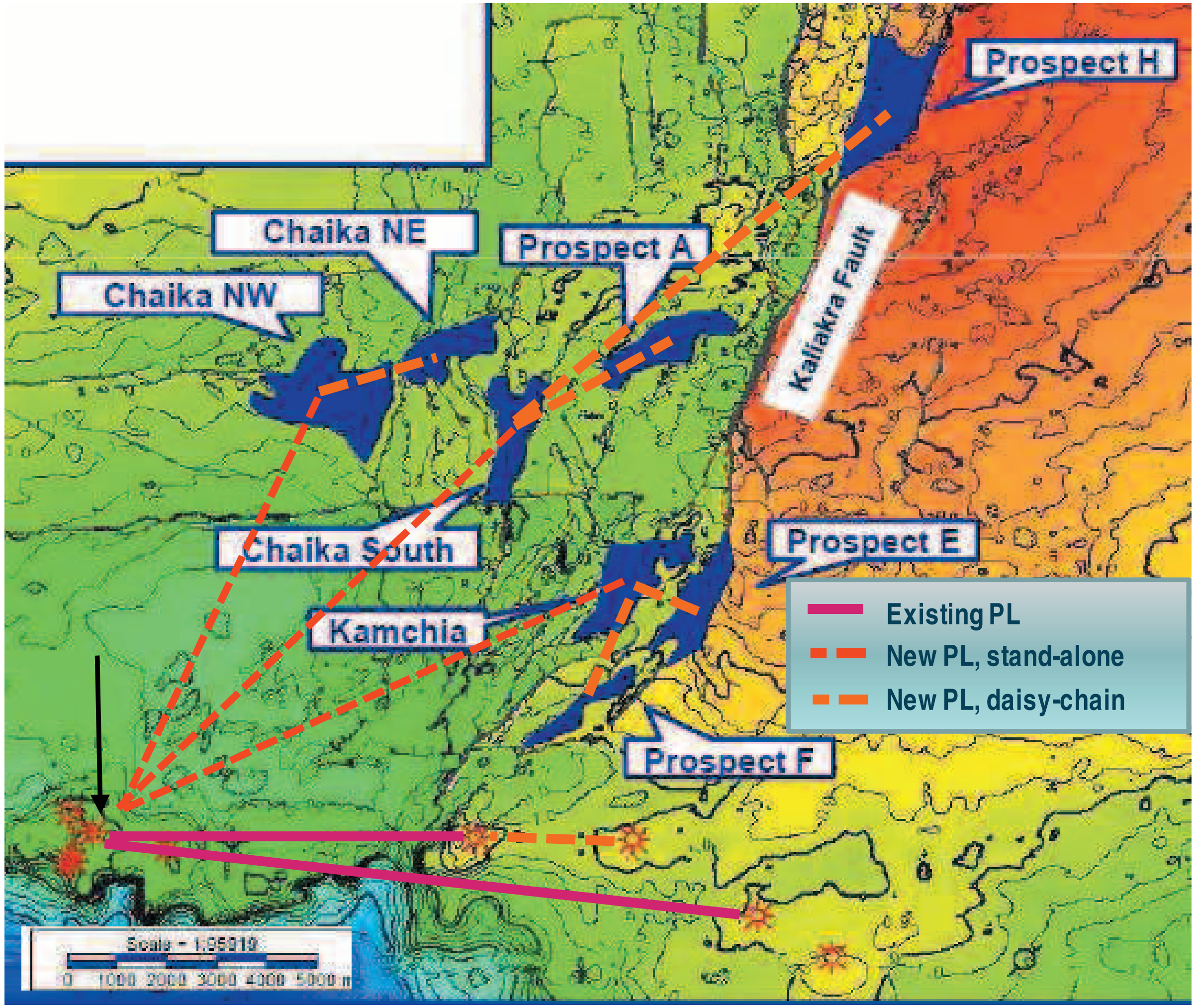


Figure 5.2

NOTICE OF EXTRAORDINARY GENERAL MEETING
of
PETROCELTIC INTERNATIONAL PLC (the "Company")

Notice is hereby given that an Extraordinary General Meeting of the Company will be held at The Westin Dublin, College Green, Westmoreland Street, Dublin 2, Ireland on 20 September 2012, at 12.30 p.m., to consider and, if thought fit, pass the following resolutions. Resolutions 1, 2 and 3 will be proposed as ordinary resolutions. Resolution 4 will be proposed as a special resolution.

ORDINARY RESOLUTIONS

1. **THAT**, the merger (the **"Merger"**) to be effected pursuant to a scheme of arrangement (the **''Scheme''**) under Part 26 of the Companies Act 2006 of the United Kingdom or takeover offer (the "**Offer**") made by or on behalf of the Company for the entire issued and to be issued share capital of Melrose Resources Plc ("**Melrose**"), substantially on the terms and subject to the conditions set out in the admission document issued by the Company dated 17 August 2012 of which this notice forms a part, be and is hereby approved, and the directors of the Company (or any duly constituted committee thereof) be authorised to: (i) take all such steps as may be necessary or desirable in connection with, and to implement, the Merger; and (ii) agree such modifications, variations, revisions or amendments to the terms and conditions of the Merger (provided that any such modifications, variations, revisions or amendments are not of a material nature), and to any documents relating thereto, as they may in their absolute discretion think fit.

2. **THAT** subject to and conditional upon the Scheme becoming effective (save for any conditions relating to: (i) delivery of an office copy of each of the court orders of the High Court of England and Wales (the "**UK Court**") sanctioning the Scheme and confirming the reduction of capital in Melrose (the "**Order**") and the statement of capital approved by the UK Court to the UK Registrar of Companies; and if so ordered by the UK Court in order to take effect, the registration by the UK Registrar of Companies of the Order effecting the reduction of capital of Melrose and the statement of capital approved by the UK Court (**"Delivery and Registration"**) and (ii) the London Stock Exchange and the Irish Stock Exchange having acknowledged to the Company or its agent (and such acknowledgment not having been withdrawn) that the ordinary shares of €0.0125 each in the Company (the "**Ordinary Shares**") will be admitted to trading on AIM and the Enterprise Securities Market of the Irish Stock Exchange respectively (**"Admission"**)); or, as the case may be, the Offer becoming or being declared wholly unconditional (save for Admission), the authorised share capital of the Company be and is hereby increased from €60,355,285.40 to €147,855,285.40 by the creation of a further 7,000,000,000 Ordinary Shares and to give effect thereto paragraph 5 of the Memorandum of Association of the Company be deleted and replaced with the following new paragraph 5:

"The share capital of the Company is €147,855,285.40 divided into 10,000,000,000 Ordinary Shares of €0.0125 each and 200,000,000 Deferred Shares of €0.114276427 each."

3. **THAT**, subject to and conditional upon the Scheme becoming effective (save for any conditions relating to Delivery and Registration or Admission), or, as the case may be, the Offer becoming or being declared wholly unconditional (save for Admission), the directors of the Company be and they are hereby generally and unconditionally authorised pursuant to section 20 of the Companies (Amendment) Act 1983 (the "**1983 Act**"), in substitution for all existing such authorities, to exercise all powers of the Company to allot relevant securities (within the meaning of section 20 of the 1983 Act) up to an aggregate nominal amount of €43,515,513.25 during the period commencing on the date of the passing of this Resolution and expiring on the earlier of the conclusion of the annual general meeting of the Company in 2013 and close of business on 11 September 2013, provided that the Company may before such expiry make an offer or agreement which would or might require relevant securities to be allotted after such expiry and the directors may allot relevant securities in pursuance of such offer or agreement as if the authority hereby conferred had not expired.

SPECIAL RESOLUTION

4. **THAT**, subject to and conditional upon the Scheme becoming effective, or, as the case may be, the Offer becoming or being declared wholly unconditional, the directors of the Company be and they are hereby empowered pursuant to section 24 of the 1983 Act, in substitution for all existing such authorities, to allot

equity securities (within the meaning of section 23 of the 1983 Act) for cash pursuant to the authority conferred by Resolution No. 3 above as if sub-section (1) of section 23 of the 1983 Act did not apply to any such allotment, provided that this power shall be limited:

(a) to the allotment of equity securities in connection with a rights issue, open offer or other invitation to or in favour of the holders of Ordinary Shares each where the equity securities respectively attributable to the interests of such holders are proportional (as nearly as may be) to the respective numbers of Ordinary Shares held by them (but subject to such exclusions or other arrangements as the directors may deem necessary or expedient to deal with fractional entitlements that would otherwise arise or with legal or practical problems under the laws of, or the requirements of any recognised regulatory body or any stock exchange in, any territory, or otherwise howsoever); and

(b) to the allotment (otherwise than pursuant to sub-paragraph (a) above) of equity securities up to an aggregate nominal amount of €2,742,584.11,

and shall expire at the earlier of the conclusion of the annual general meeting of the Company in 2013 and close of business on 11 September 2013, provided that the Company may before such expiry make an offer or agreement which would or might require equity securities to be allotted after such expiry and the directors may allot equity securities in pursuance of such offer or agreement as if the power hereby conferred had not expired.

BY ORDER OF THE BOARD

Peter Dunne

Secretary

Registered Office:
6th Floor
75 St. Stephen's Green
Dublin 2
Ireland

Dated: **17 August 2012**

Notes:

1. The Company, pursuant to Regulation 14 of the Companies Act 1990 (Uncertificated Securities) Regulations 1996 (as amended), specifies that only those persons entered on the register of members of the Company as at 6.00 p.m. on 18 September 2012 (or if the Extraordinary General Meeting is adjourned, at 6.00 p.m. on the day two days prior to the adjourned Extraordinary General Meeting) will be entitled to attend and vote at the Extraordinary General Meeting or any adjournment thereof in respect of the number of shares registered in their names at the relevant time. Changes to entries in the register of members after that time will be disregarded in determining the right of any person to attend and / or vote at the meeting.

2. A member entitled to attend and vote is entitled to appoint a proxy to attend, speak and vote on his behalf. A proxy need not be a member of the Company. A member may appoint more than one proxy in relation to the Extraordinary General Meeting, provided that the total number of such proxies shall not exceed the total number of shares carrying an entitlement to attend such meeting held by such member. Members may appoint a proxy using the enclosed form of proxy, the CREST electronic proxy appointment service (described below) or the Registrars' online proxy appointment service (also described below).

3. The deposit of an instrument of proxy will not preclude a member from attending and voting in person at the meeting.

4. To be valid, an appointment of proxy must be returned using one of the following methods:

   (i) by sending the Form of Proxy, duly completed and signed, together with any authority under which it is executed or a copy of such authority certified notarially or by a solicitor practicing in Ireland, by post to the Registrars, Computershare Investor Services (Ireland) Limited, Heron House, Corrig Road, Sandyford Industrial Estate, Dublin 18, Ireland;

(ii) in the case of CREST members, by utilising the CREST electronic proxy appointment service; or

(iii) by utilising the Registrars' online proxy appointment service at www.eproxyappointment.com,

and in each case the appointment of proxy (together with any relevant power or authority) must be received (or, in the case of the appointment of a proxy through CREST, retrieved by enquiry to CREST in the manner prescribed by CREST) by the Registrars not later than 48 hours before the time appointed for holding the meeting. If two or more valid but differing proxy appointments are received in respect of the same ordinary share, the one which is last received (regardless of its date or the date of its execution) shall be treated as replacing and revoking the others as regards that ordinary share and, if the Company is unable to determine which was last deposited, none of them shall be treated as valid in respect of that ordinary share.

5. CREST members who wish to appoint a proxy or proxies by utilising the CREST electronic proxy appointment service may do so for the meeting and any adjournment(s) thereof by utilising the procedures described in the CREST Manual. CREST Personal Members or other CREST Sponsored Members, and those CREST Members who have appointed a voting service provider(s), should refer to their CREST Sponsor or voting service provider(s), who will be able to take appropriate action on their behalf.

6. In order for a proxy appointment made by means of CREST to be valid, the appropriate CREST message (a **"CREST Proxy Instruction"**) must be properly authenticated in accordance with Euroclear UK and Ireland (EUI)'s specifications and must contain the information required for such instructions, as described in the CREST Manual. The message (whether it constitutes the appointment of a proxy or an amendment to the instruction given to a previously appointed proxy) must be transmitted so as to be received by the Registrars, Computershare Investor Services (Ireland) Limited, as issuer's agent (CREST Participant **3RA50**), by the latest time(s) for receipt of proxy appointments specified in this notice of meeting. For this purpose, the time of receipt will be taken to be the time (as determined by the timestamp applied to the message by the CREST Applications Host) from which the issuer's agent is able to retrieve the message by enquiry to CREST in the manner prescribed by CREST.

7. CREST members and, where applicable, their CREST sponsors or voting service providers should note that EUI does not make available special procedures in CREST for any particular messages. Normal system timings and limitations will therefore apply in relation to the input of CREST Proxy Instructions. It is the responsibility of the CREST member concerned to take (or, if the CREST member is a CREST Personal Member or Sponsored Member or has appointed a voting service provider(s), to procure that his CREST sponsor or voting service provider(s) take(s)) such action as shall be necessary to ensure that a message is transmitted by the CREST system by any particular time. In this connection, CREST members and, where applicable, their CREST sponsors or voting service providers are referred, in particular, to those sections of the CREST Manual concerning practical limitations of the CREST system and timings.

8. The Company may treat as invalid a CREST Proxy Instruction in the circumstances set out in Regulation 35(5)(a) of the Companies Act 1990 (Uncertificated Securities) Regulations 1996 (as amended).

9. To appoint a proxy electronically log onto the website of the Registrars, Computershare Investor Services (Ireland) Limited: www.eproxyappointment.com. Full details of the procedures are set out on the Form of Proxy.

10. The Company has included on the Form of Proxy a 'Vote Withheld' option in order for members to abstain on any particular resolution. However, it should be noted that a 'Vote Withheld' is not a vote in law and will not be counted in the calculation of the proportion of votes 'For' or 'Against' the particular resolution.

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