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If you have sold or otherwise transferred all of your EnCore Shares, you should send this document and the accompanying documents as soon as possible to the purchaser or transferee or to the stockbroker, bank or other agent through whom the sale or transfer was effected for delivery to the purchaser or the transferee. However, the distribution of this document and any accompanying documents into jurisdictions other than the United Kingdom may be restricted by law and therefore persons into whose possession this document and any accompanying documents come should inform themselves about and observe any such restrictions. Any failure to comply with these restrictions may constitute a violation of the securities laws of any such jurisdiction. In particular, such documents should not be distributed in, forwarded to or transmitted in or into any Restricted Jurisdiction. If you have sold or otherwise transferred part of your holding of EnCore Shares, please consult the bank, stockbroker or other agent through whom the sale or transfer was effected.

A copy of this document, which comprises a prospectus relating to the New Premier Shares, prepared in accordance with the Prospectus Rules made under Section 84 of FSMA and approved by the Financial Services Authority (the "FSA") under Section 87A of FSMA, has been filed with the FSA and has been made available to the public as required by Rule 3.2 of the Prospectus Rules.

You should read the whole of this document and all documents incorporated into it by reference in their entirety. In particular, you should take account of the section entitled Risk Factors on pages 8 to 14 of this document for a discussion of the risks that might affect the value of your shareholding in Premier.

Investors should only rely on the information contained in this document and contained in any documents incorporated by reference into this document. No person has been authorised to give any information or make any representations other than those contained in this document and any document incorporated by reference and, if given or made, such information or representation must not be relied upon as having been so authorised by Premier or its financial adviser. Premier will comply with its obligation to publish supplementary prospectuses containing further updated information required by law or by any regulatory authority but assumes no further obligation to publish additional information.



(Incorporated in Scotland with Registered No. SC234781)

Proposed issue of up to 65,212,513 new ordinary shares in Premier to EnCore Shareholders in connection with the proposed acquisition of EnCore by means of a scheme of arrangement under Part 26 of the Companies Act 2006 and application for admission of up to 65,212,513 ordinary shares in the Company to the Official List and to trading on the London Stock Exchange's market for listed securities

Application will be made to the FSA for the New Premier Shares to be admitted to the Official List and to the London Stock Exchange for the New Premier Shares to be admitted to trading on the London Stock Exchange's main market for listed securities. It is expected that Admission of the New Premier Shares will become effective, and that dealings in the New Premier Shares will commence, on the Effective Date which, subject to the satisfaction of certain conditions, including the sanction of the Scheme by the Court, is expected to be on 16 January 2012.

THE CONTENTS OF THIS DOCUMENT OR ANY SUBSEQUENT COMMUNICATION FROM PREMIER OR RBC CAPITAL MARKETS OR ANY OF THEIR RESPECTIVE AFFILIATES, OFFICERS, DIRECTORS, EMPLOYEES OR AGENTS ARE NOT TO BE CONSTRUED AS LEGAL, FINANCIAL OR TAX ADVICE. EACH PROSPECTIVE INVESTOR SHOULD CONSULT HIS, HER OR ITS OWN SOLICITOR, INDEPENDENT FINANCIAL ADVISER OR TAX ADVISER FOR LEGAL, FINANCIAL OR TAX ADVICE.

NONE OF THE COMPANY, RBC CAPITAL MARKETS OR THEIR RESPECTIVE REPRESENTATIVES IS MAKING ANY REPRESENTATION TO ANY OFFEREE OR PURCHASER OF THE NEW PREMIER SHARES OFFERED HEREBY REGARDING THE LEGALITY OF AN INVESTMENT BY SUCH OFFEREE OR PURCHASER UNDER APPROPRIATE INVESTMENT OR SIMILAR LAWS. EACH PROSPECTIVE INVESTOR SHOULD CONSULT WITH HIS, HER OR ITS OWN ADVISERS AS TO THE LEGAL, TAX, BUSINESS, FINANCIAL AND RELATED ASPECTS OF PURCHASE OR SUBSCRIPTION OF THE NEW PREMIER SHARES.

THIS DOCUMENT DOES NOT CONSTITUTE AN OFFER OF AND MAY NOT BE USED FOR THE PURPOSES OF, AN OFFER TO SELL OR AN INVITATION, OR THE SOLICITATION OF AN OFFER TO SUBSCRIBE FOR OR BUY, ANY PREMIER SHARES TO ANY PERSON IN ANY JURISDICTION: (i) IN WHICH SUCH OFFER OR INVITATION IS NOT AUTHORISED; (ii) IN WHICH THE PERSON MAKING SUCH OFFER OR INVITATION IS NOT QUALIFIED TO DO SO; OR (iii) IN WHICH OR TO WHOM IT IS UNLAWFUL TO MAKE SUCH OFFER OR SOLICITATION IN SUCH JURISDICTION AND IS NOT FOR DISTRIBUTION IN OR INTO ANY RESTRICTED JURISDICTION, EXCEPT AS DETERMINED BY THE COMPANY IN ITS SOLE DISCRETION AND PURSUANT TO APPLICABLE LAWS.

Dated: 18 November 2011.

This document and any accompanying documents are not being made available to EnCore Shareholders with registered addresses in any Restricted Jurisdiction and may not be treated as an invitation to subscribe for any New Premier Shares by any person resident or located in such jurisdictions or any other Restricted Jurisdiction. The New Premier Shares have not been, and will not be, registered under the applicable securities laws of any Restricted Jurisdiction. Accordingly, the New Premier Shares may not be offered, sold, delivered or transferred, directly or indirectly, in or into any Restricted Jurisdiction or to or for the account or benefit of any national, resident or citizen of any Restricted Jurisdiction.

Any persons (including, without limitation, custodians, nominees and trustees) who have a contractual or other legal obligation to forward this document or any accompanying documents to the United States or any Restricted Jurisdiction should seek appropriate advice before taking any action.

RBC Europe Limited, trading as RBC Capital Markets, which is authorised and regulated in the United Kingdom by the FSA, is acting for Premier and no-one else in connection with the Acquisition and Admission and will not regard any other person (whether or not a recipient of this document) as its client in relation to the Acquisition or Admission and will not be responsible for providing the protections afforded to its clients nor for giving advice in relation to the Acquisition or Admission or any acquisition or arrangement referred to, or information contained in, this document.

UNITED STATES

The New Premier Shares have not been, will not be, and are not required to be, registered with the SEC under the US Securities Act in reliance upon the exemption from registration requirements of the US Securities Act provided by Section 3(a)(10) of that Act. The New Premier Shares have not been, and will not be, registered under the securities laws of any state or jurisdiction of the United States and, accordingly, will only be issued to the extent that exemptions from the registration or qualification requirements of state “blue sky” securities laws are available. **Neither the SEC nor any other US federal or state securities commission or regulatory authority has approved or disapproved the New Premier Shares or passed upon the fairness or merits of such securities or upon the accuracy or adequacy of the information contained in this document. Any representation to the contrary is a criminal offence in the United States.** Reference should also be made to paragraph 11 of Part VI “Overseas Shareholders” of this document.

This document is published in connection with the Admission of New Premier Shares and does not constitute an offer to any other person or to the public generally to subscribe for or otherwise acquire the New Premier Shares. A separate Scheme Document in connection with the Scheme will be available to EnCore Shareholders.

The Scheme involves the securities of an issuer incorporated under the laws of Scotland, and this document is subject to UK disclosure requirements, which are different from those of the United States. The financial information included in this document has been prepared in accordance with accounting standards applicable in the United Kingdom that may not be comparable with the financial statements of US companies. US generally accepted accounting principles (“US GAAP”) differ in certain significant respects from each of UK generally accepted accounting principles (“UK GAAP”) and International Financial Reporting Standards (“IFRS”). None of the financial information in this document has been audited in accordance with auditing standards generally accepted in the United States or the auditing standards of the Public Company Accounting Oversight Board (United States).

Premier is a public limited company incorporated under the laws of Scotland. The Premier Directors and the executive officers of Premier are citizens or residents of countries other than the United States. Substantially all of the assets of such persons and a significant proportion of the assets of the Premier Group are located outside the United States. As a result, it may not be possible for investors to effect service of process within the United States upon such persons or Premier, or to enforce against them judgments of US courts, including judgments predicated upon civil liabilities under the securities laws of the United States or any state or territory within the United States. There is substantial doubt as to the enforceability in the United Kingdom in original actions or in actions for enforcement of judgments of US courts, based on the civil liability provisions of US federal securities laws.

Notice to New Hampshire Residents

Neither the fact that a registration statement or an application for a licence has been filed under Chapter 42 I-B of the New Hampshire Revised Statutes with the State of New Hampshire nor the fact that a security is effectively registered or a person is licensed in the State of New Hampshire constitutes a finding by the Secretary of State of New Hampshire that any document filed under RSA 421-B is true, complete and not misleading. Neither any such fact nor the fact that an exemption or exception is available for a security or a transaction means that the Secretary of State has passed in any way upon the merits or qualifications of, or recommended or given approval to, any person, security or transaction. It is unlawful to make, or cause to be made to any prospective purchaser, customer or client, any representation inconsistent with the provisions of this paragraph.

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SUMMARY

THE FOLLOWING SUMMARY INFORMATION SHOULD BE READ AS AN INTRODUCTION TO THIS PROSPECTUS. ANY DECISION TO INVEST IN PREMIER SHARES SHOULD BE BASED ON CONSIDERATION OF THIS DOCUMENT AS A WHOLE.

Where a claim relating to information contained in this document is brought before a court, a claimant investor might, under the national legislation of the EEA States, have to bear the costs of translating this document before legal proceedings are initiated. Civil liability attaches to those persons who are responsible for this summary, including any translation of this summary, but only if this summary is misleading, inaccurate or inconsistent when read together with the other parts of this document.

1. Introduction

On 5 October 2011, the Premier Board and the EnCore Board announced that they had reached agreement on the terms of a recommended acquisition by Premier (or one of its wholly owned subsidiaries) of the entire issued and to be issued share capital of EnCore.

It is intended that the Acquisition will be implemented by way of a scheme of arrangement under Part 26 of the Companies Act 2006, although Premier reserves the right in its sole discretion (subject, if required, to Panel agreement) to implement the Acquisition by making an Offer.

This document is published in connection with the Admission of New Premier Shares pursuant to the Acquisition.

2. Information on Premier and EnCore

Premier is an oil and gas exploration and production company. It is the Premier Group's ultimate parent company. The Premier Group has interests in eight countries around the world with significant operations in three core areas, the North Sea (UK and Norway), South East Asia (Indonesia and Vietnam) and the Middle East/Africa/Pakistan. It has proven and probable reserves and 2C contingent resources of 550 mmbœ and produced an average of 36,700 boepd in the first half of 2011.

EnCore is an AIM listed oil and gas exploration and production company focussed on the offshore UK Continental Shelf where its portfolio of assets includes interests in the Catcher discovery. EnCore also has a holding of just under 30 per cent. in Egdon Resources plc, an AIM listed exploration and production company focussed on onshore assets with interests in the UK and Europe.

3. Summary operating and financial information on Premier

The operating and financial information set out below has been extracted from Premier's statutory accounts for the three years ended 31 December 2010, which are incorporated by reference into this document. The information set out below does not constitute statutory accounts for any company within the meaning of Section 435 of the Companies Act 2006.

2P Reserves (mmbœ)			Production (kboepd)			Profit after tax (US\$m)			Operating cash flow (US\$m)		
2010	2009	2008	2010	2009	2008	2010	2009	2008	2010	2009	2008
261	255	228	42.8	44.2	36.5	129.8	113.0	98.3	436.0	347.7	352.3

4. Current trading and prospects of Premier

Premier generated record revenues and profits in the year ended 31 December 2010 and significant progress in respect of production growth targets has been made in 2011. Premier is targeting a run rate of 75,000 boepd for end of 2012. Recent highlights have been achieving first production in October 2011 from the Chim Sáo oil field in Vietnam and from the Gajah Baru gas field in Indonesia. These new fields are expected to boost production to 60,000 boepd by the end of 2011. First oil from the Huntington field is expected in September 2012. The recommended acquisition of EnCore will support the advancement of the important Catcher project and Premier expects that its portfolio of development projects approaching project sanction will contribute towards an anticipated 100,000 boepd of production in the medium term.

Premier continues to have good access to debt capital markets to finance investments and, from its rising cash flows, is able to fund a growing exploration programme. As a result, the Premier Directors are confident of both replacing reserves and adding to Premier's resource base, thereby underpinning future growth.

5. Dividend Policy

Premier's policy is to reward Premier Shareholders principally through share price growth and to utilise cash flow within the business.

6. Summary of the Terms of the Acquisition

Under the terms of the Scheme, which will be subject to the Conditions and to the further terms set out in the Scheme Document, Scheme Shareholders will be entitled to receive:

for each Scheme Share

70 pence in cash

A Share Alternative is being made available to Scheme Shareholders (other than Restricted Overseas Shareholders) enabling them to elect to receive New Premier Shares instead of all or part of the cash consideration to which they would otherwise be entitled under the Acquisition on the basis of 0.2067 New Premier Shares for each EnCore Share held. Based on a price of 367.30 pence per Premier Share (being the Closing Price on 16 November 2011, the last practicable date prior to the publication of this document), the Share Alternative values each EnCore Share at 75.92 pence.

Immediately following the Effective Date, assuming the maximum number of 65,212,513 New Premier Shares are issued pursuant to the Acquisition and that no Premier Shares are issued or repurchased in the period from the publication of this document to the Effective Date, it is expected that EnCore Shareholders will hold New Premier Shares representing approximately 12.2 per cent. of the enlarged issued share capital of Premier.

The Acquisition values EnCore's entire issued and to be issued share capital at approximately £221 million (approximately US\$348 million).

7. Conditions to the Acquisition

The Acquisition is conditional upon, amongst other things:

- approval of the Scheme and related resolutions by the requisite majorities of EnCore Shareholders at the Scheme Meeting and the EnCore General Meeting;
- the UK Listing Authority having acknowledged to Premier or its agent (and such acknowledgement not having been withdrawn) that the application for the admission of the New Premier Shares to the Official List with a premium listing has been approved and (after satisfaction of any conditions to which such approval is expressed to be subject ("listing conditions")) will become effective as soon as a dealing notice has been issued by the FSA and any listing conditions having been satisfied, and the London Stock Exchange having acknowledged to Premier or its agent (and such acknowledgement not having been withdrawn) that the New Premier Shares will be admitted to trading;
- the Secretary of State for Energy and Climate Change not having indicated an intention to (a) revoke or recommend the revocation of any material exploration or production licence held by the EnCore Group, or (b) require a further change of control of any member of the EnCore Group as a result of the Acquisition;
- the sanction of the Scheme and confirmation of the associated Capital Reduction by the Court at the Court Hearings; and
- the Scheme becoming Effective by a Long Stop Date of 28 February 2012, unless extended with the agreement of Premier and EnCore.

8. Risk factors

A number of risk factors affect the operating results, financial condition and prospects of the Premier Group and, following the Acquisition, the Enlarged Group. These are summarised below.

Risks relating to the Premier Group and the Enlarged Group

- Failure to access new oil and gas reserves could slow oil and gas production growth and replacement of reserves.
- The estimation of oil and gas reserves and their anticipated production involves subjective judgments and determinations, and may change based on new information from production or drilling activities or changes in economic factors.
- Failure to successfully integrate a strategic business acquisition (such as the Acquisition) may adversely affect the business of the Enlarged Group.
- Premier operates in a number of different countries throughout the world and is subject to risks from changes in currency values and exchange controls.
- Intense competition for exploration and production licences and access to exploration acreage, gas markets, oil services and other resources may lead to increased costs and reduced growth opportunities.
- The scarcity and potentially high costs of equipment and services sourced from Third Party providers could delay, restrict or lower the profitability and viability of Premier's or the Enlarged Group's projects.
- The successful continuation of existing field operations involves risks including blowouts, oil spills, explosions, geological uncertainties, equipment damage or failure and technical, fiscal, regulatory, political and other condition, which may give rise to significant liabilities and otherwise adversely affect the business of the Enlarged Group.
- The explosion and sinking in April 2010 of the *Deepwater Horizon* oil rig in the Macondo exploration well may have increased certain of the risks faced by those drilling for oil in deep water regions, including increased potential liability thresholds under environmental laws and higher insurance, operating and capital costs.
- Failure to comply with potentially complex and stringent health and safety laws and regulations may give rise to significant liabilities.
- Obtaining exploration, development or production licences and permits may become more difficult or be the subject of delay by reason of governmental or environmental consultation, which may lead to increased costs and delayed or reduced exploration and production activity.
- Real or perceived failure to adhere to Premier's business principles could harm Premier's or the Enlarged Group's reputation, which, in turn, could impact licences, financing and access to new opportunities.
- Loss of personnel to competitors or inability to attract quality human resources could affect operational performance and growth strategy.
- Fluctuation of hydrocarbon prices may affect Premier's and, following the Acquisition, the Enlarged Group's financial position.
- Premier and the Enlarged Group may require new financing to fund future exploration and development plans, which may or may not be available on favourable terms.
- Premier and, following the Acquisition, the Enlarged Group may be adversely affected by political, economic, legal, regulatory or social changes in certain countries, including by the significant influence of certain governments over the oil and gas industry.
- The ability of Premier and, following the Acquisition, the Enlarged Group to influence their partners will sometimes be limited due to their percentage ownership in non-operated development and production operations, which may result in inefficiencies or delay.
- Government action concerning the economy, such as a change in oil or gas pricing policy or taxation rules or practice or renegotiation or nullification of existing concession contracts, could have a material adverse effect on operations and profits.
- There can be no assurance that the proceeds of insurance applicable to covered risks will be adequate to cover uninsured hazards.

- Premier has, and the Enlarged Group will have, limited control over whether or not necessary governmental approvals or licences are granted or renewed, or the tax regime to which they will be subject, which may limit or delay exploration and development of oil and gas fields.
- There can be no assurance that Premier and 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 express obligation to do so.
- Any premature termination, suspension or withdrawal of licences, or failure to extend such licences which will expire before the productive life of the licensed fields, may have a material adverse effect on Premier's or the Enlarged Group's reserves and prospects.
- Macroeconomic risks, such as the global economic slowdown, could result in an adverse impact on Premier's and the Enlarged Group's financial condition.

Risk relating to the Acquisition

- The ability of the management team to run the business of the Enlarged Group effectively may be adversely affected during implementation of the Acquisition, which may take longer or be more costly than anticipated.

Risks relating to Premier Shares

- The market price of Premier Shares could be volatile and subject to fluctuations due to changes in market sentiment, speculation, operating results and business developments.
- Prospective investors should be aware that the value of an investment in Premier may go down as well as up.
- The ability of Premier to pay dividends on Premier Shares depends on its profitability, the extent to which it has sufficient distributable reserves and receipt by Premier of dividends and other distributions from subsidiaries.
- In the future Premier may decide to offer additional Premier Shares, which could have an adverse effect on the market price of Premier Shares as a whole.
- The information contained in Part VII of this document relating to taxation may be subject to legislative change.

RISK FACTORS

You should carefully consider the risks and uncertainties described below, together with all other information in this document and the information incorporated by reference into this document, before making any investment decision.

A number of factors affect the operating results, financial condition and prospects of the Premier Group and, following the Effective Date, will affect the Enlarged Group. This section describes certain risk factors considered by the Premier Directors to be material in relation to the Premier Group. These risks will, following the Effective Date, also be relevant to the Enlarged Group.

However, the risk factors described below should not be regarded as a complete and comprehensive statement of all potential risks and uncertainties. Additional risks and uncertainties that are not presently known to the Premier Directors, or which they currently deem immaterial, may also have an adverse effect on the Premier Group's and, following completion of the Acquisition, the Enlarged Group's operating results, financial condition or prospects. If any such risks were to materialise, the business, financial condition, results of operations and prospects of the Premier Group and/or the Enlarged Group could be materially adversely affected and the value of Premier Shares could decline and investors could lose all or part of their investment in Premier Shares.

The information given is as of the date of this document and, except as required by the UKLA, the London Stock Exchange, the Listing Rules, the Prospectus Rules or any other applicable law, will not be updated. Any forward looking statements are made subject to the reservations specified under "Forward-Looking Statements" on page 15 of this document.

Risks relating to the Premier Group and, following the Acquisition, the Enlarged Group

1. Reserves replacement

Future oil and gas production will depend on Premier's and, following the Acquisition, the Enlarged Group's access to new reserves through exploration, negotiations with governments and other owners of known reserves, and acquisitions. Failures in exploration or in identifying and finalising transactions to access potential reserves could slow Premier's or the Enlarged Group's oil and gas production growth and replacement of reserves. This, in turn, could have an adverse effect on the turnover and profits of Premier or the Enlarged Group.

In addition, the results of appraisal of discoveries are uncertain and may involve unprofitable efforts, not only from dry wells, but also from wells that are productive but uneconomic to develop. Appraisal and development activities may be subject to delays in obtaining governmental approvals or consents, shut-ins of connected wells, insufficient storage or transportation capacity or other geological and mechanical conditions all of which may variously increase Premier's and, following the Acquisition, the Enlarged Group's costs of operations.

Exploration activities are capital intensive and inherently uncertain in their outcome. There is therefore a risk that Premier and, following the Acquisition, the Enlarged Group will undertake exploration activities and incur significant costs in so doing with no assurance that such expenditure will result in the discovery of hydrocarbons, whether or not in commercially viable quantities. If exploration activities prove unsuccessful over a prolonged period of time, Premier or the Enlarged Group may have to reduce the number of its exploration programmes, which could adversely impact on Premier's or the Enlarged Group's oil and gas production growth and replacement of reserves. This, in turn, could have an adverse effect on the turnover and profits of Premier or the Enlarged Group.

2. Estimation of reserves, resources and production profiles

The estimation of oil and gas reserves, and their anticipated production profiles, involves subjective judgments and determinations based on available geological, technical, contractual and economic information. They are not exact determinations. In addition, these judgments may change based on new information from production or drilling activities or changes in economic factors, as well as from developments such as acquisitions and dispositions, new discoveries and extensions of existing fields and the application of improved recovery techniques. Published reserve estimates are also subject to correction for errors in the application of published rules and guidance.

The reserves, resources and production profile data contained in this document are estimates only and should not be construed as representing exact quantities. They are based on production data,

prices, costs, ownership, geophysical, geological and engineering data, and other information assembled by Premier. The estimates may prove to be incorrect and potential investors should not place undue reliance on the forward-looking statements contained in this document concerning Premier's or the Enlarged Group's reserves and resources or production levels.

If the assumptions upon which the estimates of Premier's or the Enlarged Group's hydrocarbon reserves, resources or production profiles have been based prove to be incorrect, Premier and, following the Acquisition, the Enlarged Group may be unable to recover and produce the estimated levels or quality of hydrocarbons set out in this document and Premier's or the Enlarged Group's business, prospects, financial condition or results of operations could be materially adversely affected.

3. Business acquisitions – integration and other issues

Part of Premier's strategy is to increase oil and gas reserves through strategic business acquisitions. Risks commonly associated with acquisitions of companies or businesses include the difficulty of integrating the operations and personnel of the acquired business, problems with minority shareholders in acquired companies, the potential disruption of Premier's or the Enlarged Group's own business, the possibility that indemnification agreements with the sellers may be unenforceable or insufficient to cover potential liabilities and difficulties arising out of integration. Furthermore, the value of any business Premier or the Enlarged Group acquires or invests in may be less than the amount it pays. (These risks may also apply to the Acquisition itself).

4. Currency fluctuations and exchange controls

Premier operates in a number of different countries and territories throughout the world. Premier is, and following the Acquisition the Enlarged Group will be, subject to risks from changes in currency values and exchange controls. Changes in currency values and exchange controls could have an adverse effect on Premier's or the Enlarged Group's results of operations and financial position.

5. Competition

Premier operates and, following the Acquisition, the Enlarged Group will operate, in a very challenging business environment and competition for access to exploration acreage, gas markets, oil services and rigs, technology and processes, and human resources is intense. Competitors include companies with, in many cases, greater financial resources, local contacts, staff and facilities than those of Premier or the Enlarged Group. Competition for exploration and production licences as well as other regional investment or acquisition opportunities may increase in the future. This may lead to increased costs in the carrying on of Premier's or the Enlarged Group's activities and reduced available growth opportunities. Any failure by Premier or the Enlarged Group to compete effectively could adversely affect Premier's or the Enlarged Group's operating results and financial condition.

6. Third Party contractors and providers of capital equipment

In particular, Premier has and, following the Acquisition, the Enlarged Group will have, an interest in contracts or leases, services and capital equipment from Third Party providers. Such equipment and services can be scarce and may not be readily available at the times and places required. In addition, 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. The scarcity of such equipment and services, as well as their potentially high costs, could delay, restrict or lower the profitability and viability of Premier's or the Enlarged Group's projects and therefore have a material adverse effect on Premier's or the Enlarged Group's business.

7. Production

The delivery of Premier's production plans depends, and following the Acquisition, the delivery of the Enlarged Group's production plans will depend, on the successful continuation of existing field production operations and the development of key projects. Both of these involve 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. Such potential obstacles may impair Premier's or the Enlarged Group's continuation of existing field production and delivery of key projects and, in turn, Premier's or the Enlarged Group's operational performance and financial position (including the financial impact from failure to fulfil contractual commitments related to project delivery).

Premier and, following the Acquisition, the Enlarged Group, may face interruptions or delays in the availability of infrastructure, including pipelines and storage tanks, on which exploration and production activities are dependent. The production performance of the reservoirs and wells may also be different to that forecast due to normal geological or mechanical uncertainties. Such interruptions, delays or performance differences could result in disruptions or changes to Premier's or the Enlarged Group's existing production and projects, lower production and increased costs, and may have an adverse effect on Premier's or the Enlarged Group's profitability.

Furthermore, the explosion and sinking in April 2010 of the *Deepwater Horizon* oil rig during operations on the Macondo exploration well in the Gulf of Mexico, and the resulting oil spill, may have increased certain of the risks faced by those drilling for oil in deepwater regions, including the following: increased industry standards, governmental regulation and enforcement of our and our industry's operations in a number of areas, including health and safety, financial responsibility, environmental, licensing, taxation, equipment specifications and training requirements; increased difficulty or delays in obtaining rights to drill wells in deepwater regions; higher operating costs; higher insurance costs and increased potential liability thresholds under environmental laws; decreased access to appropriate equipment, personnel and infrastructure in a timely manner; higher capital costs as a result of any increase to the risks Premier or the oil and gas industry face; and less favourable investor perception of the risk-adjusted benefits of deepwater offshore drilling. The occurrence of any of these factors, or the continuation thereof, could have a material adverse effect on Premier's or the Enlarged Group's business, financial position or future results of operations.

8. Health, Safety, Environment and Security ("HSES")

The range of Premier's and, following the Acquisition, the Enlarged Group's operated and joint venture production operations globally means that Premier's HSES risks cover, and the Enlarged Group's HSES risks will cover, a wide spectrum. These risks include 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 consequences of such risks materialising can be injuries, loss of life, environmental harm and disruption to business activities. Depending on cause and severity, the materialisation of such risks may affect Premier's or the Enlarged Group's reputation, operational performance and financial position.

In addition, failure by Premier and, following the Acquisition, the Enlarged Group, to comply with applicable legal requirements or recognised international standards may give rise to significant liabilities. HSES laws and regulations may over time become more complex and stringent or the subject of increasingly strict interpretation or enforcement. The terms of licences may include more stringent HSES requirements. 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 as well as to increased costs.

9. Reputation

It is important for maintaining Premier's and, following the Acquisition, the Enlarged Group's licences to operate and ability to secure new resources that Premier or the Enlarged Group should maintain strong and positive relationships with the governments and communities in the countries where its business is conducted. Premier's business principles govern and, following the Acquisition, the Enlarged Group's business principles will govern how Premier and the Enlarged Group conduct their affairs. Failure – real or perceived – to follow these principles, or any of the risk factors described in this document materialising, could harm Premier's or the Enlarged Group's reputation, which could, in turn, impact Premier's or the Enlarged Group's licence to operate, financing and access to new opportunities.

10. Human resources

Premier's key human resources are and, following the Acquisition, the Enlarged Group's key human resources will be essential for the successful delivery of projects and continuing operations. Loss of personnel to competitors or inability to attract quality human resources could affect Premier's or the Enlarged Group's operational performance and growth strategy.

11. Hydrocarbon prices

Historically, hydrocarbon prices have been subject to large fluctuations in response to a variety of factors beyond Premier's or EnCore's control. Factors that influence these fluctuations include operational issues, natural disasters, weather, political instability or conflicts, economic conditions or actions by major oil-exporting countries. Price fluctuations can affect Premier's business assumptions, investment decisions and financial position and, following the Acquisition, could affect the Enlarged Group's business assumptions, investment decisions and financial position. In particular, lower hydrocarbon prices may reduce the economic viability of Premier's or the Enlarged Group's projects, result in a reduction in revenues or net income, impair Premier's or the Enlarged Group's ability to make planned expenditures and could materially adversely affect Premier's or the Enlarged Group's business, prospects, financial condition and results of operations. Lower hydrocarbon prices would also reduce the extent to which the Enlarged Group can benefit from the capital allowances which will be made available pursuant to the Acquisition.

12. Current and future financing

Premier and, following the Acquisition, the Enlarged Group may require new financing to refinance certain of its existing facilities which will need to be refinanced in 2015. As at 30 June 2011, these facilities had an aggregate principal amount of approximately £879,432,145. Premier and, following the Acquisition, the Enlarged Group may also require additional financing to fund future exploration and development plans to which Premier is not currently committed.

The financing required for the purposes described above may not be available or, if available, may not be available on favourable terms. The ability of Premier or the Enlarged Group to arrange such financing in the future will depend in part upon the prevailing capital market conditions, as well as the business performance of Premier or the Enlarged Group. If adequate funds are not available, or are not available on acceptable terms, Premier or the Enlarged Group may not be able to take advantage of exploration and/or development opportunities.

13. Political, economic, legal, regulatory and social uncertainties

Premier operates and, following the Acquisition, the Enlarged Group will operate in some countries where political, economic and social transition is taking place. Specifically, Premier has interests in Egypt, Indonesia, Kenya, Mauritania, Norway, Pakistan, the UK and Vietnam, and has pre-qualified for a licensing round in Iraq. In each of these countries, changes in politics, laws and regulations could affect Premier's and the Enlarged Group's operations and earnings. Such circumstances include forced divestment of assets; limits on production; import and export restrictions; international conflicts including war; civil unrest and local security concerns that threaten the safe operation of Premier's or the Enlarged Group's facilities; price controls, tax increases and other retroactive tax claims; expropriation (including "creeping" expropriation) and nationalisation of property; terrorism; outbreaks of infectious diseases; cancellation of contract rights; and environmental regulations. It is difficult to predict the timing or severity of these occurrences or their potential effect. If such risks materialise they could affect the employees, reputation, operational performance and financial position of Premier or the Enlarged Group.

Those countries in Africa, the Middle East and South East Asia in which Premier has, and the Enlarged Group will have, operations have transportation, telecommunications and financial services infrastructures that may present logistical challenges not associated with doing business in more developed countries.

Premier and the Enlarged Group may have difficulty ascertaining its legal obligations and enforcing any rights which it may have, not only in developing countries, but also in Norway and the UK. Certain governments have in the past expropriated or nationalised property of hydrocarbon production companies operating within their jurisdictions. Sovereign or regional governments could require Premier or the Enlarged Group to grant to them larger shares of hydrocarbons or revenues than previously agreed to. Furthermore, it may be expensive and logistically burdensome to discontinue hydrocarbon exploration and/or production operations in a particular country should

economic, political, physical or other conditions subsequently deteriorate. All of these factors could materially adversely affect Premier's or the Enlarged Group's business, results of operations, financial condition or prospects.

Premier and, following the Acquisition, the Enlarged Group, may in the future acquire interests in other developing and developed countries which may be subject to or affected by similar risks to those set out above.

14. Joint ventures and partners

Inherently, oil and gas operations globally are conducted in a joint venture environment. Many of Premier's and EnCore's major projects are operated by a partner in the relevant joint venture. The ability of Premier and, following the Acquisition, the Enlarged Group, to influence their partners will sometimes be limited due to their percentage ownership in non-operated development and production operations. Non-alignment on various strategic decisions in joint ventures may result in operational or production inefficiencies or delay.

15. Governmental involvement in the oil and gas industry

The governments of countries in which Premier currently operates or may operate and, following the Acquisition, the Enlarged Group will or may operate, have exercised and continue to exercise significant influence over many aspects of their respective economies, including the oil and gas industry. Any government action concerning the economy, including the oil and gas industry (such as a change in oil or gas pricing policy or taxation rules or practice, or renegotiation or nullification of existing concession contracts), could have a material adverse effect on Premier or the Enlarged Group. For example, in the UK the Finance Act 2011 increased the supplementary charge payable in respect of profits from oil and gas production in the UK or on the UKCS from 20 per cent. to 32 per cent. Furthermore, there can be no assurance that these governments will not postpone or review projects or will not make any changes to laws, rules, regulations or policies, in each case, which could materially adversely affect Premier's or the Enlarged Group's financial position, results of operations or prospects.

16. Uninsured hazards

Premier and, following the Acquisition, the Enlarged Group may be subject to substantial liability claims due to the inherently hazardous nature of their business or for acts and omissions of subcontractors, operators or joint venture partners. Any indemnities Premier or the Enlarged Group may receive from such parties may be difficult to enforce if such sub-contractors, operators or joint venture partners lack adequate resources. There can be no assurance that the proceeds of insurance applicable to covered risks will be adequate to cover expenses relating to losses or liabilities. Accordingly, although there is a low probability of this risk materialising, Premier or the Enlarged Group may suffer material losses from uninsurable or uninsured risks or insufficient insurance coverage.

17. Licensing and other regulatory requirements

Countries in which Premier currently operates or may operate and, following the Acquisition, the Enlarged Group will or may operate, are subject to licences, regulations and approvals of governmental authorities, including those relating to the exploration, development, operation, production, marketing, pricing, transportation and storage of oil and gas, taxation, environmental, and health and safety matters.

Premier has, and the Enlarged Group will have, limited control over whether or not necessary approvals or licences (or renewals thereof) are granted, the timing of obtaining (or renewing) such licences or approvals, the terms on which they are granted or the tax regime to which Premier or the Enlarged Group or the assets in which Premier or the Enlarged Group has interests will be subject. As a result, Premier or the Enlarged Group may have limited control over the nature and timing of exploration and development of oil and gas fields in which Premier or the Enlarged Group has or seeks interests. There can be no assurance that Premier or 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 express obligation to do so, particularly in case of future licence renewals.

18. Licence withdrawal and renewal

It is possible that in the future Premier and, following the Acquisition, the Enlarged Group, may be unable or unwilling to comply with the terms or requirements of a licence in circumstances that entitle the relevant authority to suspend or withdraw the terms of such licence. Moreover, some of the exploration and production licences which are held by Premier or will be held by the Enlarged Group expire or may expire before the end of what Premier estimates or the Enlarged Group may estimate to be the productive life of the licensed fields. There can be no assurance that extensions will be granted in relation to such licences. Any failure to receive such extensions or any premature termination, suspension or withdrawal of licences may have a material adverse effect on Premier's or the Enlarged Group's reserves, business, results of operations and prospects.

19. Macroeconomic risks

One of the principal uncertainties for Premier and the Enlarged Group at present is the extent to which the global economic slowdown currently being experienced may feed through into Premier's and, following the Acquisition, the Enlarged Group's major operations, and the timing of that impact. The links between economic activities in different markets and sectors are complex and depend not only on direct drivers such as the balance of trade and investment between countries, but also on domestic monetary, fiscal and other policy responses to address macroeconomic conditions.

Risk relating to the Acquisition

The following risk is in addition to risks relating to the EnCore Group which would be assumed by the Enlarged Group on completion of the Acquisition.

20. Difficulties in integrating the Acquisition

The integration process following completion of the Acquisition is not expected to be complex. Notwithstanding this, Premier has made thorough plans in order to ensure the smooth and efficient integration of EnCore's operations and this process is expected to commence immediately following completion of the Acquisition. However successful it may be, implementation of this programme will require management time and thus may affect or impair the ability of the management team of the Enlarged Group to pursue other new business ventures during the period of implementation. If the integration process proves to be more difficult than anticipated, or if the integration takes longer than expected or if difficulties arise relating to the integration of which the Premier Directors are not yet aware, then the operations of the Enlarged Group may be adversely affected. In addition, Premier may not have or be able to retain personnel with the appropriate skill set for the tasks associated with the integration programme. This could adversely affect the implementation of Premier's business plans which, in turn, could affect the profitability of the Enlarged Group and impact negatively on the price of Premier Shares. Furthermore, there can be no assurance that the implementation cost will not exceed the cost estimated by Premier.

Premier will acquire a greater interest in and become operator of the Catcher development, which will require the establishment of an enlarged project execution team. Premier may not be able to attract or retain staff with the necessary skills for the execution of this project and, if the project proves more complex than expected, additional resources will be required to achieve project execution.

Risks relating to Premier Shares

21. Possible volatility of the price of Premier Shares

The market price of Premier Shares could be volatile and subject to significant fluctuations due to a variety of factors, including changes in sentiment in the market regarding Premier Shares (or securities similar to them), any regulatory changes affecting Premier's and, following the Acquisition, the Enlarged Group's operations, variations in Premier's and, following the Acquisition, the Enlarged Group's operating results, business developments of Premier and, following the Acquisition, the Enlarged Group or its competitors, the operating and share price performance of other companies in the industries and markets in which Premier and, following the Acquisition, the Enlarged Group operates, or speculation about Premier's and, following the Acquisition, the Enlarged Group's business in the press, media or investment community. Stock markets have from time to time experienced significant price and volume fluctuations that have affected market prices for securities and which may be unrelated to Premier's and, following the Acquisition, the Enlarged

Group's operating performance or prospects. Investors should not rely on Premier's and EnCore's results to date as an indication of future performance. Furthermore, Premier's and, following the Acquisition, the Enlarged Group's operating results and prospects from time to time may be below the expectations of market analysts and investors. Any of these events could result in a decline in the market price of Premier Shares.

22. Investments in listed securities

Prospective investors should be aware that the value of an investment in Premier may go down as well as up. The market value of Premier Shares can fluctuate and may not always reflect the underlying asset value or prospects of Premier and, following the Acquisition, the Enlarged Group.

23. Dividend payments

The ability of Premier to pay dividends on Premier Shares is a function of its profitability and the extent to which, as a matter of law, it has available to it sufficient distributable reserves out of which any proposed dividend may be paid. Premier's ability to pay dividends is also dependent upon receipt by it of dividends and other distributions from subsidiaries. Premier can give no assurances that it will be able to pay a dividend going forward.

24. Future share issues

Save for the proposed issue of New Premier Shares and the issue of any Premier Shares to executives and employees under Premier's share option schemes, Premier has no current plans for an offering of Premier Shares. However, it is possible that Premier may decide to offer additional Premier Shares in the future. An additional offering or significant sales of Premier Shares by major shareholders could have an adverse effect on the market price of Premier Shares as a whole.

25. Taxation

It should be noted that the information contained in Part VII of this document relating to taxation may be subject to legislative change which could affect the value of Premier Shares or investments held by Premier, affect Premier's ability to provide returns to shareholders and/or alter the post-tax returns to Premier Shareholders.

FORWARD LOOKING STATEMENTS

Certain statements contained in this document, including those in the Parts headed “Summary”, “Risk factors”, “Information on the Acquisition”, “Information on Premier”, “Information on EnCore” and “Operating and financial review of Premier”, constitute “forward looking statements”. In some cases, these forward looking statements can be identified by the use of forward looking terminology, including the terms “believes”, “estimates”, “plans”, “prepares”, “anticipates”, “expects”, “intends”, “may”, “will” or “should” or, in each case, their negative or other variations or comparable terminology. Investors should specifically consider the factors identified in this document, which could cause actual results to differ before making an investment decision. Such forward looking statements involve known and unknown risks, uncertainties and other factors, which may cause the actual results, performance or achievements of Premier and/or the Enlarged Group, or industry results, to be materially different from any future results, performance or achievements expressed or implied by such forward looking statements. Such forward looking statements are based on numerous assumptions regarding Premier’s present and future business strategies and the environment in which Premier and/or the Enlarged Group will operate in the future. Such risks, uncertainties and other factors are set out more fully in the section of this document headed “Risk factors” and include, among others: risks relating to “Reserves replacement”; the “Estimation of reserves, resources and production profiles”; “Business acquisitions”; “Currency fluctuations and exchange controls”; “Competition”; “Third Party contractors and providers of capital equipment”; “Production”; “Health, Safety, Environment and Security”; “Political, economic, legal, regulatory and social uncertainties” and “Governmental involvement in the oil and gas industry”. These forward looking statements speak only as at the date of this document. Except as required by the FSA, the London Stock Exchange or applicable law (including as may be required by the Listing Rules, Prospectus Rules and the Disclosure and Transparency Rules), Premier expressly disclaims any obligation or undertaking to release publicly any updates or revisions to any forward looking statements contained in this document to reflect any change in the Company’s expectations with regard thereto or any change in events, conditions or circumstances on which any such statement is based.

The statements above relating to forward looking statements should not be construed as a qualification on the opinion of the Company as to working capital set out in paragraph 8 of Part IX.

Premier will comply with its obligation to publish supplementary prospectuses containing further updated information required by law or by any regulatory authority but assumes no further obligation to publish additional information.

EXPECTED TIMETABLE OF PRINCIPAL EVENTS AND ACQUISITION STATISTICS

Latest time for lodging forms of proxy for the Scheme Meeting	11.00 a.m. on 8 December 2011
Latest time for lodging forms of proxy for the EnCore General Meeting	11.10 a.m. on 8 December 2011
Scheme Voting Record Time	6.00 p.m. on 10 December 2011
Scheme Meeting	11.00 a.m. on 12 December 2011
EnCore General Meeting	11.10 a.m. on 12 December 2011 ¹
Latest time for receipt of Form of Election or submission of a valid TTE Instruction on CREST	1.00 p.m. on 11 January 2012
Latest time for withdrawal of Form of Election or submission of a valid TTE Instruction on CREST	1.00 p.m. on 11 January 2012
Court Hearing of petition to sanction the Scheme	11 January 2012
Last day of dealings in EnCore Shares	12 January 2012
Reduction Record Time	6.00 p.m. on 12 January 2012 ²
Capital Reduction Court Hearing Date	13 January 2012 ²
Effective Date of the Scheme and Capital Reduction	16 January 2012 ²
Cancellation of admission of EnCore Shares to trading on AIM	by 8.00 a.m. on 17 January 2012 ²
Issue and listing of New Premier Shares	by 8.00 a.m. on 17 January 2012 ²
Commencement of dealings on the London Stock Exchange of New Premier Shares	by 8.00 a.m. on 17 January 2012 ²
Crediting of New Premier Shares to CREST accounts	by 8.00 a.m. on 17 January 2012 ²
Latest despatch of share certificates in respect of New Premier Shares and cheques in respect of cash and fractional entitlements	by 30 January 2012 ²

All references in this document to times are to UK time unless otherwise stated.

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- 1 The EnCore General Meeting will commence at 11.10 a.m. on 12 December 2011, or as soon thereafter as the Scheme Meeting has been concluded or adjourned.
- 2 These dates are indicative only and will depend, among other things, on the date upon which the Court sanctions the Scheme. If any of the times and/or dates above change, the revised times and/or dates will be announced through the Regulatory News Service of the London Stock Exchange.

ACQUISITION STATISTICS

Number of existing Premier Shares (as at 16 November 2011)	468,057,712
Maximum number of New Premier Shares to be issued pursuant to the Scheme	65,212,513
Maximum number of Premier Shares in issue upon completion of the Acquisition	533,270,225
Maximum number of New Premier Shares as a percentage of the maximum enlarged issued share capital of Premier	12.2 per cent.

DIRECTORS, COMPANY SECRETARY, REGISTERED OFFICE AND ADVISERS

DIRECTORS

Mike Welton (Chairman)
Simon Lockett (Chief Executive)
Tony Durrant (Finance Director)
Robin Allan (Director- Asia)
Neil Hawkings (Operations Director)
Andrew Lodge (Exploration Director)
Professor Dr. David Roberts (Non-executive Director)
Joe Darby (Non-executive Director)
David Lindsell (Non-executive Director)
Michel Romieu (Non-executive Director)
Jane Hinkley (Non-executive Director)

COMPANY SECRETARY

Stephen Huddle

REGISTERED OFFICE

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4th Floor
Saltire Court
20 Castle Terrace
Edinburgh EH1 2EN
+44 (0) 20 7730 1111

SPONSOR AND FINANCIAL ADVISER

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London EC4R 3BF

LEGAL ADVISER TO THE COMPANY AS TO ENGLISH LAW

Slaughter and May
One Bunhill Row
London EC1Y 8YY

LEGAL ADVISER TO THE SPONSOR AS TO ENGLISH LAW

Clifford Chance LLP
10 Upper Bank Street
London E14 5JJ

AUDITORS TO PREMIER AND REPORTING ACCOUNTANTS

Deloitte LLP
2 New Street Square
London EC4A 3BZ

AUDITORS TO ENCORE

PKF (UK) LLP
Farringdon Place
20 Farringdon Road
London EC1M 3AP

REGISTRARS & RECEIVING AGENT

Capita Registrars Limited
The Registry
34 Beckenham Road
Kent BR3 4TU

PART I

INFORMATION ON PREMIER AND THE ENLARGED GROUP

The selected historical financial information and other historical financial information set out in this Part I has, unless otherwise stated, been extracted without material adjustment from the audited historical financial information of Premier for the years ended 31 December 2008, 31 December 2009 and 31 December 2010 and the unaudited interim results of Premier for the six months ended 30 June 2011, which are incorporated by reference in Part IV of this document.

Investors should read the whole of this document and the documents incorporated herein by reference and should not just rely on the financial information set out in this Part I.

Unless otherwise stated, all estimates of reserves and resources have been sourced from the Competent Persons' Reports in Part V of this document and do not represent Premier's internal calculations.

1. Company information

Premier Oil plc was incorporated and registered with the name of Dalglen (No. 836) Limited in Scotland on 31 July 2002 with registration number SC234781. The name of the Company was changed from Dalglen (No. 836) Limited to Premier Oil Group Limited pursuant to a written resolution passed on 13 September 2002. The Company was re-registered as a public limited company on 10 March 2003. The name of the Company was changed from Premier Oil Group plc to Premier Oil plc pursuant to a special resolution passed on 3 March 2003, which became effective on 15 July 2003.

The principal legislation under which Premier operates, and pursuant to which the New Premier Shares will be created, is the Companies Act 1985, the Companies Act 2006 and regulations made thereunder.

The registered office of Premier is 4th Floor, Saltire Court, 20 Castle Terrace, Edinburgh EH1 2EN. Premier's head office is 23 Lower Belgrave Street, London SW1W 0NR.

Premier Oil plc acquired Premier Oil Group Limited as part of a restructuring in 2003. Premier Oil Group Limited was originally incorporated and registered in Scotland on 10 April 1934. Premier was first admitted to trading on the London Stock Exchange in 1936 and is currently a member of the FTSE 250.

2. History and development

The Premier Group was founded 77 years ago in Scotland to pursue oil and gas exploration and production activities in Trinidad. In 1936, the Group's holding company was publicly listed in London as Premier (Trinidad) Oilfields Limited, and for the next two decades the Group focussed on oil production in Trinidad.

The Group acquired its first interest in the North Sea in 1971. It expanded its presence on the UKCS when it merged with the Ball and Collins North Sea Consortium in 1977, gaining significant interests in the North Sea as well as properties in Sudan and West Africa.

In 1984, the Group purchased a 12.38 per cent. interest in the onshore oilfield at Wytch Farm in Dorset. This acquisition had a significant impact on the Group's reserve base and cash flow and continues today to make an important contribution to the Group's revenues. In June 2011, the Group announced the acquisition of an additional 17.715 per cent. interest in the onshore oilfield at Wytch Farm. Following completion of this acquisition, the Group's total interest in Wytch Farm will be 30.1 per cent.

In the late 1980s and early 1990s, the Group enjoyed a series of exploration successes, notably the discovery of the Qadirpur gas field in Pakistan in 1990, the Angus and Fife fields in the UKCS in 1983 and 1991 respectively and the Yetagun gas field in Myanmar in 1992.

In 1995, the Group acquired Pict Petroleum plc ("Pict"). Hess Corporation ("Hess"), which already had a substantial interest in Pict, became a 25 per cent. shareholder of the Group. As a result, the Group participated in numerous further North Sea oil and gas fields, including the Fife, Fergus, Galahad and Scott fields.

Supported by production revenue from the UKCS, the Group turned its attention to South East Asia with a view to developing energy resources to serve the region's rapidly expanding economies. In 1996, the Group acquired Sumatra Gulf Oil which gave it a majority interest in the Natuna Sea Block A offshore Indonesia, comprising the Anoa oil field and substantial gas reserves, as well as exploration prospects. The Group also acquired Discovery Petroleum NL of Australia, thereby obtaining an interest in the Kakap licence, also in the Natuna Sea, which added oil and gas reserves and provided access to further prospective exploration acreage.

The Group was the original licensee of concessions MI3 and MI4 in Myanmar, when they were awarded in 1990. Shortly afterwards, the Group farmed out its interests to a subsidiary of Texaco, which became the operator, and a subsidiary of Nippon Oil Corporation, whilst retaining a 30 per cent. interest. The Yetagun Field was discovered in 1992 and development began in 1996. In late 1997, Texaco sold its entire interest of 30 per cent. and transferred the role of operator to the Group. At the same time the Group sold a 30 per cent. interest to Petronas. Construction of the pipeline and facilities for this field took place during 1998 and 1999. The field started production in May 2000.

In 1998, the Group and Shell brought together their exploration and production interests in Pakistan to form a joint venture company, Premier & Shell Pakistan B.V. ("PSP"). In May 2001, the Group announced an asset swap with Shell which dismantled the partnership and, in September 2001, a new joint venture company was formed with Kufpec to hold the interests in Pakistan, Premier-Kufpec Pakistan B.V. ("PKP"). This joint venture was unwound in 2007 with each of the co-venturers now owning its share of the assets directly.

To consolidate its position as a leading independent production company in the South East Asian energy markets, the Group formed a strategic alliance with Petronas and Hess in 1999. As part of the strategic alliance, each of Petronas and Hess owned a 25 per cent. equity interest in the Group. In September 2002, the Group agreed to transfer its entire Myanmar business to Petronas and part of the Indonesian West Natuna asset to subsidiaries of Petronas and Hess. In consideration for these transfers, Petronas and Hess cancelled their combined 50 per cent. shareholding in the Group and contributed US\$376.0 million in cash and debt repayment.

As part of the reorganisation, in 2003 Premier acquired POGL and as a result became the holding company of the Group.

In 2005, the Group reorganised into four regional units: Asia, Middle East-Pakistan, North Sea and West Africa. This reorganisation took into account the successful entry into a number of new countries including Vietnam, Norway, Mauritania and the Congo. The West Africa regional unit which, at that time, was focussed on Mauritania and the Congo, was combined with the North Sea business unit in 2008. The Group also set up a joint venture with Emirates International Investment Company LLC ("EIIC") in 2008 to build a presence in the Middle East and North Africa regions.

In 2009, the Group acquired Oilexco North Sea Limited from administration, which added production, reserves and resources to the Group's North Sea unit. The acquisition provided the Group with a greater presence in the North Sea and strengthened its existing operations in the area by adding a material package of assets which comprises existing producing fields, development projects of existing discovered reserves and a portfolio of exploration prospects, together with high-quality UK operatorship capabilities.

In 2011, the Group served notice to withdraw from its licence (Marine XI) in the Congo and the Group's Africa business was combined with the Middle East-Pakistan unit. Today the Group is organised into three regional units: Asia, Middle East/Africa/Pakistan and North Sea.

The Group today is independent and pursues its strategy of low-risk development of existing discovered reserves whilst maintaining shareholder leverage to material exploration upside. The Group is pre-funded for its committed development and committed exploration programmes.

3. Organisational structure

Premier has two principal wholly-owned subsidiaries: POGL – through which it holds all of its project interests (except the interest in the Kyle field which it holds directly) – and POFJL. POFJL is a Jersey registered company incorporated for the purpose of issuing Convertible Bonds and to be a party to various financial arrangements supporting the Convertible Bonds. Further information on the Convertible Bonds is set out in Part III of this document. POGL is a Scottish registered company and has three principal wholly-owned subsidiaries: POHL, POUKL and POOBV.

POHL, a company registered in England and Wales, is also the parent company of several specially formed entities which hold the Group's interest in two PSCs in Mauritania ("PSC A" and "PSC B"), including the Group's interest in the Chinguetti field.

POUKL, a Scottish registered company, and its wholly-owned subsidiaries hold all of the Group's UK producing assets.

POOBV, a Dutch registered company, holds the Group's wholly-owned subsidiaries, Premier Oil Kakap B.V. and Premier Oil Natuna Sea B.V., which hold the Group's interests in Kakap, Indonesia and the Natuna Sea Block A, respectively. In addition, POOBV holds the Group's 49 per cent. shareholding in Premco Energy Projects Company LLC, and 50 per cent. shareholding in Premco Energy Projects B.V. These companies were incorporated pursuant to the joint venture arrangements established in January 2008 between POOBV and EILC, the aim of which is to make acquisitions in a defined area of mutual interest.

4. Business overview

4.1 Introduction

Premier has current interests in eight countries around the world and operates in three core areas: the North Sea, Asia and Middle East/Africa/Pakistan. As at 30 September 2011, Premier had a reserves and resource base of 550 mmboe. Production for the first half of 2011 was 36,700 boepd and Premier is targeting production of 100,000 boepd in the medium term.

The Existing Premier Shares are listed on the Official List of the UKLA and are admitted to trading on the London Stock Exchange (Bloomberg ticker: PMO LN). As at 16 November 2011 (the latest practicable date prior to the publication of this document), Premier had a market capitalisation of approximately £1,719 million. In the financial year ended 31 December 2010, Premier achieved revenues of US\$763.6 million and a record profit after tax of US\$129.8 million.

A breakdown of total revenues by category of activity and geographic market for the years ended 31 December 2008, 31 December 2009 and 31 December 2010 is given in the Annual Report and Accounts for Premier for those years, which are incorporated into this document by reference.

4.2 Strategy

Premier's strategy is to add significant value for shareholders through exploration and appraisal success, optimal asset management and development, and astute commercial deals. Specifically, there are five main elements to Premier's strategy:

- increasing near-term production to 75,000 boepd from its existing proven and probable reserves base;
- promoting further growth through commercialising Premier's contingent resource base of 211 mmboe;
- adding 200 mmbbls of reserves through exploration, by focusing on core geologies, in order to underpin its medium term production target of 100,000 boepd;
- making value-adding acquisitions in Premier's three core areas of Asia, Middle East/Africa/Pakistan, and the North Sea; and
- maintaining a conservative financing plan.

4.3 Asset Portfolio and organisation

The Group is organised into three regional units: Asia, Middle East/Africa/Pakistan, and North Sea.

Key Company locations are as follows:

Location	Presence
London	Corporate head office and Middle East/Africa/Pakistan Business Unit
Aberdeen	UK North Sea operations
Jakarta (Indonesia)	Indonesia operations
Ho Chi Minh City (Vietnam)	Vietnam operations
Singapore	Asia regional management
Islamabad (Pakistan)	Pakistan operations
Stavanger (Norway)	Norway operations

4.4 Key strengths and competitive advantages

Long-life production profile

Average production for 2011 is expected to be between 40,000 and 45,000 boepd, with a run rate of 60,000 boepd expected to be achieved by the end of the year. Premier has a strong reserve and resource base with 339 mmboe of 2P reserves as at 30 September 2011. As a result of the quality of Premier's assets, Premier's fields generate significant cash flow even at lower oil and gas prices.

Good quality long-term gas contracts

Substantially all of Premier's gas production is sold under profitable long-term contracts to Singapore and Pakistan government-backed customers. Revenues are denominated in US Dollars and funds are remitted directly to London bank accounts.

Substantial reserve backing, conservatively booked

Premier's production and development portfolio is supported by 2P reserves of 339 mmboe and contingent resources of 211 mmboe as at 30 September 2011.

Significant growth profile

Premier's current level of production is targeted to increase to over 75,000 boepd in the near term as a result of projects currently under development coming onstream in 2012. These projects are robust at low oil and gas prices.

Balance sheet strength

Premier has a strong balance sheet with cash balances of around US\$482.9 million and undrawn bank facilities of US\$804 million as at 30 June 2011. Premier has the credit facilities described in Part III of this document.

It is intended that Premier's planned investment programme will be financed from available cash balances and facilities and internally generated cash flows. Premier is committed to maintaining a disciplined exploration spending target each year and, where necessary, will seek farm-in partners for drilling programmes to maintain this discipline.

Downside protection through hedging

The Board's commodity pricing and hedging policy continues to be to lock in oil and gas price floors for a proportion of expected future production at a level which ensures that investment programmes for sanctioned projects are adequately funded. Floors are purchased for cash or via collars, funded by selling caps at a ceiling price. This policy has provided downside protection for the company over the period since 2008 and going forward to 2012, during which period over US\$1 billion will have been invested in new development projects. The requirement for future hedging for 2013 and beyond will be considered as new projects are sanctioned, taking into account expected future cash flows of the group and the size of the relevant investment programme.

Experienced management team with deep oil and gas industry knowledge

Premier's senior management team has a wide range of experience throughout the industry and across the business. Simon Lockett, Chief Executive, joined Premier in 1994 and worked in a variety of roles within Premier before becoming Chief Executive in 2005. Tony Durrant, Finance Director, joined Premier in 2005 having been Head of the European Natural Resources Group of Lehman Brothers since 1997. Operationally, Neil Hawkings and Robin Allan both have significant experience having spent more than 20 years each working within the industry (with ConocoPhillips and Premier respectively), while Andrew Lodge has 30 years professional experience in the oil and gas industry, at Hess, BHP Petroleum and BP.

5. Current trading and prospects

5.1 General

Premier has operations in eight countries around the world with a reserves and contingent resource base of 550 mmboe as at 30 September 2011. Premier generated record revenues and profits in the year ended 31 December 2010 and significant progress in respect of production growth targets has been made in 2011. Premier's portfolio of development projects approaching project sanction will contribute towards a targeted 100,000 boepd of production in the medium term.

5.2 Chim Sáo

On 4 October 2011, Premier received the Ready for First Oil Certificate from the FPSO contractor of the Chim Sáo oil field in Block 12W and production commenced on 10 October 2011. Premier has a 53.125 per cent. operated interest in Block 12W in the Nam Con Son Basin. During the first month of production 26,600 bopd were delivered from six wells, and approximately 30,000 bopd were produced in early November 2011. Gas export is scheduled to commence from early December 2011; and the exported gas and associated liquids are expected to add 6,000 boepd (gross) to Chim Sáo production. The successful development of the Chim Sáo field, on budget, is a significant milestone for Premier, the field partners and the contractors.

In addition, the oil discovery in the fault terrace to the north west of the Chim Sáo field, made by the previously announced CS-N2P development well, has been successfully appraised by the CS-N1P development well. The CS-N1P well intersected an estimated 89 metres of net oil bearing sands within a stacked sequence of Upper Dua sandstones. This compares with an estimated 15 metres of net oil bearing sandstones intersected in the CS-N2P well.

Separately, the Chim Sáo development drilling programme has been extended with the inclusion of a production well to accelerate recovery from a shallow reservoir within the Middle Dua Sandstone section.

5.3 Gajah Baru

Premier commenced the export of gas from the Gajah Baru facilities in the Natuna Sea on 24 October 2011.

Under a GSA approved by the Government of Indonesia in 2008, Gajah Baru is contracted to ship 90 BBtud to Singapore after a period of ramp-up of production. An additional 40 BBtud of production is dedicated to the Indonesian domestic market on Batam Island.

5.4 Huntington

Huntington is a field within the UKCS where development is progressing and Premier expects first oil in September 2012.

Teekay has agreed to acquire the Voyageur FPSO from Sevan Marine, and is financing the completion of the upgrade of the vessel. Teekay has also agreed a Heads of Terms with E.ON, the operator of the Huntington field, around the existing charter contract, with signature expected by the end of November. The sailaway of the Voyageur is targeted for 31 July 2012.

Teekay is a highly respected FPSO operator and its acquisition of the Voyageur provides Premier with greater confidence that first oil from the Huntington field will be achieved in the third quarter of 2012.

Premier continues to hold active discussions with both Teekay and Sevan regarding the potential deployment of additional vessels from the Sevan fleet on Premier's future North Sea developments.

5.5 Exploration

Premier has over 50 exploration licences worldwide. There is a continuous evaluation process in respect of each of these licences whereby identified exploration opportunities are progressed through lead and prospect status, culminating in mature 'ready-to-drill' prospects. This process follows a corporate review and approval gate system.

Premier continues to have good access to debt capital markets to finance investments and, from its rising cash flows, is able to fund a growing exploration programme. As a result, the Premier Directors are confident of both replacing reserves and adding to Premier's resource base, thereby underpinning future growth. Premier has drilled eight exploration wells and five appraisal wells to date this year with around 15 wells planned for the remainder of 2011 and the first half of 2012. In addition, after completion of the Acquisition, Premier intends to drill two wells on newly acquired EnCore acreage.

Premier's first operated well in Norway was spudded in October 2011 and is drilling the Gardrofa prospect (9/1-1S). This well is expected to reach its target depth in November 2011. In the UK, a well on the Erne prospect (Eocene Tay sandstones) in PL1875 spudded in mid-November 2011 using the WilPhoenix rig. Also in the Greater Fyne Area, the East Fyne appraisal well is expected to spud in December 2011, using the Sedco 704 rig, which will then move to drill the Bluebell prospect. In PL1430, the Catcher area licence, a 3D seismic acquisition programme is nearing completion and the next well on the licence (Carnaby) is due to spud in early 2012. In Indonesia, the Anoa Deep well is expected to spud in December 2011 and the Biawak Besar well, also in Natuna Sea Block A, will be spudded immediately thereafter.

6. Licence interests of the Enlarged Group

Premier's business is dependent on the holding of licences and approvals from government authorities, which entitle the Group, *inter alia*, to extract oil and gas. Details of the Group's key licences are set out below.

	Licence	Licence Type	Block	Operator	Equity %	Field	Expiry
Indonesia	Buton	PSC		Japex	30.00		2027
	Kakap	PSC		Star Energy PT	18.75	Kakap	2028
	Natuna Sea Block A	PSC		Premier	28.67	Anoa	2029
	Block A Aceh	PSC		PT Medco E&P	41.67	Alur Siwah	2031
	Tuna	PSC		Malaka Premier	65.00		2037
Vietnam		PSC	12W	Premier	53.125	Chim Sáo	2025
		PSC	07/03	Premier	30.00	Cá Rồng Đò	2013 ⁽¹⁾
		PSC	104-109/05	Premier	50.00		2015 ⁽¹⁾
United Kingdom	P077	Production	22/12a	Shell	50.00	Nelson ⁽²⁾	2011
	P077	Production	21/28a	Premier	39.90		2014 ⁽¹⁾
	P087	Production	22/7-F1	Premier	46.50	Nelson ⁽³⁾	2011
	P101	Production	23/21 (North & South Moth – below bottom chalk)	BG	50.00	Moth	2016
	P110	Production	22/14a (non-Everest deep)	BG	27.24	Mallory	2016
	P110	Production	22/14a (non-Everest shallow)	Premier	25.04	Huntington East	2016
	P119	Production	15/29a (area P)	Premier	60.00	Ptarmigan	2016
	P164	Production	205/26A	Premier	60.00	Solan	2018
	P185	Production	15/22 (rest of block, non-Palaeocene formation)	Nexen	50.00	Blackhorse	2018
	P201	Production	16/21a	Premier	85.00	Balmoral ⁽⁴⁾ , Glamis, Stirling ⁽⁵⁾	2018
	P201	Production	16/21a (Brenda field area)	Premier	100.00	Brenda (above 7,500ft)	2018
	P213	Production	16/26 (area P)	Premier	100.00	Caledonia	2018
	P218	Production	15/21a (Scott field area)	Nexen	45.83	Scott ⁽⁶⁾	2018
	P218	Production	15/21a (Telford field area)	Nexen	7.29	Telford ⁽⁷⁾	2018
	P233	Production	15/25a	Premier	70.00	Nicol	2018
	P257	Production	14/25a	Talisman	1.518	2016	
	P288	Production	31/21a, 31/26a, 31/26f, 31/26g, 31/27a	Hess	15.00	Angus, Fife, Flora	2016
	P300	Production	14/26a (Oddjob area)	Nexen	25.00		2016
	P344	Production	16/21b (Northern area)	Premier	55.00		2016
	P344	Production	16/21b, 16/21c	Premier	44.20	Balmoral ⁽⁴⁾ , Northern Stirling ⁽⁵⁾	2016
	P354	Production	22/2a (non-Chestnut field area)	Premier	30.00		2016
	P489	Production	15/23b	Nexen	50.00	Blackhorse	2021
	P534	Production	98/6a, 98/7a	BP	12.50	Wyth Farm (offshore) ⁽⁸⁾	2021
	P640	Production	15/24b (area B)	ConocoPhillips	50.00		2025
	P748	Production	29/2c	CNR	40.00	Kyle	2027
	P758	Production	31/26c	Hess	35.00	Fife	2027
	P811	Production	13/30b	Nexen	25.00		2011 ⁽¹⁾
	P815	Production	15/23d	Nexen	50.00	Bugle	2011 ⁽¹⁾
	P1042	Production	15/25b	Premier	100.00	Brenda	2028
	P1095	Production	16/21d	Maersk	50.00	Bladon	2011 ⁽¹⁾
	P1114	Production	22/14b, 22/19b	EON Ruhrgas	40.00	Huntington	2029
	P1157	Production	15/25e	Premier	100.00	Brenda	2030
	P1181	Production	23/22b	Premier	57.50		2012 ⁽¹⁾
	P1212	Production	15/13b	Nexen	50.00		2012 ⁽¹⁾
	P1220	Production	21/23a	Sterling	65.00	Sheryl	2012 ⁽¹⁾
	P1260	Production	22/2b	Premier	100.00	Shelley	2013 ⁽¹⁾

	Licence	Licence Type	Block	Operator	Equity %	Field	Expiry
	P1298	Production	15/26b	Nexen	50.00	Kildare/West Rochelle	2013 ⁽¹⁾
	P1420	Production	22/13b	Premier	72.73	2015 ⁽¹⁾	
	P1430	Production	28/9, 28/10c	EnCore	35.00	Catcher/ Varadero/ Burgman	2015 ⁽¹⁾
	P1466	Production	15/24c, 15/25f	Premier	100.00 ⁽⁹⁾		2015 ⁽¹⁾
	P1467	Production	15/25d	Maersk	50.00		2015 ⁽¹⁾
	P1559	Production	15/23e	Premier	100.00		2017 ⁽¹⁾
	P1577	Production	201/5, 202/24, 202/25, 202/29, 202/30, 203/16, 203/21 & 203/26	Premier	100.00		2022 ⁽¹⁾
	P1615	Production	15/26c	Endeavour	25.00	West Rochelle	2017 ⁽¹⁾
	P1620	Production	22/19c	Premier	50.00		2017 ⁽¹⁾
	P1770	Production	14/30b	Nexen	50.00		2019 ⁽¹⁾
	P1771	Production	15/9, 15/10, 15/14 & 15/15	Nexen	50.00		2019 ⁽¹⁾
	P1772	Production	15/23g	Premier	50.00		2019 ⁽¹⁾
	P1784	Production	21/7b	Premier	70.00		2019 ⁽¹⁾
	P1804	Production	22/12c & 22/26c	Maersk	30.00		2019 ⁽¹⁾
	P1875	Production	21/29d	Antrim	50.00		2019 ⁽¹⁾
	PL089	Production	SY87b, SY88b, SY89b, SY97b, SY98a, SY99a, SZ/7 & SZ/8a	BP	12.50	Wytch Farm (onshore) ⁽⁸⁾	2014
Norway	PL359	Production	16/1 (part), 16/4 (part)	Lundin	30.00		2014 ⁽¹⁾
	PL364	Production	25/2 (part), 25/3 (part), 25/5 (part) & 25/6 (part)	Det Norske	50.00	Frøy	2019
	PL374S	Production	34/2 (part) & 34/5 (part)	BG	15.00	Blåbaer	2015 ⁽¹⁾
	PL378	Production	35/12 (part), & 36/10 (part)	Wintershall	20.00	Grosbeak	2013 ⁽¹⁾
	PL378B	Production	35/12b	Wintershall	20.00		2013 ⁽¹⁾
	PL406	Production	8/3 (part), 9/1 (part), 17/12 (part), 18/10 (part) & 18/11 (part)	Premier	40.00	2013 ⁽¹⁾	
	PL407	Production	17/8 (part), 17/9 (part), 17/11 (part), 17/12 (part), 18/7 (part) & 18/10 (part)	BG	20.00	Bream	2014 ⁽¹⁾
	PL567	Production	2/6	Premier	60.00		2018 ⁽¹⁾
Pakistan	Production Leases	D&P Lease	Bolan	Mari Gas	3.75	Zarghun South	2022
		D&P Lease	Dadu	BHP	9.375	Zamzama	2022
		D&P Lease	Kirthar	ENI	6.00	Badhra	2027
		D&P Lease	Kirthar	ENI	6.00	Bhit	2020
		D&P Lease	Qadirpur	OGDCL	4.75	Qadirpur	2012
		D&P Lease	Tajjal	ENI	15.79	Kadanwari	2022
Congo	Marine IX ⁽¹⁰⁾	PSC	Marine IX	Premier	31.50		2016
Egypt	North Red Sea ⁽¹¹⁾	PSC	Block 1	Hess	20.00		2015 ⁽¹⁾
	South Darag ⁽¹²⁾	PSC	Premier		100.00		⁽¹³⁾
Kenya	PSC	L10A		BG	20.00		2017 ⁽¹⁾
		PSC	L10B	BG	25.00		2017 ⁽¹⁾
Mauritania	PSC A	PSC	Banda discovery area	Tullow	4.615		⁽¹⁴⁾
	PSC B	PSC	Banda, Tiof, Tevet discovery areas	Tullow	9.23		⁽¹⁴⁾
	PSC B	PSC	Chinguetti EEA	Petronas	8.12	Chinguetti	2029
	PSC C-10	PSC	Fomer PSC A & B exploration areas	Tullow	6.23		⁽¹⁴⁾

- (1) End of exploration period.
- (2) Unitised share of 1.31404 per cent.
- (3) Unitised share of 0.348750 per cent.
- (4) Unitised share of 78.11542 per cent.
- (5) Unitised share of 68.68 per cent.
- (6) Unitised share of 21.83 per cent.
- (7) Unitised share of 1.58677 per cent.
- (8) Unitised share of 12.38 per cent. Premier has agreed to acquire an interest of 17.715 per cent. in Wytch Farm. When the proposed transaction has completed Premier will hold a 30.385 per cent. interest and a unitised share of 30.09625 per cent.
- (9) Subject to contract, and an earn-in agreement to transfer a 40 per cent. interest to Canadian Overseas Petroleum (UK) Ltd, Premier's new interest will be 60 per cent.
- (10) Notice has been served to withdraw from this licence.
- (11) This farm-in deal has been signed and completion is subject to government approval.
- (12) This government concession has been signed and is awaiting ratification.
- (13) Awaiting government ratification.
- (14) The new agreements for extending PSC's A and B and for combining the exploration areas into the new PSC C-10 have been approved by the Government of Mauritania and are awaiting formal gazettal.

After the Acquisition, the Enlarged Group will also hold the following licences:

	Licence	Block	Operator	Equity %	Field
Ireland	4/05	Part-blocks 49/17, 49/22 & 49/23	San Leon Energy	15	Old Head of Kinsale
	5/05	57/2, 57/1 (part), 48/26 (part), 48/27 (part)	San Leon Energy	12.5	Schull
United Kingdom	P218	15/21a	Enlarged Group	28 ⁽¹⁾	Spaniards
	P1064 ⁽²⁾	210/29a & 210/30a	Sterling Resources	16.6	Cladhan
	P1243	48/1b & 48/2c	Enlarged Group	25	Cobra
	P1335	43/13a	Enlarged Group	100	
	P1430	28/9 & 28/10c	Enlarged Group	50	Catcher/Varadero/Burgman
	P1463	14/30a	Enlarged Group	40	Tudor Rose
	P1475	113/29c & 113/30	Nautical	50	Merrow
	P1655	15/21g	Enlarged Group	28 ⁽¹⁾	Spaniards
	P1769	14/29e, 20/4c & 20/5f	Enlarged Group	50	
	P1812 ⁽³⁾	28/5, 28/10 & 29/1d	Enlarged Group	100	
	P1866	13/28b	Echo Exploration	50	Beehive
	P1870	15/21d	Echo Exploration	50	
	P1876	22/5	Echo Exploration	50	

(1) Subject to regulatory approval and completion.

(2) Premier intends to sell all of EnCore's current 16.6 per cent. interest in licence P1064 after completion of the Acquisition. Please refer to Section 8 of Part VI of this document for further details.

(3) Premier intends to sell 50 per cent. of EnCore's current 100 per cent. interest in licence P1812 after completion of the Acquisition. Please refer to Section 8 of Part VI of this document for further details.

6.1 Summary of commercial terms

Indonesia

Premier operates and participates in Indonesia under the terms of PSCs which include the following main fiscal parameters: first tranche petroleum ("FTP"), domestic market obligation, cost oil/gas, profit oil/gas, investment credit ("IC"), income and withholding taxes. The terms differ across Premier's various contracts, but in general FTP is 20 per cent. shared with the government. Cost recovery is 100 per cent.; profit oil varies between 26.8 per cent. and 25 per cent. and profit gas varies between 62.5 per cent. and 58.3 per cent. Income tax ranges from 40 per cent. and 44 per cent. and withholding tax is 20 per cent. Domestic market obligation on oil is 25 per cent. of contractor profit share at 15 per cent. market price. IC uplift on capital for cost recovery is available on some capital projects at up to 55 per cent.

Vietnam

Premier operates in Vietnam Block 12W under a PSC which includes the following main fiscal parameters: royalty, cost recovery, profit share, income tax, export duty & bonuses. The royalty payment at anticipated production rates will likely be between 4 per cent. and 6 per cent. Cost recovery limit is 70 per cent. Contractor profit share is based on production rate and ranges from 82.5 per cent. to 61.5 per cent. in the anticipated range of production. Income tax is 32 per cent., although PSC 12W includes an 18 month tax holiday. Export duty is 4 per cent. Bonuses of US\$2 million to US\$3 million are due at first oil, 25mbd and 50mbd. PetroVietnam had the right to take a direct equity stake under the terms of the PSC and in the case of Chim Sáo has taken a 15 per cent. paying share.

United Kingdom

Premier's licences in the UK are governed by a tax/royalty regime, although royalty is no longer payable on any field in the UK. Government take currently comprises corporation tax ("CT") and a supplementary charge ("SCT"). CT is levied at a rate of 30 per cent. and SCT at 32 per cent., to give an effective tax rate of 62 per cent. However, Premier has capital allowances and losses in its portfolio, which can be carried forward indefinitely, of circa US\$1 billion, which offsets CT and SCT until 2017. Fields with development approval prior to 1993 are liable to Petroleum Revenue Tax ("PRT") at a rate of 50 per cent., in addition to CT and SCT. Premier's fields which are liable for PRT are Wytch Farm, Nelson, Scott and Balmoral.

Norway

Premier's licences in Norway are governed by a tax/royalty regime, although royalty is no longer payable. The main taxes are CT and special petroleum tax ("SPT"). These are levied on the total taxable offshore profits at rates of 50 per cent. and 28 per cent. respectively, giving a total marginal rate of 78 per cent. An uplift of capital expenditure of 30 per cent. is allowed for SPT. The government refunds 78 per cent. of exploration expenses.

Pakistan

Premier participates in various onshore concessions in Pakistan under a tax/royalty regime. Royalty is 12.5 per cent. and Income Tax is 50 per cent. In addition, a Workers Welfare Fund tax of 2 per cent. is payable.

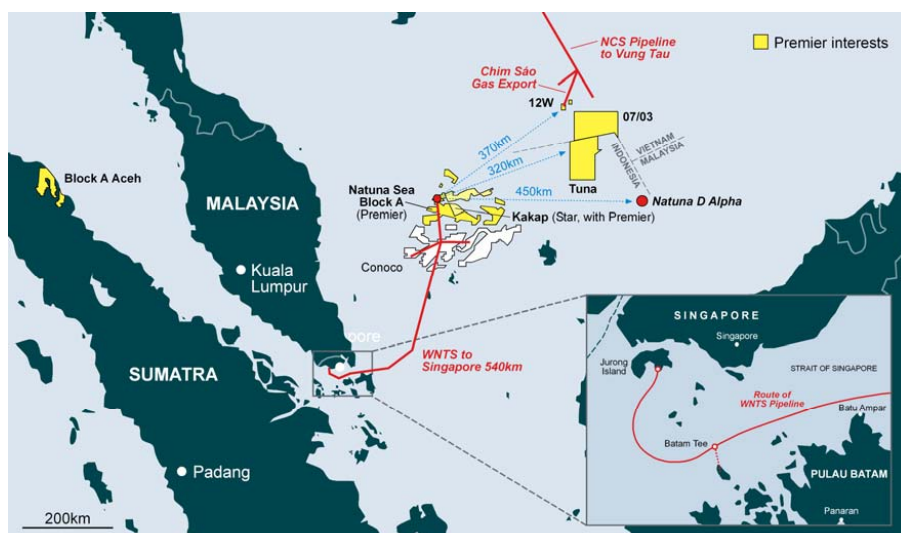
7. Premier operations

7.1 ASIA BUSINESS UNIT

In Asia, Premier has recently completed two complex multi-year projects, the Chim Sáo and Gajah Baru field developments in Vietnam and Indonesia respectively. These projects will drive Premier's production growth in the near future. Ongoing development activities will continue with the Pelikan and Naga projects in the Natuna Sea, the gas developments on Block A Aceh and evaluation of the Dua and Cá Rồng Đỏ ("CRD") projects in Vietnam. Exploration in Asia continues with additional wells planned for the next 12 months.

Reserves and contingent resources attributable to Premier's South East Asian assets are 275 mmbob, which accounts for 50 per cent. of the Enlarged Group's total. Working interest production for the region for the half year ended 30 June 2011 was 10,800 boepd. This was exclusively from Indonesia and represented 28 per cent. of Premier's global production.

Asia Operations



7.1.1 Indonesia

Reserves and resources in Indonesia are 211 mmboe, representing 38 per cent. of the Enlarged Group's global total.

Natuna Sea Block A – producing asset, development projects & exploration, 28.67 per cent. operated interest

The Natuna Sea Block A licence was obtained by Sumatra Gulf Oil in 1979. Oil production from the Anoa field began in November 1990 from nine platform wells located in the East Lobe. Following Premier's acquisition of Sumatra Gulf Oil in 1996, additional development was undertaken with the installation of the processing and compression Anoa Gas Export platform and the West Natuna Transportation System ("WNTS") pipeline for gas export to Singapore.

Gas is currently produced from the Anoa and Gajah Baru gas fields in Natuna Sea Block A PSC and from fields in the Kakap PSC in which Premier also has an interest (see below). The two PSCs are located adjacent to each other some 500 kilometres north east of Singapore in the West Natuna Sea. Gas from the fields is exported to Singapore through the 650 kilometre WNTS pipeline.

Deliveries under a US Dollar gas contract ("GSA1") with SembCorp, a government-controlled Singaporean utility, commenced in January 2001 and are expected to continue under a "life of field" contract until 2029. SembCorp sells the gas to various end users including SUT Co-Gen, Tuas Power and Exxon Chemicals.

In April 2008 the Premier Group signed three further fully termed GSAs ("GSA2", "GSA3" and "GSA4") with SembCorp for additional gas sales into the Singapore market, and with PLN and UBE for gas sales to be used in power generation in Batam, Indonesia. Gajah Baru is the first of a number of fields to be developed to supply the additional gas. Under GSA2, Gajah Baru is contracted to ship 90 BBtud to Singapore after a period of ramp-up production. An additional 40 BBtud of production is dedicated to Batam Island. Export of gas to Singapore from the Gajah Baru facilities commenced on 24 October 2011.

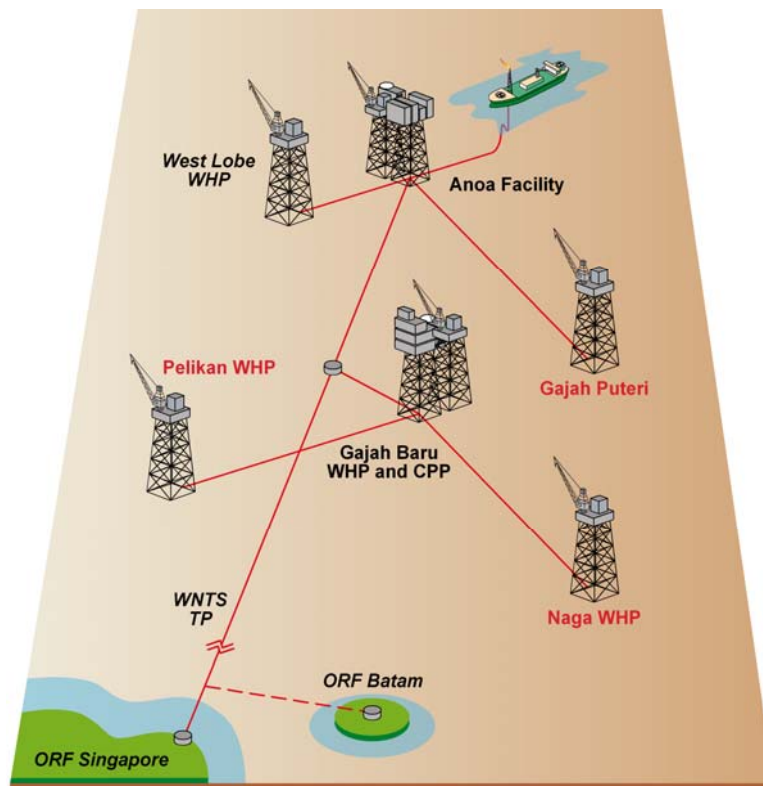
Development work on the Pelikan and Naga fields is targeting first gas in late 2013. The Pelikan and Naga fields, which will be dedicated to maintaining the gas profiles of GSA1 and GSA2 respectively, will be tied in to the new Gajah Baru central processing platform for export via the WNTS. Work will then commence on the next development project, the tie-in of the Gajah Puteri field, to maintain gas deliverability in the future.

During 2010, the Natuna Sea Block A sold an overall average of 160 billion BBtud (gross) from its gas export facility, while the non-operated Kakap Block contributed a further 54 BBtud (gross).

Gas pricing is directly related to HSFO pricing which moves broadly in line with international crude prices. Average production for the first half of 2011 was 8,600 boepd net to Premier. Estimated 2P

reserves and 2C contingent resources for the block are 82 mmboe net to Premier. Partners in Natuna Sea Block A are Kufpec (33.33 per cent.), Hess (23 per cent.) and Petronas (15 per cent.). The diagram below provides an illustration of the current facilities and those that are expected to be in place by 2015.

Natuna A 2015



Kakap field – producing asset, 18.75 per cent. non-operated interest

The Kakap field was discovered by a subsidiary of Marathon Oil in 1978, with well KG-IX, and first production commenced in March 1986. Kakap consists of 10 separate fields, which have been developed with a combination of platforms and subsea tie-backs to the Kakap FPSO, where the oil is stabilised and exported via tankers.

Premier acquired its interest in the Kakap field in December 1996 through the acquisition of Discovery Petroleum NL. Gas production started in 2001 and is sold under GSA1 to Singapore (SembCorp) as described above.

Average production from Kakap for the first half of 2011 was 2,192 boepd net to Premier. Estimated 2P reserves for the PSC are 8.5 mmboe net to Premier. Partners in the Kakap field are Star Energy (operator, 56.25 per cent.), PetroChina (15 per cent.), and Pertamina (10 per cent.).

Block A Aceh – development project, 41.67 per cent. non-operated interest

In April 2006, Premier acquired a 16.7 per cent. equity share in Block A Aceh (formerly North Sumatra PSC Block A) onshore Indonesia from a subsidiary of ExxonMobil. This equity interest was subsequently increased to 41.67 per cent. in January 2007. The block contains three undeveloped discoveries (Alur Siwah, Alur Rambong, and Julu Rayeu).

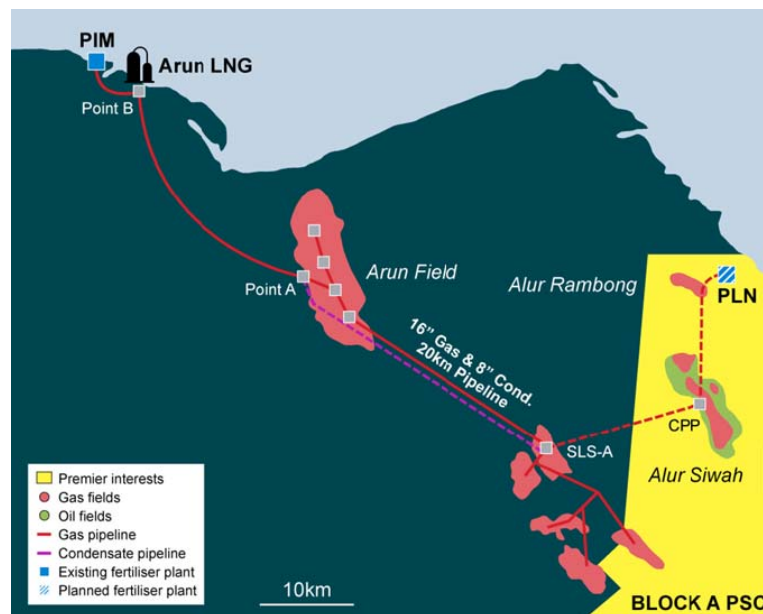
The operator of Block A Aceh, MedcoEnergi (“Medco”), and its partners have secured approval from the Indonesian regulator, BPMIGAS, for the development plan of the block and first gas is targeted for 2013. A fully termed extension to the Block A Aceh PSC was executed with the Government of Indonesia and provincial Government of Aceh on 28 October 2010, with the extended PSC effective from 1 September 2011.

Medco and PT Pupuk Iskander Muda (“PIM”) have agreed a fixed floor price of US\$6.50 per MMBtu for gas with an additional upside profit share element which is related to urea prices. The

contract allows for minimum sales of 223 TBtu with ultimate sales expected of over 400 TBtu. Gas will be delivered through a new 20 kilometre pipeline to a delivery point at an existing pipeline which will transport the gas to the PIM plant, approximately 70 kilometres away.

Estimated 2P reserves and contingent resources for Block A Aceh are 121 mmboe net to Premier. Partners in the field are Medco (operator, 41.67 per cent.) and Japex (16.67 per cent.).

Block A Aceh



Tuna Block – exploration, 65 per cent. operated interest

In March 2007, Premier was awarded a 65 per cent. operated interest in the Natuna “Tuna” offshore block by the Indonesian Government. The block is located adjacent to and immediately to the south of Block 07/03 in Vietnam in which Premier holds a 30 per cent. operated interest.

Premier drilled two wells – Gajah Laut Utara and Belut Laut – on the Tuna acreage in 2011. Both wells encountered oil shows but the reservoirs were of poor quality. Subsurface work will now focus on prospects at shallower depths where good reservoir properties are expected to be preserved up-dip from the now proven source rocks. At least five such prospects have been identified in this Tuna Block and in the neighbouring Block 07/03 in Vietnam.

Premier’s partners in Tuna are Mitsui Oil Exploration Company Limited (“MOECO”) (20 per cent.) and GS Calpex (15 per cent.).

Buton Block – exploration, 30 per cent. non-operated interest

In December 2006, Premier was awarded a 30 per cent. non-operated interest of an onshore exploration licence on Buton Island, Sulawesi, by the Indonesian Government. The block lies on the south eastern side of Buton Island. Oil seeps are prolific on the island and large volumes of oil have been generated as evidenced by the commercial asphalt mining operations that have been ongoing for many years.

The committed work programme includes 265 kilometres of 2D seismic designed to confirm at depth the structures mapped at surface, and one exploration well, Benteng-1. The Benteng-1 exploration well is planned for the first quarter of 2012.

The partners in Buton are Japex (operator, 40 per cent.) and Kufpec (30 per cent.).

7.1.2 Vietnam

2P reserves and 2C contingent resources in Vietnam are 64 mmboe, representing 12 per cent. of the Enlarged Group’s global total.

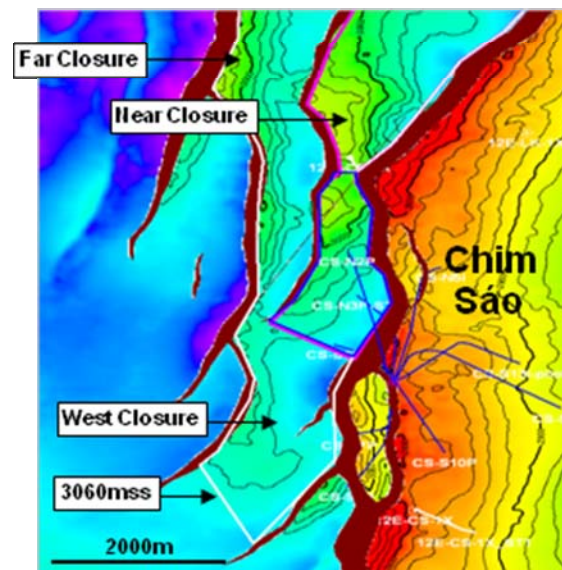
Block 12W – producing asset, development project and exploration, 53.13 per cent. operated interest

Premier acquired a 75 per cent. interest in Block 12W located in the Nam Con Son Basin from Delek Energy Systems Limited (“Delek”) in 2004, and subsequently farmed-out part of its interest to Santos Limited leaving Premier with a 37.5 per cent. operated interest. In 2009, Premier acquired Delek’s remaining 25 per cent. interest in Block 12W and PetroVietnam subsequently exercised its back-in-right to acquire a 15 per cent. interest. As a result, Premier holds a 53.13 per cent. interest in Block 12W, while Santos and PetroVietnam hold 31.875 per cent. and 15 per cent. respectively.

The area has similar geology to the West Natuna Sea area, approximately 300 kilometres to the south west. The Group announced two discoveries – Dua and Chim Sáo – on the block in 2006. Chim Sáo was successfully appraised in 2008.

A field development plan for Chim Sáo was submitted to the Vietnamese Government and approved in 2008. During the Chim Sáo development drilling programme, the CS-N2P well intersected an estimated 15 metres of net oil bearing sandstones in the fault terrace to the north west of the field. This was subsequently appraised by the CS-N1P development well which intersected an estimated 89 metres of net oil bearing sands within a stacked sequence of Upper Dua sandstones.

Chim Sáo was brought on-stream in mid-October 2011. During the first month of production 26,600 bopd were delivered from six wells. Gas export is scheduled to commence from early December 2011; and the exported gas and associated liquids are expected to add 6,000 boepd (gross) to Chim Sáo production. Block 12W has an estimated 40 mmbœ of 2P reserves and 2C contingent resources, but this figure does not include the expected additional reserves from the north west fault terrace.

Chim Sáo**Block 07/03 – exploration, 30 per cent. operated interest**

Block 07/03 is located in the Nam Con Son Basin, immediately to the south east of Block 12W.

In 2009, the CRD exploration well (07-CRD-1X) on Block 07/03 intersected approximately 90 metres net oil and gas pay within multiple stacked reservoir layers. In April 2011, Premier appraised the exploration success at CRD in Block 07/03. Two drill stem tests of hydrocarbon bearing sands in the Oligocene section were conducted. The first zone tested flowed gas and condensate at rates of 9.7 million mmscfd and 870 bopd respectively through a 40/64 inch choke, and the second zone tested flowed gas and condensate at rates of 17 mmscfd and 1,730 bopd respectively through a 56/64 inch choke. The well was sidetracked to further evaluate the distribution of hydrocarbons in the Miocene sands. Commercial development of the CRD

accumulation is now under review along with further investigation of the exploration potential of the rest of Block 07/03.

Partners in Block 07/03 are VAMEX (40 per cent.), Pacific (5 per cent.), PetroVietnam (10 per cent.) and Pearl Energy (15 per cent.).

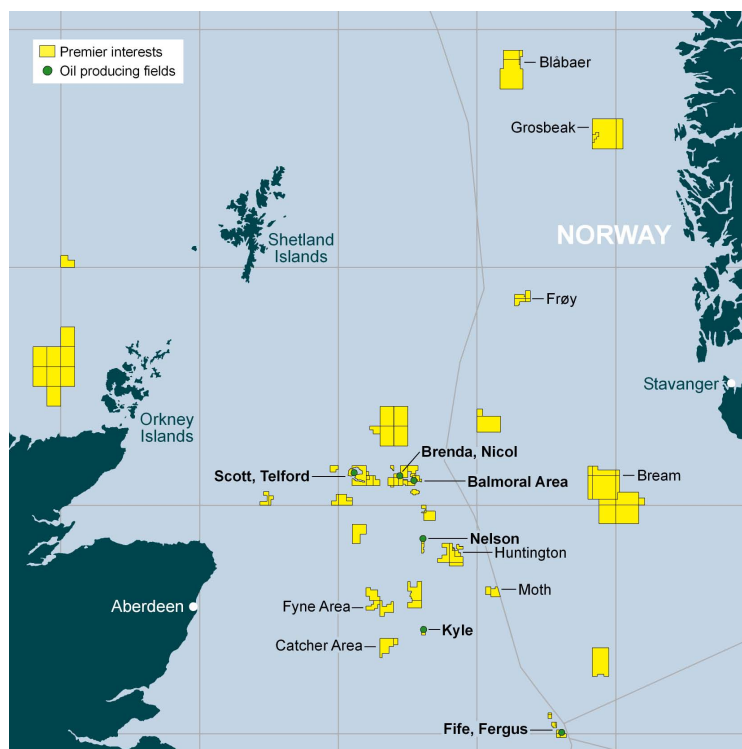
7.2 NORTH SEA BUSINESS UNIT

Estimated 2P reserves and resources in the Enlarged Group's acreage in the North Sea are 220 mmbbl, 40 per cent. of the Enlarged Group's total. With 10.5 kboepd produced in the region in the first half of 2011, the United Kingdom accounted for 31 per cent. of Premier's total production.

To date, all production from the North Sea Business Unit has been from the United Kingdom, with exploration and development activities progressing in Norway. The development portfolio in the North Sea has moved forward significantly in recent months with new projects under construction (Huntington and Rochelle), new projects acquired (Solan and Fyne), and several new projects progressing to sanction, the most significant of which is the development of the Catcher area.

On completion of the Acquisition, the Enlarged Group will own a 50 per cent. interest in the Catcher area. The transaction will also deliver operatorship of Catcher, allowing Premier to work with the partnership group to optimise field development.

North Sea Operations



7.2.1 United Kingdom

Balmoral Area (Balmoral, Glamis, Stirling, Brenda & Nicol fields) – producing asset

The Balmoral, Glamis, Stirling, Brenda & Nicol fields are located in Blocks 16/21a and 16/21b in the UK Central North Sea, 200 kilometres northeast of Aberdeen. Premier acquired its interest in the Balmoral area fields through its acquisition of Oilexco in 2009. The Balmoral area fields produce via a floating production facility located on the Balmoral field. Oil is transported via the Brae-Forties link to Cruden Bay and overland to Hound Point.

Production in the Balmoral area fields for the first half of 2011 was 3,400 boepd net to Premier. Estimated remaining 2P reserves in the Balmoral area fields are 10.6 mmbbl net to Premier.

Wytch Farm – producing asset 30.1 per cent., non-operated interest

In June 2011, Premier announced the acquisition of an additional 17.715 per cent in Wytch Farm, Europe's largest onshore oil field, for an initial cash consideration of US\$96 million (the "Wytch

Farm Acquisition”). On completion of the Wytch Farm Acquisition in December 2011, this will bring Premier’s total interest in Wytch Farm to 30.1 per cent. Premier will support the transition of operatorship to Perenco which, on completion of a related transaction, will hold 50.1 per cent of Wytch Farm.

Production from Wytch Farm was 1,200 boepd net to Premier in the first half of 2011. Assuming completion of the Wytch Farm Acquisition, estimated remaining 2P reserves in the Wytch Farm area are 17.1 mmboe net to Premier; and partners in Wytch Farm will be Perenco (operator, 50.1 per cent), Maersk (7.43 per cent) and Talisman Energy Inc. (4.95 per cent).

Kyle – producing field, 40 per cent. non-operated interest

In 1995, Premier acquired a 20 per cent. interest in the P748 licence, which contains the Kyle oil field, through its acquisition of Pict. In 1997 Premier increased its equity interest in this oilfield from 20 per cent. to 35 per cent. by acquiring Mobil’s remaining equity interest. In 2002, Premier purchased a further 5 per cent. interest for £3.44 million from ROC Oil Company Limited.

Following a successful extended well test with the Petrojarl-1 FPSO in 2000, the Kyle field has been developed via sub-sea wells connected to two manifolds (North and South) tied back 18 kilometres to the Maersk-operated Maersk Curlew FPSO. Oil and gas production via the Maersk Curlew FPSO began in 2001. A gas lift project was completed in 2007 alongside facility upgrades on the Petrojarl Banff host processing facility.

Production from the Kyle oil and gas field in the first half of 2011 was 2,400 boepd net to Premier. Estimated remaining 2P reserves are 3.1 mmboe net to Premier. Partners in Kyle are CNR (operator. 45.71 per cent.) and Dana Petroleum (14.29 per cent.).

Scott – producing field, 21.83 per cent. interest

Scott has proven to be one of the larger and more productive oil fields to be found on the UKCS. Premier acquired a 1.798 per cent equity stake in the 15/21 licence as part of its acquisition of Pict in 1995.

In May 2007, Premier announced the successful completion of a transaction to pre-empt Hess’s proposed sale of its interest in part of the Scott field. Specifically, Premier increased its existing 1.798 per cent. holding to 21.83 per cent. for a net consideration of US\$52.6 million. Letters of credit for approximately £53 million have been issued at the request of Premier in favour of Hess in respect of its share of any decommissioning or clean-up costs.

Production from Scott and Telford in the first half of 2011 averaged 3,400 boepd net to Premier. Estimated remaining 2P reserves are 5.7 mmboe net to Premier.

Nelson – producing asset, 1.65 per cent. non-operated interest

The large Nelson oil and gas field is located to the south east of the Forties field. Nelson was discovered in December 1987. Following an extensive appraisal drilling programme in the late 1980s, estimates of recoverable reserves were significantly increased. The field was subsequently developed using a conventional stand-alone fixed steel platform with one subsea template located six kilometres to the south. First oil was achieved in February 1994.

Oil is exported via a spurline to the Forties Pipeline System and onwards to the BP-operated terminal facilities at Cruden Bay. Gas export is via the Fulmar pipeline to the Shell-operated terminal facilities at St Fergus.

Estimated remaining 2P reserves are 0.3 mmboe net to Premier.

Huntington – development project, 40 per cent. non-operated interest

Premier acquired a 40 per cent. non-operated interest in the Huntington light oil field in 2009 as a result of the Oilexco acquisition. A field development plan was sanctioned in November 2010.

Teekay has agreed to acquire the Voyageur FPSO from Sevan Marine, and is financing the completion of the upgrade of the vessel. Teekay has also agreed a Heads of Terms with E.ON, the operator of the Huntington field, around the existing charter contract, with signature expected by the end of November 2011. The sailaway of the Voyageur is targeted for 31 July 2012 with first oil in September 2012.

2P reserves are estimated at 14.9 mmboe net to Premier. Partners in Huntington are E.ON (operator 25 per cent.), Noreco (20 per cent.) and Carrizo Oil and Gas (15 per cent.).

Rochelle – development project, 15 per cent, non-operated interest

Good progress has been made on the UK development project Rochelle, which comprises East and West Rochelle. The Rochelle project, in which Premier will hold a 15 per cent. unitised equity stake, will be developed in two almost parallel phases. Phase 1 will see East Rochelle developed for first gas, which is to be produced via the Scott platform, in November 2012. East Rochelle received development sanction in January 2011. Phase 2 will entail the tie-in of the West Rochelle project to the East Rochelle subsea production manifold. The West Rochelle development was sanctioned in October 2011.

Rochelle is estimated to have 3.2 mmboe of 2P reserves net to Premier. Partners in Rochelle are Endeavour (operator) and Nexen.

The Catcher Block – development project, 50 per cent. operated interest

As a result of the Acquisition, Premier will increase its interest in the Catcher area by 15 per cent., taking the overall interest of the Enlarged Group to 50 per cent. and giving Premier operatorship. The Catcher area is located in the central North Sea and comprises the Catcher, Catcher East, Catcher North, Varadero and Burgman discoveries. Commercial quantities of hydrocarbons have been proven and the joint venture is working towards a Catcher area development.

Estimated 2P reserves for the Catcher block are 42 mmboe net to the Enlarged Group. Upon completion of the Acquisition, the partners in the Catcher area will be Wintershall (20 per cent.), Nautical Petroleum (15 per cent.) and Agora Oil & Gas (15 per cent.).

Solan – development project, 60 per cent. operated interest

In May 2011, Premier signed a sale and purchase agreement under which Premier acquired a 60 per cent. equity interest in Solan and would become the development operator of the field at the date of sanction.

Estimated 2C contingent resources for the Solan field are 30 mmboe net to Premier. Chrysaor Limited is Premier's partner in the field with an equity stake of 40 per cent.

Fyne – development project and exploration, 39.9 per cent operated interest

In March 2011, Premier exercised its option to drill the East Fyne appraisal well under its joint venture and earn-in agreement with Antrim. By exercising its option, Premier acquired a 39.9 per cent. operated interest in Block 21/28a, which contains the Fyne field, in return for a carry of up to US\$50 million towards the development costs, including the cost of the appraisal well. Pre-development work of the project has been progressed with the aim of sanctioning development in early 2012 for first oil in 2014. Separately, Premier has secured the Transocean Sedco 704 semi-submersible rig to drill the East Fyne appraisal well, which is scheduled to spud in the fourth quarter of 2011.

The Fyne Area was estimated to have 13.3 mmboe of 2C contingent resources net to Premier. Partners in the Fyne Area are Antrim (35.1 per cent.) and First Oil (25 per cent.).

Premier signed a heads of agreement in June 2011 to gain additional acreage in the Greater Fyne area by participating in the Erne exploration well on Block 21/29d. The Erne well, which spudded on 12 November 2011, will target the Eocene Tay formation oil prospect located between the Fyne and Guillemot NW fields in the UK Central North Sea. A successful Erne exploration well – along with the results of the East Fyne appraisal well – will be taken into account as development planning for the Fyne field continues.

Premier's partner in the Erne exploration well is Antrim, with a 50 per cent. interest.

Tudor Rose – exploration, 40 per cent. operated interest

After the Acquisition, the Enlarged Group will hold a 40 per cent. operated interest in an undeveloped discovery in the central North Sea known as Tudor Rose, which encountered an 80 foot heavy oil column within tertiary sands when it was drilled by the previous licensee in 1983. This established an oil-water contact at 3,283 feet. The critical issue which needs to be established to determine if Tudor Rose can be commercially exploited is the quality and viscosity of the oil in place. EnCore has signed a letter of award with ADTI Inc. for the Sedco 704 rig for the drilling of an appraisal well on the Tudor Rose discovery and this well was spudded on 16 November 2011.

The block contains three additional prospects, including the Buffalo prospect, identified within the Lower Cretaceous and Upper Jurassic intervals.

Partners in Tudor Rose are Nautical Petroleum (20 per cent.), Endeavour Energy (20 per cent.) and EnQuest (20 per cent.).

Spaniards – exploration, 28 per cent. operated interest

After the Acquisition, the Enlarged Group will hold a 28 per cent. operated interest in the Spaniards area in the central North Sea, which EnCore acquired in the 25th Licensing Round as a traditional licence.

The first well to appraise the Spaniards discovery is expected to commence drilling in the third quarter of 2012, subject to suitable rig availability and receipt of the necessary permitting and site survey approvals.

Partners in Spaniards are Nautical Petroleum (21 per cent.), Serica Energy (21 per cent.), DEO Petroleum (12.62 per cent.), Faroe Petroleum (8.40 per cent.), Maersk (5.74 per cent.) and Atlantic Petroleum (3.24 per cent.).

7.2.2 Norway

Frøy – development project, 50 per cent. non-operated interest

The Frøy oil field was abandoned in 2001 by a previous operator due to the imminent abandonment of the nearby Frigg field to which it was tied back. Premier was awarded a 50 per cent. non-operated interest in licence PL364 which contains the Frøy field in the 2005 APA licensing round.

The development plans for the Frøy field received Premier support for moving to the next phase. However, the current operator has indicated that, due to limited resources and commitments elsewhere, they will not be proceeding with the project at this time. Dialogue with the operator for commercial arrangements to progress Frøy continues.

Estimated 2P reserves are 27 mmbbl net to Premier. Det Norske Oljeselskap is the current operator of Frøy with a 50 per cent. interest.

Bream – development project, 20 per cent. non-operated interest

The Bream field has a 2P reserves estimate of 5.3 mmbbls of oil net to Premier. Discussions continue with the identified FPSO contractor for the Bream field development. A formal development plan is expected to be submitted in the first half of 2012. Partners in the field are BG (operator, 40 per cent.) Skeie Energy (20 per cent.) and Sprint Energy (20 per cent.).

Gardrofa – exploration, 40 per cent. operated interest

In the first half of 2011, Premier was granted permission by the Norway Petroleum Safety Authority to drill Premier's first operated well in Norway, the Gardrofa well in PL406, which spudded in October 2011. Premier was awarded the licence in APA 2006.

Partners in Gardrofa are Skeie Energy (40 per cent.) and Spring Energy (20 per cent.).

7.3 MIDDLE EAST/AFRICA/PAKISTAN BUSINESS UNIT

2P reserves and 2C contingent resources in the Middle East/Africa/Pakistan are 54 mmbbl, which represents 10 per cent. of the Enlarged Group's total. With 15,600 boepd produced in the region in the first half of 2011, Africa and Pakistan accounted for 43 per cent. of Premier's total production.

7.3.1 Pakistan

Partners in Pakistan are Skeie Energy (40 per cent.) and Spring Energy (20 per cent.). Premier has been present in Pakistan, as a non-operator, since 1988. In 1990, Premier discovered the Qadirpur field. Since then, Premier has acquired interests in five other fields, all located in agricultural lowlands. All fields are long-life gas projects with licences expiring between 2015 and 2023 and have relatively low operating costs. All production is sold at the wellhead to the government-owned gas utilities, SSGCL and SNGPL. Revenues are denominated in US Dollars and funds are remitted directly to London bank accounts. No production has been lost as a result of political disturbances.

Average production in Pakistan during the first half of 2011 was 14,900 boepd net to Premier (being 41 per cent. of the Company's total production for that period), which is stable when

compared to production figures for 2010. Production was maintained by maximising output from existing gas fields through infill drilling and the implementation of front end compression projects.

2P reserves and 2C contingent resources in Pakistan are 44 mmboe net to Premier.

Pakistan Operations



Qadirpur – producing asset, 4.75 per cent. non-operated interest

The Qadirpur gas field was discovered in 1990 following a seismic survey on the Qadirpur block. The field was declared commercial in 1992 and production commenced in October 1995. The field operator is the OGDCL, the state-owned oil and gas company.

Phase I of the Qadirpur development was completed with gas supplies initially at the rate of 100 mmcf/d commencing to SNGPL in October 1995 with four wells onstream. Shortly thereafter, gas sales were increased to 200 mmcf/d and were maintained at that level until late 1999. In addition, in December 2000, raw gas supply started to the nearby Liberty power plant at 40 mmcf/d.

Phase II of the Qadirpur development was completed in January 2004 expanding the gas plant capacity to 400 mmcf/d. Phase III of the development was completed in the first quarter of 2004 when total gas sales from Qadirpur gas field were increased from 400 mmcf/d to 500 mmcf/d. The project to enhance the plant capacity from 500 mmcf/d to 600 mmcf/d achieved first gas in the first quarter of 2008. Estimated remaining 2P reserves in the Qadirpur field are 10.4 mmboe net to Premier. Production for the first half of 2011 averaged 3,800 boepd net to Premier, higher than the previous year due to a wellhead compression project coming onstream in the fourth quarter of 2010. In addition, an extended reach development well was completed in June 2011 and has been tied in to the production facility. The partners in the Qadirpur field are OGDCL (operator, 75 per cent.), Kufpec Pakistan B.V. (13.25 per cent.) and Pakistan Petroleum (7 per cent.).

Bhit and Badhra – producing asset, 6 per cent. non-operated interest

The Bhit gas field was discovered by a subsidiary of Lasmo plc (“Lasmo”) in 1997. The Group's equity in the concession was obtained in January 1999 through the joint venture company PSP. Following the de-merger of PSP in 2001, the equity interest of 12 per cent., was retained by PKP, the joint venture between Kufpec and Premier. Subsequent to the demerger of PKP, Premier retained a 6 per cent. equity stake in the Bhit gas field. In late 1997, Lasmo commenced an aggressive appraisal programme on the concessions combined with seismic data acquisition.

The Bhit partners signed a GSPA with SSGCL in November 2000 for 270 mmcf and initial gas sales were achieved in late December 2002. A supplemental GSPA to increase the Bhit ACQ from 270 mmcf to 300 mmcf has since been signed by the gas buyer SSGCL and joint venture partners.

The Badhra field was discovered by the Badhra-1 well, drilled by a subsidiary of the Hunt Oil Company in 1958/1959, and was plugged and abandoned at a depth of 1,333 metres. Badhra-2, located three kilometres to the north of Badhra-1, was drilled by Lasmo in late 1998 to a depth of 3,495 metres. Wire line logs and gas shows indicated the presence of a gas column, and a test of an 11 metres thick interval produced gas at rates of up to 10.4 mmcf. The Mughal Kot sandstone had not previously been encountered in the Kirthar fold belt, and represented a new play in the area. The Badhra field was appraised in 2003, which formulated the basis of the field development plan. The Pakistan Government approved the field development plan in January 2004 and the field started producing in January 2008. Further field development is tied to Bhit Phase-2 development. The Badhra-6 development well is planned to be drilled in the fourth quarter of 2012.

Bhit and Badhra are now supplying approximately 340 mmscf, which is above the annual contracted gas quantity of 300 mmscf. 2P reserves are estimated at 5.1 mmboe net to Premier, and production averaged 3,400 boepd in the first half of 2011. Partners in the Bhit/Badhra field are ENI (operator, 40 per cent.), OGDCL (20 per cent.), Shell (28 per cent.) and Kufpec (6 per cent.).

Kadanwari – producing asset, 15.79 per cent. non-operated interest

Lasmo discovered the Kadanwari gas field with the Kadanwari-1 well in 1989. The field was brought onstream in May 1995 and Premier acquired its initial interest in 1996. The gas is processed in a central processing facility, originally designed for gas sales capacity of 175 mmcf. In 2006, the K-15 well was tied back to the processing plant, which compensated for the natural decline of the field and also provided some production redundancy. The Kadanwari gas field is currently supplying approximately 66 mmscf. This is expected to rise to in excess of 75 mmscf after the K-27 well is tied in later this year. The K-28 exploration well is planned to spud in November 2011, and the K-29 development well is planned for the second quarter of 2012. The Kadanwari production lease runs until 2022.

2P reserves and 2C contingent resources are estimated at 10.5 mmboe net to Premier, and net production for the first half of 2011 averaged 2,300 boepd. Improved production performance relative to the first half of 2010 is mainly due to the drilling and tie-in of exploration well K-19 in the second half of 2010 and the successful K-18 sidetrack well, which came onstream in February 2011. Contributing to future deliverability of the Kadanwari gas field is the exploration well K-27, which exceeded expectations and tested at 51 mmscf in April 2011.

Partners in the Kadanwari field are ENI (operator, 18.42 per cent.), OGDCL (50 per cent.) and Kufpec (15.79 per cent.).

Zamzama – producing asset, 9.375 per cent. non-operated interest

The Zamzama gas field was discovered by Premier in May 1998. Premier drilled the Zamzama-1 well as part of its farm-in to the block. Zamzama-2 well was drilled to appraise the field in March 1999. To define the Zamzama structure better, a drilling campaign was conducted in 2002 to 2003. During this period, five further appraisal and development wells were drilled which all proved successful with commercial gas flow at surface. In April 2000, the consortium of partners signed a GSA with SSGCL for the supply of 70 mmcf of gas from the Zamzama field.

In April 2001, gas production started from extended well tests of the Zamzama-1 discovery well and Zamzama-2 appraisal well under a 21-month contract signed with SSGCL for 60 mmcf. As per the Phase-1 development plan, two trains of dehydration plants with a capacity of 140 mmcf were installed and commissioned in July 2003. Gas contracts were signed in the fourth quarter of 2001 with SSGCL and SNGPL covering the supply of up to 320 mmcf. Another gas supply contract was signed with SSGCL for an additional supply of 150 mmcf in 2005. A front end compression project is in progress: one out of two compressors has been commissioned, with the second planned to be commissioned in August 2012. Zamzama is currently supplying approximately 430 mmscf.

2P reserves and 2C contingent resources are estimated at 18 mmboe net to Premier, and net production for the first half of 2011 was 5,400 boepd. Partners in the Zamzama field are BHP

Billiton (operator, 38.5 per cent.), GHPL (25 per cent.), ENI (17.75 per cent.) and Kufpec (9.375 per cent.).

7.3.2 Egypt

South Darag Block – exploration asset, 100 per cent. operated interest

A 100 per cent. interest in the South Darag Block in the Gulf of Suez was awarded to Premier in March 2010 for a three year initial term. The award is awaiting government ratification. Three leads have been identified in the block with an estimated total unrisks prospective resource of 50 to 150 mmbbls of oil.

North Red Sea Block 1 – exploration asset, 20 per cent. non-operated interest

Premier farmed into the North Red Sea Block 1 with Hess in December 2010. Specifically, Premier contributed to the cost of the NRS-2 (Cherry) exploration well in return for a 20 per cent interest. The exploration well, which was the first test of a significant deep water play in the northern Red Sea, was drilled in early 2011 and encountered hydrocarbon shows but did not intersect reservoir quality sandstones. Results of the well are now being integrated with geologic, seismic and engineering data to determine if alternate opportunities exist elsewhere on the block.

The partner in North Red Sea Block 1 is Hess (operator, 80 per cent.)

7.3.3 Kenya

In May 2011, Premier entered Kenya with the signing of two PSCs for offshore exploration blocks L10A and L10B. The Group holds a 20 per cent equity interest in L10A and a 25 per cent. equity interest in L10B. The forward plan in Kenya is for the joint venture partners to acquire 2D and 3D seismic data across the area, for better definition of the numerous leads and prospects. Acquisition commenced in November 2011.

The partners in L10A include BG (operator, 40 per cent.), Cove Energy (25 per cent.) and Pancontinental (15 per cent.)

The partners in L10B include BG (operator, 45 per cent.), Cove Energy (15 per cent.) and Pancontinental (15 per cent.).

7.3.4 Mauritania

Chinguetti – producing asset, 8.123 per cent. non-operated interest

In Mauritania, the Chinguetti field averaged 700 boepd net to Premier during the first half of 2011 and natural decline of the field continues to be less than expected. The new agreements for extending PSC A and PSC B, which include combining the exploration areas into a new PSC (PSC C-10), have been approved by the Government of Mauritania and are awaiting formal gazettal.

Estimated remaining 2P reserves are 0.7 mmboe net to Premier. Partners in the field are Petronas (operator, 47.384 per cent.), Tullow Oil (19.008 per cent.), Société Mauritanienne des Hydrocarbures (12 per cent.), Kufpec (10.234 per cent.) and ROC (3.25 per cent.).

7.3.5 Middle East

In 2008, Premier executed a shareholder agreement with EIIC to form two new joint venture companies to pursue the acquisition of upstream oil and gas assets across the Middle East and North Africa region. The first joint venture, Premco Energy Projects Company LLC, is owned 49 per cent. by Premier and 51 per cent. by EIIC and will hold all joint venture assets which are acquired in the United Arab Emirates. The second joint venture, Premco Energy Projects B.V., is owned 50 per cent. by Premier, 50 per cent. by EIIC, and will hold all joint venture assets which are acquired in the Middle East and North Africa region (excluding the United Arab Emirates).

This joint venture will enable Premier to access acquisition opportunities across the Middle East and North Africa region and build a material oil and gas business across the Middle East and North Africa. A number of potential projects have already been identified but no acquisitions have been made to date.

In 2011, Premier pre-qualified as a non-operator for the Iraq fourth licensing round which is expected to take place early in 2012.

PART II

OPERATING AND FINANCIAL REVIEW OF PREMIER

Incorporation by reference

The operating and financial review of the Company as set out in the Company's Annual Reports and Accounts for 2008, 2009 and 2010 and the Company's unaudited interim results for the six months ended 30 June 2011, which are available on the Company's website at www.premier-oil.com, are hereby incorporated by reference into this document.

Cross reference list

The following list is intended to enable investors to identify easily specific items of financial information which have been incorporated by reference into this document. The sections of the documents listed below which are not incorporated by reference are either not relevant to investors or are superseded by information elsewhere in this document.

Operating and financial review for the Company for the six months ended 30 June 2011

The page numbers below refer to the relevant pages of the Company's unaudited interim results for the six months ended 30 June 2011:

- The section headed "Operational Review" on pages 6-12.
- The section headed "Financial Review" on pages 13-16.

Operating and financial review for the Company for the year ended 31 December 2010

The page numbers below refer to the relevant pages of the Company's Annual Report and Accounts for the year ended 31 December 2010:

- The section headed "Operations Review" on pages 6-11.
- The section headed "Financial Review" on pages 16-19.

Operating and financial review for the Company for the year ended 31 December 2009

The page numbers below refer to the relevant pages of the Company's Annual Report and Accounts for the year ended 31 December 2009:

- The section headed "Operations Review" on pages 6-10.
- The section headed "Financial Review" on pages 14-19.

Operating and financial review and consolidated financial statements for the Company for the year ended 31 December 2008

The page numbers below refer to the relevant pages of the Company's Annual Report and Accounts for the year ended 31 December 2008:

- The section headed "Chief Executive's Review" on pages 4-11.
- The section headed "Financial Review" on pages 12-14.

PART III

CAPITAL RESOURCES

Capitalisation and Indebtedness

The following table shows the capitalisation and indebtedness of the Premier Group as at 31 October 2011.

	<i>US\$m</i>
Total current debt	
Guaranteed	0
Secured	27.0
Unguaranteed/unsecured	175.0
	202.0
Total non-current debt (excluding current portion of long-term debt)	
Guaranteed	0
Secured	0
Unguaranteed/unsecured	1,177.5
	1,177.5
Shareholders equity	
Share capital	98.8
Share premium	274.4
Other reserves	850.5
Total	1,223.7
Cash	35.5
Cash equivalents (bank deposits)	625.3
Trading receivables	489.5
Total liquidity	1,150.3
Current bank debt	27.0
Current portion of non-current debt	175.0
Other current financial debt	0
Current financial debt	202.0
Net current cash/(financial indebtedness)	948.3
Non current bank loans	600.0
Bonds issued	226.8
Other non current borrowings	350.7
Non current financial indebtedness	1,177.5
Net cash/(financial indebtedness)	(229.2)

Liquidity and capital resources

The Group's liquidity requirements arise from its working capital needs and its programmes of capital expenditure. These requirements are met by a combination of cash resources, the re-investment of cash flows from producing fields and the draw-down of bank facilities. The Group's businesses display no significant seasonality in their borrowing requirements.

Premier anticipates managing its balance sheet by balancing long-term debt to equity in the range of 30:70 over the medium-term. Interest rate coverage is anticipated to remain a minimum of four times.

Treasury structure and objectives

Premier operates a centralised treasury section which is responsible for the management of the investment of surplus funds, for making draw downs under bank facilities, for foreign exchange management and for commodity hedging. Business units only have funds for working capital purposes and will cash call Premier's treasury on a monthly or bi-monthly basis for the funds required. Cash from sales made by the business units in the UK, Indonesia, Pakistan and Mauritania are received in London bank accounts in US Dollars and Pounds Sterling and are managed as part of Premier's total available funds.

The Company's activities expose it to financial risks of changes, primarily in oil and gas prices but also foreign currency exchange and interest rates. The Company uses derivative financial instruments to hedge certain of these risk exposures. The use of financial derivatives is governed by the Group's policies and approved by the Board, which provide written principles on the use of financial derivatives.

As Premier reports in US Dollars, the foreign exchange strategy undertaken by Premier's treasury is to fund in US Dollars providing a hedge against the almost exclusively US Dollar denominated assets. Surpluses in both US Dollars and to a lesser extent Pounds Sterling and Norwegian Krone are maintained as a float to meet short-term cash needs of the business and, to the extent that there are any shortfalls in Pounds Sterling and Norwegian Krone income to meet this expenditure, US Dollars will be swapped into these currencies to cover this. Investments are made on a short-term basis (no more than 3 months) in bank deposits with the bank group participants, and AAA liquidity funds.

It is Company policy that all transactions involving derivatives must be directly related to the underlying business of the Company. The Company does not use derivative financial instruments for speculative exposures. The Company undertakes oil and gas price hedging periodically within Board limits to protect operating cash flow against weak prices.

Premier's commodity hedging policy is to lock in oil and gas price floors for a portion of expected future production at a level which protects the cash flow of the Group and the business plan. Current policy has been to hedge using zero cost collars. As at 30 June 2011, the Group had 3.42 million barrels of Dated Brent oil hedged with collars at an average floor price of US\$44.95/bbls and an average cap of US\$90.53/bbls, all of which were embedded through off-take agreements to the end of 2012. The Group also maintains a hedging position in Singapore 180 HSFO, which underlies the pricing mechanism for gas sold into the Singapore market. A total of 222,000 metric tonnes have been hedged to the period ending mid-year 2013 with a floor of US\$250.0/mt and a cap of US\$500.0/mt. Premier undertook further oil and gas hedging in October 2011 with a total of 2.1 mmbbls of oil for 2012 being sold forward at an average price of US\$105.35 and a total of 132,000 metric tonnes of Singapore 180 HSFO for 2012 being sold forward at an average price of US\$622.18/mt.

Interest rate risk

As at 30 September 2011, US\$450.0 million of the Group's long-term bank borrowings had been swapped from floating rate to fixed rate. Under these interest rate swap contracts, the Group has agreed to exchange the difference between fixed and floating interest amounts calculated on agreed notional principal amounts. Such contracts enable the Group to mitigate the risk of changing interest rates and the cash flow exposure on the issued variable rate debt held.

Cash flows (US\$ million)

	<i>Half year to 30 June 2011</i>	<i>12 months to 31 December 2010</i>	<i>12 months to 31 December 2009</i>
Net cash from operating activities	242.3	436.0	347.7
Investing activities:			
Capital expenditure	(296.8)	(514.1)	(303.1)
Pre-licence exploration costs	(10.2)	(18.9)	(20.3)
Acquisition of subsidiaries	—	—	(574.2)
Acquisition of oil and gas properties	(86.5)	(7.4)	(83.9)
Proceeds from disposal of oil and gas properties	—	20.4	14.8
Recovery of cash previously held in a decommissioning trust	—	69.2	—
Net cash used in investing activities	(393.5)	(450.8)	(966.7)
Financing activities:			
Proceeds from issuance of ordinary shares	0.1	0.3	252.2
Expenses on issuance of ordinary shares	—	—	(12.2)
Purchase of shares for ESOP Trust	(0.9)	(8.3)	(2.5)
Proceeds from drawdown of long-term bank loans	14.8	310.0	353.0
Proceeds from issuance of senior loan notes	350.7	—	—
Debt arrangement fees	(1.8)	(17.9)	(25.6)
Repayment of long-term bank loans	(10.0)	(178.0)	—
Interest paid	(20.8)	(40.9)	(21.2)
Net cash from financing activities	332.1	65.2	543.7
Currency translation differences relating to cash and cash equivalents	2.3	(1.3)	2.2
Net (decrease)/increase in cash and cash equivalents	183.2	49.1	(73.1)
Cash and cash equivalents at the beginning of the period	299.7	250.6	323.7
Cash and cash equivalents at the end of the period	482.9	299.7	250.6

Cash flow from operating activities in the six months to 30 June 2011 was US\$242.3 million after accounting for tax payments of US\$3.6 million.

Capital Expenditure (US\$ million)

	<i>Half year to 30 June 2011</i>	<i>12 months to 31 December 2010</i>	<i>12 months to December 2009</i>
Fields/development projects	177.0	347.1	192.5
Exploration	118.7	164.7	107.5
Other	1.1	2.3	3.1
Total	296.8	514.1	303.1

Capital expenditure in the six months to 30 June 2011 totalled US\$296.8 million.

The principal field and development projects were the Chim Sáo, Gajah Baru and Huntington projects.

Cash position and debt

Net debt at 31 October 2011 amounted to US\$718.7 million, with cash resources of US\$660.8 million.

	<i>31 October 2011</i>	<i>30 June 2011</i>	<i>31 December 2010</i>	<i>31 December 2009</i>
Net debt (US\$ million)				
Cash and cash equivalents	660.8	482.9	299.7	250.6
Convertible bonds*	(226.8)	(224.2)	(220.4)	(213.2)
Other long-term debt**	(1,152.7)	(840.6)	(485.0)	(353.0)
Total net debt	(718.7)	(581.9)	(405.7)	(315.6)

* The convertible bonds have a nominal value of US\$250 million, an equity conversion price of £3.39 and a final maturity date of 27 June 2014.

** This includes drawdown of US\$300 million from the available Revolving Credit Facility, which was repaid on 10 November 2011.

Credit facilities

Premier has the following credit facilities in place:

	<i>Balance Available at 31 October 2011</i>	<i>Balance Outstanding at 31 October 2011</i>	<i>Interest Rate%</i>	<i>Maturity</i>
Revolving Credit Facility	US\$456,805,000	US\$300,000,000*	LIBOR + 2.50	31 March 2015
Letter of Credit Facility	£132,000,000	£63,600,000	2.25	31 March 2015
Letter of Credit Facility	£267,500,000	£120,600,000	2.25	31 March 2015
Term Loan Facility	US\$300,000,000	US\$300,000,000	LIBOR + 2.50	7 May 2015
Term Loan Facility	US\$175,000,000	US\$175,000,000	LIBOR + 4.00	21 March 2012
Exploration Financing Facility	NOK 150,000,000	NOK 150,000,000	NIBOR + 1.45	31 December 2012
Senior Notes A	EUR 75,000,000	EUR 75,000,000	5.32	9 June 2018
Senior Notes B	US\$70,000,000	US\$70,000,000	5.11	9 June 2018
Senior Notes C	US\$174,000,000	US\$174,000,000	5.78	9 June 2021

* Premier repaid US\$300 million under the Revolving Credit Facility on 10 November 2011.

The facilities include financial covenants that require Premier to maintain certain financial ratios, which are calculated in accordance with IFRS:

- (A) the ratio of its consolidated net debt (including Letters of Credit considered as drawn down) to EBITDAX must not exceed 3.00:1.00 for a measurement period being a twelve month period ending on the last day of a financial half year of the parent company;
- (B) the ratio of its EBITDAX to group consolidated net interest payable must not fall below 4.00:1.00 for any measurement period; and/or
- (C) the aggregate unconsolidated proven and probable reserves of the relevant guarantor subsidiaries of Premier must not at any time amount to less than 90 per cent. of the consolidated proven and probable reserves of the Group.

EBITDAX is defined as earnings before interest, taxes, depreciation and amortisation before exploration write-off.

Premier has complied with these covenants since the execution of the facilities.

Premier entered into an amendment agreement on 26 October 2011 with the lenders of the Revolving Credit Facility, that provides that, of the Revolving Credit Facility's total commitments, up to US\$350 million (the "Acquisition Facility") is available for the purposes of the Acquisition. The Acquisition Facility is more particularly described in the section headed "Material Contracts" in Part IX of this document.

Undrawn cash balances (US\$ million)

	<i>31 October 2011</i>	<i>31 December 2010</i>	<i>31 December 2009</i>
Expiring in less than one year	—	—	—
Expiring in more than one year, but not more than two years	—	17.2	—
Expiring in more than two years, but not more than five years	156.8	446.8	328.2

The undrawn balance on the letter of credit facilities as at 30 June 2011 was £215.3 million. The drawn amount of US\$300 million from the Revolving Credit Facility was repaid on 10 November 2011.

Convertible bonds

In June 2007, the Group issued bonds at a par value of US\$250 million which are convertible into Premier Shares at any time until six days before their maturity date of 27 June 2014. Interest of 2.875 per cent. per annum will be paid semi-annually in arrears up to that date.

Private Placement

In June 2011, Premier issued seven and ten year senior notes in the US Private Placement market amounting to US\$350.7 million. These carry an average interest rate of 5.4 per cent. per annum and will redeem in 2018 and 2021. The notes rank *pari passu* with all other unsecured and unsubordinated financial indebtedness. Interest is paid semi-annually.

Articles of association

In addition to the banking covenants, Premier's articles of association set out the borrowing limits placed on the Premier Directors. The amount outstanding on all borrowings by Premier shall not exceed at any time, without previous sanction of an ordinary resolution, an amount equal to four times the adjusted capital and reserves.

PART IV

HISTORICAL FINANCIAL INFORMATION RELATING TO PREMIER

Basis of Financial Information

The financial statements of Premier included in the consolidated audited Annual Reports and Accounts of Premier for the financial years ended 31 December 2008, 31 December 2009 and 31 December 2010 together with the audit reports of Deloitte LLP thereon are incorporated by reference into this document. The audit reports for the financial years ended 31 December 2008, 31 December 2009 and 31 December 2010 were unqualified. The financial statements for the years ended 31 December 2008, 31 December 2009 and 31 December 2010 were prepared in accordance with IFRS.

The unaudited consolidated interim financial statements of Premier for the six months ended 30 June 2011, together with Deloitte LLP's review thereon, are incorporated by reference into this document.

Cross-Reference List

The following list is intended to enable investors to identify easily specific items of information which have been incorporated by reference into this document. The sections of the documents listed below which are not incorporated by reference are either not relevant to investors or are superseded by information elsewhere in this document.

Financial Statements for the year ended 31 December 2008 and Independent Audit Report thereon

The page numbers below refer to the relevant pages of the Annual Report and Accounts of Premier for the financial year ended 31 December 2008:

- Auditors' Report page 78.
- Consolidated Income Statement page 53.
- Consolidated Balance Sheet page 54.
- Consolidated Cash Flow Statement page 55.
- Notes to the Accounts pages 56-77.

Financial Statements for the year ended 31 December 2009 and Independent Audit Report thereon

The page numbers below refer to the relevant pages of the Annual Report and Accounts of Premier for the financial year ended 31 December 2009:

- Auditors' Report page 57.
- Consolidated Income Statement page 58.
- Consolidated Balance Sheet page 59.
- Consolidated Cash Flow Statement page 61.
- Notes to the Accounts pages 62-82.

Financial Statements for the year ended 31 December 2010 and Independent Audit Report thereon

The page numbers below refer to the relevant pages of the Annual Report and Accounts of Premier for the financial year ended 31 December 2010:

- Auditors' Report page 66.
- Consolidated Income Statement page 67.
- Consolidated Balance Sheet page 69.
- Consolidated Statement of Changes in Equity page 70.
- Consolidated Cash Flow Statement page 71.
- Notes to the Accounts pages 72-97.

Interim statement of results for the six months ended 30 June 2011 and Independent Review thereon

- Auditors' review pages 33-34.
- Condensed consolidated Income Statement page 18.
- Consolidated Balance Sheet page 19.
- Consolidated Statement of Changes in Equity page 20.
- Consolidated Cash Flow Statement page 21.
- Notes to the Accounts pages 22-33.

PART V

COMPETENT PERSONS' REPORTS

Set out below are two reports.

The first has been prepared by DeGolyer and MacNaughton and reports on the estimates of the extent of certain proven and possible reserves and of the value of the proven and proven plus-probable reserves owned by Premier.

The second has been prepared by Resource Investment Strategy Consultants and reports on prospective and certain contingent resources of Premier.

DEGOLYER AND MACNAUGHTON
5001 SPRING VALLEY ROAD
SUITE 800 EAST
DALLAS, TEXAS 75244

November 18, 2011

Premier Oil Plc
23 Lower Belgrave Street
London, SW1W 0NR
United Kingdom

RBC Europe Limited
Riverbank House
2 Swan Lane
London EC4R 3BF
United Kingdom

Ladies and Gentlemen:

Pursuant to your request, we have prepared estimates, as of September 30, 2011, of the extent of certain proved, probable, and possible oil, condensate, natural gas liquids (NGL), and marketable-gas reserves, an appraisal of the value of the proved and proved-plus-probable reserves, and the extent only of the 1C (low), 2C (best), and 3C (high) contingent resources owned by Premier Oil Plc (Premier) located in various countries.

Estimates of proved, probable, and possible reserves and contingent resources have been prepared according to 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 notes of the London Stock Exchange. The reserves definitions are discussed in detail under the Definition of Reserves heading of this report. The contingent resources definitions are discussed in detail under the Definition of Contingent Resources heading of this report.

Reserves estimated in this report are expressed as gross and working-interest reserves. Gross reserves are defined as the total estimated petroleum to be produced from these properties after September 30, 2011. Working-interest reserves are defined as that portion of the gross reserves to be produced from the properties attributable to the interests owned by Premier, as of September 30, 2011, before deduction of any associated royalty burden and net profits payable or government profit share.

Values for proved and proved-plus-probable (non-risk-adjusted) reserves in this report were estimated using prices specified by Premier. An explanation of the future price and cost assumptions is included in the Valuation of Reserves section of this report. Values shown in this report are expressed in terms of future net revenue and net present worth. Future net revenue is defined as the revenue attributable to the interests of Premier after deducting direct operating expenses, capital costs, host country taxes, and all interests, including royalties, attributable to others. Operating expenses include field operating expenses, transportation expenses, compression charges, and an allocation of overhead that directly relates to production activities. Capital costs include such items as platforms, pipelines, wells, and compressors. Future income tax expenses were taken into account for all countries except the United Kingdom by determining the appropriate host country taxes to be paid. Net present worth is defined as the future net revenue derived from proved and probable reserves discounted at a specified arbitrary discount rate compounded monthly over the expected period of realization. Present worth values herein are included as totals at discount rates of 8 and 10 percent.

The contingent resources estimated in this report are expressed as gross contingent resources and working-interest contingent resources. Gross contingent resources are defined as the total estimated petroleum that is potentially recoverable after September 30, 2011. Working-interest contingent resources are defined as that portion of the gross contingent resources potentially to be produced from the properties attributable to the interests owned by Premier, as of September 30, 2011, before deduction of any associated royalty burdens and net profits payable or government profit share.

The contingent resources estimated herein are those quantities of oil or gas that are potentially recoverable from known accumulations but which are not currently considered to be commercially recoverable because of the lack of a firm plan of development with the necessary partner or government approval, the lack of a market, or the lack of the proper delineation necessary to establish the size of the accumulation for commercial purposes. The contingent resources estimates in this report are provided as a means of comparison to other resources and do not provide a means of direct comparison to reserves.

Estimates of petroleum reserves, future net revenue, and contingent resources should be regarded only as estimates that may change as additional information becomes available. Not only are such reserves, resources, and revenue estimates based on that information which is currently available, but such estimates

are also subject to the uncertainties inherent in the application of judgmental factors in interpreting such information. Contingent resources quantities should not be confused with those quantities that are associated with reserves due to the additional risks involved. The contingent resources quantities that might actually be recovered should they be developed may differ significantly from the estimates presented herein. There is no certainty that it will be commercially viable to produce any portion of the contingent resources evaluated herein. The contingent resources estimated in this report have an economic status of “Undetermined” and a project maturity of “Development Pending,” “Development on Hold,” or “Development not Viable.”

In this report, key information has been provided on the fields evaluated herein. As far as we are aware, there are no special factors which would affect the production business of Premier that would require additional information for the proper evaluation of these fields. We have prepared estimates of Premier’s reserves and contingent resources on an annual basis for more than 10 years. Reserves estimated herein, are by definition, commercial. Economic limits are based on the Base Case price and cost assumptions provided by Premier and contained in the Valuation of Reserves section of this report.

Information used in the preparation of this report was obtained from Premier. In the preparation of this report we have relied upon information furnished by Premier with respect to the property interests to be evaluated, production from such properties, current costs of operation and development, current prices for production, agreements relating to current and future operations and sales of production, concession expiration dates, and various other information and data that were accepted as represented. Although we have not conducted an independent verification, the information used in this report appears reasonable. The technical staff of Premier involved with the assessment and implementation of development of Premier’s petroleum assets adhere to the generally accepted practices of the petroleum industry. The staff members appear to be experienced and technically competent in their fields of expertise. Site visits to the producing fields evaluated herein were not made by DeGolyer and MacNaughton. Existing production data, reports from third parties, and photographic evidence of the fields were considered adequate because the fields are in established producing venues.

For the purposes of Prospectus Rule 5.5.3R(2)(f), DeGolyer and MacNaughton is responsible for this letter report, contained in Part V of the Prospectus dated November 18, 2011, of Premier, and the estimates of mineral reserves and resources

contained herein, as well as for such estimates and statements and information specifically attributed to DeGolyer and MacNaughton or extracted from this report and included in the Prospectus under the headings “Premier Operations” of “Part I,” “Competent Persons’ Reports” of “Part V,” and “Part IX: Additional Information” under paragraph “13,” and in the form and context in which they appear. 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 in this report as well as references to such information extracted from this report and statements and information attributed to DeGolyer and MacNaughton and included in the Prospectus under the above referenced sections in the form and context in which they appear are in accordance with the facts and contain no omission likely to affect their import. This declaration is included in this report for the Prospectus in compliance with Annex 1, item 1.2 of the Prospectus Directive Regulation.

Executive Summary

Premier has interests in properties for which reserves have been estimated herein located in Indonesia, Mauritania, Norway, Pakistan, the United Kingdom, and Vietnam. Of the 29 field areas evaluated, 16 are currently producing. The most significant reserves centers (greater than an estimated proved-plus-probable working-interest reserves of 25 million barrels of oil equivalent) are the Natuna Block A fields and the North Sumatra Block A fields located in Indonesia and the Chim Sao field located in Vietnam.

In Indonesia, Premier has interests in three production sharing contracts (PSC) governed by the Government of Indonesia: the Natuna Block A PSC, the Kakap PSC, and the North Sumatra Block A PSC. Of these fields, Premier operates only the Natuna Block A PSC. The fields in these PSCs are predominantly gas producing in terms of product sales and are therefore subject to existing gas supply agreements and their associated terms. The proved-plus-probable oil equivalent working-interest reserves estimated for these PSCs combine to represent approximately 38 percent of Premier’s total estimated oil equivalent working-interest reserves. The combined gross producing rates in May 2011 from these fields were approximately 5,625 barrels per day of oil and condensate and 209 million cubic feet per day (MMcf/d) of sales gas.

Premier has interests in the Chinguetti field located offshore Mauritania in an Exclusive Exploitation Area (EEA) held under the terms of a PSC. The

Chinguetti field produces oil from subsea wells to a floating production, storage, and offloading vessel (FPSO). The field averaged approximately 7,600 barrels of oil per day (BOPD) in June 2011, from eight wells. Estimated proved-plus-probable oil equivalent working-interest reserves for this field represent less than 1 percent of Premier's total proved-plus-probable oil equivalent working-interest reserves.

Reserves have been estimated for the Bream and Froy fields located in Norway. These fields are not currently producing. Premier holds a 20-percent working interest in the Bream field and a 50-percent working interest in the Froy field. Both fields are oil fields, though associated marketable gas reserves have been estimated for the Froy field for fuel use. The estimated proved-plus-probable oil equivalent working-interest reserves for the fields located in Norway represent approximately 9 percent of Premier's total oil equivalent working-interest reserves. These fields are expected to begin producing in 2014.

In Pakistan, Premier has interests in the Badhra, Bhit, Kadanwari, Qadirpur, Zamzama, and Zarghun South fields. All of the fields are gas fields with associated condensate production. These fields are subject to production licenses that have, in some cases, been extended by the Government of Pakistan. All fields produce or will produce subject to gas supply agreements. Only the Zarghun South field is not producing and Premier's interest in the field is an overriding royalty interest. Combined, these fields produced at around 3,035 barrels of condensate per day and 1,244 MMcf/d of sales gas during early June 2011. The estimated proved-plus-probable oil equivalent working-interest reserves for these fields represent approximately 11 percent of Premier's estimated total proved-plus-probable oil equivalent working-interest reserves. Premier does not serve as operator for any of its fields in Pakistan.

Premier holds varied interests in 18 fields in the United Kingdom for which reserves have been estimated in this report. Premier's interests in these fields in the United Kingdom make up approximately 30 percent of its total proved-plus-probable oil equivalent working-interest reserves. In May 2011, BP announced that an agreement had been reached with Perenco by which BP would divest its approximately 68-percent working interest in certain assets located onshore and offshore of Dorset, England, which is inclusive of the Wytch Farm area assets (Wytch Farm, Wareham, and Beacon fields). Premier has represented that it has served a pre-emption notice to BP in order to acquire an additional 17.715-percent working interest in the Wytch Farm area assets, bringing its working interest to approximately 30.1 percent. Premier has also represented that it has reached an

agreement with Perenco setting out the basis on which the acquisition of the Wytch Farm area assets will be executed. The effective date of the acquisition is expected to be January 1, 2011. Premier has represented that the transaction is expected to close in December 2011. At the request of Premier and on the basis of the pending transaction, estimates of working-interest reserves and contingent resources, and net present worth were prepared based on a working interest of 30.1 percent.

Premier owns a 35-percent working interest in the fields in the Catcher field area (Catcher, Catcher North, Varadero, and Burgman). Premier has represented that it is currently in the process of finalizing an acquisition of the working interest (15 percent) attributable to Encore Oil plc (Encore) in the licenses for these fields. At the request of Premier, an evaluation of the reserves, contingent resources, and net present worth of the proved and proved-plus-probable reserves has been performed herein on the basis of the working interest attributable to both Premier and Encore. As such, the estimates of working-interest reserves and contingent resources and the estimated net present worth of the proved and proved-plus-probable reserves attributable to the fields in the Catcher field area consider the combined working interest of 50 percent.

Premier has recently completed the process of developing the Chim Sao field located offshore Vietnam. Premier has reported that the field began producing in October 2011 at rates between 25,000 and 30,000 BOPD during the first few weeks of October. Estimated proved-plus-probable oil equivalent working-interest reserves for the Chim Sao field represent approximately 11 percent of Premier's estimated total proved-plus-probable oil equivalent working-interest reserves.

Premier has indicated that it has now drilled two appraisal wells in the fault block to the north and west of the Chim Sao field. According to Premier, the CS-N2P well penetrated potentially oil-bearing Upper Dua sandstones, but wireline logs were not available from the well with which to estimate the quality of the reservoir rock. Premier has represented that the CS-N1P well was drilled in the third quarter of 2011 and encountered 89 meters of oil-bearing sands within a stacked sequence of Upper Dua sandstones. The data associated with the CS-N1P well were not available with which to estimate in-place volumes or potentially recoverable quantities. No estimates of reserves or contingent resources have been prepared considering the results of these two wells.

In order to estimate barrels of oil equivalent (BOE), marketable gas volumes were converted using the following methodology. Marketable gas was converted to

British thermal units (Btu) on a field-by-field basis using calorific values ranging from 695 Btu per cubic foot (Btu/cf) to 1,185 Btu/cf. The resultant quantities were then converted to barrels of oil equivalent (BOE) using field specific factors that range from 4.6 to 6.6 million Btu per BOE.

Estimates of the gross proved, probable, and possible oil, condensate, NGL, and marketable gas reserves for the properties evaluated in this report, as of September 30, 2011, are summarized by country as follows, expressed in thousands of barrels (Mbbl), millions of cubic feet (MMcf), and thousands of barrels of oil equivalent (MBOE):

Country	Premier's Gross Reserves								
	Oil, Condensate, and NGL			Marketable Gas			Oil Equivalent		
	Proved (Mbbl)	Probable (Mbbl)	Possible (Mbbl)	Proved (MMcf)	Probable (MMcf)	Possible (MMcf)	Proved (MBOE)	Probable (MBOE)	Possible (MBOE)
Indonesia	23,650	19,105	4,824	1,380,356	661,728	85,475	274,624	142,117	20,812
Mauritania	3,179	5,480	6,204	0	0	0	3,179	5,480	6,204
Norway	0	76,850	68,884	0	18,665	8,201	0	80,244	70,375
Pakistan	6,130	2,655	358	2,145,436	1,145,576	390,608	339,275	178,444	64,143
United Kingdom	141,434	122,842	100,166	131,944	99,084	66,957	165,671	140,913	112,374
Vietnam	35,860	22,269	12,352	33,281	31,085	10,914	42,374	28,353	14,488
Total	210,253	249,201	192,788	3,691,017	1,956,138	562,155	825,123	575,551	288,396

Notes:

1. Probable and possible reserves have not been risk adjusted to make them comparable to proved reserves.
2. Marketable gas has been converted to oil equivalent on a field-by-field basis.

Estimates of the working-interest proved, probable, and possible oil, condensate, NGL, and marketable gas reserves evaluated for this report, as of September 30, 2011, are listed by country as follows, expressed in thousands of barrels (Mbbl), millions of cubic feet (MMcf), and thousands of barrels of oil equivalent (MBOE):

Country	Premier's Working-Interest Reserves								
	Oil, Condensate, and NGL			Marketable Gas			Oil Equivalent		
	Proved (Mbbl)	Probable (Mbbl)	Possible (Mbbl)	Proved (MMcf)	Probable (MMcf)	Possible (MMcf)	Proved (MBOE)	Probable (MBOE)	Possible (MBOE)
Indonesia	7,692	4,911	1,129	451,045	201,722	25,842	88,393	41,919	5,748
Mauritania	258	445	504	0	0	0	258	445	504
Norway	0	30,424	19,757	0	9,333	4,101	0	32,121	20,503
Pakistan	503	206	22	154,207	78,109	33,519	24,517	12,262	5,657
United Kingdom	44,710	48,042	41,102	26,729	20,599	17,169	49,670	51,810	44,238
Vietnam	19,051	11,830	6,562	17,681	16,514	5,798	22,512	15,062	7,697
Total	72,214	95,858	69,076	649,662	326,277	86,429	185,350	153,619	84,347

Notes:

1. Probable and possible reserves have not been risk adjusted to make them comparable to proved reserves.
2. Marketable gas has been converted to barrels of oil equivalent on a field-by-field basis.

Contingent resources have been estimated for certain of Premier's properties worldwide and classified with an economic status of "Undetermined." Contingent resources estimated for Premier's interests in Pakistan are a combination of those quantities recoverable after the expiration of license agreements and quantities associated with the tight gas potential in the Kadanwari field. In Indonesia, estimated contingent resources are primarily associated with gas field discoveries for which development is dependent on the negotiation of gas sales agreements and the subsequent development of those fields. The contingent resources estimated for certain fields in the United Kingdom reflect undeveloped discoveries whose development plan is not yet confirmed as well as those quantities recoverable from existing producing fields where operating expenses can be reduced by the sharing of those expenses with satellite field developments. The Dua field in Vietnam, a discovered oil and gas field located offshore Vietnam, is expected to be approved for development after Premier obtains joint venture approval and an approved field development plan.

The estimated gross contingent resources for the properties evaluated in this report, as of September 30, 2011, are summarized by country and economic status category (Undetermined) as follows, expressed in thousands of barrels (Mbbl), millions of cubic feet (MMcf), and thousands of barrels of oil equivalent (MBOE):

Economic Status Country	Gross Contingent Resources								
	Oil, Condensate, and NGL			Marketable Gas			Oil Equivalent		
	1C (Mbbl)	2C (Mbbl)	3C (Mbbl)	1C (MMcf)	2C (MMcf)	3C (MMcf)	1C (MBOE)	2C (MBOE)	3C (MBOE)
Undetermined									
Indonesia	1,026	6,037	19,413	26,212	132,206	721,231	5,983	31,038	155,803
Norway	3,030	8,787	11,499	0	0	0	3,030	8,787	11,499
Pakistan	0	185	1,041	82,414	291,192	996,102	14,370	49,817	161,488
United Kingdom	75,509	128,074	192,751	45,711	66,798	88,085	83,917	140,327	208,884
Vietnam	5,923	10,000	16,561	24,439	39,029	67,936	10,707	17,639	29,858
Total Undetermined	85,488	153,083	241,265	178,776	529,225	1,873,354	118,007	247,608	567,532

Notes:

1. Application of any risk factor to contingent resources quantities does not equate contingent resources with reserves.
2. There is no certainty that it will be commercially viable to produce any portion of the contingent resources evaluated herein.

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The estimated working-interest contingent resources for the properties evaluated in this report, as of September 30, 2011, are summarized by country and economic status category (Undetermined) as follows, expressed in thousands of barrels (Mbbl), millions of cubic feet (MMcf), and thousands of barrels of oil equivalent (MBOE):

Economic Status Country	Premier's Working-Interest Contingent Resources								
	Oil, Condensate, and NGL			Marketable Gas			Oil Equivalent		
	1C (Mbbl)	2C (Mbbl)	3C (Mbbl)	1C (MMcf)	2C (MMcf)	3C (MMcf)	1C (MBOE)	2C (MBOE)	3C (MBOE)
Undetermined									
Indonesia	295	1,731	5,565	7,514	37,899	206,755	1,716	8,898	44,664
Norway	1,212	3,515	4,600	0	0	0	1,212	3,515	4,600
Pakistan	0	17	83	13,013	42,923	102,513	2,269	7,395	17,138
United Kingdom	36,978	64,052	95,792	19,369	29,021	38,414	40,538	69,370	102,822
Vietnam	3,147	5,312	8,798	12,984	20,734	36,091	5,688	9,370	15,862
Total Undetermined	41,632	74,627	114,838	52,880	130,577	383,773	51,423	98,548	185,086

Notes:

1. Application of any risk factor to contingent resources quantities does not equate contingent resources with reserves.
2. There is no certainty that it will be commercially viable to produce any portion of the contingent resources evaluated herein.

Estimates of the net present worth of the proved and proved-plus-probable reserves attributable to Premier's evaluated interests, as of September 30, 2011, discounted at rates of 8 and 10 percent and expressed in millions of United States dollars (MM U.S.\$) under the base case and sensitivity cases are presented in the following tables:

Base Case – Net Present Worth			
Proved		Proved plus Probable	
At 8 Percent (MM U.S.\$)	At 10 Percent (MM U.S.\$)	At 8 Percent (MM U.S.\$)	At 10 Percent (MM U.S.\$)
2,495.2	2,371.1	5,124.8	4,706.4
Sensitivity Case – Low Price Case – Net Present Worth			
Proved		Proved plus Probable	
At 8 Percent (MM U.S.\$)	At 10 Percent (MM U.S.\$)	At 8 Percent (MM U.S.\$)	At 10 Percent (MM U.S.\$)
2,003.9	1,905.9	4,158.0	3,808.1

Note: Values for probable reserves have not been risk adjusted to make them comparable to values for proved reserves.

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Sensitivity Case – High Price Case – Net Present Worth			
Proved		Proved plus Probable	
At 8 Percent	At 10 Percent	At 8 Percent	At 10 Percent
(MM U.S.\$)	(MM U.S.\$)	(MM U.S.\$)	(MM U.S.\$)
3,082.0	2,928.4	6,137.4	5,645.0

Note: Values for probable reserves have not been risk adjusted to make them comparable to values for proved reserves.

Definition of Reserves

The proved, probable, and possible reserves presented in this report 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. The petroleum reserves are defined as follows:

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.

Proved Reserves – Proved Reserves are those quantities of petroleum which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods, and government regulations. If deterministic methods are used, the term reasonable certainty is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90-percent probability that the quantities actually recovered will equal or exceed the estimate.

Unproved Reserves – Unproved Reserves are based on geoscience and/or engineering data similar to that used in estimates of Proved Reserves, but technical or other uncertainties preclude such reserves

being classified as Proved. Unproved Reserves may be further categorized as Probable Reserves and Possible Reserves.

Probable Reserves – Probable Reserves are those additional Reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves. It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50-percent probability that the actual quantities recovered will equal or exceed the 2P estimate.

Possible Reserves – 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 Reserves (3P), which is equivalent to the high estimate scenario. In this context, when probabilistic methods are used, there should be at least a 10-percent probability that the actual quantities recovered will equal or exceed the 3P estimate.

Reserves Status Categories – Reserves status categories define the development and producing status of wells and reservoirs.

Developed Reserves – Developed Reserves are expected quantities to be recovered from existing wells and facilities. Reserves are considered developed only after the necessary equipment has been installed, or when the costs to do so are relatively minor compared to the cost of a well. Where required facilities become unavailable, it may be necessary to reclassify Developed Reserves as Undeveloped. Developed Reserves may be further sub-classified as Producing or Non-Producing.

Developed Producing Reserves – Developed Producing Reserves are expected to be recovered from completion intervals that 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.

Developed Non-Producing Reserves – Developed Non-Producing Reserves 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 yet 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 require additional completion work or future recompletion prior to the start of production. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

Undeveloped Reserves – Undeveloped Reserves are quantities expected to be recovered through future investments: (1) from new wells on undrilled acreage in known accumulations, (2) from deepening existing wells to a different (but known) reservoir, (3) from infill wells that will increase recovery, or (4) where a relatively large expenditure (e.g. when compared to the cost of drilling a new well) is required to (a) recomplete an existing well or (b) install production or transportation facilities for primary or improved recovery projects.

The extent to which probable and possible reserves ultimately may be reclassified as proved reserves is dependent upon future drilling, testing, and well performance. The degree of risk to be applied in evaluating probable and possible reserves is influenced by economic and technological factors as well as the time element. Probable and possible reserves in this report have not been adjusted in consideration of these additional risks to make them comparable to proved reserves.

Estimation of Reserves

Summary

The estimated gross proved, probable, and possible reserves for the properties evaluated in this report for Premier, as of September 30, 2011, are summarized as follows, expressed in thousands of barrels (Mbbl), millions of cubic feet (MMcf), and thousands of barrels of oil equivalent (MBOE):

Country	Premier's Gross Reserves								
	Oil, Condensate, and NGL			Marketable Gas			Oil Equivalent		
	Proved (Mbbl)	Probable (Mbbl)	Possible (Mbbl)	Proved (MMcf)	Probable (MMcf)	Possible (MMcf)	Proved (MBOE)	Probable (MBOE)	Possible (MBOE)
Indonesia	23,650	19,105	4,824	1,380,356	661,728	85,475	274,624	142,117	20,812
Mauritania	3,179	5,480	6,204	0	0	0	3,179	5,480	6,204
Norway	0	76,850	68,884	0	18,665	8,201	0	80,244	70,375
Pakistan	6,130	2,655	358	2,145,436	1,145,576	390,608	339,275	178,444	64,143
United Kingdom	141,434	122,842	100,166	131,944	99,084	66,957	165,671	140,913	112,374
Vietnam	35,860	22,269	12,352	33,281	31,085	10,914	42,374	28,353	14,488
Total	210,253	249,201	192,788	3,691,017	1,956,138	562,155	825,123	575,551	288,396

Notes:

1. Probable and possible reserves have not been risk adjusted to make them comparable to proved reserves.
2. Marketable gas has been converted to oil equivalent on a field-by-field basis.

Estimates of the working-interest proved, probable, and possible reserves, as of September 30, 2011, evaluated herein are listed by country as follows, expressed in thousands of barrels (Mbbl), millions of cubic feet (MMcf), and thousands of barrels of oil equivalent (MBOE):

Country	Premier's Working-Interest Reserves								
	Oil, Condensate, and NGL			Marketable Gas			Oil Equivalent		
	Proved (Mbbl)	Probable (Mbbl)	Possible (Mbbl)	Proved (MMcf)	Probable (MMcf)	Possible (MMcf)	Proved (MBOE)	Probable (MBOE)	Possible (MBOE)
Indonesia	7,692	4,911	1,129	451,045	201,722	25,842	88,393	41,919	5,748
Mauritania	258	445	504	0	0	0	258	445	504
Norway	0	30,424	19,757	0	9,333	4,101	0	32,121	20,503
Pakistan	503	206	22	154,207	78,109	33,519	24,517	12,262	5,657
United Kingdom	44,710	48,042	41,102	26,729	20,599	17,169	49,670	51,810	44,238
Vietnam	19,051	11,830	6,562	17,681	16,514	5,798	22,512	15,062	7,697
Total	72,214	95,858	69,076	649,662	326,277	86,429	185,350	153,619	84,347

Notes:

1. Probable and possible reserves have not been risk adjusted to make them comparable to proved reserves.
2. Marketable gas has been converted to barrels of oil equivalent on a field-by-field basis.

Procedure/Methodology

Estimates of reserves were prepared by the use of appropriate geologic, petroleum engineering, and evaluation principles and techniques that are in accordance with practices generally recognized by the petroleum industry and in accordance with definitions consistent with those established by the PRMS. The method or combination of methods used in the analysis of each reservoir was tempered by experience with similar reservoirs, stage of development, quality and completeness of basic data, and production history.

When applicable, the volumetric method was used to estimate the original oil in place (OOIP) and original gas in place (OGIP). Structure maps were prepared to delineate each reservoir, and isopach maps were constructed to estimate reservoir volume. Electrical logs, radioactivity logs, core analyses, and other available data were used to prepare these maps as well as to estimate representative values for porosity and water saturation.

Estimates of ultimate recovery were obtained after applying recovery factors to OOIP or OGIP. These recovery factors were based on consideration of the type of energy inherent in the reservoirs, analyses of the petroleum, the structural positions of the properties, and the production histories. When applicable, material-balance and other engineering methods were used to estimate recovery factors. An analysis of reservoir performance, including production rate, reservoir pressure, and gas/oil ratio (GOR) behavior, was used in the estimation of reserves.

In certain cases, when the previously named methods could not be used, reserves were estimated by analogy with similar wells or reservoirs for which more complete data were available.

Reserves estimates presented herein are based on data available through September 2011. For certain field areas, production was available only through April, May, or June 2011. Production was estimated for the remaining months to arrive at the estimated cumulative production for each field area at September 30, 2011. Estimates of reserves were prepared by subtracting the estimated cumulative production from the estimated gross ultimate recovery.

The reserves forecasts contained herein terminate at the economic limit as defined under the Definition of Reserves heading of this report or at the end of the concession life, whichever occurs first. If a concession expires before the economic production limit is reached, production that could be obtained after the concession

expiration, which would otherwise be classified as reserves, has been classified as contingent resources.

Reserves estimated in this report are supported by details of drilling results through September 2011, analyses of available geological data, well-test results, pressures, available core data, and production performance. This report takes into account all relevant information supplied to us by Premier.

The oil, condensate, and NGL reserves estimated in this report are expressed in terms of 42 United States gallons per barrel. Crude oil reserves are to be recovered by conventional field operations. NGL reserves are to be recovered from gas processing and can include C₃, C₄, and C₅₊ fractions. Condensate reserves are to be recovered both by normal field separation and by low-temperature separation from gas processing.

Gas quantities included in this report are expressed as marketable gas at a pressure base of 14.7 pounds per square inch absolute (psia) and a temperature base of 60 degrees Fahrenheit (°F). Marketable gas is defined as wet gas after reduction for shrinkage resulting from field separation; processing, including removal of nonhydrocarbon gas to meet pipeline specifications and NGL extraction; and flare and other losses but not from fuel usage. Fuel gas is included as reserves. Wet gas is the total gas produced from the reservoir prior to processing or separation and includes all nonhydrocarbon components and the gas equivalent of condensate. The marketable gas is converted to Btu on a field-by-field basis using calorific values ranging from 695 to 1,185 Btu/cf. The resultant quantities are then converted to barrels of oil equivalent (BOE) using field specific factors that range from 4.6 to 6.6 million Btu per BOE.

Detailed field discussions of these reserves are contained in the appendix to this letter report. Estimates of reserves were made using volumetric, performance methods, and material-balance methods.

Definition of Contingent Resources

Petroleum resources included in this report are classified as contingent 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 development drilling, the contingent resources estimated herein cannot be classified as reserves. The petroleum resources are classified as follows:

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 economic status groups:

Marginal Contingent Resources – 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 – 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.

Undetermined Contingent Resources – 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.”

The estimation of resources quantities for an accumulation 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 volumes. In all cases, the range of uncertainty is dependent on the

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amount and quality of both technical and commercial data that are available and may change as more data become available.

1C (Low), 2C (Best), and 3C (High) Estimates – Estimates of petroleum resources in this report are expressed using the terms 1C (low) estimate, 2C (best) estimate, and 3C (high) estimate to reflect the range of uncertainty.

Estimation of Contingent Resources

Summary

The estimated gross contingent resources for the properties evaluated in this report, as of September 30, 2011, are summarized by economic status category (Undetermined) as follows, expressed in thousands of barrels (Mbbl), millions of cubic feet (MMcf), and thousands of barrels of oil equivalent (MBOE):

Economic Status Country	Gross Contingent Resources								
	Oil, Condensate, and NGL			Marketable Gas			Oil Equivalent		
	1C (Mbbl)	2C (Mbbl)	3C (Mbbl)	1C (MMcf)	2C (MMcf)	3C (MMcf)	1C (MBOE)	2C (MBOE)	3C (MBOE)
Undetermined									
Indonesia	1,026	6,037	19,413	26,212	132,206	721,231	5,983	31,038	155,803
Norway	3,030	8,787	11,499	0	0	0	3,030	8,787	11,499
Pakistan	0	185	1,041	82,414	291,192	996,102	14,370	49,817	161,488
United Kingdom	75,509	128,074	192,751	45,711	66,798	88,085	83,917	140,327	208,884
Vietnam	5,923	10,000	16,561	24,439	39,029	67,936	10,707	17,639	29,858
Total Undetermined	85,488	153,083	241,265	178,776	529,225	1,873,354	118,007	247,608	567,532

Notes:

1. Application of any risk factor to contingent resources quantities does not equate contingent resources with reserves.
2. There is no certainty that it will be commercially viable to produce any portion of the contingent resources evaluated herein.

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The estimated working-interest contingent resources for the properties evaluated in this report, as of September 30, 2011, are summarized by economic status category (Undetermined) as follows, expressed in thousands of barrels (Mbbl), millions of cubic feet (MMcf), or thousands of barrels of oil equivalent (MBOE):

Economic Status	Premier's Working-Interest Contingent Resources								
	Oil, Condensate, and NGL			Marketable Gas			Oil Equivalent		
	1C	2C	3C	1C	2C	3C	1C	2C	3C
Country	(Mbbl)	(Mbbl)	(Mbbl)	(MMcf)	(MMcf)	(MMcf)	(MBOE)	(MBOE)	(MBOE)
Undetermined									
Indonesia	295	1,731	5,565	7,514	37,899	206,755	1,716	8,898	44,664
Norway	1,212	3,515	4,600	0	0	0	1,212	3,515	4,600
Pakistan	0	17	83	13,013	42,923	102,513	2,269	7,395	17,138
United Kingdom	36,978	64,052	95,792	19,369	29,021	38,414	40,538	69,370	102,822
Vietnam	3,147	5,312	8,798	12,984	20,734	36,091	5,688	9,370	15,862
Total Undetermined	41,632	74,627	114,838	52,880	130,577	383,773	51,423	98,548	185,086

Notes:

1. Application of any risk factor to contingent resources quantities does not equate contingent resources with reserves.
2. There is no certainty that it will be commercially viable to produce any portion of the contingent resources evaluated herein.

Procedure/Methodology

Estimates of contingent resources were prepared by the use of appropriate geologic, petroleum engineering, and evaluation principles and techniques that are in accordance with practices generally recognized by the petroleum industry and in accordance with definitions consistent with those established by the PRMS. The method or combination of methods used in the analysis of each reservoir was tempered by experience with similar reservoirs, stage of development, quality and completeness of basic data, and production history.

When applicable, the volumetric method was used to estimate the OOIP and OGIP. Structure maps were prepared to delineate each reservoir, and isopach maps were constructed to estimate reservoir volume. Electrical logs, radioactivity logs, core analyses, and other available data were used to prepare these maps as well as to estimate representative values for porosity and water saturation.

Estimates of ultimate recovery were obtained after applying recovery factors to OOIP or OGIP. These recovery factors were based on consideration of the type of energy inherent in the reservoirs, analyses of the petroleum, the structural positions of the properties, and the production histories. When applicable, material-balance and other engineering methods were used to estimate recovery factors. An analysis of reservoir performance, including production rate, reservoir pressure, and GOR behavior, was used in the estimation of contingent resources.

In certain cases, when the previously named methods could not be used, contingent resources were estimated by analogy with similar wells or reservoirs for which more complete data were available.

Contingent resources estimates presented herein are based on data available through September 2011.

Quantities that may be produced after the expiration of concessions, which would otherwise be classified as reserves, have been classified herein as contingent resources.

Contingent resources estimated in this report are supported by details of drilling results through September 2011, analyses of available geological data, well-test results, pressures, available core data, and production performance. This report takes into account all relevant information supplied to us by Premier.

The oil, condensate, and NGL contingent resources estimated in this report are expressed in terms of 42 United States gallons per barrel. Crude oil contingent resources are to be recovered by conventional field operations. NGL contingent resources are to be recovered from gas processing, and can include C₃, C₄, and C₅₊ fractions. Condensate contingent resources are to be recovered both by normal field separation and by low-temperature separation from gas processing.

Gas quantities included in this report are expressed as marketable gas at a pressure base of 14.7 psia and a temperature base of 60 °F. Marketable gas is defined as wet gas after reduction for shrinkage resulting from field separation; processing, including removal of nonhydrocarbon gas to meet pipeline specifications and NGL extraction; and flare and other losses but not from fuel usage. Fuel gas is included as contingent resources. Wet gas is the total gas produced from the reservoir prior to processing or separation and includes all nonhydrocarbon components and the gas equivalent of condensate. The marketable gas is converted to Btu on a field-by-field basis using calorific values ranging from 695 to 1,185 Btu/cf. The resultant quantities are then converted to BOE using field specific factors that range from 4.6 to 6.6 million Btu per BOE.

Estimates of contingent resources as presented herein are based on the quantities of petroleum that may be produced after the expiration of an existing PSC or license agreement, that are associated with satellite fields to existing production operations for which a development plan has not been finalized or for which

sufficient commitment has not been obtained to proceed with development, or that are currently identified from engineering and geological data to be potentially recoverable but will require additional data acquisition, assessment, or investigation.

Detailed field discussions of the contingent resources are contained in the Appendix to this letter report. Estimates of contingent resources were made using volumetric evaluation, performance analysis, and material-balance methods.

Valuation of Reserves

This report has been prepared using initial prices and costs and future price and cost assumptions specified by Premier. Estimates of future net revenue and present worth of proved and proved-plus-probable reserves have been prepared in accordance with guidelines of the PRMS.

In this report, values for proved and proved-plus-probable reserves are based on projections of estimated future production and revenue prepared for these properties with no risk adjustment applied to the probable reserves. Probable reserves involve substantially higher risks than proved reserves. Revenue values for proved-plus-probable reserves have not been adjusted to account for such risks; this adjustment would be necessary in order to make proved-plus-probable reserves values comparable with values for proved reserves.

Revenue values of the proved and proved-plus-probable reserves were developed utilizing methods generally accepted by the petroleum industry. Production forecasts of the proved and proved-plus-probable (non-risk-adjusted) reserves were based on the development plan for each field. The future net revenue and net present worth of each field's reserves were estimated using the price and cost assumptions, monetary conversion values, and the appropriate concession terms provided by Premier.

The properties evaluated in Indonesia, Mauritania, and Vietnam are subject to terms of PSCs. The revenue values presented herein reflect the terms of each respective contract. The working-interest reserves and contingent resources presented in the report do not exclude the government's share of profit entitlement and are therefore not equivalent to entitlement reserves.

The net present worth of the proved and proved-plus-probable (non-risk-adjusted) reserves of the fields have been estimated using three price scenarios provided by Premier. These assumptions are as follows:

Base Case Scenario

- i) Oil prices were based on the Brent oil price, expressed in U.S.\$ per barrel, of U.S.\$90.00 per barrel in 2011 and escalated at a rate of 2.5 percent per year beginning January 1, 2012, through the life of the evaluation. Prices for individual fields may vary from the Brent marker price based on quality and transportation differentials. The Brent oil price and the individual field differentials were provided by Premier. Gas prices were based on terms specified in the sales contracts.
- ii) An exchange rate of U.S.\$1.60 per U.K.£1.00 was used to convert U.K.£ to U.S.\$.

Sensitivity Case Scenario – Low Price Case

- i) Oil prices were based on a Brent oil price, expressed in U.S.\$ per barrel, of U.S.\$75.00 per barrel in 2011 and escalated at a rate of 2.5 percent per year through the life of the evaluation. Prices for individual fields may vary from the Brent marker price based on quality and transportation differentials. The Brent oil price and the individual field differentials were provided by Premier. Gas prices were based on terms specified in the sales contracts.
- ii) An exchange rate of U.S.\$1.60 per U.K.£1.00 was used to convert U.K.£ to U.S.\$.

Sensitivity Case Scenario – High Price Case

- i) Oil prices were based on a Brent oil price, expressed in U.S.\$ per barrel, of U.S.\$105.00 per barrel in 2011 and escalated at a rate of 2.5 percent per year through the life of the evaluation. Prices for individual fields may vary from the Brent marker price based on quality and transportation differentials. The Brent oil price and the individual field differentials were provided by Premier. Gas prices were based on terms specified in the sales contracts.
- ii) An exchange rate of U.S.\$1.60 per U.K.£1.00 was used to convert U.K.£ to U.S.\$.

Unescalated cost data for the proved and proved-plus-probable reserves were provided by Premier. The capital investment and operating expense forecasts were reviewed in detail and modified in accordance with the production forecasts. The operating expense and capital cost forecasts included herein have been adjusted to account for the effects of inflation at a rate of 2.5 percent per year beginning in 2012. Abandonment costs were included in the analysis where applicable. The royalty and tax provisions and the terms of PSCs were assumed to remain unchanged from current legislation. All unescalated cost data remained unchanged for each price scenario.

Values for the United Kingdom assets include a deduction for United Kingdom corporation tax. The corporation tax was applied at an effective rate based on information provided by Premier and varies depending on the specific price scenario as follows: Base Case – 39 percent, Low Price Case – 28 percent, and High Price Case – 44 percent. In the estimation of the effective corporate tax rates, Premier has represented that no consideration was given to future expenditures related to exploration or appraisal drilling activities that Premier has planned, including the potential development of fields for which contingent resources have been estimated. As such, neither the potential capital expenditures nor the potential tax benefits that may result from those activities have been included in the estimation of the effective corporate tax rates. Consequently, neither these potential capital expenditures nor these potential tax benefits have been considered in the after-corporate tax estimates of present worth of the proved and proved-plus-probable reserves evaluated herein.

Estimates of the net present worth discounted at 8 and 10 percent of the proved and non-risk-adjusted proved-plus-probable reserves of the petroleum interests attributable to Premier using the base case price scenario and the low and high price case scenarios, expressed in millions of United States dollars (MM U.S.\$), are presented in the following table. Values for net present worth are estimated as of September 30, 2011.

Base Case – Net Present Worth			
Proved		Proved plus Probable	
At 8 Percent (MM U.S.\$)	At 10 Percent (MM U.S.\$)	At 8 Percent (MM U.S.\$)	At 10 Percent (MM U.S.\$)
2,495.2	2,371.1	5,124.8	4,706.4

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Sensitivity Case – Low Price Case – Net Present Worth			
Proved		Proved plus Probable	
At 8 Percent	At 10 Percent	At 8 Percent	At 10 Percent
(MM U.S.\$)	(MM U.S.\$)	(MM U.S.\$)	(MM U.S.\$)
2,003.9	1,905.9	4,158.0	3,808.1

Note: Values for probable reserves have not been risk adjusted to make them comparable to values for proved reserves.

Sensitivity Case – High Price Case – Net Present Worth			
Proved		Proved plus Probable	
At 8 Percent	At 10 Percent	At 8 Percent	At 10 Percent
(MM U.S.\$)	(MM U.S.\$)	(MM U.S.\$)	(MM U.S.\$)
3,082.0	2,928.4	6,137.4	5,645.0

Note: Values for probable reserves have not been risk adjusted to make them comparable to values for proved reserves.

Summary and Conclusions

Estimates of proved, probable, and possible oil, condensate, NGL, and marketable-gas reserves, as of September 30, 2011, attributable to working interests owned by Premier and evaluated herein are listed below, expressed in thousands of barrels (Mbbl) and millions of cubic feet (MMcf):

	Working-Interest Reserves Summary		
	Proved	Probable*	Possible*
Oil, Condensate, and NGL, Mbbl	72,214	95,858	69,076
Marketable Gas, MMcf	649,662	326,277	86,429

Note: Probable and possible reserves have not been risk adjusted to make them comparable to proved reserves.

DEGOLYER AND MACNAUGHTON

Estimates of contingent oil, condensate, NGL, and marketable-gas resources, as of September 30, 2011, attributable to the working interests owned by Premier and evaluated herein are listed below, expressed in Mbbl and MMcf:

	Working-Interest Contingent Resources Summary		
	1C	2C	3C
Undetermined			
Oil, Condensate, and NGL, Mbbl	41,632	74,627	114,838
Marketable Gas, MMcf	52,880	130,577	383,773

Notes:

1. Application of any risk factor to contingent resources quantities does not equate contingent resources with reserves.
2. There is no certainty that it will be commercially viable to produce any portion of the contingent resources evaluated herein.

Estimates of the net present worth discounted at 8 and 10 percent of the proved and non-risk-adjusted proved-plus-probable reserves of the petroleum interests attributable to Premier, using the base case price scenario and the low and high price case scenarios, expressed in millions of United States dollars (MM U.S.\$), are presented in the following table. Values for net present worth are estimated as of September 30, 2011.

	Net Present Worth (MM U.S.\$)	
	8 Percent	10 Percent
Base Case Scenario		
Proved	2,495.2	2,371.1
Proved plus Probable	5,124.8	4,706.4
Low Price Case Scenario		
Proved	2,003.9	1,905.9
Proved plus Probable	4,158.0	3,808.1
High Price Case Scenario		
Proved	3,082.0	2,928.4
Proved plus Probable	6,137.4	5,645.0

Note: Values for probable reserves have not been risk adjusted to make them comparable to values for proved reserves.

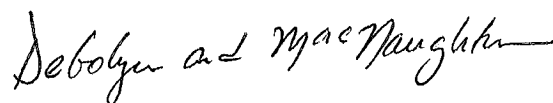
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Professional Qualifications

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. R. M. Shuck. Mr. Shuck is a Senior Vice President with DeGolyer and MacNaughton, Manager of the firm's Asia/Pacific/Latin America Division, a Registered Professional Engineer in the State of Texas, and a member of the Society of Petroleum Engineers. He has over 32 years of oil and gas industry experience.

Very truly yours,



DeGOLYER and MacNAUGHTON
Texas Registered Engineering Firm F-716




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APPENDIX
to
LETTER REPORT
as of
SEPTEMBER 30, 2011
to
PREMIER OIL Plc
dated
NOVEMBER 18, 2011

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Field Discussion – Reserves

Indonesia

Premier holds interests in three production sharing contract (PSC) areas in Indonesia: the Kakap PSC, the Natuna Sea Block ‘A’ PSC, and the North Sumatra Block ‘A’ PSC. The Kakap PSC and the Natuna Sea Block ‘A’ PSC are on production. Premier operates the Natuna Sea Block ‘A’ PSC.

Natuna Sea Block ‘A’ Fields

The fields located in the Natuna Sea Block ‘A’ PSC are the Anoa, Beruang, Bison, Gajah Baru, Gajah Puteri, Iguana, Macan Tutul, Lembu Peteng, Naga, and Pelikan fields. Premier assumed operatorship of the PSC in 1996. The production license for the Block ‘A’ fields expires in October 2029.

The West Natuna Basin formed in the Tertiary as a failed intracratonic rift on the Sunda shield. In the Late Eocene-Oligocene period, regional extension created grabens, half grabens, and normal faults that generally strike northeast to southwest and northwest to southeast. In the Miocene, regional compression created wrench faulting and thrusting. This compression event reactivated some existing normal faults and caused basin inversions.

The basin crust is Cretaceous-age igneous and metamorphic rocks. The earliest basin sediments are late Eocene to early Oligocene in age and consist of continental, fluvial, and nearshore arkosic sandstones and conglomerates. These sediments are unconformably overlain by the interbedded sandstones and shales of the Miocene-age Lower and Upper Gabus Formations, which were deposited in fluvial channels and alluvial plains and in lacustrine to shallow marine and deltaic environments. An unconformity separates the Upper Gabus from the overlying Barat Formation, composed of estuarine or shallow marine shales and sandstones. Above the Barat is the early- to middle-Miocene Arang Formation, which contains sandstones, shales, coals, and claystones deposited in shallow marine and coal-swamp coastal plain environments related to basin inversion and relative sea level changes. Above an Upper Arang unconformity is the Upper Miocene to Recent-age Muda Formation, containing shallow marine mudstones, shales, and sandstones.

Gas Sales Agreement 1

Gas sales from Block 'A' to SembCorp in Singapore began in December 2000. The gas sales agreement (GSA) 1 calls for 325 million cubic feet per day (MMcf/d) of gas to be produced from three separate license blocks in the Natuna Sea, 126 billion British thermal units per day (BBtu/d) of which has been allocated to the Block 'A' PSC. Gas produced from the Anoa, Bison, Gajah Puteri, and Pelikan fields (termed the "SembCorp" or GSA 1 fields) are dedicated to this contract. The GSA 1 allows for the historic shortfall of production from the Kakap Block to be made up by Block 'A' and the Natuna Block 'B.' With the Kakap shortfall forecast to continue, the Block 'A' portion of GSA 1 gas sales includes additional annual sales rates above the 126 BBtu/d to include the Block 'A' portion of Kakap make-up gas.

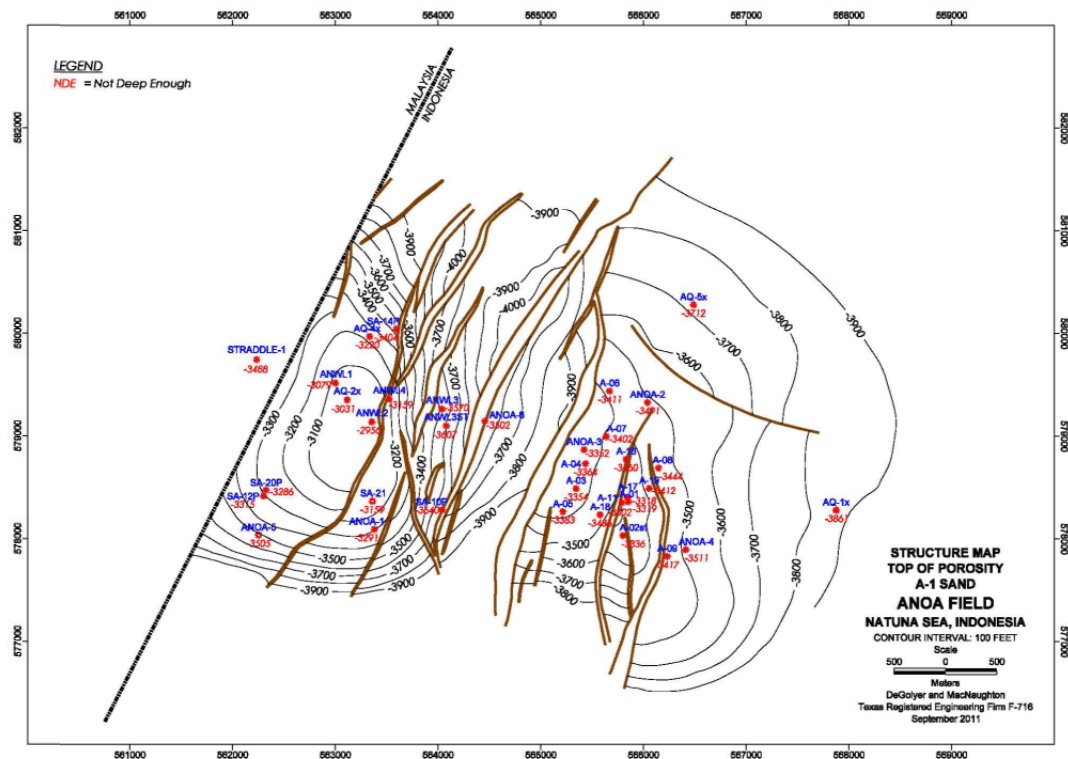
Anoa Field

The Anoa field is located in the West Natuna Basin. The field is about 200 kilometers southeast of peninsular Malaysia, 240 kilometers north-northwest of the Anambas Archipelago, and 1,300 kilometers north of Jakarta. The water depth in the area of the field is about 250 feet.

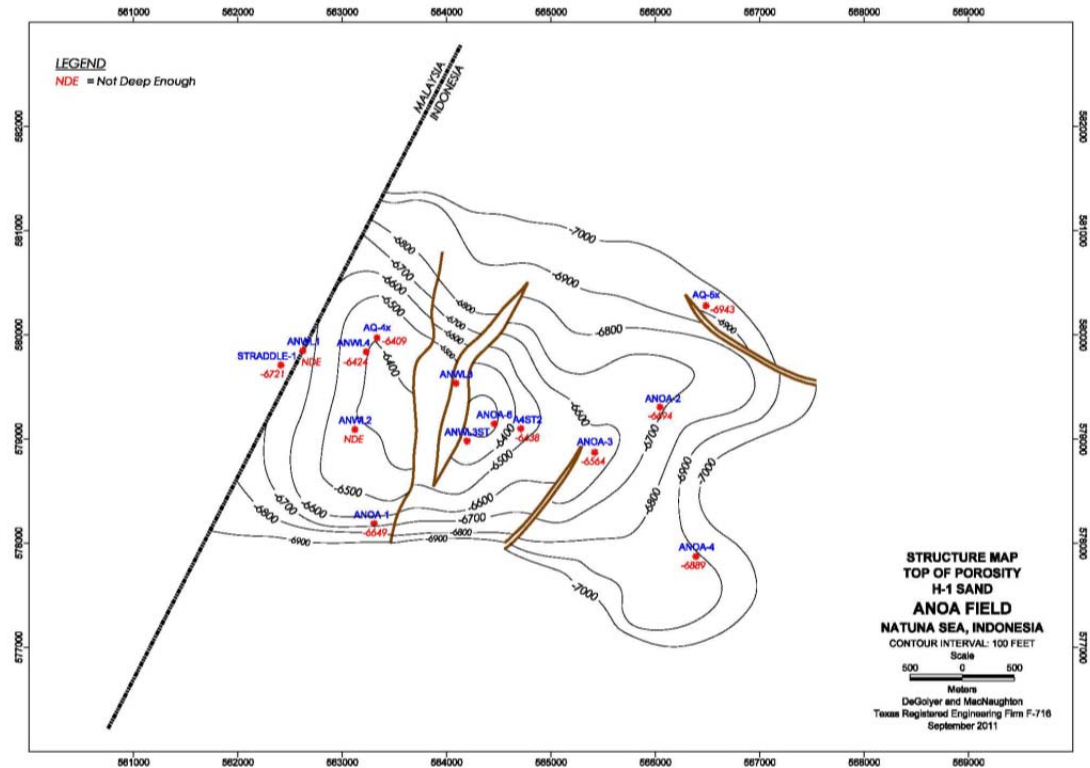
The Anoa field is an elongate, faulted, anticlinal structure with four-way dip closure that extends approximately 4 kilometers north to south and 6 kilometers east to west. The Anoa structure was discovered in 1974. Development drilling in began in 1990 and production from the field commenced in November 1990.

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Petroleum reservoirs are found in deltaic and distributary channel sandstones of the Middle Gabus Formation. Faulting divides the field into West, Central, and East blocks, with minor faulting further dividing some reservoirs. Gas and oil reservoirs are found in 14 deltaic, distributary channel, and overbank sand intervals in the Oligocene Middle and Lower Gabus intervals. These reservoirs, identified as the A through H reservoirs, consist of lacustrine shales with delta-front silts and sands, mouth bars and distributary channel sands, and over-bank crevasse splay shales, silts, and sands. The reservoirs are found between the depths of 3,300 and 6,850 feet subsea. Seven of these are oil reservoirs with associated gas caps. The figures below show structure maps on top structure of the A-1 and H-1 sands in the Anoa field and are generally representative of the Anoa field structure.



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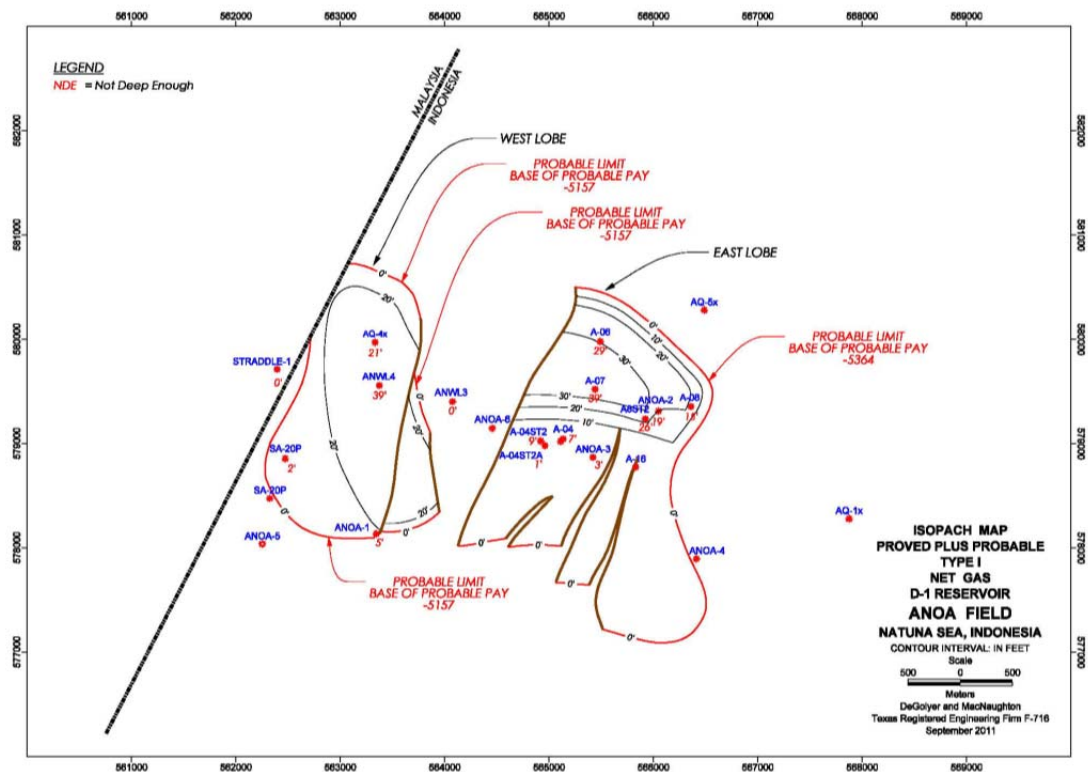


For those reservoirs where the volumetric method was applied, estimates of ultimate recovery were obtained after applying recovery factors to original oil in place (OOIP) or original gas in place (OGIP). These recovery factors were based on consideration of the type of energy inherent in the reservoirs, analyses of the petroleum, the structural positions of the properties, and the production histories. When applicable, material-balance and other engineering methods were used to estimate recovery factors. In such cases, an analysis of reservoir performance was used in the estimation of reserves.

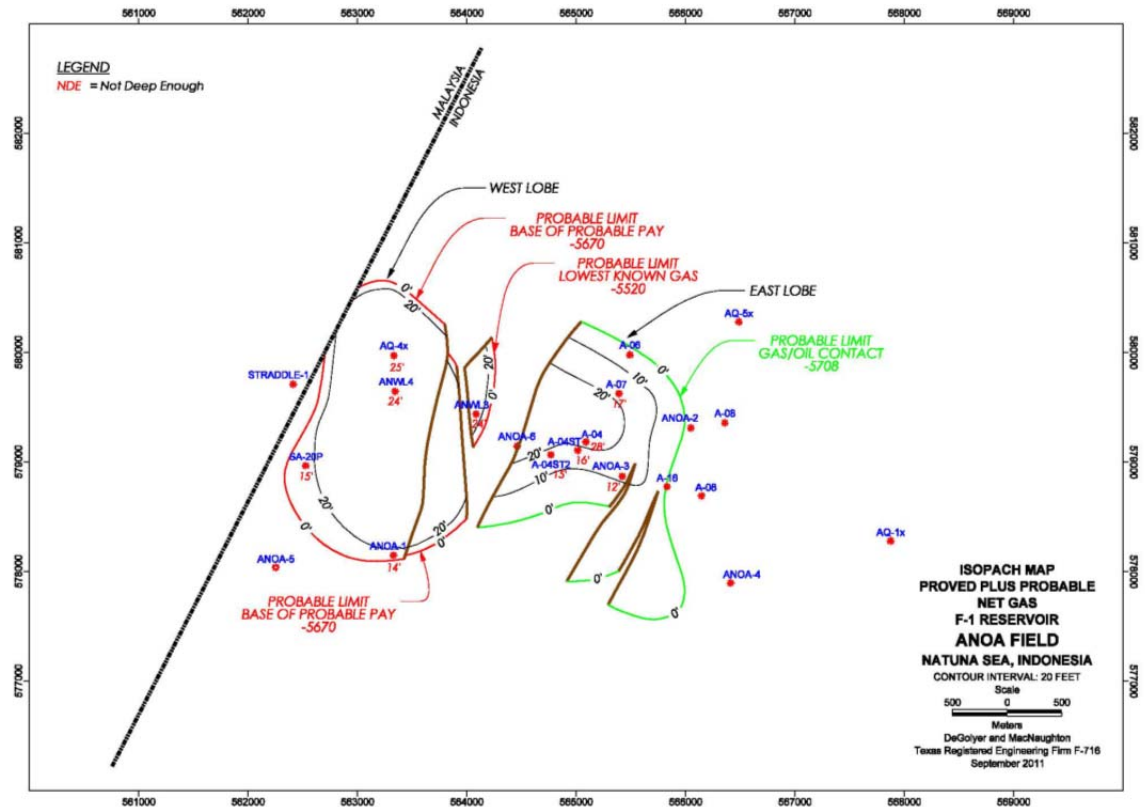
In reservoirs that were limited by the lowest occurrence of hydrocarbons and not by water contacts, additional isopach maps were prepared using reservoir limits that were projected downdip using linear pressure gradients from wireline tests or drill-stem tests (DST). Lower reservoir limits in some reservoirs were projected to a depth between the lowest known hydrocarbons and highest occurrence of water, based on the characteristics of the particular reservoir. Reservoir quantities associated with the projected reservoir limits were generally associated with reserves classified as probable and possible.

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For gas reservoirs without sufficient performance data or reliable trends, the reservoir quantities associated with proved, probable, and possible reserves were estimated from net pay isopach maps prepared using the structure maps for each reservoir and petrophysical analysis. Shown below are figures illustrating the net gas isopach maps of the D-1 reservoir and F-1 reservoir. These maps were used to estimate OGIP for in these gas reservoirs.



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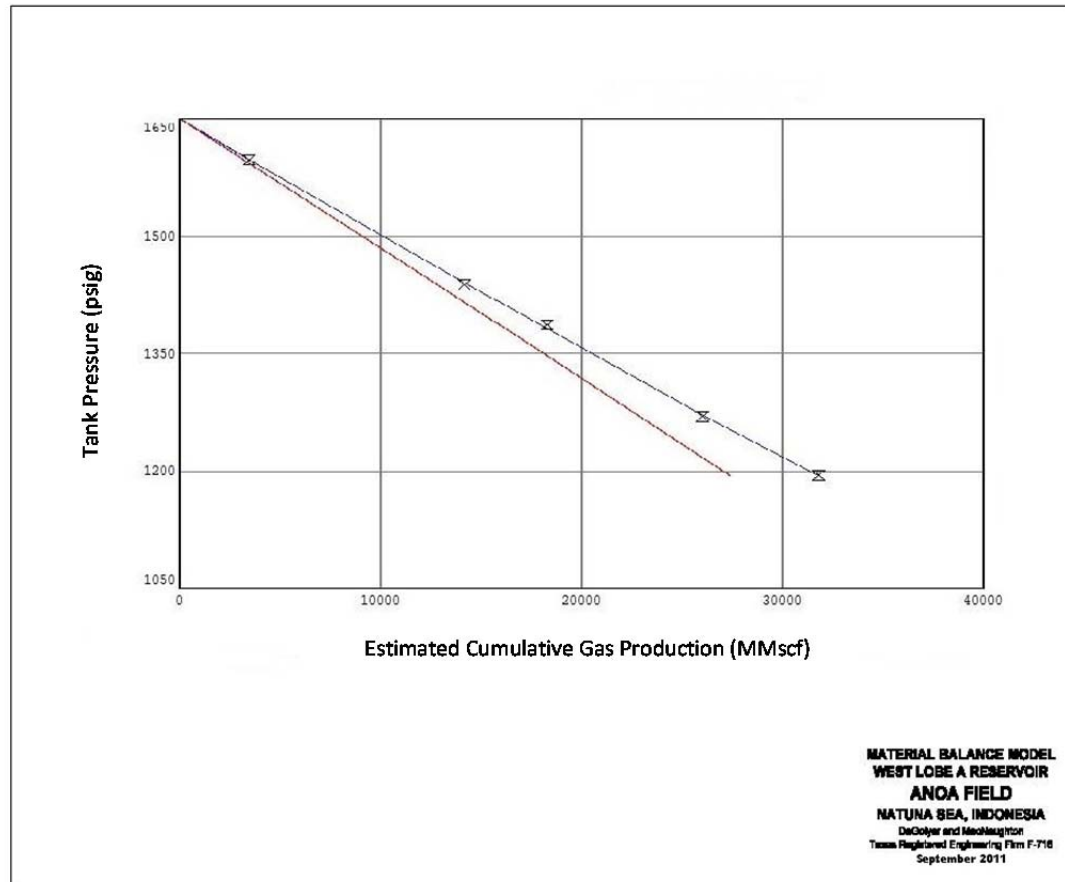


Material-balance models were used to estimate the OGIP and gross ultimate recovery (GUR) for reservoirs with sufficient production history and pressure data. These material-balance models for various reservoirs included estimates of aquifer influx, historic gas migration from outside of the block boundary, transmissibility between east and west lobes within reservoirs, comingled production, and communication between reservoirs.

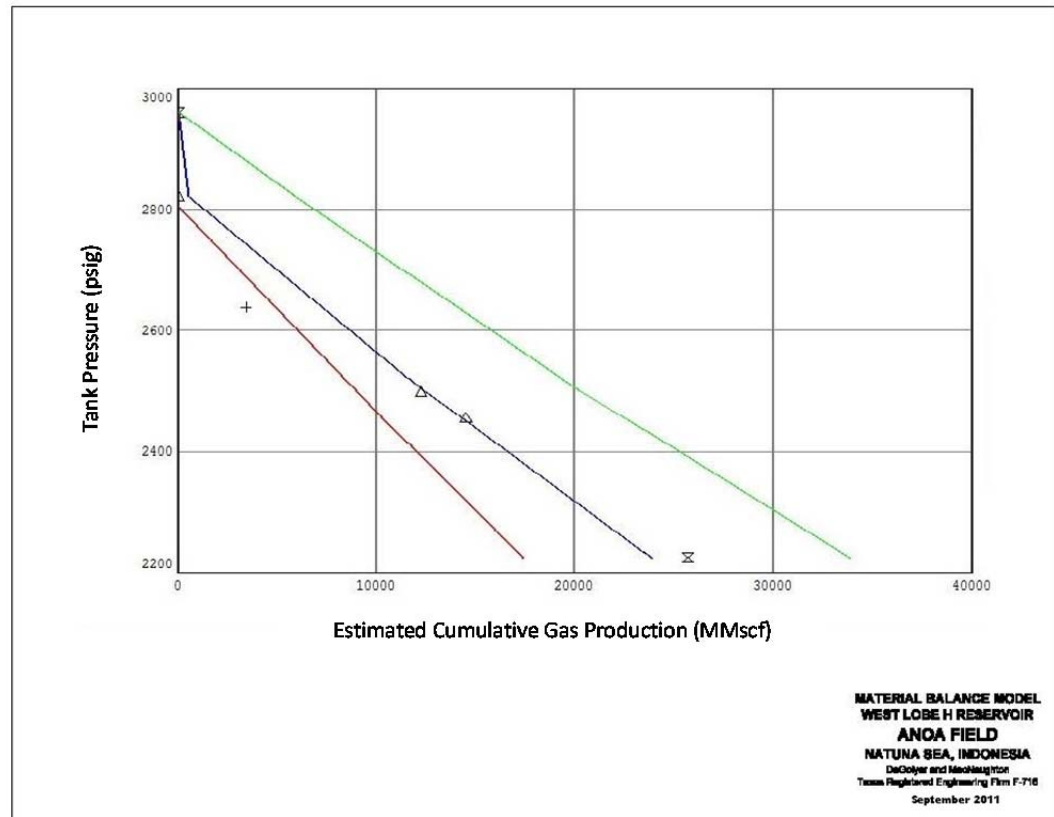
Such material balance models were used to estimate the OGIP and GUR for the west lobe A-2 and A-3 non-associated gas reservoirs.

The west lobe A-2 and A-3 reservoirs have produced more than 40 percent of their estimated OGIP comingled from the WL-1 well since late 2006 and the WL-2 well since late 2010. This production data, as well as pressure data and fluid and rock properties, were incorporated in the material-balance model for the A-2 and A-3

reservoirs. Shown below is a plot from the material balance model used to estimate the OGIP of the west lobe A2 and A3 reservoirs.



The H sands are another major reservoir in the Anoa field where a material balance model was used to estimate the OGIP and GUR of the reservoir. The H sands, like most reservoirs in the Anoa field, are roughly divided into a west lobe and an east lobe. However, unlike the other sands, the H sands demonstrate transmissibility between the lobes. A material-balance model was created to estimate the OGIP for the west-lobe and east-lobe H sand reservoirs with transmissibility modeled between the east and west lobes in the H sands. Pressure communication is demonstrated in the plot of the west lobe H sands shown below. The pressure in the west lobe H sands is shown declining as a result of production in the east lobe H sands.



In certain cases, when the previously named methods could not be used, recovery factors were estimated by analogy with similar wells or reservoirs for which more complete data were available. The west lobe C sands are an example of this. Performance data is pointing to a higher OGIP than the original volumetric estimate, however there is not sufficient pressure data to create a reliable material-balance model for this reservoir without using analogy of the estimated water influx shown in the west lobe A-2 and A-3 sands and H sands. This model was then used, as described above with the west lobe A-2 and A-3 sands, to estimate the OGIP and GUR for the west lobe C sands.

For oil reservoirs whose performance disclosed a reliable decline in producing-rate trends or other diagnostic characteristics, reserves were estimated by the application of appropriate decline curves or other performance relationships. In the analyses of production-decline curves, reserves were estimated only to the limits of economic production based on current economic conditions. Shown below are representative plots of rate versus producing time trends used to estimate remaining reserves for oil wells in various reservoirs in the Anoa field.

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In oil reservoirs that have not produced or where insufficient performance data exist, the volumetric method was used. Recovery factors for these reservoirs were based on analogy with similar producing reservoirs in the Anoa field or other fields within the West Natuna Sea for which recovery factors were estimated from analysis of performance trends.

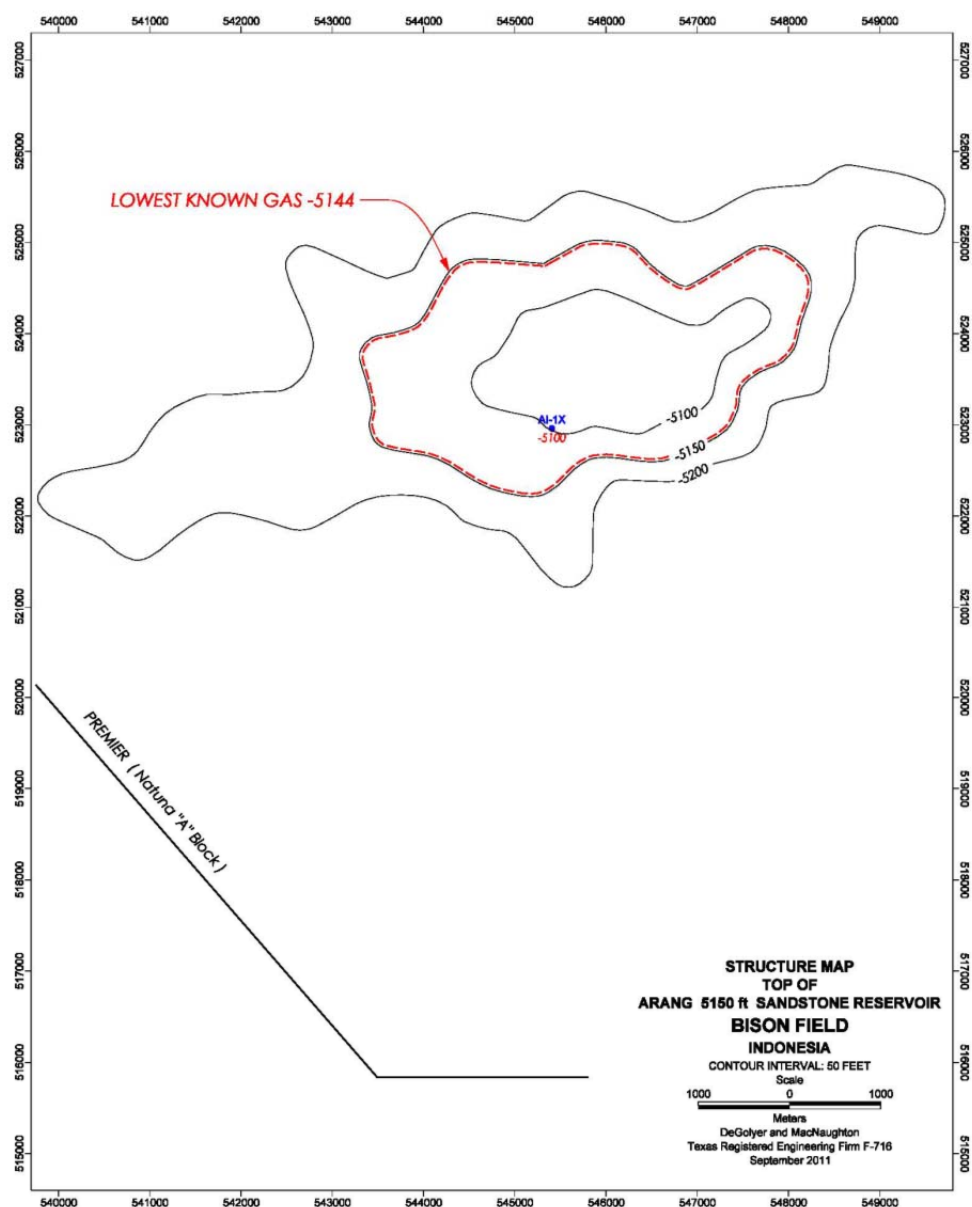
The Anoa field was discovered by Agip in 1974 by the crestally located AQ-2X well and was further delineated by the AQ-3X, AQ-4X, and AQ-5X wells by 1976. Further delineation was conducted by Sumatra Gulf starting in 1979. Three-dimensional (3-D) seismic data were collected over the field in 1986 and subsequently in 1998. Development drilling by Amoseas began in 1990 and the field was brought on production in November of that year. Premier drilled the A-22 horizontal well, deepened the A-11 well, and worked over the A-7 well in 2011.

There are currently nine producing oil wells and seven producing gas wells in the Anoa field. Some of the gas produced from the field has been used for pressure maintenance and gas lift.

Bison Field

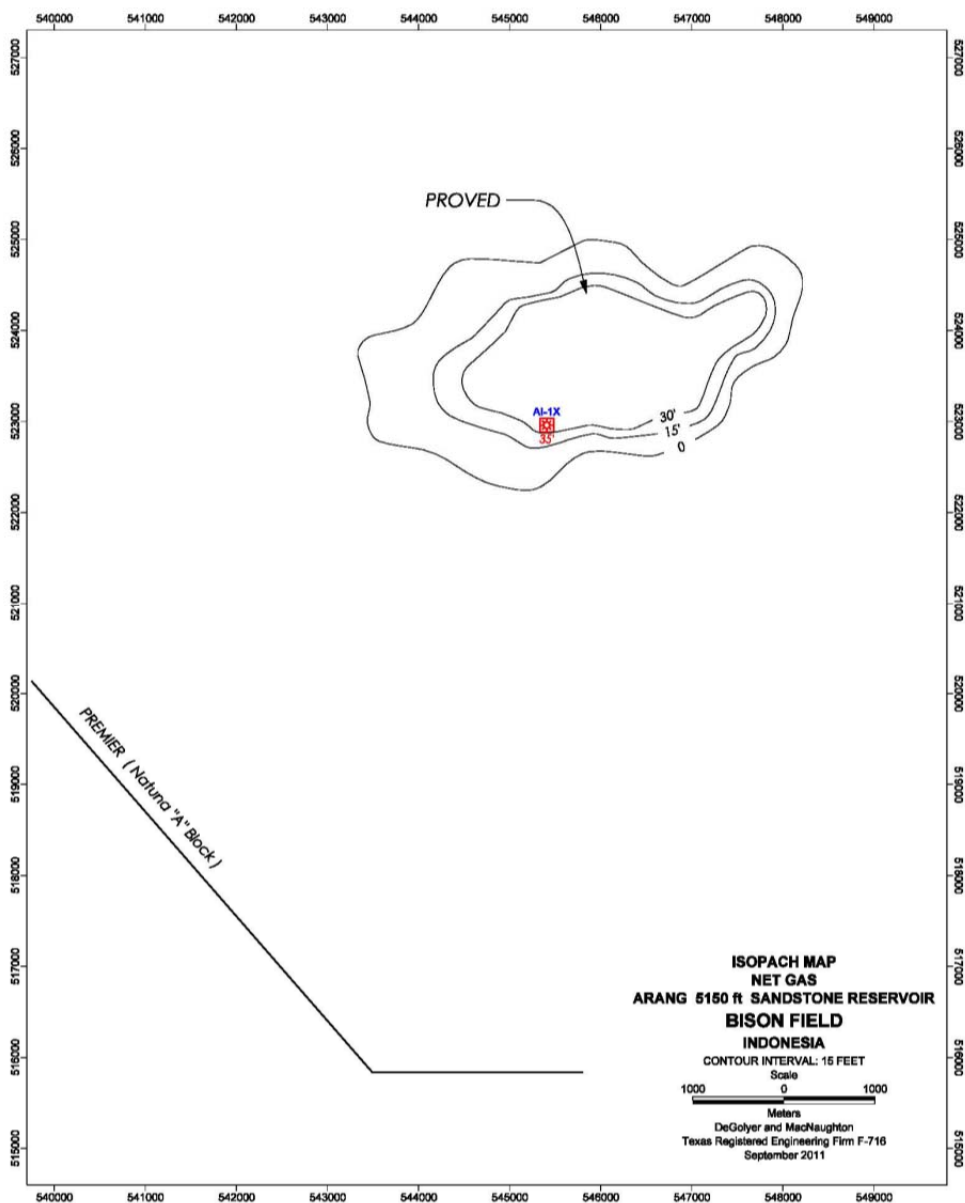
The Bison field is a gas accumulation located to the south of the Anoa field. It is an unfaulted, simple four-way closure with gas trapped in several Arang and Gabus sands.

The Bison structure was identified from two-dimensional (2-D) seismic lines as a simple inversion anticline. The field was discovered by Agip in 1972 by the crestally located well AI-1X. The structure of the Arang 5150 ft sandstone MA-Ca-3 layer is shown on the following figure.



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Eleven gas reservoirs were mapped for the Bison field. Proved-plus-probable reserves were estimated only in the Middle Arang reservoirs. Maps used for the volumetric estimate of proved reserves were limited by the lowest known gas (LKG). Additional probable and possible volumes were estimated downdip of the LKG. Shown in the following figure is a net pay map of the Arang 5150 ft sandstone (MA-Ca-3 layer).



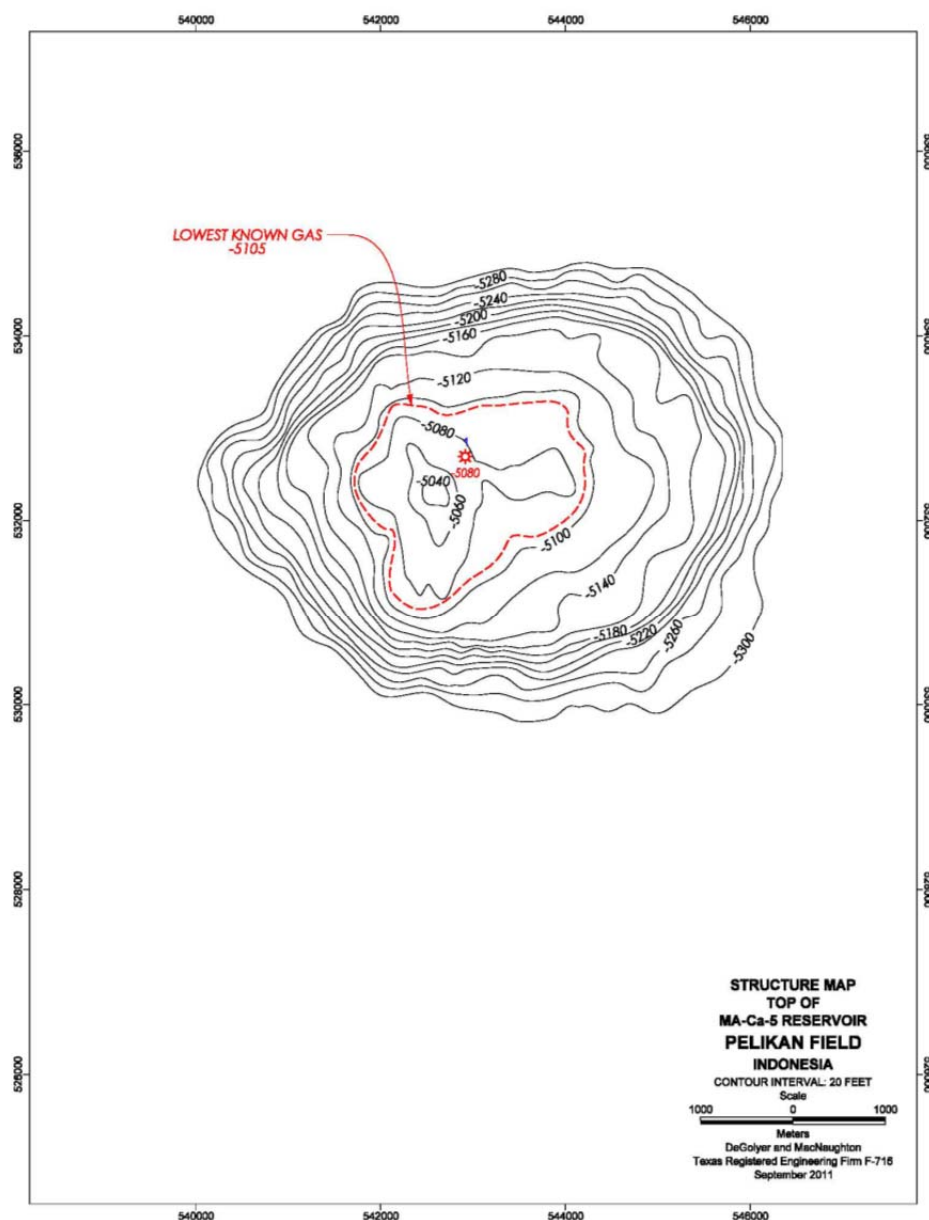
Premier plans to bring the Bison field onstream in 2016 to 2017, or as needed to fulfill the GSA 1 gas sales requirements.

Pelikan Field

The Pelikan field is an unfaulted, low-relief anticline with four-way dip closure located in the West Natuna Basin. The field lies beneath 263 feet of Indonesia waters about 140 kilometers north of the Anambas Archipelago, 200 kilometers east of peninsular Malaysia, and 1,100 kilometers north of Jakarta. The gas-productive reservoirs are found in shallow marine deltaic and distributary channel sands of the lower Miocene Upper and Middle Arang Formation and in marginal marine and fluvial sands of the Oligocene Gabus Formation.

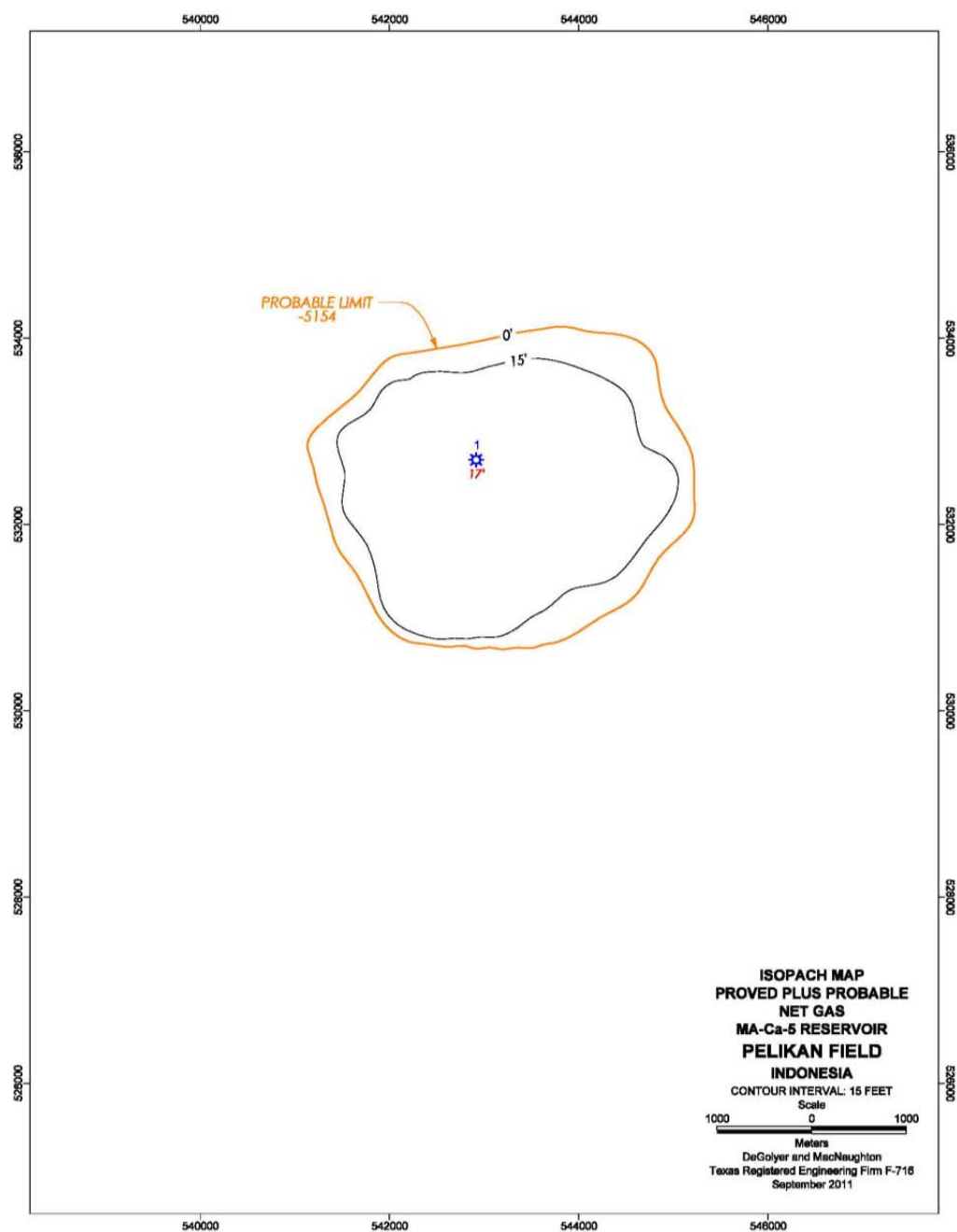
The Pelikan structure was identified by 2-D seismic data as a simple inversion anticline, but the field is currently evaluated using a more recent 3-D seismic survey. The discovery well, Pelikan-1, was drilled on the southwest flank of the structure by Premier in 1997 and tested gas and condensate in Arang and Gabus reservoirs. The location of the well and the structural configuration of the field are shown on the structure map on top of the MA-Ca-5 sandstone shown as follows.

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Sixteen gas reservoirs were mapped in the Pelikan field. Two reservoirs were mapped to the gas/water contact (GWC) and the remaining reservoirs were mapped to the LKG. Additional probable and possible volume was included down dip of the LKG. Conventional subsurface reservoir mapping was used to develop the volumetric estimates of OGIP. A net gas isopach map for the largest gas reservoir in the field, the MA-Ca-5 sand, is shown below.

DEGOLYER AND MACNAUGHTON



Premier plans to bring the Pelikan field onstream in 2013 or as needed to fulfill the GSA 1 gas sales.

Gajah Puteri Field

The Gajah Puteri field is an elongate, westward-plunging, moderately faulted anticline with three-way dip closure located south-southeast of the Anoa field. Pay is found in channel sands of the Lower Arang and Gabus Formations.

The Gajah Puteri structure was identified from 2-D seismic data as an inversion anticline. The field was discovered by Sumatra Gulf in 1981 with the Gajah Puteri-1 well. The Gajah Puteri-2 well was drilled and tested by Premier in 1997. A 3-D seismic survey was also conducted over the field in 1997. Revisions to the estimated in-place volumes in the Gabus sands were made using new seismic data received in late 2010.

Seventeen reservoirs were evaluated in the Gajah Puteri field evaluation, with 6 Arang reservoirs and 11 Gabus gas reservoirs identified. The reservoirs were mapped to the GWC or LKG to use in the estimation of proved reserves, with additional probable or possible in-place volumes estimated downdip of the LKG.

Premier plans to bring the Gajah Puteri field onstream in 2015 or as needed to fulfill the GSA 1 gas sales.

Gas Sales Agreements 2, 3, and 4

In 2008, gas sales agreements (GSA) 2, 3, and 4 were signed for sales from the Gaja Baru, Naga, and Iguana fields and a plan of development for the fields was approved by BPMIGAS. GSA 2 includes sales of 90 BBtu/d to SembGas in Singapore and GSA 3 and 4 sales will be 35 BBtu/d of domestic sales to Batam Island for power generation, pending completion of the gas transportation agreements. The total contract gas quantity includes 542,000 BBtu on plateau plus a production tail until the end of the PSC agreement.

Gajah Baru Field

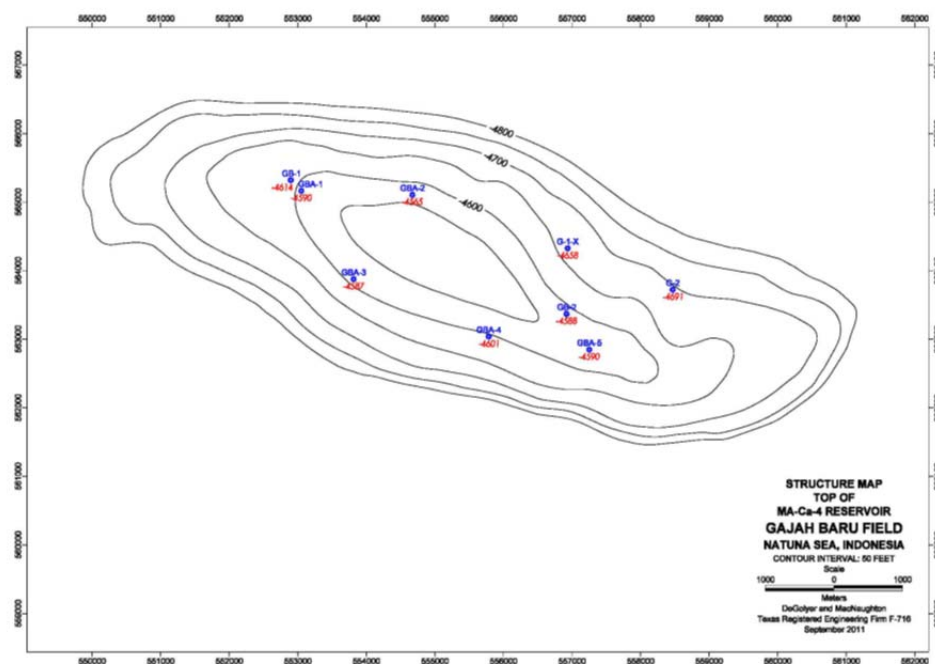
The Gajah Baru field is an unfaulted, east/west-trending, four-way closure located to the south of Anoa field. Nine wells have been drilled in the main closure, and 13 Upper and Middle Arang gas-bearing sandstone reservoirs have been identified. In a separate accumulation west of the main closure, a tenth well found three of the same gas-bearing reservoirs. The Phase 1 development drilling of five wells began in 2010. The wells were completed in the first quarter of 2011 and Premier has reported that the field came onstream in October 2011.

The seismic data set was a good quality 3-D survey that could be used for structural interpretation. Numerous seismic amplitude anomalies were associated with the gas reservoirs. However, due to vertical stacking of the gas reservoirs, the seismic amplitude response of the deeper sands was often masked by shallower amplitudes. Seismic time-to-depth conversion was performed using a regression function derived from the check-shot data in the Gajah Baru-1 well. The final depth structure maps were tied to the formation tops at well control.

Seismic amplitude maps generally showed good conformance between the amplitude limits and the projected GWC derived from modular dynamic testing (MDT) data. Where the amplitude outlines showed a general conformance with structure, the depth structure maps were conformed to the depth contour of the fluid contacts. For the thinner, intervening reservoirs where the seismic data were less definitive, the net pay isopach maps were drawn using the values from the well control.

Thirteen productive reservoirs in the Upper and Middle Arang intervals were evaluated for this study. Structural interpretations based on seismic data were combined with petrophysical evaluations to support isopach mapping of individual reservoirs. Reservoir volumes were classified using petrophysical evaluations of LKG and GWC. Where reservoir volumes were limited by the base of a sandstone in a well and not defined by water contacts, additional reservoir volumes were estimated downdip of the sandstone base. The limits of these downdip estimations were usually defined by linear pressure gradients from MDT data. In all reservoirs, trends of sand thickness were taken into account. Conventional subsurface reservoir mapping was used to develop the volumetric estimates for this study. Shown below is a structure map of the Ma-CA-4 reservoir in the Gajah Baru field.

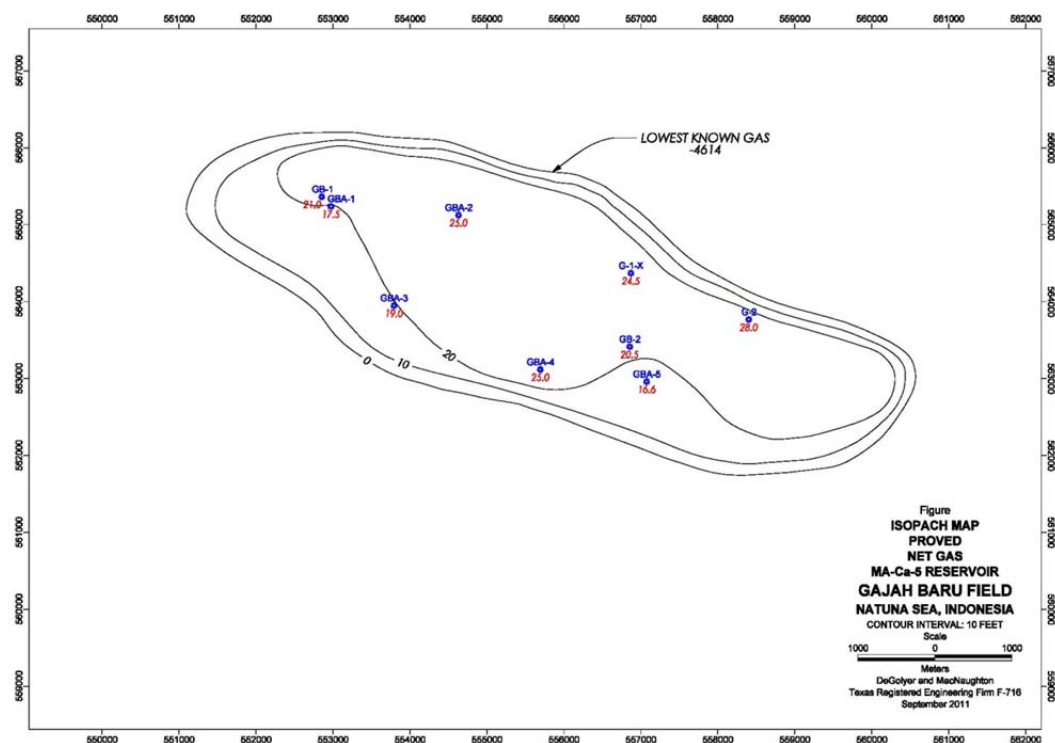
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More than 80 percent of the proved-plus-probable reserves in the field are contained in the MA-Ca-3, MA-Ca-4, and MA-Ca-5 reservoirs in the Middle Arang.

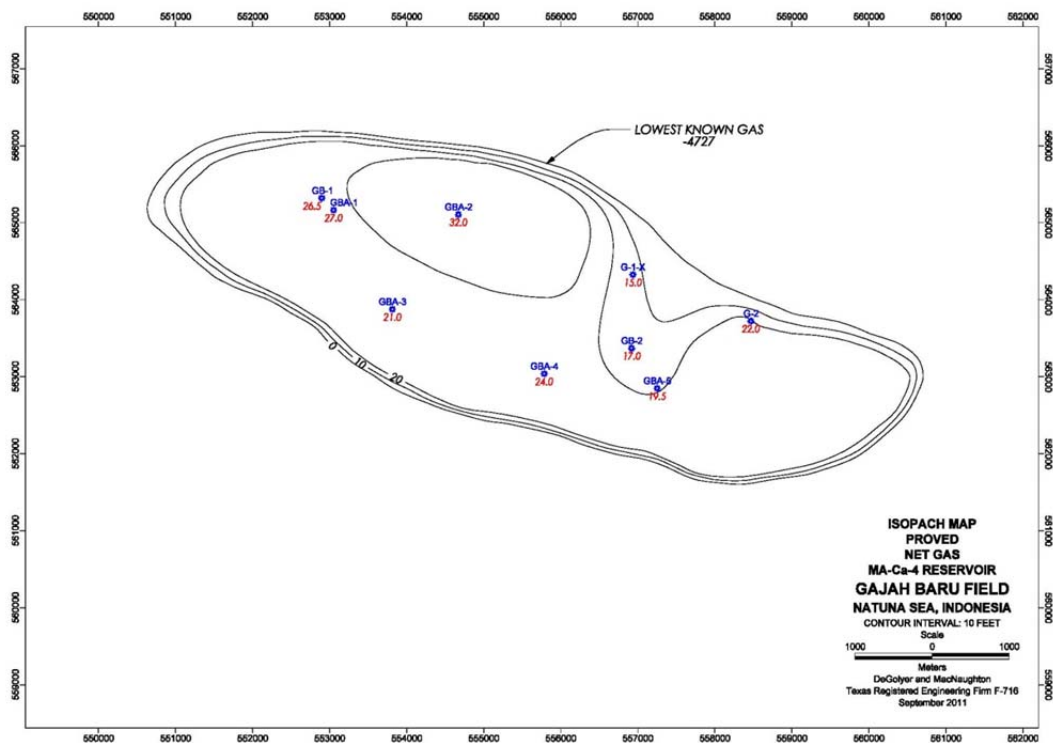
In the MA-Ca-5 reservoir, all nine wells are interpreted to be productive. The structural limit associated with proved reserves was the LKG at 4,614 feet subsea, shown in the net pay isopach map as follows.

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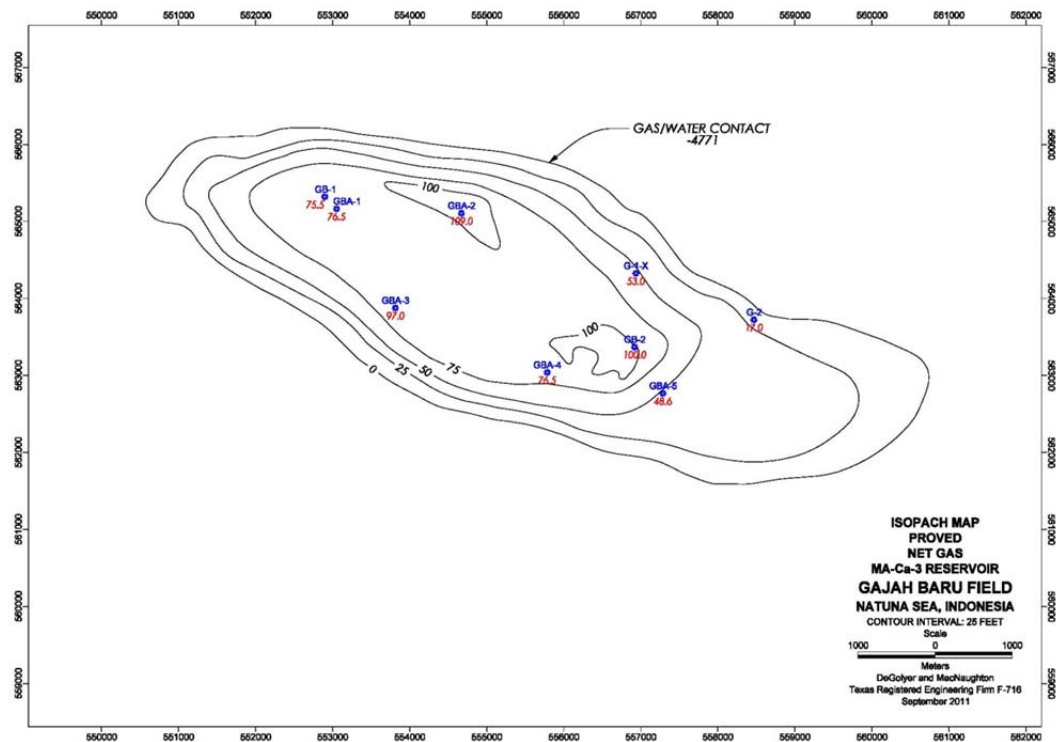


Reservoir volumes in the MA-Ca-4 and MA-Ca-3 reservoirs were interpreted in a similar manner. OGIP associated with proved reserves in the MA-Ca-4 was limited to the LKG at 4,727 feet subsea. Shown below is a net pay isopach map of the MA-Ca-4 reservoir.

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In the MA-Ca-3 reservoir, the structural limit associated with proved reserves was the GWC from the Gajah-2 well at 4,771 feet subsea. The five new wells were drilled to target the seismic amplitude in the Middle Arang sands. These amplitudes were used in the contouring of the thicker part of the sands seen in the Gajah Baru-2 and GBA-2 wells shown below in the net pay isopach map of the MA-Ca-3 reservoir.



Premier reports that the Gajah Baru field came onstream in October 2011. The field development plan calls for the five development wells to be produced to fulfill the GSA 2, 3, and 4 rate until the Naga field comes on stream, which Premier plans for 2014. The Gajah Baru wells will first target the MA-Ca-3 reservoir, with one well completed in the MA-Ca-5. Wells will be recompleted up to the MA-Ca-4 reservoir as needed and produce commingled with the MA-Ca-3 reservoir. The smaller reservoirs will be produced later in the field life.

Iguana Field

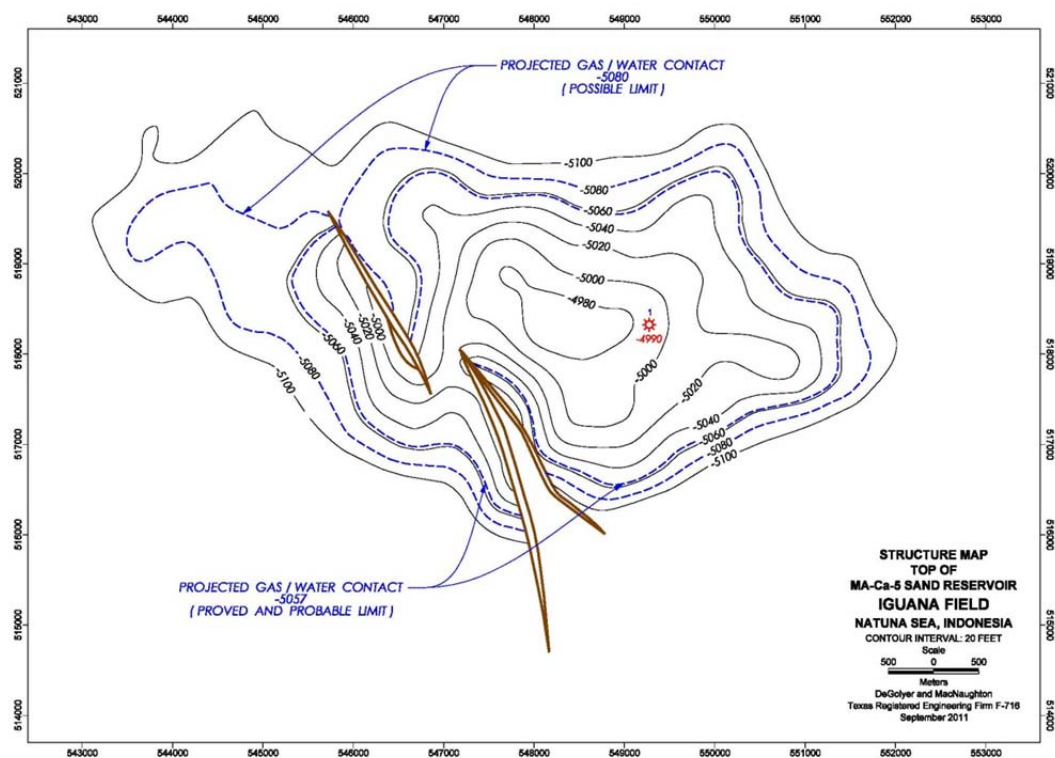
The Iguana field is a faulted four-way closure located on the southeast side of the Bison field. One well, the Iguana-1, has been drilled and six gas-bearing sandstone reservoirs in the middle Arang have been identified.

The seismic data set used for interpretation of the Iguana field was a good quality 3-D survey. Maps based on the seismic interpretation were prepared for the two largest gas productive levels, UA-Aa-8 and MA-Ca-5. The seismic data quality across the Iguana field was adequate for structural interpretation and the gas sands were observed to be associated with the amplitude anomalies. Although the

amplitudes were generally contaminated with noise, smoothed amplitude maps were useful in identifying reservoir sand trends. The correlation between net pay thickness and amplitude was better defined for the MA-Ca-5 horizon than for the UA-Aa-8 horizon. These horizon amplitude data, constrained by well control, were incorporated into the final net pay thickness mapping. Check-shot data from the Iguana-1 well were used for time-to-depth conversion using a linear regression. The final depth structure maps for the UA-Aa-8 and MA-Ca-5 horizons were tied to the formation tops at well control.

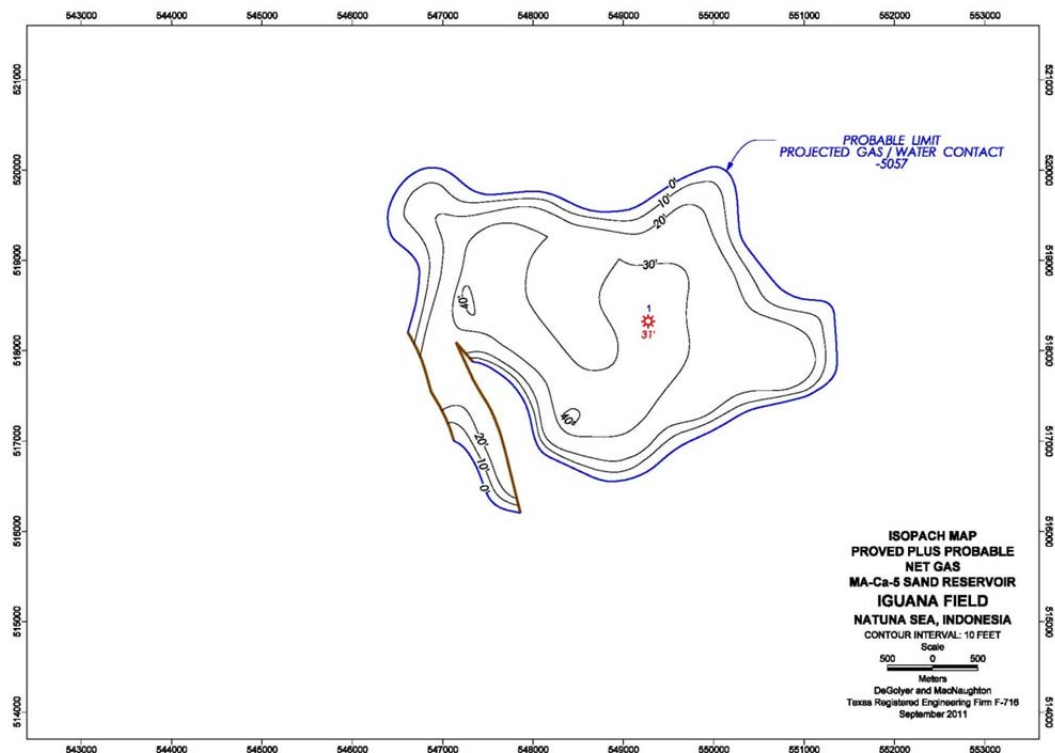
Structural interpretations were combined with petrophysical evaluations to support isopachous net pay mapping of the six individual gas-bearing reservoirs. The seismic amplitude maps of the UA-Aa-8 and MA-Ca-5 horizons showed good conformance between high amplitude limits and projected GWC derived from the MDT data. For some of the reservoirs, the MDT data were ambiguous due to vertical variations in aquifer pressure. In these cases the amplitude outlines and structure maps were used to reconcile uncertainties in the projected contacts. Where the amplitude outlines showed a general conformance with structure, the depth structure maps were altered to fit the depth contour of the fluid contacts more precisely. The amplitude maps were then used as a qualitative guide to map net pay thickness away from the well control. Where the seismic data were unable to resolve thicknesses, the net pay isopach maps were generated using only the values from the available well control for the thinner reservoirs. Conventional subsurface reservoir mapping was used to develop the volumetric estimates for this study. Shown below is a representative structure map on the top of the MA-Ca-5 reservoir.

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More than 85 percent of the proved-plus-probable reserves in the field are attributable to the MA-Ca-5 reservoir. The proved reservoir limit was estimated at the projected GWC at 5,057 feet subsea. Seismic amplitudes were used to evaluate the reservoir, and maximum reservoir thickness was limited to the maximum thickness observed in the well. The proved area was further limited in the western part of the reservoir because of the distance from well control. For the reservoir volume used in estimating probable reserves, the projected GWC was used as the reservoir downdip limit. A larger area on the western side of the field is included in this volume and the interior portion of the reservoir was interpreted to thicken beyond the maximum thickness observed in the well. Shown below is a net pay isopach map of the MA-Ca-5 reservoir.

DEGOLYER AND MACNAUGHTON



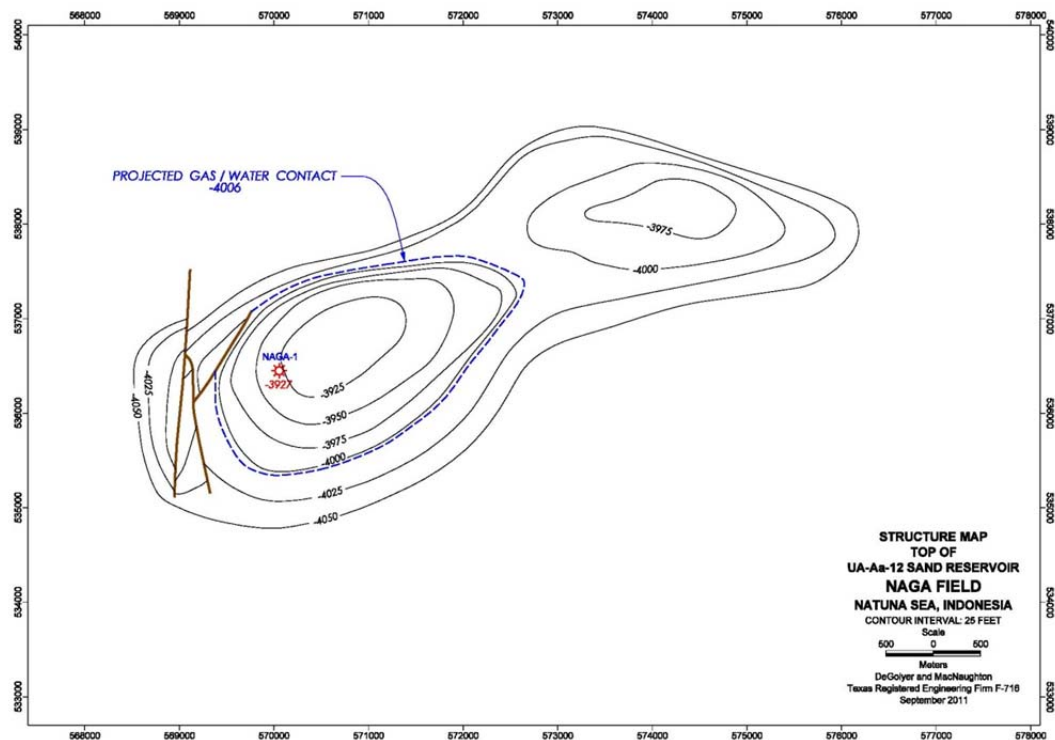
Premier plans to bring the Iguana field onstream in 2016 and 2017, or as needed to fulfill the GSA 2, 3, and 4 gas sales.

Naga Field

The Naga field is an unfaulted four-way closure located east of Pelikan field. One well has been drilled and 17 upper and middle Arang gas-bearing sandstone reservoirs have been identified.

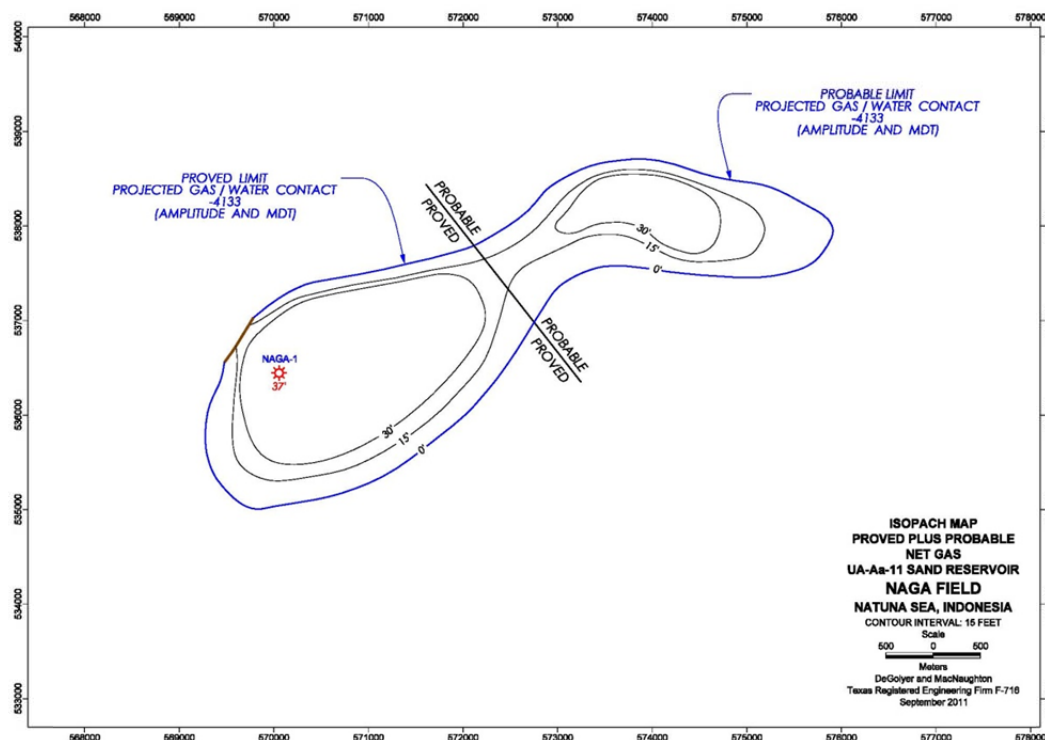
Seventeen sandstone intervals in the Upper and Middle Arang were mapped for this study. Structural interpretations were combined with petrophysical evaluations to support isopachous net pay mapping of individual reservoirs. Conventional subsurface reservoir mapping was used to develop the volumetric estimates for this study. Shown below is a representative structure map on the top of the UA-Aa-12 reservoir.

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Nearly 67 percent of the proved-plus-probable reserves in the field are contained in the UA-Aa-12, UA-Aa-11, and MA-Ca-5 reservoirs. Structure and net gas isopach maps show the reserves categories and limits used in the estimation of reserves for these reservoirs. Reserves associated with the accumulation east of the well control were classified as probable or possible depending on the structural relationship between the two areas and any evidence of seismic amplitude. Shown below are the proved-plus-probable net pay isopach maps of the UA-Aa-11 and MA-Ca-5 reservoirs.

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Premier plans to bring the Naga field onstream in 2014 or as needed to fulfill the GSA 2, 3, and 4.

Kakap PSC Fields

The fields in the Kakap PSC are situated in the West Natuna Basin beneath Indonesian waters 250 to 350 feet deep, about 1,100 kilometers north of Jakarta. The Kakap PSC is operated by Star Energy Kakap Limited and the production license extends to June 2028. Twelve fields were evaluated in the Kakap block in this report: the KF, KG, KH, KRA, KRA South, KI, KN, KR, KRN, KG-5AX, Nelayan, and Jangkar. The fields are operated from four fixed platforms and from several subsea tie-backs.

The West Natuna Basin is a Tertiary rift structure located on the Sunda shield. The oil and gas reservoirs are found in sands of middle Eocene to early Miocene age. The fields are typically clastic-hosted, fault-bounded, simple asymmetric anticlinal structures. Reservoir characteristics are generally favorable

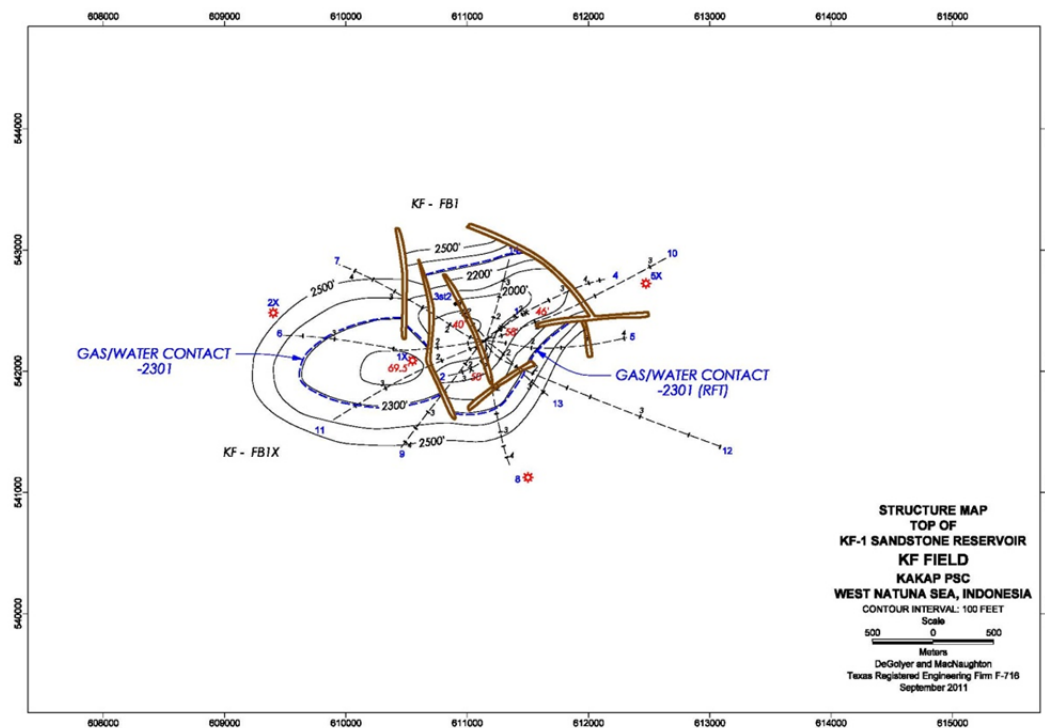
with medium to high porosity, water saturation is moderate to low for most reservoirs, and shale volume is variable.

KF Field

The KF field is an east-west elongate, faulted, asymmetric anticlinal structure with four-way dip closure. It lies beneath approximately 300 feet of water and is 170 kilometers north-northwest of the Anambas Archipelago. The KF structure was identified from 2-D seismic data as a faulted anticline and was discovered by Marathon in 1985 with the crestally located KF-1X well. The KF field was placed on production in late 1989 and has produced 54 millions of barrels (MMbbl) of oil and 109 billion cubic feet (Bcf) of gas (net of gas reinjection) from oil sands in the Lower Gabus Formation.

The field is faulted into three major blocks and subordinate faulting further divides reservoirs in certain sands. There were nine major pay intervals in the Gabus and Barat Formations of the KF field evaluated in this report, including seven non-associated gas sands and two oil sands with gas caps. The reservoirs are mapped to LKG or lowest known oil (LKO), gas/oil contact (GOC), or GWC. Over 90 percent of the estimated recoverable proved-plus-probable gas is solution gas from the Lower Gabus oil sands. A structure map on the top of the KF-1 sandstone is shown in the following figure.

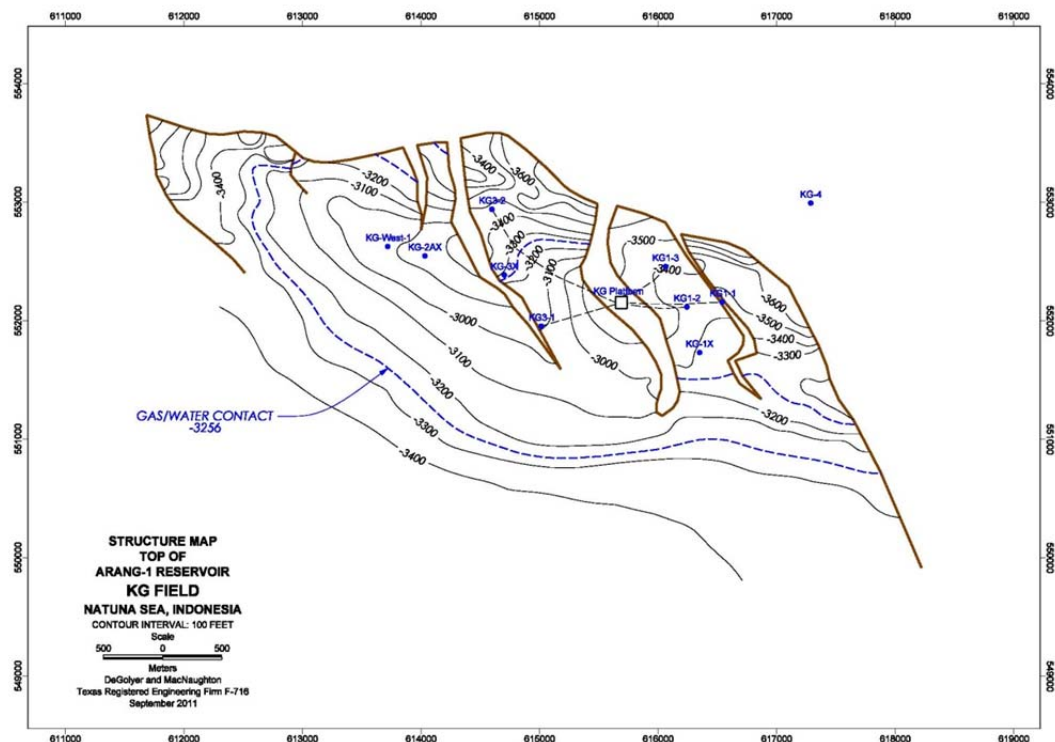
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KG Field

The KG is an elongated, faulted, anticlinal structure with four-way dip closure approximately 10 kilometers north-northwest of the KF field. The structure was identified from 2-D seismic data and discovered by Marathon in 1978 by the KG-1X well. In 1992, 3-D seismic data were collected over the field and the KG field was placed on production in 1995 with three completions in the oil sands of Pasir, Barat, and Upper Gabus Formations and gas Arang Formations. Two more producing wells were completed in these sands in 1997 and 1998 and in 2007 the KG W-1 well was drill for completion in the Arang gas reservoirs. In 2010 the KG W-1 well was tied into the KG production system and placed on production. The KG field has produced 28 MMbbl of oil and condensate and 87 Bcf of gas. A structure map on the top of the Arang-1 reservoir top is shown below.

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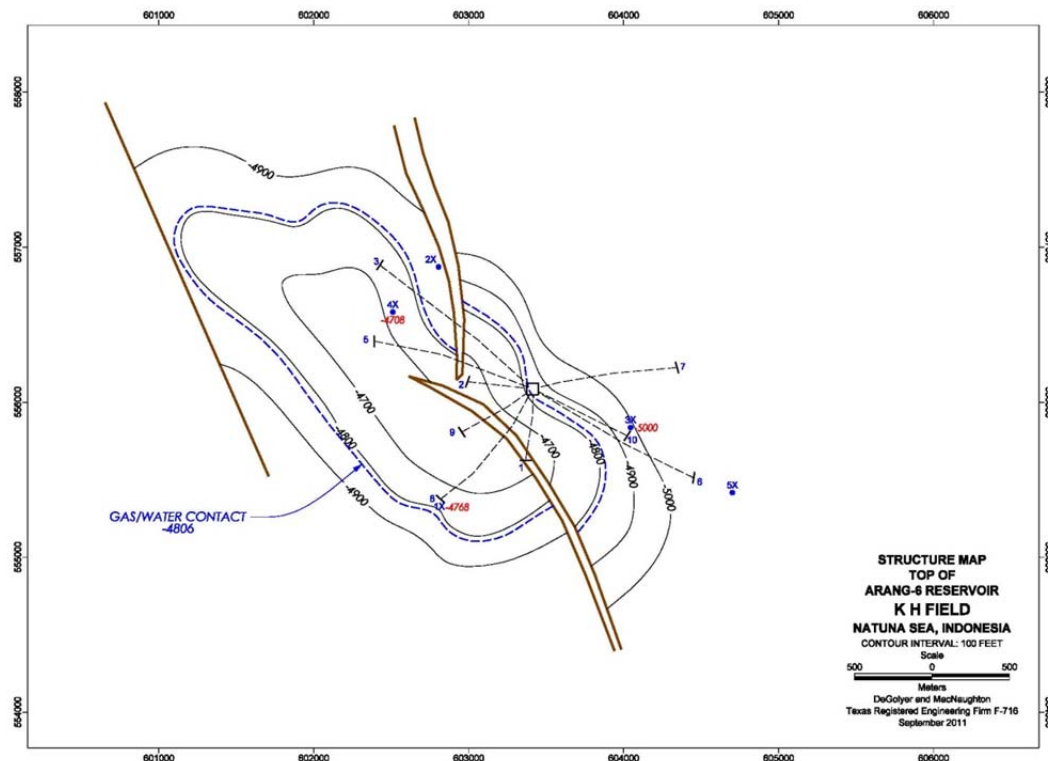


Seven gas reservoirs were mapped in the KG field for this evaluation. The field is faulted into three major blocks and subordinate faulting further divides reservoirs in certain sands. Reservoirs were mapped to LKG, LKO, GOC, or GWC.

KH Field

The KH field is an elongate, faulted, inverted anticlinal structure with a four-way dip closure approximately 11 kilometers west-northwest of the KG field. The structure was identified from 2-D seismic data as a faulted anticline related to a major fault, separating the field into two major fault blocks. The field was discovered with the KH-1X well in 1980 by Marathon, which then added five more delineation wells. The field has produced 27 MMbbl of oil and condensate and 194 Bcf of gas from sands in the Arang, Pasir, Barat, and Gabus Formations. The structural configuration of the field is shown in the following figure of the structure map on the top of the Arang-6 reservoir.

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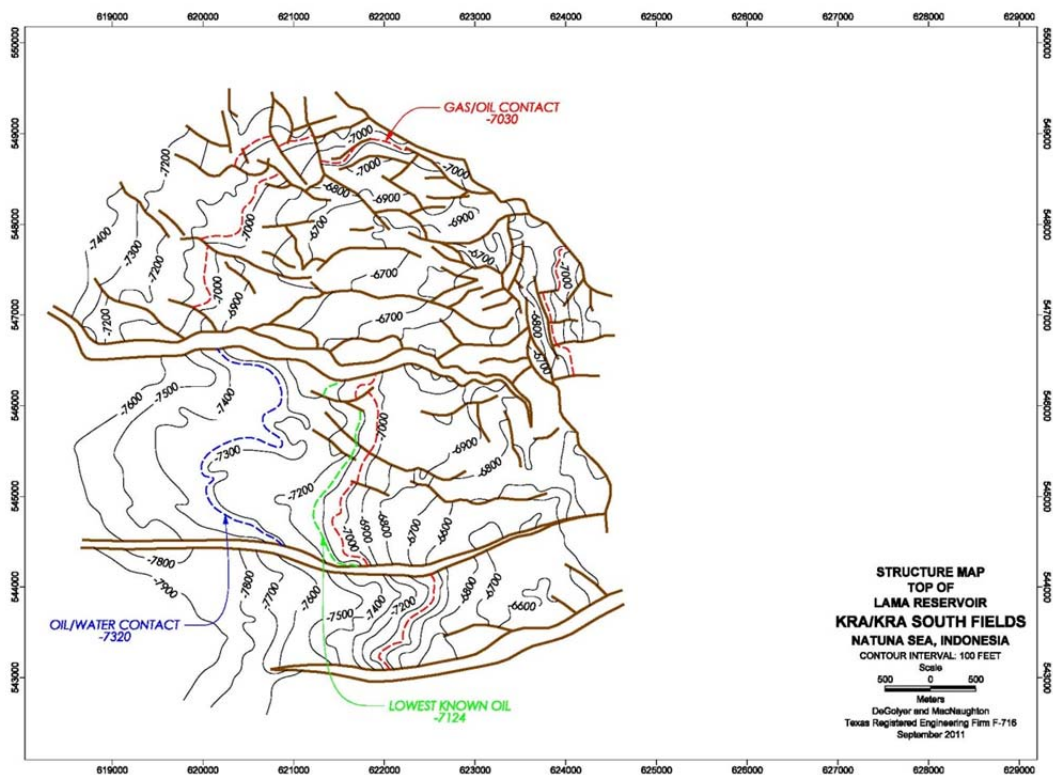


Reservoirs in KH with sufficient production history were estimated using rate versus producing time trends, while volumetric estimates based on net pay maps were used for the KH-9 reservoir.

KRA Field

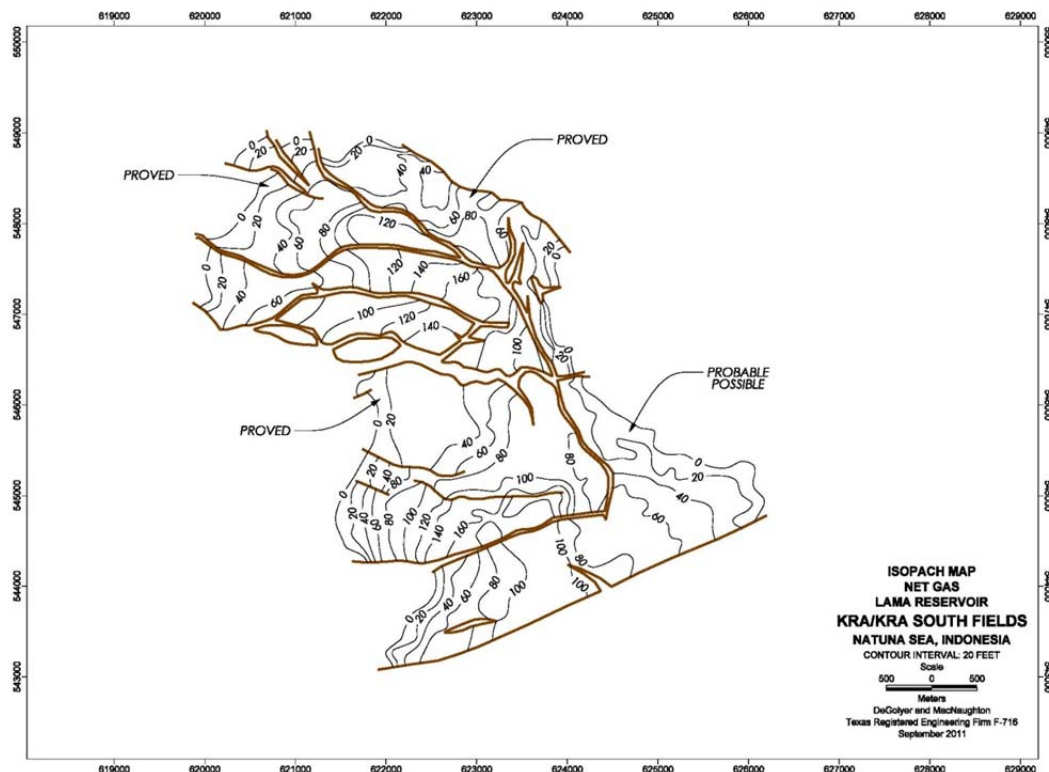
The KRA field is a northwest-southeast elongate, faulted anticlinal structure with combination fault and dip closure. It is approximately 4 kilometers southeast of the KG field and 10 kilometers east-southeast of the KF field. Pay is found in oil and gas-cap sands in the late Eocene Lama Formation. The KRA structure was originally identified from 2-D seismic data as a paleobasement high draped with Eocene and younger clastics. The field was discovered by Marathon in 1991 with the KRA-1X well. The KRA field was placed on production with four wells completed in the oil reservoir in 1995. Since then 10 more production wells have been completed in the oil reservoir and gas cap. The KRA field has produced 20 MMbbl of oil and 141 Bcf of gas (net of gas reinjection). The structural configuration of the field is illustrated by the structure map on the top of the Lama reservoir in the KRA and KRA South fields shown below.

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The oil reserves for the KRA field were estimated using rate versus producing time trends of existing wells. The remaining gas-cap reserves were estimated by the volumetric method. The net gas isopach map of the Lama gas cap in the KRA and KRA South fields is shown in the following figure.

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KRA South Field

The KRA South field is southeast of and adjacent to the KRA field. The two fields are separated by a large fault. The KRA South field was discovered in 1992 by Marathon with the KRA-2X well. Production from the KRA South field began in 1998 when the Ketam-1ST well was completed in the Gabus Formation. The well produced for 2 years, then was temporarily abandoned in 2000. In 2006 it was recompleted in the gas cap of the Lama Formation. In 2007 the KRA-2X well was reactivated to also produce the gas cap of the Lama Formation. The KRA field has produced 24 Bcf of gas and 2 MMbbl of condensate. Reserves for the KRA South field were estimated by the volumetric method. Additional probable and possible reserves have been estimated in the eastern flank of the closure where the sands appear to thicken. A structure and net gas isopach map for the Lama reservoir for this field are shown above in the discussion of the KRA field.

Jangkar Field

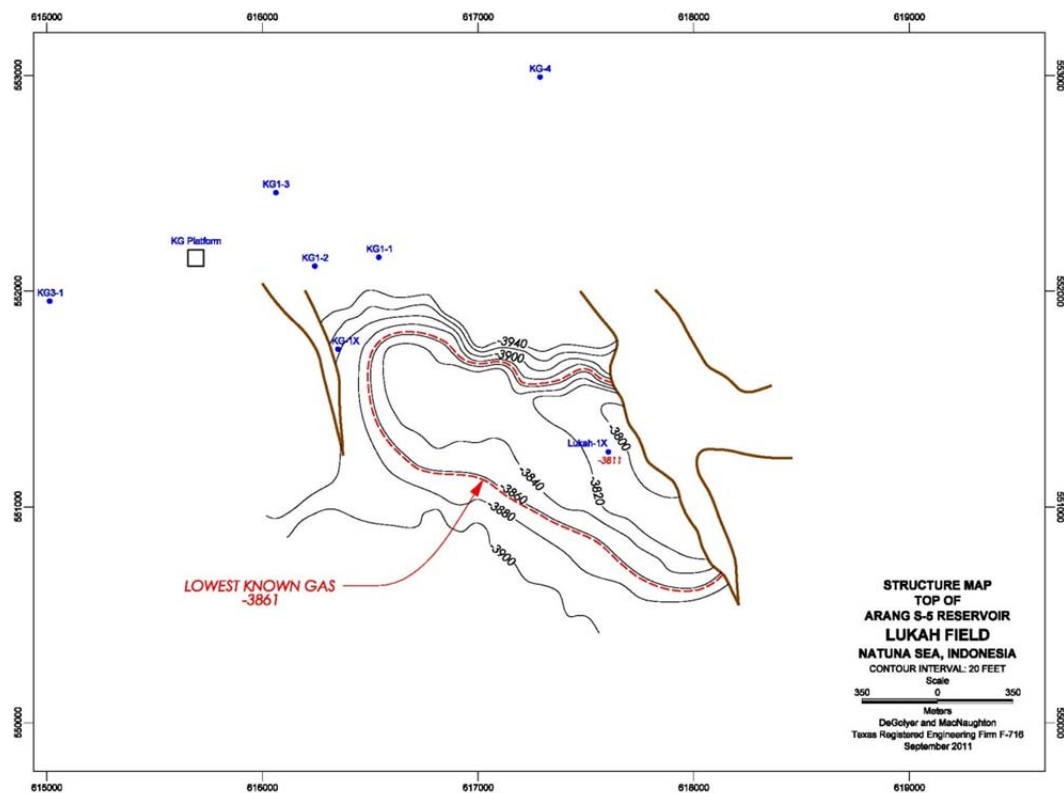
The Jangkar field was discovered in 1998 with the Jangkar-1X and Jangkar-2X wells. From 1998 through 2003, the Jangkar-2X well produced 3 MMbbl of oil and 6 Bcf of gas from an oil sand in the Pasir Formation. In 2005 the well was

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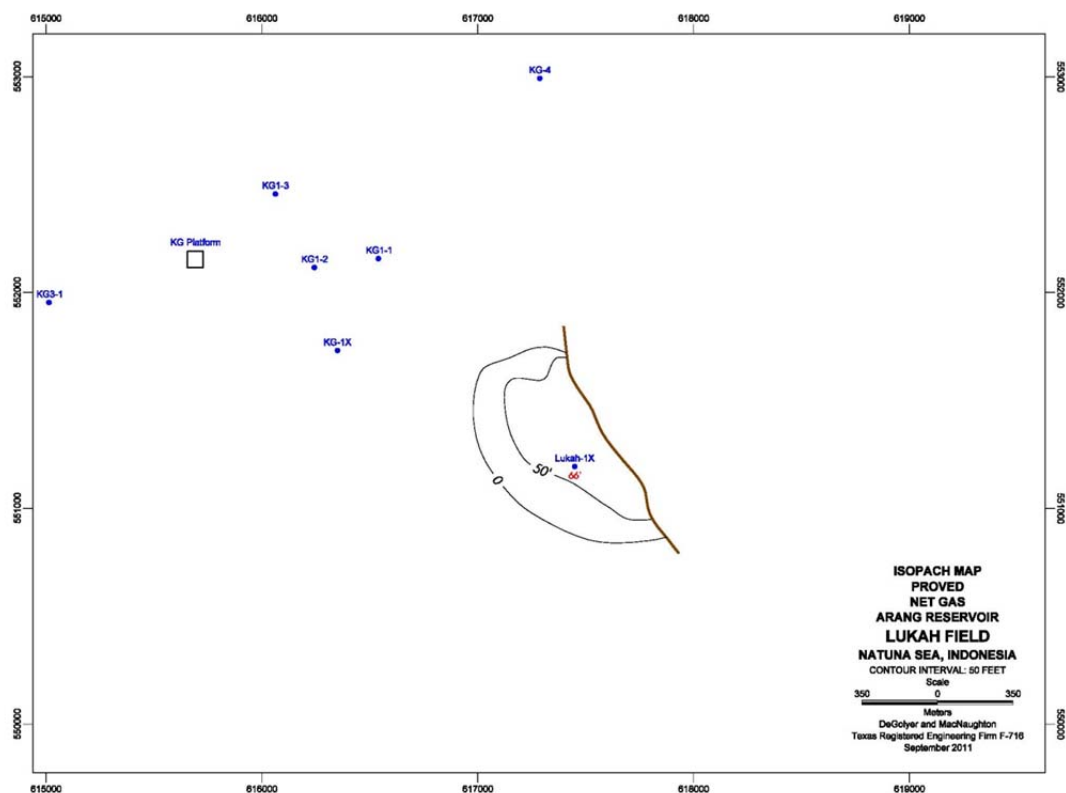
recompleted to produce both the gas cap and oil zone of another sand in the Pasir Formation. It produced 2 MMbbl of oil and 7 Bcf of gas before it was shut in. No reserves have been estimated for the Jangkar field.

Lukah Field

The Lukah field is located approximately 1 kilometer southeast of the KG field. The field was discovered in May 2006 when the Lukah-1X well flow tested at 19.7 MMcf/d (commingled) from two gas sands in the Arang Formation. The two gas sands, the Arang 0 sand and the Arang 6 sand, lie at depths of 3,000 feet true vertical depth subsea (TVDSS), and 3,800 feet TVDSS, respectively. In 2010 the Lukah-1X well was tied into the KG field facilities and placed on production from the Arang-0 and Arang-6 reservoirs. Reserves for the Lukah field were estimated by the volumetric method and are recoverable from the Lukah-1X well. The following figures show the structure map on the top of the Arang-6 and the net gas isopach map of the Arang reservoir for this field.



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Nelayan Field

The Nelayan field is located less than 1 kilometer northeast of the KG field. It is a single-well oil field that has produced over 0.8 MMbbl oil and over 3 Bcf of gas since 1997. Proved producing oil reserves were estimated for the Nelayan field using rate versus producing time decline trends. The gas produce is flared and therefore zero gas reserves were estimated for the field.

KI Field

The KI field is a single-well gas field in a north/south-trending fault block east of the KH field. The field was discovered with the KI-1X/1XD wells in 1981 with pay in the upper Gabus L5 sand. The wells were plugged and abandoned in 1981 and zero reserves have been estimated for the KI field. There are no reserves estimated for the KI field.

KN Field

The KN field is a single-well gas field in a north/south-trending fault block west of the KG field. The field was discovered with the KN-1X well in 1981 with pay

in the Pasir and Upper Gabus Formations. The wells was plugged and abandoned in 1982 and no reserves have been estimated for the KN field.

KR Field

The KR field is a single-well oil field in a north/south-trending fault block north of the KRA field. The field was discovered with the KR-1X well in 1995 with pay in the Gabus Formation. From 1995 through 2005, the well produced 1 MMbbl of oil and 3 Bcf gas before being shut in with high water production. The field was placed back on production in late 2010. Proved reserves were estimated using rate versus producing time trends and probable reserves were based on increased oil rate that will require plugging back the high water zones in the well.

KRN Field

The KRN field is a single-well oil field in a north/south-trending, tilted fault block northwest of the KRA field. The field was discovered in 1995 with the KRN-1X well. The well was completed in the Gabus Formation as a subsea oil producer and tied back to the KRA platform. The well has produced 4 MMbbl oil and 3 Bcf gas. Reserves were estimated using rate versus producing time trends.

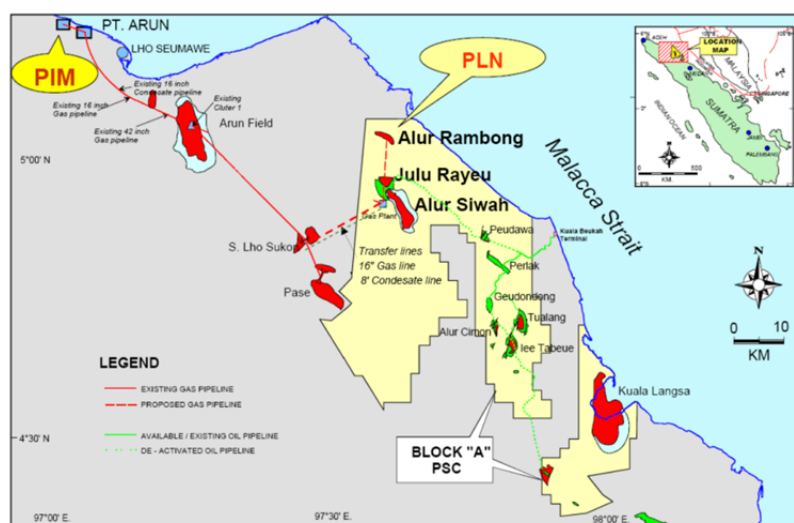
KG-5A Field

The KG-5A field is a single-well oil field in a north/south-trending fault block northeast of the KG field. The field was discovered with the KG-5X well in 1984. In 1995 the KG-5AX well was completed in the Pasir oil sand as a subsea oil producer and tied back to the KG platform. In early 2008 the KG-5A well was shut in, having produced 2 MMbbl oil and 1 Bcf gas. There have been no reserves estimated for the KG-5A field.

Gas sales from the Kakap PSC to SembCorp in Singapore began in July 2001. Structural interpretations were based on seismic data combined with petrophysical pay summaries to support isopachous mapping of individual reservoirs. When sufficient production data were available, performance trends were used as the basis for reserves estimates.

North Sumatra Block 'A'

The North Sumatra Block 'A' PSC area lies in the North Sumatra Basin and contains four gas fields and nine oil fields, none of which are currently producing. The fields evaluated for this report are the Alur Rambong, the Alur Siwah, and the Julu Rayeu gas fields, as well as the Geudongdong, Iee Tabeu, and Tualang oil fields. A location map of the PSC area is shown as follows.



Location Map – courtesy of Premier

The North Sumatra Basin is bounded by the Barison mountain front to the southwest, by the Asahan Arch to the southeast, by the Andaman Sea to the northwest, and by the Malacca Platform to the northeast. The basin exhibits a northwest-southeast structural trend for both folding and faulting. The primary productive reservoirs in the North Sumatra Basin lie in the Peutu and Baong gas

Alur Rambong Field

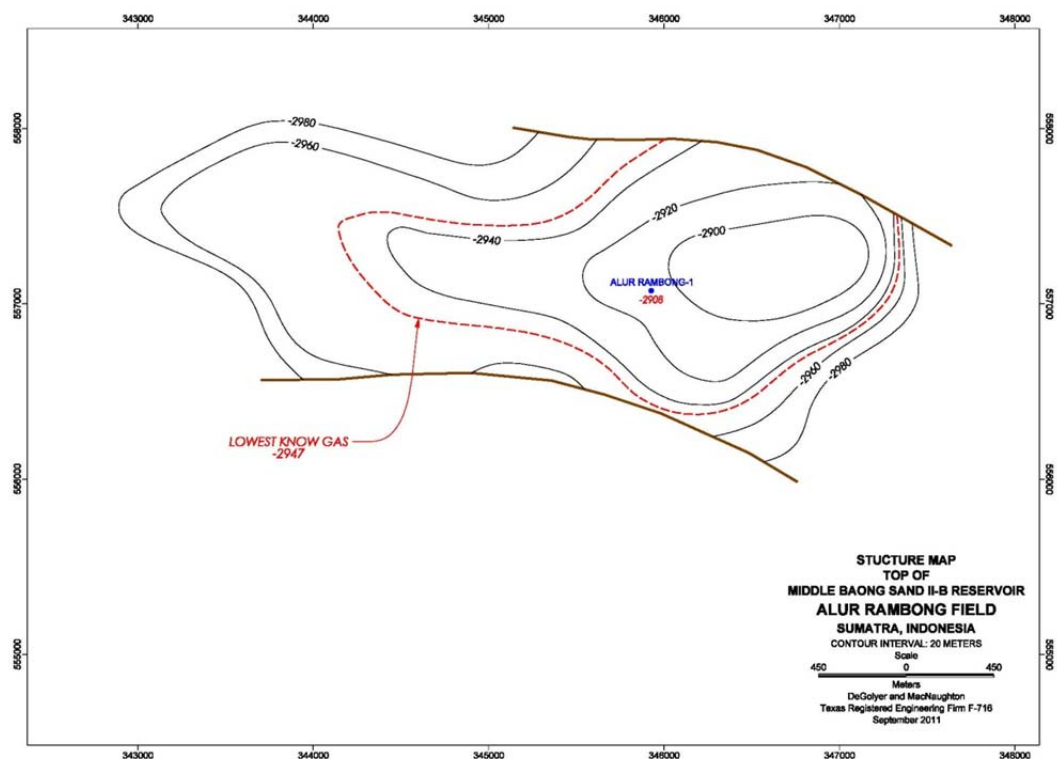
The Alur Rambong gas field is located onshore in the Sumatra Basin, approximately 80 kilometers northwest of Langsa in Aceh Province. The field was discovered by the Alur Rambong-1 well, which was drilled in 1993. No other wells have been drilled in this field.

The gas sands in the Alur Rambong field lie within the Baong Formation at depths of 2,900 meters subsea. The gas reservoirs are contained within an anticlinal structure about 5 kilometers long by 1.5 kilometers wide. The gas pay is in two Middle Baong Formation sands, which are estimated to be in communication through a natural fracture system. The well did not encounter water in either sand.

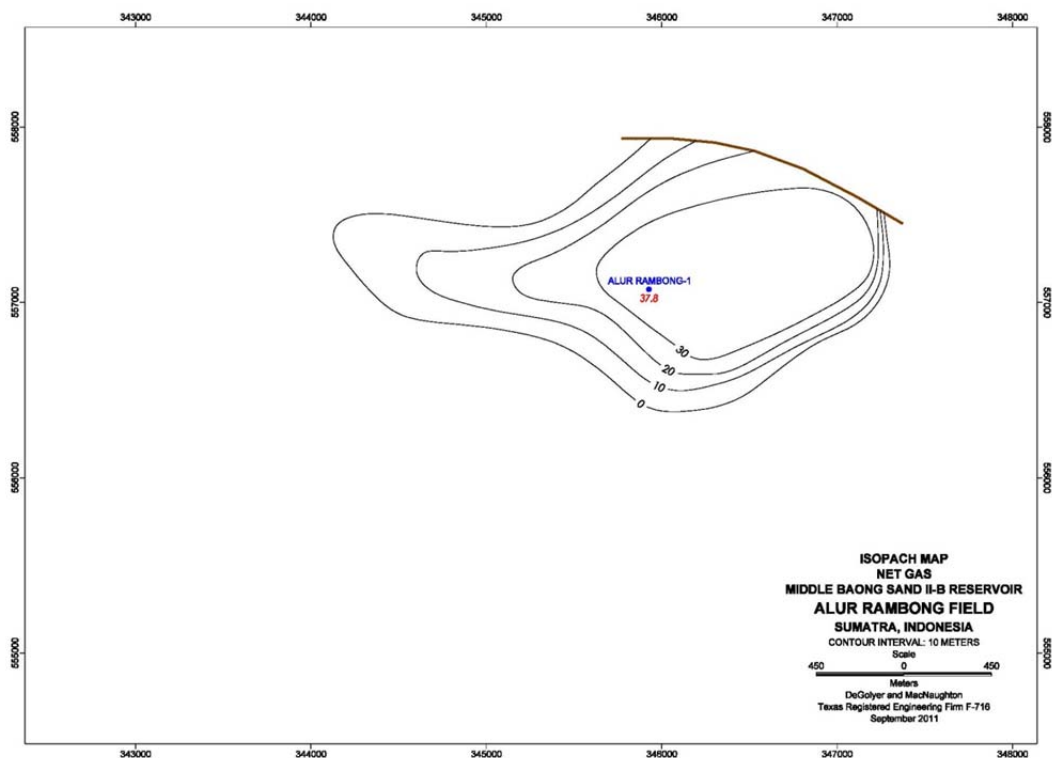
Estimates of reserves for the two gas reservoirs were prepared using the volumetric method. Structure maps and isopach maps were prepared using all available petrophysical analyses of all well log and core data. The average porosities for the two reservoirs range from 10 to 14 percent, and the average water saturation values range from 30 to 37 percent. OGIP was estimated from these maps. Shown

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below is a structure map on the top of the Baong II-B reservoir and the associated proved net gas isopach map.



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Reserves were estimated by multiplying OGIP by the gas recovery factors. Recovery factors for the Alur Rambong field reservoirs were estimated based on a depletion-drive mechanism with no water influx. The gas recovery factor associated with the reserves of Alur Rambong is estimated to be 84 percent. The reservoir gas contains 11 mole percent of impurities (carbon dioxide and nitrogen). The hydrocarbon composition is mostly methane. The gross heating value of the gas is 1,220 British thermal units (Btu) per cubic foot.

The development of the Alur Rambong field will include drilling one new well and recompleting the Alur Rambong-1 well. The field will produce through a pipeline to a central production facility, which will be located approximately 20 kilometers away at the Alur Siwah field.

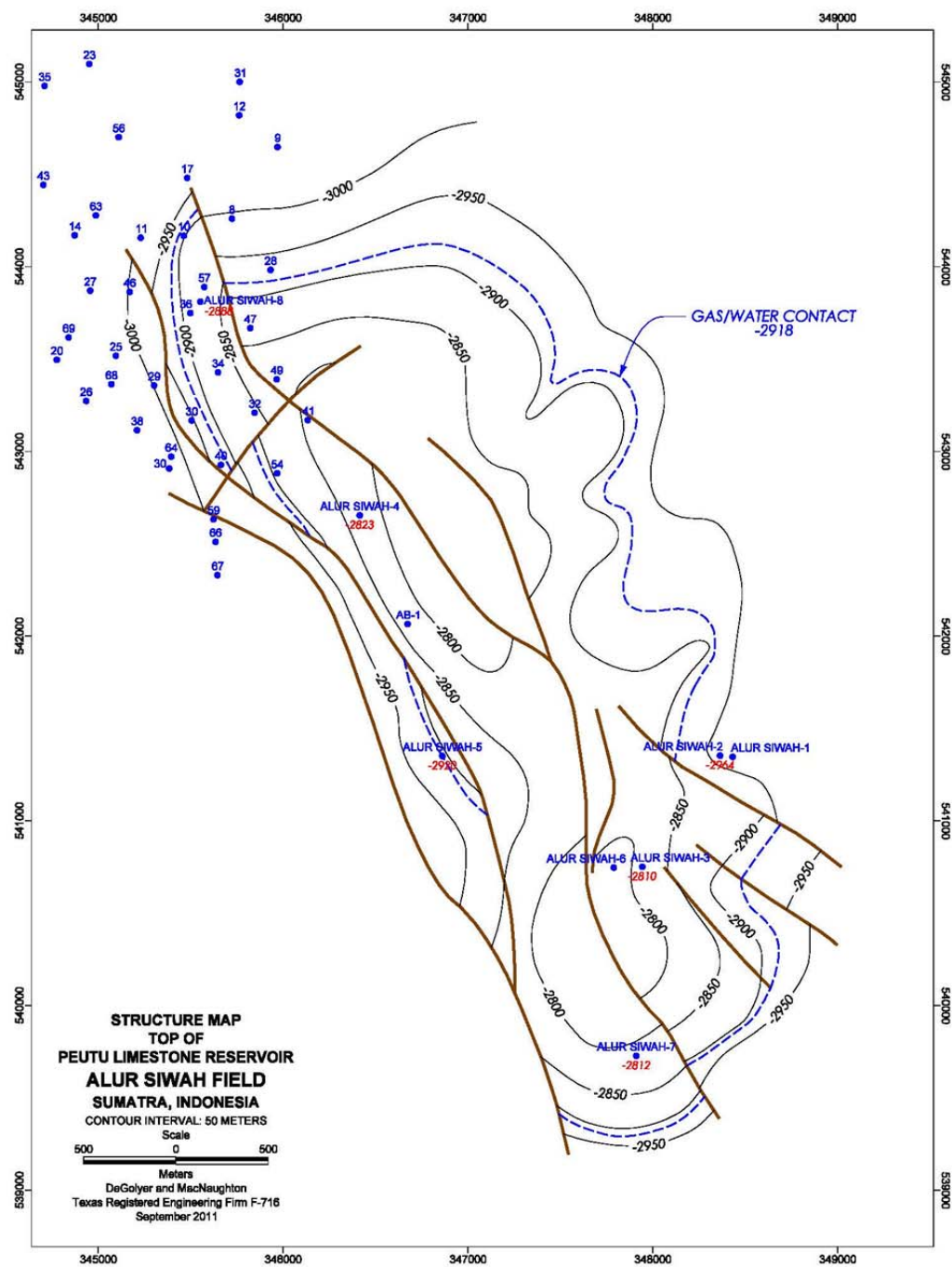
Alur Siwah Field

The Alur Siwah gas field is located onshore in the Sumatra Basin, approximately 65 kilometers northwest of Langsa in Aceh Province. The field was discovered with the Alur Siwah-3 well drilled in 1972.

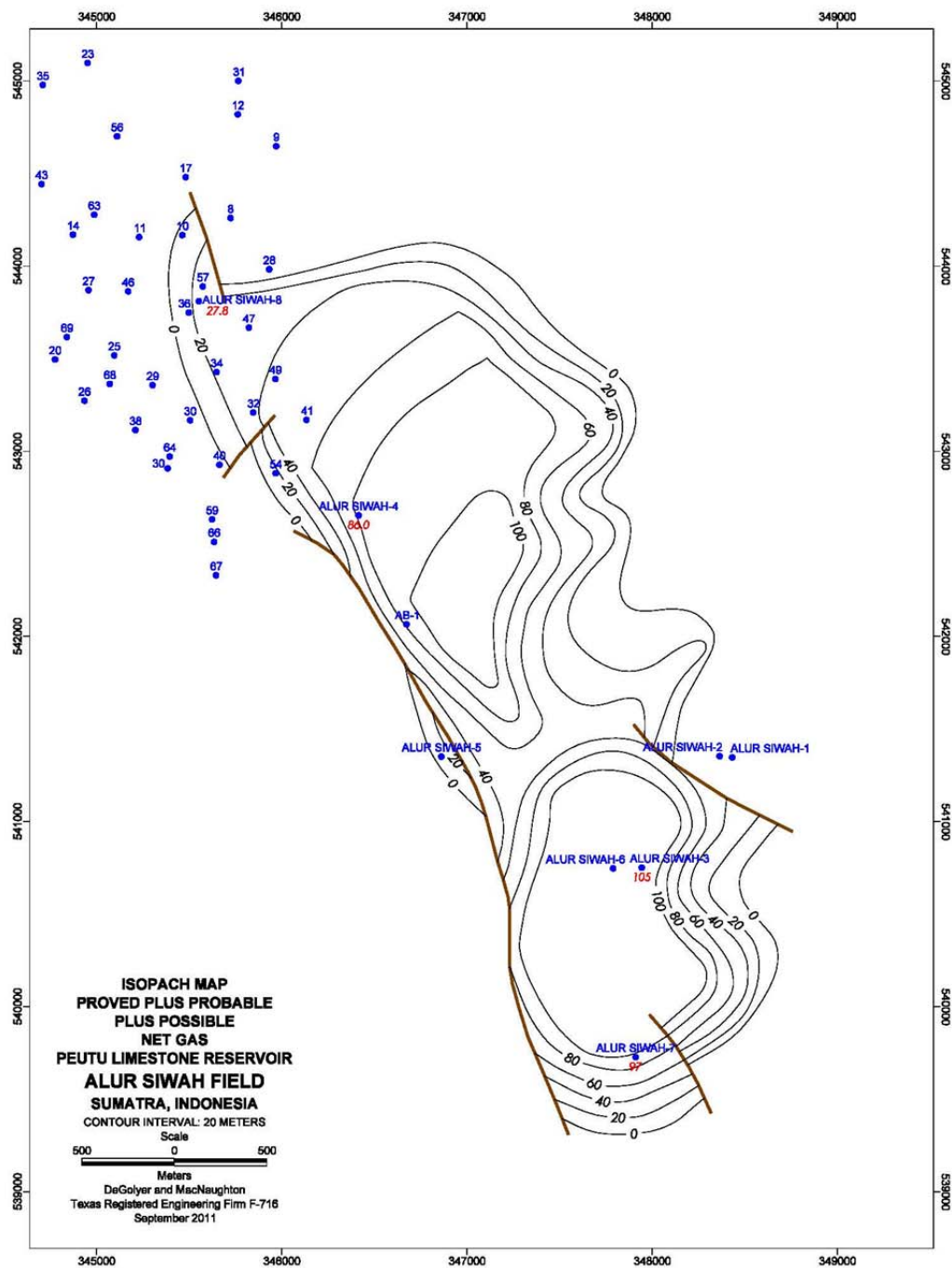
The primary gas reservoirs in the Alur Siwah field lie within the Peutu Limestone. The field is a limestone reef about 9 kilometers long by 3 kilometers wide. The reef is approximately 450 meters thick, but only about the upper 100 meters is above the GWC, which is at 2,918 meters subsea. Beneath the Peutu Formation is a second gas-bearing zone which lies in the Tampur Formation dolomites. This zone was discovered in 1982 with the drilling of the Alur Siwah-8 well. The LKG level in this zone is at 2,934 meters subsea. Seven appraisal wells have been drilled to these two gas-bearing zones: Alur Siwah wells -4, -5, -6, -7, -8, -9, and -10ST. The Alur Siwah-4 well penetrated the pay section but blew out and was abandoned. The Alur Siwah-5 well missed the gas reservoir and was low and wet.

Estimates of reserves for the two gas reservoirs were prepared using the volumetric method. Structure maps and isopach maps were prepared using all available petrophysical analyses of all well log and core data. The average porosities for the two reservoirs range from 9 to 13 percent, and the average water saturation values range from 22 to 40 percent. OGIP was estimated from these maps. Shown below are the structure map on the top of the Peutu limestone reservoir and the associated proved-plus-probable-plus possible net gas isopach map for this field.

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Reserves were estimated by multiplying OGIP by the gas recovery factors. Recovery factors for the Alur Siwah field reservoirs were estimated based on a depletion-drive mechanism with no water influx. The gas recovery factors associated with the reserves of Alur Siwah range from 76 to 77 percent. The reservoir gas

contains 27 mole percent of impurities (carbon dioxide and nitrogen). The hydrocarbon composition is mostly methane. The gross heating value, based on this gas composition, is estimated to be 790 Btu per cubic foot.

The development of the Alur Siwah field will include drilling 15 new wells and recompleting the AS-8 and AS-9 wells, all to be used as producers. A central production facility will be located at the Alur Siwah field, which will handle gas from all three North Sumatra Block 'A' gas fields. The facility will convert 95 percent of the hydrogen sulphide (H_2S) to solid sulphur product to be used in local agriculture and will burn the remaining 5 percent H_2S .

Julu Rayeu Field

The Julu Rayeu gas field is located onshore in the Sumatra Basin, approximately 70 kilometers northwest of Langsa in Aceh Province. The gas reservoirs in the Julu Rayeu field lie in a roughly domal structure about 4 kilometers long by 3 kilometers wide. The reservoirs are found at depths ranging from 1,350 to 1,900 meters subsea. A large number of wells were available to define the field. The underlying oil reservoirs of the Julu Rayeu field were discovered more than 60 years ago. The gas reserves in this report are in the gas-cap gas reservoirs and nonassociated gas reservoirs of the field. Some of the gas has been produced from these reservoirs, and the reserves account for the gas production through 1994.

Estimates of reserves for the gas reservoirs were prepared using the volumetric method. Structure maps and isopach maps were prepared using all available petrophysical analyses of all well log and core data. The average porosities for the two reservoirs range from 17 to 21 percent, and the average water saturation values range from 30 to 60 percent. OGIP was estimated from these maps.

Reserves were estimated by multiplying OGIP by the gas recovery factors. Recovery factors for the Julu Rayeu field reservoirs were estimated based on a depletion-drive mechanism with no water influx. The gas recovery factors associated with the reserves of Julu Rayeu range between 77 and 82 percent. The reservoir gas contains 1 mole percent of impurities (carbon dioxide and nitrogen). The hydrocarbon composition is mostly methane. The gross heating value of the gas is 1,150 Btu per cubic foot.

The development of the Julu Rayeu field will include recompleting eight of the wells. Six will be used as producers, while two of the wells will be used to reinject water produced from the field into an oil sand. The field will produce

through a pipeline to a central production facility located several kilometers away at the Alur Siwah field.

In 2010, an amended 20-year extension of the PSC, effective September 1, 2011, was signed, a new Plan of Development (POD) was approved, and a memorandum of understanding was signed for a GSA with the Pupuk Iskandar Muda (PIM) fertilizer plant and with PLN for electricity generation. The GSA calls for sales of 110 BBtu/d to PIM and sales of 15 BBtu/d to PLN through 2031. Both of these sales agreements call for the gas at a minimum Btu content of 925 Btu per cubic foot and a maximum of 15 percent carbon dioxide. Included in the new POD is a commitment to two exploration wells in Alur Siwah. Gas sales are planned to begin in 2013.

Tualang and Iee Tabeu Fields

The Tualang and Iee Tabeu fields are shallow oil fields located in the North Sumatra Block A. The fields were discovered in the 1970s and placed on production and operated by Medco Energi until 2006 when they were shut in due to civil unrest. A pilot program to re-perforate and return these and other shallow oil fields to production was recently completed with returns showing lower rates than expected. Quantities associated with this redevelopment for the Tualang and Iee Tabeu fields are estimated and have been classified as contingent resources with an economic status of Undetermined.

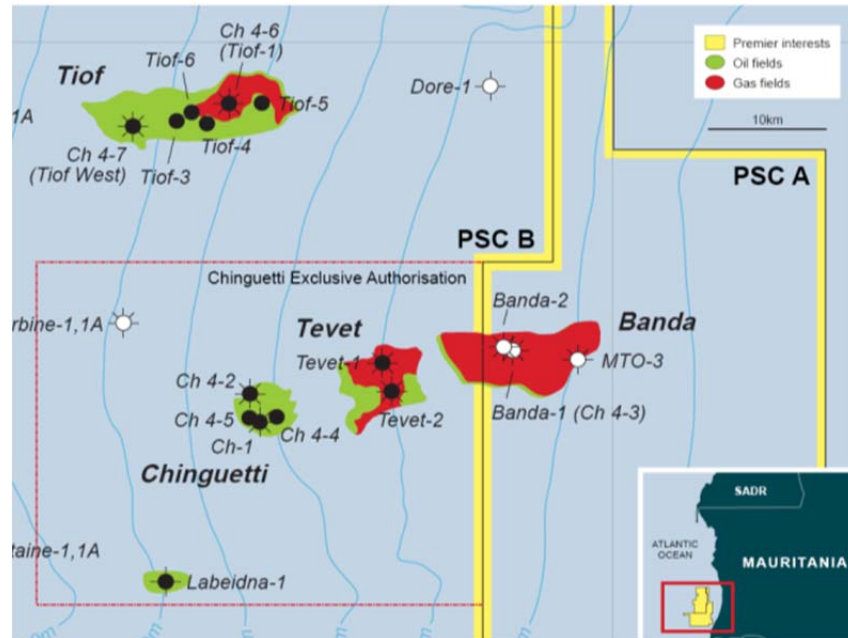
Mauritania

Premier has interests in two PSCs offshore Mauritania, Africa. They are PSC-A, which includes part of Blocks 3, 4, and 5, and PSC-B, which includes part of Blocks 4 and 5. The operator is Petronas. The estimates herein are based on a license limit beyond economic limits, so the quantities are not limited by license limits.

The PSCs are located in a passive margin basin on the west African margin. The basin extends from deep offshore waters onto the coast just west of the Mauritanides and the Taoudini Basin in central Mauritania.

Three significant oil discoveries have been made within PSC-A and PSC-B. These discoveries are the Chinguetti, Tiof, and Tevet fields. Other discoveries have been made within PSC-A and PSC-B, including the Banda gas field and the

Labeidna oil discovery. The Chinguetti, Tevet, and Labeidna fields lie in an Exclusive Exploitation Area (EEA), which expires on May 19, 2029. The Chinguetti field is the only discovery that has been evaluated for the purposes of this report.



Location Map – courtesy of Premier

Chinguetti Field

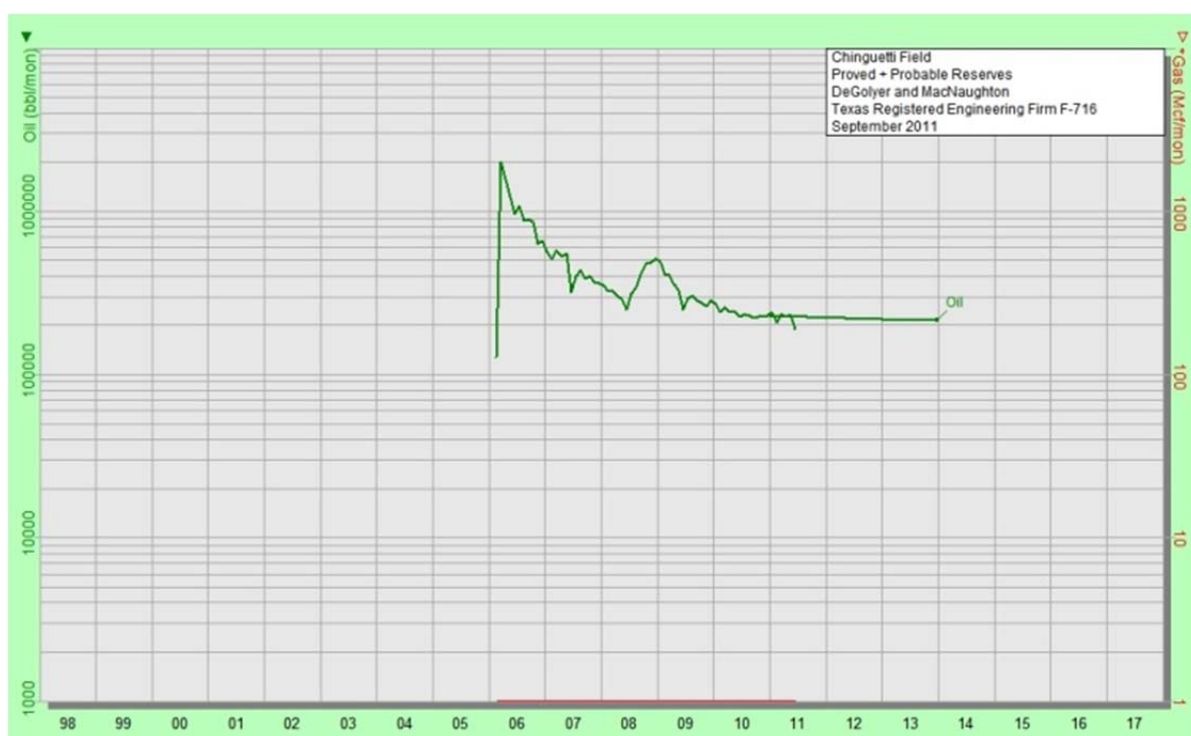
The Chinguetti field lies within the physical boundaries of PSC-B, 80 kilometers off the coast of Mauritania in 800 meters of water. The Chinguetti field is owned and operated under the auspices of the Chinguetti EEA production license. The field was discovered in May 2001 by the Chinguetti-1 well, which was drilled on the south flank of a salt dome. Delineation drilling began in 2002, with first production from six producers and five injectors in late 2006. The latest wells were drilled in 2008. Production is collected by a floating, production, storage, and offloading (FPSO) vessel.

The Chinguetti field is a highly faulted, salt-cored dome. The producing lower Miocene-age sandstones were deposited in a deepwater environment around a growing salt dome. Syn-depositional movement of the salt dome has influenced the depositional patterns of the reservoir sandstones, making well-to-well correlation uncertain. Differing oil/water contacts (OWC) indicate the presence of compartmentalization. Initially, the compartments were interpreted to coincide with major faults, but tracer and pressure analysis indicate that some faults may not seal and that the compartmentalization may also be partially stratigraphic. The OOIP is

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approximately 385 million barrels, and cumulative production is about 27 million barrels. The field was producing approximately 7,600 barrels of oil per day (BOPD) in June 2011.

The geological complexities have created challenges to additional drilling, and no new wells have been drilled since 2008. Proved reserves are based on continuation of current production trends in the existing wells, while probable and possible reserves include better well performance than currently observed in existing wells. The historical production data and the proved-plus-probable reserves forecast are shown in the following figure.



Norway

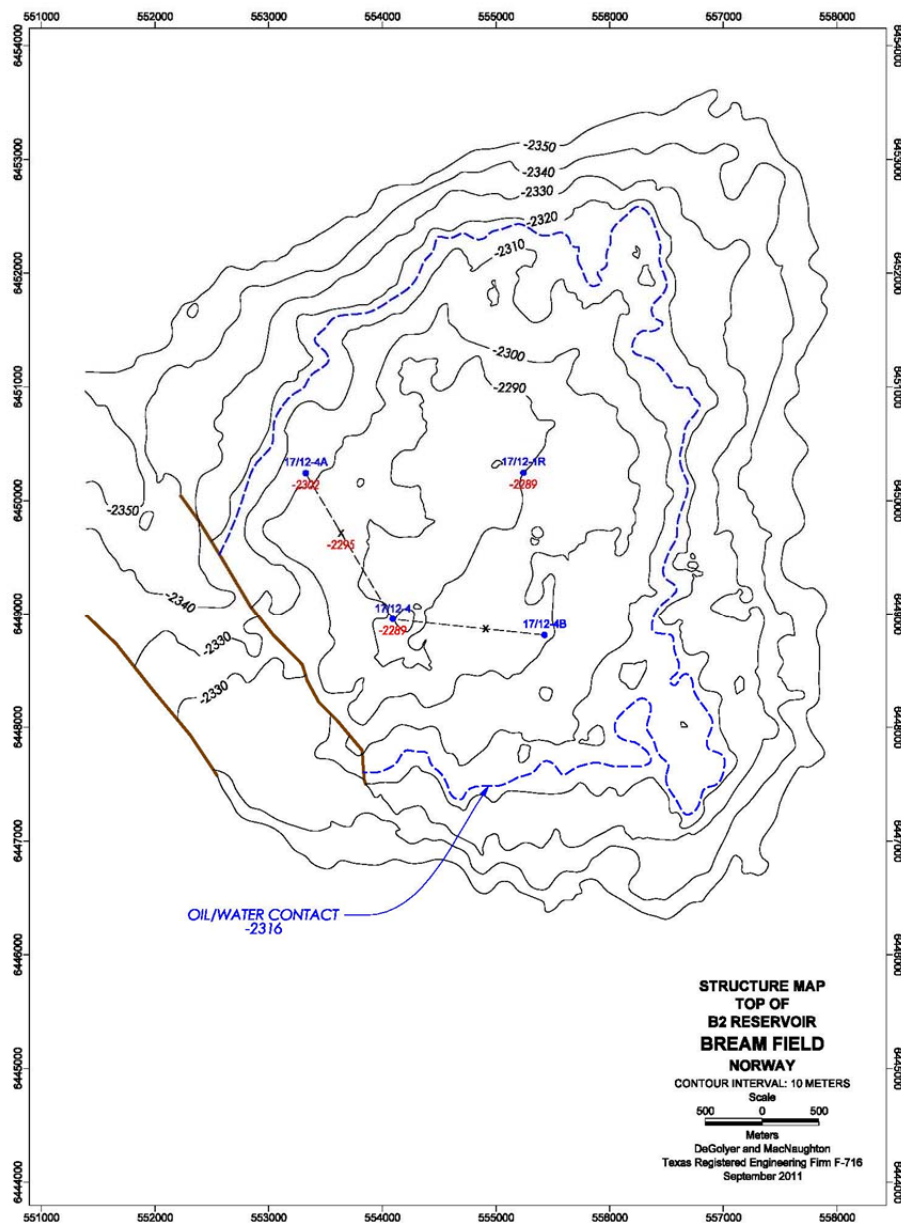
Bream Field

Bream is an oil discovery in PL407 offshore Norway. Well 17/12-1 tested up to 1,000 BOPD, and three additional appraisal wells were drilled in 2009. The field will produce from the Jurassic Bryne sandstone and is situated in the Egersund Basin about 110 kilometers offshore Norway. The field is a four-way dip closure without significant faulting. The reservoir is fair quality, with average porosity of 21 percent and water saturation of 20 percent. Permeability looks favorable in a

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range from 100 millidarcys to as high as 3,000 millidarcys. The tests produce low gas-oil ratios, and it is likely that artificial lift will be required to produce the field.

The planned development includes up to four subsea horizontal production wells and two injectors connected to a leased FPSO. The formal approval of the official plan for development and operation (PDO) is expected in 2011 or 2012. Probable and possible reserves have been estimated to reflect oil recovery ranges from 25 to 40 percent based on analogous fields and analysis of the well test results. The following figure shows the structure on the top of the B2 reservoir of the Bream field.



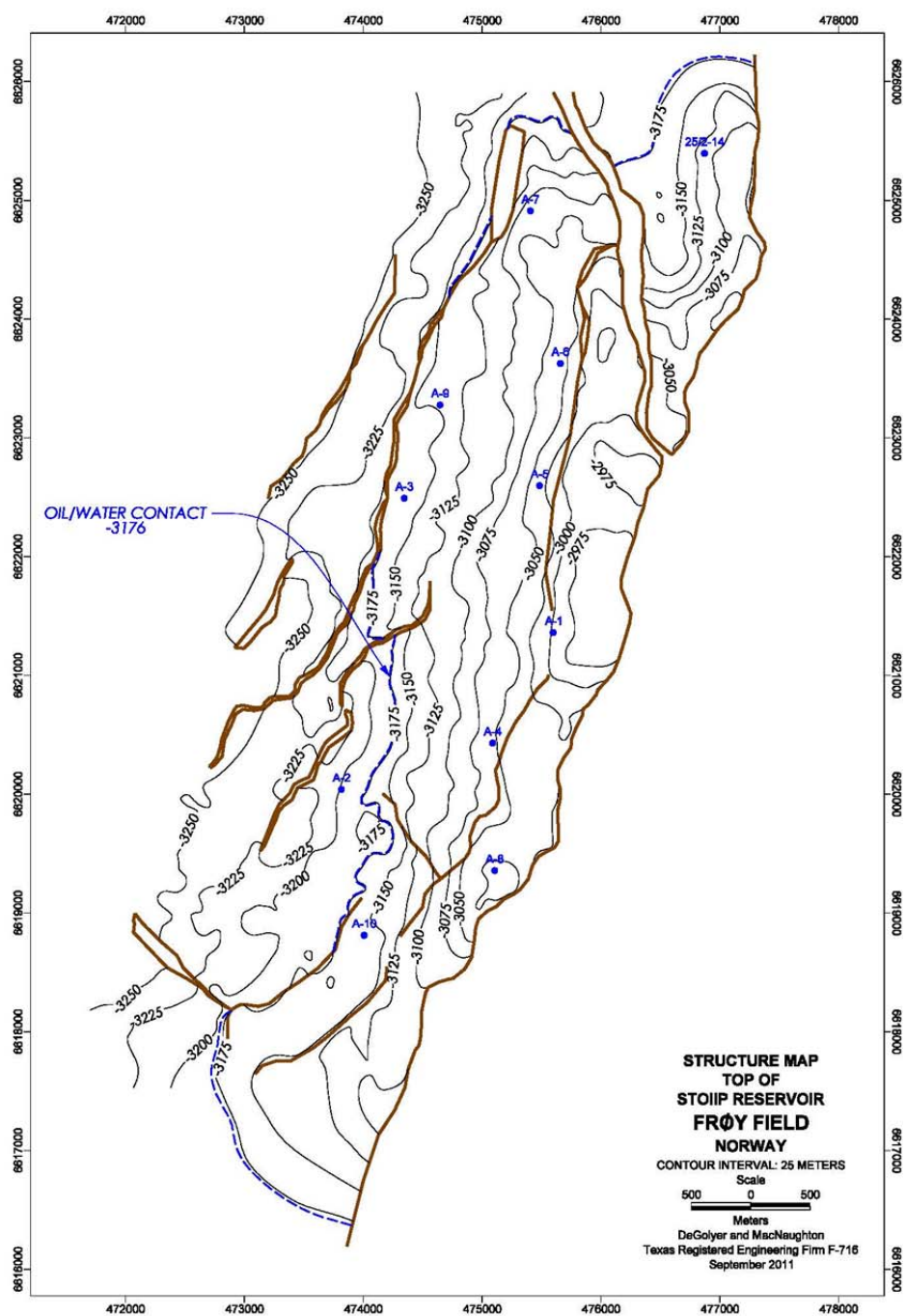
Froy Field

A group including Premier was awarded a license in Blocks 25/2, 25/3, 25/5, and 23/6 offshore Norway in 2006. The blocks include the abandoned Froy field, and the group intends to restart the field with deviated wells and focus development using 3-D seismic data. The field originally produced from 1995 until 2001 from the Jurassic Brent and recovered approximately 38 million barrels.

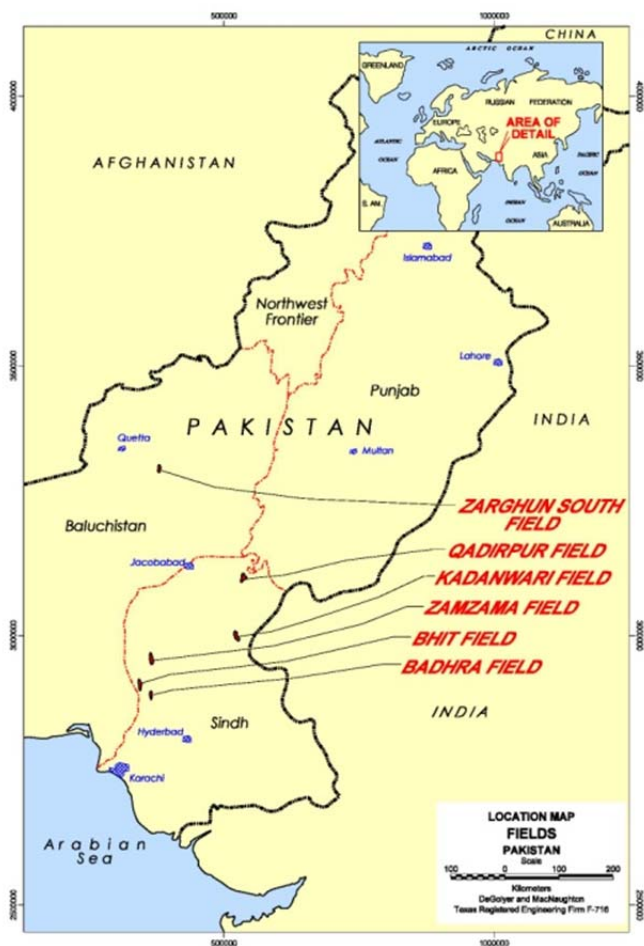
The field is compartmentalized and will be developed with eight deviated producing wells and six deviated injection wells. OOIP is estimated to be approximately 225 million barrels. The field's missed compartments are being assessed using 3-D seismic data to allow better well placement. A final plan of development is being submitted, and water-alternating gas (WAG) or simultaneous-water-alternating-gas injection will be a key element. An ultimate recovery of 40 to 45 percent is targeted based on analogous fields, including the nearby Varg field.

The estimate case associated with potential proved reserves is based on all development costs being incurred but recovery limited to 30 percent. This scenario is not economic using the pricing assumptions in this report. Probable reserves are reflective of development with successful application of horizontal wells across fault barriers and an ultimate recovery of 40 percent of OOIP. Possible reserves reflect 45-percent recovery, which would require additional drilling to achieve. The following figure shows the structural configuration of the Froy field at the top of the STOIP reservoir.

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Pakistan

Premier owns interests in several production licenses in Pakistan. The reserves estimated herein were limited to the earlier of the license expiration date or economic limit. The license expiration dates are as follows: Badhra (January 2027), Bhit (September 2020), Kadanwari (primary-December 2012, with 10-year extension through December 2022), Qadirpur (primary-August 2012, with an approved 5-year extension through August 2017 and an additional 5-year extension to August 2022), Zamzama (April 2022), and Zarghun South (January 2029). The location of these fields as is illustrated in the following figure.



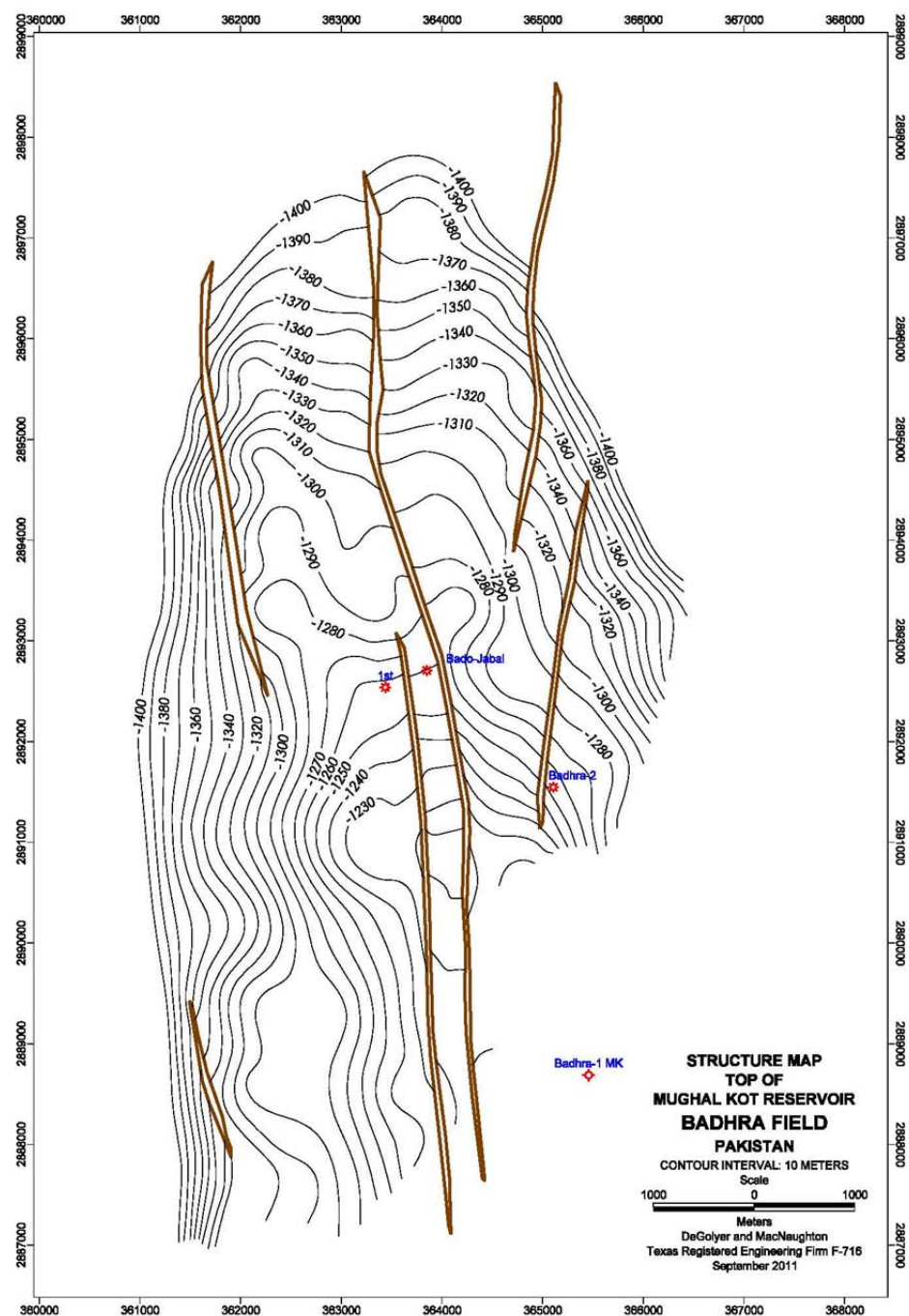
Badhra Field

The Badhra field is located within the Kirthar concession in the Sindh Province of Pakistan. Premier holds a 6.0-percent working interest in the Kirthar concession which is operated by ENI Pakistan Limited. The Badhra field was

discovered in 1999 by the Badhra-2 well and a Development and Production Lease (D&PL) was granted in 2005 for a term of 20 years. First gas production began in January 2008. Produced gas is sent via pipeline to the Bhit central processing facility located on the southern end of the Bhit Field more than 10 kilometers away. Produced gas is sold as part of a gas sales agreement with Sui Southern Gas Company (SSGC) with an annual contract quantity (ACQ) of 109.46 Bcf of sales gas that includes both the Bhit and Badhra fields. Historically, SSGC has taken more gas than specified by the ACQ.

Three wells have been drilled to define the Badhra field structure with the Badhra-2 and the Bado Jabal-1 wells penetrating the deeper petroleum-bearing horizons. In addition, a 3-D seismic database has been acquired and interpreted to help define the structure. Shown in the figure below is a structure map on the top of the Mughal Kot Formation.

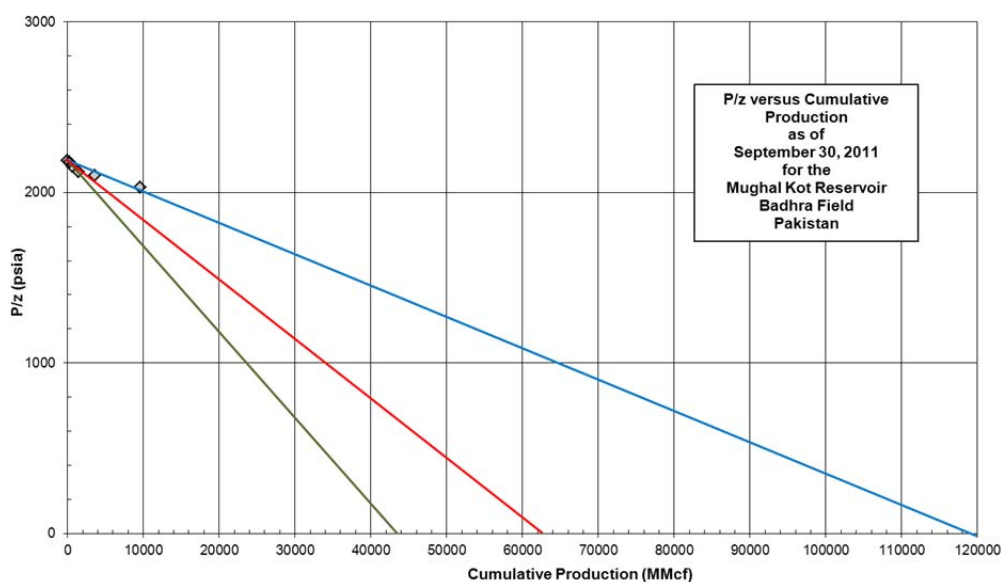
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The Badhra-2 well reached the Cretaceous Lower Goru Formation and drill-stem tested the Cretaceous Mughal Kot Sandstones (C sand reservoir) at a rate of 10.35 MMcf/d at 220 pounds per square inch gauge (psig) flowing tubing pressure. The Parh Limestone was also drill-stem tested but did not flow. The Badhra field is

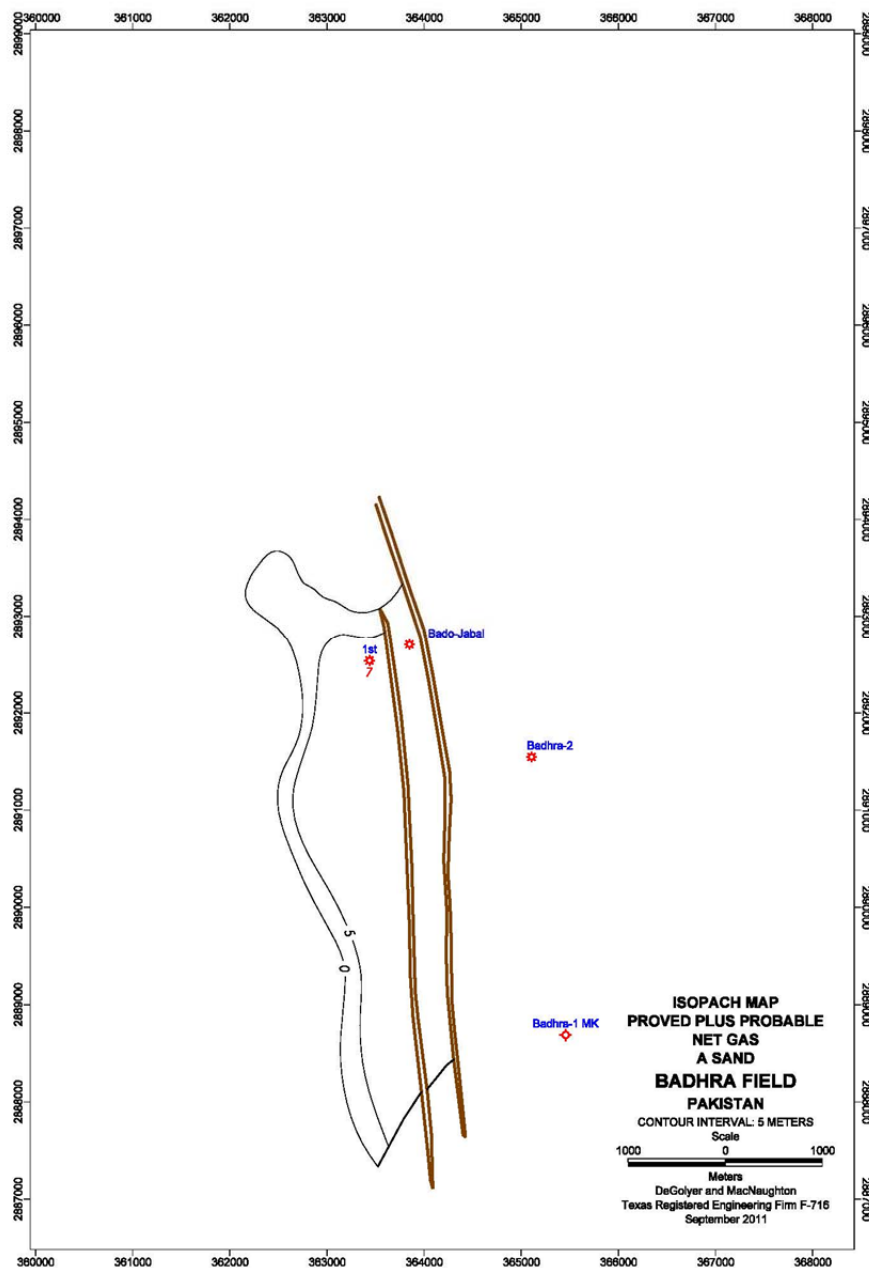
interpreted as an anticlinal feature similar to the Bhit field. The Badhra South-1 was drilled in 2008 to assess a possible accumulation as well as deeper targets in the southern part of the concession but was a dry hole. The Bado Jabal-1 well was drilled in 2010 to the north and west of the Badhra-2 well and found a correlative gas-bearing Mughal Kot interval. Depletion in the Mughal Kot C sand reservoir at the Bado Jabal-1 penetration as a result of production from the Badhra-2 well was indicated. The Bado Jabal-1 well also penetrated gas-bearing intervals in the Mughal Kot A and E sands. The Pab Formation was tested in 2002 in the Badhra-2 well but did not flow at commercial rates.

Material-balance analysis was performed to estimate OGIP for proved, probable, and possible reserves for the Mughal Kot C sand reservoir. Combination of the pressure data from both the Badhra-2 and Bado Jabal-1 wells indicates differing trends. The early time pressure data was used to estimate the OGIP (43,645 MMcf) associated with proved reserves. Material-balance analysis of the pressure data using a moderate aquifer was used to estimate the OGIP (62,900 MMcf) associated with proved-plus-probable reserves. Proved-plus-probable-plus-possible reserves were estimated based on an OGIP of 119,684 MMcf, which corresponds to a constant volume depletion assessment using the last pressure point to strongly weight the line fit to the data. The following figure shows the material-balance plot with both the Badhra-2 and Bado Jabal-1 points indicated and the fit used to estimate the range OGIP volumes used in estimating proved (green), probable (red), and possible (blue) reserves.

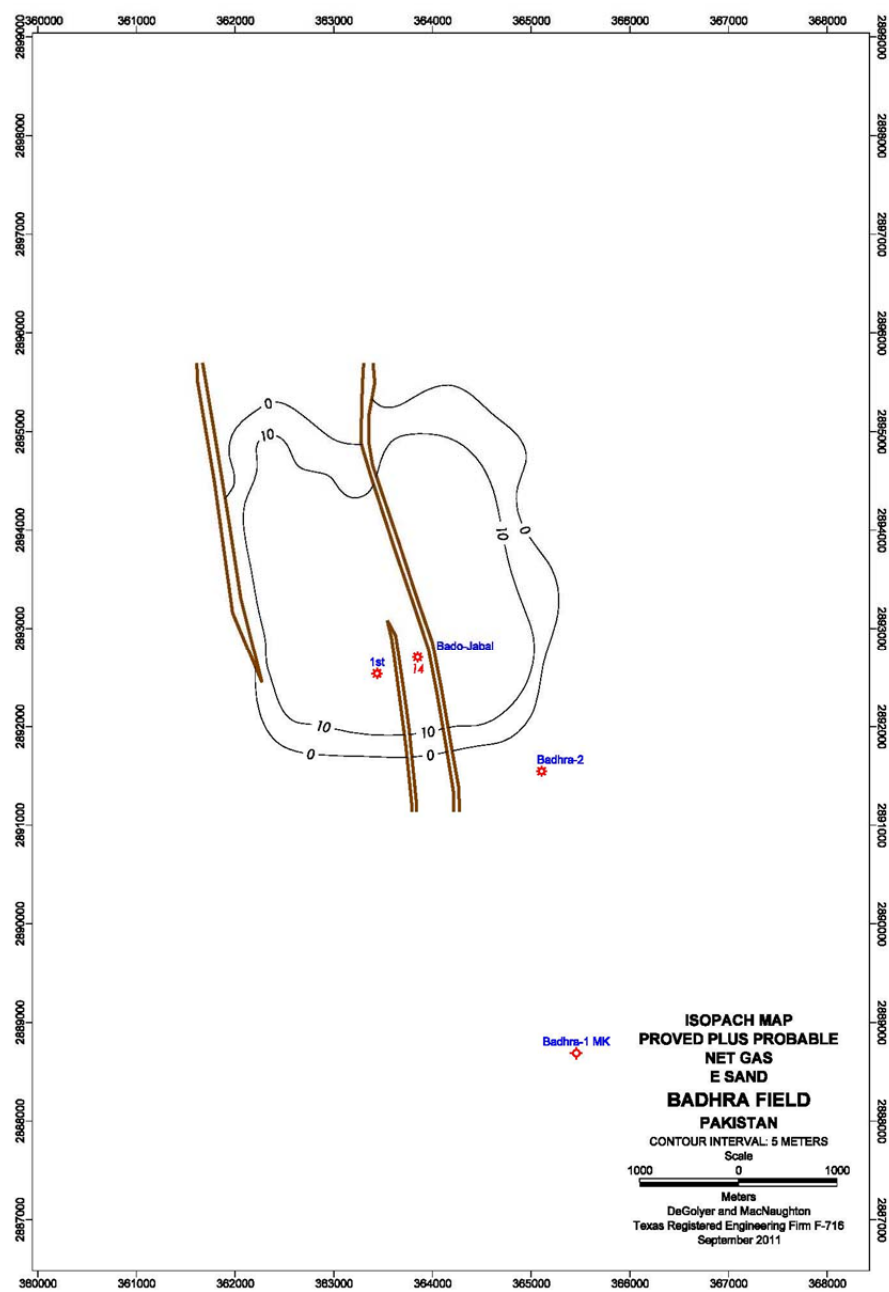


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Estimates of proved, probable, and possible reserves for the A and E sands were based on volumetric interpretation. The figure below shows the interpreted net gas isopach maps used for estimating OGIP volumes for the Mughal Kot A and E sands, respectively.



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Recovery factors employed in estimating reserves were based on the expected abandonment surface pressure at the wellhead for the Badhra field wells. Currently, flowing wellhead pressures are between 700 and 760 psig for the two producing wells in the Badhra field. As comparison, two wells in the Bhit field with wellhead compression are producing at flowing wellhead pressures of around 425 psig. An abandonment wellhead pressure of 550 pounds per square inch absolute (psia) has been used to estimate proved reserves based on the addition of wellhead compression. Abandonment wellhead pressures of 450 psia and 350 psia have been used to estimate probable and possible reserves, respectively, for the Mughal Kot C sand reservoir. Recovery factors used to estimate proved, probable, and possible reserves for the A and E sands were limited to 70 percent pending assessment of the likely drive mechanism for those reservoirs.

The Badhra-2 well was stimulated in October 2010 with no apparent significant improvement in performance. The joint venture group is considering an additional development well directionally drilled to target the Mughal Kot “C,” “D,” and “E” sands in 2011.

Bhit Field

The Bhit field is a 1997 discovery in the Kirthar concession, which lies predominately within the Sindh Province of Pakistan. The Bhit structural closure is approximately 150 kilometers north-northeast of Karachi and is associated with a large, erosionally breached, north/south-trending anticline that is part of the Kirthar fold belt. Surface topography is indicative of the subsurface structure that makes up the Bhit field, which is also true of other major Pakistani gas fields, such as the Sui and Pirkoh fields in the Baluchistan Province.

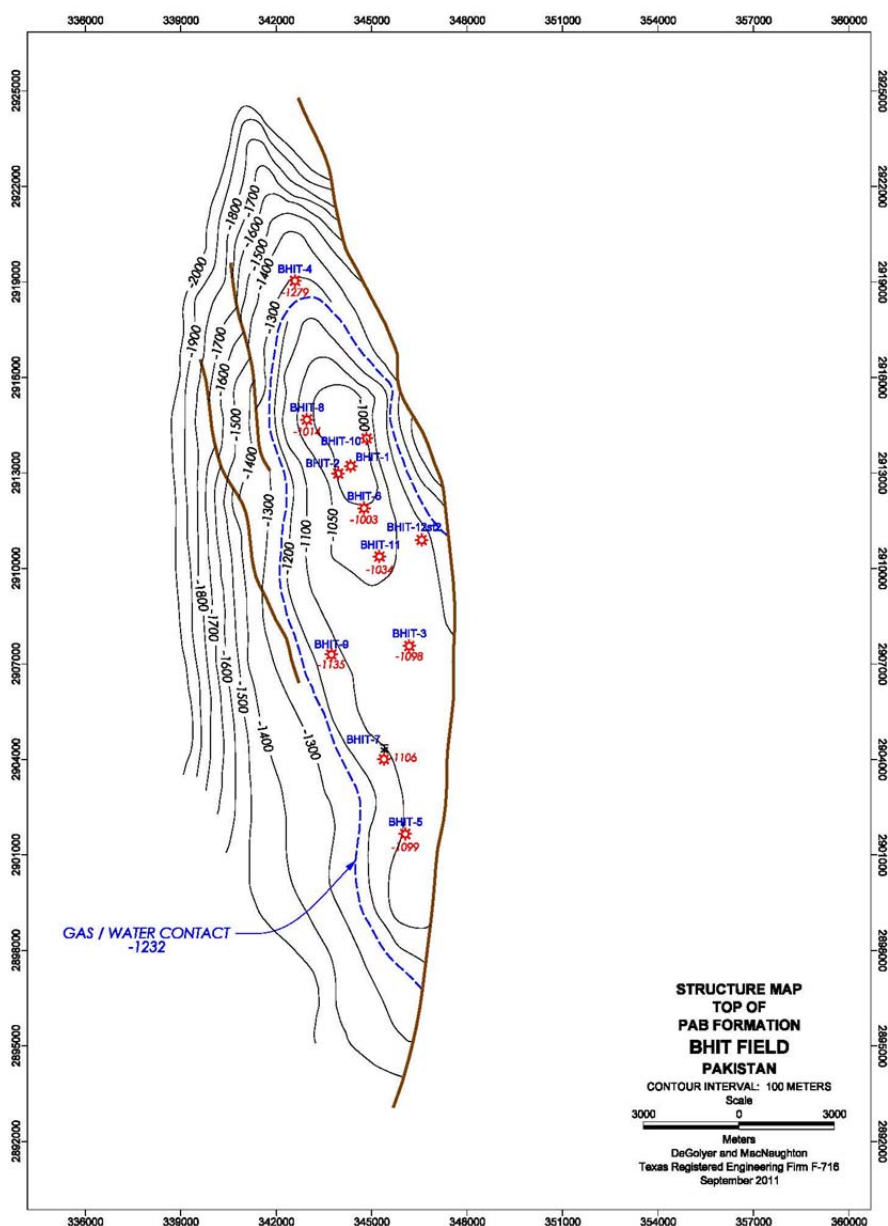
Premier holds a 6.0 percent working interest in the Kirthar concession, which includes both the Bhit and Badhra fields. ENI Pakistan Limited operates the Bhit field. Following discovery, the Government of Pakistan granted a D&PL to the owners of the Bhit field (1999) for a term of 20 years. First gas from the Bhit field began in December 2002. The Bhit central processing facility conditions produced gas from the field for sale to SSGC. Gas sales to SSGC are based on a gas sales agreement with an ACQ of 109.46 Bcf per year of sales gas. Historically, SSGC has taken gas at rates above the ACQ.

The primary hydrocarbon-bearing reservoir of the Bhit field is the Lower Cretaceous Pab Sandstone. The Pab reservoir seal is the overlying Khadro Shale.

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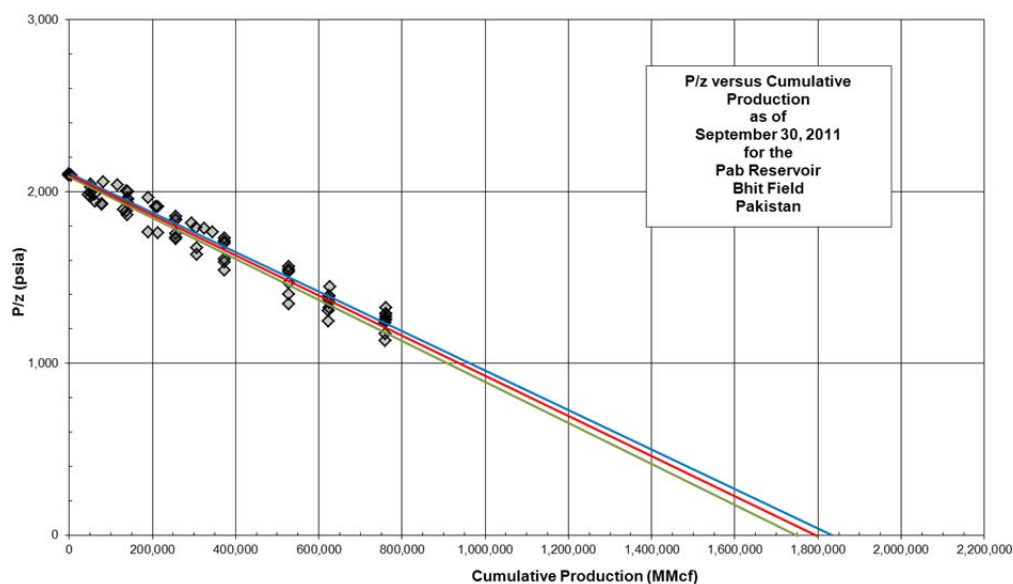
The Pab reservoir is underpressured relative to a normal gradient, which made development drilling problematic over the years.

Most of the Bhit field gas reserves are classified as proved on the basis of 13 development wells, reasonably strong historical pressure trends, 3-D seismic data that indicate a clearly defined structure, and a field-wide GWC at 1,232 meters subsea. The Bhit-12ST was drilled in 2008 and the Bhit-10 was drilled in 2009. A structure map on the top of Pab Formation is shown below.



Analysis of Pab Formation gas samples indicates inerts content of approximately 18.3-percent nitrogen and 1.0-percent carbon dioxide. On the basis of pressure-volume-temperature analysis, this gas is very dry, such that methane accounts for more than 98 percent of the hydrocarbon components. In estimating marketable gas, full wellstream gas in the Bhit field was reduced by 10.5 percent, which represents a portion of the nitrogen, carbon dioxide, and flare. Condensate yield averages approximately 1 barrel per MMcf of gas.

Material-balance calculations performed on a field-wide basis indicate a range of possible OGIP estimates. Three views representing a range of OGIP (figure shown below) were used to estimate proved (green), probable (red), and possible (blue) reserves. OGIP volumes of 1.735 trillion cubic feet (Tcf), 1.789 Tcf, and 1.825 Tcf represented the range of OGIP.

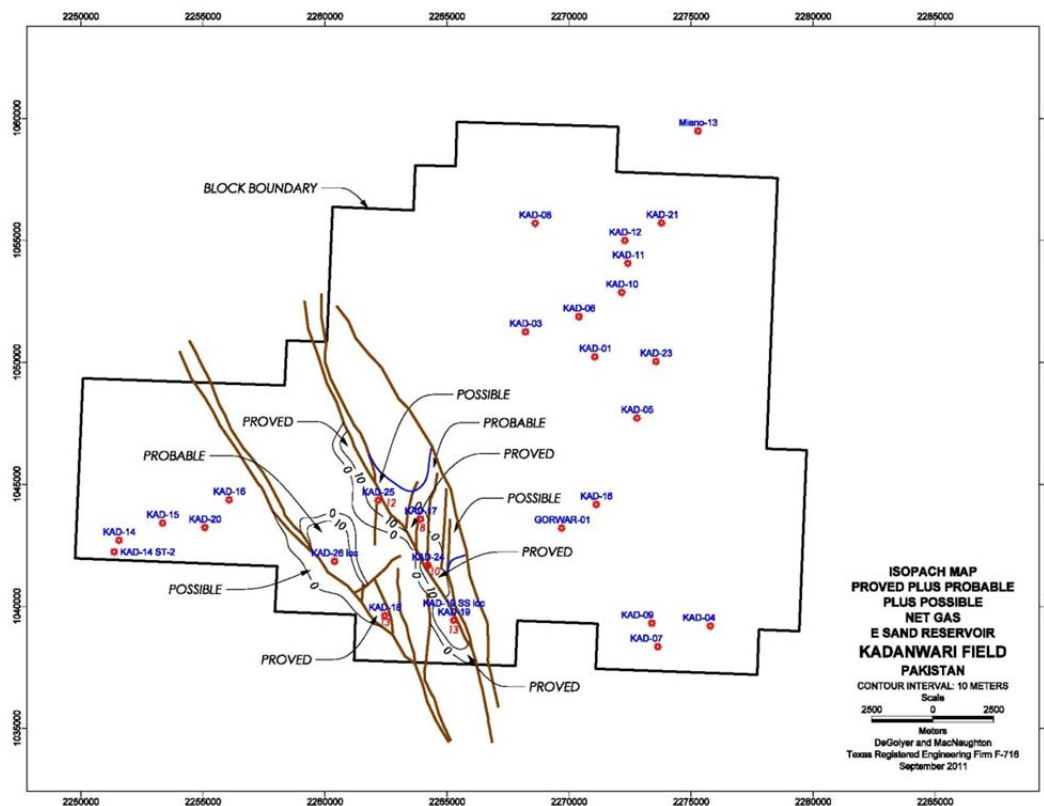


Recovery factors for the Pab reservoir were estimated on the basis of initial reservoir pressures, rock properties, and flow rate performance. A recovery factor of 85 percent of the OGIP was used to estimate proved reserves and considered an abandonment surface pressure of 275 psia. The recovery factor used in estimating probable and possible reserves was 87 percent based on a surface abandonment pressure of 200 psia. Currently, wellhead compression has been installed on all of the wells in the field. Two wells are producing at lower flowing wellhead pressures of around 425 psig. Proved undeveloped reserves have been estimated for the Bhit-13, -14, and -15 well locations, which are planned to be drilled in 2011 and 2012.

Kadanwari Field

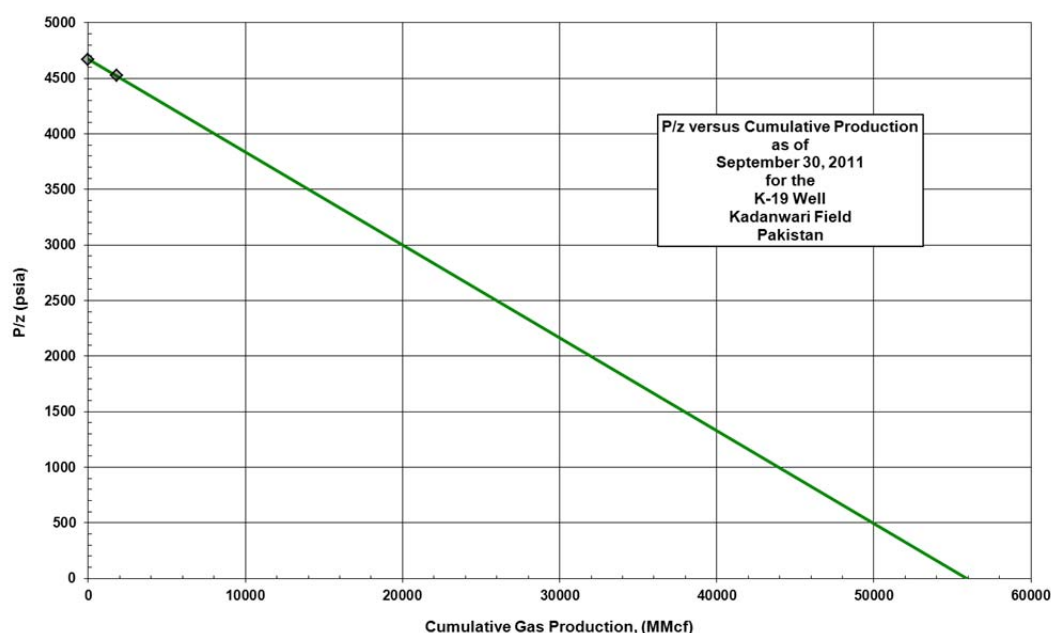
The Kadanwari field is located in the Thar Desert near the southeastern border of Pakistan approximately 75 kilometers southeast of Sukkur in the Khairpur district of the Sindh Province. The Government of Pakistan awarded a Petroleum Concession for the Tajjal block on July 21, 1987. The Kadanwari field was discovered in September 1989 with the successful drilling of the Kadanwari-1 (K-1) well which found gas-bearing sands in the Lower Cretaceous Lower Goru Formation. The operator of the field is ENI Pakistan Limited. Premier holds a 15.79-percent working interest in the Kadanwari field. The field began production in May 1995. The primary expiration date for the mining lease was December 2012; however, the working interest owners have applied for and received a 10-year extension to continue production operations.

Development wells have been drilled to define the Lower Goru sands at depths down to 11,000 feet. Currently, 9 wells are producing. The produced gas is very dry, with about 13-percent inert content and a condensate yield of 0.1 barrel per MMcf of gas. Reservoir temperatures are very hot at approximately 340 degrees Fahrenheit (°F). Gas production began in May 1995 from the Lower Goru E sand. Currently, seven wells produce from the E sand, one well from the D sand, and three wells from G sand. Exploration and delineation drilling in the field in recent years has led to a revival of producing rates in the field. Most recently, the K-10, -11, -12 well E sand compartment was extended with the drilling of the K-21 and K-23 wells which indicated partial depletion from the existing producers. In addition, the K-17, K-18, K-19, and K-24 wells have found gas bearing Lower Goru sands away from the existing development areas. In 2011, the K-25 Dir-A, the K-26, and the K-27 wells were drilled and completed. The K-25 Dir-A was tested at 3.9 MMcf/d but at a flowing wellhead pressure of 270 psig. Tie-in of the well is under consideration. The K-26 well tested as tight and is under consideration for a hydraulic fracture treatment. The K-27 well successfully tested the F sand in June 2011 flowing more than 50 MMcf/d at 3,130 psig wellhead pressure. A structure map on the top of the Lower Goru E sand is shown in the following figure.

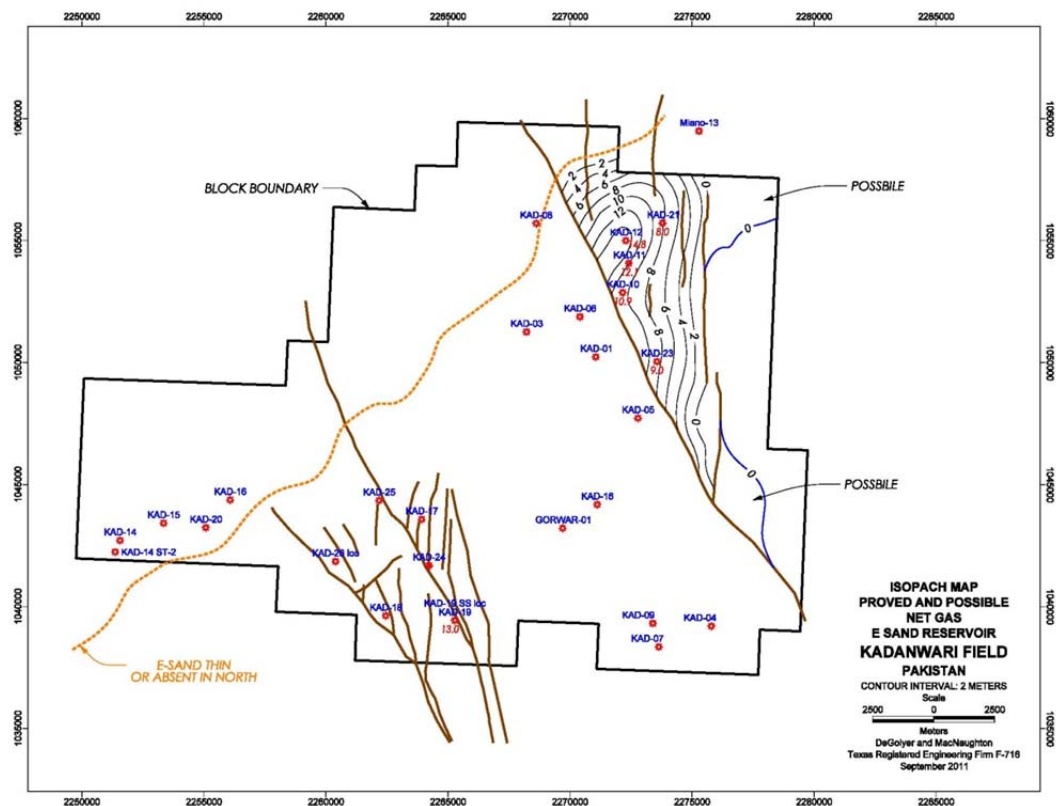


Three fault blocks have been mapped in the northern part of the Kadanwari field. The largest and structurally highest fault block is the central closure, which contains the Kadanwari-1, -6, and -8 wells. The smaller western fault block contains the Kadanwari-3 well. The northeastern fault block contains the Kadanwari-10, -11, and -12 wells and contributes the majority of the production. The two southern fault blocks are drained by the Kadanwari-4, -7, and -9 wells and are depleted. The Kadanwari-13, -14, and -15 wells were drilled in the southwestern part of the license near the Sawan field to test the extent of the G sand seen in the Sawan field. The Kadanwari-13 well confirmed the presence of gas; however, it flowed at noncommercial rates. The Kadanwari-14 and -15 wells are producing gas. The K-20 well was drilled in 2009 south and east of the K-15 well but found poorer quality G sand. The K-18 well was drilled in the southeast corner of the license area and found a gas-bearing E sand interval and is currently producing. The K-17 well was drilled in a fault block north and east of the K-18 well and produces from the E sand.

Premier drilled the Kadanwari-19 well in late 2009 to test a prospective closure identified through amplitude response. The well encountered gas-bearing reservoir in the Lower Goru E sand at about 3,296 meters subsea. The structural accumulation is a three-way dip closure bounded to the east by a northwest/southeast-trending strike-slip fault. The well was tested in the top 6 meters of the E sand at up to 31 MMcf/d of gas at a flowing tubing pressure of more than 3,700 psia. Based on material-balance analysis, pressure analysis, and volumetric interpretation of the K-19 structure, estimates of the OGIP associated with proved, probable, and possible reserves were prepared. The mapped OGIP associated with the spillpoint of the structure agrees with the reservoir size estimated using the pressure transient analysis and was used to estimate proved reserves. Probable reserves were estimated from the OGIP derived from material-balance analysis (shown below).



In 2010, the working interest owners drilled the K-21 and K-23 wells in the K-10, -11, and -12 area finding partial depletion of the E sand at those locations. These wells indicate a larger OGIP than previously mapped and suggest the historical material-balance-based OGIP was conservative. Revised maps were prepared to estimate OGIP associated with proved, probable, and possible reserves.



The K-25 well was also drilled in 2010 and is located north of the K-19 well along the same east-bounding fault but across a structural low. The well was not on production from the E sand at the time that this report was prepared. The K-24 well was also drilled in 2010 near the K-17 well, but in a separate fault block. The K-24 well is producing from the E sand. The K-27 well found a gas productive F sand east of the K-4 well based on amplitude data. Reserves were estimated using volumetric interpretation. The well is scheduled to be tied in by the fourth quarter of 2011.

A combination of material balance and volumetric evaluation has been used to estimate OGIP for the Kadanwari field reservoirs. In certain cases, performance analysis trends have been used to estimate reserves.

The owners of the Kadanwari field have identified four development well locations to be drilled in 2011. Additional well locations have been identified for development beginning in 2012 and are associated with probable and possible reserves. The operator has undertaken a work program to assess the potential for

tight gas development in the Kadanwari field starting with a re-entry and multi-fracturing approach using the K-1 well. Estimates of recoverable quantities associated with this project have been classified as contingent resources pending the results of the work on the K-1 well.

The owners of the Kadanwari field negotiated an extension to the primary term of the license agreement of 10 years based on a new negotiated gas price.

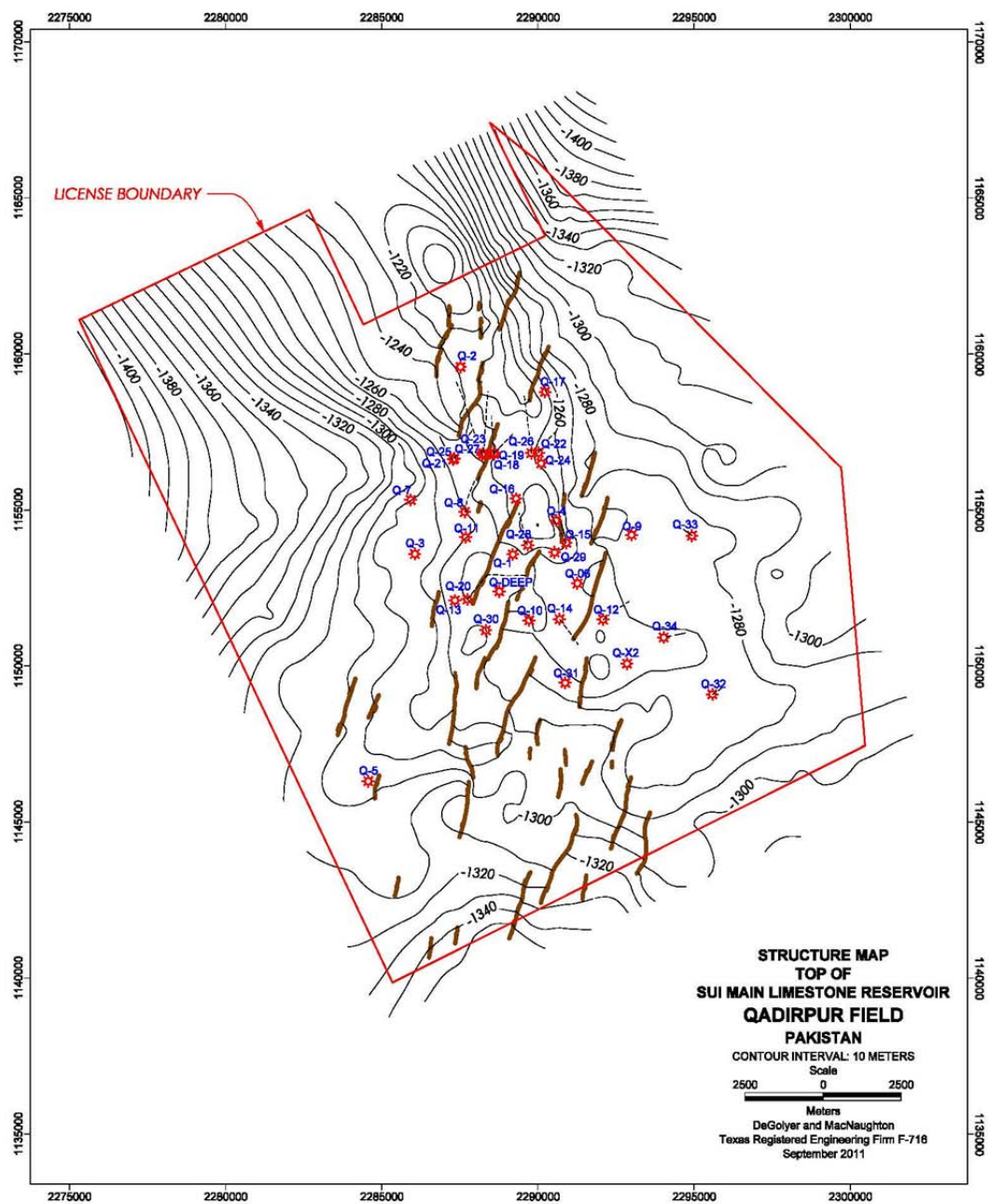
Qadirpur Field

The Qadirpur field, located in the Sindh Province of Pakistan, was discovered in May 1990. The field is productive in three gas-bearing reservoirs: the Sui Main Limestone (SML), the Sui Upper Limestone (SUL), and the Habib Rahi Limestone (HRL). The field lies south of and adjacent to the Kandhkot field. A petroleum concession was awarded by the Government of Pakistan in 1992 for a term of 20 years. Production from the field began in September 1995. The Qadirpur field is operated by Oil and Gas Development Company Limited (OGDCL) and Premier holds a 4.75-percent working interest in the petroleum concession.

The working interest owners of the Qadirpur field have made application (August 12, 2010) to the Government of Pakistan to extend the lease for 5 years as is allowed under Rule 32 of the Pakistan Petroleum Exploration and Production Rules of 1986. On October 1, 2010, the Government approved the revised development plan which showed production through 2022. Since that time, the working interest owners have made a formal application to extend the lease to 2022 (10 years) which is consistent with the Government-approved revised field development plan of the same term. Historically, the Government of Pakistan has extended leases in Pakistan if commercial production was ongoing as was the case for the Kadanwari field. Reserves have been estimated through 2022 and contingent resources have been estimated for those quantities recoverable after 2022.

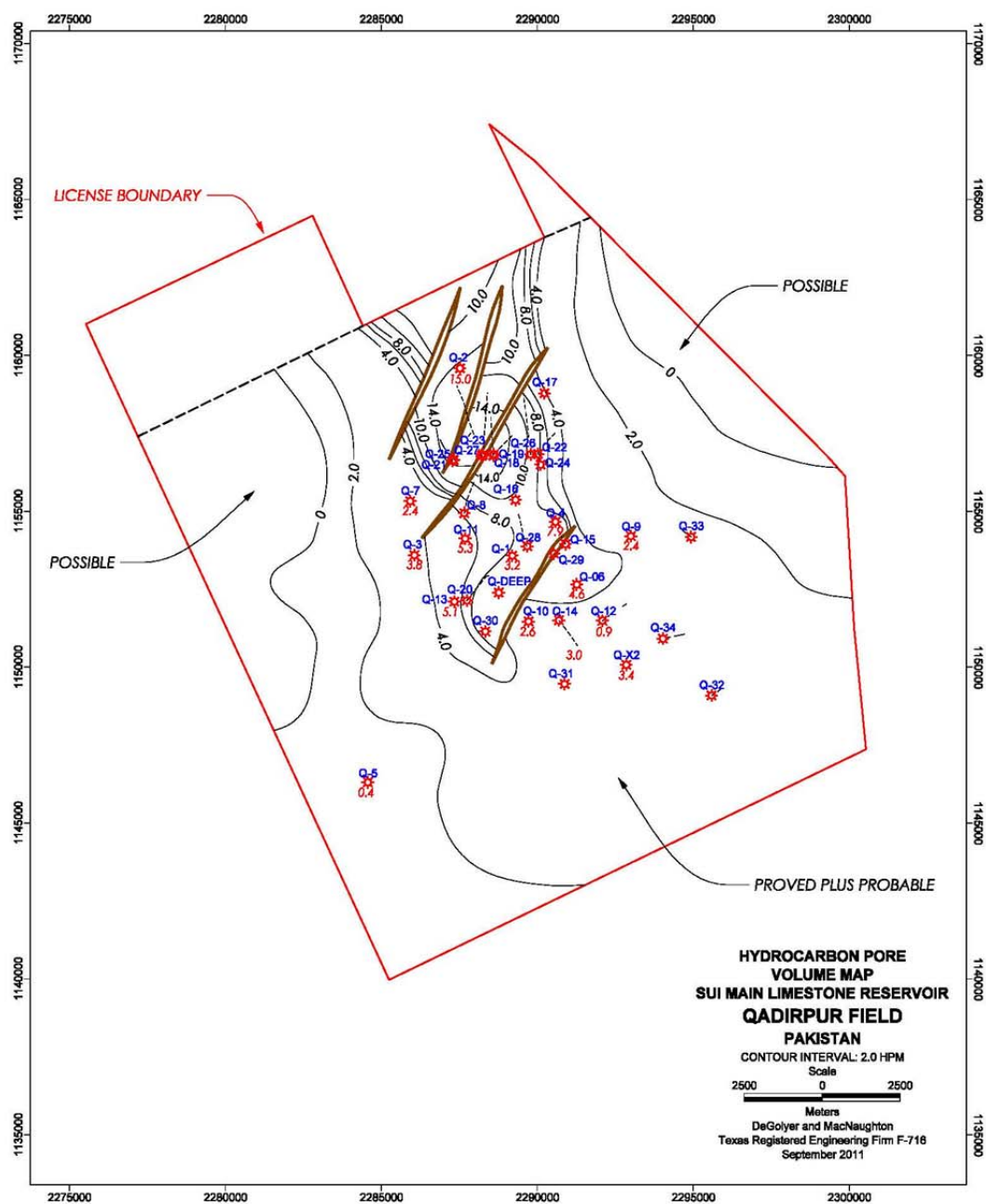
The structural configuration of the Qadirpur field is a continuation of the broad structural nose that plunges to the south through the Qadirpur concession area and is part of the Mari Kandhkot high. Currently, more than 40 wells have been drilled to delineate the field, the majority of those wells having been completed in the highly productive SML. A structure map on the top of the SML is shown below.

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Thirty-seven wells are producing on average over 530 MMcf/d of full wellstream gas. Produced gas is treated for reduction of carbon dioxide content from more than 5 percent to 2 percent and sold to Sui Northern Gas Pipeline Limited (SNGPL). The initial annual contract quantity (ACQ) was for 240 MMcf/d of processed gas along with 100 MMcf/d of dehydrated gas. Phase II of the field development increased the ACQ to 365 MMcf/d of processed gas with dehydrated gas available for swing production. Plant capacity increased to 500 MMcf/d from the end of the first quarter in 2004. The Liberty Power Project, which utilizes the produced gas to generate electricity, began operations at the end of 2000 and uses 40 to 45 MMcf/d, on average, of sales gas solely from the Qadirpur field. Potential exists for expansion of this power project to include an additional required feed of up to 50 MMcf/d. The forecast of future volumes included consideration of commitments to both the SNGPL and the Liberty Power Project through further development of the SML, followed by development of the SUL and HRL in future years. Sales gas rates average in the range of 500 MMcf/d of sales gas. Reserves have been estimated volumetrically for all three reservoirs. Material balance analysis of the SML indicates an OGIP very similar to that indicated by volumetric interpretation. Because the Kandhkot and Qadirpur fields produce from common reservoirs, material balance of only the Qadirpur field data does not account for the effects of withdrawals from the Kandhkot field. The relatively comparable results from both the volumetric and the limited material balance analysis provide confidence in regard to in-place volumes. A net hydrocarbon pore volume map of the SML reservoir is shown in the following figure.

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Estimates of reserves were prepared using recovery factors consistent with the deliverability capacity of the producing wells and expected surface abandonment conditions at the time of the lease expiration at the end of 2017. In October 2010, flowing wellhead pressures for all wells ranged from 840 to 900 psig with an average of around 855 psig. Wellhead compression has been installed at 14 stations and was operational at year-end 2010. An abandonment wellhead pressure of 500 psia was used for estimating proved reserves for the SML and SUL reservoirs. Probable and possible reserves were estimated based on an abandonment wellhead pressure of 400 psia.

In 2006, the partnership drilled the Qadirpur Deep-1 well to test for the presence of hydrocarbon-bearing sands in the Lower Goru and Sembar Formations. Because of the limitations on available equipment with which to safely test the deeper sands in this well, the well stood idle until late in 2008 when the well was drill-stem tested. DST 2 tested the Sembar Sand-5 reservoir with reasonably good results. The well tested at upwards of 4.3 MMcf/d with a flowing surface pressure of around 600 to 620 psia. Premier has advised that the well ceased flowing due to poor reservoir rock properties. The well has since been recompleted to the SML. No offset drilling locations have been considered as reserves for this field area based on the performance of the discovery well. Contingent resources have been estimated for potential development options for the non-delineated area of this field in the Sembar Sand-5 reservoir.

Two SUL wells were drilled in 2010 (QP-40 and -41). Three extended reach wells are planned to be drilled in the future that will be drilled on the northern boundary of the license area.

Zamzama Field

The Zamzama field is located in the Zamzama D&PL area about 10 kilometers west of the city of Dadu, about 210 kilometers northeast of Karachi, and 50 kilometers northeast of the Bhit field. The field is operated by BHP. Premier holds a 9.375-percent working interest in the Zamzama D&PL. The Zamzama D&PL was awarded for a term of 20 years (expiration in April 2022). Early production from the field began in March 2001.

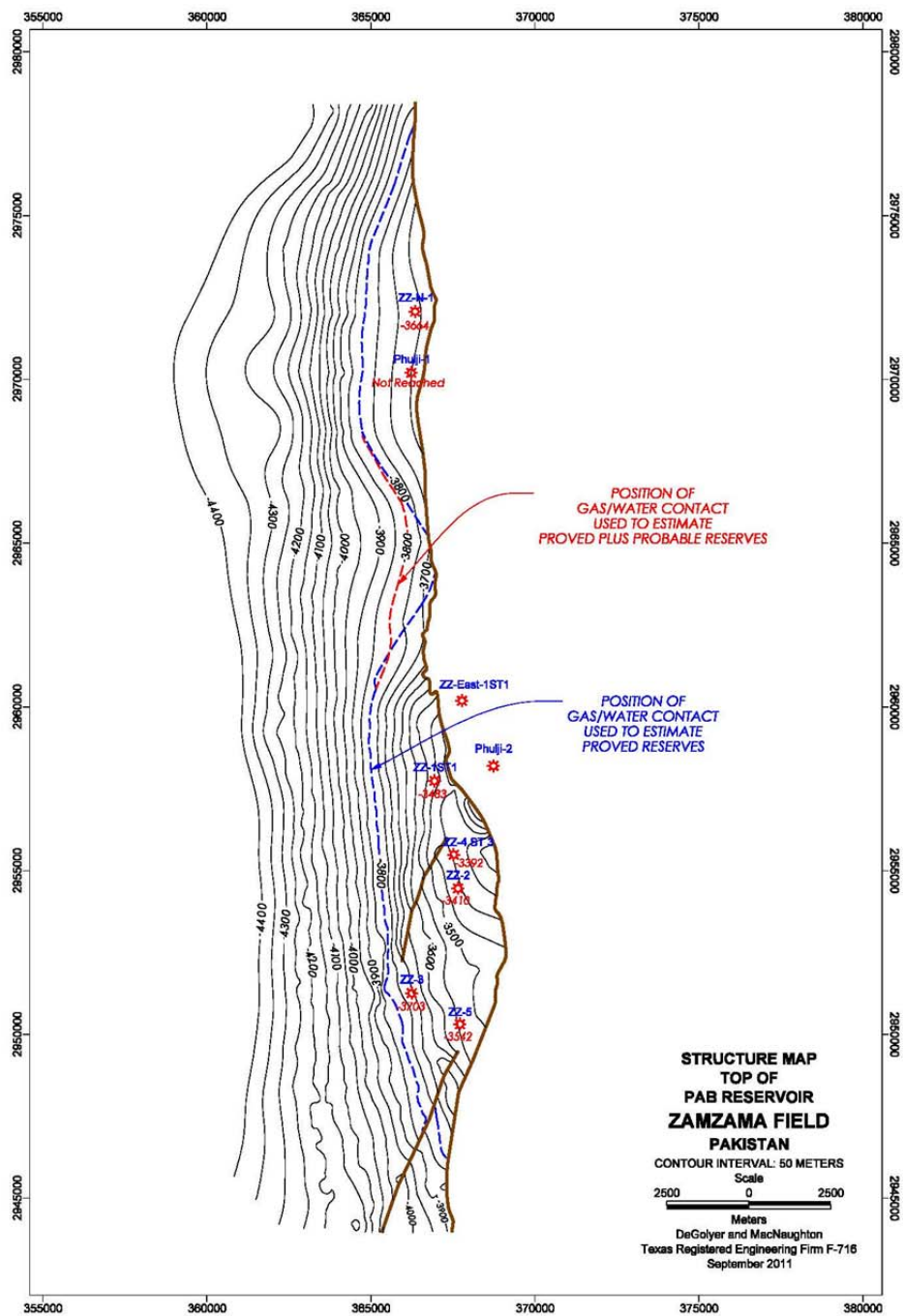
Gas sales from the field are governed by five gas contracts totaling 2,294 Bcf of sales gas. These contracts are with both Sui Northern Gas Pipelines Limited (SNGPL) and SSGC. Only the early well test (EWT) contract has expired (73 Bcf of sales gas).

The Zamzama structure is an elongated anticline, oriented northwest to southeast, which formed along an east-verging thrust fault system. The Zamzama-1ST1 well, drilled in 1998, discovered and tested gas from the Pab Formation in a large closure along the hanging-wall fault block. The Zamzama-2 appraisal well was drilled in 1999. At the Pab reservoir level, the field is about 32 kilometers long and 4 kilometers wide.

A total of 11 wells (Zamzama-1 through -7, Zamzama North-1, Zamzama East-1, and Phulji-1 and -2) have been drilled in the field. The Zamzama-3, -4, -5, -6, and -7 development wells were drilled in the southern main area between mid-2002 and 2010. The Zamzama North-1 well was drilled in mid-2003 and the Zamzama East-1 well was drilled in late 2003. The field began producing from the Zamzama-2 well in March 2001. The Zamzama-1ST1 began producing June 2001 and by July 2003, the Zamzama-3, -4, and -5 wells had commenced production. The Zamzama North-1, -6, and -7 wells were brought online in 2009.

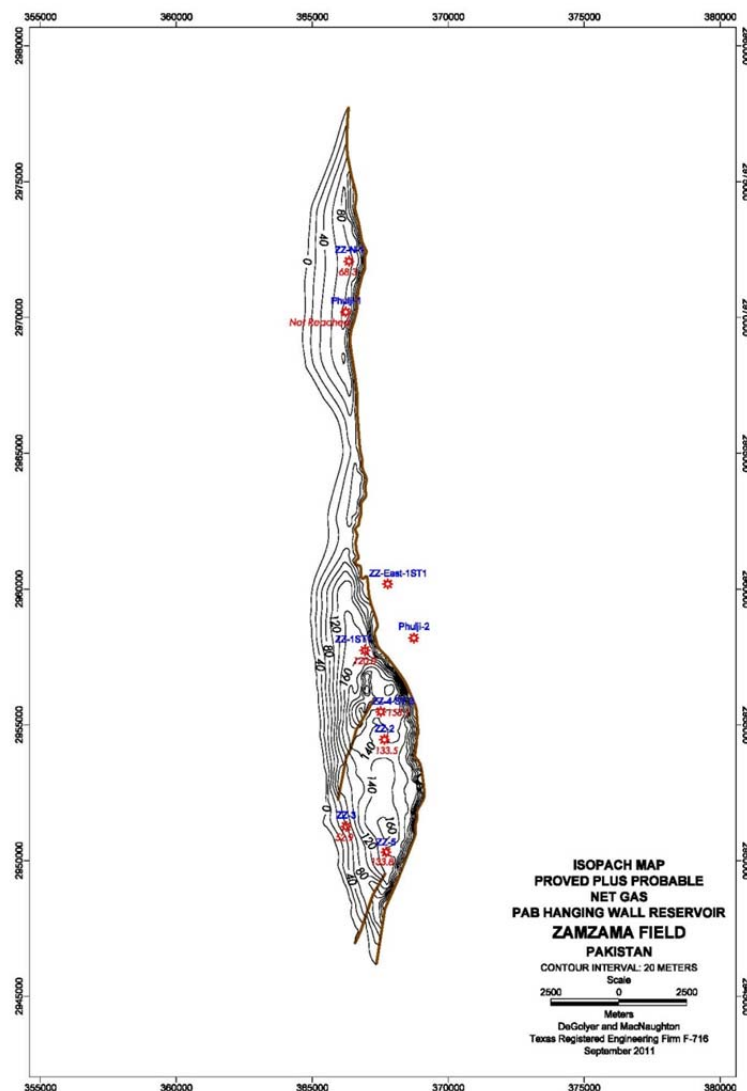
The field is divided into the hanging wall and the footwall areas. The hanging wall is subdivided into northern and southern structural crests. The Pab Sandstone is the primary reservoir interval. The overlying Khadro Limestone appears to be gas-bearing in all wells but has not been tested. The Zamzama field comprises two stratigraphic units and three structural areas for volumetric evaluation. The figure below shows a structure map on the top of the Pab Sandstone.

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The structure map constructed on the top of the Pab reservoir was used to estimate reservoir volumes. A common lower structural limit at a depth of 3,800 meters subsea was used for both the Pab and Khadro Formations across the entire field. This lower limit was based on the pressure-derived GWC at 3,803 meters subsea and the LKG observed in the wells at a depth of 3,799 meters subsea. Isopach maps were prepared for both reservoirs and used to estimate volumetric gas in place. Material-balance analysis resulted in comparable estimates of OGIP with the volumetric interpretation. A net gas pay isopach map for the Pab reservoir used in estimating proved and probable reserves is provided in the following figure.



Recovery factors for the two reservoirs were estimated on the basis of initial reservoir pressures, rock properties, flow rate performance, and surface abandonment conditions consistent with compression operations. Front-end compression is undergoing installation and is scheduled to be completed in 2011. Flowing wellhead pressures in 2010 ranged between 1,600 and 1,800 psig at total full wellstream gas rates of around 500 MMcf/d. Expected surface abandonment pressures associated with compression operations are 700 psig for estimating proved reserves. Probable reserves were estimated using a surface abandonment pressure of 500 psig. Possible reserves consider a surface abandonment pressure of 350 psig. Because there is some concern over the influx of water from the aquifer, recovery factors have been slightly reduced to accommodate for this uncertainty. Wireline pressure data and material balance analysis suggest the probability of some degree of water influx.

Zarghun South Field

The Zarghun South field lies within the Bolan concession in the Baluchistan Province of Pakistan. The field is currently defined by 2-D seismic data and the Zarghun South-1 exploration well, which was drilled in 1998. The Zarghun South-1 well found gas-bearing zones in the Jurassic Chiltan Formation and the Cretaceous Parh Dolomite, Mughal Kot, and Dungan Formations.

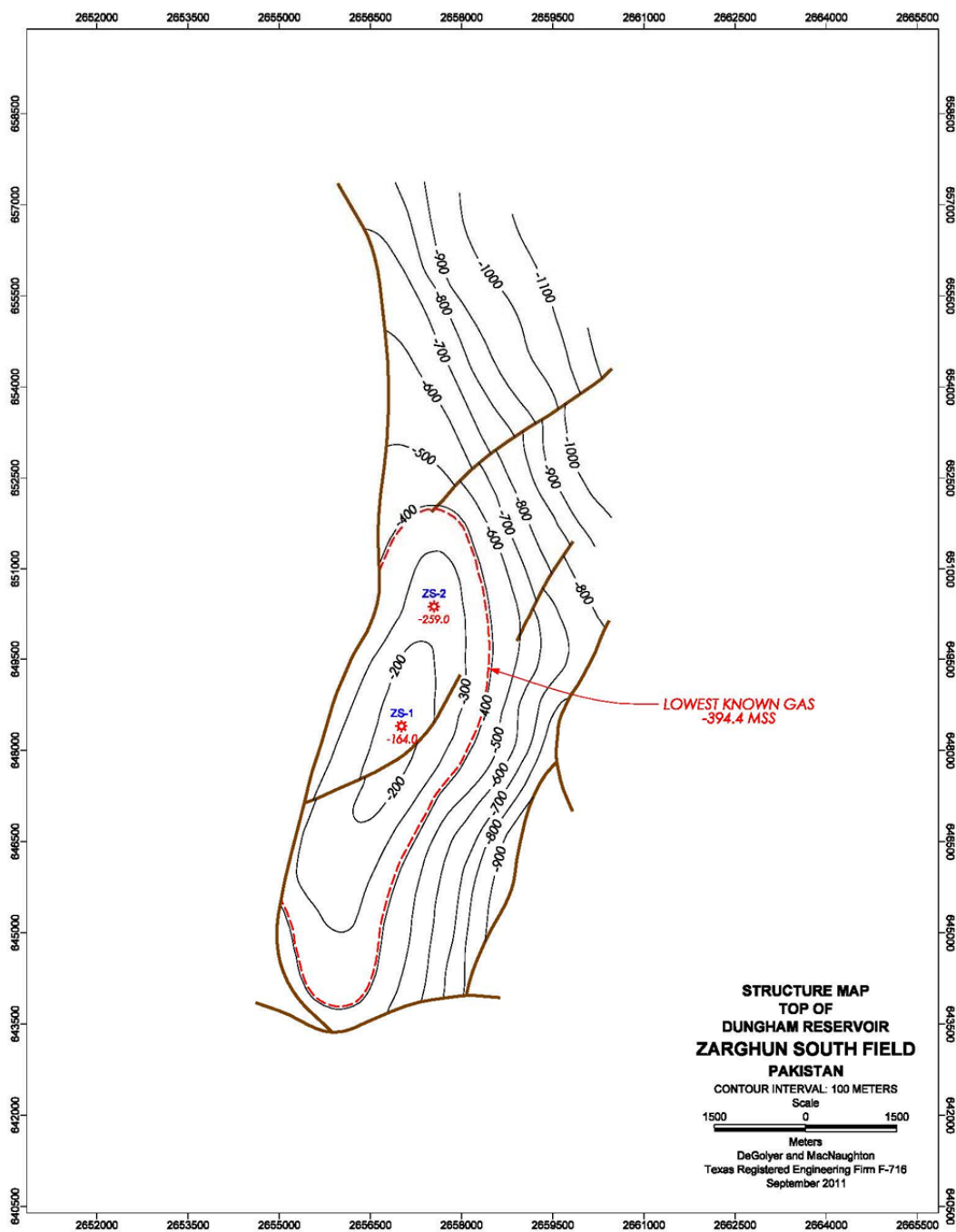
The Zarghun South field petroleum concession agreement was awarded in 1994. A D&PL was awarded in January 2004 with Mari Gas Company as the assigned operator and majority working interest owner. The term of the license is 25 years. Premier's working interest in the license is carried by the other interest owners such that Premier maintains a 3.75-percent overriding interest in the license. A gas sales agreement was signed in 2008, but the owners are awaiting a gas pricing agreement to be approved by the Government of Pakistan.

The Zarghun South-2 well was drilled as an appraisal well approximately 2 kilometers north of the Zarghun South-1 well. The well successfully tested gas in the Dungan Formation, but the Chilton was found to be water bearing.

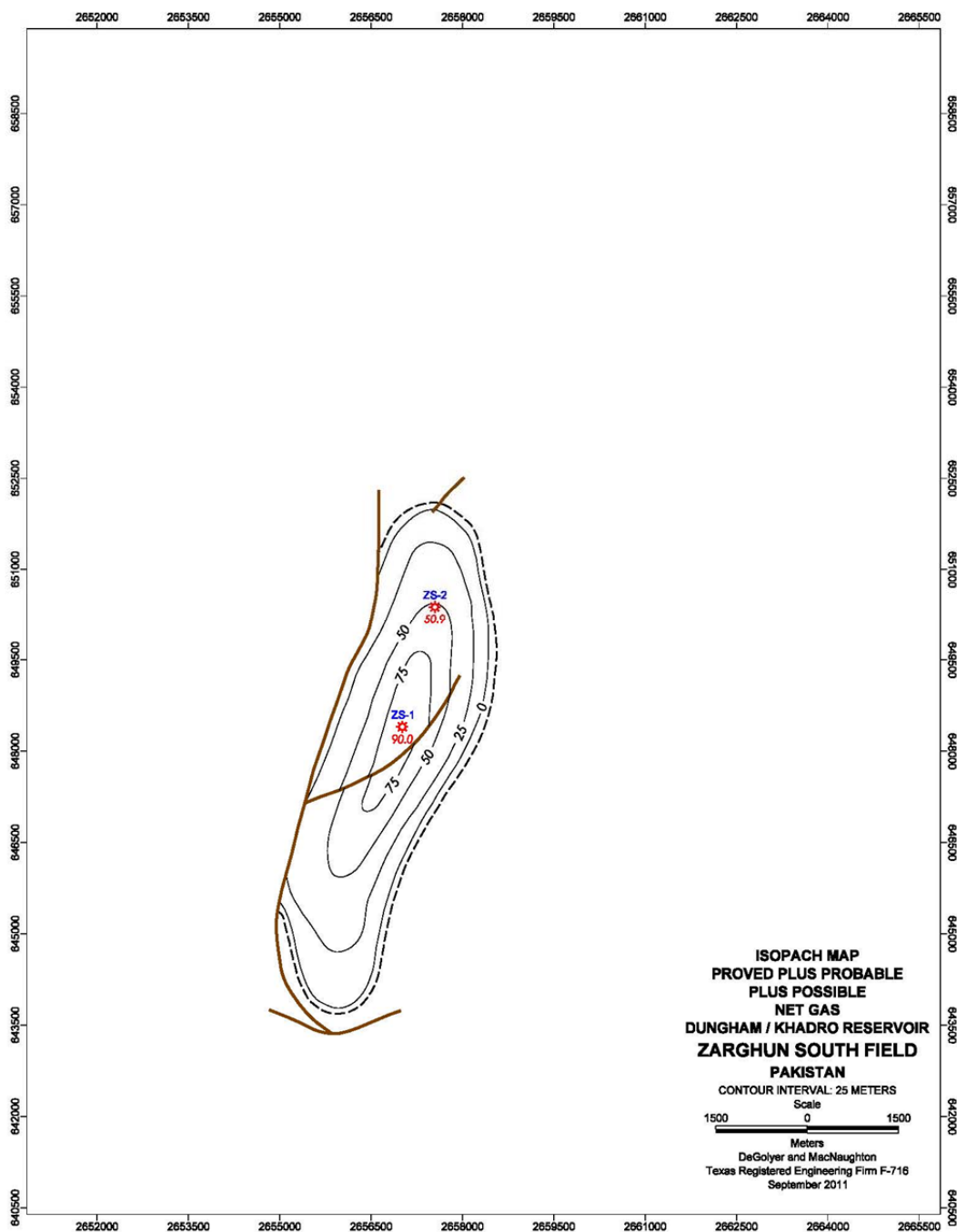
The Zarghun South field is a north/south-oriented anticlinal feature bounded by faults on the downdip eastern and western edges. DST established proved gas production in these zones, though commingling makes zonal contribution difficult to assess. Isolated testing of the Dungan and Chiltan Formations was performed with good results. Because of the poor matrix rock properties, it appears that these formations rely on natural fractures to aid in formation conductivity based on flow

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tests. The following figures show the structural interpretation as well as a net gas isopach map for the Zarghun field.



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Recovery factors used in estimating reserves were derived using test information, bottomhole pressure data, and expectations regarding drive mechanism and surface abandonment pressures. Because of the fractured nature of the reservoirs and uncertainties regarding the influence of aquifer influx via water

coning, recovery factors for the proved and probable reserves were relatively moderate.

United Kingdom

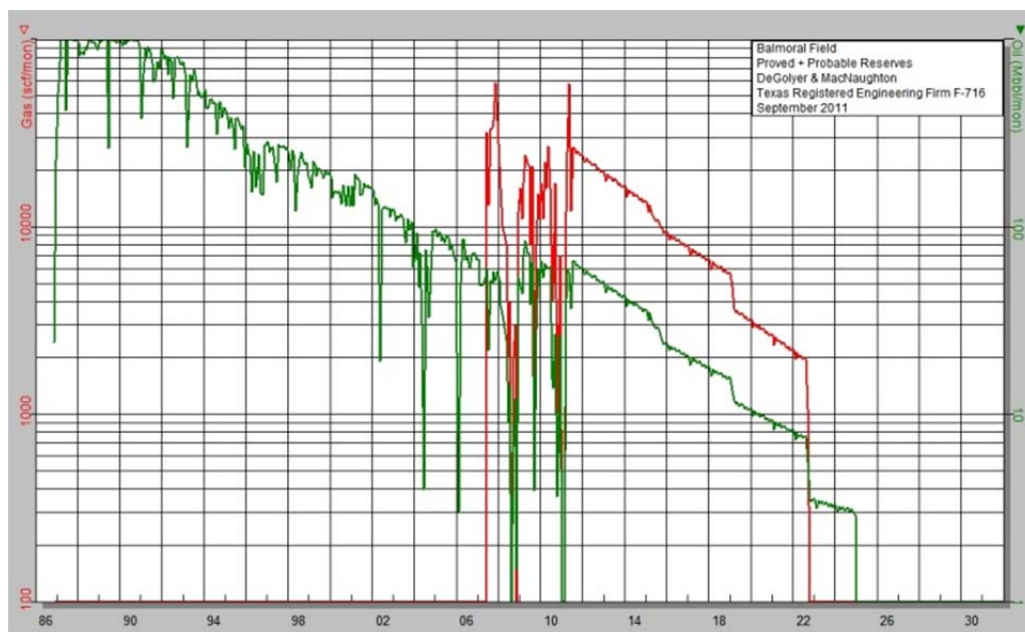
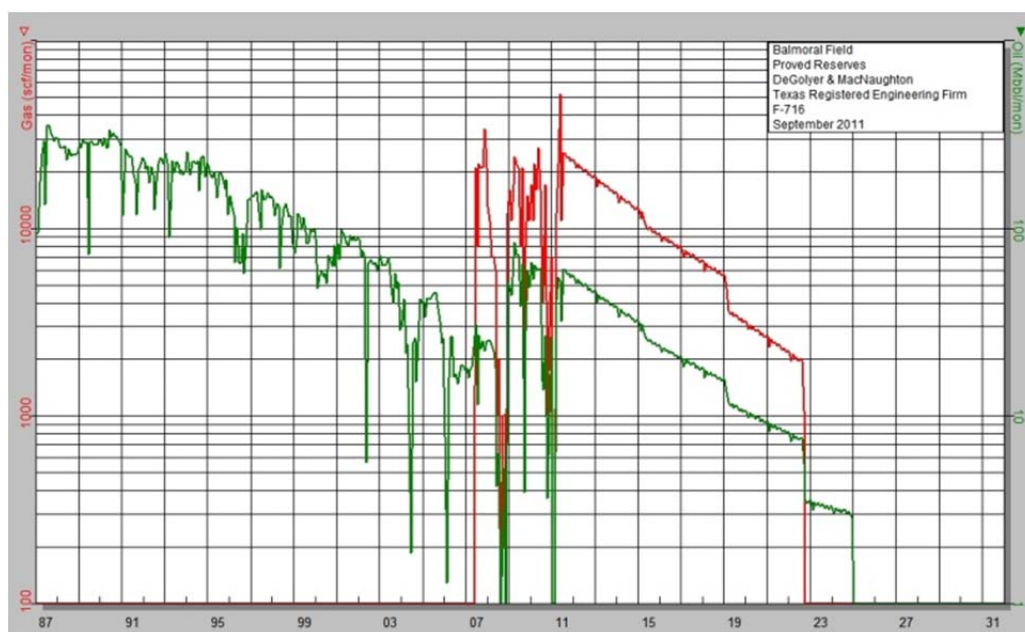
Premier owns interests in the Balmoral, Beacon, Brenda, Caledonia, Greater Catcher Area, Huntington, Kyle, Nelson, Nicol, Greater Rochelle, Scott, Stirling, Telford, Wyth Farm, and Wareham fields.

Balmoral Field

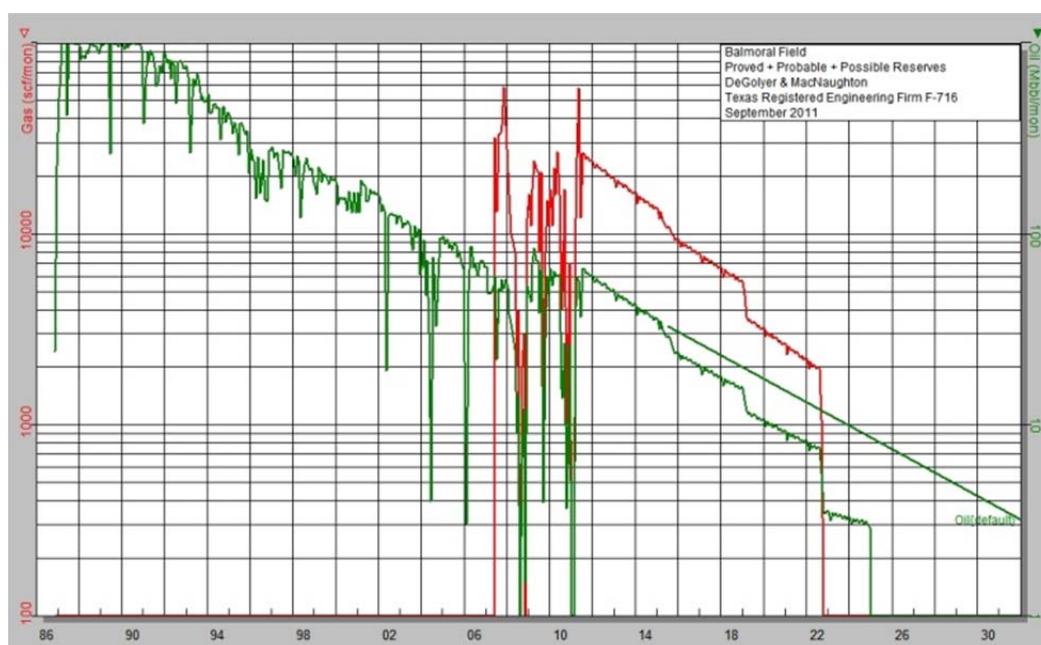
The Balmoral field was discovered in 1975 when the 16/21-1 well penetrated oil-bearing sands in the Andrew Formation. The Balmoral field is located in the United Kingdom North Sea about 140 kilometers northeast of Aberdeen. The discovery well was completed in the Andrew Formation as a subsea well and tied back to the Balmoral floating production facility, with production beginning in November 1986. Public-domain estimates of OOIP range from 300 million barrels and up.

The Andrew Formation sands have been characterized as having been deposited as part of a submarine fan complex. Since initial discovery, the field has been developed with 13 production wells and 6 water injection wells. At the end of 2011, only three wells were still producing at a combined rate of about 1,850 BOPD and 92-percent water cut. Cumulative production is about 101 million barrels. Estimates of proved, proved-plus-probable, and proved-plus-probable-plus-possible reserves were prepared using performance analysis, including exponential decline and water-oil ratio trends, and are shown in the following figures.

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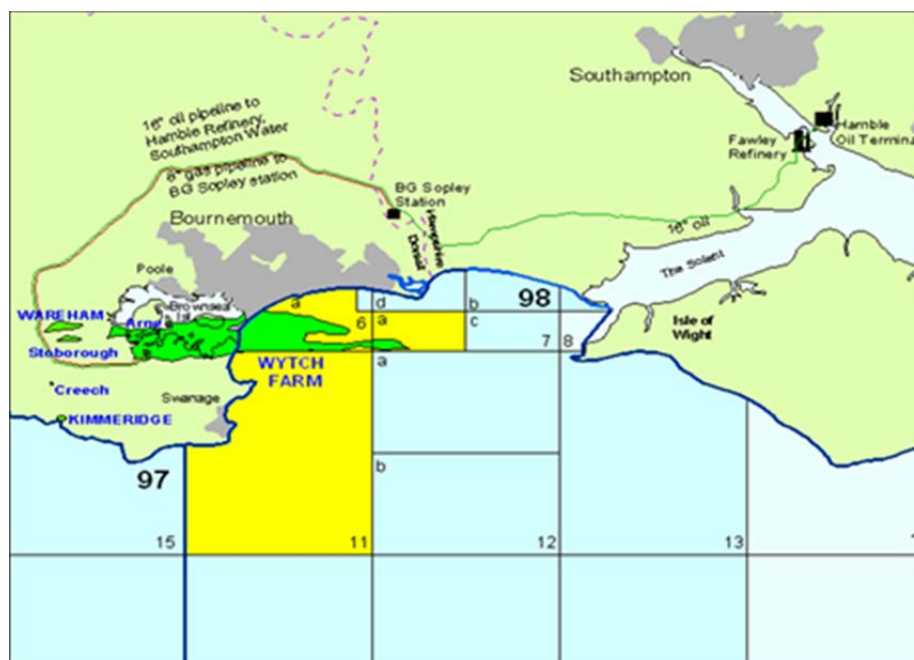


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Beacon Field

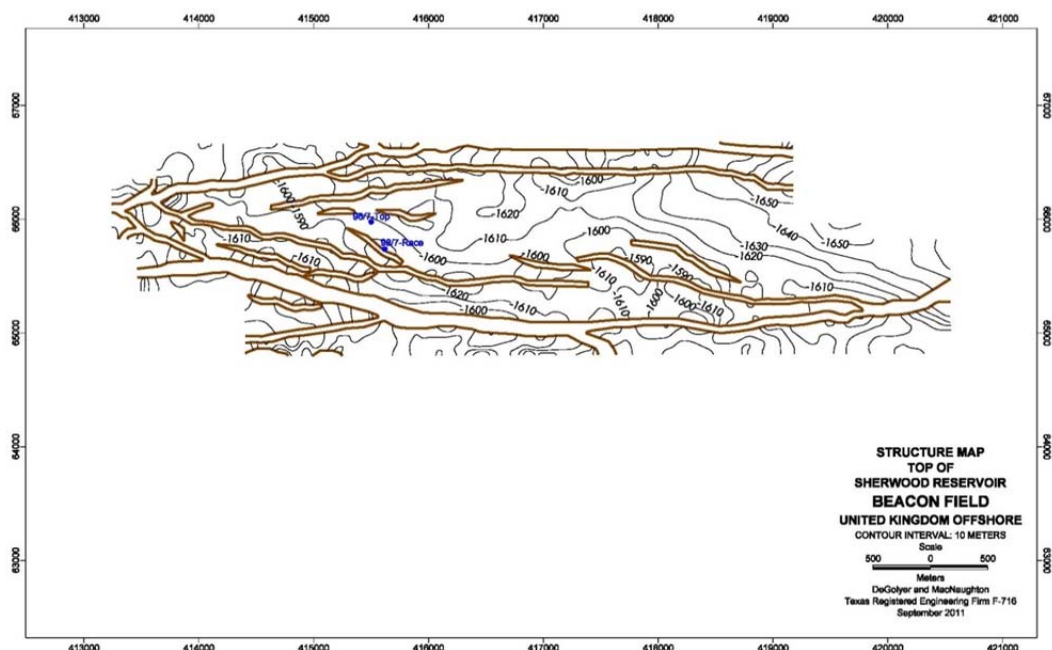
The Beacon Field is located in Dorset, on the southern coast of England approximately 17 miles from Poole. The field lies offshore in one of the most environmentally sensitive areas of the United Kingdom and is planned to be developed from an onshore location with horizontal extended-reach drilling. The field is an eastward extension of the Wytech Farm Field under Poole Bay.



Location Map – courtesy of Premier

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The field consists of a highly faulted east-west/trending horst block with a crest at approximately 1,550 meters subsea. The distribution of OOIP is currently divided into three main segments, (East, West, and South) with seismic surveys showing faulting in the western portion of the field to be more complex. Although mapping indicates most of the field to be in a single compartment, internal faulting and potential compartmentalization continue to be a concern. The mapping of the top structure is the main uncertainty due to problems with estimating seismic velocities.

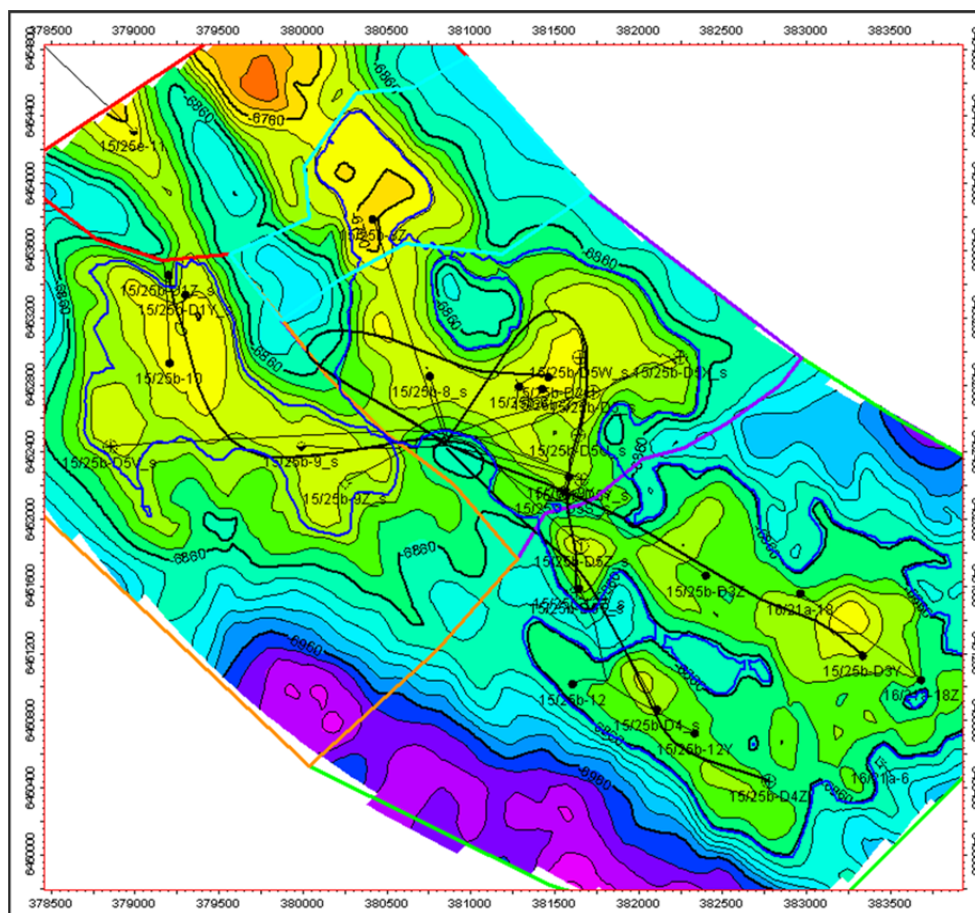


The only well currently in the field is the 98/7-2 exploration well drilled in 1987. This discovery well, drilled in the West segment, tested 1,090 BOPD from a 23-meter-thick interval in the Triassic Sherwood Sandstone and encountered an estimated OWC at 1,623 meters subsea.

The planned development well is set 15 kilometers from the 'M' drilling location. Proved, probable, and possible reserves have been estimated for the field. The reserves were estimated from volumetric evaluation of in-place volumes. First oil is expected in 2015.

Brenda Field

The Brenda field is located in Block 15/25b and 16/21a of the United Kingdom Central North Sea in approximately 500 feet of water. The field was discovered by Sun Oil Company in 1989 with the drilling and testing of the 16/21a-18 exploration well and its sidetrack 16/21a-18z. Numerous appraisal wells have been drilled and tested since discovery. Currently, Brenda produces from four horizontal wells: 15/25b-D1, 15/25b-D2, 15/25b-D3, and 15/25b-D4. The D1, D2, and D3 wells initiated production in June of 2007. The D4 well started producing in August 2007 followed by the D5 well in July of 2008. (The 15/25b-D appears to have watered out and is currently shut-in). Brenda production is tied back to the Balmoral floating production vessel (FPV).



Structure Map on Balmoral Sandstone – courtesy of Premier

The Brenda field produces 39 °API oil from the Upper Balmoral Sandstone of Paleocene age. The reservoir is located along a debris-flow-channel trend, which also runs through the Nicol and McCulloch fields to the northwest. These channel sands

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are of good reservoir quality and have been observed to exhibit an average porosity and permeability of 25 percent and 350 millidarcys, respectively. The reservoir area is limited by lateral pinchouts of the main sands toward the channel margins. The reservoir is further complicated by the meandering and cross-incisions of multiple channels. Brenda is separated into three regions based on differing OWC. The D1 region has an OWC at 6,809.5 feet TVDSS. The D2/D5 and D3/D4 regions are mapped to an OWC at 6,843.7 feet TVDSS and 6,863.4 feet TVDSS, respectively. Although the regions have different contacts, depletion effects between regions indicate they likely are in communication with the same aquifer. Forecasts of the proved, proved-plus-probable, and proved-plus-probable-plus-possible reserves are shown in the following figures.

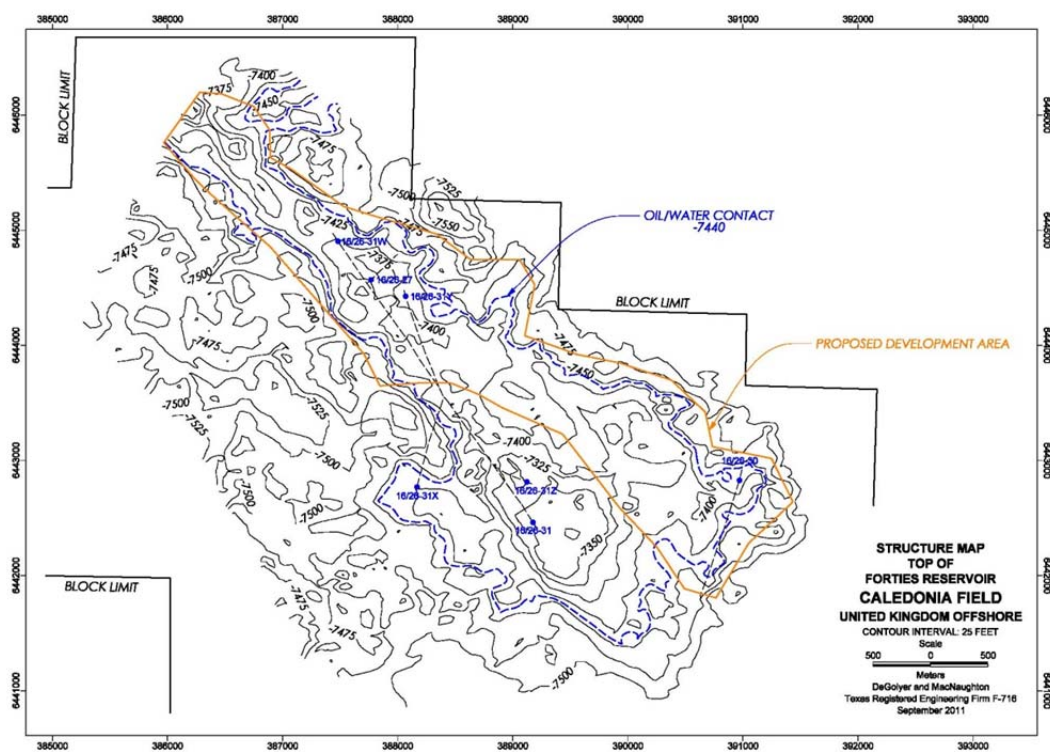


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Caledonia Field

The Caledonia field was discovered in 1977 and is located in Block 16/26. The field has produced from a single horizontal well, 16/26-30y. This well was tied back to the Britannia platform in 2004 and continues to be produced intermittently to that platform. The well has produced about 6 MMbbl from the Forties sandstone. The well was shut in during 2008 because production was falling off quickly. There have been several new wells to appraise the northern, western, and eastern part of the field. The western flank requires further evaluation before quantities can be determined. This field has probable and possible reserves based on the decision to redevelop the northern lobe of the field. The northern lobe of the field is expected to be tied into the Balmoral FPV with first oil in 2012. A structure map on the top of the Forties reservoir is shown below.



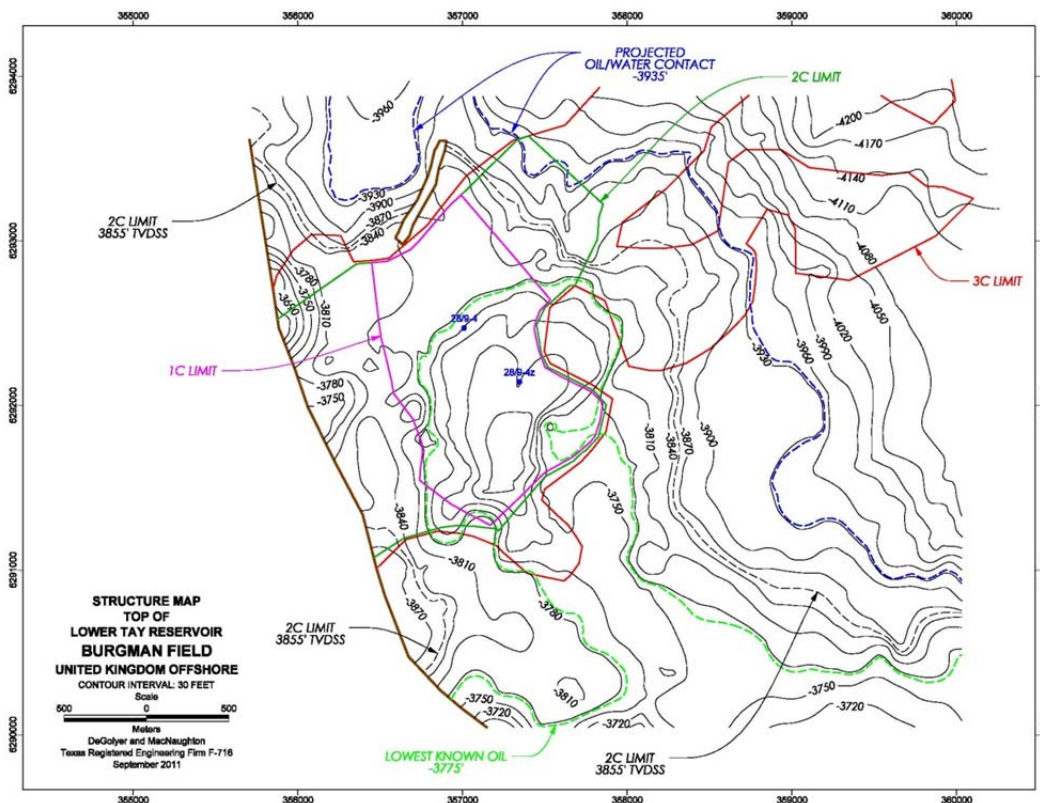
Greater Catcher Area

Premier owns a 35-percent working interest in the fields in the Catcher field area (Catcher, Catcher North, Varadero, and Burgman). Premier has represented that it is currently in the process of finalizing an acquisition of the working interest (15 percent) attributable to Encore Oil plc (Encore) in the licenses for these fields. At

the request of Premier, an evaluation of the reserves, contingent resources, and net present worth of the proved and proved-plus-probable reserves has been performed herein on the basis of the working interest attributable to both Premier and Encore. As such, the estimates of working-interest reserves and contingent resources and the estimated net present worth of the proved and proved-plus-probable reserves attributable to the fields in the Catcher field area consider the combined working interest of 50 percent.

Burgman Field

The Burgman accumulation is located in Block 28/9 in the United Kingdom North Sea and has been penetrated by the discovery well (28/9-4) and a sidetrack (28/9-4z). The accumulation is bounded to the southwest by a major normal fault. The primary trapping mechanism is stratigraphic as indicated by seismic amplitude data. One oil-bearing zone, the Lower Tay, has been evaluated.



The field has been evaluated volumetrically by estimating the oil in place and using analogous recovery factors based on producing fields in the area. The development plan calls for tying the field to other fields in the Greater Catcher area for production from one central platform.

For the purposes of mapping hydrocarbons in place, the downdip limit for proved reserves is 3,775 feet TVDSS as defined by an observed LKO in the 28/9-4 well. The downdip limit for proved-plus-probable-plus-possible reserves is at 3,935 feet TVDSS as indicated by a MDT-projected OWC (POWC), while the downdip limit for proved-plus-probable reserves is the midpoint between the LKO and POWC.

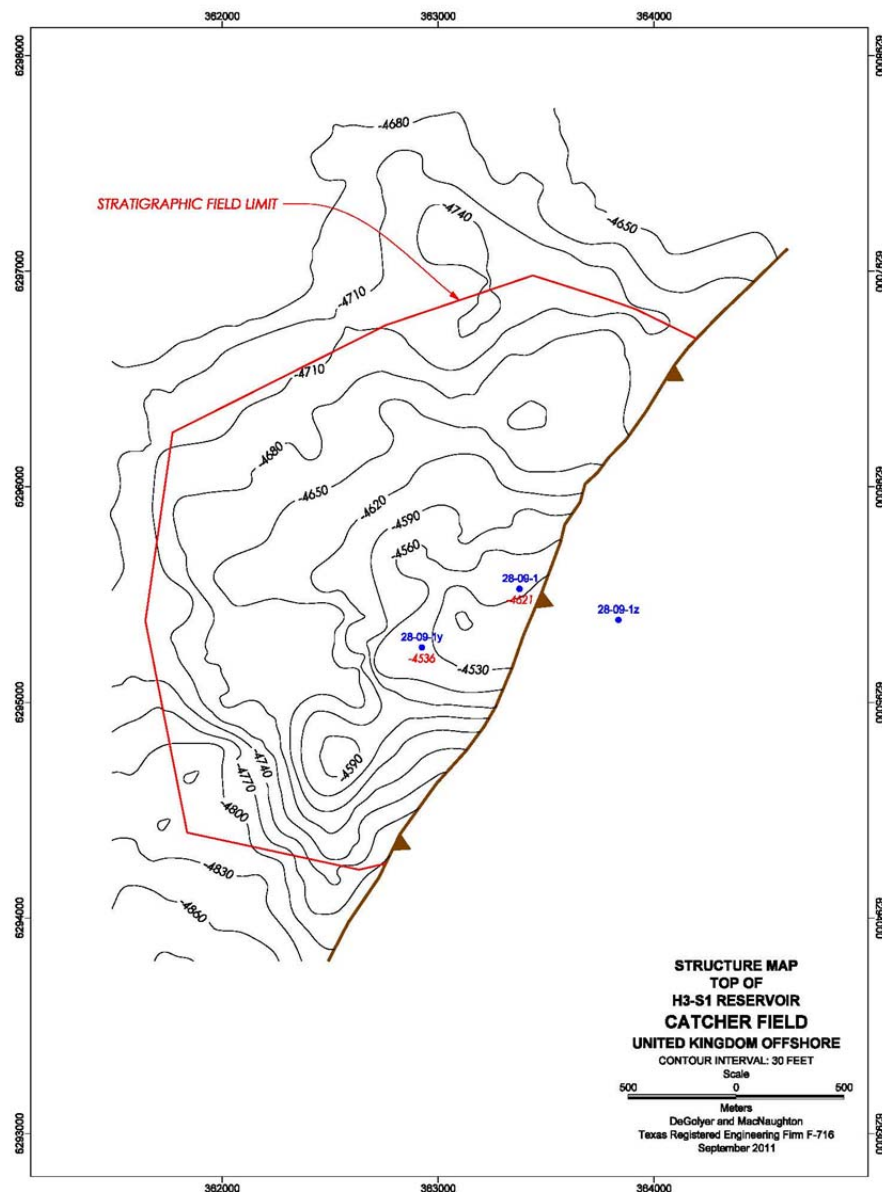
Depletion drive has been used to estimate proved reserves, and water pressure maintenance from start-up has been used to estimate proved-plus-probable and proved-plus-probable-plus-possible reserves, as is common with fields in the area. Production is staggered as to meet the constraints of the planned Greater Catcher FPSO.

Catcher Field

The Catcher field is located in Block 28/9 in the United Kingdom North Sea and was discovered in 2010 when the 28/9-1 well penetrated oil-bearing sands in the Cromarty and Tay Formations. Current development plans call for the field to be produced from a subsea tie-back to the Greater Catcher FPSO, with five producing wells and four injectors, together with the three other fields in the Greater Catcher Area.

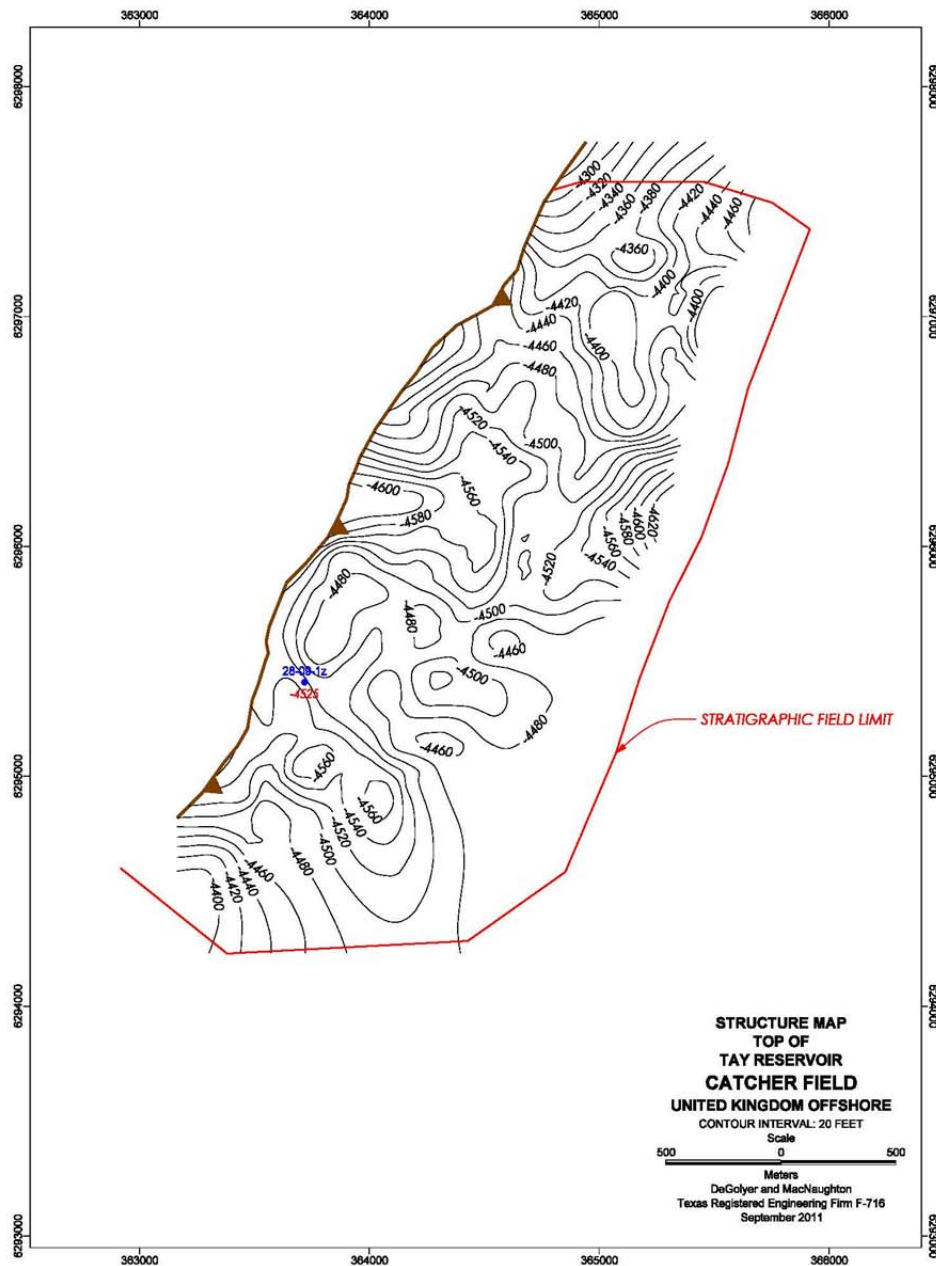
A structure map on the top of the H3S1 reservoir is shown on the following figure.

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The Cromarty sand is composed of turbidites derived from the erosion of the Scotland and Shetland uplifts in the early Eocene. The Eocene Tay sands consist of deepwater turbidites that fed through a number of discrete channel systems, which in turn fed into a more widespread turbidite system to the west.

A structure map on the top of the Tay sand reservoir is shown in the following figure.



Catcher North Field

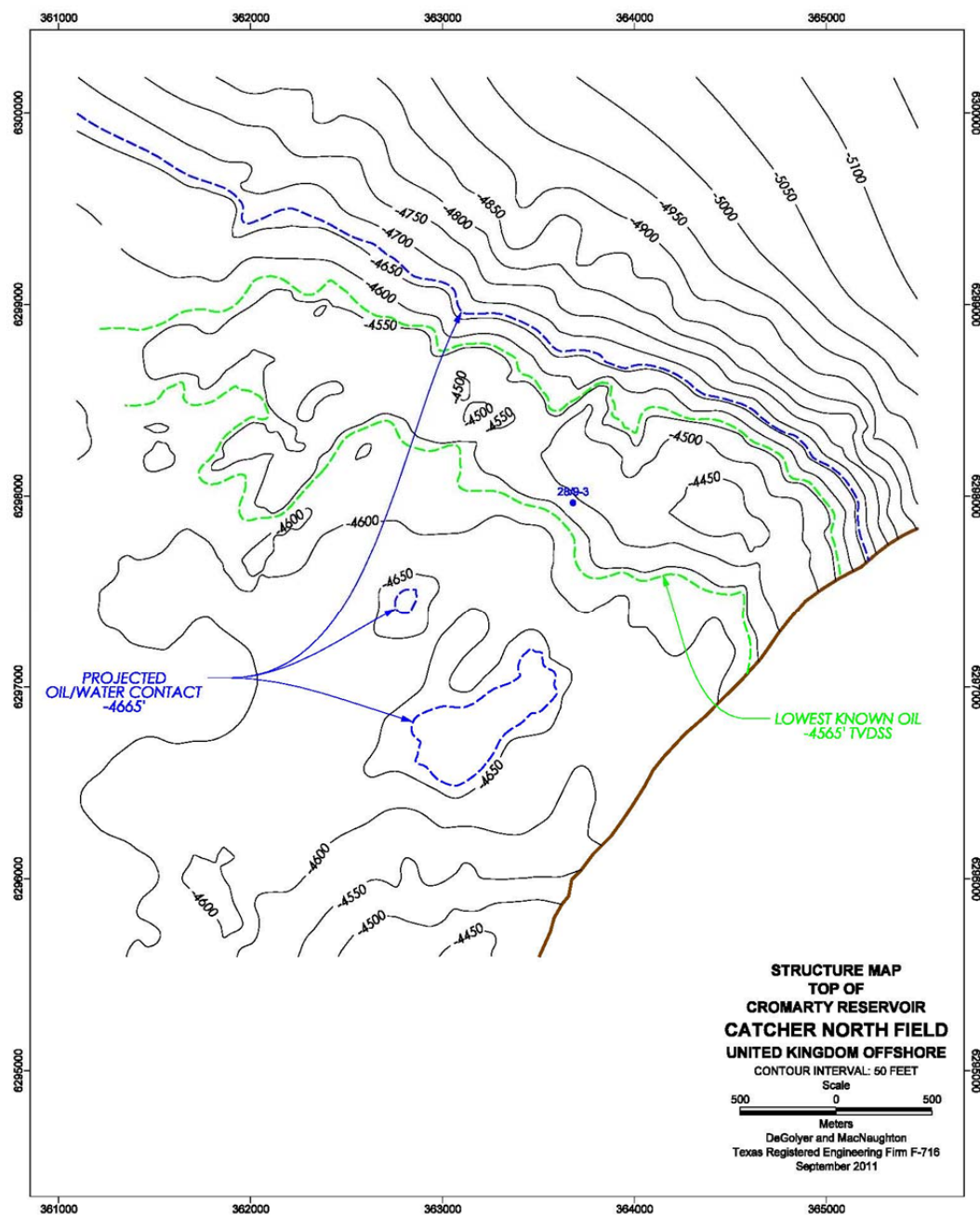
The Catcher North accumulation is located in Block 28/9, in the United Kingdom North Sea. To date a single well, 28/9-3, has been drilled. One oil-bearing reservoir, the Cromarty sand, has been evaluated. An additional gas zone in the Tay Formation was penetrated, but would not be an economic target under the anticipated development scheme. The structure is composed of a four-way dip

closure. The primary trapping mechanism for the field is stratigraphic, with stratigraphic pinch-outs to the north, south, and west indicated by seismic amplitude data. The field is bounded to the southeast by a northeast-trending normal fault.

A downdip limit of 4,565 feet TVDSS based on the observed LKO was used to estimate proved reserves volumetrically. Additionally, the area associated with proved reserves was limited to the main part of the structure immediately surrounding the well. For the OOIP associated with proved-plus-probable and proved-plus-probable-plus-possible reserves, a downdip limit of 4,665 feet TVDSS was used, based on a MDT-projected OWC. Since this contact falls well below the mapped spillpoint to the south and west of the Catcher North structure, stratigraphic limits were utilized to the south and west.

Analogous recovery factors from producing fields were used to determine recoverable quantities, which are contingent on tying the field back to larger fields, and presumably a subsea tie-back to the planned Greater Catcher FPSO. A depletion case was estimated for the proved reserves, with an immediate water-injection plan utilized for the proved-plus-probable and proved-plus-probable-plus-possible reserves. Costs are based on analogy to the Catcher field, and production is staggered as to meet the constraints of the planned Greater Catcher FPSO.

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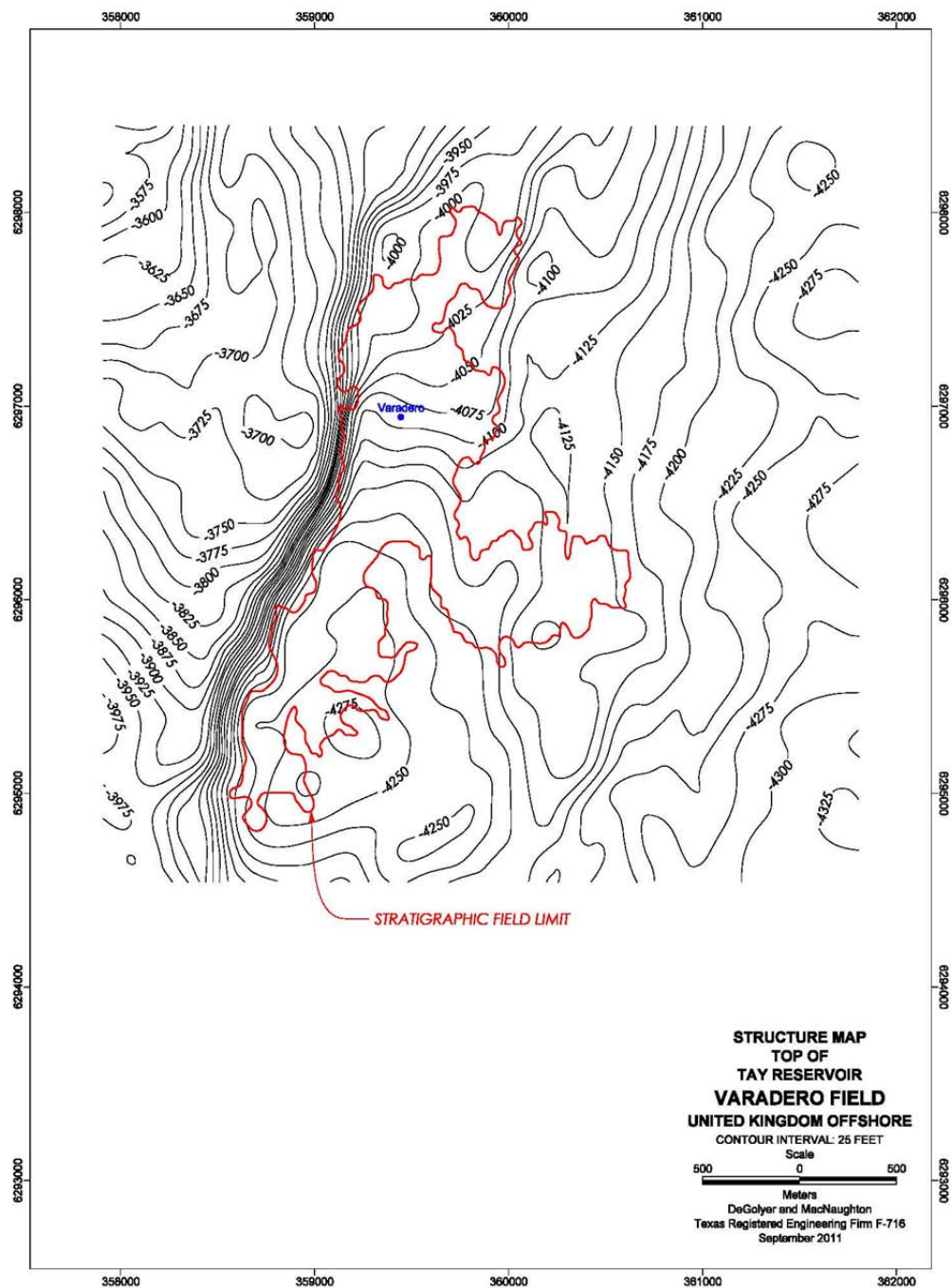


Varadero Field

The Varadero field is an oil discovery located approximately 2 kilometers west of the Catcher field in the United Kingdom North Sea. To date, a single well

drilled in 2010, the 28/9-2, has been used to define the reservoir. The 28/9-2 well penetrated the Tay interval encountering two oil-bearing sands (approximately 68 feet of sand) separated by a shale interval in the well. The well has not been tested but is analogous to productive reservoirs in this area of the North Sea. Wireline pressure data indicated a relatively significant oil column with an apparent gas cap in the overlying sediments at 4,027 feet TVDSS. The well was drilled to an LKO at 4,196 feet TVDSS in the lower Tay sand, while an OWC was estimated using the wireline pressure data at 4,267 feet TVDSS (see the figure below). Based on geophysical attributes of the mapped structure and the single well penetration, the distribution of the reservoir quality rock is constrained stratigraphically, occurring as an injected sand. The two distinct sands, while apparent in the penetrated well, are interpreted to be effectively a single unit with limited overlap, such that the thickness of the oil-bearing sands reflect a single sand member in terms of average thickness. Average porosity is approximately 35 percent and average water saturation is about 11 percent in the productive interval. A structure map on the top of the Tay reservoir is shown in the following figure.

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In the absence of a structural component to the trap of oil in the field, the area containing productive reservoir rock actually appears as a structural low. The gas cap, which doesn't appear to exist at the prevailing structural elevations of the productive Tay sands, is not considered for development. The field is expected to be developed using three subsea wells, including one water injection well, and tied back to the Greater Catcher FPSO. First production is expected to begin in 2014. Estimates of proved, probable, and possible reserves have been made utilizing volumetric analysis, incorporating analogous field performance (Alba and Harding fields, for example), and the expected development scenario. Recovery is expected to range from 30 to 50 percent.

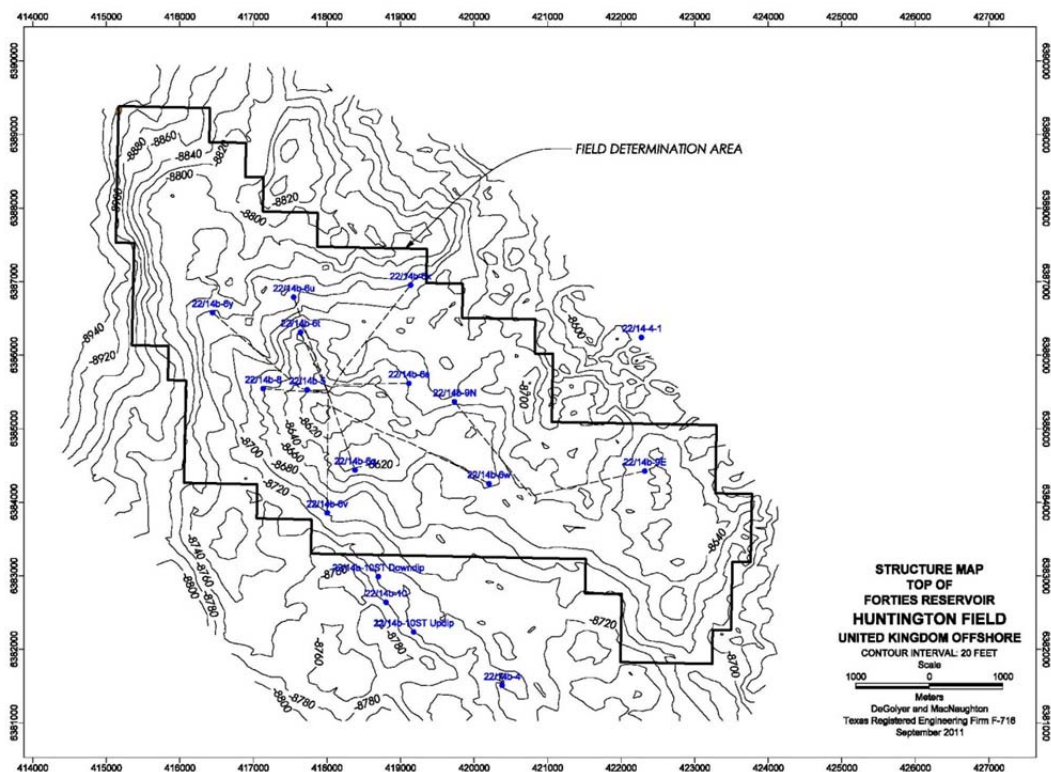
Huntington Field

The Huntington field is located in Block 24/14b in the United Kingdom Central North Sea, immediately southwest of the Everest gas and condensate field. The discovery well, 22/14b-5, was drilled in 2007 and tested the Paleocene Forties sandstone at 3,200 BOPD of 40 °API oil. It also tested the deeper Jurassic Fulmar (Huntington Deep) at 2,890 BOPD of 39 °API oil. Significant appraisal drilling has been undertaken consisting of a total of 10 penetrations.

The proposed development envisages five horizontal producers in the Forties tied back to a leased FPSO. First production is anticipated for late 2012. Proved undeveloped, probable, and possible reserves are based on volumetric methodology. Estimates of proved reserves for the Huntington field were estimated by applying a recovery factor consistent to estimates of OOIP derived from the volumetric interpretation. Estimated petrophysical parameters of net-to-gross ratio, porosity, and water saturation were applied to the gross rock volume in the geological model above limiting elevations. These petrophysical parameters result from a key well study of the eight 22/14b-6 sidetrack wells. Estimates using this methodology were prepared for each of the three license blocks that make up the Field Determination Area. Probable and possible reserves for the Huntington Field were estimated using the modeled petrophysical parameters within the geological model for estimates of OOIP after the application of recovery factor. These estimates also do not include the 9z area in license 14a.

The figure below shows the Huntington field structure at the top of the Forties Formation.

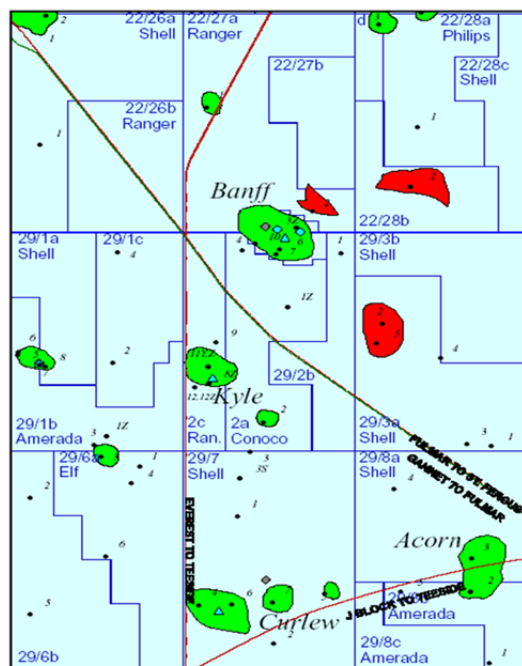
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Kyle Field

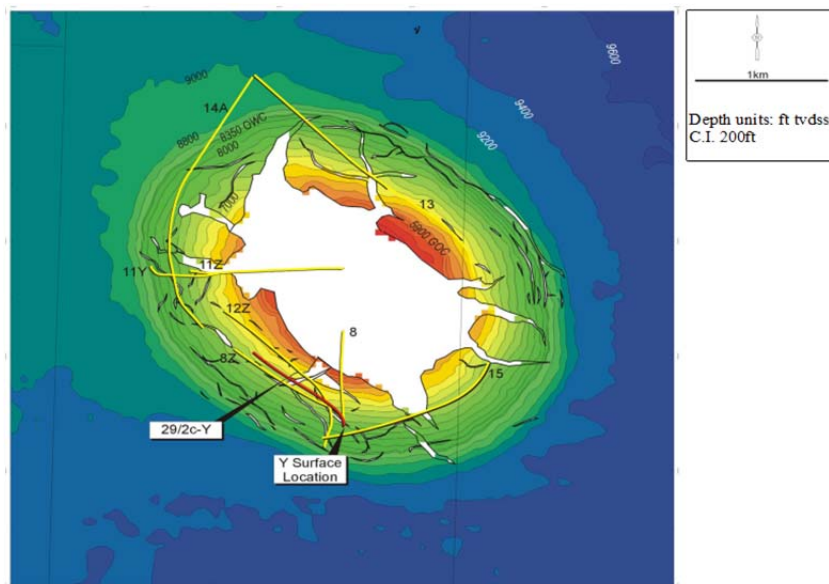
The Kyle field, operated by CNR International (U.K.) Ltd., is located approximately 125 miles southeast of Aberdeen. Water depth at the Kyle field is 300 feet. The field is situated in the central salt basin with the main productive formations being the Sele and Lista Sandstones and the Ekofisk and Tor Chalk.

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Location Map – Courtesy of Premier

The field is structurally controlled by a salt diapir that penetrated and displaced the overlying sandstone and chalk reservoirs. The reservoirs are composed of rings of highly fractured chalk and sandstone surrounding the salt dome. To date, four horizontal wells have been drilled to develop the field. A structure map on the top of the Chalk reservoir is shown in the following figure.



Structure Map – Courtesy of Premier

The K-12Z well began producing on an extended well test in 2000. The K-13 well began continuous production operations in 2001, but is now on cyclic production with the K-12Z well. The K-14 well was drilled and completed in 2001 and began producing in November 2001. The Paleocene well (K-14) and the Chalk wells are producing to the Banff FPSO. The K-15 well came on production in July 2002. Gas lift operations were successfully installed in the summer of 2007. The field is divided into four major fault blocks that surround the salt diapir with faults extending radially outward from the salt. The four existing wells have penetrated and produce from all but the southeast fault block. Kyle field reserves were estimated using volumetrically derived OOIP and production performance trends. A forecast of the proved-plus-probable reserves for the field is shown in the following figure.



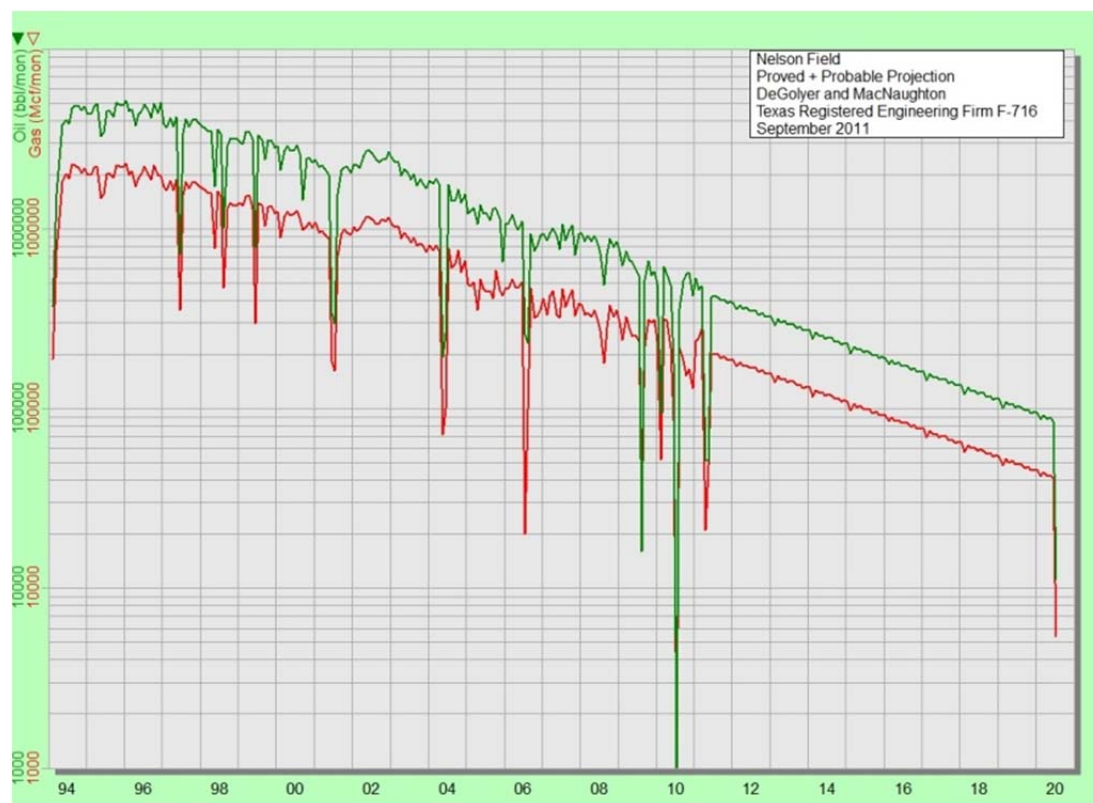
Nelson Field

The Nelson field is located in the North Sea, 202 kilometers northeast of Aberdeen, in Blocks 22/11, 22/6a, 22/7, and 22/12a. The field is a dip-closed structure and is one of a series of Paleocene sandstone oil accumulations on the Forties Montrose High. Premier owns a 1.66-percent working interest in the Nelson field.

Nelson is a mature field with cumulative oil production of approximately 446 million barrels since production began in 1994. There have been 32 oil producers

drilled in the Nelson field and there are currently two active water injection wells. All produced water from the field is re-injected and all gas production is consumed as fuel. The oil produced in the field is 37 to 44 °API crude with low sulphur content. The production rate in December 2010 was approximately 14,000 BOPD.

Reserves estimates for the Nelson field are based on performance analysis. Rate versus time plots, water cut versus cumulative oil plots, and oil rate versus cumulative oil plots were all used to estimate reserves. Proved, probable, and possible reserves were estimated by considering a range of decline scenarios for the field. The figure below shows the projection used to estimate the proved-plus-probable reserves.



Premier's estimate of OOIP in the Nelson field is approximately one billion barrels of oil. Estimates of reserves were based on performance trend analyses.

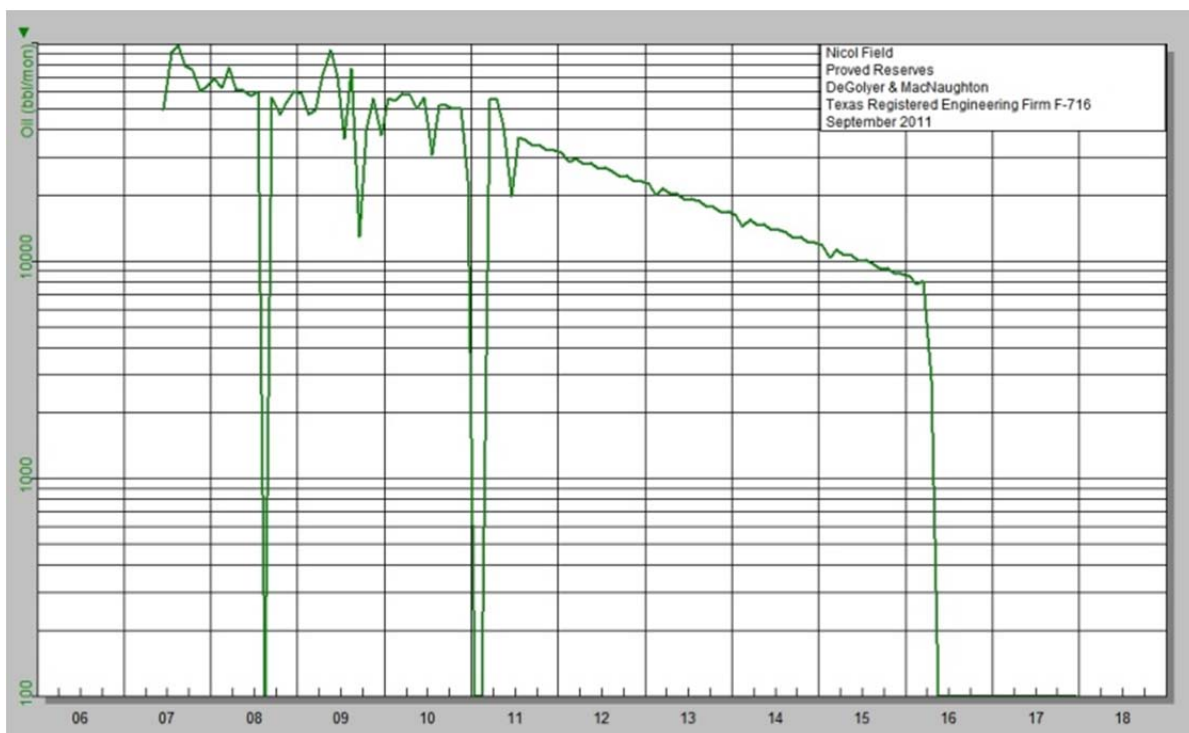
Nicol Field

The Nicol field lies in Block 15/25a of the United Kingdom North Sea, approximately 120 kilometers northeast of Aberdeen. The field was discovered in 1988 by the 15/25A-2 well, which was completed in the Balmoral Sandstone

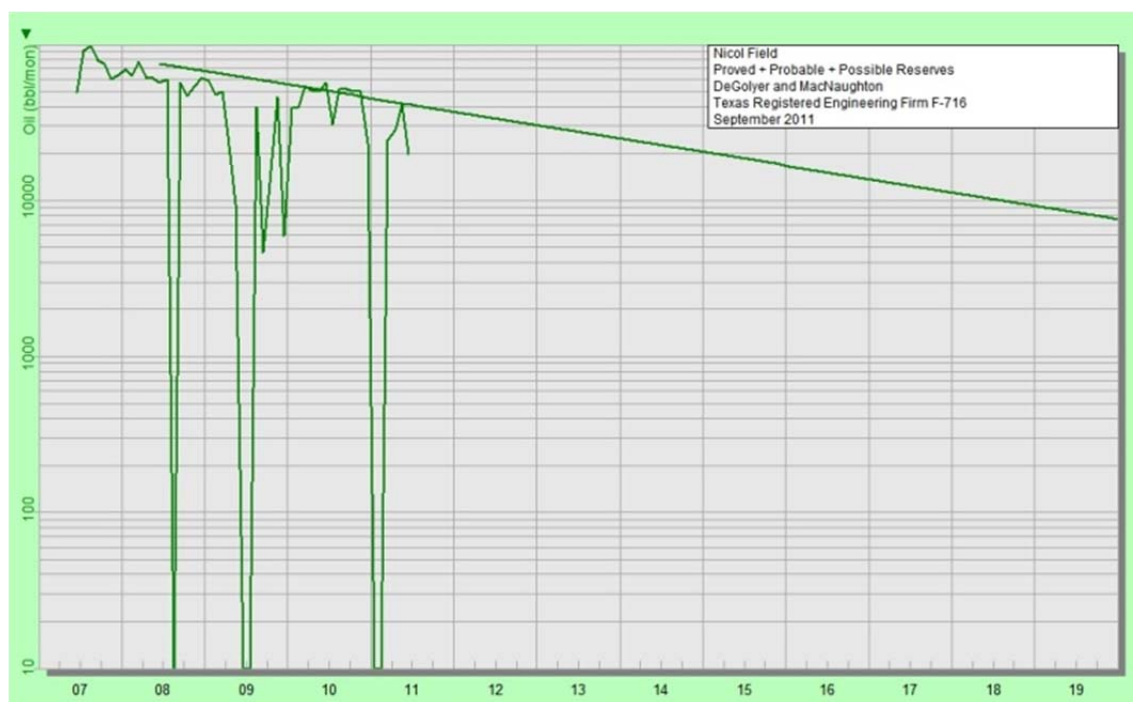
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Formation as a subsea well and brought online in 2006. The well was tied back to the Brenda manifold, which, in turn, has forwarded produced fluids to the Balmoral floating production facility. A second well, the 15/25A-N2 well, was completed in 2009 and began production in 2010. Available estimates of OOIP, provided by Premier, range from 19 to 24 million barrels of oil. Cumulative production is approximately 2.7 million barrels.

Estimates of proved, proved-plus-probable, and proved-plus-probable-plus-possible reserves have been estimated for this field based on decline curve analysis of historic production trends as shown in the following figures.



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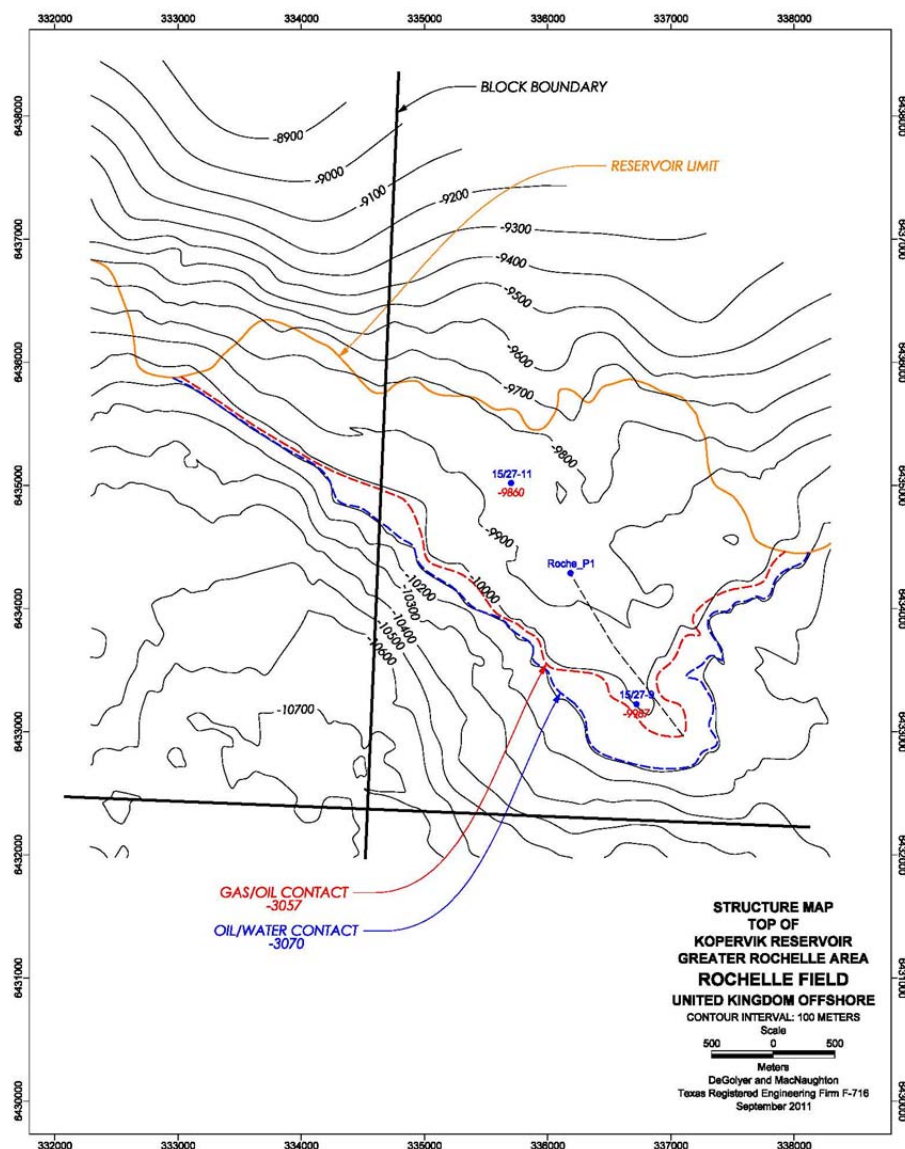


Greater Rochelle Field Area

For the purposes of this report, the Greater Rochelle area encompasses two accumulations: the Rochelle field, and the West Rochelle. The two accumulations are separate structures but may share communication in the aquifer.

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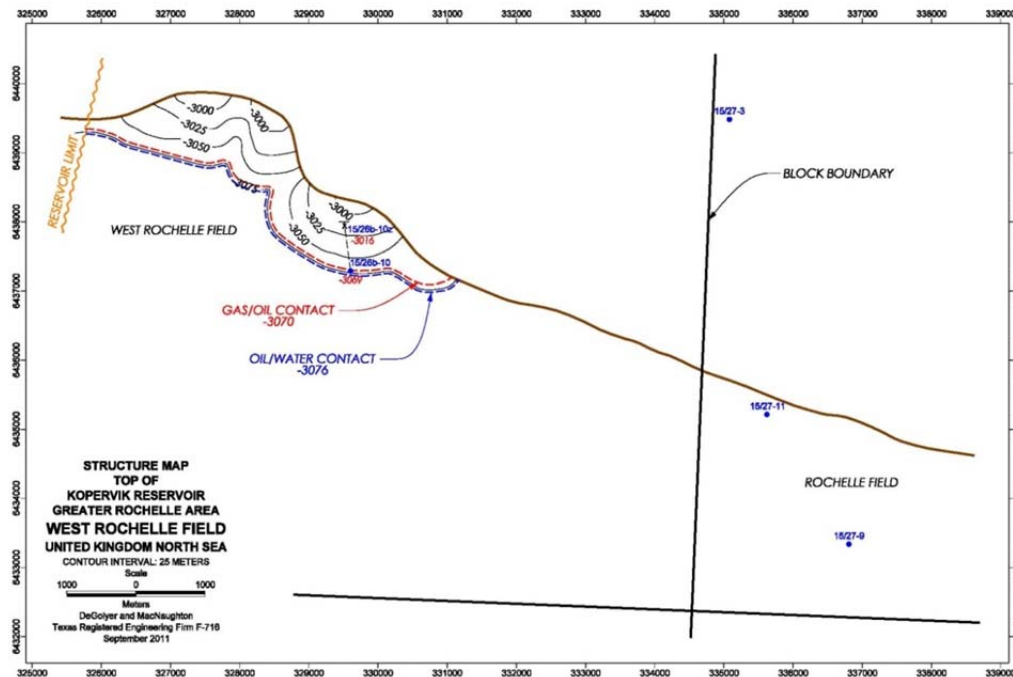
The Rochelle field is a gas-condensate accumulation discovered in 2000 and appraised in early 2009 with the drilling of the 15/27-11 well. The field is southwest of the Scott field offshore of the United Kingdom. The productive reservoir is the Lower Cretaceous Kopervik Sand. The appraisal well was tested at rates between 8 and 36 million cubic feet per day, with some pressure depletion since discovery. The field was evaluated using volumetric analysis of the gas accumulation. There is a thin oil rim in the field that will not be a target for development. The proved reserves are based on an area restricted to the drainage of the appraisal well in the top of the structure. The proved-plus-probable and proved-plus-probable-plus-possible reserves are based drainage of the full structure.





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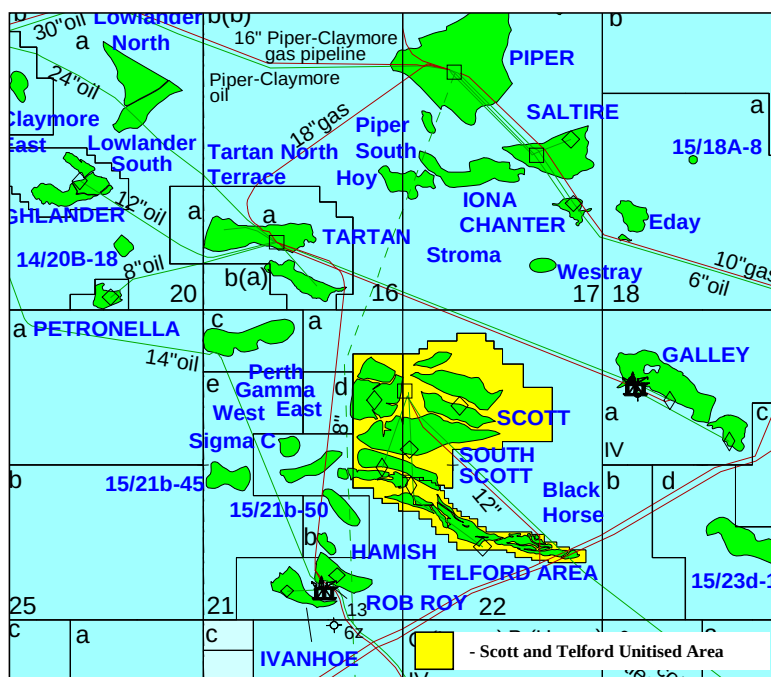


The proposed Greater Rochelle development would include up to four producers tied back to a FPSO vessel. Shown below is a structure map on the top of the Koperik for the Greater Rochelle field area.

Scott Field

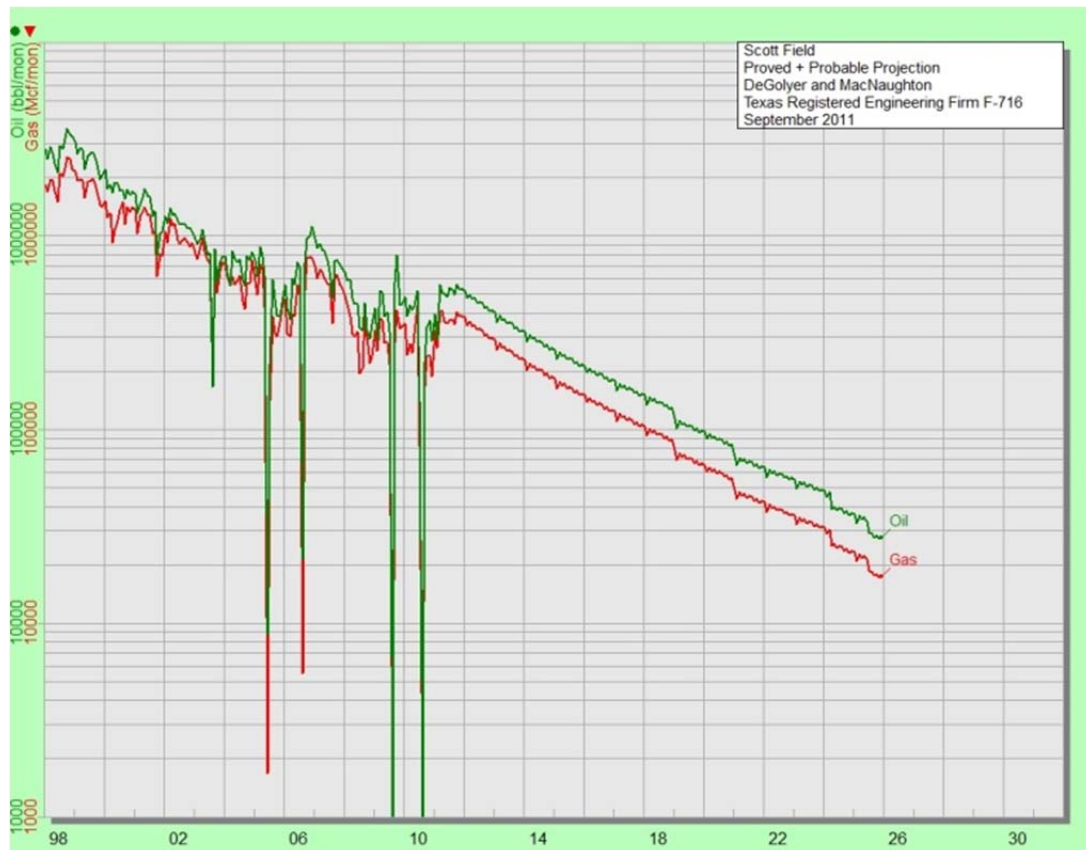
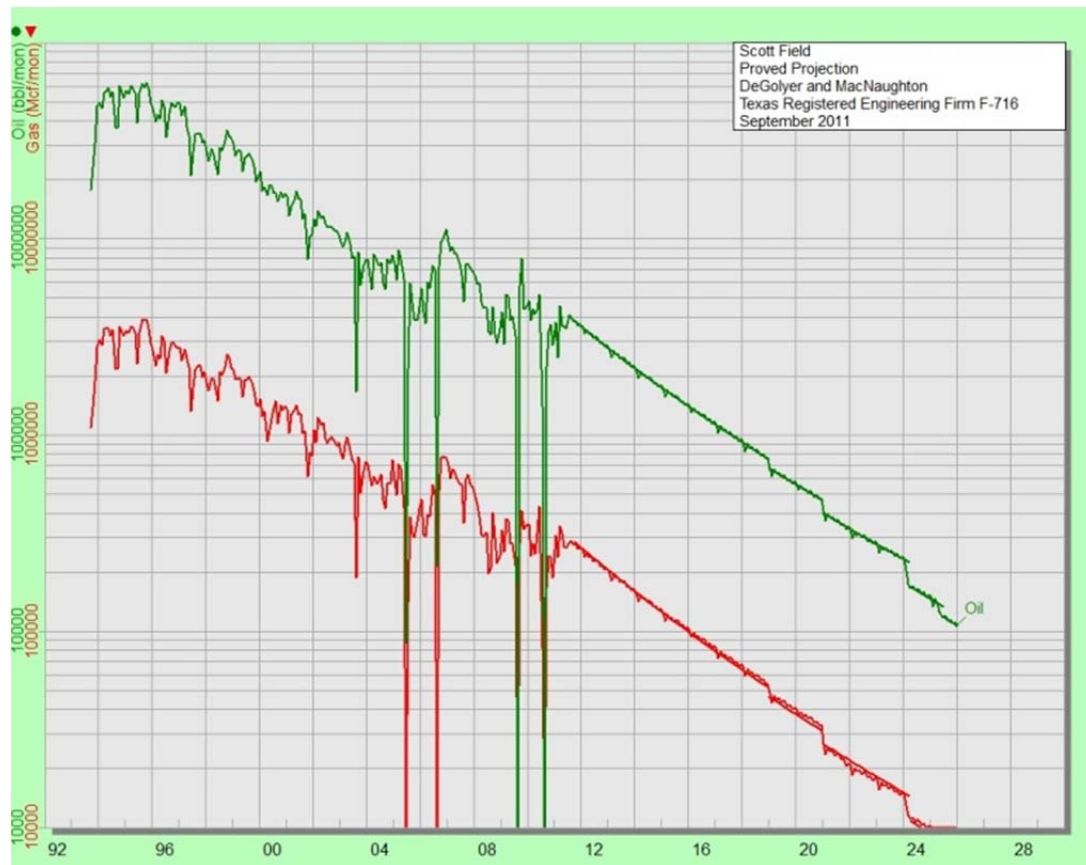
The Scott field has shown to be more complex than originally envisioned prior to full development. Utilizing 3-D seismic and analyses of wells already drilled, an ongoing but limited drilling program has continued over the last few years. Well maintenance and intervention have become increasingly important in field operations. The focus of recent drilling has been to capture unswept oil and access unpenetrated fault compartments. Proved developed reserves reflect existing wells. Probable reserves have been estimated for improved performance. Possible reserves have been estimated for recovery above that associated with probable reserves. Projections of proved, proved-plus-probable, and proved-plus-probable-plus-possible reserves are shown in the following figures.

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Location Map – courtesy of Premier

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Stirling Field

The Stirling field is located in license block 16/21, offshore the United Kingdom. The field was discovered in 1980 by the 16/21a-2 well. First oil production was in October, 1993, from the A-20z well. Cumulative production from the field is about 3.6 million barrels of 38.7 °API oil.

The Stirling field produces about 400 BOPD at 90-percent water cut from one well in the fractured Devonian sandstone, with average porosity of 9.5 percent and permeability of less than 1 millidarcy.

Proved developed reserves were estimated based on the performance of the existing well in the field, while probable and possible reserves estimates were based on improved recovery efficiencies in the reservoir. The following figures show the performance trend analysis used in the estimation of proved and proved-plus-probable reserves.

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Telford Field

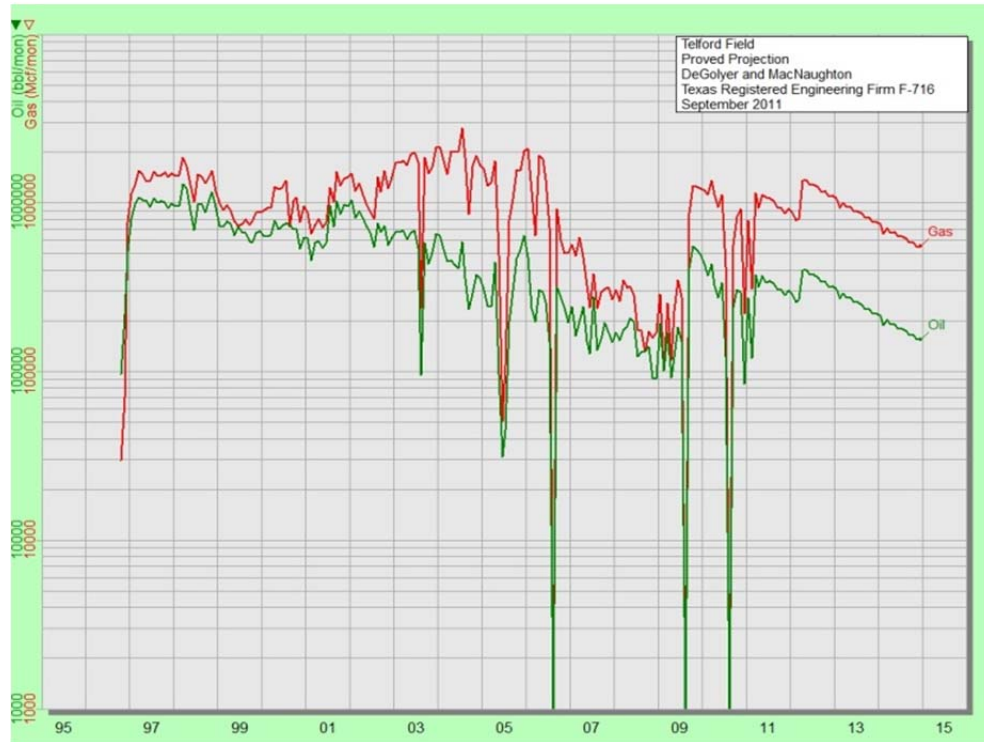
The Telford field, which is located in license Blocks 15/22 and 15/21a immediately south of the Scott field, includes the West, Central, East Telford, and Marmion areas. The fields have tested oil from the Piper and Scott sands in wells drilled by Hess and Amoco. Hess assumed operatorship of the field following first oil production. The field is now operated by Nexen Inc.

The Telford field is a long, narrow structure lying immediately upthrown to the fault that forms the southern boundary of the Scott field. The Telford field, along with the Marmion, was developed as a satellite to the Scott field. The Scott field platform supplies processing and injection facilities for these fields. Oil production ceased in Marmion in 2001.

The West Telford area began gas-cap blowdown in late 2002. The Central Telford area has been on production since December 1996. Successful water shut-off workovers have been performed in the field with good success; however, water production continues to increase and future water shut-off workover opportunities are limited. The East Telford area, which produces from the 15/22–G17z, has begun to produce water. The G19 and G20 wells have been drilled in East Telford. The G19 is on production and both wells are awaiting an additional flowline to allow production from the wells simultaneously.

Proved reserves were estimated based on the performance of the existing wells in the field, while probable and possible reserves estimates include consideration of an additional flowline, workovers, and blowdown.

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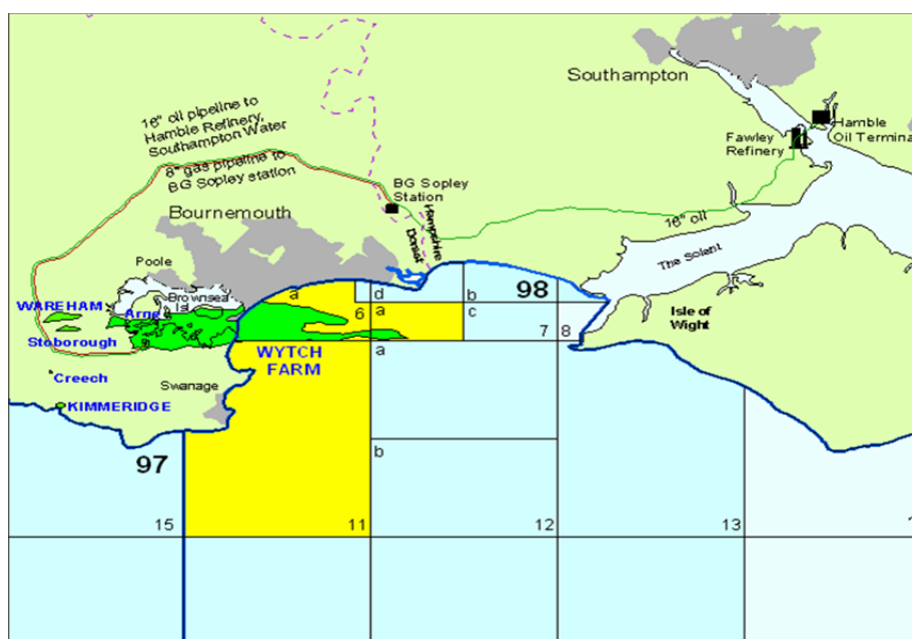


Wytch Farm and Wareham Fields

The Wytch Farm field, which is operated by BP, is a coastal oil field in Dorset with production from onshore and offshore areas. The majority of the production is from the Sherwood reservoir with small contributions from the Bridport and Frome reservoirs. The field has been producing since 1990 and reliable production trends have been established. Condensate and oil are exported by pipeline to Hamble, gas is exported directly into the British Gas network, and liquefied petroleum gas is exported by tank car. Since 2005, the Wytch Farm field operations have been gas deficient, and all produced gas is used for operations. Reservoir pressure is augmented by water injection. Development drilling is ongoing, and emphasis has been placed on the use of horizontal wells to optimize recovery.

The Wareham field is located about 10 kilometers west of the Wytch Farm field. The field was discovered in 1964 and began producing in 1991. Produced fluids were sent via pipeline to the Wytch Farm field for processing. The Wareham field is not currently producing.

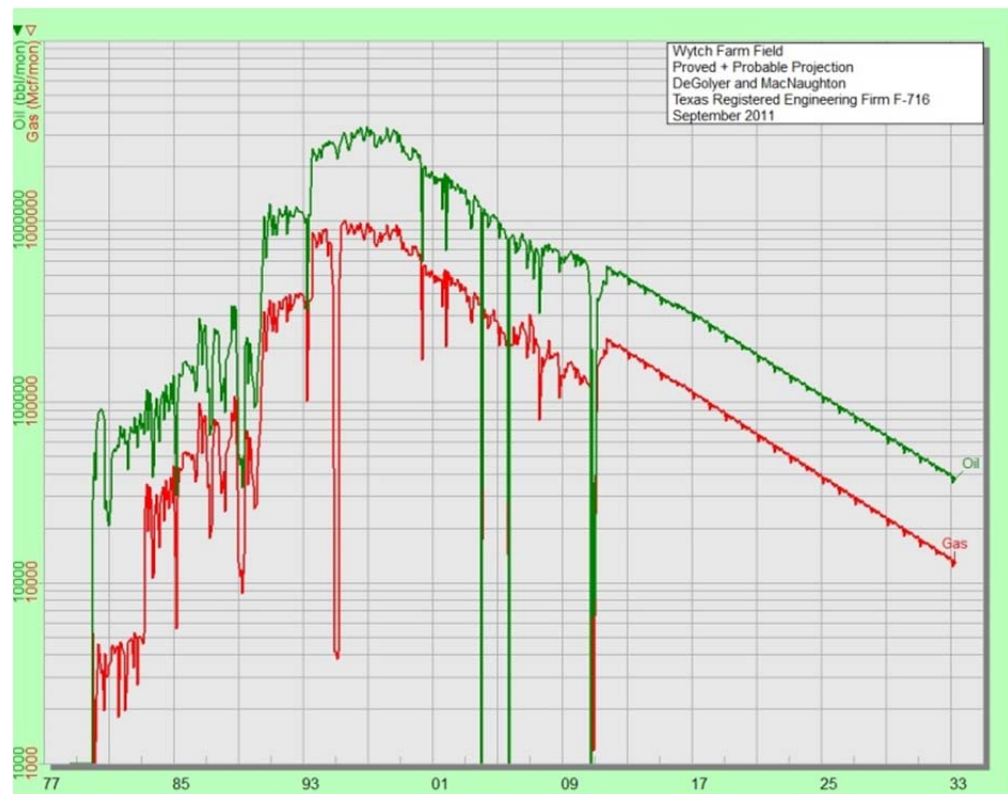
In May 2011, BP announced that an agreement had been reached with Perenco by which BP would divest its approximately 68-percent working interest in certain assets located onshore and offshore of Dorset, England, which is inclusive of the Wytch Farm area assets (Wytch Farm, Wareham, and Beacon fields). Premier has represented that it has served a pre-emption notice to BP in order to acquire an additional 17.715-percent working interest in the Wytch Farm area assets, bringing its working interest to approximately 30.1 percent. Premier has also represented that it has reached an agreement with Perenco setting out the basis on which the acquisition of the Wytch Farm area assets will be executed. The effective date of the acquisition is expected to be January 1, 2011. Premier has represented that the transaction is expected to close in December 2011. At the request of Premier and on the basis of the pending transaction, estimates of working-interest reserves and contingent resources, and net present worth were prepared based on a working interest of 30.1 percent.



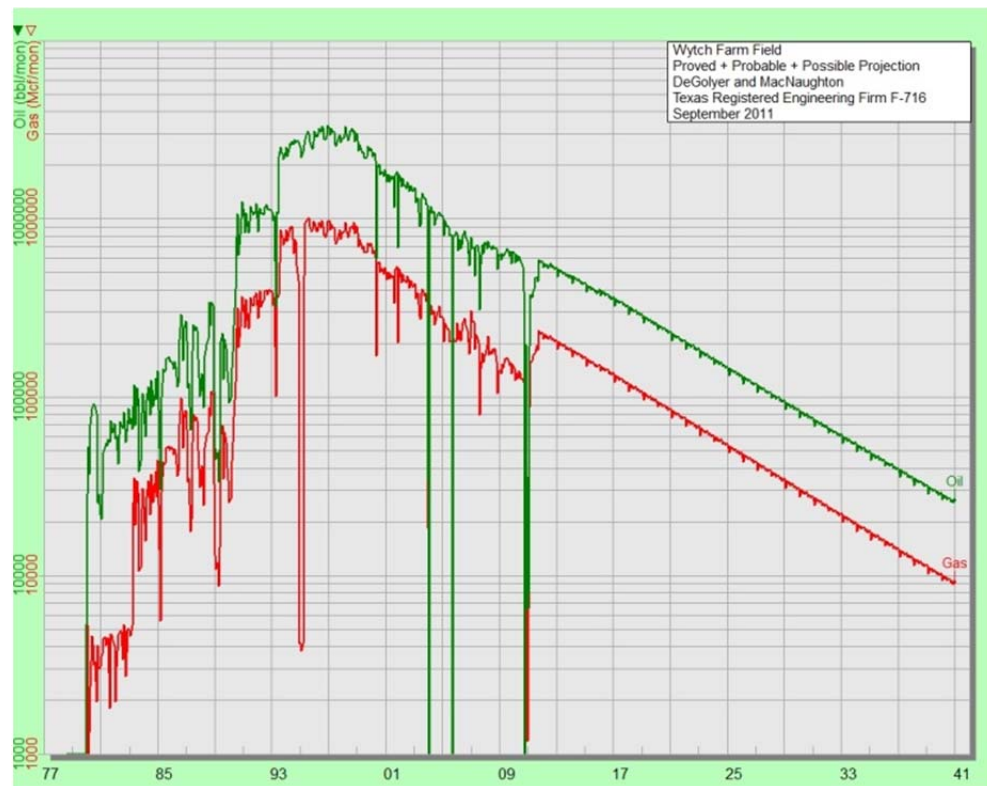
Location Map – courtesy of Premier

Estimates of proved reserves are based on extrapolating production performance trends of existing wells, while probable reserves have been estimated for additional infill locations, improved performance, and water handling optimization. Possible reserves have been estimated to reflect better performance in the field. A satellite field, Wareham, has been productive in the Sherwood Formation; however, no reserves have been estimated for the field.

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Vietnam

Chim Sao Field

The Chim Sao and Dua fields are located in Block 12E and 12W in the Nam Con Son Basin offshore Vietnam. The Chim Sao field was discovered in 2006 with the 12E-CS-1X well, which encountered oil-bearing strata in the Early Miocene Dua Sands at a depth of around 3,500 meters subsea. Two appraisal wells were drilled to delineate the field (12W-CS-2X and the 12E-CS-1X-ST1 wells).

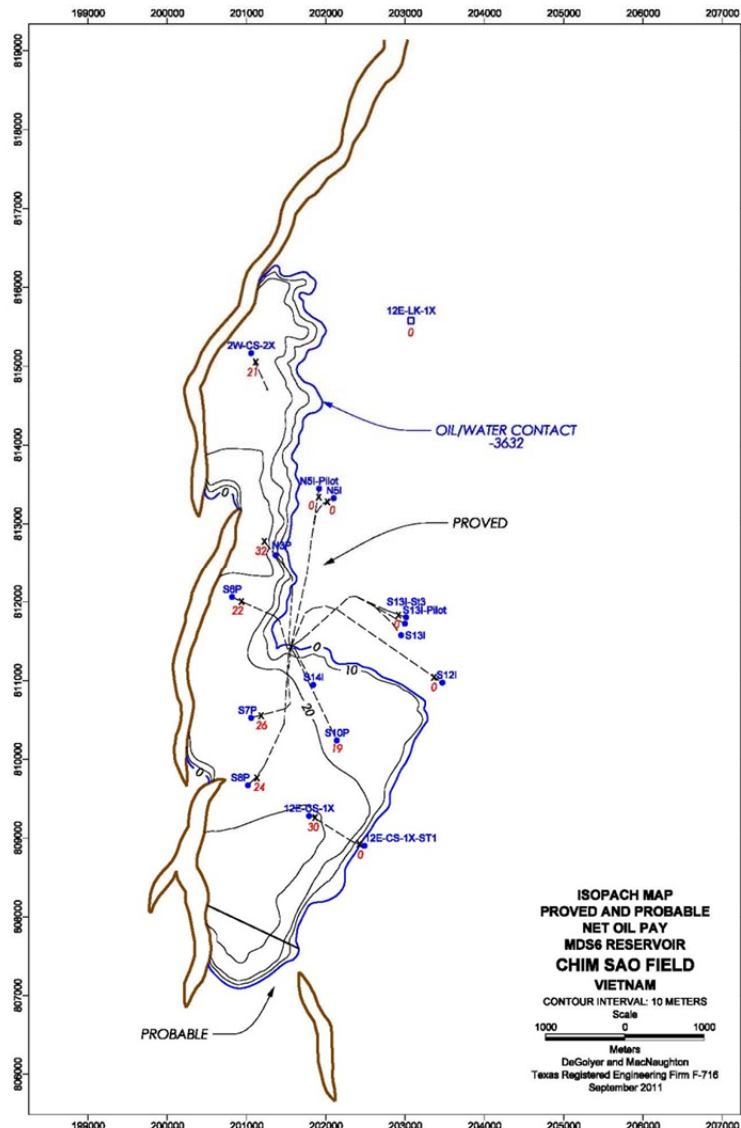


Ownership of the block has changed hands several times prior to Premier farming in to the block in 2004. Currently, Premier holds a 53.125-percent working interest in the PSC area. Premier acquired a 3-D seismic survey in 2005 that has been used to update the structural interpretation of the framework of Dua field. In 2006, Premier acquired 1,505 kilometers of 2-D seismic data and in 2007, a 1,600 square kilometer survey over the Chim Sao field area. In 2006, Premier negotiated with the Vietnam Oil and Gas Corporation to merge the Block 12E PSC into the Block 12W PSC and reached agreement in February 2007. An amended Investment License was issued on June 14, 2007, ratifying the merger.

The Chim Sao field consists of a three-way dip closure against a west-bounding fault (trending north to south). There are a number of antithetic faults

of the Aquitanian and early Burdigalian section. The Middle Dua sands in this field are subdivided into seven sand-rich intervals (MDS0 through MDS6) and are overlain by the Middle Dua shale interval. Oil-bearing intervals are the MDS0, MDS1, MDS5 and MDS6 sands. Oil has been sampled via wireline formation tester from all but the MDS0 sand. Drill stem testing of the MDS6 reservoir in the -1X well flowed 2,133 BOPD with a gravity of 41.7 °API. The MDS6 was tested in the -1X flowing at a rate of 2,725 BOPD with a gravity of 40.1 °API.

Estimates of OOIP were made using limiting elevations associated with LKO or OWC. OOIP associated with proved reserves was based on LKO in the absence of a penetrated OWC. Projected OWCs from wireline pressure data were used in estimating OOIP associated with probable and possible reserves. Where structural or stratigraphic uncertainty was present due to limited well control, those areas were considered for estimating probable or possible reserves. The following figures illustrate the distribution of OOIP used in estimating the various classifications of reserves.



After submitting an Outline for Development Plan in 2008 for approval, Premier subsequently revised its development plan to consider one rather than two wellhead platforms. Premier is finalizing the field development with five producers and two injectors drilled through mid-2011. An FPSO will be used for handling produced fluids and a gas export line will be used for gas sales after fuel usage. The wellhead platform, which has been installed, contains 20 slots (4 dual and 12 single slots) for wells and is set in approximately 96 meters of water depth. Initial development design is for nine producers and six injection wells. A single FPSO unit with storage capacity of 600 million barrels and rate capacities of 50,000 barrels of oil per day, 50 MMcf/d, and 90,000 barrels of water injection per day. A 10-inch

associated gas export line will tie into the Nam Con Son gas export line from TNK-BP's Lan Tay field to the Dinh Co Terminal. According to Premier, the field came online in October 2011 with rates reported to be 25,000 to 30,000 BOPD.

Estimates of reserves are based on volumetric interpretation of the in-place volumes in conjunction with the field development for waterflood operations. Material balance modeling software was used to prepare forecasts based on special core analysis data, well productivities, and future operating parameters in order to estimate a range of recovery factors. Variations in the estimated residual oil saturation as a proxy for volumetric sweep efficiency uncertainty were the primary means of assessing recovery factors. Forecasts considered a peak off-take rate of 25,000 BOPD from nine producers and six injectors. The waterflood is planned to be primarily a peripheral flood with downdip producers converted to injectors as they water out.

Premier is also assessing potential oil quantities in the fault block northwest of the Chim Sao closure, which have been penetrated but not logged. In addition, the MDS1 reservoir is being considered for development pending approval from the partners in the block. These quantities have been classified as contingent resources.

The estimated Premier gross proved, probable, and possible reserves for the properties evaluated in this report using the base case price scenario, as of September 30, 2011, are summarized as follows, expressed in thousands of barrels (Mbbl) and millions of cubic feet (MMcf), as well as in thousands of barrels of oil equivalent (MBOE):

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Country Field	Premier's Gross Reserves – Base Case								
	Oil, Condensate, and NGL			Marketable Gas			Oil Equivalent		
	Proved (Mbbl)	Probable (Mbbl)	Possible (Mbbl)	Proved (MMcf)	Probable (MMcf)	Possible (MMcf)	Proved (MBOE)	Probable (MBOE)	Possible (MBOE)
Indonesia									
Natuna Block 'A'	6,903	6,292	0	799,605	471,552	0	158,114	95,466	0
Kakap	5,520	9,742	3,848	87,968	55,409	42,644	23,912	21,327	12,764
North Sumatra Block 'A'	11,227	3,071	976	492,783	134,767	42,831	92,598	25,324	8,048
Total Indonesia	23,650	19,105	4,824	1,380,356	661,728	85,475	274,624	142,117	20,812
Mauritania									
Chinguetti	3,179	5,480	6,204	0	0	0	3,179	5,480	6,204
Norway									
Bream	0	26,670	48,950	0	0	0	0	26,670	48,950
Froy	0	50,180	19,934	0	18,665	8,201	0	53,574	21,425
Total Norway	0	76,850	68,884	0	18,665	8,201	0	80,244	70,375
Pakistan									
Badhra/Bhit	394	81	74	417,030	86,711	82,396	70,401	14,637	13,906
Kadanwari	32	17	46	89,827	48,034	128,614	15,695	8,393	22,472
Qadirpur/Qadirpur Deep	1,297	868	215	810,849	614,857	153,265	124,023	93,929	23,412
Zamzama	4,397	1,677	0	807,932	378,073	0	125,891	58,530	0
Zarghun South	10	12	23	19,798	17,901	26,333	3,265	2,955	4,353
Total Pakistan	6,130	2,655	358	2,145,436	1,145,576	390,608	339,275	178,444	64,143
United Kingdom									
Balmoral	1,988	885	841	0	0	0	1,988	885	841
Beacon	3,182	5,588	4,289	340	598	459	3,244	5,697	4,372
Brenda	2,144	4,093	3,442	853	1,804	1,449	2,299	4,421	3,705
Caledonia	1,019	749	1,669	204	150	334	1,056	776	1,730
Greater Catcher Area	24,342	55,668	47,822	6,993	15,462	13,526	25,613	58,479	50,281
Huntington	22,326	9,786	7,136	19,870	8,709	6,351	25,939	11,369	8,291
Kyle	4,432	1,292	834	7,254	1,642	1,029	5,999	1,647	1,056
Nelson	14,482	4,851	5,473	0	0	0	14,482	4,851	5,473
Nicol	937	443	675	0	0	0	937	443	675
Rochelle	3,458	2,230	1,748	53,049	34,419	26,778	13,103	8,488	6,617
Scott	14,880	6,096	9,500	10,258	3,769	5,959	16,745	6,781	10,583
Stirling	552	398	417	0	0	0	552	398	417
Telford	11,352	10,616	4,046	31,369	32,212	10,931	17,055	16,473	6,033
Wyth Farm/Wareham	36,340	20,147	12,274	1,754	319	141	36,659	20,205	12,300
Total United Kingdom	141,434	122,842	100,166	131,944	99,084	66,957	165,671	140,913	112,374
Vietnam									
Chim Sao	35,860	22,269	12,352	33,281	31,085	10,914	42,374	28,353	14,488
Grand Total	210,253	249,201	192,788	3,691,017	1,956,138	562,155	825,123	575,551	288,396

Notes:

1. Probable and possible reserves have not been risk adjusted to make them comparable to proved reserves.
2. Marketable gas has been converted to oil equivalent on a field-by-field basis.

Estimates of the working-interest proved, probable, and possible reserves for the base case price scenario, as of September 30, 2011, evaluated herein are listed as follows, expressed in thousands of barrels (Mbbl) or millions of cubic feet (MMcf), as well as in thousands of barrels of oil equivalent (MBOE):

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Country Field	Premier's Working-Interest Reserves – Base Case								
	Oil, Condensate, and NGL			Marketable Gas			Oil Equivalent		
	Proved (Mbbl)	Probable (Mbbl)	Possible (Mbbl)	Proved (MMcf)	Probable (MMcf)	Possible (MMcf)	Proved (MBOE)	Probable (MBOE)	Possible (MBOE)
Indonesia									
Natuna Block 'A'	1,979	1,804	0	229,223	135,180	0	45,327	27,368	0
Kakap	1,035	1,827	722	16,494	10,389	7,996	4,483	3,999	2,394
North Sumatra Block 'A'	4,678	1,280	407	205,328	56,153	17,846	38,583	10,552	3,354
Total Indonesia	7,692	4,911	1,129	451,045	201,722	25,842	88,393	41,919	5,748
Mauritania									
Chinguetti	258	445	504	0	0	0	258	445	504
Norway									
Bream	0	5,334	9,790	0	0	0	0	5,334	9,790
Froy	0	25,090	9,967	0	9,333	4,101	0	26,787	10,713
Total Norway	0	30,424	19,757	0	9,333	4,101	0	32,121	20,503
Pakistan									
Badhra/Bhit	24	5	4	25,022	5,203	4,944	4,224	878	834
Kadanwari	5	3	7	14,184	7,585	20,308	2,478	1,326	3,548
Qadirpur/Qadirpur Deep	62	41	10	38,515	29,206	7,280	5,891	4,461	1,112
Zamzama	412	157	0	75,744	35,444	0	11,802	5,487	0
Zarghun South	0	0	1	742	671	987	122	110	163
Total Pakistan	503	206	22	154,207	78,109	33,519	24,517	12,262	5,657
United Kingdom									
Balmoral	1,553	691	657	0	0	0	1,553	691	657
Beacon	958	1,682	1,291	102	180	138	977	1,715	1,316
Brenda	2,144	4,093	3,442	853	1,804	1,449	2,299	4,421	3,705
Caledonia	1,019	749	1,669	204	150	334	1,056	776	1,730
Greater Catcher Area	12,171	27,834	23,911	3,497	7,731	6,763	12,807	29,240	25,141
Huntington	8,930	3,914	2,854	7,948	3,484	2,540	10,375	4,547	3,316
Kyle	1,773	517	334	2,902	657	412	2,400	659	423
Nelson	241	81	91	0	0	0	241	81	91
Nicol	656	310	473	0	0	0	656	310	473
Rochelle	519	335	262	7,957	5,163	4,017	1,966	1,274	992
Scott	3,249	1,331	2,074	2,240	823	1,301	3,656	1,481	2,311
Stirling	379	273	286	0	0	0	379	273	286
Telford	180	168	64	498	511	173	271	261	95
Wytch Farm/Wareham	10,938	6,064	3,694	528	96	42	11,034	6,081	3,702
Total United Kingdom	44,710	48,042	41,102	26,729	20,599	17,169	49,670	51,810	44,238
Vietnam									
Chim Sao	19,051	11,830	6,562	17,681	16,514	5,798	22,512	15,062	7,697
Grand Total	72,214	95,858	69,076	649,662	326,277	86,429	185,350	153,619	84,347

Notes:

1. Probable and possible reserves have not been risk adjusted to make them comparable to proved reserves.
2. Marketable gas has been converted to oil equivalent on a field-by-field basis.

Field Discussion – Contingent Resources

Following is a discussion of the contingent resources estimated herein. All of the following contingent resources have an economic status of “Undetermined.”

Indonesia

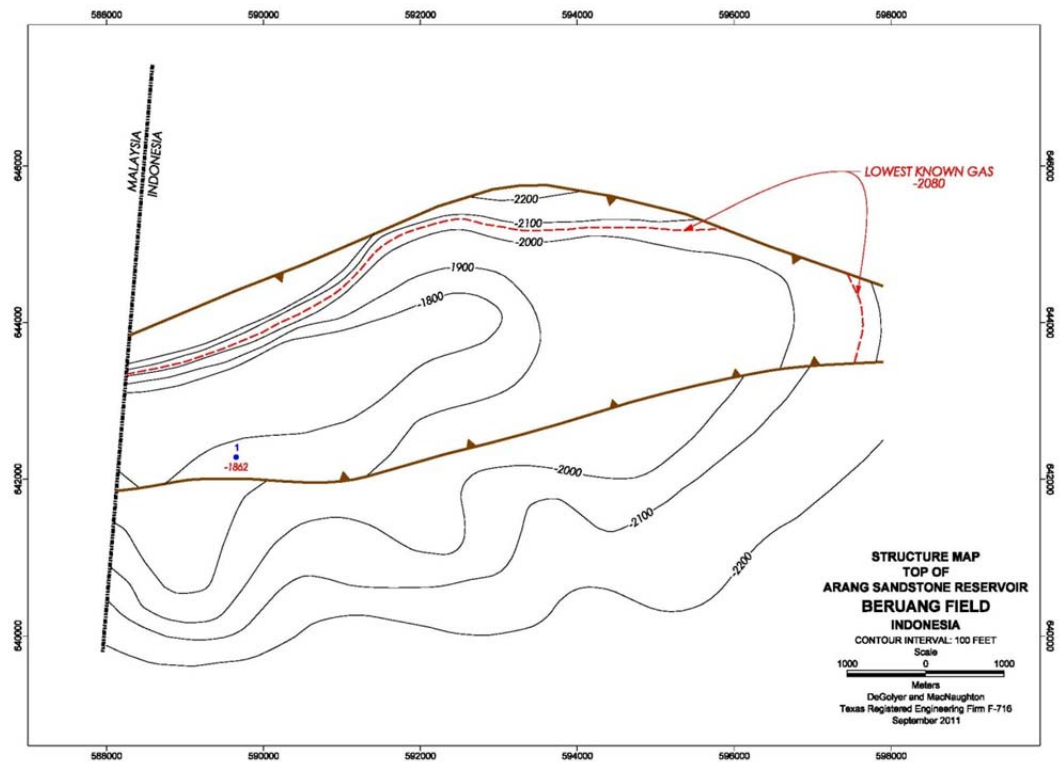
Natuna Sea Block ‘A’

The Beruang, Lembu Peteng, and Macan Tutul fields are not included in the current Natuna Sea Block ‘A’ gas sales agreements. All quantities for these three fields have been classified as contingent resources. For fields included in the sales agreements, quantities in excess of the sales agreements have also been classified as contingent resources. This includes quantities in the Anoa, Bison, Gajah Baru, Gajah Puteri, Iguana, Naga, and Pelikan fields.

Beruang Field

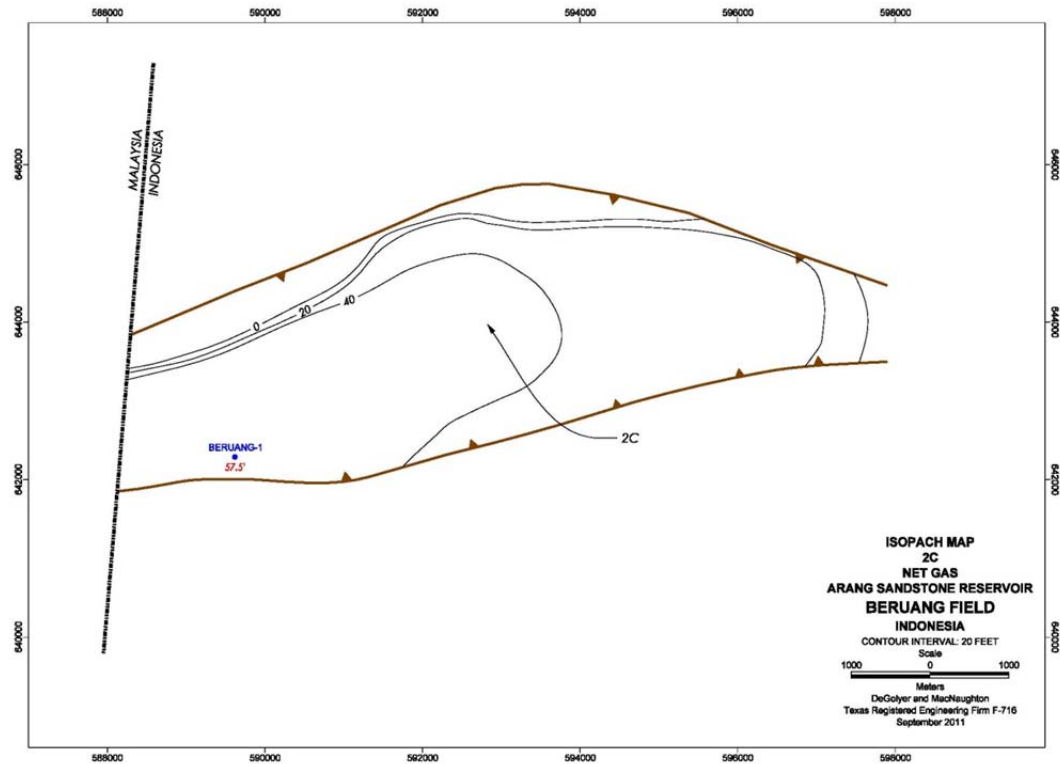
The Beruang field is an east-west, elongate, breached anticlinal culmination with four-way dip closure located north of the Anoa field. Pay is found in channel sands of the Lower Arang Formation. The Beruang structure was identified from 2-D seismic data as a faulted anticline. The field was discovered in 1982 by Sumatra Gulf with the crestally located Beruang-1 well and has seen no further drilling. The location of this well and the structural configuration of the Lower Arang is shown below.

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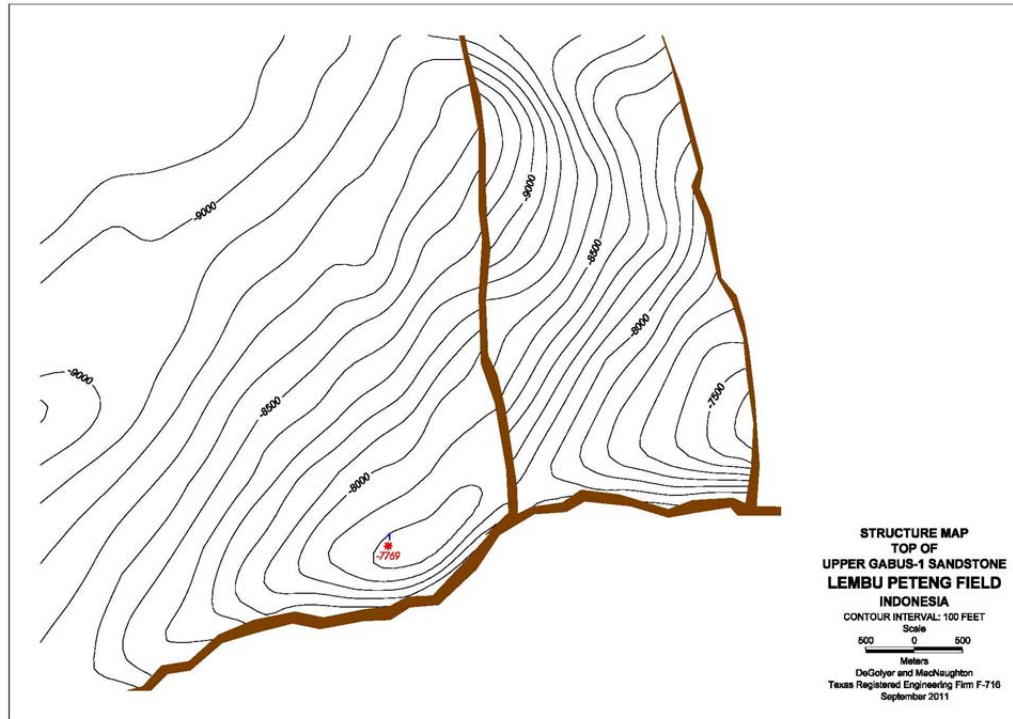
One gas reservoir was mapped for the Beruang evaluation to a LKG at 2,080 feet subsea and to an updip structurally coherent seismic amplitude limit, which may represent a loss of effective reservoir porosity or permeability near the crestal portion of the reservoir. The volume estimated between the LKG and the updip amplitude limit is included in the 2C contingent resources estimate. Shown below is a net pay map of the Lower Arang reservoir in the Beruang field.

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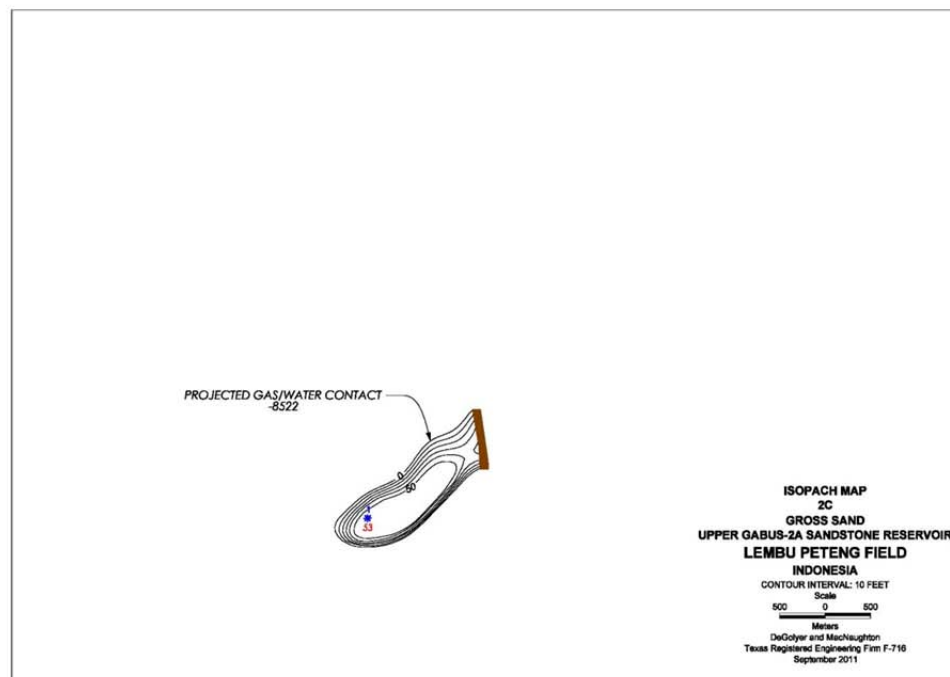
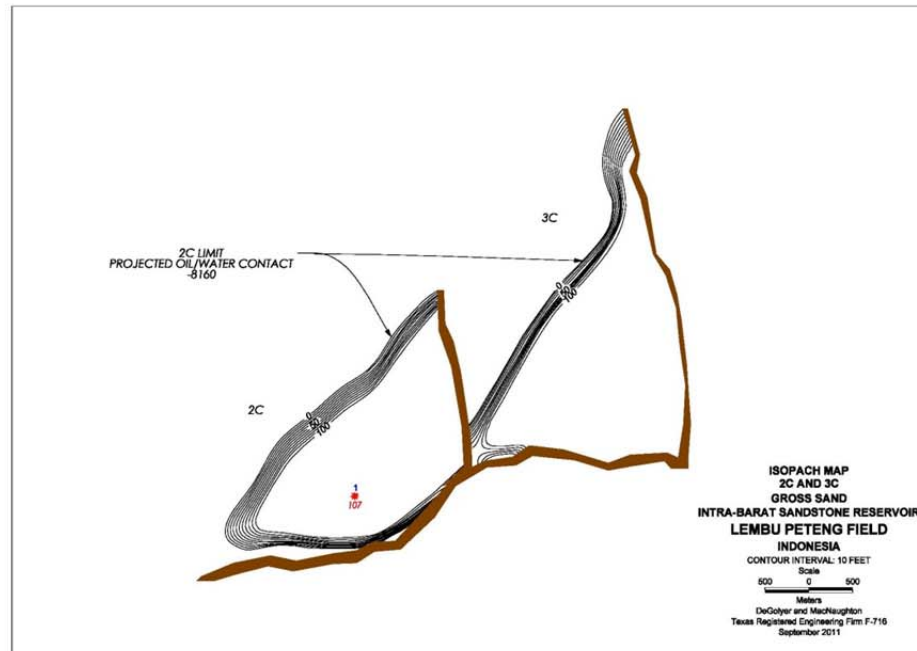
Lembu Peteng Field

The Lembu Peteng field, located 35 kilometers southeast of the Anoa field, was discovered in 2006 when the Lembu Peteng-1 well encountered an oil sand in the Intra Barat Formation at 7,800 feet subsea and encountered four gas sands in the Gabus Formation at depths ranging from 8,250 feet subsea to 8,850 feet subsea. Shown below is a representative structure map of the Upper Gabus-1 Formation.



Total net oil thickness and gas thickness found in the well are approximately 50 feet and 120 feet, respectively. Average porosity estimates in these reservoir sands range from approximately 10 to 12 percent, and average water saturation estimates range from approximately 24 to 52 percent. Estimates of contingent resources were based on the volumetric method using openhole logs, wireline pressures, DST data, and Premier's structural interpretation of the field. Shown below are net pay isopach maps of the Intra-Barat and Upper Gabus-2A reservoirs.

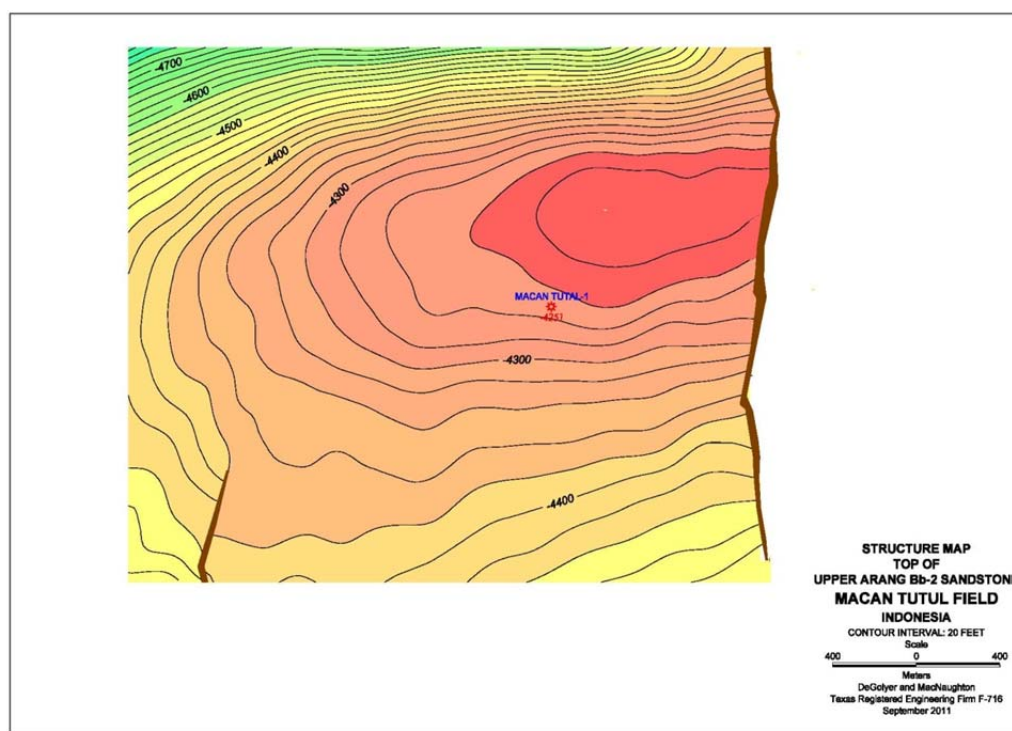
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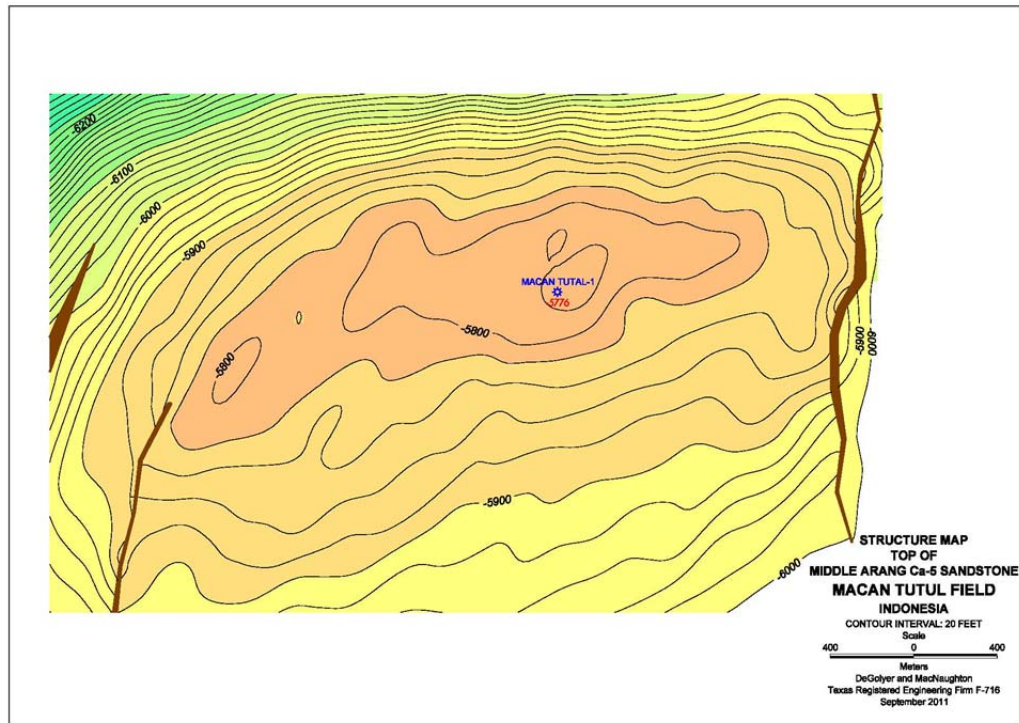


The Lembu Peteng-1 flowed at rates of 9 MMcf/d of gas and 600 barrels of condensate per day during a DST of two gas sands that lie at depths of 8,270 and 8,450 feet subsea and have a total of 85 feet of pay. In a DST of the oil sand, the well flowed at rates of 600 BOPD and 0.3 MMcf/d of gas. No other wells have been drilled in the field.

Macan Tutul Field

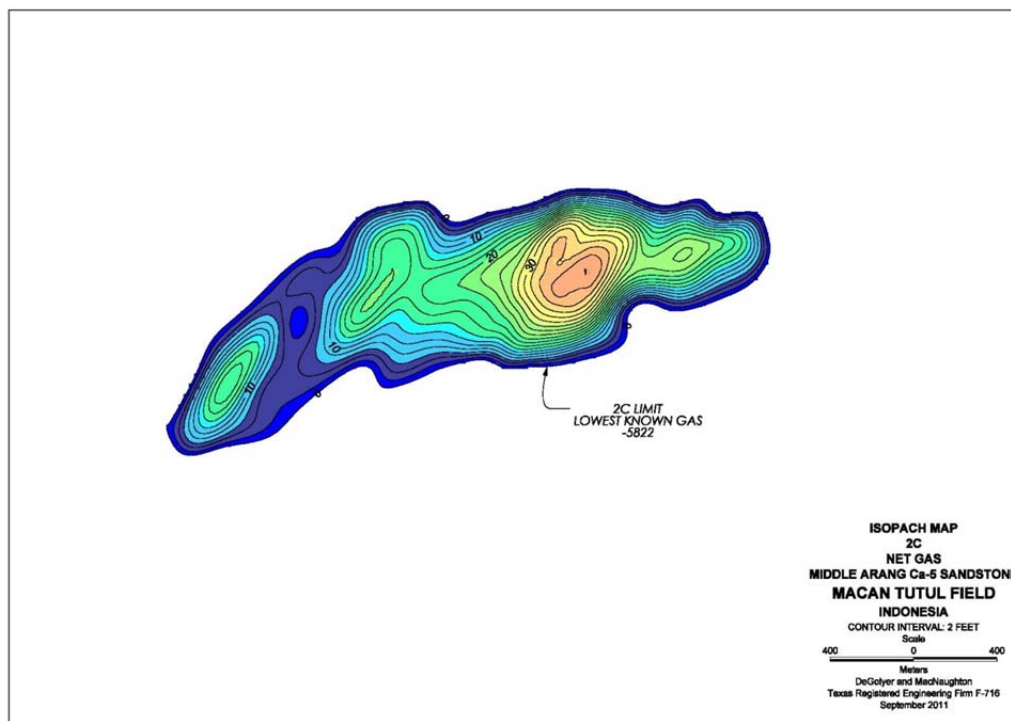
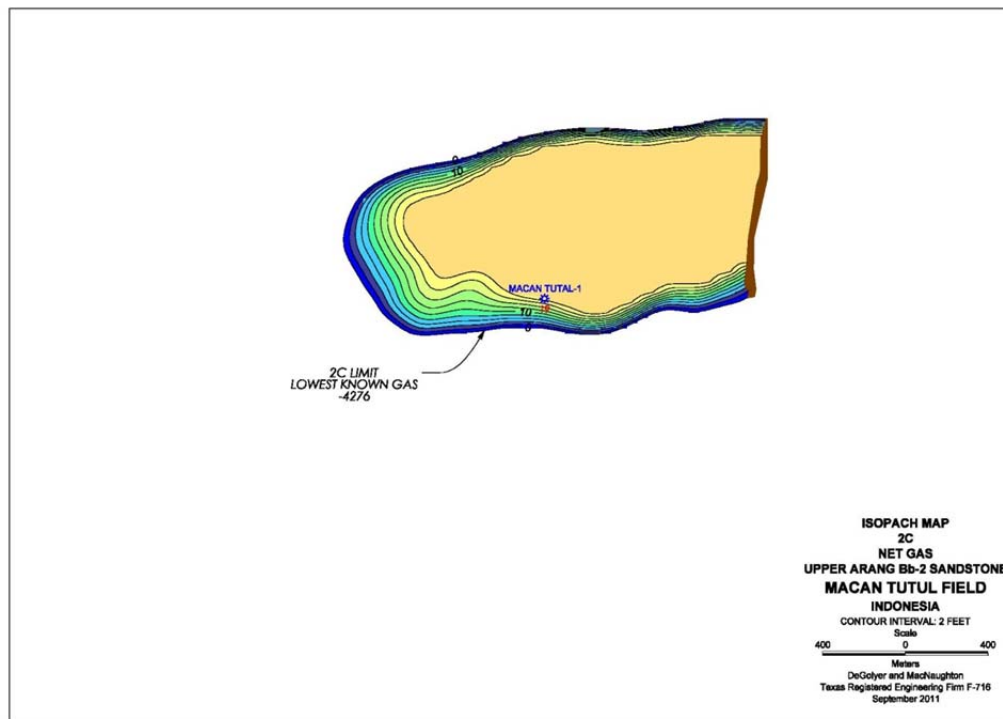
The Macan Tutul field, located 10 kilometers south of the Anoa field, was discovered in 2006 when the Macan Tutul-1 well encountered seven gas sands in the Arang Formation at depths ranging from 4,250 feet subsea to 6,150 feet subsea. Shown below are structure maps of the Upper Arang Bb-2 and Middle Arang Ca-5 Formations.





Total net gas thickness found in the well is approximately 110 feet. Average porosity estimates in these gas sands range from approximately 20 to 25 percent, and water saturation estimates range from approximately 39 to 67 percent. Estimates of contingent resources were based on the volumetric method using openhole log data, wireline pressure data, and Premier's structural interpretation of the field. No DSTs were carried out in the well. No other wells have been drilled in the field. Shown below are net gas isopach maps of the Upper Arang Bb-2 and Middle Arang Ca-5 reservoirs.

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Kakap Fields

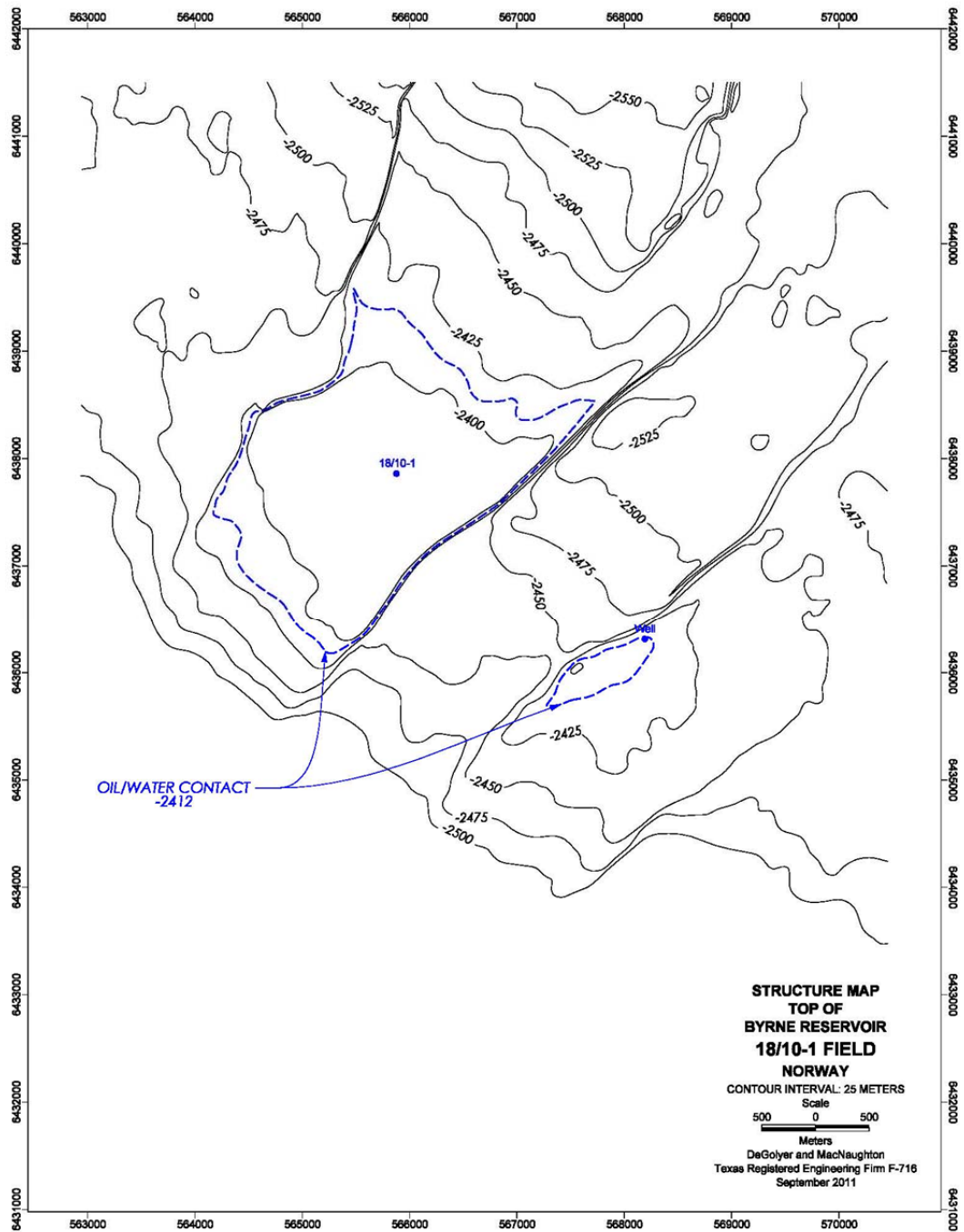
Quantities in excess of the GSA 1 and volumes that are not economically recoverable are considered contingent resources. This includes volumes in various Kakap fields.

Norway

18/10 Discovery

This discovery in Block 18/10 offshore Norway is in the Egersund Basin, near the Yme and Bream fields. Well 18/10-1 was drilled in 1980 and was tested at 1,855 BOPD in the Bryne reservoir. A considerable range of area, thickness, and recovery ranges can be projected from available data. There are several fault blocks indicated by seismic structural mapping, and the discovered resources are limited to the large fault block containing the discovery well. Consideration of potential appraisal drilling or a development plan is in progress. It is anticipated that synergies with nearby fields will facilitate development, but there is significant uncertainty in what the eventual plan will be. Contingent resources have been estimated based on volumetric estimates anchored in the thickness and rock properties in the discovery well, with recovery factors ranging from 20 to 33 percent of the OOIP.

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Pakistan

Kadanwari Field

Contingent resources have been estimated for the Kadanwari field based on production that is estimated to occur after the expiration of the lease term.

Contingent resources have also been estimated based on potential development of the tight gas sands found in the Lower Goru C, D, F and G sands of the field. The G sand represents the largest of the in place volumes identified. The operator currently is planning to stimulate the K-1 well using a multiple-fracture treatment in 2011. The K-1 well will be re-entered and completed in the Lower Goru G sands and fracture treated. Premier has represented that both vertical and horizontal wells will be assessed using existing wells and new drills during the development process with a total of 52 wells initially identified for the work program. Estimates of contingent resource quantities were prepared based on a range of potential production forecasts reflecting preliminary simulation results provided by Premier. Low, Best, and High case contingent resources were estimated using probabilistic methods where distributions were prepared to represent geological, petrophysical, and reservoir engineering parameters. The number of wells used in the development was varied between 26 and 78 wells with the most likely number of 52 wells.

Forecasts of potential contingent resources recovery were prepared based on “type” wells brought online according to the development scenario provided by Premier. Premier provided estimates of a successful single well of U.S.\$16 million which includes U.S.\$10 million in drilling costs, U.S.\$3 million in completion costs including fracture treatment, and an additional U.S.\$3 million for well tie-in and wellhead facilities. The drilling campaign is scheduled to drill the first 36 wells by the end of 2015 with the balance drilled by 2022.

Qadirpur Field

Contingent resources quantities have been estimated for the Qadirpur field for gas and condensate quantities that could be produced after the expiration of the primary production period.

In 2006, the partnership drilled the Qadirpur Deep-1 well to test for the presence of hydrocarbon-bearing sands in the Lower Goru and Sembar Formations. Because of the limitations on available equipment with which to safely test the deeper sands in this well, the well stood idle until late in 2008 when the well was

drill-stem tested. DST 2 tested the Sembar Sand-5 reservoir with reasonably good results. The well tested at roughly 4.3 MMcf/d with a flowing surface pressure of around 600 to 620 psia. After placing the well on production initially, the well has since ceased flowing due to poor reservoir rock properties. Contingent resources have been estimated for potential development options for the non-delineated area of this field in the Sembar Sand-5 reservoir.

Zamzama Field

Contingent resources have been estimated for the Zamzama field based on the limits of the gas contracts currently in place. Reserves were limited to the contracted volumes. Those quantities of recoverable gas not covered by the contracts were classified as contingent resources. These contingent resources have an economic status of Undetermined and have been forecast based on the existing field performance expectations but after the gas sales agreements are no longer in effect.

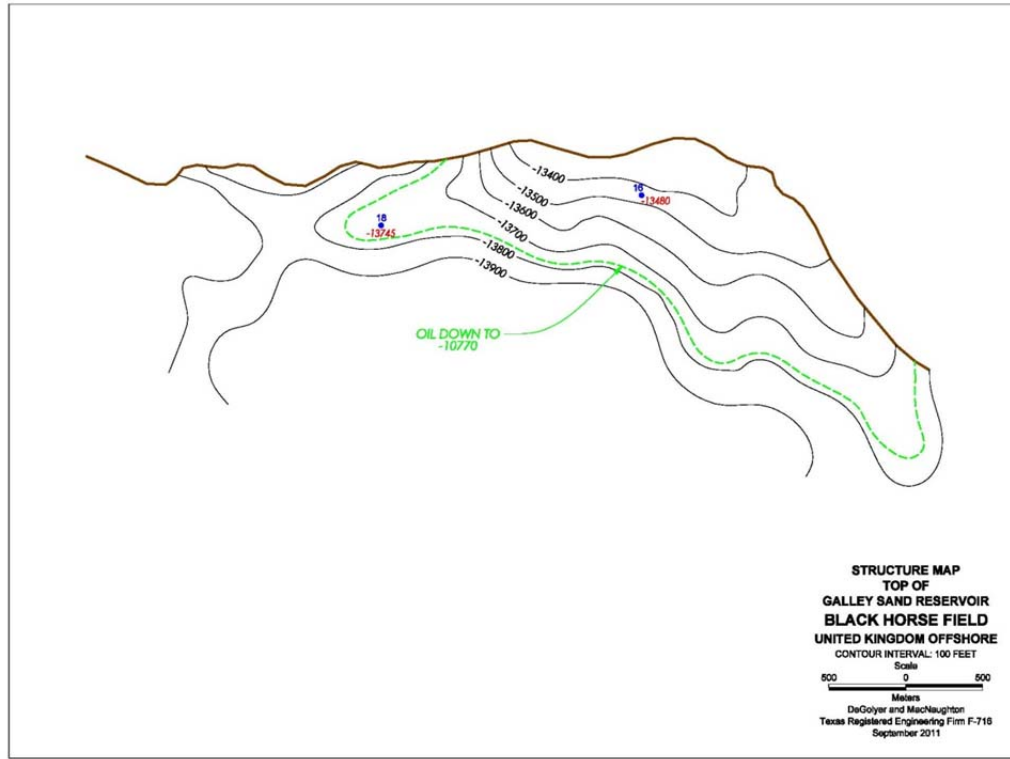
United Kingdom

Premier owns interests in the Blackhorse, Bladon, Buale, Caledonia, Fyne and Satellites (Dandy North, Dandy South, area 4), Huntington Deep, Kyle, Ptarmigan, and Solan fields.

Blackhorse Field

The Blackhorse field is located in Block 15/22 of the United Kingdom Central North Sea. The field is in about 500 feet of water, approximately 120 miles northeast of Aberdeen. The discovery well, 15/22-16, was drilled and tested in 2002 and found oil-bearing Dirk and Galley sandstones at approximately 13,500 feet TVDSS. A drill stem test measured 6,500 BOPD of 40 °API oil in the discovery well. A successful confirmation well, 15/22-18, was tested at 5,200 BOPD in 2005.

The Blackhorse structure is a three-way dip closure from east to west, bounded by a closing fault to the north. The reservoirs are Upper Jurassic deep marine turbiditic sandstones and are overpressured and undersaturated. The Galley reservoir is limited downdip by an OWC at 13,770 feet TVDSS, and the Dirk is limited by an LKO at 13,740 feet TVDSS. The OOIP in the combined Dirk and Galley reservoirs is approximately 43 million barrels. A structure map on the top of Galley reservoir is shown below.



Blackhorse is currently viewed as upside to the Bugle development to optimize pipeline capacity as Bugle field depletes. As such, the estimated recoverable quantities from this discovery are classified as contingent resources, pending Bugle field development progress and an agreement for shared transportation. The likely field development includes converting the two appraisal wells to producers and drilling a third well. These wells would be tied into the 8-inch Bugle pipeline, which then is connected to the Scott field platform. First production from Blackhorse would be anticipated to begin in late 2015. Contingent resources have been estimated based on volumetric analysis, with 2C and 3C including projected contacts and full-structure development.

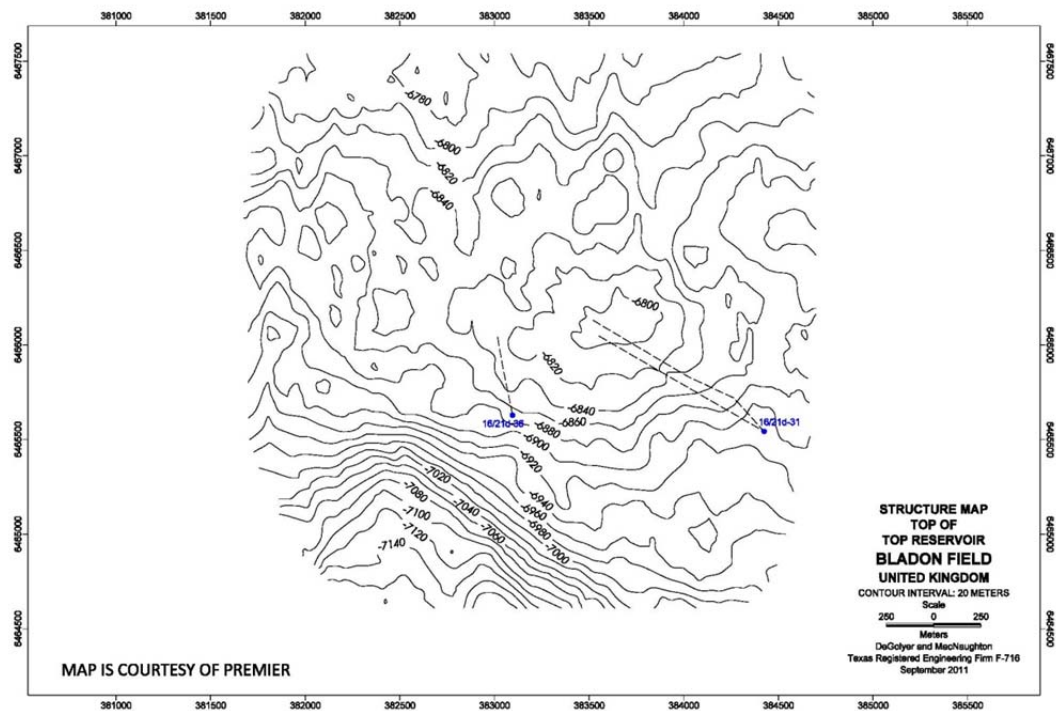
Bladon Field

Bladon is a shut-in field that was discovered by the Arco 16/21d-31 well in November 1996. It was developed in 1997 by a single horizontal well (16/21d-31z) with 996 feet of gross reservoir. This well was shut in at 80-percent water cut in May 2000 after producing 4.43 million barrels. An appraisal well (16/21d-36) was drilled in 2008 to test the east-west channel concept, with plans to complete this well

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as a horizontal producer. However, this well encountered only 16 feet of pay and was not completed.

The primary reservoir in the Bladon field is a Paleocene turbidite with 38.7 °API oil. The bubblepoint pressure of the reservoir oil is measured at 1,300 pounds per square inch absolute (psia), and the oil formation volume factor is estimated to be between 1.19 – 1.27 reservoir barrels per stock tank barrel. The field is split into two areas: the core area around the 16/21d-31 well, with the potential to flow at high water cuts, and the low-relief peripheral area that is expected to have very limited potential. A structure map on the top of the reservoir is shown below.



The potential re-development plan for Bladon would be a return of the 16/21d-31z well to production while managing the high water cut to be profitable. No additional wells are planned to be drilled.

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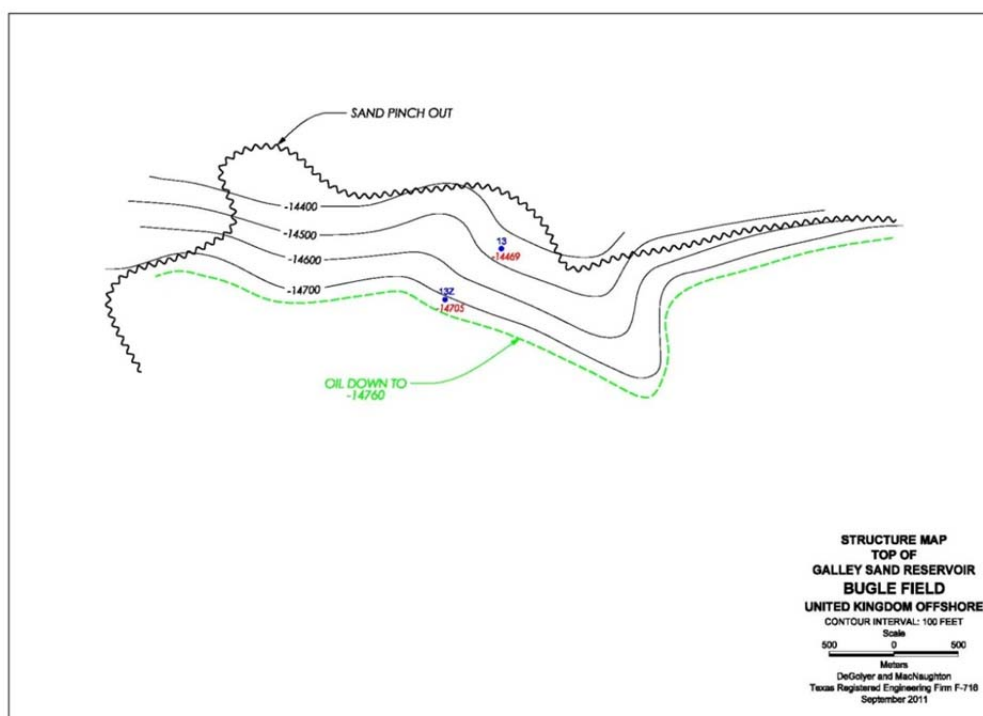


Recoverable quantities in the Bladon field are considered contingent resources due to the uncertainty economic viability of re-development, the lack of production facilities, and uncertain financial commitment. The 1C quantities are estimated from the performance analysis of the original development well, based on restoring the 16/21d-31z well to production at the previous production and decline rates. The 2C and 3C quantities were estimated considering potential performance upside in the well.

Bugle Field

The Bugle field is located in Block 15/23d of the United Kingdom Central North Sea approximately 125 miles northeast of Aberdeen. The discovery well, 15/23d-13 was drilled in 1996 into the Dirk and Galley sandstones at approximately 14,300 feet TVDSS. The well tested at 7,400 BOPD of 43 °API oil and 9 million cubic feet of solution gas. The discovery was confirmed by the 15/23d-13z sidetrack.

The Bugle structure is controlled by stratigraphic closure of the Late Jurassic Dirk and Galley sandstone reservoirs. The reservoirs were both formed by high density turbidite mass flows and are overpressured and undersaturated. The Bugle field is separated into North and South regions. Reserves are estimated for the Bugle South region. Shown in the following figure is a structure map on the top of the Galley reservoir.



Bugle South, discovered by 15/23d-13 and sidetrack 15/23d-13z, contains both Dirk and Galley reservoirs. The Dirk and Galley reservoirs are not in pressure communication in this area. Downhole pressure measurements in the Dirk indicate that the reservoir is in pressure communication between the 15/23d-13 and 15/23d-13z wells. The Dirk reservoir is mapped to an LKO at 14,617 feet TVDSS, as observed in the 15/23d-13z well. The average Dirk porosity and water saturation are 15 and 23 percent, respectively. Downhole pressure measurements in the Galley are inconclusive regarding pressure communication between the 15/23d-13 and 15/23d-13z wells; however, the reservoir is likely to be connected between the two wells. The Galley reservoir is mapped to an LKO/OWC at 14,760 feet TVDSS, which was observed in the 15/23d-13z. The Galley porosity and water saturation are 16

and 46 percent, respectively. Bugle South OOIP is estimated to be approximately 36.4 million barrels.

Development options for Bugle South call for drilling one more well and likely converting 15/23d-13 to a producer. The wells will be tied back to Scott platform via an 8-inch, 24-kilometer pipeline and riser. Low case contingent resources are based on a one-well scenario; best case contingent resources and high case contingent resources are based on a two-well scenario. First production is anticipated for early 2015. Contingent resources are based on deterministic volumetric analysis.

Caledonia Field

The Caledonia field was discovered in 1977 and is located in Block 16/26. The field has produced from a single horizontal well, 16/26-30y. This well was tied back to the Britannia platform in 2004. The well has produced about 6 MMbbl from the Forties sandstone. The well was shut in during 2008 because production was falling off quickly. There have been several new wells to appraise the northern, western, and eastern part of the field. The western flank requires further evaluation before quantities can be determined. This field has contingent resources estimated for the eastern lobe of the field.

Fyne Field and Satellites (Dandy North, Dandy South, Area 4)

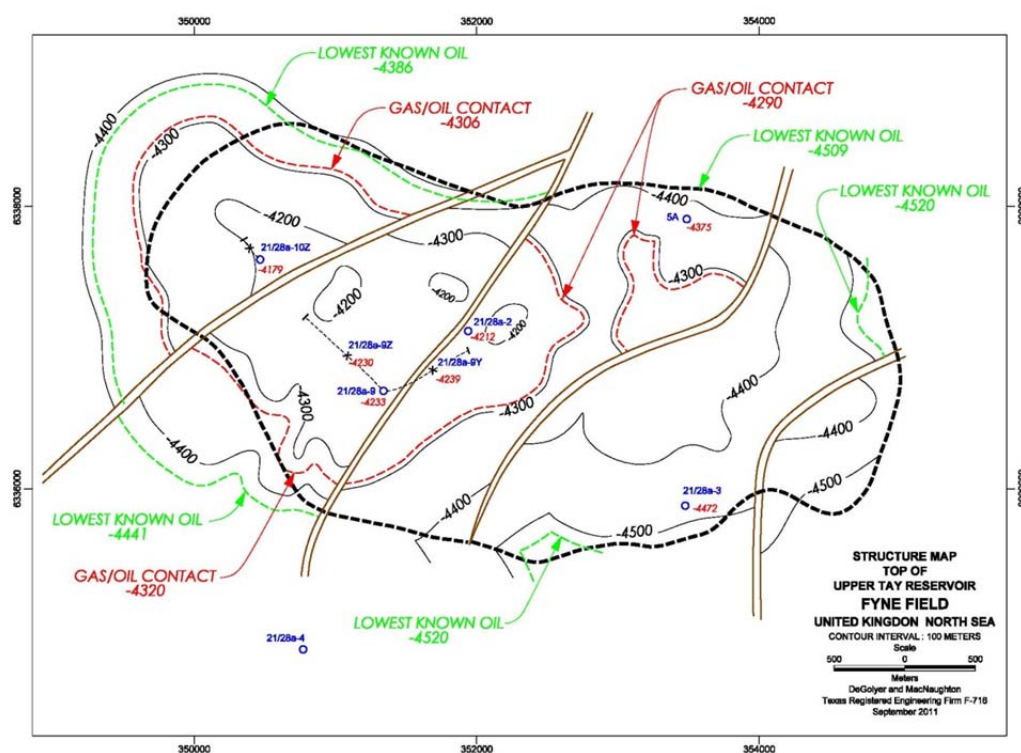
The Fyne field is located in the North Sea offshore the United Kingdom in block 21/28. This field was discovered by the 21/28a-1 well, and the primary reservoir is the Eocene Tay. The Fyne field includes several satellite discoveries (Dandy North, Dandy South, and Area 4), which are small accumulations discovered below shallow gas accumulations. The Fyne field itself has an extremely low bubblepoint pressure, which may be attributable to a seal breach and a gas chimney. The Fyne field and its satellites are being considered as a single development. The Fyne field has contingent resources pending an upcoming appraisal well and a commitment to develop.

The 1C contingent resources for the satellites are limited to seismic anomalies (areas below the gas clouds). The 2C and 3C quantities include structure interpreted beyond the limits of the seismic anomalies. Those quantities are anticipated to be produced by either the existing well or a development twin in the 1C case and by additional producers and injectors as required for 2C and 3C quantities, all of which would be tied back to the Fyne field.

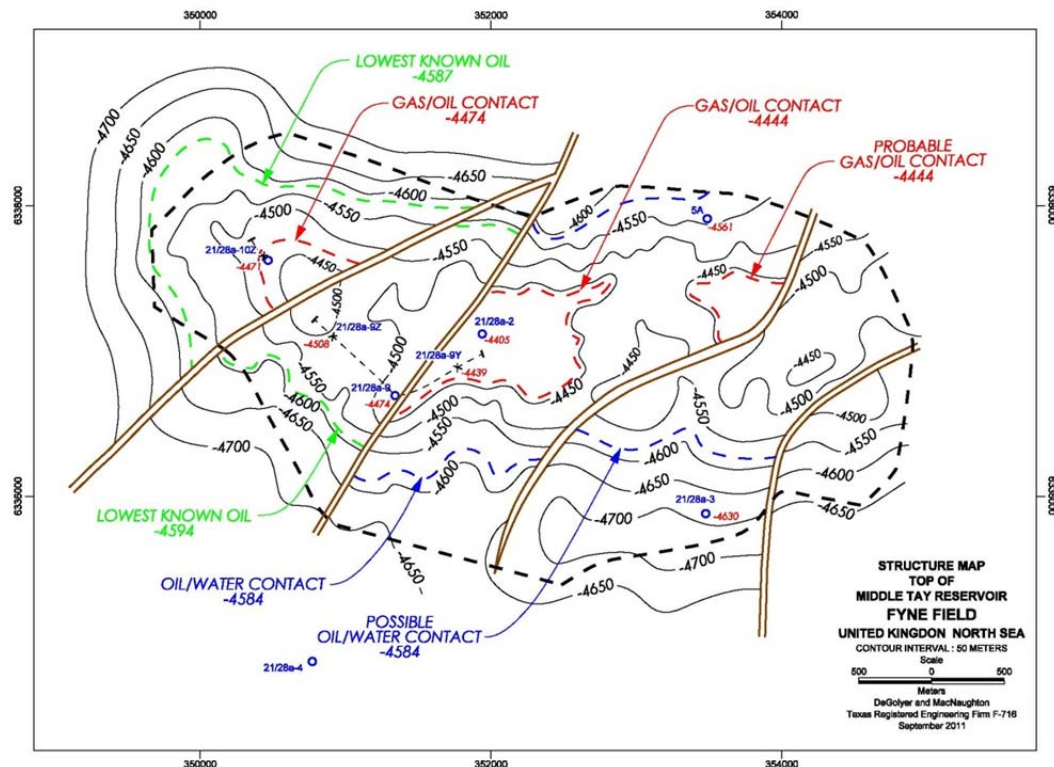
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The Fyne field's primary closure has five wells and three sidetracks that delineate this feature. The field has hydrocarbons in two reservoirs, the Upper Tay and the Middle Tay. These reservoirs have different fluid contacts and are not interpreted to be in pressure communication.

The Upper Tay reservoir has four fault blocks with hydrocarbons. On the west flank, the 10/10z wells have a GOC at 4,306 feet subsea and a LKO at 4,386 feet subsea. The fault block with the 9/9z wells has a GOC at 4320 feet subsea and an LKO at 4,441 feet subsea. The fault block with the 2 and 9y wells has a GOC at 4,290 feet subsea and an LKO at 4,509 feet subsea. The eastern fault block with the 3 well has an LKO at 4,520 feet subsea.



The Middle Tay reservoir has four fault blocks with hydrocarbon. On the west flank, the 10/10z wells have a GOC at 4,474 feet subsea and an LKO at 4,587 feet subsea. The fault block with the 9/9z wells has an LKO at 4,594 feet subsea. No gas cap has been penetrated on this block. The fault block with the 2 and 9y wells has a GOC at 4,444 feet subsea and an OWC at 4,584 feet subsea. The eastern fault block has the 3 well, which is downdip and wet at 4,630 feet subsea. A possible OWC at 4,584 feet subsea was interpreted updip of the 3 well.

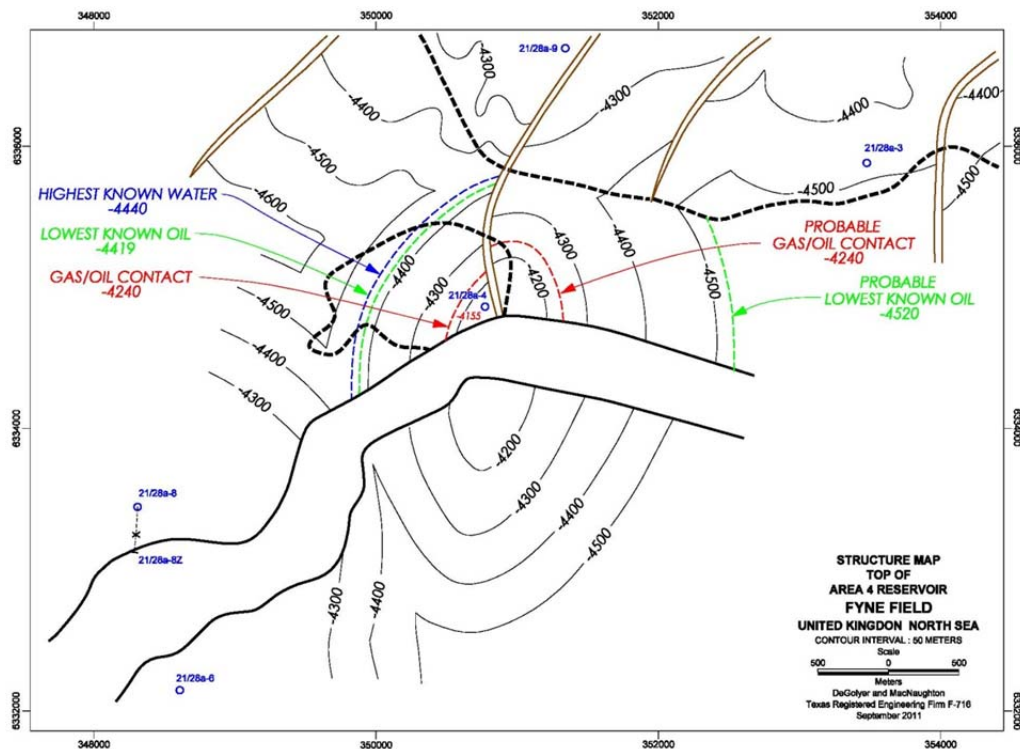


The satellite structures in the Fyne field are salt-related features with three-way dip closure. Each of these structures uses a shale-filled channel for part of its closure. The shale-filled channel is related to a sedimentary platform to the west where accumulating sediment flowed down a slope, to the east. The associated turbidity current created a channel running east to west, in the vicinity of the 21/28a-4, 21/28a-6, and 21/28a-8 wells.

Three of the four Fyne field satellite wells tested a separate closure. The 21/28a-4 well tested a feature called Area 4. The 21/28a-4 well in Area 4 is about 2

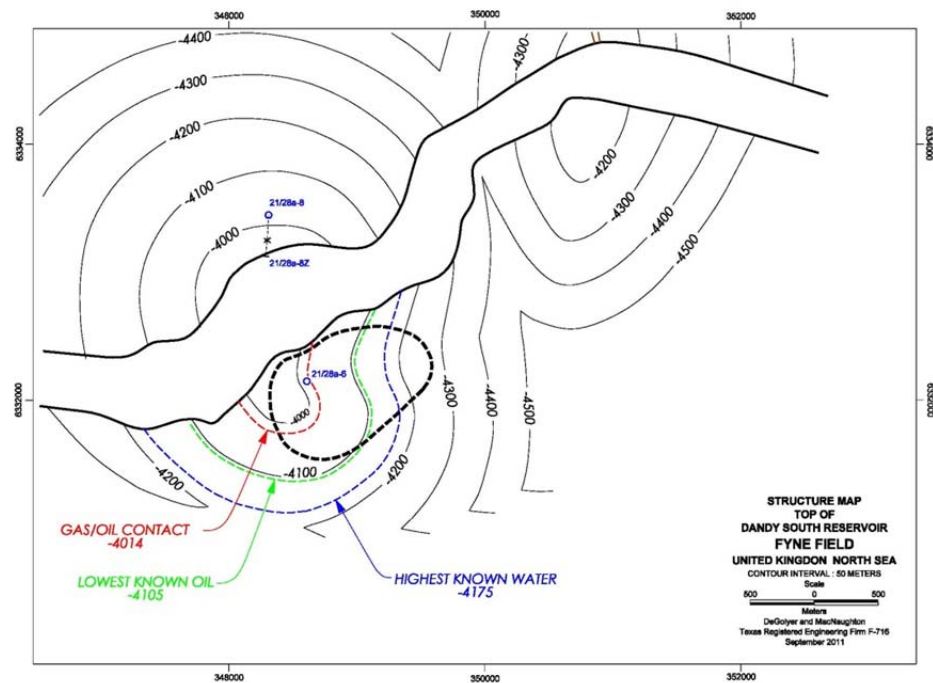
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kilometers south of the 21/28a-9 well in the Fyne field. This well found hydrocarbons in the Tay reservoir. There is a GOC at 4,240 feet subsea and an LKO at 4,419 feet subsea. The limit of closure is interpreted to be 4,440 feet subsea. A small fault cuts the middle of the Area 4 structure leaving the eastern fault block upthrown and without a well penetration. This eastern fault block is interpreted to have the same GOC seen in the 4 well but has a probable LKO of 4,520 feet subsea based on the 3 well in the Fyne field to the north. All quantities in the eastern fault block were estimate as 2C.

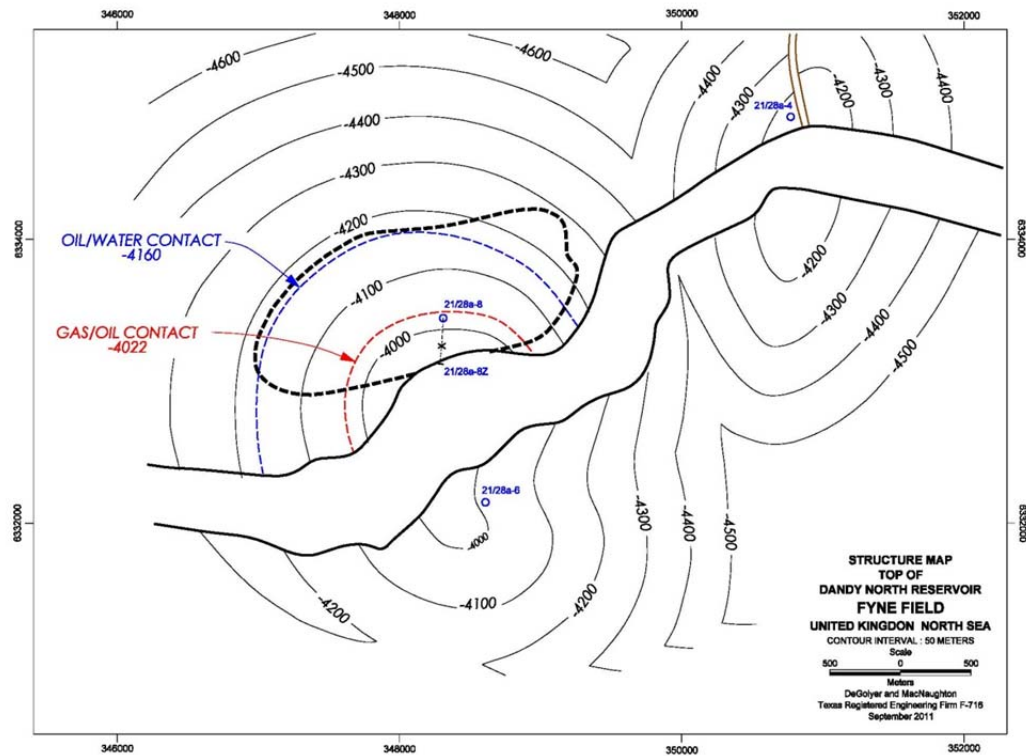


The 21/28a-6 well tested a structure southwest of the 21/28a-4 well. This structure is referred to as Dandy South. The Dandy South accumulation has a GOC at 4,014 feet subsea, an LKO at 4,105 feet subsea, and a highest known water (HKW) at 4,175 feet subsea. The HKW at 4,175 feet subsea is interpreted to be the limit of closure.

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The 21/28a-8 well and its sidetrack 21/28a-8z tested the Dandy North structure. The Dandy North accumulation has a GOC at 4,022 feet subsea and an OWC at 4,160 feet subsea.

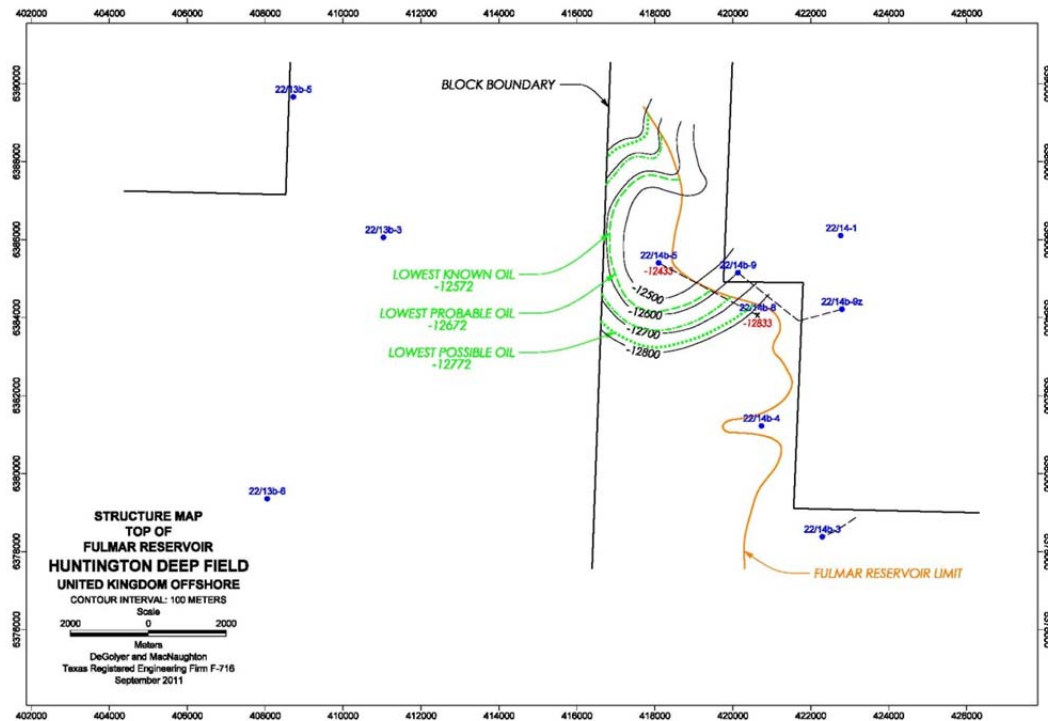


The two Dandy field structures are cut by a shale-filled channel. The channel was originally cut into the top of the Tay reservoir but was starved of sand and is now filled with shale. This shale-filled channel is interpreted as a barrier between Dandy South and Dandy North. The channel is also the southern closure for Dandy North and the northern closure for Dandy South.

Huntington Deep Field

The Huntington Deep field consists of the oil-bearing Jurassic Fulmar reservoir. The Huntington Deep field is located in Block 24/14b, offshore United Kingdom. The discovery well, 22/14b-5, was drilled in 2007 and tested the Paleocene Forties sandstone at 3,200 BOPD of 40 °API oil. The well also tested the deeper Jurassic Fulmar reservoir (Huntington Deep) at 2,890 BOPD of 39 °API oil. Contingent resources have been estimated for the Fulmar reservoir. Development of the Fulmar reservoir has not yet been sanctioned, though work is underway to define the plan of development. A structure map on the top of the Jurassic Fulmar reservoir is shown in the figure below.

DEGOLYER AND MACNAUGHTON

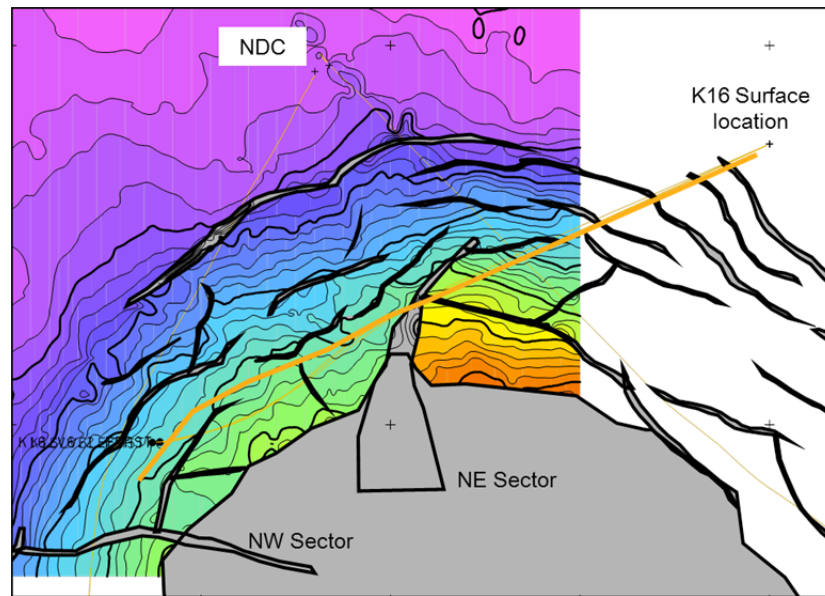


The development plan currently under consideration envisages two vertical wells (subsea) tied back to a leased FPSO vessel.

Kyle Field

The Kyle field, operated by CNR International (U.K.) Ltd., is located approximately 125 miles southeast of Aberdeen. Water depth at the Kyle field is 300 feet. The Kyle field contains both reserves and contingent resources. The reserves estimated are based on the existing four wells in the field and their performance trends. The contingent resources are associated with the K-16 well.

The K-16 well has been considered for several years but commitment on the part of the working interest owners has not yet been reached. The well path is intended to provide drainage of the northwestern (primary) as well as the northeastern (secondary) flank of the structure targeting the Forties, Cromarty and Mey sand reservoirs. Estimates of contingent resources were prepared using volumetric interpretation of the OOIP.

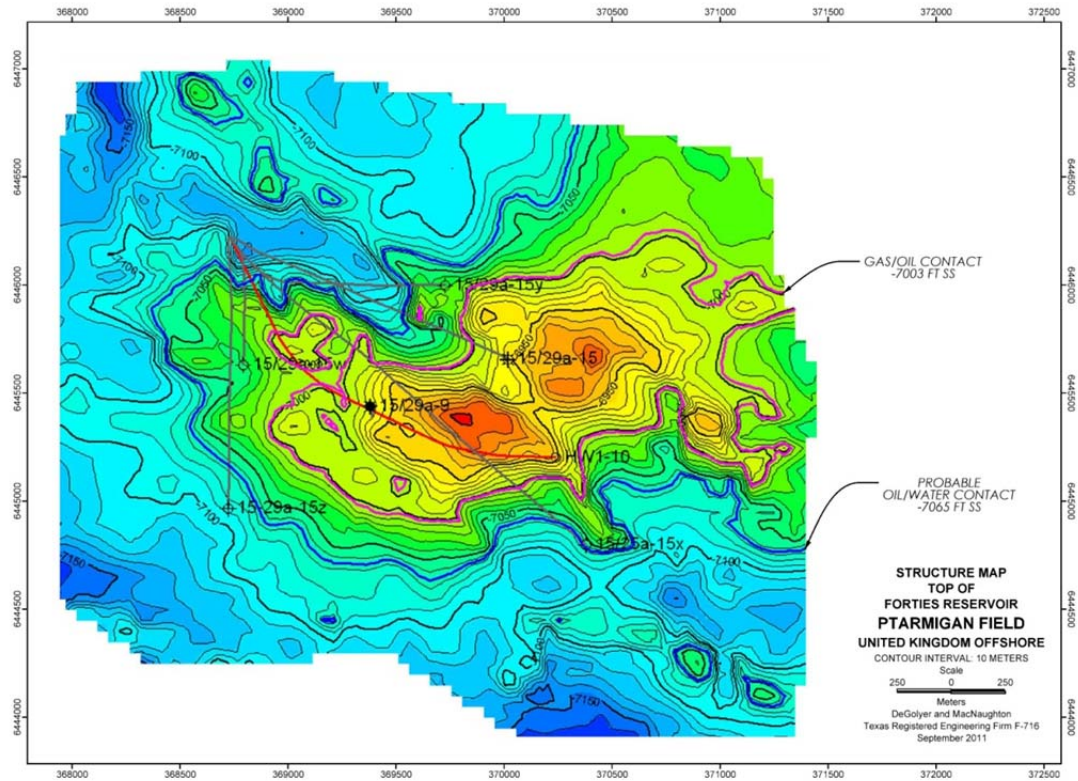


Location Map – courtesy of Premier

Ptarmigan Field

The Ptarmigan field is an undeveloped oil field offshore the United Kingdom in the Central North Sea. It is near the northwestern extremity of the Britannia Field and approximately 21 kilometers west of the Caledonia field. Ptarmigan Field was discovered by Texaco in September 1994 with the drilling of the 15/29a-9 well. This well encountered 63 feet of net pay (16 feet of gas on 47 feet of oil) in a Paleocene Forties sandstone deposit. Measured flow rates from the DST in the discovery well were 1,889 BOPD and 1.4 million MMcf/d. In July 2007, five legs of an appraisal well cluster were drilled.

The primary reservoir in the Ptarmigan field is the Paleocene Forties Sandstone, which is split into the upper and main channels. The main channel, which is connected to the regional aquifer, has far superior reservoir properties than the upper channel, which is silty and largely gas bearing. A LKO was observed at 7,050 feet TVDSS and, based on the results of the pressure measurements in the well, an OWC was estimated at 7,065 feet TVDSS. The bubblepoint of the reservoir oil is measured at 3,082 psia. Pressure measurements in the five-well appraisal program indicate the field is in pressure communication with an aquifer; therefore, aquifer water drive is the most likely production drive mechanism.



The development plan for Ptarmigan will likely include a single horizontal well (shown in red in the figure above) targeting the thickest oil accumulation and completed with sand screens over the productive interval. Fluid will be produced into a subsea flowline and tied back to the Balmoral floating production vessel. Production will be assisted by gas lift as water cut increases and the overlying gas cap is depleted. A portion of the gas will be used on the platform as fuel.

Because the Ptarmigan field is not yet on production, recoverable quantities were estimated by the volumetric method. Porosity and water saturation were estimated using available petrophysical data. Average porosity is approximately 23 percent, and average water saturation is approximately 15 percent. The recovery factor is estimated to be between 35 and 50 percent.

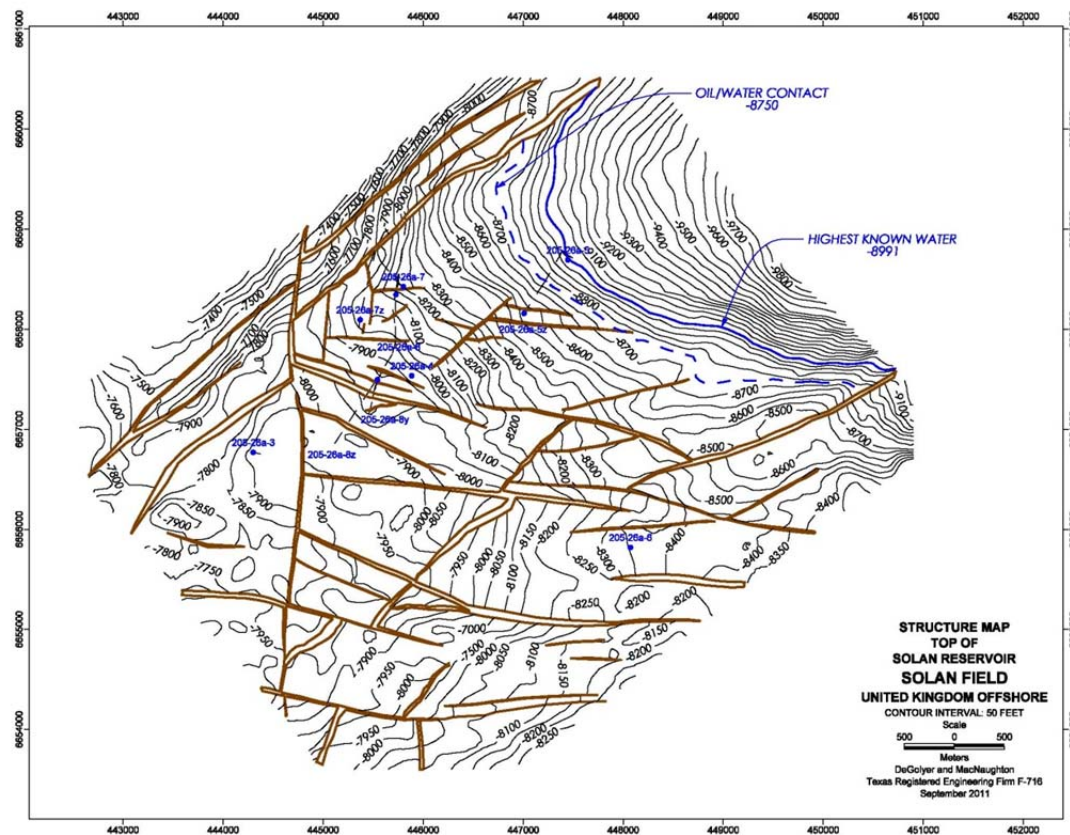
Recoverable quantities estimated in the Ptarmigan field are classified as contingent resources due to the uncertainty of commitment to future development. Quantities associated with 1C were determined using the observed thickness of the discovery well in the main (lower channel) region. Quantities associated with 2C and

3C include the main (lower channel) and upper channel regions with increasing thickness.

Solan Field

The Solan field is located in the U.K. North Sea about 35 kilometers from Schiehallion field. The field was discovered in 1991 when the 205/26a-4 well was drilled and penetrated the Solan structure, Jurassic-age sandstone at 7,900 feet subsea. There have been six appraisal wells drilled to date.

The field has not produced but has been successfully tested. 1C, 2C, and 3C contingent resources have been estimated for the Solan field based on volumetric analysis. OOIP associated with 1C contingent resources is based on a field-wide OWC at 8,750 feet subsea. This is the depth of the contact as indicated by pressure data. The OOIP associated with 3C contingent resources considered the water contact to be at 8,991 feet subsea, which is the depth of the highest known water (HKW) seen in the 205-26a-5 appraisal well. OOIP associated with 2C contingent resources considers the contact to be mid-way between the two referenced depths at 8,870 feet subsea. The figure below shows a structure map on the top of the Solan reservoir.



Premier and Chrysaor concluded an agreement last May that resulted in Premier becoming a 60-percent owner of the Solan license. The anticipated development of the field would include drilling two oil producers and two water injection wells along with the installation of a platform and necessary facilities. Recovery factors have been estimated to range from 20 to 50 percent, depending upon the performance of the drilled wells and the volumetric sweep efficiency from the injection.

Vietnam

Chim Sao Field

The MDS0, MDS1, MDS2, and MDS4 reservoirs in the Chim Sao field have been classified as contingent resources. Only the MDS1 reservoir appears to be of sufficient size for development. Premier and the block partners are currently considering development using a single producer and single injector. Premier anticipates partner approval in the fourth quarter of 2011. Estimates of contingent resources were prepared volumetrically.

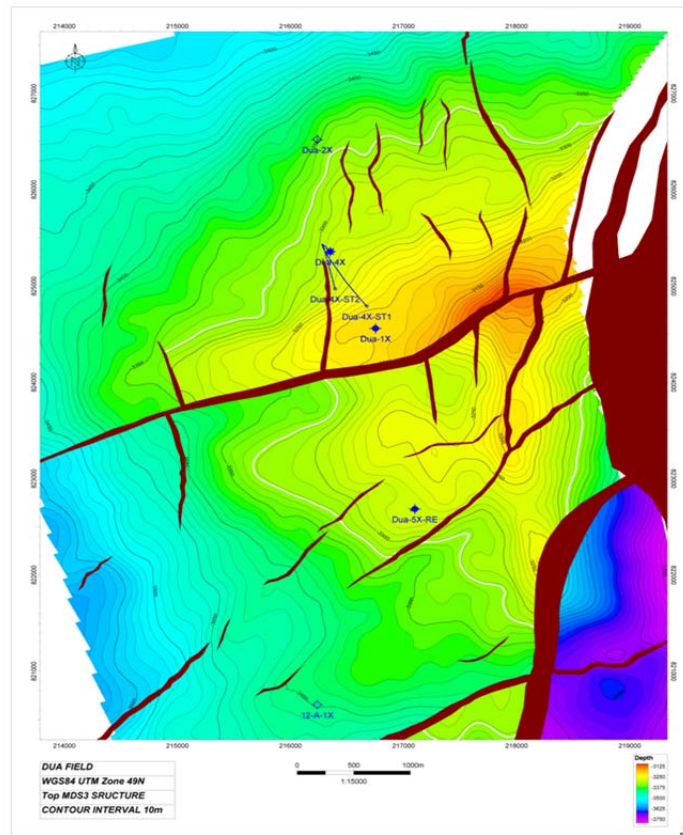
Dua Field

The Dua field was discovered in 1974 by Pecten with the Dua-1X well, which penetrated hydrocarbon-bearing Miocene-age Middle Dua sandstones. The Dua-2X appraisal well was drilled in 1975 but was a dry hole. In 1979, the 12-A-1X well was drilled to the south of the structure but was also a dry hole. In 2006, Premier drilled the Dua-4X, -4XST1, -4XST2, and -5X RE wells in 2006 to further delineate the field. Premier is the operator of the field and holds a 53.125-percent working interest. This field was included in the agreement between Premier and Vietnam Oil and Gas Corporation to merge the 12E and 12W blocks into a single PSC in February 2007. Contingent resources quantities have been estimated for discovered oil and gas reservoirs in the Dua field.

The Dua field lies within the Nam Con Son Basin, offshore southern Vietnam. The Nam Con Son Basin is an extensional basin associated with the opening of the Bien Dong or East Sea. The Aquitanian and early Burdigalian sections of the early to middle Miocene are fluvio-deltaic to shallow marine sandstones and shales of the Lower, Middle, and Upper Dua Formation. The Middle Dua sands are subdivided into six sand-rich zones. Oil-bearing strata have been identified in the MDS1, MDS2, MDAS, MDS5, and MDS6 sands, while associated gas caps have been identified in the MDS1, MDS3, and MDS5 sands. DST have been

carried out in the Middle Dua sands in the Dua-1X well testing the MDS2 sand at a rate of 1,500 BOPD and the MDS1 sand at a rate of 11.5 MMcf/d and 620 barrels of condensate per day. In the Dua-5X RE well, the MDS6 was drill stem tested at a rate of 250 BOPD and the MDS3 sand flowed at rate of 5,440 BOPD.

The Dua field consists of two primary fault blocks separated by a major east/west-trending fault. Three-way dip closure forms the downdip limit of the field to the north, west, and south. The structural interpretation was prepared using the well control and 3-D seismic data initially acquired in 2005. A structure map on the top of the MDS3 interval is shown in the following figure.



Structure Map – courtesy of Premier

The Dua-1X and Dua-4X (plus sidetracks) were drilled in the northern fault block while the Dua-5X RE well penetrated the southern accumulation. Each reservoir was mapped with OOIP or OGIP estimates limited by elevations associated with LKO, GOC, or OWC depending on contingent resources classification. Estimates of OOIP associated with 1C contingent resources were limited by the LKO, whereas the projected OWC was used as the downdip limit for OOIP

associated with estimates of 2C and 3C contingent resources. Projected contacts were derived from wireline pressure data acquired during drilling of the wells.

There is synergy for the development of the Dua field now that the Chim Sao field development is nearly complete. The Chim Sao field will provide a tie-back location for the Dua field to include processing and storage facilities and a gas export line for produced gas volumes. Premier has studied the various development options available in order to optimize the potential development options for the Dua field. Premier has proposed a development plan to the joint venture partners that will utilize a subsea development option that employs three development wells. Premier is pursuing partner approval and preparing an outline for development plan followed by a FDP.

The estimated gross and working-interest contingent resources for the properties evaluated in this report, as of September 30, 2011, are summarized by economic status category (Undetermined) as follows, expressed in thousands of barrels (Mbbbl), millions of cubic feet (MMcf), and thousands of barrels of oil equivalent (MBOE):

Country Concession	Gross Contingent Resources								
	Oil, Condensate, and NGL			Marketable Gas			Oil Equivalent		
	1C (Mbbbl)	2C (Mbbbl)	3C (Mbbbl)	1C (MMcf)	2C (MMcf)	3C (MMcf)	1C (MBOE)	2C (MBOE)	3C (MBOE)
Indonesia									
Natuna Block 'A'	1,026	6,037	19,413	26,212	132,206	721,231	5,983	31,038	155,803
Kakap	0	0	0	0	0	0	0	0	0
North Sumatra Block 'A'	0	0	0	0	0	0	0	0	0
Total Indonesia	1,026	6,037	19,413	26,212	132,206	721,231	5,983	31,038	155,803
Norway									
18/10 Discovery	3,030	8,787	11,499	0	0	0	3,030	8,787	11,499
Pakistan									
Kadanwari	0	0	0	82,414	243,552	428,044	14,370	42,468	74,637
Qadirpur	0	0	96	0	0	158,408	0	0	24,072
Qadirpur Deep	0	0	218	0	0	237,912	0	0	36,227
Zamzama	0	185	727	0	47,640	171,738	0	7,349	26,552
Total Pakistan	0	185	1,041	82,414	291,192	996,102	14,370	49,817	161,488

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Table – (Continued)

United Kingdom									
Area 4	892	3,571	8,071	214	928	1,276	931	3,740	8,303
Blackhorse	5,880	12,995	21,230	4,233	9,534	15,723	6,650	14,728	24,089
Bladon	776	1,070	1,582	335	461	682	837	1,154	1,706
Bugle	3,578	9,092	14,852	4,372	11,110	18,148	4,373	11,112	18,152
Caledonia	164	1,214	1,823	33	244	365	170	1,259	1,889
Dandy	3,740	7,002	15,566	9,576	11,142	13,827	5,481	9,028	18,080
Fyne	22,984	29,633	39,923	17,995	20,241	22,567	26,256	33,313	44,026
Huntington	5,660	8,082	10,905	2,932	4,187	5,649	6,193	8,843	11,932
Kyle	1,260	1,432	1,547	2,771	3,149	3,401	1,858	2,112	2,282
Ptarmigan	2,880	4,585	5,094	3,250	5,802	6,447	3,473	5,640	6,267
Solan	27,695	49,398	72,158	0	0	0	27,695	49,398	72,158
Total United Kingdom	75,509	128,074	192,751	45,711	66,798	88,085	83,917	140,327	208,884
Vietnam									
Chim Sao	1,231	3,430	5,726	3,028	7,039	9,416	1,824	4,808	7,569
Dua	4,692	6,570	10,835	21,411	31,990	58,520	8,883	12,831	22,289
Total Vietnam	5,923	10,000	16,561	24,439	39,029	67,936	10,707	17,639	29,858
Grand Total	85,488	153,083	241,265	178,776	529,225	1,873,354	118,007	247,608	567,532

Notes:

1. Application of any risk factor to contingent resources quantities does not equate contingent resources with reserves.
2. There is no certainty that it will be commercially viable to produce any portion of the contingent resources evaluated herein.

Country Concession	Working-Interest Contingent Resources								
	Oil, Condensate, and NGL			Marketable Gas			Oil Equivalent		
	1C (Mbbl)	2C (Mbbl)	3C (Mbbl)	1C (MMcf)	2C (MMcf)	3C (MMcf)	1C (MBOE)	2C (MBOE)	3C (MBOE)
Indonesia									
Natuna Block 'A'	295	1,731	5,565	7,514	37,899	206,755	1,716	8,898	44,664
Kakap	0	0	0	0	0	0	0	0	0
North Sumatra Block 'A'	0	0	0	0	0	0	0	0	0
Total Indonesia	295	1,731	5,565	7,514	37,899	206,755	1,716	8,898	44,664
Norway									
18/10 Discovery	1,212	3,515	4,600	0	0	0	1,212	3,515	4,600
Pakistan									
Kadanwari	0	0	0	13,013	38,457	67,588	2,269	6,706	11,785
Qadirpur	0	0	5	0	0	7,524	0	0	1,144
Qadirpur Deep	0	0	10	0	0	11,301	0	0	1,720
Zamzama	0	17	68	0	4,466	16,100	0	689	2,489
Total Pakistan	0	17	83	13,013	42,923	102,513	2,269	7,395	17,138

Table – (Continued)

United Kingdom									
Area 4	356	1,425	3,220	85	370	509	371	1,492	3,313
Blackhorse	2,940	6,498	10,615	2,117	4,767	7,862	3,325	7,365	12,044
Bladon	388	535	791	168	231	341	419	577	853
Bugle	1,467	3,728	6,089	1,793	4,555	7,441	1,793	4,556	7,442
Caledonia	164	1,214	1,823	33	244	365	170	1,258	1,889
Dandy	1,492	2,794	6,211	3,821	4,446	5,517	2,187	3,602	7,214
Fyne	9,171	11,824	15,929	7,180	8,076	9,004	10,476	13,292	17,566
Huntington	2,151	3,071	4,144	1,114	1,591	2,147	2,354	3,360	4,534
Kyle	504	573	619	1,108	1,260	1,360	743	845	913
Ptarmigan	1,728	2,751	3,056	1,950	3,481	3,868	2,083	3,384	3,759
Solan	16,617	29,639	43,295	0	0	0	16,617	29,639	43,295
Total United Kingdom	36,978	64,052	95,792	19,369	29,021	38,414	40,538	69,370	102,822
Vietnam									
Chim Sao	654	1,822	3,042	1,609	3,739	5,002	969	2,554	4,021
Dua	2,493	3,490	5,756	11,375	16,995	31,089	4,719	6,816	11,841
Total Vietnam	3,147	5,312	8,798	12,984	20,734	36,091	5,688	9,370	15,862
Grand Total	41,632	74,627	114,838	52,880	130,577	383,773	51,423	95,548	185,086

Notes:

1. Application of any risk factor to contingent resources quantities does not equate contingent resources with reserves.
2. There is no certainty that it will be commercially viable to produce any portion of the contingent resources evaluated herein.

Valuation of Reserves

This report has been prepared using initial prices and costs and future price and cost assumptions specified by Premier. Estimates of future net revenue and present worth of proved and proved-plus-probable reserves have been prepared in accordance with guidelines of the PRMS.

In this report, values for proved and proved-plus-probable reserves are based on projections of estimated future production and revenue prepared for these properties with no risk adjustment applied to the probable reserves. Probable reserves involve substantially higher risks than proved reserves. Revenue values for proved-plus-probable reserves have not been adjusted to account for such risks; this adjustment would be necessary in order to make proved-plus-probable reserves values comparable with values for proved reserves.

Revenue values of the proved and proved-plus-probable reserves were developed utilizing the methods generally accepted by the petroleum industry. Production forecasts of the proved and proved-plus-probable (non-risk-adjusted)

reserves were based on the development plan for each field. The future net revenue and net present worth of each field's reserves were estimated using the price and cost assumptions, monetary conversion values, and the appropriate concession terms provided by Premier.

The properties evaluated in Indonesia, Mauritania, and Vietnam are subject to terms of PSCs. The revenue values presented herein reflect the terms of each respective contract. The working-interest reserves and contingent resources presented in the report do not exclude the government's share of profit entitlement and are therefore not equivalent to entitlement reserves.

The net present worth of the proved and proved-plus-probable (non-risk-adjusted) reserves of the fields have been estimated using the base case and sensitivity price scenarios provided by Premier. The assumptions are as follows:

Base Case Scenario

- i) Oil prices were based on the Brent oil price, expressed in United States dollars (U.S.\$) per barrel, of U.S.\$90.00 per barrel in 2011 and escalated at a rate of 2.5 percent per year through the life of the evaluation. Prices for individual fields may vary from the Brent marker price based on quality and transportation differentials. The Brent oil price and the individual field differentials were provided by Premier. Gas prices were based on terms specified in the sales contracts.
- ii) An exchange rate of U.S.\$1.60 per 1.00 United Kingdom pound sterling (U.K.£) was used to convert U.K.£ to U.S.\$.

Sensitivity Case Scenario – Low Price Case

- i) Oil prices were based on a Brent oil price, expressed in U.S.\$ per barrel, of U.S.\$75.00 per barrel in 2011 and escalated at a rate of 2.5 percent per year through the life of the evaluation. Prices for individual fields may vary from the Brent marker price based on quality and transportation differentials. The Brent oil price and the individual field differentials were provided by Premier. Gas prices were based on terms specified in the sales contracts.
- ii) An exchange rate of U.S.\$1.60 per U.K.£1.00 was used to convert U.K.£ to U.S.\$.

Sensitivity Case Scenario – High Price Case

- i) Oil prices were based on a Brent oil price, expressed in U.S.\$ per barrel, of U.S.\$105.00 per barrel in 2011 and escalated at a rate of 2.5 percent per year through the life of the evaluation. Prices for individual fields may vary from the Brent marker price based on quality and transportation differentials. The Brent oil price and the individual field differentials were provided by Premier. Gas prices were based on terms specified in the sales contracts.
- ii) An exchange rate of U.S.\$1.60 per U.K.£1.00 was used to convert U.K.£ to U.S.\$.

Unescalated cost data for the proved and proved-plus-probable reserves were provided by Premier. The capital investment and operating expense forecasts were reviewed in detail and modified in accordance with the production forecast. The operating expense and capital cost forecasts included herein have been escalated at a rate of 2.5 percent per year beginning in 2012. Abandonment costs were included in the analysis where applicable. The royalty and tax provisions and the terms of PSCs were assumed to remain unchanged from current legislation. All cost data remained unchanged for the price scenarios.

Central corporate overheads have not been charged against the valuation of the fields. Values for the United Kingdom assets include a deduction for United Kingdom corporation tax. The corporation tax was applied at an effective rate based on information provided by Premier and varies depending on the specific price scenario as follows: Base Case – 39 percent, Low Price Case – 28 percent, and High Price Case – 44 percent. In the estimation of the effective corporate tax rates, Premier has represented that no consideration was given to future expenditures related to exploration or appraisal drilling activities that Premier has planned, including the potential development of fields for which contingent resources have been estimated. As such, neither the potential capital expenditures nor the potential tax benefits that may result from those activities have been included in the estimation of the effective corporate tax rates. Consequently, neither these potential capital expenditures nor these potential tax benefits have been considered in the after-corporate tax estimates of present worth of the proved and proved-plus-probable reserves evaluated herein.

No value is attributed to future tariffing business that may arise but is not currently identified.

Estimates of the net present worth discounted at 8 and 10 percent of the proved and proved-plus-probable (non-risk-adjusted) reserves of the petroleum interests attributable to Premier, using the base case and sensitivity price scenarios expressed in millions of United States dollars (MM U.S.\$) for the forecast pricing scenario are presented in the following table. Values for net present worth are estimated as of September 30, 2011.

Base Case – Net Present Worth			
Proved		Proved plus Probable	
At 8 Percent (MM U.S.\$)	At 10 Percent (MM U.S.\$)	At 8 Percent (MM U.S.\$)	At 10 Percent (MM U.S.\$)
2,495.2	2,371.1	5,124.8	4,706.4

Note: Values for probable reserves have not been risk adjusted to make them comparable to values for proved reserves.

Sensitivity Case – Low Price Case – Net Present Worth			
Proved		Proved plus Probable	
At 8 Percent (MM U.S.\$)	At 10 Percent (MM U.S.\$)	At 8 Percent (MM U.S.\$)	At 10 Percent (MM U.S.\$)
2,003.9	1,905.9	4,158.0	3,808.1

Sensitivity Case – High Price Case – Net Present Worth			
Proved		Proved plus Probable	
At 8 Percent (MM U.S.\$)	At 10 Percent (MM U.S.\$)	At 8 Percent (MM U.S.\$)	At 10 Percent (MM U.S.\$)
3,082.0	2,928.4	6,137.4	5,645.0

Note: Values for probable reserves have not been risk adjusted to make them comparable to values for proved reserves.

Summary and Conclusions

Estimates of proved, probable, and possible oil, condensate, NGL, and marketable-gas reserves, as of September 30, 2011, attributable to working interests owned by Premier and evaluated herein are listed below, expressed in thousands of barrels (Mbbl) and millions of cubic feet (MMcf):

	Working-Interest Reserves Summary		
	Proved	Probable*	Possible*
Oil, Condensate, and NGL, Mbbl	72,214	95,858	69,076
Marketable Gas, MMcf	649,662	326,277	86,429

Note: Probable and possible reserves have not been risk adjusted to make them comparable to proved reserves.

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Estimates of contingent oil, condensate, NGL, and marketable-gas resources, as of September 30, 2011, attributable to the working interests owned by Premier and evaluated herein are listed below, expressed in Mbbl and MMcf:

	Working-Interest Contingent Resources Summary		
	1C	2C	3C
Undetermined			
Oil, Condensate, and NGL, Mbbl	41,632	74,627	114,838
Marketable Gas, MMcf	52,880	130,577	383,773

Notes:

1. Application of any risk factor to contingent resources quantities does not equate contingent resources with reserves.
2. There is no certainty that it will be commercially viable to produce any portion of the contingent resources evaluated herein.

Estimates of the net present worth discounted at 8 and 10 percent of the proved and non-risk-adjusted proved-plus-probable reserves of the petroleum interests attributable to Premier, using the base case and sensitivity price scenarios expressed in millions of United States dollars (MM U.S.\$) are presented in the following table. Values for net present worth are estimated as of September 30, 2011.

	Net Present Worth (MM U.S.\$)	
	8 Percent	10 Percent
Base Case Scenario		
Proved	2,495.2	2,371.1
Proved plus Probable	5,124.8	4,706.4
Low Price Case Scenario		
Proved	2,003.9	1,905.9
Proved plus Probable	4,158.0	3,808.1
High Price Case Scenario		
Proved	3,082.0	2,928.4
Proved plus Probable	6,137.4	5,645.0

Note: Values for probable reserves have not been risk adjusted to make them comparable to values for proved reserves.



Report on Prospective and Certain Contingent Resources

18 November 2011

INTEGRITY EXPERIENCE ADVICE

DECLARATION

RISC has given and not withdrawn its written consent to the issue of this prospectus, with its name included within it, and to the inclusion of this report and references to this report in the prospectus. For the purposes of Prospectus Rule 5.5.3R(2)(f) RISC accepts responsibility for the information contained in the RISC report set out in this part of the prospectus and those parts of the prospectus which include references to this report and declares that to the best knowledge and belief of RISC, having taken all reasonable care to ensure that such is the case, the information contained herein is in accordance with the facts and does not omit anything likely to affect the import of such information

This report is for both parties below:

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1 SUMMARY

Premier has a well diversified and international portfolio of exploration and production assets in Egypt, Indonesia, Kenya, Mauritania, Norway, Pakistan, UK and Vietnam. RISC reviewed forty eight prospects and leads and twelve discoveries (Contingent Resources) defined as the Primary List. These prospects are high-ranked prospects which are considered by Premier to be candidates for drilling in the near to medium term under current oil and gas price expectations. The contingent resources include oil and gas discoveries that are marginal or sub-commercial under current economic conditions or which have not yet been assessed sufficiently for development plans to be proposed. Premier advise that assets closer to development decision have been evaluated in a separate report by DeGolyer and MacNaughton.

Premier also provided a further list of prospects and leads which are currently less well evaluated or have higher risk and hence have a lower probability of being drilled in the near to medium term. These are termed Secondary List Prospects and Leads. In addition, Premier has recently acquired exploration acreage where data acquisition and interpretation is not yet advanced enough to define specific leads and prospects (e.g. Kenya).

Premier provided access to technical data and interpretations, conceptual production scenarios and development plans and economic models. In conducting this review, RISC staff visited Premier's offices in Jakarta, Stavanger, Ho Chi Minh City and London and interacted with Premier operational staff responsible for the assets in their geographical areas.

RISC undertook systematic evaluations of in-place and recoverable volumes, geologic Probability of Success, conceptual development plans and associated production profiles based on observed reservoir data on a prospect by prospect basis. RISC created development scenarios grouping prospects where it made sense to do so from a development perspective.

RISC's view on contingent resources is based on a review of information provided by Premier, and is summarised by country in the table below. The contingent resource estimates (2C estimates) provided in the table are mean estimates and are unrisks.

1.1 Summary of Contingent Resources

Country	100% Share		Premier Share
	HIIP (Mean)	Resources (Mean)	Resources (Mean)
	MMboe	MMboe	MMboe
UK	84	25	12
Norway	38	13	2
Indonesia	269	193	72
Mauritania	1131	161	9
Vietnam	206	67	17
Total	1728	459	112

Table 1-1 Contingent resources

1.2 Summary of 'Primary' Prospective Resources

Country	100% Share		Premier Share	
	HIIP (Mean)	Resources (Mean)	Resources (Mean)	Riskd Resources (Mean)
	MMboe	MMboe	MMboe	MMboe
UK	501	246	143	40
Norway	705	219	62	17
Indonesia	1758	434	204	49
Mauritania	1176	296	20	2
Vietnam	2424	710	225	40
Pakistan	64	44	3	0
Total	6628	1949	657	148

Table 1-2 Primary Prospective Resources by Country

1.3 Summary of 'Secondary' Prospective Resources

Country	100% Share	Premier Share	
	Resources (Mean)	Resources (Mean)	Risk Resources (Mean)
	MMboe	MMboe	MMboe
UK	367	133	34
Norway	149	90	20
Mauritania	567	34	3
Indonesia	39	17	2
Egypt	315	63	7
Vietnam	134	67	5
Pakistan	3	0	0
Total	1574	404	71

Table 1-3 Premier Secondary Prospective Resources Summary

We have carried out our assessment of resources in accordance with the Society of Petroleum Engineers Petroleum Resource Management System (PRMS).

Some of the above interests are held under Production Sharing Contracts or similar which define cost recovery and production sharing mechanisms. It is normal practice in the industry and a requirement of certain regulatory regimes that company entitlements to reserves and production are reported on a net economic interest basis.



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PART VI

INFORMATION ON THE ACQUISITION

1. Introduction

On 5 October 2011, the Premier Board and the EnCore Board announced that they had reached agreement on the terms of a recommended acquisition by Premier (or one of its wholly owned subsidiaries) of the entire issued and to be issued share capital of EnCore.

Subject to the satisfaction or, where appropriate, waiver of the Conditions, it is expected that the Acquisition will become effective on 16 January 2012.

2. Terms of the Acquisition

It is intended that the Acquisition will be implemented by way of a Court-sanctioned scheme of arrangement under Part 26 of the Companies Act 2006. The purpose of the Scheme is to enable Premier to acquire the whole of the issued and to be issued share capital of EnCore. Under the terms of the Acquisition, which will be subject to the Conditions and to the further terms in the Scheme Document, Scheme Shareholders will be entitled to receive:

for each Scheme Share	70 pence in cash
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A Share Alternative is being made available to Scheme Shareholders (other than Restricted Overseas Shareholders) enabling them to elect to receive New Premier Shares instead of all or part of the cash consideration to which they would otherwise be entitled under the Acquisition on the basis of 0.2067 New Premier Shares for each EnCore Share held at the Reduction Record Time. Based on a price of 367.30 pence per Premier Share (being the Closing Price on 16 November 2011, the last practicable date prior to the publication of this document), the Share Alternative values each EnCore Share at 75.92 pence. Further details of the Share Alternative are set out in paragraph 9 below.

Immediately following the Effective Date, assuming the maximum number of 65,212,513 New Premier Shares are issued pursuant to the Acquisition and that no Premier Shares are issued or repurchased in the period from the publication of this document to the Effective Date, it is expected that EnCore Shareholders will hold New Premier Shares representing approximately 12.2 per cent. of the enlarged issued share capital of Premier and Existing Premier Shareholders will hold approximately 87.8 per cent. of the enlarged issued share capital of Premier.

The Acquisition values EnCore's entire issued and to be issued share capital at approximately £221 million (approximately US\$348 million).

Subject to the consent of the Panel (if applicable), Premier reserves the right to elect to implement the Acquisition by way of an Offer. In such event, the Acquisition will be implemented on the same terms (with such amendments as may be necessary or as may be required to incorporate an acceptance condition set at 90 per cent. of the shares to which the Acquisition relates or such other percentage as may be required by the Panel and subject to the availability of an exemption (if required) from the registration requirements of the US Securities Act and such amendments (if any) that Premier deems necessary in connection with US securities laws), so far as applicable, as those which would apply to the implementation of the Acquisition by means of the Scheme, and further documentation relating to the Offer would be issued. Any such Offer will be made in accordance with applicable securities laws, including without limitation Regulation 14E of the US Securities Exchange Act of 1934.

3. Background to, and reasons for, the Acquisition

The Acquisition is in line with Premier's stated strategy of acquiring high quality assets in existing core areas using its strong balance sheet. The Acquisition adds to Premier's operated position in the UK North Sea and its attractive portfolio of development assets. Specifically, the Acquisition would:

- increase Premier's interest in UK Licence PL1430 (the Catcher area), including the Catcher field, one of the largest discoveries in the UK North Sea in recent years, by 15 per cent. taking Premier's overall interest to 50 per cent.;
- provide Premier with operatorship of the Catcher area, allowing Premier to work with the remaining partners to optimise field development;

- build on Premier's active UK exploration programme through the additions of interest in the Coaster prospect east of Catcher and the Tudor Rose and Spaniards prospects close to Premier's existing Scott area facilities;
- add an additional estimated 12.6 million barrels of discovered oil reserves from wells drilled to date in the Catcher area;
- include EnCore's UK ring fenced tax losses, currently estimated based on EnCore's historic expenditures to be approximately £13.5 million (excluding approximately £17.5 million which Premier intends to transfer to TAQA after completion of the Acquisition); and
- enable Premier to build on the success already achieved by EnCore by applying Premier's greater operational and financial strength to EnCore's portfolio.

4. Financing of the Acquisition

The cash consideration payable to EnCore Shareholders pursuant to the Acquisition will be provided by Premier from available cash resources and, if applicable, the Acquisition Facility.

5. Irrevocable Undertakings and Letter of Intent

The EnCore Directors have irrevocably undertaken to vote in favour of the Scheme in respect of their own beneficial holdings totalling 21,692,984 issued EnCore Shares representing in aggregate approximately 7.3 per cent. of EnCore's issued share capital as at 16 November 2011 (being the latest practicable date prior to the printing of this document). The executive EnCore Directors have also irrevocably undertaken to elect for the Share Alternative in respect of their own beneficial holdings totalling 32,543,859 issued and to be issued EnCore Shares representing in aggregate approximately 10.3 per cent. of the fully diluted share capital of EnCore as at 16 November 2011.

These irrevocable undertakings provided by the EnCore Directors cease to be binding if the Scheme has not become effective by the Long Stop Date and prior to that time Premier has not issued an Offer Document, or an Offer Document is issued before the Long Stop Date and the Offer lapses or is withdrawn without having become wholly unconditional.

In addition, EnCore's shareholder BlackRock has confirmed its current intention to vote in favour of the Scheme. As at 16 November 2011 (being the latest practicable date prior to the publication of this document), BlackRock controlled voting rights in respect of 8,017,156 EnCore Shares representing approximately 2.71 per cent. of EnCore's issued share capital as at 16 November 2011.

6. Management and employees of EnCore

Premier has a high regard for the skills and experience of the existing management and employees of EnCore and therefore confirms that, upon and following completion of the Acquisition, it intends to comply with the contractual and other entitlements of existing employees in relation to pension and employment rights.

7. Conditions of the Acquisition

The Acquisition will be conditional, amongst other things, upon:

- (a) the Scheme becoming unconditional and Effective by no later than the Long Stop Date, or such later date (if any) as Premier and EnCore may, with the consent of the Panel, agree and (if required) the Court may allow;
- (b) its approval by a majority in number representing not less than three-fourths in value of the Scheme Shareholders who are on the register of members of EnCore at the Scheme Voting Record Time present and voting, either in person or by proxy, at the Scheme Meeting and at any separate class meeting which may be required by the Court or at any adjournment of any such meeting;
- (c) all resolutions necessary to approve and implement the Scheme being duly passed by the requisite majority or majorities at the EnCore General Meeting or at any adjournment of that meeting;
- (d) the sanction of the Scheme with or without modification (but subject to any such modification being acceptable to Premier and EnCore) and the confirmation of the Capital Reduction by the Court and (i) the delivery of an office copy of each of the Reduction Court Order and of

the minute confirming the Capital Reduction to the Registrar of Companies and (ii) if so ordered by the Court in order to take effect, the registration of the Reduction Court Order by the Registrar of Companies;

- (e) no indication having been made by the Office of Fair Trading in the United Kingdom that the Acquisition or any matter arising there from or related thereto will be referred to the Competition Commission;
- (f) the UK Listing Authority having acknowledged to Premier or its agent (and such acknowledgement not having been withdrawn) that the application for the admission of the New Premier Shares to the Official List with a premium listing has been approved and (after satisfaction of any conditions to which such approval is expressed to be subject ("listing conditions")) will become effective as soon as a dealing notice has been issued by the FSA and any listing conditions having been satisfied, and the London Stock Exchange having acknowledged to Premier or its agent (and such acknowledgement not having been withdrawn) that the New Premier Shares will be admitted to trading; and
- (g) the Secretary of State for Energy and Climate Change not having indicated an intention to (i) revoke or recommend the revocation of any material exploration or production licence held by any member of the EnCore Group or (ii) to require a further change of control of any such member as a result of the implementation of the Acquisition.

To the extent permitted by law and subject to the requirements of the Panel, Premier reserves the right to waive, in whole or in part, all or any of the conditions referred to in paragraphs (e) and (g).

8. Disposal of certain EnCore assets to TAQA

Premier has agreed with TAQA Bratani Limited ("TAQA") that, immediately after completion of the Acquisition and subject to the satisfaction of certain conditions, it will sell to TAQA certain non-core assets which it will have acquired when it acquires EnCore. These assets include EnCore's 16.6 per cent. interest in the Cladhan area (Blocks 210/29a and 210/30a) and 50 per cent. of EnCore's 100 per cent. interest in the Coaster prospect east of Catcher (Blocks 28/5, 29/1d and 28/10a).

9. Further details of the Acquisition

The New Premier Shares and the Share Alternative

A Share Alternative is being made available to Scheme Shareholders (other than Restricted Overseas Shareholders). The Share Alternative will enable such shareholders to elect to take New Premier Shares instead of all or part of the cash which they would otherwise be entitled to receive under the Acquisition.

The Share Alternative will be made available on the basis of 0.2067 New Premier Shares for each Scheme Share held. Based on a price of 367.30 pence per Premier Share (being the Closing Price on 16 November 2011, the last practicable date prior to the publication of this document), the Share Alternative values each EnCore Share at 75.92 pence.

The New Premier Shares to be issued pursuant to the Share Alternative will be ordinary shares of 12.5 pence each in the capital of Premier. The New Premier Shares will be issued in registered form, will be capable of being held in both certificated and uncertificated form, will be issued credited as fully paid and will rank *pari passu* in all respects with the existing Premier Shares, including as to the right to receive and retain all dividends and other distributions declared, paid or made after the Effective Date. The New Premier Shares will be denominated in Pounds Sterling.

Fractions of New Premier Shares will not be allotted or issued pursuant to the Acquisition. Fractional entitlements will be aggregated and sold in the market, and the net proceeds of sale will be distributed pro rata to persons entitled thereto. However, individual entitlements of less than £5 will be retained for the benefit of Premier.

EnCore Share Option Plans

The Acquisition will extend to all EnCore Shares issued (whether upon the exercise of the options and/or the vesting of awards or otherwise) under the EnCore Share Option Plans before the Scheme becomes Effective. EnCore and Premier will be writing to participants in the EnCore Share Option Plans to inform them of the effect of the Scheme on their rights under the EnCore Share Option Plans. Appropriate proposals will be made in due course to participants in the EnCore Share Option Plans.

Implementation of the Scheme and cancellation of listing

It is intended that the Acquisition will be effected by a Court-sanctioned scheme of arrangement between EnCore and the Scheme Shareholders under Part 26 of the Companies Act 2006. The purpose of the Scheme is to provide for Premier to become the owner of the whole of the issued and to be issued share capital of EnCore.

Under the Scheme, the Acquisition is to be achieved by the cancellation of the Scheme Shares held by Scheme Shareholders and the application of the reserve arising from such cancellation in paying up in full a number of new EnCore Shares (which is equal to the number of Scheme Shares cancelled) and issuing the same to Premier in return for which Scheme Shareholders will receive consideration on the basis set out in paragraph 2 above.

To become effective, the Scheme requires the approval at the Scheme Meeting of a majority in number of the Scheme Shareholders present and voting (and entitled to vote), either in person or by proxy, representing not less than 75 per cent. of the Scheme Shares held by such Scheme Shareholders and the passing of requisite resolutions at the EnCore General Meeting. The EnCore General Meeting will be held immediately after the Scheme Meeting.

Following the Meetings, the Scheme must be sanctioned by the Court and the associated Capital Reduction must be confirmed by the Court. The Scheme will only become effective once a copy of the Scheme Court Order and a copy of the Reduction Court Order are delivered to (or, if so ordered by the Court, the Reduction Court Order is registered by) the Registrar of Companies.

Upon the Scheme becoming Effective, it will be binding on all Scheme Shareholders, irrespective of whether or not they attended or voted at the Meetings, and the consideration will be despatched by Premier to Scheme Shareholders no later than 14 days after the Effective Date.

Prior to the Scheme becoming Effective, EnCore will make an application to the London Stock Exchange for the cancellation of trading in the EnCore Shares on AIM to take effect from the Business Day immediately after the Effective Date. The last day of dealings in EnCore Shares on AIM is expected to be the day falling two Business Days prior to the Effective Date and no transfers will be registered after 6.00 p.m. on that date. On the Effective Date, share certificates in respect of EnCore Shares will cease to be valid and should be destroyed. In addition, entitlements to EnCore Shares held within the CREST system will be cancelled on the Effective Date.

10. Settlement, listing and dealing of New Premier Shares

Applications will be made to the UKLA and to the London Stock Exchange for the New Premier Shares to be issued in connection with the Acquisition to be admitted to the Official List with a premium listing and to trading on the London Stock Exchange's main market for listed securities. It is expected that Admission of the New Premier Shares to the Official List and to trading on the London Stock Exchange's main market for listed securities will become effective, and that dealings for normal settlement in the New Premier Shares will commence, on the Business Day after the date on which the Scheme becomes Effective.

The Existing Premier Shares are already admitted to CREST. It is expected that all of the New Premier Shares, when issued and fully paid, will be capable of being held and transferred by means of CREST. It is expected that the New Premier Shares will trade under ISIN GB00B43G0577.

Further details on listing, dealing and settlement will be included in the Scheme Document.

11. Overseas Shareholders

United States

The New Premier Shares to be issued under the Scheme have not been, will not be, and are not required to be, registered under the US Securities Act in reliance upon the exemption from the registration requirements of the US Securities Act provided by Section 3(a)(10) of that Act. The New Premier Shares have not been, and will not be, registered under the securities laws of any state or jurisdiction of the United States and, accordingly, will only be issued to the extent that exemptions from the registration or qualification requirements of state "blue sky" securities laws are available. For the purpose of qualifying for the exemption from the registration requirements of the US Securities Act provided by Section 3(a)(10) of that Act with respect to the New Premier Shares issued pursuant to the Scheme, Premier and EnCore will advise the Court that Premier will rely on the Section 3(a)(10) exemption based on the Court's sanctioning of the Scheme, which will be

relied upon by Premier as an approval of the Scheme following a hearing upon the fairness of the terms and conditions of the Scheme to Scheme Shareholders at which hearing all such shareholders will be entitled to attend in person or through counsel to support or oppose the sanctioning of the Scheme and with respect to which notification has been or will be given to all such shareholders.

The New Premier Shares to be issued under the Scheme should not be treated as “restricted securities” within the meaning of Rule 144(a)(3) under the US Securities Act, and persons who receive New Premier Shares in the Scheme (other than “affiliates”, as described below) may resell such New Premier Shares without restriction under the US Securities Act. An EnCore Shareholder in the United States who is an affiliate of Premier within the 90 days prior to the implementation of the Scheme or following implementation of the Scheme may only resell New Premier Shares received as part of the Scheme pursuant to registration under the US Securities Act or pursuant to an applicable exemption from registration (including in a transaction that satisfies the applicable requirements of Regulation S under the US Securities Act). Whether a person is an affiliate of a company for purposes of the US Securities Act depends on the circumstances, but affiliates can include certain officers, directors and significant shareholders. Persons who believe they may be affiliates of Premier should consult their own legal advisers prior to any sale of New Premier Shares issued under the Scheme.

The New Premier Shares will not be listed on a US securities exchange or quoted on any inter-dealer quotation system in the United States. Premier does not intend to take any action to facilitate a market in New Premier Shares in the United States. Consequently, Premier believes that it is unlikely that an active trading market in the United States will develop for the New Premier Shares.

Neither the SEC nor any other US federal or state securities commission or regulatory authority has approved or disapproved of the New Premier Shares or passed an opinion upon the accuracy or adequacy of this document. Any representation to the contrary is a criminal offence in the United States.

This document does not address any US federal income tax consequences of the Scheme to EnCore Shareholders who are citizens or residents of the United States. EnCore Shareholders who are citizens or residents of the United States should consult their own legal and tax advisers with respect to the legal and tax consequences of the Scheme in their particular circumstances.

Other Jurisdictions

This document has been approved by the FSA, being the competent authority in the United Kingdom. The Company has requested the FSA to provide a certificate of approval and a copy of this document to the competent authority in the Republic of Ireland pursuant to the passporting provisions of FSMA.

This document and any accompanying documents are not being made available to Overseas Shareholders with registered addresses in any Restricted Jurisdiction and this document may not be treated as an invitation to subscribe for any New Premier Shares by any person resident or located in such jurisdictions or any other Restricted Jurisdiction.

The New Premier Shares have not been, and will not be, registered under the applicable securities laws of any Restricted Jurisdiction. Accordingly, the New Premier Shares may not be offered, sold, delivered or transferred, directly or indirectly, in or into any Restricted Jurisdiction to or for the account or benefit of any national, resident or citizen of any Restricted Jurisdiction.

The implications of the Scheme for Overseas Shareholders may be affected by the laws of relevant jurisdictions. Such Overseas Shareholders should inform themselves about and observe any applicable legal requirements. Any person outside the UK who is resident in, or who has a registered address in, or is a citizen of, an overseas jurisdiction and who is to receive New Premier Shares pursuant to the Scheme should consult his or her professional advisers and satisfy himself or herself as to the full observance of the laws of the relevant jurisdiction in connection with the Scheme, including obtaining any requisite governmental or other consents, observing any other requisite formalities and paying any issue, transfer or other taxes due in such jurisdiction.

This document has been prepared for the purposes of complying with English law, the Prospectus Rules and the Listing Rules, and the information disclosed may not be the same as that which

could have been disclosed if this document had been prepared in accordance with the laws of jurisdictions outside the United Kingdom.

THIS DOCUMENT DOES NOT CONSTITUTE AN OFFER TO SELL OR THE SOLICITATION OF AN OFFER TO BUY ANY SECURITY. NONE OF THE SECURITIES REFERRED TO IN THIS DOCUMENT SHALL BE SOLD, ISSUED OR TRANSFERRED IN ANY JURISDICTION IN CONTRAVENTION OF APPLICABLE LAW.

Overseas Shareholders should consult their own legal and tax advisers with respect to the legal and tax consequences of the Scheme in their particular circumstances.

PART VII

UNITED KINGDOM TAXATION CONSIDERATIONS

The comments set out below are based on existing United Kingdom law and what is understood to be current HM Revenue & Customs practice, both of which are subject to change, possibly with retrospective effect. They are intended as a general guide only and apply only to Premier Shareholders and Scheme Shareholders who are resident, or in the case of individuals, ordinarily resident for tax purposes in (and only in) the United Kingdom (except insofar as express reference is made to the treatment of non-United Kingdom residents), who hold Premier Shares as an investment (other than under a personal equity plan or individual savings account) and who are the absolute beneficial owners thereof. Certain categories of shareholders, such as traders, broker dealers, insurance companies and collective investment schemes, and shareholders who have (or are deemed to have) acquired their shares by virtue of or in connection with an office or employment, may be subject to special rules and this summary does not apply to such shareholders. The comments set out below relate only to certain limited aspects of the taxation treatment of shareholders.

Premier Shareholders and Scheme Shareholders who are in any doubt about their tax position, or who are resident or otherwise subject to taxation in a jurisdiction outside the United Kingdom, should consult their own professional advisers immediately.

Taxation of dividends

General

Premier is not required to withhold at source any amount in respect of United Kingdom tax when paying a dividend.

Individual shareholders within the charge to United Kingdom Income Tax

If Premier pays a dividend to a shareholder who is an individual resident or ordinarily resident (for tax purposes) in the United Kingdom or who carries on a trade, profession or vocation through a branch or agency in the United Kingdom and who holds Premier Shares for the purposes of such trade, profession or vocation or for such branch or agency, the shareholder will be entitled to a tax credit equal to one-ninth of the dividend received. The dividend received plus the related tax credit (the “gross dividend”) will be part of the shareholder’s total income for United Kingdom income tax purposes and will be regarded as the highest part of that individual’s income. However, in calculating the shareholder’s liability to income tax in respect of the gross dividend, the tax credit (which equates to 10 per cent. of the gross dividend) is set off against the tax chargeable on the gross dividend.

Basic rate taxpayers

In the case of a shareholder who is liable to income tax at the basic rate, the shareholder will be subject to tax on the gross dividend at the rate of 10 per cent. The tax credit will, in consequence, satisfy in full the shareholder’s liability to income tax on the gross dividend.

Higher rate taxpayers

In the case of a shareholder who is liable to income tax at the higher rate, the shareholder will be subject to tax on the gross dividend at the rate of 32.5 per cent., to the extent that the gross dividend falls above the threshold for the higher rate of income tax when it is treated (as mentioned above) as the highest part of the shareholder’s income. This means that the tax credit will satisfy only part of the shareholder’s liability to income tax on the gross dividend, so that the shareholder will have to account for income tax equal to 22.5 per cent. of the gross dividend (which equates to 25 per cent. of the dividend received). For example, assuming the entire gross dividend falls above the higher rate threshold and below the additional rate threshold, a dividend of £90 from Premier would represent a gross dividend of £100 (after the addition of the tax credit of £10) and the shareholder would be required to account for income tax of £22.50 on the dividend, being £32.50 (i.e. 32.5 per cent. of £100) less £10 (the amount of the tax credit).

Additional rate taxpayers

In the case of a shareholder who is liable to income tax at the additional rate, the shareholder will be subject to tax on the gross dividend at the rate of 42.5 per cent., to the extent that the gross

dividend falls above the threshold for the additional rate of income tax when it is treated (as mentioned above) as the highest part of the shareholder's income. This means that the tax credit will satisfy only part of the shareholder's liability to income tax on the gross dividend, so that the shareholder will have to account for income tax equal to 32.5 per cent. of the gross dividend (which equates to approximately 36.1 per cent. of the dividend received). For example, assuming the entire gross dividend falls above the additional rate threshold, a dividend of £90 from Premier would represent a gross dividend of £100 (after the addition of the tax credit of £10) and the shareholder would be required to account for income tax of £32.50 on the dividend, being £42.50 (i.e. 42.5 per cent. of £100) less £10 (the amount of the tax credit).

Corporate shareholders within the charge to United Kingdom Corporation Tax

Shareholders within the charge to United Kingdom corporation tax which are "small companies" (for the purposes of United Kingdom taxation of dividends) will not generally be subject to tax on dividends from Premier.

Other shareholders within the charge to United Kingdom corporation tax will not be subject to tax on dividends (including dividends from Premier) so long as the dividends fall within an exempt class and certain conditions are met. In general, dividends paid on shares that are "ordinary share capital" for United Kingdom tax purposes and are not redeemable and dividends paid to a person holding less than 10 per cent. of the issued share capital of the payer (or any class of that share capital) are examples of dividends that fall within an exempt class.

No payment of tax credit

A shareholder who is not liable to tax on dividends received from Premier in respect of his New Premier Shares will not be entitled to claim payment of the tax credit in respect of those dividends.

Non-residents

Individuals who are not resident in the UK will generally not be subject to UK income tax on UK dividends received.

The right of a shareholder who is not resident (for tax purposes) in the United Kingdom to a tax credit in respect of a dividend received from Premier in respect of his New Premier Shares and to claim payment of any part of that tax credit will depend on the existence and terms of any double taxation convention between the United Kingdom and the country in which the holder is resident, although generally no such payment will be available. Shareholders who are not resident in the United Kingdom may also be subject to tax on dividend income under any law to which they are subject outside the United Kingdom. Shareholders who are not solely resident in the United Kingdom should consult their own professional adviser concerning their tax liabilities on dividends received, whether they are entitled to claim any part of the tax credit and, if so, the procedure for doing so.

Taxation of chargeable gains

Shareholders who are resident or, in the case of individuals, ordinarily resident in the United Kingdom, or who cease to be resident or ordinarily resident in the United Kingdom or fall to be regarded as resident in a territory outside the United Kingdom for the purposes of double taxation arrangements for a temporary period, or who carry on a trade, profession or vocation through a branch or agency, or in the case of a company, a permanent establishment in the United Kingdom to which the shares are attributable may, depending on their circumstances, be liable to United Kingdom taxation on chargeable gains in respect of gains arising from a sale or other disposal of New Premier Shares and/or from a sale or disposal of Scheme Shares pursuant to the Scheme. Further details on the United Kingdom tax treatment of Scheme Shareholders are set out in Part V of the Scheme Document.

Stamp Duty and Stamp Duty Reserve Tax ("SDRT")

(a) New Premier Shares

No United Kingdom stamp duty or SDRT will generally be payable on the allotment and issue of New Premier Shares.

(b) Scheme of Arrangement

As the Scheme involves a cancellation of existing EnCore Shares and an issue of New Premier Shares to the EnCore Shareholders, there would be no "transfer on sale" for stamp duty purposes

or agreement to transfer for SDRT purposes. Therefore no stamp duty or SDRT charge should arise in respect of the EnCore Shares. Further details on the United Kingdom tax treatment of Scheme Shareholders are set out in Part V of the Scheme Document.

(c) Subsequent transfers

Subject to an exemption for certain low value transactions, any subsequent dealings in New Premier Shares will generally be subject to stamp duty or SDRT in the normal way. The transfer on sale of New Premier Shares will be liable to ad valorem stamp duty, generally at the rate of 0.5 per cent. thereof (rounded to the nearest multiple of £5) of the consideration paid. An unconditional agreement to transfer such shares will be liable to SDRT, generally at the rate of 0.5 per cent. of the consideration paid, but such liability will be cancelled or a right to a repayment in respect of the SDRT liability will arise if the agreement is completed by a duly stamped transfer within six years of the agreement having become unconditional. Stamp duty or SDRT is normally the liability of the purchaser. Under the CREST system for paperless share transfers, no stamp duty or SDRT will arise on a transfer of shares into the system provided, in the case of SDRT, the transfer is not for money or money's worth. Transfers of shares within CREST are liable to SDRT (at a rate of 0.5 per cent. of the amount or value of the consideration payable) rather than stamp duty, and SDRT on relevant transactions settled within the system or reported through it for regulatory purposes will be collected by CREST.

The above statements are intended only as a general guide and it should be noted that certain categories of person, including market makers, brokers, dealers and other specified market intermediaries, are entitled to exemption from stamp duty and SDRT in respect of purchases of securities in specified circumstances. Certain other persons, being mainly those connected within depositary arrangements and clearance services, are generally liable to account for stamp duty or SDRT at a higher rate on securities issued or transferred to them. Other persons may, although not primarily liable for SDRT, be required to notify and account for it.

The comments above relating to stamp duty and SDRT apply whether or not a Shareholder is resident or ordinarily resident in the United Kingdom.

PART VIII

DIRECTORS, RESPONSIBLE PERSONS, CORPORATE GOVERNANCE AND EMPLOYEES

1. Persons Responsible

The Premier Directors, whose names appear at paragraph 2 below, and the Company accept responsibility for the information contained in this document. To the best of the knowledge of the Premier Directors and the Company (who have taken all reasonable care to ensure that such is the case) such information is in accordance with the facts and does not contain anything likely to affect the import of such information.

2. Directors

The following table sets out information relating to each of the Premier Directors as at the date of this document:

<i>Name</i>	<i>Age</i>	<i>Position</i>
Executive Directors:		
Simon Lockett	47	Chief Executive
Tony Durrant	53	Finance Director
Robin Allan	51	Director – Asia
Neil Hawkings	50	Operations Director
Andrew Lodge	55	Exploration Director
Non-Executive Directors:		
Mike Welton	65	Chairman
Professor Dr. David Roberts	68	Non-Executive Director
Joe Darby	63	Non-Executive Director
David Lindsell	64	Non-Executive Director
Michel Romieu	72	Non-Executive Director
Jane Hinkley	61	Non-Executive Director

The business address of all the Premier Directors is 23 Lower Belgrave Street, London SW1W 0NR.

Director's Profiles

Set forth below are the business experience and principal business activities performed outside of Premier by the current Premier Board members, as well as the dates of their initial appointment as directors.

Simon Lockett

Simon Lockett joined Premier in January 1994 from Shell and has worked in a variety of roles for Premier, including the management of investor relations, as Commercial Manager in Indonesia and as Country Manager in Albania. He became a member of the Premier Board in December 2003 as Operations Director. He was appointed Chief Executive in March 2005.

Tony Durrant

Tony Durrant joined Premier in June 2005. After qualifying as a chartered accountant with Arthur Andersen, he joined Lehman Brothers in London, initially as an oil sector analyst. He joined the investment banking division of Lehman in 1987 and from 1997 was a Managing Director and Head of the European Natural Resources Group. In this role, he managed both client relationships and numerous transactions for a variety of European and North American clients. He joined the Premier Board in July 2005 as Finance Director.

Robin Allan

Robin Allan joined Premier from Burmah Oil in July 1986, working initially as a geologist. After technical and new venture roles he spent six years in South East Asia, initially managing Premier's Asian existing and new venture business and later becoming Premier's Country Manager in

Indonesia. He became a member of the Premier Board in December 2003 as Director of Business Development. Mr Allan returned to Asia in 2009 as Director – Asia, and manages the Asian portfolio from the Singapore office.

Neil Hawkings

Neil Hawkings joined Premier in May 2005 after more than 20 years with ConocoPhillips where he worked in a variety of engineering, commercial and management roles around the world, undertaking assignments in the UK, Dubai and Indonesia. He joined the Premier Board in March 2006 as Operations Director.

Andrew Lodge

Andrew Lodge has been Exploration Director of Premier since April 2009. Prior to joining Premier, Mr Lodge was Vice President – Exploration at Hess, where he was responsible for Europe, North Africa, Asia and Australia for nine years. Previously, he was Vice President – Exploration, Asset Manager and Group Exploration Advisor for BHP Petroleum, based in London and Australia. Prior to joining BHP Petroleum, Andrew worked for BP as a geophysicist.

Mike Welton

Mike Welton joined Premier's Board in June 2009 as a non-executive director and became Chairman in October 2009. Mr Welton is also Chairman of Southern Water Services Ltd and a director of Morrison Utility Services and High Speed Two, the government-owned LLC set up to examine high speed rail connections between London and the West Midlands. He sits on the advisory board of Montrose Associates. Mr Welton was previously Chairman of Hanson plc (2005-2007), the Turkish/British Business Council and the UK Government's Railway Sector Advisory Group. He was also Chief Executive of Balfour Beatty plc (1999-2004).

Professor Dr. David Roberts

Professor Dr. David Roberts joined Premier in June 2006 as a non-executive director. Professor Roberts has over 30 years experience in all aspects of exploration worldwide and extensive knowledge of deep water areas, sedimentary basins, stratigraphy and prospect assessment. He spent 22 years with BP in a number of technical roles, including Global Exploration Adviser and Distinguished Exploration Adviser. Professor Dr. Roberts is a non-executive director of GETECH plc and Medserv plc and has established his own geoscience consultancy. He is a visiting professor and fellow of Royal Holloway, University of London, the University of Southampton and IFP School in Paris.

Joe Darby

Joe Darby is currently the Senior Independent Director on Premier's Board. He joined the Board as a non-executive director in September 2007. Mr Darby has over 40 years of experience in the energy sector, including eight years with Shell Petroleum before becoming Managing Director of Thomson North Sea Ltd. He has held a number of senior roles, including Chief Executive, with LASMO plc. Mr Darby is a non-executive director of Alkane Energy plc and has held non-executive roles at Nordaq Energy plc, British Nuclear Fuels plc, Mowlem plc and Centurion Energy Inc. He was Chairman of Mowlem plc (2005-2006) and Faroe Petroleum plc (2003-2007).

David Lindsell

David Lindsell joined Premier's Board in January 2008 as a non-executive director. He was a partner at Ernst & Young LLP for nearly 30 years and has extensive experience across a range of industry sectors, with a strong knowledge of the oil and gas sector. Mr Lindsell is currently a non-executive director of Drax Group plc and Gartmore Group Ltd and is Deputy Chairman of the Financial Reporting Review Panel.

Michel Romieu

Michel Romieu joined Premier's Board as a non-executive director in January 2008. Mr Romieu has over 30 years experience in the international energy sector, including 25 years with the Elf Group, where he held several senior positions including Chief Executive of Elf UK and the group's gas division. He was elected President of the UK Offshore Operator's Association for the year 1995, and held the position of Director for Gas of CRE, the French energy regulator, from 2000 to 2003. He has established his own consultancy specialising in providing advice to the gas industry, and is a lecturer at the French Petroleum Institute. Mr Romieu is also President of Uprigaz.

Jane Hinkley

Jane Hinkley joined Premier's Board in September 2010 as a non-executive director. Ms Hinkley is a qualified chartered accountant with executive experience primarily in international shipping. She has held managing directorships at Navion Shipping AS and Gotaas-Larsen Shipping Corporation. She has been an independent director on the board of Teekay GP LLC, an international provider of marine transportation services for LNG, LPG and crude oil, since 2005 and also previously held the position of non-executive director of Revus Energy ASA, a Norwegian exploration and production company.

3. Directors' Service Contracts and Emoluments

Base salary, fees, bonuses and benefits-in-kind

Premier's remuneration policy for executive Directors is to provide remuneration packages which reward employees fairly and responsibly for their contributions and aim to deliver superior remuneration for superior performance. The Remuneration Committee, as set out in paragraph 6 below, takes account of the level of remuneration paid in respect of comparable positions in similar companies within the industry, as well as broadly similar sized companies by market capitalisation in the FTSE 250 index, and also pay and conditions throughout the remainder of the group.

The amount of remuneration paid and benefits in kind granted to the Directors by Premier for services to Premier in the financial year ended 31 December 2010 (being the last full financial year for Premier) is set out in the Remuneration Report on pages 40-58 of Premier's Annual Report and Accounts for the year ended 31 December 2010, which is incorporated into this document by reference. Specifically, the remuneration paid to the executive Directors during the year ended 31 December 2010, including salary, benefits and bonuses, is set out in the table headed "Directors' emoluments" on page 48 of the Annual Report and Accounts, and the remuneration paid to the non-executive Directors during that year is set out in the table headed page 49 of the Annual Report and Accounts.

Retirement benefits

The retirement benefits of the Premier Directors are set out in the section headed "Pension Schemes" on pages 49 and 50 of Premier's Annual Report and Accounts for the year ended 31 December 2010, which is incorporated into this document by reference.

The total amounts set aside by Premier to provide retirement benefits for its employees are set out under the heading "Group pension schemes" on page 93 of the Annual Report and Accounts for the year ended 31 December 2010, which is incorporated into this document by reference.

Share ownership and options held by Directors

The interests, all of which are beneficial, of the Premier Directors (i) as at 16 November 2011, being the last practicable date prior to the publication of this document; and (ii) as expected to subsist immediately following the Acquisition, assuming the maximum number of 65,212,513 New Premier Shares are issued pursuant to the Acquisition, are set out in the following table:

	<i>Interests as at 16 November 2011</i>		<i>Interests immediately following Admission*</i>	
	<i>Number of shares</i>	<i>Percentage of issued share capital</i>	<i>Number of shares</i>	<i>Percentage of issued share capital**</i>
Robin Allan	404,759	0.086	404,759	0.076
Joe Darby	23,108	0.005	23,108	0.004
Tony Durrant	857,618	0.183	857,618	0.161
Neil Hawkings	505,394	0.108	505,394	0.095
Jane Hinkley	4,000	0.001	4,000	0.001
David Lindsell	17,332	0.004	17,332	0.003
Simon Lockett	1,255,394	0.268	1,255,394	0.235
Andrew Lodge	213,447	0.046	213,447	0.041
Professor Dr. David Roberts	None	—	None	—
Michel Romieu	None	—	None	—
Mike Welton	22,531	0.005	22,531	0.004

* The executive Directors will increase their interests in Premier Shares between 16 November 2011 and the Effective Date on account of purchases made through Premier's Share Incentive Plan.

** Assuming that the maximum number of New Premier Shares to be issued pursuant to the Scheme is issued.

Taken together, the combined percentage interest of the Premier Directors in the issued ordinary share capital as at 16 November 2011 was approximately 0.706 per cent.

Details of options over Premier Shares held by the Premier Directors are set out below. They are not included in the interests of the Premier Directors shown in the table above.

	<i>Number of Premier Shares subject to option</i>	<i>Exercise Price (£)</i>	<i>Date from which exercisable</i>	<i>Expiry Date</i>
Robin Allan	8,048	2.0344	01/06/2012	30/11/2012
Simon Lockett	3,480	2.605	01/06/2013	30/11/2013
Andrew Lodge	3,480	2.605	01/06/2013	31/12/2013

The Directors' interests in deferred bonus shares, deferred and matching share awards under the Asset and Equity Plan and Share Incentive Plan entitlements for the financial year ended 31 December 2010 (being the last full financial year for Premier) are set out in the section headed "Remuneration Report" on page 40 of Premier's Annual Report and Accounts for the year ended 31 December 2010, which is incorporated into this document by reference. The interests stated in the Annual Report and Accounts for the year ended 31 December 2010 are stated prior to the 4:1 share split, effective as of 8.00 a.m. on Monday 23 May 2011.

Save as disclosed in this paragraph 3, no Premier Director nor their immediate families, nor any person connected with any Premier Director within the meaning of Section 252 of the Companies Act 2006, has any interests (beneficial or non-beneficial) in the share capital of Premier or any of its subsidiaries.

4. Directors' Interests

No Premier 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 Premier and which was effected by Premier during the current or immediately preceding financial year and which remains in any respect outstanding or unperformed.

There are no outstanding loans granted by Premier or any member of the Premier Group to any of the Premier Directors, nor has any guarantee been provided by Premier or any of its subsidiaries for their benefit.

5. Service Contracts of the Directors

Executive Directors' Service Contracts

The service contract of each executive Director may be terminated on 12 months' notice in writing by either side, in accordance with current market practice. In such event, the compensation commitments in respect of their contracts could amount to 12 months' remuneration based on base salary, long-term incentive scheme entitlement, benefits-in-kind and pension rights during the notice period. In line with normal market practice, an individual may receive an annual bonus for the proportion of a financial year worked before cessation of employment but there will be no right to any bonus for any period of notice not worked.

There are provisions for earlier termination in certain circumstances. If such circumstances were to arise, the executive Director concerned would have no claim against the Company for damages or any other remedy in respect of the termination. The Remuneration Committee would apply general principles of mitigation to any payment made to a departing executive Director and would consider each case on an individual basis.

Messrs Lockett and Allan have service contracts dated 9 December 2003. Mr Durrant has a service contract dated 1 July 2005; Mr Hawkings has a service contract dated 23 March 2006; and Mr Lodge has a service contract dated 20 April 2009.

Non-Executive Directors' letters of appointment

Non-executive Directors of Premier have letters of appointment, which are all effective for a period of three years (subject to reappointment by members in general meeting) and all of which have a notice period of three months. Mr Welton and Professor Dr. Roberts have service contracts dated 23 September 2009; Mr Darby and Ms Hinkley each have a service contract dated 1 September 2010 and Messrs Lindsell and Romieu have service contracts dated 17 January 2011.

6. Corporate Governance

Premier is firmly committed to high standards of corporate governance. Premier has established procedures and policies to ensure compliance with the Corporate Governance Code. Premier has complied throughout the accounting period to the year ended 31 December 2010 with the provisions of Section 1 of the Corporate Governance Code, except where reported in the section headed "Corporate Governance" on page 28 of Premier's Annual Report and Accounts for the year ended 31 December 2010, which is incorporated into this document by reference.

Board committees

The Premier Board has established Remuneration, Audit and Risk and Nomination Committees. Each committee has formal terms of reference approved by the Board which can be found on the Company's website. Board committees are authorised to engage the services of external advisers as they deem necessary. With the exception of Kepler Associates, which assisted the Remuneration Committee, no external advisers materially assisted any committee during the year ended 31 December 2010.

Remuneration Committee

The Remuneration Committee determines the remuneration of the Chairman, the executive Directors and senior management. The Remuneration Committee is composed entirely of non-executive Directors and comprises Ms Hinkley (Chairman), Mr Darby, who is the Company's senior non-executive independent Director, Professor Dr. Roberts and Mr Lindsell. The Premier Board considers the membership of the Remuneration Committee to be in compliance with the Corporate Governance Code.

The Committee acts within its agreed written terms of reference and complies with the relevant provisions of the Corporate Governance Code in implementing its remuneration policy.

The role of the Remuneration Committee includes:

- considering and determining the remuneration policy for the Chairman, executive Directors and senior management;

- within this agreed policy, considering and determining the total compensation package of each executive Director;
- considering and advising on the general principles under which remuneration is applied to employees of the Company;
- determining the awards to be made under the Company's long-term incentive schemes; and
- determining the policy for pension arrangements, service agreements and termination payments to the Directors.

Kepler Associates were appointed as the independent adviser to the Remuneration Committee in October 2011. Prior to this, Hewitt New Bridge Street (a trading name of Aon Corporation) was the independent adviser to the Remuneration Committee. Neither Hewitt New Bridge Street nor any other part of Aon Corporation provided other services to the Company during the year ended 31 December 2010. The Committee also takes advice from Capita Hartshead in relation to pension policy.

Audit and Risk Committee

The Audit and Risk Committee, comprising only non-executive Directors, reviews the Group's accounts and its internal controls. The Committee's terms of reference include all matters indicated by Disclosure and Transparency Rule 7.1 and the Corporate Governance Code. The members of the Audit and Risk Committee are Messrs Lindsell (Chairman), Darby and Romieu. The Premier Board considers all members of the Committee to have the relevant commercial, financial and accounting experience to assess effectively the complex financial reporting, risk and internal control issues relevant to the Company.

Minutes of the meetings of the Committee are distributed to all Premier Board members, all of whom are invited to attend meetings of the Committee (as observers) since the Premier Board believes that the work of the Committee, particularly in the areas of risk management and internal control, is increasingly important for all Board members.

The Audit and Risk Committee is responsible for:

- monitoring the integrity of the financial statements of the Company and formal announcements relating to the Company's financial performance and reviewing any significant financial reporting judgements contained in them;
- reviewing the Company's internal financial and operational control and risk management systems;
- reviewing accounting policies, accounting treatments and disclosures in financial reports to ensure clarity and completeness;
- overseeing the Company's relationship with its external auditors, including making recommendations as to the appointment or reappointment of the external auditors, their terms of engagement and monitoring their independence; and
- reviewing the Company's whistleblowing procedures and ensuring these are adequately published within the organisation, that the Committee chairman is promptly informed of any issues, and that there are arrangements in place for the investigation of any alleged improprieties.

Nomination Committee

The Nomination Committee meets as and when required and comprises Mr Welton (Chairman), Messrs Darby, Lindsell, Lockett and Romieu, Ms Hinkley, and Professor Dr. Roberts. The Premier Board considers the membership of the Nomination Committee to be in compliance with the Corporate Governance Code.

The role of the Nomination Committee includes:

- reviewing the structure, size and composition of the Board and making recommendations to the Board with regard to any adjustments that are deemed necessary. This requires an ongoing assessment of the appropriate skills-mix required at Board level in light of the strategy of the Company in the medium-term;

- responsibility for identifying and nominating candidates, subject to Board approval, to fill Board vacancies as and when they arise and to prepare a description of the role and capabilities required for a particular appointment; and
- the assessment of time required to fulfil the role of chairman of the Company, Senior Independent Director and Non-Executive Director, ensuring that current members of the Premier Board have devoted sufficient time to their duties and that any candidates have sufficient time to undertake the roles.

7. Employees

The average number of employees of the Group for the last three financial years is stated in note 4 to the financial statements in Premier's Annual Report and Accounts for the years ended 31 December 2008, 31 December 2009 and 31 December 2010, which are incorporated into this document by reference.

8. Directors' Confirmations

At the date of this document none of the Premier Directors:

- has any convictions in relation to fraudulent offences for at least the previous five years;
- has been associated with any bankruptcy, receivership or liquidation while acting in the capacity of a member of the administrative, management or supervisory body or of senior manager of any company for at least the previous five years; or
- has been subject to any official public incrimination and/or sanction of him by any statutory or regulatory authority (including any designated professional bodies) nor has ever 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 an issuer or from acting in the management or conduct of the affairs of any issuer for at least the previous five years.

9. Conflicts of interest

Formal procedures are in place to ensure the Board's powers of authorisation of conflicts or potential conflicts of interest of the Directors are operated effectively. The Directors determined that during 2010 these procedures were enforced and adhered to appropriately. The following actual and potential conflicts of interest between the Directors' duties to the Company and their private interests and/or other duties have been authorised by the Board for the purposes of Section 175(4)(b) of the Companies Act:

<i>Director</i>	<i>Date Authorised</i>	<i>Potential or Actual Conflict</i>	<i>Details of Conflict</i>
Joe Darby	21/10/2011	Potential	Mr Darby's daughter works in finance for BG plc, which is a competitor of the Group and therefore could possibly give rise to a conflict.
	21/10/2011	Potential	Mr Darby's son works in finance for Centrica plc, which is a potential customer and a competitor of the Group, which therefore could possibly give rise to a conflict.
Tony Durrant	21/10/2011	Actual	Mr Durrant is also a director of Premier Pension Plan Trustees Limited, the trustee company for the Premier Oil plc Retirement and Death Benefits Plan.
Professor Dr. David Roberts	21/10/2011	Potential	Mr Roberts' daughter works as a trade control analyst for BP Oil, which is a competitor of the Group and therefore could possibly give rise to a conflict.
Mike Welton	21/10/2011	Potential	Mr Welton's son works as an analyst for Wood Mackenzie which is a supplier of oil and gas consulting and other services and therefore could possibly give rise to a conflict.

There are no other potential conflicts of interest relating to any of the Premier Directors and no interests, including conflicting ones, that are material to the Acquisition.

No Director has or had during the year ended 31 December 2010 or half year ended 30 June 2011 a material interest in any significant contract with Premier or any of its subsidiaries.

10. Directorships and Partnerships

The following Premier Directors hold or have held in the past five years the following directorships in companies in addition to their directorships of Premier and past or current members of the Group and are or have been a member of any of the following partnerships in the past five years:

<i>Director</i>	<i>Position</i>	<i>Company</i>	<i>Still held</i>
Joe Darby	Director	Alkane Energy plc	Yes
	Director	British Nuclear Fuels Limited (formerly plc)	No
	Director	Faroe Petroleum plc	No
	Director	Mallards Reach (Oakley) Management Company Limited	No
	Director	Sandleigh Limited	Yes
Tony Durrant	Director	Nordaq Energy plc	No
	Director	Clipper Windpower Limited	No
Neil Hawkings	Director	The United Kingdom Offshore Oil and Gas Industry Association Limited	No
	Director	Teekay GP LLC	Yes
Jane Hinkley	Director	Revus Energy ASA	No
	Director	Abbey Gateway Enterprises Limited	No
David Lindsell	Director	Drax Group plc	Yes
	Director	Gartmore Group Limited	Yes
	Director	The BM Co Pension Trustee Company Limited	Yes
	Director	The British Museum Company Limited	Yes
	Director	The British Museum Friends	No
	Director	St Albans School	No
	Director	St Albans School Woollam Trustee Company	No
	Partner	Ernst & Young LLP	No
Andrew Lodge	Director	Hess Egypt Limited	No
	Director	Hess (Indonesia Deepwater) Limited	No
	Director	Hess (Indonesia-Kasuri) Limited	No
	Director	Hess (Indonesia-Semai IV) Limited	No
	Director	Hess (Indonesia-Semai V) Limited	No
	Director	Hess (Malaysia-Block F) Limited	No
	Director	Hess (Malaysia-SB 302) Limited	No
	Director	Hess (North Africa) Exploration Limited	No
	Director	Hess (Offshore Egypt) Exploration Limited	No
	Director	Hess Australia (Dampier) Pty Limited	No
	Director	Hess Australia (Exmouth) Pty Limited	No
	Director	Hess Australia (North West Shelf) Pty Limited	No
	Director	Hess Australia (Offshore) Pty Limited	No
	Director	Hess Australia Exploration (New Ventures) Pty Limited	No
	Director	Hess Egypt Exploration Limited	No
	Director	Hess Egypt New Ventures Limited	No
	Director	Hess Egypt West Mediterranean Limited	No
	Director	Hess Exploration (Carnarvon) Pty Limited	No
	Director	Hess Exploration (Thailand) Co. Limited	No
	Director	Hess Exploration Australia Pty Limited	No
	Director	Hess Exploration Ireland Limited	No
	Director	Hess Libya Exploration Limited	No
	Director	Hess Norge AS	No
	Director	Hess Production (Australia) Pty Limited	No
	Director	Hess (Indonesia Jambi-Merang) Limited	No
	Director	Hess (Indonesia Pangkah) Limited	No
	Director	Hess (Indonesia-Blora) Limited	No
	Director	Hess Indonesia New Ventures Limited	No
	Director	Hess Overseas Limited	No
	Director	Hess (Indonesia-Tanjung Aru) Limited	No
	Director	Hess (Faroes) Limited	No
	Director	Hess (Thailand) Limited	No

<i>Director</i>	<i>Position</i>	<i>Company</i>	<i>Still held</i>
	Director	Hess Limited	No
	Director	Hess Indonesia (North Masela) Limited	No
	Director	Hess (Indonesia-South Sesulu) Limited	No
	Director	Hess Services UK Limited	No
	Director	Hess Holdings UK Limited	No
	Director	Hess (Martaban) Limited	No
	Director	Hess Indonesia Exploration Limited	No
	Director	Hess (Indonesia) Limited	No
	Director	Amerada Hess (Khazar) Limited	No
	Director	Hess (Australia) Limited	No
	Director	Hess (Azerbaijan) Limited	No
	Director	Hess (Yemen) Limited	No
	Director	Amerada Hess (Brasil) Limited	No
	Director	Amerada Hess (Vietnam) Limited	No
	Director	Amerada Hess (Argentina) Limited	No
	Director	Amerada Hess (CAO) Limited	No
	Director	Amerada Hess (China) Limited	No
	Director	Amerada Hess (France) Limited	No
	Director	Amerada Hess (Germany) Limited	No
	Director	Amerada Hess (Indonesia) Limited	No
	Director	Amerada Hess (Ireland) Limited	No
	Director	Amerada Hess (MAN) Limited	No
	Director	Amerada Hess (NAOC) Limited	No
	Director	Amerada Hess (Netherlands) Limited	No
	Director	Amerada Hess (Indonesia-Pagatan) Limited	No
	Director	Amerada Hess (Indonesia-Sesulu) Limited	No
	Director	Amerada Hess (IOM) Limited	No
Professor Dr. David Roberts	Director	Geological Trading Limited	No
	Director	Getech Group plc	Yes
	Director	Roberts Geosciences Consulting Limited	No
	Director	Rockall GeoSciences Limited	No
	Director	Roberts Geosciences Consulting Malta Limited	Yes
Michel Romieu	Director	Sican Petroleum plc	Yes
Mike Welton	Director	G4S 308 (UK) Limited	Yes
	Director	Greensands Holdings Limited	Yes
	Director	Hanson Limited	No
	Director	High Speed Two (HS2) Limited	Yes
	Director	Morrison Utility Services Group Limited	Yes
	Director	Southern Water Services Limited	Yes
	Director	Southern Water (NR) Holdings Limited	Yes
	Director	Southern Water (NR) Limited	Yes
	Director	Southern Water Investments Limited	Yes
	Director	Southern Water Limited	Yes
	Director	Southern Water Services Group Limited	Yes
	Director	Southern Water Services (Finance) Limited	Yes
	Director	SWS Group Holdings Limited	Yes
	Director	SWS Holdings Limited	Yes
	Director	Defacto 1119 Limited	No

PART IX

ADDITIONAL INFORMATION

1. The Company

The Company was incorporated and registered with the name of Dalglen (No. 836) Limited in Scotland on 31 July 2002 with registration number SC234781. The name of the Company was changed from Dalglen (No. 836) Limited to Premier Oil Group Limited pursuant to a written resolution passed on 13 September 2002. The Company was re-registered as a public limited company on 10 March 2003. The name of the Company was changed from Premier Oil Group plc to Premier Oil plc pursuant to a special resolution passed on 3 March 2003, which became effective on 15 July 2003.

The principal legislation under which Premier operates, and pursuant to which the New Premier Shares will be created, is the Companies Act 1985, the Companies Act 2006 and regulations made thereunder.

The Company is domiciled in the United Kingdom and its registered office is 4th Floor, Saltire Court, 20 Castle Terrace, Edinburgh EH1 2EN. Premier's head office is 23 Lower Belgrave Street, London SW1W 0NR.

Premier Oil plc acquired Premier Oil Group Limited as part of a restructuring in 2003. Premier Oil Group Limited was originally incorporated and registered in Scotland on 10 April 1934.

The Existing Premier Shares are listed on the Official List of the UKLA and are admitted to trading on the London Stock Exchange. The ISIN of the Existing Premier Shares is GB00B43G0577. The Premier Shares are in registered form and may be held in either certificated or uncertificated form.

2. Share Capital

Premier has one class of Ordinary Share which carries no right to fixed income. Each share carries one right to vote at General Meetings of the Company. There are no specific restrictions on the size of a holding or the transfer of shares, which are both governed by the general provisions of the Articles of Association and prevailing legislation. The Premier Directors are not aware of any agreements between holders of the Company's shares that may result in restrictions on the transfer of securities or on voting rights. No person has any special rights of control over the Company's share capital and all issued shares are fully-paid.

The rights of the holders of ordinary shares rank *pari passu* in all respects with each other in relation to dividends. On a return of capital on a winding up or otherwise (other than on conversion, redemption or purchase of shares) the rights of the holders of ordinary shares to participate in the distribution of the assets of the Company available for distribution rank *pari passu* in all respects with each other.

As at 16 November 2011, being the latest practicable date prior to the publication of this document, the Company's issued share capital was 468,057,712 ordinary shares having a nominal value of 12.5 pence each. Immediately following the Effective Date, assuming the maximum number of 65,212,513 New Premier Shares is issued pursuant to the Acquisition and that no Premier Shares are issued or repurchased in the period from the publication of this document to the Effective Date, the number of issued Premier Shares will be 533,270,225.

History of share capital

The Company was incorporated with a share capital of £100 divided into 100 shares of £1 each. The authorised share capital of the Company was increased to £100,000 pursuant to a written resolution passed on 13 September 2002, by the creation of £99,900 shares of £1 each. By a special resolution passed on 3 February 2003, 49,998 shares of £1 each were redesignated as redeemable preference shares of £1 each.

By a special resolution passed on 3 February 2003 and which became effective on 15 July 2003: (i) the share capital of the Company was increased to £399,394,555.875, by the creation of a further 15,971,782,235 shares of 2.5 pence each; (ii) each of the 49,998 redeemable preference shares of £1 each were redesignated and subdivided into 40 shares of 2.5 pence each; (iii) each of the 50,002 shares of £1 each were subdivided into 40 shares of 2.5 pence each; (iv) then every 7 authorised but unissued shares of 2.5 pence each were consolidated into one share of

17.5 pence each; and (v) 2,282,254,605 shares were redesignated as 2,250,000,000 ordinary shares of 17.5 pence each and 32,254,605 non-voting convertible shares of 17.5 pence each.

By a special resolution passed on 3 February 2003, which was confirmed by the Court of Session and became effective on 12 September 2003, the share capital of the Company was reduced by (i) cancelling 12.5 pence of paid up capital on each Ordinary Share of 17.5 pence each and non-voting convertible share of 17.5 pence each in issue on 11 September 2003; and then (ii) cancelling each Ordinary Share of 5 pence each and non-voting convertible share of 5 pence each held by Amerada Hess Limited and Petronas International Corporation Limited on 11 September 2003. By a special resolution passed on 3 February 2003 and which became effective on 12 September 2003 (following the reduction of capital), the ordinary share capital of the Company was consolidated into 311,904,002 ordinary shares of 50 pence each (with the authorised but unissued non voting convertible shares of 17.5 pence left unchanged).

By a special resolution passed on 6 June 2008 the authorised share capital of the Company was increased by £0.525 to £157,612.282 by the creation of three non-voting convertible shares of 17.5 pence each. By a special resolution passed on 6 June 2008 the 9,487,317 existing authorised but unissued non-voting convertible shares of 17.5 pence each in the capital of the Company and three further such shares created on 6 June 2008, were consolidated and redesignated as 3,320,562 ordinary shares of 50 pence each in the capital of the Company.

On 25 March 2009, Premier announced its proposal to raise approximately £171 million (US\$269.7 million) by way of a fully underwritten rights issue. Under the proposal, the Company offered its shareholders the opportunity to acquire four new ordinary shares for every nine ordinary shares held at a price of 485 pence per new ordinary share. The proposal was subject to authorisation by shareholders which was obtained at a General Meeting held on 20 April 2009. The offer period commenced on 21 April 2009 and closed for acceptance on 6 May 2009. Dealing in the new shares began on 7 May 2009.

By a special resolution passed on 21 May 2010, Premier's authorised share capital was removed from its Articles of Association. The Premier Directors will still be limited as to the number of shares they can at any time allot because allotment authority continues to be required under the Companies Act 2006, save in respect of employee share schemes.

By an ordinary resolution passed on 20 May 2011, which became effective on 23 May 2011, each of the Company's ordinary shares of 50 pence each was sub-divided into four new ordinary shares of 12.5 pence each (the "Share Split"). The Share Split resulted in shareholders holding four new ordinary shares of 12.5 pence each in the Company for each existing ordinary share they held immediately prior to the Share Split.

Share buy-back

Pursuant to an authority granted at its annual general meeting held on 20 May 2011, Premier is authorised to make market purchases of its own shares of an aggregate nominal value of up to £17,459,386. Premier is currently considering whether to exercise this authority and to make market purchases of its own shares through a share buy-back programme which, if approved, would be undertaken following completion of the Acquisition. The Premier Directors would only exercise this authority if they believed that it would be in the best interests of Premier Shareholders generally.

Shares held by or on behalf of Premier

As at 16 November 2011 (the latest practicable date prior to the publication of this document), the Company held no shares in treasury.

Share-based payments

Ordinary shares with an aggregate nominal value of £11,423 were issued during 2010 relating to Premier's share option plans (2009: £12,113). Ordinary shares with a nominal value of £850,000 were issued to the Premier Oil plc Employee Benefit Trust during 2010 and in April 2011 ordinary shares with a nominal value of £300,000 were issued to the Premier Oil plc Employee Benefit Trust, in each case to be used to satisfy future awards under the Company's long-term incentive arrangements.

Share Option Plans

Premier has share option schemes under which options to subscribe for the Company's shares have been granted to certain executives and employees. Options granted are normally exercisable not less than three years after their grant and will lapse on their tenth anniversary. Options cannot be exercised until pre-determined performance conditions have been achieved.

Under the Savings Related Share Option Scheme, eligible employees with six months or more continuous service can join the scheme. Employees can save up to a maximum of £250 per month through payroll deductions for a period of three or five years, after which time they can acquire shares at up to a 20 per cent discount.

Under the Share Incentive Plan employees are invited to make contributions to buy partnership shares. If an employee agrees to buy partnership shares the Company currently matches the number of partnership shares bought with an award of shares, on a one-for-one basis.

The weighted average share price at the date of exercise for share options exercised in 2010 was £14.28. The options outstanding at 31 December 2010 had a weighted average exercise price of £8.33 and a weighted average remaining contractual life of 3.0 years.

The fair value of the options granted during the year was determined using the Black-Scholes valuation model and is not material.

The group recognised a cost of US\$52.7 million and US\$27.3 million related to equity-settled share-based payment transactions in 2010 and 2009 respectively.

Asset and Equity Plan

The Asset and Equity Plan is designed to reward employees for improvement in the asset value of the business and the market value of the Company over a three-year period and is operated by reference to two bonus pools – an equity bonus pool and an asset bonus pool. The asset bonus pool is created by reference to the increase in the net asset value per share of the Company over a three-year period and the equity bonus pool is created by reference to the increase in the equity market value per share of the Company over a three-year period.

The Company uses a Monte Carlo simulation model to calculate the value of the equity bonus pool of the plan.

The main assumptions used for the calculations are as follows:

Volatility:	31.5 per cent.
Risk free rate of interest:	4.4 per cent.
Historic market value growth factor:	109.0 per cent.

For the asset bonus pool a discounted cash flow model based on the average oil price over the period is used to calculate the final value of the pool and to estimate the value of future asset bonus pools.

The Asset and Equity Plan expired in 2009 and the award granted in 2008, which matured at the end of 2010, is the last award remaining under the plan.

Long Term Incentive Plan

The Long Term Incentive Plan ("LTIP") was introduced in 2009 to provide a long-term all-employee scheme which motivates all employees and provides a longer-term perspective to the total remuneration package. Awards under the LTIP comprise three elements: Equity Pool Awards, Performance Share Awards that vest after the expiry of a three-year performance period, and a potential Matching Award that vests at the expiry of a further three-year performance period, commencing at the end of the three-year performance period for Equity Pool and Performance Share Awards.

Full details about this plan are set out in the section headed "Remuneration Report" on pages 40-58 of the Premier Annual Report and Accounts for the year ended 31 December 2010.

The Company uses a Monte Carlo simulation model to calculate the value of the equity bonus pool of the plan and of the Performance Share Awards.

The main assumptions used for the calculations are as follows:

Volatility:	40.0 per cent. to 41.0 per cent.
Risk free rate of interest:	3.3 per cent. to 3.7 per cent.
Correlation factor with comparator group:	0.29 to 0.30

For the year ended 31 December 2010, the total cost recognised by the Premier Group for long-term incentive arrangements was US\$38.9 million (2009: US\$46.1 million), with a cumulative liability on the balance sheet of US\$nil (2009: US\$28.4 million).

A credit of US\$52.7 million has been recorded in retained earnings (2009: US\$27.3 million) for all equity-settled payments of the Group. Like other elements of remuneration, this charge is processed through the time-writing system which allocates cost, based on time spent by individuals, to various entities within the Premier group. Part of this cost is therefore capitalised as directly attributable to capital projects and part is charged to the income statement as operating costs, pre-licence exploration costs or general and administration costs.

Restrictions on free transferability

Save as set out below, the Premier Shares are freely transferable.

Premier may, under the Companies Act 2006, send out statutory notices to those it knows or has reasonable cause to believe have an interest in its shares, asking for details of those who have an interest and the extent of their interest in a particular holding of shares. When a person receives a statutory notice and fails to provide any information required by the notice within the time specified in it, Premier can apply to the Court for an order directing, among other things, that any transfer of the shares which are the subject of the statutory notice is void. The Directors may also, without giving any reason, refuse to register the transfer of any Premier Shares which are not fully paid.

Mandatory takeover bids, squeeze-out and sell-out rules

Other than as provided by the City Code and Chapter 3 of Part 28 of the Companies Act 2006, there are no rules or provisions relating to mandatory bids and/or squeeze-out and sell-out rules relating to the Premier Shares.

Public takeover bids in the last and current financial years

There have been no public takeover bids by Third Parties in respect of the share capital of Premier in the last or current financial year.

Existing Shareholder authorities

At the annual general meeting of the Company on 20 May 2011, the following resolutions were passed:

- (A) That the Directors be authorised generally and unconditionally, in substitution for existing authorities and powers granted to the Directors prior to the passing of this resolution to exercise all the powers of the Company, in accordance with Section 551 of the Companies Act 2006 (the "Act"), to allot shares in the Company and to grant rights to subscribe for or convert any security into shares in the Company:
- (a) up to a nominal amount of £19,399,300 (such amount to be reduced by the nominal amount allotted or granted under part (b) below in excess of such sum); and
 - (b) comprising equity securities (as defined in Section 560 of the Act) up to a nominal amount of £38,798,600 (such amount to be reduced by any allotments or grants made under part (a) above) in connection with an offer by way of a rights issue:
 - (i) to ordinary shareholders in proportion (as nearly as may be practicable) to their existing holdings; and
 - (ii) to holders of other equity securities as required by the rights of those securities or as the Directors otherwise consider necessary,

and so that the Directors may impose any limits or restrictions and make any arrangements which they consider necessary or appropriate to deal with treasury shares, fractional entitlements, record dates, legal, regulatory or practical problems in, or under the laws of, any territory or any other matter, provided that these authorities shall expire at the conclusion of the annual general meeting of the Company to be held in 2012, save that the Company may before such expiry make an offer or agreement which would or might require shares to be

allotted or rights to subscribe for or convert securities into shares to be granted after such expiry and the Directors may allot shares or grant rights to subscribe for or convert securities into shares in pursuance of such an offer or agreement as if the authorities conferred hereby had not expired.

- (B) To empower the Directors pursuant to Section 571 of the Act, in substitution of any existing authorities and powers granted to Directors prior to the passing of this resolution to allot equity securities (within the meaning of Section 560 of the Act) for cash and/or sell ordinary shares held by the Company as treasury shares for cash under the authority conferred by Resolution A above as if Section 561 of the Act did not apply to any such allotment or sale, provided that this power shall be limited:
- (a) to the allotment of equity securities and sale of treasury shares for cash in connection with an offer of, or invitation to apply for, equity securities (but, in the case of the authority granted under paragraph (b) of Resolution A above, by way of a rights issue only) to ordinary shareholders in proportion (as nearly as may be practicable) to their existing holdings of ordinary shares, but subject to such exclusions or other arrangements as the Directors may deem necessary or expedient in respect of fractions or legal or practical problems in any jurisdiction or any other matter; and
 - (b) in the case of the authority granted under paragraph (a) of Resolution A above and/or in the case of any sale of treasury shares for cash, to the allotment (otherwise than under paragraph (a) above) of equity securities or sale of treasury shares up to a nominal amount of £2,909,895;

and shall expire at the conclusion of the annual general meeting of the Company to be held in 2012, save that the Company may before such expiry make an offer or agreement which would or might require shares to be allotted (and treasury shares to be sold) after such expiry and the Directors may allot equity securities (and sell treasury shares) in pursuance of such an offer or agreement as if the power conferred hereby had not expired.

- (C) To authorise the Company, generally and unconditionally in accordance with Section 701 of the Act to make market purchases (as defined in Section 693(4) of the Act) of ordinary shares, provided that:
- (a) the Company may only purchase, under this authority, ordinary shares with an aggregate nominal value of up to £17,459,386;
 - (b) the Company does not pay less (exclusive of expenses) for each ordinary share than the nominal value of such share;
 - (c) the Company does not pay more (exclusive of expenses) for each Ordinary Share than the higher of (i) 5 per cent. over the average of the closing mid market price of the ordinary shares for the five Business Days immediately preceding the date on which the Company agrees to buy the shares concerned, based on share prices published in the Official List and (ii) that stipulated by Article 5(1) of the Buy-back and Stabilisation Regulation, Commission Regulation (EC) of 22 December 2003.

This authority shall continue until the conclusion of the annual general meeting of the Company to be held in 2012 provided that if the Company has agreed before this date to purchase ordinary shares where these purchases will or may be executed (either wholly or in part) after the authority terminates the Company may complete such a purchase as if the authority conferred hereby had not expired.

3. Articles of Association

The following is a summary of Premier's Articles of Association, which are available for inspection at Premier's registered office. The Articles of Association, which were adopted in May 2010, contain provisions (among others) to the following effect:

(A) Objects

The Company's objects are unrestricted.

(B) Share rights

Subject to the Companies Act and other shareholders' rights, shares may be issued with such rights and restrictions as the Company may by ordinary resolution decide, or (if there is no such resolution or so far as it does not make specific provision) as the Board may decide. Redeemable

shares may be issued. Subject to the Articles, the Companies Act and other shareholders' rights, unissued shares are at the disposal of the Board.

(C) Voting rights

Subject to any rights or restrictions attaching to any class of shares, every member present in person at a general meeting has, upon a show of hands, one vote, and every member present in person or by proxy has, upon a poll, one vote for every share held by him. Resolutions put to the meeting will generally be decided on a show of hands. No member shall be entitled to vote at any general meeting in respect of any share held by him if he has not paid any amount relating to that share which is due at the time of the meeting or if a member has been served with a restriction notice (as defined in the Articles) after failure to provide the Company with information concerning interests in those shares required to be provided under the Companies Act.

(D) Dividends and other distributions

Subject to the Companies Act, the Company's shareholders can declare dividends by passing an ordinary resolution. No such dividend can exceed the amount recommended by the Board. Subject to the Companies Act, the Directors may pay interim dividends, and also any fixed rate dividend, if they consider that the financial position of the Company justifies such payments. If the Board acts in good faith, it is not liable for any loss that shareholders may suffer because a lawful dividend has been paid on other shares which rank equally with or behind their shares.

The Board may withhold payment of all or any part of any dividends (including scrip dividends) or other money which would otherwise be payable in respect of the Company's shares from a person with a 0.25 per cent. interest (as described in the Articles) if such a person has been served with a restriction notice after failure to provide the Company with information concerning interests in those shares required to be provided under the Companies Act.

Except insofar as the rights attaching to, or the terms of issue of, any share otherwise provide, all dividends will be divided and paid in proportions based on the amounts which have been paid up on the shares during any period for which the dividend is paid. Dividends may be declared or paid in any currency.

The Board may, if authorised by an ordinary resolution of the Company, offer ordinary shareholders the right to choose to receive extra ordinary shares which are credited as fully paid up, instead of some or all of their cash dividend.

If a dividend has not been claimed for 12 years after being declared or becoming due for payment, it will be forfeited and go back to the Company.

The Company may stop sending dividend payments through the post, or cease using any other method of payment (including payment through CREST), for any dividend if, either (i) at least two consecutive payments have remained uncashed or are returned undelivered or that means of payment has failed or (ii) one payment remains uncashed or is returned undelivered or that means of payment has failed and reasonable enquiries have failed to establish any new address or account of the registered holder. The Company will resume sending dividend payments if requested in writing by the shareholder.

(E) Variation of Rights

Subject to the Companies Act, rights attached to any class of shares may be varied with the written consent of the holders of not less than three-quarters in nominal value of the issued shares of that class, or by an extraordinary resolution passed at a separate general meeting of the holders of those shares. At every such separate general meeting (except an adjourned meeting) the quorum shall be two persons holding or representing by proxy not less than one-third in nominal value of the issued shares of the class.

(F) Lien, Forfeiture and Untraced Shareholders

The Company has a lien (enforceable by sale) on all partly-paid shares for any money owed to the Company for the shares. The Directors are entitled to exercise their right of sale where the money owed by the shareholder is payable immediately, the Directors have given notice to the shareholder of the amount owed (stating the amount due, demanding payment and setting out the Directors' right to enforce the lien through sale), the notice has been served on the shareholder and the Directors have waited 14 days for the shareholder to pay the sum due.

The Board can also call on shareholders to pay any money which has not yet been paid to the Company for their shares as well as any interest which may accrue from the date of the call until the date it is satisfied and any expenses incurred as a result of the non-payment of the call. The Directors can send the shareholder a notice requiring payment of the unpaid amount; the notice must demand payment of the sum due plus interest and expenses, give the date by which the total is due (which must be at least 14 days after the date of the notice), specify where payment is to be made and state the Company's right of forfeiture in respect of outstanding calls. Where this call remains unsatisfied the shares can be forfeited; the shares become the property of the Company and the Directors can dispose of them in any way they decide.

As regards certificated shares, if during a 12 year period at least 3 cash dividends have gone unclaimed and at least 3 letters from the Company have not been responded to the Company may publish a notice in a national and local newspaper stating its intention to sell the shares. If, during the 3 months following the notice, the shareholder still fails to respond, the Company may sell the shares. If the untraced shareholder does not claim the proceeds of the sale of his/her shares within six years of such sale (i.e. it has been at least 18 years since the shareholder last claimed a dividend or communicated with the Company) then the proceeds of the sale are forfeited and belong to the Company absolutely.

(G) Transfer of shares

Any member may transfer all or any of his certificated shares by an instrument of transfer in any usual form or in any other form which the Board may approve. The instrument of transfer must be executed by or on behalf of the transferor and (in the case of a partly-paid share) the transferee and the transferor will continue to be treated as the holder until the transferee's name is entered in the register.

The Board may, without giving any reason, refuse to register the transfer of any shares which are not fully paid. The Board may also decline to register a transfer of certificated shares if the instrument of transfer:

- (a) is not properly stamped to show the payment of any applicable stamp duty and accompanied by the relevant share certificate and such other evidence of the right to transfer as the Board may reasonably require;
- (b) is in respect of more than one class of share; and
- (c) is to joint transferees and is in favour of more than four such transferees.

Furthermore, where a shareholder holds over 0.25 per cent. of the existing shares in a particular class and has been served with a restriction notice the Board can refuse to register a transfer of any shares which are certificated shares unless they are satisfied that they have been transferred to an independent Third Party.

Any shares in the Company may be held in uncertificated form and these shares must be transferred through CREST. (Provisions of the Articles do not apply to any uncertificated shares to the extent that such provisions are inconsistent with the holding of shares in uncertificated form with the transfer of shares through CREST or with any provision of the Uncertificated Securities Regulations 2001.) If according to the Articles or any relevant legislation the Company has the right to sell, transfer or otherwise deal with the CREST shares the Directors may require the holder of that share to change the CREST share to a certificated share.

The Board may decline to register a transfer of CREST shares in the circumstances set out in the Uncertificated Securities Regulations (as defined in the Articles) and where, in the case of a transfer to joint holders, the number of joint holders to whom the uncertificated share is to be transferred exceeds four.

(H) Meetings

Before a general meeting can start there must be at least two people present who are entitled to vote (shareholders or proxies or both). Every Director is entitled to speak at the general meeting. The Chairman is entitled to adjourn a meeting, whether quorate or not, for any reason so that the business of the meeting can be carried out properly and can also adjourn a quorate meeting with the agreement of the meeting. Meetings can be adjourned indefinitely and more than once. A general meeting adjourned for lack of quorum must be held at least 10 clear days after the original meeting.

(i) Change of name

The Directors may change the name of the Company by passing a board resolution.

(j) Directors

(i) Appointment of Directors

The Company must have a minimum of two Directors and a maximum of 20 and the Directors are not required to hold shares in the Company. Directors may be appointed by the Company by ordinary resolution or by the Board. The only people who can be appointed as Directors at a general meeting are those Directors retiring during the meeting, persons recommended by the Directors or persons recommended by the shareholders where the shareholder is entitled to vote and delivers to the Company notice of his intention to recommend the relevant individual along with the individual's consent.

(ii) Removal of Directors

In addition to any power to remove Directors conferred by legislation, the Company can remove a Director before the end of his term in office by passing a special resolution.

(iii) Retirement of Directors

At every annual general meeting the following must retire from office; any Director who has been appointed by the Board since the last annual general meeting, any Director who held office at the time of the preceding two annual general meetings and who did not retire then and any Director who has been in office as a non-executive Director, for more than 9 years at the date of the meeting. Any retiring Director may offer himself up for reappointment and can be reappointed by an ordinary resolution of the shareholders.

(iv) Vacation of Office by Directors

In addition to the legislative provisions on vacation of a Directors' office, any Director automatically vacates his office as Director if; he gives the Company written notice of his resignation; he offers to resign and this offer is accepted; all of the other Directors (where there are at least three) pass a resolution requiring him to vacate; he is suffering from a physical or mental health illness and the Directors pass a resolution removing him from office; he has missed Directors' meetings for a continuous 6 month period without permission and the Directors pass a resolution removing him; or a bankruptcy order is made against him.

(v) Alternate Directors

Any Director can appoint another person to act as a Director in his place. Where this person is not already a Director their appointment requires the approval of the Directors.

(vi) Remuneration of Directors

The total fees paid to all of the Directors (excluding any payments made to executive Directors or under any other provision of the Articles) must not exceed £600,000 a year or such higher sum decided on by ordinary resolution of the Company. Any Director who is appointed to any executive office will be entitled to receive such remuneration (whether as salary, commission, profit share or any other form of remuneration) as the Board or any committee authorised by the Board may decide, either in addition to or in place of his fees as a Director. In addition, any Director who, in the opinion of the Board or any committee authorised by the Board, performs any special or extra services for the Company, may be paid such extra remuneration as the Board or any committee authorised by the Board may determine. Each Director may be paid his reasonable travelling, hotel and incidental expenses of attending and returning from meetings of the Board, or committees of the Board or of the Company or any other meeting which as a Director he is entitled to attend, and will be paid all expenses properly and reasonably incurred by him in connection with the Company's business or in the performance of his duties as a Director. The Company can also fund a Director or a Director of its holding Company for any purpose permitted by the Companies Act and, as far as permitted by the legislation, can indemnify any Director against any liability.

(vii) Pensions and Gratuities for Directors

The Board or any committee authorised by the Board may exercise the powers of the Company to provide benefits either by the payment of gratuities or pensions or by insurance or in any other manner for any Director or former Director or his relations or dependents. However, no benefits (except those provided for by the Articles) may be granted to a Director or former Director who has not been employed by or held an executive office or place of profit under the Company or any

of its subsidiary undertakings or their respective predecessors in business without the approval of an ordinary resolution of the Company.

(viii) Permitted Interests of Directors

The Directors may authorise any matter which would otherwise involve a Director breaching his duty under the Companies Act to avoid conflicts of interest. In order to obtain authorisation the Director must tell the nature and extent of his interest to the Board as soon as possible and in sufficient detail. Any Director (including the conflicted Director) may propose this authorisation. In considering this proposal the conflicted Director will not be entitled to vote and will not count in the quorum and may be excluded from the meeting whilst the decision is taken.

Where authority is given the Board may specify such terms to be imposed on the Director as the Board thinks fit e.g. the conflicted Director may be excluded from the receipt of certain information. The Board may also provide that the Director is not bound to disclose to the Company any information which he comes into possession of otherwise than in his role as a Director where disclosure would entail a breach of confidence. The Board may provide that the terms of the authorisation be recorded in writing and any authority given may be varied or revoked at any time.

Where a Director is indirectly or directly interested in a contract with the Company this must be disclosed in accordance with the Companies Act. Where this is the case the Director may do the following:

- have any kind of interest in a contract with or involving the Company;
- hold any office (except that of auditor) with the Company;
- do paid professional work for the Company;
- become a director of any holding company or subsidiary of the Company; and/or
- be a director of any other company so long as the appointment cannot reasonably be regarded as giving rise to a conflict of interest.

(ix) Restrictions on voting

A Director cannot vote or be counted in the quorum when the Board is considering his appointment to a position within the Company or a company in which the Company has an interest. Furthermore, except as mentioned below, no Director may vote on, or be counted in a quorum in relation to, any resolution of the Board in respect of any contract in which he has an interest. A Director can only vote where his interest cannot reasonably be regarded as material or where the only material interest he has in it is included in the following list:

- a resolution about giving him any security or any indemnity for any money which he, or any other person, has lent at the request, or for the benefit, of the Company or any of its subsidiary undertakings;
- a resolution about giving any security or any indemnity to any other person for a debt or obligation which is owed by the Company or any of its subsidiary undertakings, to that other person, if the director has taken responsibility for some or all of that debt or obligation. The Director can take this responsibility by giving a guarantee, indemnity or security;
- a resolution giving him any other indemnity where all Directors are also being offered indemnities on substantially similar terms;
- a resolution about the Company funding any expenditure incurred defending proceedings where all Directors are also being offered indemnities on substantially similar terms;
- a resolution about any proposal relating to an offer of any shares or debentures or other securities for subscription or purchase by the Company or any of its subsidiary undertakings, if the Director takes part because he is a holder of shares, debentures or other securities, or if he takes part in the underwriting or sub-underwriting of the offer;
- a resolution about a contract in which he has an interest because of his interest in securities of the Company;
- a resolution regarding a contract with a company in which the Director has an interest (including where the Director is a director or shareholder of that other company) as long as he does not hold an interest in shares representing one percent or more of any class of equity share capital of that company or of the voting rights in that company;

- a resolution relating to a pension fund, superannuation scheme, retirement, death or disability fund where these benefits are provided to employees generally;
- any arrangement for the benefit of employees of the Company or any of its subsidiary undertakings which gives him benefits which are also generally given to the employees to whom the arrangement relates; or
- a resolution about any proposal relating to any insurance which the Company can buy and renew for the benefit of the Directors or of a group of people which includes the Directors.

Subject to the provisions of the Companies Act, the Company may by ordinary resolution suspend or relax the above provisions to any extent or ratify any contract which has not been properly authorised in accordance with the above provisions.

(x) Borrowing powers

Subject to the Company's Articles of Association, the Companies Act and any directions given by the Company by special resolution, the business of the Company will be managed by the Board who may use all the Company's powers.

In particular, the Board may exercise all the Company's powers to borrow money and to mortgage or charge any of its undertaking, property, assets and uncalled capital, to issue debentures and other securities and to give security for any debt, liability or obligation of the Company or any Third Party. The Board will limit the total borrowings of the Company and, so far as it is able, its subsidiary undertakings so as to ensure that the total amount of the Group's borrowings does not exceed four times the Company's adjusted capital and reserves. However, the Company may pass an ordinary resolution allowing borrowings to exceed such a limit.

4. Major Shareholders

As at 16 November 2011, being the latest practicable date prior to the publication of this document, Premier had received notification from the following institutions, in accordance with Chapter 5 of the Disclosure and Transparency Rules, of interests in excess of 3 per cent. of the Company's issued ordinary shares:

<i>Shareholder</i>	<i>Notified Number of Voting Rights</i>	<i>Notified Percentage of Voting Rights</i>
BlackRock Inc*	11,224,700	9.79
AXA Investment Managers SA	40,173,814	8.58
Ameriprise Financial, Inc*	4,028,672	5.076
Schroders plc	23,423,734	5.00
Aviva plc and subsidiaries (direct interests)*	3,859,897	4.87
Bear Stearns International Trading Limited*	2,552,847	3.109
Norges Bank	14,057,260	3.00

* These notifications were received prior to the 4:1 share split, effective as of 8.00 a.m. on 23 May 2011.

Save as disclosed above, the Premier Directors are not aware of any person who is interested directly or indirectly in three per cent. or more of the issued share capital of the Company.

None of the Company's major shareholders has or will have different voting rights attached to the shares they hold in the Company.

As at 16 November 2011, being the latest practicable date prior to the publication of this document, the Company was not aware of any person or persons who directly or indirectly, jointly or severally, exercise or could exercise control over the Company, nor is it aware of any arrangements, the operation of which may at a subsequent date result in a change in control of the Company.

5. Related Party Transactions

A description of the material provisions of agreements and other documents between the Group and various individuals and entities that may be deemed to be related parties is given in note 24 to each of Premier's Annual Reports and Accounts for the years ended 31 December 2010 and 31 December 2009 and note 25 to the financial statements in Premier's Annual Report and Accounts for the year ended 31 December 2008, which are incorporated into this document by reference. No

such transactions have been entered into by any member of the Group during the period between 1 January 2011 and 16 November 2011, the latest practicable date prior to the publication of this document.

6. Material Contracts

A summary of the contracts (not being contracts entered into in the ordinary course of business) that have been entered into by the Company or any member of the Group within the two years immediately preceding the date of this document which are or may be material or which have been entered into by the Company or any member of the Group at any other time and which contain provisions under which the Company or any member of the Group has an obligation or entitlement that is material to the Group as at the date of this document, is set out below:

(A) Contracts relating to the Convertible Bonds

Premier is guarantor to a US\$250,000,000 2.875 per cent. Guaranteed Convertible Bond (the "Bonds") issued by POFJL, one of Premier's principal wholly-owned subsidiaries, on 27 June 2007.

Subject to and in accordance with the terms and conditions of the Bonds, the Bonds are convertible into preference shares in POFJL which, in turn, are exchangeable for ordinary shares in Premier.

The conversion rights and exchange rights are guaranteed by Premier pursuant to a Deed Poll dated 27 June 2007 (see below).

Unless previously purchased and cancelled, redeemed or converted, the Bonds will be redeemed on 27 June 2014. The Bonds are in registered form and issued in the principal amounts of US\$100,000 and integral multiples of US\$1,000 in excess thereof up to and including US\$199,000. The Bonds are represented by a global registered bond (the "Global Bond") held on behalf of Euroclear and Clearstream, Luxembourg. The Global Bond is exchangeable in certain limited circumstances in whole, but not in part, for definitive registered Bonds.

The Bonds bear interest from and including 27 June 2007 (the "Closing Date") at 2.875 per cent. per annum payable semi-annually in equal instalments in arrears on 27 June and 27 December each year, commencing on 27 December 2007.

Premier entered the following ongoing contracts in respect of the Bond issue:

(i) Trust Deed

The Trust Deed dated 27 June 2007 (the "Trust Deed") between POFJL, Premier and Deutsche Trustee Company Limited (as Trustee) sets out, *inter alia*, (i) the form and terms and conditions of the original definitive registered Bonds, (ii) the guarantee given by Premier and (iii) the appointment of the Trustee, all in a manner as is customary in such deeds.

The terms and conditions of the Bonds are customary for securities of this nature. In particular:

- POFJL and Premier make a negative pledge that, so long as any Bond remains outstanding, they will not create or permit to subsist any mortgage, charge or other form of encumbrance or security interest unless approved by the Trustee, in its absolute discretion;
- no transfer of a Bond will be valid unless and until entered on a register to be kept by POFJL; and
- the Trustee at its discretion, and if so requested by holders of not less than 25 per cent. in principal amount of the Bonds then outstanding or if so directed by an extraordinary resolution of the bondholders, shall give notice in writing to POFJL that the Bonds are due and payable at the principal amount together with accrued interest if any of the events of default occur, which include, *inter alia*: non-payment on maturity for a period of seven calendar days; non-payment of any interest due for a period of 14 calendar days; breach by Premier or POFJL of any obligations in the Bonds or the Trust Deed not remedied within 30 days; and if insolvency or winding-up occur or are threatened by POFJL, Premier or any material subsidiary.

In the Trust Deed, Premier unconditionally and irrevocably guarantees the due and punctual payment of all sums from time to time payable by POFJL in respect of the Bonds and the due and punctual performance by POFJL of all of POFJL's other obligations in respect of the Bonds. The guarantee constitutes an unsubordinated, direct, unconditional and (subject to terms and conditions) unsecured obligation of Premier and shall, save for such exceptions as may be provided by applicable law and subject to relevant conditions, at all times rank at least equally with all its other present and future unsecured and unsubordinated obligations.

Premier's obligations under the Trust Deed remain in full force until no sum remains payable under the Trust Deed or the Bonds.

The Trust Deed appoints the Trustee subject to such terms and conditions as are customary in such deeds, including, among others, that moneys held by the Trustee may be invested in its name, or under its control in any investments or other assets and in such currency as the Trustee, in its absolute discretion, think fit.

The Trust Deed is governed by English law.

(ii) Paying, Transfer and Exchange Agency Agreement

The paying, transfer and exchange agency agreement dated 27 June 2007 (the "Agency Agreement") between, amongst others, POFJL, Premier, Deutsche Bank (as the Paying, Transfer and Exchange Agent) and Deutsche Trustee Company Limited (as the Trustee) sets out, *inter alia*, the terms of appointment and duties of Deutsche Bank AG, London Branch in its capacity as Paying, Transfer and Exchange Agent.

The Agency Agreement contains such terms and conditions as are customary in such an agreement.

As regards moneys held by the Paying, Transfer and Exchange Agent following payments in respect of the Bonds, the Paying, Transfer and Exchange Agent may deal with moneys paid to it under the Agency Agreement in the same manner as other moneys paid to it as a banker by its customers except that: (i) it may not exercise any lien, right of set-off or similar claim in respect of them; and, (ii) it shall not be liable to anyone for interest on any sums held by it under the Agency Agreement. No money held by the Paying, Transfer and Exchange Agent need be segregated except as required by law.

The Agency Agreement also sets out such powers of the Trustee as are customary in agreements of this nature, including its capacity to insist that all moneys, documents and records in respect of the Bonds are delivered to the Trustee if a potential event of default or an event of default has occurred.

POFJL and Premier jointly and severally indemnify the Paying, Transfer and Exchange Agent against any loss, liability, cost, action or expense which it may properly incur or which may be made against it arising out of or in relation to or in connection with its appointment or the exercise of its functions, except such as may result from a breach by it of the Agency Agreement or its fraud, wilful default, negligence or bad faith.

POFJL and Premier may, with the prior written approval of the Trustee, at any time terminate the appointment of the Paying, Transfer and Exchange Agent by giving it at least 60 days' notice to that effect.

The Agency Agreement is governed by English law.

(iii) Deed Poll

The deed poll was executed on 27 June 2007 (the "Deed Poll") by Premier in favour of POFJL and the holders of preference shares in the capital of POFJL.

Premier undertakes to POFJL and to each of the holders of preference shares in the capital of POFJL, to the extent that the amounts due are not paid by POFJL, to make due and punctual payment of all redemption monies, dividends and other amounts expressed to be payable in respect of the preference shares in the capital of POFJL. The Deed Poll is a continuing guarantee and remains in full force and effect until all redemption monies, dividends and other amounts expressed to be payable have been paid in full.

The Deed Poll also sets out Premier's purchase offer whereby Premier offers and undertakes to each of the holders of preference shares in the capital of POFJL, and to POFJL, to purchase the preference shares allotted and issued on the conversion of any Bond and, in consideration for such purchase, to deliver fully paid ordinary shares in Premier to the holders of preference shares in the capital of POFJL.

Furthermore, Premier also undertakes in the Deed Poll that it will, in the event of failure of POFJL to perform the same when due to be performed: (i) procure the performance by POFJL of all obligations to be performed by POFJL; and, (ii) procure the enforcement by POFJL of all POFJL's rights, in either case, with respect to the exchange rights and share exchange rights of holders of the Bonds.

The Deed Poll is governed by English law.

(B) Credit Agreements

The Company has entered into the following credit agreements:

- (i) a revolving loan and letter of credit facility agreement dated 29 October 2010 as amended from time to time including on 26 October 2011 (the “Facilities Agreement”);
 - (ii) a US\$300,000,000 term loan facility agreement dated 30 April 2010 as amended on 27 October 2010 (the “US\$300m Term Loan Facility”); and
 - (iii) a US\$175,000,000 term loan dated 11 September 2009, as amended on 30 November 2009 and 27 October 2010 (the “US\$175m Term Loan Facility”).
- (i) Facilities Agreement

The lenders under the Facilities Agreement as of the date of this document are The Bank of Tokyo-Mitsubishi UFJ, Ltd., Barclays Bank PLC, Bayerische Landesbank, London Branch, BNP Paribas, Citibank N.A., London Branch, Commonwealth Bank of Australia, DBS Bank Ltd, London Branch, Deutsche Bank AG, London Branch, DNB Nor Bank ASA, HSBC Bank plc, ING Bank NV, Lloyds TSB Bank plc, Natixis, Nordea Bank Finland Plc, London Branch, Royal Bank of Canada, Standard Chartered Bank, Sumitomo Mitsui Banking Corporation and Sumitomo Mitsui Banking Corporation Europe Limited.

The Facilities Agreement provides a Revolving Credit Facility of US\$456,805,000 and letter of credit facilities of £132,000,000 and £267,500,000 (the “**Letter of Credit Facilities**”). The Revolving Credit Facility is available for general corporate purposes. The Letter of Credit Facilities may be used to issue certain letters of credit or loans specified in the Facilities Agreement.

An amendment agreement dated 26 October 2011 provides that, of the Revolving Credit Facility commitments, up to US\$350,000,000 (the “**Acquisition Facility**”) is available for a period not exceeding 180 days after 26 October 2011 (and ending earlier if certain events occur such as, subject to certain conditions, the Scheme’s expiry) (“**Acquisition Period**”), for (a) payment of consideration payable to EnCore Shareholders pursuant to the Acquisition and (b) payment of amounts to holders of EnCore Share Options in consideration of the cancellation of those options. The Acquisition is subject to a number of Conditions. If all the Conditions are met or waived, Premier is required to proceed with the Acquisition. Accordingly, once the Acquisition becomes unconditional, it is to be funded using funds to be drawn under the Acquisition Facility.

Loans drawn under the Facilities Agreement bear interest at the aggregate of (a) an agreed margin per annum; (b) LIBOR; and (c) mandatory costs, if any. The margin is calculated based on Premier’s and certain of its subsidiaries’ consolidated leverage ratio and can range from 1.75 per cent. to 3.00 per cent. per annum. Interest on overdue amounts is charged at a rate of 1.00 per cent. per annum above the rate otherwise applicable to loans drawn down under the Facilities Agreement. Certain fees are payable in connection with the Facilities Agreement including a commitment fee payable on the undrawn, uncanceled amount of each lender’s commitment. A letter of credit fee is payable in respect of letters of credit issued under the Letter of Credit Facilities. The letter of credit fee is payable on the daily outstanding amount of each Letter of Credit issued under the Letter of Credit Facilities and the letter of credit fee is calculated based on Premier’s and certain of its subsidiaries’ consolidated leverage ratio.

Each loan made under the Facilities Agreement is repayable in full on the last day of its term. The term of a loan made under the Facilities Agreement can be one, two, three or six months or any other period as agreed by Premier and the lenders. The scheduled final maturity date under the Facilities Agreement is 31 March 2015. Loans or letters of credit may be voluntarily prepaid and the Facilities Agreement provides for mandatory prepayment in certain instances, including on a change of control of Premier (which will occur if any person or group of persons acting in concert gains control of Premier).

Premier and certain of its subsidiaries guarantee each borrower’s payment obligations under the Facilities Agreement and grant various indemnities. The Facilities Agreement also contains certain covenants which require Premier to ensure that, among other things, the aggregate “proven and probable” (as defined by the Oil Industry Accounting Committee’s “Statement of Recommended Practice”) petroleum reserves of the guarantors of the Facilities Agreement shall not be less than 90 per cent. of Premier’s consolidated “proven and probable” petroleum reserves. Under the Facilities Agreement, Premier is, subject to certain conditions, also required to ensure that any

material subsidiary (other than certain non-recourse subsidiaries) becomes a guarantor under the Facilities Agreement.

The Facilities Agreement contains customary covenants which limit the ability of Premier and its subsidiaries, subject to certain exceptions, from, among other things:

- (A) in the case of subsidiaries who are not guarantors or borrowers under the Facilities Agreement, incurring or having outstanding Financial Indebtedness (as such term is defined in the Facilities Agreement), with the exception of certain Financial Indebtedness including:
 - (a) any Financial Indebtedness incurred by certain non-recourse subsidiaries whose principal activity is or will be the ownership and development and/or operation of a petroleum production licence or field; and
 - (b) a general exception for incurring additional Financial Indebtedness not exceeding a total of US\$60,000,000 at any time;
- (B) creating or allowing to exist any security interest on any of its assets, with the exception of various permitted security interests including:
 - (a) any security interest created by certain non-recourse subsidiaries whose principal activity is or will be the ownership and development and/or operation of a petroleum production licence or field; and
 - (b) a general exception for Premier and its subsidiaries to create or allow to exist security interests (except over certain specified assets) securing other debts not exceeding a total of US\$75,000,000 at any time;
- (C) making any investment or acquisition that qualifies as a Class 1 Transaction under the Listing Rules except if:
 - (a) that acquisition or investment is a Class 1 Transaction solely by virtue of the application of the profits test;
 - (b) the relevant acquisition or investment is completed by no later than 30 April 2013; and
 - (c) the consideration payable in the relevant transaction does not exceed US\$400,000,000 in aggregate;
- (D) in the case of Premier, redeeming or repurchasing its share capital, with the exception of any redemption or repurchase of share capital not exceeding in aggregate £20,000,000 per annum;
- (E) merging with any other entity other than in relation to certain intra-group re-organisations;
- (F) disposing of interests in the onshore oilfield at Wytch Farm in Dorset or in the Natuna Sea Block A offshore Indonesia unless it is to other guarantors under the Facilities Agreement; and
- (G) disposing of any of their other assets unless such disposal is on arms' length terms for fair value, with certain exceptions including an exception for certain intra-group transfers.

In addition the Facilities Agreement contains several financial covenants including a covenant that Premier and its subsidiaries do not exceed a leverage ratio of 3.00 to 1 and a covenant that Premier and its subsidiaries maintain a minimum interest coverage ratio of 4.00 to 1.

The Facilities Agreement also contains customary representations and warranties and conditions precedent.

The Facilities Agreement contains various events of default including non-payment, failure to comply with covenants, breaches of representations, cross default (in relation to other Financial Indebtedness in an amount of US\$10,000,000 or more), material adverse change, certain nationalisation or expropriation of assets, and certain insolvency events. If an event of default is outstanding, the lenders may cancel any undrawn commitments, demand immediate repayment of all amounts outstanding under the Revolving Credit Facility and the Letter of Credit Facilities and exercise any other rights they may have under the Finance Documents (as such term is defined in the Facilities Agreement). However, within the Acquisition Period, such rights are only exercisable by the lenders in respect of the Acquisition Facility in more limited circumstances. These include

certain major events of default including certain insolvency events in relation to Premier and certain of its subsidiaries, breaches of certain major representations and failure to comply with certain major covenants including those described at (A) to (C) and (E) to (G) above.

(ii) US\$300m Term Loan Facility

The original lenders under the US\$300m Term Loan Facility are Lloyds TSB Bank plc and Mediobanca International (Luxembourg) S.A. The US\$300m Term Loan Facility has a final maturity date of 7 May 2015 and is available for general corporate purposes.

Drawings under the US\$300m Term Loan Facility bear interest at the aggregate of (a) an agreed margin per annum; (b) LIBOR; and (c) additional mandatory costs, if any, to cover regulatory or reserve accounts. The margin in respect of the US\$300m Term Loan Facility is 2.50 per cent. per annum. Interest on overdue amounts is charged at a rate of 1.00 per cent. per annum above the rate at which the loan is drawn down under the US\$300m Term Loan Facility.

The Company and various members of the Group are required to guarantee the payment obligations of each borrower under the US\$300m Term Loan Facility and to grant various indemnities.

The loan drawn down under the US\$300m Term Loan Facility must be repaid in full on the final maturity date. The US\$300m Term Loan Facility allows voluntary prepayment and also contains certain mandatory prepayment events requiring the facility to be immediately prepaid in full. These events include the occurrence of a change of control of the Company (which will occur if any person or group of persons acting in concert gains control of the Company) and the completion of a class 1 transaction by a member of the Group.

The US\$300m Term Loan Facility includes events of default which will entitle the lenders to terminate the facility and demand immediate repayment. The US\$300m Term Loan Facility also contains customary representations and warranties, affirmative and negative covenants, and conditions precedent. The Company is also required to ensure that financial covenants relating to permitted leverage and interest cover ratios are met.

The US\$300m Term Loan Facility is governed by English law.

(iii) US\$175m Term Loan Facility

The original lenders under the US\$175m Term Loan Facility are Lloyds TSB Bank plc, HSBC Bank plc, The Bank of Tokyo-Mitsubishi UFJ, Ltd., Royal Bank of Canada, Standard Chartered Bank and BNP Paribas S.A. The US\$175m Term Loan Facility is available for general corporate purposes.

Drawings under the US\$175m Term Loan Facility bear interest at the aggregate of (a) an agreed margin per annum; (b) LIBOR; and (c) additional mandatory costs, if any, to cover regulatory or reserve accounts. The initial margin in respect of the US\$175m Term Loan Facility is 3.50 per cent. per annum and the margin is subsequently calculated by reference to a leverage-based margin ratchet. Interest on overdue amounts is charged at a rate of 1.00 per cent. per annum above the rate at which the loan is drawn down under the US\$175m Term Loan Facility.

The Company and various members of the Group are required to guarantee the payment obligations of each borrower under the US\$175m Term Loan Facility and to grant various indemnities.

The loan drawn down under the US\$175m Term Loan Facility must be repaid in full on the final maturity date, currently 21 March 2012. The US\$175m Term Loan Facility allows voluntary prepayment and also contains certain mandatory prepayment events requiring the facility to be immediately prepaid in full. These events include the occurrence of a change of control of the Company (which will occur if any person or group of persons acting in concert gains control of the Company).

The US\$175m Term Loan Facility includes events of default which will entitle the lenders to terminate the facility and demand immediate repayment. The US\$175m Term Loan Facility also contains customary representations and warranties, affirmative and negative covenants, and conditions precedent. The Company is also required to ensure that financial covenants relating to permitted leverage and interest cover ratios are met.

The US\$175m Term Loan Facility is governed by English law.

(C) Note Purchase Agreement

The Company has entered into a note purchase agreement dated 9 June 2011 (the “NPA”) which provides for the issue and sale of a series of senior notes by Premier Oil UK Limited (the “Issuer”) pursuant to a United States private placement. The notes were issued on 9 June 2011 in tranches of €75,000,000 (the “Series A Notes”), US\$70,000,000 (the “Series B Notes”) and US\$174,000,000 (the “Series C Notes”) (together the “Notes”).

Interest is payable on the Series A Notes at 5.32 per cent. per annum, the Series B Notes at 5.11 per cent. per annum and the Series C Notes at 5.78 per cent per annum. In each case interest is payable semi-annually in arrears on 9 June and 9 December each year, commencing on 9 December 2011. The Series A Notes and the Series B Notes mature on 9 June 2018 and the Series C Notes mature on 9 June 2021. The proceeds of the sale of the Notes may be used for other general corporate purposes.

The unpaid principal balance of each series of the Notes must be repaid on the maturity dates specified above. The Issuer has the option to prepay the Notes in whole or in part at any time after issue. If such optional prepayment is made, the Issuer must pay an amount equal to par plus accrued interest plus the make whole amount, if any. In the event of a change of control of the Company (where a person or a group of persons acting in concert gain control of the Company), the Issuer must offer to prepay the entire unpaid principal amount of notes held by each holder at 100 per cent. of the principal amount of the notes at par, together with interest.

The payment of the Notes and the performance by the Issuer of its obligations under the NPA are guaranteed by the Company and various members of the Group.

The NPA contains representations and warranties customary for agreements of this kind. The NPA includes customary affirmative covenants together with negative covenants restricting (subject in each case to certain specified exceptions) transactions with affiliates, mergers and consolidations, the sale of assets, the creation of liens and the incurrence of financial indebtedness. The Company is also required to ensure that financial covenants relating to permitted leverage ratios, interest cover ratios and project investments are met.

The NPA contains events of default including non-payment of principal or interest due on the Notes, breach of representation or warranty, breach of covenant, cross default and insolvency of the Company or certain members of the Group. The occurrence of an event of default results (subject to certain conditions specified in the NPA) in all of the Notes then outstanding becoming immediately due and payable.

The NPA is governed by English law.

7. Significant Subsidiaries

The Company acts as the holding company of the Group. The Company holds (directly or indirectly) interests in the capital of the following undertakings, being those which are considered by the Company to be likely to have a significant effect on the assessment of the Company's assets and liabilities, financial position or profits and losses. Each of these companies is a wholly-owned subsidiary of the Group and the issued share capital is fully paid. To avoid a statement of excessive length, details of investments which are not significant have been omitted.

Unless otherwise stated, the registered office of all companies registered in Scotland is 4th Floor, Saltire Court, 20 Castle Terrace, Edinburgh EH1 2EN; the registered address of all companies registered in England and Wales is 23 Lower Belgrave Street, London SW1W 0NR; and the registered address of all companies registered in The Netherlands is Prinsenhof Building 19th Floor, Prinses Margrietplantsoen 76, The Hague 2595 BR, The Netherlands.

<i>Name</i>	<i>Country of Incorporation</i>	<i>Principal Activity</i>
Premier Oil Group Limited*	Scotland	Intermediate holding company, UK
Premier Oil Finance (Jersey) Limited*	Jersey (Registered office: 22 Grenville Street St. Helier Jersey JE4 8PX)	Convertible bond issuing company, Jersey
Premier Oil Holdings Limited	England & Wales	Intermediate holding company, UK
Premier Oil Overseas BV	The Netherlands	Intermediate holding company, The Netherlands
Premier Oil UK Ltd	Scotland	Exploration, production and development, UK
Premier Oil Natuna Sea BV	The Netherlands	Exploration, production and development, Indonesia
Premier Oil Kakap BV	The Netherlands	Exploration, production and development, Indonesia
Premier Oil Sumatra (North) BV	The Netherlands	Exploration, production and development, Indonesia
Premier Oil Pakistan Holdings BV	The Netherlands	Intermediate holding company, The Netherlands
PKP Exploration Limited	England & Wales	Exploration, production and development, Pakistan
PKP Kadanwari 2 Limited	Cayman Islands	Exploration, production and development, Pakistan
PKP Kirthar 2 BV	The Netherlands	Exploration, production and development, Pakistan
Premier Oil Vietnam Offshore BV	The Netherlands	Exploration, production and development, Vietnam
Premier Oil (Vietnam) Limited	British Virgin Islands	Exploration, production and development, Vietnam
Premier Oil Norge AS	Norway	Exploration, production and development, Norway

* Held directly by Premier Oil plc. All other companies are held through subsidiary undertakings.

Joint Ventures

The Premier Group has a 49 per cent. interest in Premco Energy Projects Company LLC, a company registered in the United Arab Emirates, and a 50 per cent. interest in Premco Energy Projects BV, a company registered in The Netherlands. The results of these two jointly controlled entities, which are indirectly held through subsidiary undertakings and which are involved in business development opportunities across the Middle East and North Africa region, are accounted for using proportionate consolidation and were immaterial to the group in 2010 and 2009.

8. Working Capital Statement

The Company is of the opinion that, taking account of its existing financing facilities and existing cash resources, the working capital available to the Premier Group is sufficient for its present requirements, that is, for at least the twelve months following the date of the publication of this document.

9. Litigation

There have been no governmental, legal or arbitration proceedings, including such proceedings which are pending or threatened of which Premier is aware, during the 12 months preceding the date of this document which may have, or have had in the recent past, significant effects on the Premier Group's financial position or profitability.

10. Sources and Bases of selected financial information

In this document:

- (A) Unless otherwise stated, financial information relating to Premier has been extracted or provided (without material adjustment) from the audited annual report and accounts for Premier for the year ended 31 December 2010 reported under IFRS and, as relevant, the unaudited interim report and accounts for the six months ended 30 June 2011 reported under IFRS.
- (B) As at the close of business on 16 November 2011, Premier had in issue 468,057,712 ordinary shares of 12.5 pence each and EnCore had in issue 295,328,560 ordinary shares of 5 pence each.
- (C) Unless otherwise stated, the value of the Acquisition is calculated:
 - (a) by reference to the recommended cash consideration of 70 pence for each Scheme Share; and
 - (b) on the basis of the issued and to be issued ordinary share capital of EnCore, being 315,493,530 Encore Shares as referred to in paragraph 10(I) below.
- (D) The maximum number of New Premier Shares to be issued pursuant to the Acquisition is 65,212,513 New Premier Shares.
- (E) All share prices are expressed in pence.
- (F) Unless otherwise stated, all estimates of reserves and resources have been sourced from the Competent Persons' Reports in Part V of this document and do not represent Premier's internal calculations.
- (G) Unless otherwise stated, all prices quoted for Premier Shares and EnCore Shares are closing mid-market prices and are derived from the Daily Official List of the London Stock Exchange.
- (H) Where information has been sourced from a third party, Premier confirms that the information has been accurately reproduced and, as far as Premier is aware and able to ascertain from information published by that third party, no facts have been omitted which would render the reproduced information inaccurate or misleading. Where third party information has been used, the source of such information has been identified wherever it appears in this document.
- (I) The fully diluted ordinary share capital of EnCore (being 315,493,530 EnCore Shares) is calculated on the basis of:
 - (a) the number of issued EnCore Shares on 4 October 2011, the last Business Day prior to the date of the Scheme Announcement, being 292,695,488; and
 - (b) any further EnCore Shares which may be issued on or after the date of the Scheme Announcement on the exercise of options or vesting of awards under the EnCore Share Option Plans, amounting in aggregate to 22,798,042 EnCore Shares.
- (J) An exchange rate of US\$1.5769 to £1 has been used, being the exchange rate as at 5.00 p.m. in London on 16 November 2011, sourced from Bloomberg.

11. Significant Change

There has been no significant change in the trading or financial position of the Premier Group since 30 June 2011, the date to which Premier's last interim report was prepared.

No material changes have occurred since the date of the Competent Persons' Reports which appear in Part V of this document, the omission of which would make those reports misleading.

12. Dividend Policy

Premier's policy is to reward Premier Shareholders principally through share price growth and to utilise cash flow within the business.

13. Consent

RISC (UK) Limited, whose address is 53 Chandos Place, Covent Garden, London WC2N 4HS, has given and has not withdrawn its written consent to the inclusion in this document of references to its name in the form and context in which they appear and its report in Part V in the form and

context in which they appear and has authorized the contents of that report for the purposes of paragraph 5.5.3R(2)(f) of the Prospectus Rules.

DeGolyer and MacNaughton, whose address is 5001 Spring Valley Road, Suite 800 East, Dallas, Texas 75244, USA, has given and has not withdrawn its written consent to the inclusion in this document of references to its name in the form and context in which they appear and its report in Part V in the form and context in which they appear and has authorized the contents of that report for the purposes of paragraph 5.5.3R(2)(f) of the Prospectus Rules.

14. Principal Establishments

Premier has the following principal establishment:

<i>Property address</i>	<i>Current use</i>	<i>Description and tenure</i>	<i>Current rent</i>
23 Lower Belgrave Street London SW1W 0NR	Office	Leasehold – expires 13/10/2014	£925,000 p.a.

There are no environmental issues which may affect Premier's utilisation of its properties.

15. Acquisition costs

The aggregate costs and expenses payable by Premier in connection with the Acquisition are estimated to amount to approximately £2.98 million (excluding amounts in respect of VAT).

16. Documents available for inspection

Copies of the following documents:

- (i) the consent letters referred to in paragraph 13 above;
- (ii) the Premier Articles of Association;
- (iii) Premier's Annual Report and Accounts for the financial year ended 31 December 2008;
- (iv) Premier's Annual Report and Accounts for the financial year ended 31 December 2009;
- (v) Premier's Annual Report and Accounts for the financial year ended 31 December 2010;
- (vi) Premier's Interim Report for the six month period ended 30 June 2011;
- (vii) the Scheme Document; and
- (viii) this document,

are available for inspection during usual business hours on any weekday (Saturdays, Sundays and public holidays excepted) for a period from the date of publication of this document until Admission at the offices of Slaughter and May, One Bunhill Row, London EC1Y 8YY.

APPENDIX I

DEFINITIONS

The following definitions apply throughout this document unless the context otherwise requires:

“2C”	means best estimate;
“2D”	means two dimensional;
“2P”	means proven and probable;
“ACQ”	means Annual Contract Quarterly;
“Acquisition”	means the proposed acquisition of the entire issued and to be issued ordinary share capital of EnCore by Premier;
“Acquisition Facility”	means the facility of US\$350 million as described in Parts III and IX of this document;
“Admission”	means admission of the New Premier Shares to the Official List of the UKLA in accordance with the Listing Rules and to trading on the London Stock Exchange’s market for listed securities in accordance with the Admission and Disclosure Standards or, if Premier and EnCore so determine and subject to the consent of the Panel, the UKLA agreeing to admit such shares to the Official List and the London Stock Exchange agreeing to admit such shares to trading subject only to (i) the allotment of such shares and/or (ii) the Acquisition becoming Effective;
“Admission and Disclosure Standards”	means the requirements contained in the London Stock Exchange’s publication “Admission and Disclosure Standards” (as amended from time to time) containing, amongst other things, the admission requirements to be observed by companies seeking admission to trading on the London Stock Exchange’s market for listed securities;
“AIM”	means AIM market, a market operated by the London Stock Exchange;
“APA”	means awards in pre-defined areas on the Norwegian Coastal Shelf;
“bbls”	means barrels;
“BBtud”	means billion British thermal units per day;
“BlackRock”	BlackRock Investment Management (UK) Limited;
“Board”	means the board of directors of Premier or EnCore as appropriate;
“boepd”	means barrels of oil equivalent per day;
“bopd”	means barrels of oil per day;
“Business Day”	means any day on which banks generally are open for the transaction of business other than a Saturday, Sunday or public holiday;
“Capital Reduction”	means the proposed reduction in the share capital of EnCore pursuant to the scheme;
“City Code”	means the City Code on Takeovers and Mergers of the United Kingdom;
“Closing Price”	means the closing middle market quotations of a share derived from the London Stock Exchange Daily Official List;
“Corporate Governance Code”	means the UK Corporate Governance Code of the Financial Reporting Council June 2010;
“Companies Act 2006”	means the Companies Act 2006, and shall be construed as a reference to it as it may from time to time be amended, modified or re-enacted;

“Conditions”	means the conditions to the Acquisition summarised in paragraph 7 of Part VI of this document and set out in Appendix I of the Scheme Announcement and Part IV of the Scheme Document;
“Convertible Bonds”	means the US\$250,000,000 2.875 per cent. guaranteed convertible bond issued by POFJL on 27 June 2007, as described in Part IX of this document;
“Court”	means the High Court of Justice in England and Wales;
“Court Hearing”	means the hearing by the Court of the claim form to sanction the Scheme;
“CRD”	means Cá Ròng Đò;
“CREST”	means the relevant system (as defined in the Uncertificated Securities Regulations 2001 (SI 2001/3755)) in respect of which Euroclear UK & Ireland Limited is the Operator (as defined in the Uncertificated Securities Regulations 2001 (SI 2001/3755));
“Crest Manual”	means the rules governing the operation of CREST, consisting of the CREST Reference Manual, the CREST International Manual, the CREST Rules, the Registrars Service Standards, the Settlement Discipline Rules, the CCSS Operations Manual, the Daily Timetable, the CREST Application Procedure and the CREST Glossary of Terms (all as defined in the CREST Glossary of Terms promulgated by Euroclear on 15 July 1996 and as amended from time to time);
“CT”	means corporation tax;
“Daily Official List”	means the daily official list of the London Stock Exchange;
“Disclosure and Transparency Rules”	means the disclosure and transparency rules made by the FSA under section 73A of FSMA;
“EBITDAX”	means earnings before interest, taxation, depreciation, amortisation; and exploration expenses;
“EEA States”	means states which are contracting parties to the agreement on the European Economic Area signed at Oporto on 2 May 1992, as it has effect for the time being;
“Effective”	means, in the context of the Acquisition: (i) if the Acquisition is implemented by way of the Scheme, the Scheme having become effective pursuant to its terms; or (ii) if the Acquisition is implemented by way of an Offer, such Offer having been declared or become unconditional in all respects in accordance with the requirements of the City Code;
“Effective Date”	means the date on which the Acquisition becomes Effective, which is expected to be 16 January 2012;
“EnCore”	means EnCore Oil plc, registered in England and Wales (no. 03328217);
“EnCore Board”	means the board of directors of EnCore;
“EnCore Directors”	means the directors of EnCore;
“EnCore General Meeting”	means the general meeting of the EnCore Shareholders (and any adjournment thereof) convened for the purposes of considering and, if thought fit, approving certain resolutions in connection with the Scheme;
“EnCore Group”	means EnCore and its subsidiaries and subsidiary undertakings at the relevant time;
“EnCore Shareholders”	means holders of EnCore Shares;
“EnCore Share Option Plans”	means the EnCore Oil plc 2006 Share Option Plan consisting of an unapproved share option plan, as amended, and individual

	agreements pursuant to which options were granted to former employees of EnCore prior to 3 March 2006;
“EnCore Shares”	means the ordinary shares of 5 pence each in the capital of EnCore and, after the Reduction Record Time, if applicable, A shares and B shares in the share capital of EnCore as reclassified pursuant to the Scheme;
“Enlarged Group”	means the Premier Group including the EnCore Group following the Effective Date;
“Existing Premier Shareholders”	means holders of existing Premier Shares;
“Existing Premier Shares”	means the Premier Shares in issue as at the time the New Premier Shares are issued pursuant to the Scheme;
“Form of Election”	means the form of election for Scheme Shareholders to make the Share Election in respect of the Share Alternative;
“FSA”	means the UK Financial Services Authority;
“FSMA”	means the Financial Services and Markets Act 2000;
“FPSO”	means Floating Production, Storage and Offloading Vessel;
“FTP”	means first tranche petroleum;
“Group”	means, as relevant, the Premier Group, the EnCore Group or the Enlarged Group;
“GSA”	means Gas Sales Agreement;
“GSPA”	means Gas Sales and Purchase Agreement;
“HSES”	means Health, Safety, Environment and Security;
“HSFO”	means High Sulphur Fuel Oil;
“IC”	means investment credit;
“IFRS”	means International Financial Reporting Standards as adopted in the European Union;
“ISIN”	means International Securities Identification Number;
“kboepd”	means thousand barrels of oil equivalent per day;
“LIBOR”	means the London InterBank Offered Rate of interest;
“Listing Rules”	means the rules and regulations of the UKLA as amended;
“LLC”	mean limited liability company;
“London Stock Exchange”	means London Stock Exchange plc;
“Long Stop Date”	means 5.00 p.m. on 28 February 2012;
“mbd”	means thousand barrels per day;
“mt”	means metric tonne;
“mmbbls”	means million barrels;
“mmboe”	means million barrels of oil equivalent;
“MMBtu”	means million British thermal units per day;
“mmcfd”	means million cubic feet per day;
“mmscfd”	means million standard cubic feet per day;
“New Premier Shares”	means Premier Shares proposed to be issued pursuant to the Scheme;
“NIBOR”	means the Norwegian InterBank Offered Rate of interest;
“Offer”	means, should the Acquisition be implemented by way of a takeover offer as defined in Chapter 3 of Part 28 of the Companies Act 2006, the recommended offer to be made by or on behalf of Premier to acquire the entire issued and to be issued ordinary

“Offer Document”	share capital of EnCore and, where the context admits, any subsequent revision, variation, extension or renewal of such offer; means, should the Acquisition be implemented by means of an Offer, the document to be sent to EnCore Shareholders which will contain, <i>inter alia</i> , the terms and conditions of the Offer;
“Official List”	means the premium segment of the official list of the UK Listing Authority;
“OGDCL”	means Oil and Gas Development Company Limited;
“Oilexco”	means Oilexco North Sea Limited;
“Overseas Shareholders”	means Scheme Shareholders who are resident in, ordinarily resident in, or citizens of, jurisdictions outside the United Kingdom;
“Panel”	means the United Kingdom Panel on Takeovers and Mergers;
“PKP”	means Premier-Kufpec Pakistan B.V.;
“POFJL”	means Premier Oil Finance (Jersey) Limited;
“POGL”	means Premier Oil Group Limited;
“POHL”	means Premier Oil Holdings Limited;
“POOBV”	means Premier Oil Overseas B.V.;
“POUKL”	means Premier Oil UK Limited;
“PSP”	means Premier & Shell Pakistan B.V.;
“Premier” or the “Company”	means Premier Oil plc, incorporated in Scotland (Registered No. SC234781);
“Premier Board”	means the board of directors of Premier;
“Premier Directors” or “Directors”	means the directors of Premier;
“Premier Group”	means Premier and its subsidiary undertakings from time to time;
“Premier Shareholders”	means holders of Premier Shares;
“Premier Shares”	means ordinary shares of 12.5 pence each in the capital of Premier (including, if the context requires, the New Premier Shares);
“Prospectus”	means this document which comprises a prospectus prepared in accordance with the Prospectus Rules;
“Prospectus Rules”	means the rules made for the purposes of Part IV of FSMA in relation to the offer of securities to the public and the admission of securities to trading on a regulated market;
“PRT”	means Petroleum Revenue Tax;
“PSC”	means Production Sharing Contract;
“RBC Capital Markets”	means RBC Europe Limited, trading as RBC Capital Markets;
“Reduction Court Order”	means the order of the Court under Section 648 of the Companies Act 2006 confirming the Capital Reduction;
“Reduction Record Time”	means 6.00 p.m. on the Business Day immediately preceding the date on which the Reduction Court Order is made;
“Restricted Jurisdiction”	means any jurisdiction where offering the New Premier Shares or making them available for subscription or purchase would breach any applicable law;
“Restricted Overseas Shareholder”	means any Overseas Shareholder who is prohibited from making or is deemed not to have made a valid share election for the Share Alternative (including, without limitation, any Overseas Shareholder who is resident in any Restricted Jurisdiction);
“Revolving Credit Facility”	means the revolving credit facility Premier has in place described in Part III of this document;

“Scheme”	means the proposed scheme of arrangement under Part 26 of the Companies Act 2006 between EnCore and the Scheme Shareholders to implement the Acquisition;
“Scheme Announcement”	means the joint announcement, made by Premier and EnCore dated 5 October 2011, of the terms of Premier’s offer to acquire the entire issued and to be issued ordinary share capital of EnCore;
“Scheme Document”	means the document to be dispatched to Scheme Shareholders in relation to the Scheme comprising the particulars required by Section 897 of the Companies Act 2006;
“Scheme Meeting”	means the meeting of Scheme Shareholders, as convened by order of the Court pursuant to Section 896 of the Companies Act 2006, to consider and, if thought fit, approve the Scheme (with or without amendment), and any adjournment thereof;
“Scheme Shareholders”	means holders of Scheme Shares;
“Scheme Shares”	means the EnCore Shares: a) in issue at the date of the Scheme Document; b) issued after the date of the Scheme Document and prior to the Scheme Voting Record Time; and c) issued at or after the Scheme Voting Record Time but on or before the Reduction Record Time, either on terms that the original or any subsequent holders of such shares are to be bound by the Scheme or in respect of which their holders are, or shall have agreed in writing to be, bound by the Scheme in each case other than EnCore Shares (if any) held by the Premier Group;
“Scheme Voting Record Time”	means the time and date specified in the Scheme Document by reference to which entitlement to vote on the Scheme will be determined, expected to be 6.00 p.m. on the day which is two days before the Scheme Meeting or, if the Scheme Meeting is adjourned, 6.00 p.m. on the day which is two days before the date of such adjourned Scheme Meeting;
“SCT”	means supplementary charge;
“SDRT”	means stamp duty reserve tax;
“Share Alternative”	means the alternative whereby EnCore Shareholders (other than Restricted Overseas Shareholders) may elect to receive new Premier Shares instead of all or part of the cash consideration which they would otherwise be entitled to receive under the Acquisition;
“SNGPL”	means Sui Northern Gas Pipelines Limited;
“SSGCL”	means Sui Southern Gas Company Limited;
“TAQA”	means TAQA Bratani Limited;
“TBtu”	means trillion British thermal units;
“Third Party”	means any government, government department or governmental, quasi governmental, supranational, statutory, regulatory, environmental or investigative body, court, stock exchange, trade agency, association, institution or any other body or person whatsoever in any jurisdiction;
“TTE Instruction”	means a transfer to escrow instruction as defined in the Crest Manual;
“UK” or “United Kingdom”	means the United Kingdom of Great Britain and Northern Ireland;
“UKCS”	means United Kingdom Continental Shelf;

“UK GAAP”	means generally accepted accounting principles in the United Kingdom;
“UK Listing Authority” or “UKLA”	means the United Kingdom Financial Services Authority in its capacity as the competent authority for listing under Part VI of the UK Financial Services and Markets Act 2000;
“US” or “United States”	means the United States of America, its territories and possessions, any State of the United States and the District of Columbia;
“US Securities Act”	means the United States Securities Act of 1933, as amended; and
“VAT”	any value added tax imposed under Directive 2006/112/EC, the Value Added Tax Act 1994 and/or any primary or secondary legislation supplemental to either of them.

All references to legislation in this document are to the legislation of England and Wales unless the contrary is indicated. Any reference to any provision of any legislation shall include any amendment, modification, re-enactment or extension thereof.

Words importing the singular shall include the plural and vice versa, and words importing the masculine gender shall include the feminine or neutral gender.

For the purpose of this document, **“subsidiary”**, **“subsidiary undertaking”**, **“undertaking”** and **“associated undertaking”** have the meanings given by the Companies Act 2006 and the Large and Medium-sized Companies and Groups (Accounts and Reports) Regulations 2008 (as applicable)(but for this purpose ignoring Regulation 19(1)(b) of Schedule 6 of the Large and Medium-sized Companies and Groups (Accounts and Reports) Regulations 2008).

References to **“£”**, **“sterling”**, **“p”** and **“pence”** are to the lawful currency of the United Kingdom; references to **“US\$”** and **“US Dollars”** are to the lawful currency of the United States; references to **“EUR”**, **“€”** and **“euros”** are to the lawful currency of the participating member states of the European Union which have adopted the single currency in accordance with the EC Treaty of Rome dated 25 March 1957 (as subsequently amended); and references to **“NOK”** and **“Norwegian Krone”** are to the lawful currency of Norway.

APPENDIX II

RELEVANT DOCUMENTATION

This Prospectus should be read and construed in conjunction with certain documents which have been previously published and filed with the FSA and which shall be deemed to be incorporated in, and form part of, this Prospectus.

The table below lists the documents from which information is incorporated by reference into this document in compliance with Prospectus Rule 2.4.1. To the extent that any document or information incorporated by reference or attached to this Prospectus itself incorporates any information by reference, either expressly or impliedly, such information will not form part of this Prospectus for the purposes of the Prospectus Rules.

The following documentation is available for inspection in accordance with section 16 of Part IX (Additional Information):

<i>Information incorporated by reference into this document</i>	<i>Location of incorporation in this document</i>	<i>Page number in this document</i>
Premier's Annual Report and Accounts for the financial year ended 31 December 2008	Part II – "Operating and Financial Review of Premier"	40
	Part IV – "Historical Financial Information relating to Premier"	46
Premier's Annual Report and Accounts for the financial year ended 31 December 2009	Part II – "Operating and Financial Review of Premier"	40
	Part IV – "Historical Financial Information relating to Premier"	46
Premier's Annual Report and Accounts for the financial year ended 31 December 2010	Part II – "Operating and Financial Review of Premier"	40
	Part IV – "Historical Financial Information relating to Premier"	46
Premier's Interim Report for the six month period ended 30 June 2011	Part II – "Operating and Financial Review of Premier"	40
	Part IV – "Historical Financial Information relating to Premier"	47

