BAYTEX ENERGY CORP.
Form F-10
February 06, 2014

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As filed with the Securities and Exchange Commission on February 6, 2014

Registration No. 333-

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM F-10

REGISTRATION STATEMENT
UNDER
THE SECURITIES ACT OF 1933

BAYTEX ENERGY CORP.

(Exact name of registrant as specified in its charter)

Alberta, Canada

(Province or other jurisdiction of incorporation or organization)

1381

(Primary Standard Industrial Classification Code Number, if applicable)

Not applicable

(I.R.S. Employer Identification No., if applicable)

2800, 520 3rd Avenue S.W.
Calgary, Alberta, Canada, T2P 0R3
Tel: 587-952-3000

(Address and telephone number of Registrant's principal executive offices)

Baytex Energy USA Ltd.
600 17th St., Suite 1600 S.
Denver, CO 80202
Tel: 303-825-2777

(Name, address (including zip code) and telephone number (including area code) of agent for service in the United States)

Copies to:

Murray J. Desrosiers **Baytex Energy Corp.** **2800, 520 3rd Avenue S.W.** **Calgary, Alberta, Canada, T2P 0R3** **Tel: 587-952-3000**	**Shannon M. Gangl** **Burnet, Duckworth & Palmer LLP** **2400, 525 8th Avenue S.W.** **Calgary, Alberta, Canada T2P 1G1**	**Andrew J. Foley, Esq.** **Paul, Weiss, Rifkind, Wharton & Garrison LLP** **1285 Avenue of the Americas** **New York, New York**	**James M. Prince** **Vinson & Elkins LLP** **1001 Fannin Street** **Suite 2500** **Houston, TX 77002-6760** **Tel: 713-758-3710**	**John S. Osler, QC** **McCarthy Tétrault** **Suite 3300** **421 7th Avenue SW** **Calgary, AB T2P 4K9** **Tel: 403-260-3554**

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Approximate date of commencement of proposed sale to the public: As soon as practicable after this Registration Statement becomes effective.

Province of Alberta, Canada

(Principal jurisdiction regulating this offering)

It is proposed that this filing shall become effective (check appropriate box below):

A. o upon filing with the Commission pursuant to Rule 467(a) (if in connection with an offering being made contemporaneously in the United States and Canada).

B. ý at some future date (check the appropriate box below):

1. o pursuant to Rule 467(b) on ( ) at ( ) (designate a time not sooner than 7 calendar days after filing).
2. o pursuant to Rule 467(b) on ( ) at ( ) (designate a time 7 calendar days or sooner after filing) because the securities regulatory authority in the review jurisdiction has issued a receipt or notification of clearance on ( ).
3. o pursuant to Rule 467(b) as soon as practicable after notification of the Commission by the Registrant or the Canadian securities regulatory authority of the review jurisdiction that a receipt or notification of clearance has been issued with respect hereto.
4. ý after the filing of the next amendment to this Form (if preliminary material is being filed).

If any of the securities being registered on this Form are to be offered on a delayed or continuous basis pursuant to the home jurisdiction's shelf prospectus offering procedures, check the following box. o

CALCULATION OF REGISTRATION FEE

Title of Each Class of Securities to be Registered	**Amount to be Registered**	**Proposed Maximum Offering Price per Subscription Receipt**	**Proposed Maximum Aggregate Offering Price(1)**	**Amount of Registration Fee(1)**
Subscription Receipts			U.S.$1,351,200,000	U.S.$174,034.56

(1) Calculated pursuant to Rule 457(o) under the Securities Act of 1933, as amended. U.S. dollar amounts are calculated based on the Bank of Canada noon rate of US$0.9008=Cdn$1.00 on February 5, 2014.

The Registrant hereby amends this registration statement on such date or dates as may be necessary to delay its effective date until the registration statement shall become effective as provided in Rule 467 under the Securities Act of 1933 or on such date as the Commission, acting pursuant to Section 8(a) of the Act, may determine.

Information has been incorporated by reference into this short form prospectus from documents filed with securities commissions or similar authorities in Canada*. Copies of the documents incorporated herein by reference may be obtained on request without charge from the Corporate Secretary of Baytex Energy Corp. at Suite 2800, Centennial Place, East Tower, 520 - 3rd Avenue S.W., Calgary, Alberta, Canada, T2P 0R3, Telephone (587) 952-3000 and are also available electronically at* www.sedar.com.

PRELIMINARY SHORT FORM PROSPECTUS
SUBJECT TO COMPLETION, DATED FEBRUARY 6, 2014

New Issue **February 6, 2014**

$

Subscription Receipts each
representing the right to receive one Common Share

$ per Subscription Receipt

We are hereby qualifying for distribution subscription receipts (the "**Subscription Receipts**") at a price of $ per Subscription Receipt (the "**Offering**"). Each Subscription Receipt will entitle the holder thereof to receive, without payment of additional consideration or further action on the part of such holder, one common share ("**Common Share**") in our capital (an "**Underlying Common Share**") upon closing of the Acquisition (as defined herein).

The terms of the Offering, including the offering price for the Subscription Receipts, were determined by negotiation between us and Scotia Capital Inc. ("**Scotia**") and RBC Dominion Securities Inc. (collectively, the "**Underwriters**"). See "*Plan of Distribution*".

The gross proceeds from the sale of the Subscription Receipts (the "**Escrowed Funds**") will be held by Valiant Trust Company, as escrow agent (the "**Escrow Agent**"), and invested in short-term obligations of, or guaranteed by, the Government of Canada (or other approved investments). Upon satisfaction of the Escrow Condition (as defined herein) on or before 5:00 p.m. (Calgary time) on June 30, 2014, the Escrowed Funds and the interest earned thereon (less any amounts required to pay the Dividend Equivalent Amount (as defined herein) upon the issuance of the Underlying Common Shares, if applicable) will be released to us to enable us to convert these funds to Australian dollars and complete the Acquisition. On the closing of the Acquisition, each holder of Subscription Receipts will receive one Underlying Common Share for each Subscription Receipt held, without payment of additional consideration or further action on the part of such holder, and such holder will also be entitled to receive the Dividend Equivalent Amount, being an amount per Subscription Receipt equal to the amount per Common Share of any cash dividends for which record date(s) have occurred during the period commencing on the closing of the Offering through the date immediately preceding the date the Underlying Common Shares are issued pursuant to the Subscription Receipts. See "*Details of the Offering*".

On February 6, 2014, we entered into an agreement to acquire, through a scheme of arrangement under Australian law, all of the fully diluted shares of Aurora Oil & Gas Limited (TSX: AEF, ASX: AUT) ("Aurora") for total consideration of approximately $1.8 billion, plus assumed debt of approximately $744 million, for a total transaction value of approximately $2.6 billion (the "**Acquisition**"), as described in more detail under "*Recent Developments The Acquisition*" and "*About Aurora*".

We will utilize the Escrowed Funds to pay a portion of the purchase price for the Acquisition. If: (i) the Acquisition is not completed by June 30, 2014; (ii) the Implementation Agreement (as defined herein) is terminated in accordance with its terms at any earlier time; or (iii) we have advised the Underwriters or announced to the public that we do not intend to proceed with the Acquisition (the time of occurrence of any such event being the "**Termination Time**"), holders of Subscription Receipts shall receive an amount equal to the full subscription price attributable to the Subscription Receipts and their *pro rata* entitlement to interest accrued on such amount up to and including the Termination Time. See "*Details of the Offering*".

Further particulars concerning the attributes of the Subscription Receipts are set out under "*Details of the Offering*" and further particulars concerning the attributes of the Common Shares are set out under "*Description of Common Shares*".

	Price to the Public[(1)]	**Underwriters' Fee[(2)]**	**Net Proceeds to the Corporation[(3)]**
Per Subscription Receipt	$	$	$
Total[(4)]	$	$	$

Notes:

(1) All dollar amounts in this short form prospectus are expressed in Canadian dollars, except where otherwise indicated.

(2) The fee payable to the Underwriters is 4.0% of the gross proceeds of the Offering (the "**Underwriters' Fee**"). The Underwriters' Fee in respect of the Subscription Receipts is payable as to 50% upon the closing of the Offering and 50% upon the closing of the Acquisition. If closing of the Acquisition has not occurred by June 30, 2014, the Underwriters' Fee will be reduced to the amount payable upon closing of the Offering. See "*Details of the Offering*" and "*Plan of Distribution*".

(3) Excluding interest accrued, if any, on the Escrowed Funds, and before deducting expenses of the Offering, estimated to be $3 million (exclusive of GST), which will be deducted from our general funds.

(4) We have granted to the Underwriters an option (the "**Over-allotment Option**") to purchase up to an additional Subscription Receipts at a price of $ per Subscription Receipt on the same terms and conditions as the Offering, exercisable from time to time, in whole or in part, for a period commencing at closing of the Offering and ending on the earlier of: (i) 30 days following closing of the Offering; and (ii) the Termination Time, to cover over-allotments, if any, and for market stabilization purposes. A purchaser who acquires Subscription Receipts forming part of the Underwriters' over-allocation position acquires those Subscription Receipts under this short form prospectus, regardless of whether the over-allocation position is ultimately filled through the exercise of the Over-allotment Option or secondary market purchases. If the Over-allotment Option is exercised in full, the total gross proceeds of the Offering, the Underwriters' Fee and the net proceeds to us (before deducting expenses of the Offering) will be $, $ and $, respectively. This short form prospectus also qualifies the distribution of the Subscription Receipts issuable upon exercise of the Over-allotment Option. See "*Plan of Distribution*" and the table below.

The following table sets forth the number of Subscription Receipts that may be offered by us pursuant to the Over-allotment Option.

Underwriters' Position	**Maximum size or number of securities held**	**Exercise period**	**Exercise price**
Over-allotment Option	Subscription Receipts	Commencing at closing of the Offering and ending on the earlier of: (i) 30 days following closing of the Offering; and (ii) the Termination Time	$ per Subscription Receipt

NEITHER THE U.S. SECURITIES AND EXCHANGE COMMISSION NOR ANY STATE SECURITIES COMMISSION HAS APPROVED OR DISAPPROVED OF THE SUBSCRIPTION RECEIPTS NOR PASSED UPON THE ACCURACY OR ADEQUACY OF THIS SHORT FORM PROSPECTUS. ANY REPRESENTATION TO THE CONTRARY IS A CRIMINAL OFFENCE.

Your ability to enforce civil liabilities under United States federal securities laws may be affected adversely by the fact that we are formed under the laws of the Province of Alberta, that some of our officers and directors are residents of Canada or otherwise reside outside of the United States, that some or all of the Underwriters and experts named in this short form prospectus may be residents of Canada or otherwise reside outside of the United States, and that a substantial portion of our assets and the assets of said persons may be located outside the United States.

Mary Ellen Peters, one of our directors, resides outside of Canada. Ms. Peters has appointed Burnet, Duckworth & Palmer LLP, Suite 2400, 525 - 8th Avenue S.W., Calgary, Alberta, Canada, T2P 1G1, as her agent for service of process. In addition, all or some of the designated professionals of BDO Audit (WA) Pty Ltd., Aurora's external auditor and Ryder Scott Company, L.P., Aurora's independent qualified reserves evaluator are incorporated, continued or otherwise organized under the laws of a foreign jurisdiction or reside outside of Canada. BDO Audit (WA) Pty Ltd. has appointed BDO Canada LLP, Suite 600, 36 Toronto Street, Toronto, Ontario M5C 2C5 as its agent for service of process. Ryder Scott Company, L.P has appointed Ryder Scott Canada at Suite 600, 1015 4th St. S.W., Calgary, Alberta, Canada T2R 1J4 as its agent for service of process. It may not be possible for you to enforce judgments obtained in Canada against a person that resides outside of Canada, even if the party has appointed an agent for service of process. See "*Enforcement of Judgments Against Foreign Persons or Companies*".

We are permitted, under the multi-jurisdictional disclosure system adopted by the United States and Canada, to prepare this short form prospectus in accordance with the disclosure requirements of Canada. Prospective investors should be aware that such requirements are different from those of the United States. Our financial statements included or incorporated by reference in this short form prospectus have been prepared in accordance with Canadian generally accepted accounting principles ("Canadian GAAP") (which, since January 1, 2011, have been consistent with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board) and are subject to Canadian auditing and auditor independence standards. Aurora's historical financial statements contained in this short form prospectus have been prepared in accordance with Australian Accounting

Standards ("AAS"), which include Australian equivalents to IFRS. Compliance with AAS ensures compliance with IFRS as issued by the International Accounting Standards Board. Canadian GAAP and AAS differs from generally accepted accounting principles in the United States ("U.S. GAAP"). Thus, these financial statements may not be comparable to financial statements of United States companies.

Data on oil and gas reserves contained in or incorporated by reference into this short form prospectus has been prepared in accordance with Canadian disclosure standards, which are not comparable in all respects to United States disclosure standards. See "*Presentation of Financial and Oil and Gas Information*".

Prospective investors should be aware that the acquisition of the Subscription Receipts described herein may have tax consequences both in the United States and Canada. Such consequences may not be fully described herein. See "*Certain Canadian Federal Income Tax Considerations*" and "*Certain United States Federal Income Tax Considerations*".

Our outstanding Common Shares are listed and posted for trading on the Toronto Stock Exchange (the "**TSX**") and the New York Stock Exchange ("**NYSE**") under the trading symbol "BTE". On February 5, 2014, the last trading day prior to the public announcement of the Offering, the closing price of the Common Shares on the TSX was $41.16 per Common Share and the closing price of the Common Shares on the NYSE was U.S.$37.16 per Common Share.

The Underwriters, as principals, conditionally offer the Subscription Receipts, subject to prior sale, if, as and when issued by us and accepted by the Underwriters in accordance with the conditions contained in the Underwriting Agreement (as defined herein). The Offering is subject to the approval of certain legal matters relating to Canadian law on our behalf by Burnet, Duckworth & Palmer LLP, Calgary, Alberta and on behalf of the Underwriters by McCarthy Tétrault LLP, Calgary, Alberta and to the approval of certain legal matters relating to United States law on our behalf by Paul, Weiss, Rifkind, Wharton & Garrison LLP, New York, New York and on behalf of the Underwriters by Vinson & Elkins LLP, Houston, Texas.

Subscriptions for Subscription Receipts will be received subject to rejection or allotment in whole or in part and the right is reserved to close the subscription books at any time without notice. The closing of the Offering is anticipated to occur on or about February 24, 2014 or such other date as may be agreed upon by us and the Underwriters (the "**Closing Date**"), but in any event not later than March 28, 2014. Except in certain limited circumstances: (i) Subscription Receipts and Underlying Common Shares will be registered and represented electronically through the non-certificated inventory of CDS Clearing and Depository Services Inc. ("**CDS**"); (ii) no certificates evidencing the Subscription Receipts and Underlying Common Shares will be issued; and (iii) purchasers of Subscription Receipts will receive only a customer confirmation from the Underwriter or other registered dealer who is a CDS participant and from or through whom a beneficial interest in the Subscription Receipts is purchased. See "*Plan of Distribution*".

Subject to applicable laws, the Underwriters may, in connection with the Offering, effect transactions which stabilize or maintain the market price of the Common Shares at levels other than those that might otherwise prevail on the open market in accordance with applicable market stabilization rules. Such transactions, if commenced, may be discontinued at any time. **The Underwriters propose to offer the Subscription Receipts initially at the offering price specified above. After a reasonable effort has been made to sell all the Subscription Receipts at the price specified, the Underwriters may subsequently reduce the selling price to investors from time to time in order to sell any of the Subscription Receipts remaining unsold. Any such reduction will not affect the proceeds received by us.** See "*Plan of Distribution*".

Scotia is a wholly-owned subsidiary of a Canadian chartered bank which has agreed to fully underwrite and commit to provide us with new senior secured credit facilities which will replace the Credit Facilities (as defined under the heading "*Consolidated Capitalization*") in connection with the Acquisition. Each of Scotia and RBC Dominion Securities Inc. are wholly-owned subsidiaries of Canadian chartered banks, which are lenders to our subsidiary, Baytex Energy Ltd. ("**Baytex Energy**") pursuant to the Credit Facilities. Scotia has also provided financial advice to us in connection with the Acquisition. Consequently, we may be considered to be a connected issuer to each of these Underwriters for the purposes of securities regulations in certain provinces. See "*Relationship between Us and the Underwriters*" and "*Use of Proceeds*".

There is currently no market through which the Subscription Receipts may be sold and there is no guarantee that an active trading market will develop. Accordingly, purchasers may not be able to resell the Subscription Receipts distributed under this short form prospectus. This may affect the pricing of the Subscription Receipts in the secondary market, the transparency and the availability of trading prices and the liquidity of the Subscription Receipts. See "*Risk Factors*".

An investment in the securities offered hereunder is speculative and involves a high degree of risk. The risk factors identified under the headings "*Risk Factors*" and "*Forward-Looking Statements*" in this short form prospectus, the Annual Information Form (as defined herein) and the Annual MD&A (as defined herein) should be carefully reviewed and evaluated by prospective subscribers before purchasing the securities being offered hereunder.

Our head office is located at Suite 2800, Centennial Place, East Tower, 520 - 3rd Avenue S.W., Calgary, Alberta, Canada, T2P 0R3 and our registered office is located at Suite 2400, 525 - 8th Avenue S.W., Calgary, Alberta, Canada, T2P 1G1.

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IMPORTANT NOTICE ABOUT INFORMATION IN THIS SHORT FORM PROSPECTUS

You should rely only on the information contained or incorporated by reference in this short form prospectus, and, if you reside in the United States, on the other information included in the registration statement of which this short form prospectus forms a part. We have not, and the Underwriters have not, authorized anyone to provide you with different information. If anyone provides you with different or inconsistent information, you should not rely on it. You should assume that only the information appearing in this short form prospectus, as well as information we previously filed with the securities regulatory authority in each of the provinces of Canada and with the SEC that is incorporated by reference into this short form prospectus, is accurate as of the respective dates of the applicable documents. Our business, financial condition, results of operations and prospects may have changed since those dates.

We are not, and the Underwriters are not, making an offer to sell these Subscription Receipts in any jurisdiction where the offer or sale is not permitted.

PRESENTATION OF FINANCIAL AND OIL AND GAS INFORMATION

Unless indicated otherwise, our financial information in this short form prospectus, including the documents incorporated by reference herein, has been prepared in accordance with Canadian GAAP (which, since January 1, 2011, have been consistent with IFRS as issued by the International Accounting Standards Board). Aurora's historical financial statements contained in this short form prospectus have been prepared in accordance with AAS, which include Australian equivalents to the IFRS. Compliance with AAS ensures compliance with IFRS as issued by the International Accounting Standards Board. Canadian GAAP and AAS differ from U.S. GAAP and thus these financial statements may not be comparable to the financial statements of U.S. companies.

The securities regulatory authorities in Canada have adopted NI 51-101 (as defined below), which imposes oil and gas disclosure standards for Canadian public issuers engaged in oil and gas activities. The recovery and resource estimates provided in this short form prospectus and in the documents incorporated by reference herein are estimates only. Actual reserves and contingent resources (and any volumes that may be reclassified as reserves) and future production from such reserves or contingent resources may be greater than or less than the estimates provided herein.

The determination of oil and gas reserves involves the preparation of estimates that have an inherent degree of associated uncertainty. Categories of proved and probable reserves have been established to reflect the level of these uncertainties and to provide an indication of the probability of recovery. The estimation and classification of reserves requires the application of professional judgment combined with geological and engineering knowledge to assess whether or not specific reserves classification criteria have been satisfied. Knowledge of concepts including uncertainty and risk, probability and statistics, and deterministic and probabilistic estimation methods is required to properly use and apply reserves definitions.

All estimates of future revenue in this prospectus and in the documents incorporated herein by reference are, unless otherwise noted, after the deduction of royalties, development costs, production costs and well abandonment costs but before deduction of future income tax expenses and before consideration of indirect costs such as administrative, overhead and other miscellaneous expenses. The estimated future net revenues contained in this prospectus and in the documents incorporated herein by reference do not represent the fair market value of the applicable reserves.

There is no assurance that the forecast price and cost assumptions estimated will be attained and variances could be material. The recovery and reserves estimates described herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual reserves may be greater or less than the estimates provided herein and in the documents incorporated herein by reference. The estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.

Unless otherwise stated, all of the reserves information contained herein and in the documents incorporated herein by reference, have been calculated and reported using assumptions and methodology guidelines outlined in accordance with the standards contained in the COGE Handbook, NI 51-101 and the reserve definitions contained in the Canadian Securities Administrators Staff Notice 51-324. Numbers in the reserves tables and other oil and gas information contained in this prospectus may not add due to rounding.

NI 51-101 permits oil and gas issuers, in their filings with Canadian securities regulatory authorities, to disclose not only proved, probable and possible reserves but also resources, and to disclose reserves and production on a gross basis before deducting royalties. Probable reserves, possible reserves and resources are of a higher risk and are less likely to be accurately estimated or recovered than proved reserves. We are permitted to disclose reserves in accordance with Canadian securities law requirements and the disclosure herein and in the documents incorporated by reference herein may include reserves designated as probable reserves, possible reserves and resources, as defined under Canadian standards.

The SEC does not permit the inclusion of estimates of resources in reports filed with it by companies domiciled in the United States.

The SEC definitions of proved, probable and possible reserves are different than NI 51-101; therefore, proved, probable and possible reserves disclosed herein and in the documents incorporated by reference into this short form prospectus may not be comparable to United States standards. The SEC currently requires United States oil and gas companies, in their filings with the SEC, to disclose only proved reserves after the deduction of royalties and interests of others but permits the optional disclosure of probable and possible reserves, as defined under SEC rules. The SEC does not allow proved and probable reserves to be aggregated except in the case of reserves determined using probabilistic methods, whereas NI 51-101 requires issuers to disclose aggregate proved and probable reserves.

Moreover, as permitted by NI 51-101, we have determined and disclosed herein, and in the documents incorporated by reference, the net present value of future net revenue from our reserves and the reserves associated with the Aurora Assets (as defined herein) using only forecast prices and costs. The SEC requires that reserves and related future net revenue be estimated based on historical 12-month average prices, but permits the optional disclosure of revenue estimates based on different price and cost criteria, including standardized future prices or management's own forecasts.

Additional information prepared in accordance with Accounting Standards Codification 932 "Extractive Activities Oil & Gas" issued by the United States Financial Accounting Standards Board ("**ASC 932**") relating to our petroleum and natural gas reserves is set forth in the Supplemental Oil and Gas Disclosures (as defined herein), which is incorporated herein by reference.

ASC 932 disclosure relating to Aurora's petroleum and natural gas reserves is not, and is not required to be; included in this short form prospectus.

Certain documents incorporated by reference into this short form prospectus contain estimates of "contingent resources". The SEC would prohibit a United States oil and gas company from including an estimate of "contingent resources" in its filings with the SEC. "Contingent resources" are not, and should not be confused with, petroleum and natural gas reserves. "Contingent resources" are defined in the COGE Handbook (as defined herein) as: "those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political and regulatory matters or a lack of markets. It is also appropriate to classify as contingent resources the estimated discovered recoverable quantities associated with a project in the early evaluation stage."

The outstanding contingencies applicable to our disclosed contingent resources do not include economic contingencies. Economic contingent resources are those resources that are currently economically recoverable based on specific forecasts of commodity prices and costs.

A range of contingent resources estimates (low, best and high) were prepared by the independent qualified reserves evaluators. A low estimate (C1) is considered to be a conservative estimate of the quantity of the resource that will actually be recovered. It is likely that the actual remaining quantities recovered will exceed the low estimate. Those resources in the low estimate have the highest degree of certainty (a 90% confidence level) that the actual quantities recovered will equal or exceed the estimate. A best estimate (C2) is considered to be the best estimate of the quantity of the resource that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. Those resources in the best estimate have a 50% confidence level that the actual quantities recovered will equal or exceed the estimate. A high estimate (C3) is considered to be an optimistic estimate of the quantity of the resource that will actually be recovered. It is unlikely that the actual remaining quantities of resource recovered will equal or exceed the high estimate. Those resources in the high estimate have a lower degree of certainty (a 10% confidence level) that the actual quantities recovered will equal or exceed the estimate.

The primary contingencies which currently prevent the classification of our contingent resources as reserves consist of: preparation of firm development plans, including determination of the specific scope and timing of the project; project sanction; access to capital markets; stakeholder and regulatory approvals; access to required services and field development infrastructure; oil prices and price differentials between light, medium and heavy gravity crude oils; future drilling program and testing results; further reservoir delineation and studies; facility design work; limitations to development based on adverse topography or other surface restrictions; and the uncertainty regarding marketing and transportation of petroleum from development areas.

There is no certainty that it will be commercially viable to produce any portion of the contingent resources or that we will produce any portion of the volumes currently classified as contingent resources. The estimates of contingent resources involve implied assessment, based on certain estimates and assumptions, that the resource described exists in the quantities predicted or estimated and that the resource can be profitably produced in the future.

Other principal differences between SEC oil and gas disclosure requirements and NI 51-101 include the following, some of which may be material:

- the SEC mandates disclosure of reserves by geographic area only, whereas NI 51-101 requires disclosure of more reserve categories and product types;

- the SEC's rules in estimating reserves differ from NI 51-101 in areas such as the use of reliable technology, aerial extent around a drilled location, quantities below the lowest known oil and quantities across an undrilled fault block; and

- U.S. rules limit reserve bookings on undrilled acreage to "those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances," whereas under NI 51-101, reserves may be recognized on undrilled properties beyond directly offsetting spacing units if there is "compelling evidence of reservoir continuity".

The NGLs referred to in this prospectus are reported on a combined basis with any condensate as required under NI 51-101.

SELECTED DEFINITIONS

Unless the context otherwise requires, all references in this short form prospectus to "**Baytex**", the "**Corporation**", "**we**", "**us**" or "**our**" means Baytex Energy Corp. and its consolidated subsidiaries, any partnership of which Baytex Energy Corp. and its subsidiaries are the partners and our significant equity investments and joint ventures.

In this short form prospectus, the following terms shall have the following meanings:

"**2013 Acquired Assets**" means the 100% operated WI in approximately 2,700 net acres in the Heard Ranch and Axle Tree blocks in South Texas, together with interests in 11 net producing wells as well as associated interests in field infrastructure and related assets, acquired by Aurora on March 29, 2013 with an effective date of March 1, 2013.

"**2017 Aurora Notes**" means the U.S.$365 million aggregate principal amount of 9.875% senior unsecured notes issued by a subsidiary of Aurora which are due February 15, 2017 and will be assumed by us in connection with the Acquisition.

"**2020 Aurora Notes**" means the U.S.$300 million aggregate principal amount of 7.50% senior unsecured notes issued by a subsidiary of Aurora which are due April 1, 2020 and will be assumed by us in connection with the Acquisition.

"**2021 Debentures**" means our U.S.$150 million 6.75% series B senior unsecured debentures due February 17, 2021 and issued pursuant to the Canadian Indenture.

"**2022 Debentures**" means our $300 million 6.625% series C senior unsecured debentures due July 19, 2022 and issued pursuant to the Canadian Indenture.

"**ABCA**" means the *Business Corporations Act* (Alberta), R.S.A. 2000, c. B-9, including the regulations promulgated thereunder, as amended from time to time.

"**Acquisition**" means the proposed acquisition by us of all of the issued and outstanding Aurora Shares pursuant to the Implementation Agreement.

"**AMI**" means area of mutual interest, a contractually defined area in which oil and gas companies hold oil and gas rights.

"**Annual Information Form**" has the meaning ascribed thereto under "*Documents Incorporated by Reference*".

"**Annual Financial Statements**" has the meaning ascribed thereto under "*Documents Incorporated by Reference*".

"**Annual MD&A**" has the meaning ascribed thereto under "*Documents Incorporated by Reference*".

"**ASIC**" means the Australian Securities and Investments Commission.

"**ASX**" means ASX Limited (ABN 98 008 624 691) and, where the context permits, the Australian Securities Exchange operated by ASX Limited.

"**Aurora**" means Aurora Oil & Gas Limited, a publicly traded corporation organized under the Corporations Act.

"**Aurora 2012 Reserves Report**" means the independent engineering evaluation of Aurora's oil and natural gas reserves dated January 30, 2013 prepared by Ryder Scott effective December 31, 2012, which is entitled "*Aurora Oil & Gas Limited Estimated Future Reserves and Income Attributable to Certain Leasehold Interests*".

"**Aurora 2013 Reserves Report**" means the independent engineering evaluation of Aurora's oil and natural gas reserves dated January 31, 2014 prepared by Ryder Scott effective December 31, 2013, which is entitled "*Aurora Oil & Gas Limited Estimated Future Reserves and Income Attributable to Certain Leasehold Interests*".

"**Aurora Assets**" means those oil, petroleum and natural gas properties and related assets of Aurora described in more detail under "*Recent Developments The Acquisition*" and "*About Aurora*".

"**Aurora Board**" means the board of directors of Aurora.

"**Aurora Notes**" means collectively, the 2017 Aurora Notes and the 2020 Aurora Notes.

"**Aurora Options**" has the meaning ascribed thereto under "*Recent Developments The Acquisition*".

"**Aurora Performance Rights**" has the meaning ascribed thereto under "*Recent Developments The Acquisition*".

"**Aurora Reserves Reports**" means the Aurora 2012 Reserves Report and the Aurora 2013 Reserves Report.

"**Aurora Shareholders**" means the holders of all of the issued and outstanding Aurora Shares.

"**Aurora Shares**" means the ordinary shares in the capital of Aurora, as presently constituted.

"**Australian Court**" means the Federal Court of Australia (Western Australian Registry) or any other court of competent jurisdiction under the Corporations Act (as agreed by the parties to the Implementation Agreement in writing).

"**Baytex Energy**" means Baytex Energy Ltd., a corporation amalgamated under the ABCA and our wholly-owned subsidiary.

"**Board of Directors**" means our board of directors.

"**Canadian Indenture**" means the amended and restated trust indenture which provides for the issuance of Debt Securities in Canada among us, as issuer, Baytex Energy and certain of our other subsidiaries, as guarantors, and Valiant Trust Company, as trustee, dated January 1, 2011, as supplemented by a supplemental trust indentures dated February 17, 2011, February 18, 2011, July 19, 2012 and December 19, 2012. The 2021 Debentures and the 2022 Debentures were issued under the Canadian Indenture.

"**CDS**" means CDS Clearing and Depository Services Inc.

"**COGE Handbook**" means the Canadian Oil and Gas Evaluation Handbook.

"**Common Shares**" means the common shares in our capital.

"**Common Share Rights Incentive Plan**" means our Common Share Rights Incentive Plan, as described in the Information Circular under "*Executive Compensation Common Share Rights Incentive Plan*".

"**Corporations Act**" means the Australian Corporations Act 2001 (Cth).

"**Credit Facilities**" has the meaning ascribed thereto under "*Consolidated Capitalization*".

"**Debentures**" means, collectively, the 2021 Debentures and the 2022 Debentures.

"**Debt Securities**" means our senior or subordinated debt securities.

"**Developed Non-Producing Reserves**" are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.

"**Developed Producing Reserves**" are those reserves that are expected to be recovered from completion in intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

"**Developed Reserves**" are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for example, when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.

"**development costs**" means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas from reserves. More specifically, development costs, including applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to: (a) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground draining, road building, and relocating public roads, gas lines and power lines, pumping equipment and wellhead assembly; (b) drill and equip development wells, development type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and wellhead assembly; (c) acquire, construct and install production facilities such as flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and (d) provide improved recovery systems.

"**development well**" means a well drilled inside the established limits of an oil and gas reservoir, or in close proximity to the edge of the reservoir, to the depth of a stratigraphic horizon known to be productive.

"**Dividend Equivalent Amount**" means an amount per Subscription Receipt equal to the amount per Common Share of any cash dividends for which record date(s) have occurred during the period beginning on the closing date of the Offering to the date immediately preceding the date the Underlying Common Shares are issued pursuant to the Subscription Receipts.

"**Eagle Ford**" means the Eagle Ford shale trend in South Texas, which produces oil, natural gas, natural gas liquids and condensate.

"**Elixir**" means Elixir Petroleum Limited.

"**EDGAR**" means the Electronic Data Gathering, Analysis and Retrieval System established by the SEC.

"**Effective Date**" in relation to the Acquisition means the date on which the Acquisition becomes effective.

"**Escrow Agent**" means Valiant Trust Company, which is deemed an "Acceptable Institution" under the guidelines of the Investment Industry Regulatory Organization of Canada and the Canadian Investor Protection Fund, in its capacity as escrow agent pursuant to the Subscription Receipt Agreement.

"**Escrow Condition**" has the meaning ascribed thereto under "*Details of the Offering*".

"**Escrowed Funds**" means the gross proceeds from the sale of the Subscription Receipts.

"**Exchange Act**" means the *United States Securities Exchange Act of 1934*, as amended.

"**Existing Target Facility**" means the existing U.S.$300 million senior secured credit facility established under the credit agreement dated as of November 7, 2011 among Aurora USA Oil & Gas, Inc., Aurora, UBS AG, Stamford Branch, as administrative agent and the financial institutions party thereto, as amended and supplemented.

"**exploration costs**" means costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects that may contain oil and gas reserves, including costs of drilling exploratory wells and exploratory type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property and after acquiring the property. Exploration costs, which include applicable operating costs of support equipment and facilities and other costs of exploration activities, are: (a) costs of topographical, geochemical, geological and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews and others conducting those studies; (b) costs of carrying and retaining unproved properties, such as delay rentals, taxes (other than income and capital taxes) on properties, legal costs for title defence, and the maintenance of land and lease records; (c) dry hole contributions and bottom hole contributions; (d) costs of drilling and equipping exploratory wells; and (e) costs of drilling exploratory type stratigraphic test wells.

"**exploratory well**" means a well that is not a development well, a service well or a stratigraphic test well.

"**Final Order**" means the order issued by the Australian Court pursuant to section 411(4)(b) of the Corporations Act approving the Acquisition.

"**forecast prices and costs**" means in relation to an issuer, prices and costs that are: (a) generally acceptable as being a reasonable outlook of the future; and (b) if and only to the extent that, there are fixed or presently determinable future prices or costs to which an issuer is legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in paragraph (a).

"**Flour Bluff Field**" means the Flour Bluff Gas Field located near Corpus Christi, Texas.

"**gross**" means: (a) in relation to an issuer's interest in production or reserves, its "company gross reserves", which are its working interest (operating or non-operating) share before deduction of royalties and without including any royalty interests of the issuer; (b) in relation to wells, the total number of wells in which an issuer has an interest; and (c) in relation to properties, the total area of properties in which an issuer has an interest.

"**Implementation Agreement**" means the Implementation Agreement between us and Aurora dated effective February 6, 2014 pursuant to which we have agreed to acquire all of the issued and outstanding Aurora Shares, as more particularly described under "*Recent Developments The Acquisition*".

"**HSR Act**" means the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended, and the rules and regulations thereunder.

"**Incentive Plan**" means our Common Share Rights Incentive Plan, as described in the Information Circular under *"Executive Compensation Common Share Rights Incentive Plan".*

"**Information Circular**" has the meaning ascribed thereto under "*Documents Incorporated by Reference*".

"**Interim Financial Statements**" has the meaning ascribed thereto under "*Documents Incorporated by Reference*".

"**Interim MD&A**" has the meaning ascribed thereto under "*Documents Incorporated by Reference*".

"**Ipanema**" means the Ipanema AMI in the Sugarkane Field.

"**Longhorn**" means the Longhorn AMI in the Sugarkane Field.

"**JOA**" means joint operating agreement among co-owners of WIs in a designated field, AMI, unit or lease.

"**Marathon**" means Marathon Oil EF LLC, a wholly-owned subsidiary of Marathon Oil Corporation.

"**net**" means: (a) in relation to an issuer's interest in production or reserves its working interest (operating or non-operating) share after deduction of royalty obligations, plus its royalty interests in production or reserves; (b) in relation to an issuer's interest in wells, the number of wells obtained by aggregating the issuer's working interest in each of its gross wells; and (c) in relation to an issuer's interest in a property, the total area in which the issuer has an interest multiplied by the working interest owned by the issuer.

"**New Credit Facilities**" has the meaning ascribed thereto under See "*Recent Developments New Credit Facilities*".

"**NI 51-101**" means National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities*.

"**Notes**" means the unsecured subordinated promissory notes issued by Baytex Energy and certain other Operating Entities to us.

"**NYSE**" means the New York Stock Exchange.

"**Operating Entities**" means our direct and indirect wholly-owned subsidiaries that are actively involved in the acquisition, production, processing, transportation and marketing of crude oil, natural gas liquids and natural gas, being Baytex Energy, Baytex Energy Partnership and Baytex Energy USA Ltd., and "**Operating Entity**" means any one of them, as applicable.

"**Participant**" means a participant in the depository service of CDS.

"**Possible Reserves**" are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves.

"**Probable Reserves**" are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

"**Proved Reserves**" are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

"**Reserves**" are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on: (a) analysis of drilling, geological, geophysical, and engineering data; (b) the use of established technology; and (c) specified economic conditions, which are generally accepted as being reasonable and shall be disclosed. Reserves are classified according to the degree of certainty associated with the estimates.

"**Ryder Scott**" means Ryder Scott Company, L.P, independent petroleum consultants of Houston, Texas.

"**service well**" means a well drilled or completed for the purpose of supporting production in an existing field. Wells in this class are drilled for the following specific purposes: gas injection (natural gas, propane, butane or flue gas), water injection, steam injection, air injection, salt water disposal, water supply for injection, observation or injection for combustion.

"**Scotia**" means Scotia Capital Inc.

"**SEC**" means the U.S. Securities and Exchange Commission.

"**SEDAR**" means the System for Electronic Document Analysis and Retrieval established by the provincial securities regulatory authorities in Canada.

"**Share Award Incentive Plan**" means our Share Award Incentive Plan, as described in the Information Circular under *"Executive Compensation Share Award Incentive Plan"*.

"**Shareholders**" mean the holders from time to time of Common Shares.

"**Sproule**" means Sproule Associates Limited, independent petroleum consultants of Calgary, Alberta, Canada.

"**Sproule Report**" means the independent evaluation of our oil and natural gas reserves prepared by Sproule dated March 11, 2013 and effective December 31, 2012 entitled "*Evaluation of the P&NG Reserves of Baytex Energy Corp. (As of December 31, 2012)*".

"**Subscription Receipt Agreement**" means the agreement to be dated the date of closing of the Offering among us, Scotia and the Escrow Agent governing the terms of the Subscription Receipts.

"**Subscription Receipt Beneficial Owner**" means a purchaser acquiring a beneficial interest in the Subscription Receipts.

"**Subscription Receipt Certificates**" means the certificates representing the Subscription Receipts.

"**Subscription Receipts**" means the subscription receipts offered hereby.

"**subsidiary**" has the meaning ascribed thereto in the ABCA and, for greater certainty, includes all corporations, partnerships and trusts owned, controlled or directed, directly or indirectly, by us.

"**Sugarkane Field**" means the Sugarkane natural gas and condensate field within the Eagle Ford and includes the two contiguous fields designated by the Railroad Commission of Texas as the Sugarkane and Eagleville Fields.

"**Supplemental Oil and Gas Disclosures**" has the meaning ascribed thereto under "*Documents Incorporated by Reference*".

"**Tax Act**" means the *Income Tax Act* (Canada), as amended, including the regulations promulgated thereunder.

"**Termination Time**" has the meaning ascribed thereto under "*Details of the Offering*".

"**TSX**" means the Toronto Stock Exchange.

"**Underlying Common Shares**" means the Common Shares issuable pursuant to the terms of the Subscription Receipts.

"**Underwriters**" means, collectively, Scotia and RBC Dominion Securities Inc.

"**Underwriting Agreement**" means the agreement to be entered into among us and the Underwriters in respect of the Offering.

"**Undeveloped Reserves**" are those reserves expected to be recovered from known accumulations where a significant expenditure (e.g., when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable, possible) to which they are assigned. In multi-well pools, it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to sub-divide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities and completion intervals in the pool and their respective development and production status.

"**United States**" or "**U.S.**" means the United States, as defined in Rule 902(l) under Regulation S under the United States Securities Act of 1933, as amended.

"**U.S. GAAP**" means United States generally accepted accounting principles.

"**WI**" means working interest, an interest in an oil and gas lease that gives the owner the right to drill and produce oil and gas on the leased acreage.

Words importing the singular number only include the plural, and vice versa, and words importing any gender include all genders.

CONVERSIONS

The following table sets forth certain conversions between Standard Imperial Units and the International System of Units (or metric units).

To Convert From	To	Multiply By
Mcf	cubic metres	28.174
cubic metres	cubic feet	35.494
Bbls	cubic metres	0.159
cubic metres	Bbls	6.289
Feet	Metres	0.305
Metres	Feet	3.281
Miles	kilometres	1.609
Kilometres	Miles	0.621
Acres	hectares	0.405
Hectares	Acres	2.471
Gigajoules	MMbtu	0.950
MMbtu	gigajoules	1.0526

ABBREVIATIONS

Oil and Natural Gas Liquids		Natural Gas	
Bbl	barrel	Mcf	thousand cubic feet
Bbls	barrels	MMcf	million cubic feet
Bbls/d	barrels per day	Bcf	billion cubic feet
Mbbls	thousand barrels	Mcf/d	thousand cubic feet per day
MMbbls	million barrels	MMcf/d	million cubic feet per day
Mstb	thousand stock tank barrels of oil	MMbtu	million British Thermal Units
NGLs	natural gas liquids	GJ	Gigajoule

Other	
AECO	the natural gas storage facility located at Suffield, Alberta, connected to TransCanada's Alberta System
API	American Petroleum Institute
°API	an indication of the specific gravity of crude oil measured on the API gravity scale
BOE or Boe	barrel or barrels of oil equivalent, using the conversion factor of six Mcf of natural gas being equivalent to one barrel of oil
Boe/d	barrels of oil equivalent per day
m^3	cubic metres
MBoe	thousand barrels of oil equivalent
Mcfe	thousand cubic feet of gas equivalent, using the conversion factor of 1 barrel of oil being equivalent to 6 Mcf of natural gas
MMBoe	million barrels of oil equivalent
RLI	reserve life index
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for the crude oil standard grade
WCS	Western Canadian Select heavy oil reference price
$000s	thousands of dollars
$MM	millions of dollars

CONVENTIONS

Certain terms used herein are defined in the "*Selected Definitions*". Certain other terms used herein but not defined herein are defined in NI 51-101 and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101. All financial information herein has been presented in Canadian dollars in accordance with GAAP, except where otherwise indicated. References to "$" or "CDN$" are to Canadian dollars, references to "U.S.$" are to United States dollars and references to "A$" are to Australian dollars.

OIL AND GAS EQUIVALENCY

The term "Boe" means a barrel of oil equivalent on the basis of 6 Mcf of natural gas to 1 Bbl of oil. The term "Mcfe" means a thousand cubic feet of gas equivalent on the basis of 1 Bbl of oil to 6 Mcf of natural gas. Boes and Mcfes may be misleading, particularly if used in isolation. A Boe conversion ratio of 6 Mcf: 1 Bbl or an Mcfe conversion ratio of 1 Bbl: 6 Mcf a is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6 Mcf: 1Bbl, utilizing a conversion ratio at 6 Mcf: 1 Bbl may be misleading as an indication of value.

NON-GAAP FINANCIAL MEASURES

In this short form prospectus and the documents incorporated by reference herein, we refer to certain financial measures (such as funds from operations, payout ratio, total monetary debt, net debt and operating netback) which do not have any standardized meaning prescribed by Canadian GAAP and are considered non-GAAP measures. While funds from operations, payout ratio and operating netback are commonly used in the oil and gas industry, our determination of these measures may not be comparable with calculations of similar measures for other issuers.

Funds from Operations

We define funds from operations as cash flow from operating activities adjusted for financing costs, changes in non-cash operating working capital and other operating items. We believe that this measure assists in providing a more complete understanding of certain aspects of our results of operations and financial performance, including our ability to generate the cash flow necessary to fund future dividends to shareholders and capital investments.

Funds from operations as used herein, as it relates to Aurora, means funds provided by operating activities before changes in non-cash working capital. We consider it a key measure as it demonstrates the ability of the business to generate the cash flow necessary to fund future growth through capital investment.

However, funds from operations should not be construed as an alternative to traditional performance measures determined in accordance with Canadian GAAP or U.S. GAAP, such as cash flow from operating activities and net income. Please refer to our most recent management's discussion and analysis of financial condition and results of operations, which is incorporated by reference herein, for a reconciliation of funds from operations to cash flow from operating activities.

Payout Ratio

We define payout ratio as cash dividends (net of participation in our dividend reinvestment plan) divided by funds from operations. We believe that this measure assists in providing a more complete understanding of certain aspects of our results of operations and financial performance, including our ability to generate the cash flow necessary to fund future dividends to shareholders and capital investments.

Total Monetary Debt and Net Debt

We define total monetary debt as the sum of monetary working capital, being current assets less current liabilities (excluding non-cash items such as unrealized gains or losses on financial derivatives), the principal amount of long-term debt and long-term bank loan. We believe that this measure assists in providing a more complete understanding of our cash liabilities.

Operating Netback

We define operating netback as product revenue less royalties, production and operating expenses and transportation expenses divided by barrels of oil equivalent sales volume for the applicable period. We believe that this measure assists in characterizing our ability to generate cash margin on a unit of production basis. Aurora defines operating netback as revenue from production less royalties, production taxes, gathering and transportation costs, facility maintenance and operated costs calculated on a Boe basis.

ENFORCEMENT OF JUDGMENTS AGAINST FOREIGN PERSONS OR COMPANIES

Mary Ellen Peters, one of our directors, resides outside of Canada. Ms. Peters has appointed Burnet, Duckworth & Palmer LLP, Suite 2400, 525 - 8th Avenue S.W., Calgary, Alberta, Canada, T2P 1G1, as her agent for service of process. In addition, all or some of the designated professionals of BDO Audit (WA) Pty Ltd., Aurora's external auditor and Ryder Scott Company, L.P., Aurora's independent qualified reserves evaluator are incorporated, continued or otherwise organized under the laws of a foreign jurisdiction or reside outside of Canada. BDO Audit (WA) Pty Ltd. has appointed BDO Canada LLP, Suite 600, 36 Toronto Street, Toronto, Ontario M5C 2C5 as its agent for service of process. Ryder Scott Company, L.P has appointed Ryder Scott Canada at Suite 600, 1015 4th St. S.W., Calgary, Alberta, Canada T2R 1J4 as its agent for service of process. It may not be possible for you to enforce judgments obtained in Canada against a person that resides outside of Canada, even if the party has appointed an agent for service of process.

Purchasers are advised that it may not be possible for investors to enforce judgments obtained in Canada against a person that resides outside of Canada, even if the party has appointed an agent for service of process.

We are a corporation formed under, and governed by, the laws of the Province of Alberta, Canada and our principal place of business is in Canada. Substantially all of our directors and officers and the experts named in this short form short form prospectus are residents of Canada or otherwise reside outside of the United States, and all or a substantial portion of their assets and our assets are located outside the United States. As a result, it may be difficult for investors in the United States to effect service of process within the United States upon those directors, officers and experts who are not residents of the United States or to enforce against them judgments of United States courts based upon civil liability under the United States federal securities laws or the securities laws of any state within the United States.

We have been advised by our Canadian counsel, Burnet, Duckworth & Palmer LLP, that there is substantial doubt whether an action could be brought in Canada in the first instance on the basis of liability predicated solely upon United States federal securities laws. We have appointed Baytex Energy USA Ltd., 600 - 17th Street, Suite 1600 S, Denver, CO 80202, as our agent in the United States upon which service of process against us may be made in any action based on this short form prospectus.

We filed with the SEC, concurrently with our registration statement on Form F-10 of which this short form prospectus forms a part, an appointment of agent for service of process on Form F-X. Under the Form F-X, we appointed Baytex Energy USA Ltd. as our agent for service of process in the United States in connection with any investigation or administrative proceeding conducted by the SEC, and any civil suit or action brought against or involving us in a United States court arising out of or related to or concerning the offering of debt securities under this short form prospectus.

DOCUMENTS INCORPORATED BY REFERENCE

Information has been incorporated, or deemed to be incorporated by reference, into this short form prospectus from documents filed with securities commissions or similar authorities in Canada and with the SEC in the United States. Copies of the documents incorporated herein by reference may be obtained on request without charge from our Corporate Secretary at Suite 2800, Centennial Place, East Tower, 520 - 3rd Avenue S.W., Calgary, Alberta, Canada, T2P 0R3, Telephone: (587) 952-3000. In addition, copies of the documents incorporated herein by reference may be obtained from the securities commissions or similar authorities in Canada through the SEDAR website at www.sedar.com and in the United States through EDGAR at the SEC's website at www.sec.gov.

Under applicable securities laws in Canada and the United States, the Canadian securities commissions and the SEC allow us to incorporate by reference certain information that we file with them, which means that we can disclose important information to you by referring you to those documents. Information that is incorporated by reference is an important part of this short form prospectus. The following documents filed with securities commissions or similar authorities in each of the provinces of Canada and with the SEC in the United States are incorporated by reference into this short form prospectus:

(a) our annual information form for the year ended December 31, 2012 dated March 25, 2013 (the "**Annual Information Form**");

(b) our audited consolidated financial statements as at December 31, 2012 and 2011 and for the years then ended, together with the notes thereto and the auditor's report thereon (the "**Annual Financial Statements**");

(c) our management's discussion and analysis of operating and financial results for the year ended December 31, 2012 (the "**Annual MD&A**");

(d) the supplemental disclosure of our oil and gas producing activities prepared in accordance with Accounting Standards Codification 932 "Extractive Activities Oil & Gas" issued by the United States Financial Accounting Standards Board, which was filed on SEDAR under the category "Other" on March 26, 2013 (the "**Supplemental Oil and Gas Disclosures**");

(e) our Information Circular Proxy Statement dated April 1, 2013 relating to the annual and special meeting of Shareholders held on May 14, 2013 (the "**Information Circular**");

(f) our condensed interim unaudited consolidated financial statements as at September 30, 2013 and 2012 and for the nine month periods ended September 30, 2013 and 2012, together with the notes thereto (the "**Interim Financial Statements**");

(g) our management's discussion and analysis of operating and financial results for the nine month period ended September 30, 2013 (the "**Interim MD&A**");

(h) the "template version" (as such term is defined in National Instrument 41-101 *General Prospectus Requirements*) of the term sheet for the Offering dated and filed February 6, 2014; and

(i) our investor presentation for the Offering dated and filed February 6, 2014.

Any documents of the type described in Section 11.1 of Form 44-101F1 *Short Form Prospectus* promulgated under National Instrument 44-101 *Short Form Prospectus Distributions* (including, without limitation, any annual information form, audited consolidated financial statements, together with the auditor's report thereon, and related management's discussion and analysis, information circular, material change reports, marketing materials, business acquisition reports and condensed interim unaudited consolidated financial statements and related management's discussion and analysis) subsequently filed by us with the securities commissions or similar regulatory authorities in the relevant provinces of Canada after the date of this short form prospectus and prior to the termination of the Offering shall be deemed to be incorporated by reference herein in this short form prospectus. In addition, any similar documents filed by us with the SEC in our periodic reports on Form 6-K or annual reports on Form 40-F and any other documents filed with or furnished to the SEC pursuant to Section 13(a), 13(c) or 15(d) of the Exchange Act, in each case after the date of this short form prospectus and prior to the termination of the Offering, shall be deemed to be incorporated by reference into

this short form prospectus and the registration statement of which this short form prospectus forms a part. To the extent that any document or information incorporated by reference into this short form prospectus is included in a report that is filed with or furnished to the SEC on Form 40-F, 20-F, 10-K, 10-Q, 8-K or 6-K (or any respective successor form), such document or information shall also be deemed to be incorporated by reference as an exhibit to the registration statement of which this short form prospectus forms a part.

Any statement contained in this short form prospectus or in a document (or part of a document) incorporated or deemed to be incorporated by reference herein shall be deemed to be modified or superseded to the extent that a statement contained in this short form prospectus or in a document (or part of a document) incorporated or deemed to be incorporated by reference herein (or in any other subsequently filed document which also is or is deemed to be incorporated by reference) modifies or supersedes that statement. The modifying or superseding statement need not state that it has modified or superseded a prior statement or include any other information set forth in the document that it modifies or supersedes. The making of a modifying or superseding statement is not to be deemed an admission for any purposes that the modified or superseded statement, when made, constituted a misrepresentation, an untrue statement of a material fact or an omission to state a material fact that is required to be stated or that is necessary to make a statement not misleading in light of the circumstances in which it was made. Any statement so modified or superseded shall not be deemed, except as so modified or superseded, to be incorporated by reference into or to constitute a part of this short form prospectus.

MARKETING MATERIALS

Any "template version" of any "marketing materials" (as such terms are defined under applicable Canadian securities laws) that are utilized by the Underwriters in connection with the Offering are not part of this short form prospectus to the extent that the contents of the template version of the marketing materials have been modified or superseded by a statement contained in this short form prospectus. Any template version of any marketing material that has been, or will be, filed on SEDAR before the termination of the distribution under the Offering (including any amendments to, or an amended version of, any template version of any marketing materials) is deemed to be incorporated into this short form prospectus.

FORWARD-LOOKING STATEMENTS

In the interest of providing shareholders and potential investors with information regarding Baytex and Aurora, including management's assessment of future plans and operations, certain statements made in this short form prospectus and the documents incorporated by reference are "forward-looking statements" within the meaning of Section 27A of the *United States Securities Act of 1933*, as amended, Section 2 of the *Exchange Act* and "forward looking information" within the meaning of applicable Canadian securities legislation (collectively, "**forward looking statements**"). In some cases, forward-looking statements can be identified by terminology such as "anticipate", "believe", "continue", "could", "estimate", "expect", "forecast", "intend", "may", "objective", "ongoing", "outlook", "potential", "project", "plan", "should", "target", "would", "will" or similar words suggesting future outcomes, events or performance. The forward-looking statements contained in this short form prospectus speak only as of the date thereof and are expressly qualified by this cautionary statement.

Specifically, this short form prospectus contains forward-looking statements relating to, but not limited to: our plans to increase our dividend upon completion of the Acquisition; the anticipated benefits from the Acquisition, including our belief that the Acquisition will be an excellent fit with our business model and will provide shareholders with exposure to a low-risk, repeatable, high-return asset with leading capital efficiencies; our beliefs that the assets acquired as part of the Acquisition will provide material production, long-term growth and high quality reserves with upside potential; our expectations and anticipated timing of receipt of positive cash flow from the acquired assets; our expectations regarding the effect of well downspacing, improving completion techniques and new development targets on the reserves potential of the acquired assets; forecasted production and production mix following completion of the Acquisition; anticipated effect of the Acquisition on us, including in respect of reserves, production and funds from operations; Aurora's forecasted production and production growth for 2014; pro forma production, reserves, funds from operations, operating netbacks, liquidity, bank debt, working capital and debt to funds from our operation following completion of the Acquisition; average estimated reserves per well from Aurora's wells on the acquired assets; accretive, operating and financial metrics and the strategic rationale for the Acquisition; drilling plans, including number of wells planned for 2014 on the acquired assets; expectations regarding the Acquisition and the Offering, including anticipated timing of mailing of the scheme booklet to Aurora shareholders, timing of completion of the Acquisition and the Offering, and approvals required for the Acquisition; and the terms of the Subscription Receipts. In addition, information and statements relating to resources and reserves are deemed to be forward-looking statements, as they involve implied assessment, based on certain estimates and assumptions, that the resources or reserves, as applicable, described exist in quantities predicted or estimated, and that the reserves can be profitably produced in the future. Cash dividends on our Common Shares are paid at the discretion of our Board of Directors and can fluctuate. In establishing the level of cash dividends, our Board of Directors considers all factors that it deems relevant, including, without limitation, the outlook for commodity prices, our operational execution, the amount of funds from operations and capital expenditures and our prevailing financial circumstances at the time. Although we believe that the expectations and assumptions on which the forward-looking statements are based are reasonable, undue reliance should not be placed on the forward-looking statements because we can give no assurance that they will prove to be correct. See "*Special Notes to Reader Forward-Looking Statements*" in the Annual Information Form, which is incorporated by reference into this short form prospectus and which is available on the SEDAR website at www.sedar.com and through EDGAR at the SEC's website at www.sec.gov for further information with respect to forward-looking statements.

The forward-looking statements contained in this short form prospectus are based on certain key assumptions regarding, among other things: the receipt of regulatory, shareholder and other approvals for the Acquisition; our ability to execute and realize on the anticipated benefits of the Acquisition; timing of closing and regulatory approvals for the Offering; petroleum and natural gas prices and pricing differentials between light, medium and heavy gravity crude oil; well production rates and reserve volumes; our ability to add production and reserves through our exploration and development activities; capital expenditure levels; the availability and cost of labour and other industry services; the amount of future cash dividends that we intend to pay; interest and foreign exchange rates; the continuance of existing and, in certain circumstances, proposed tax and royalty regimes; our ability to develop our crude oil and natural gas properties and the acquired assets in the manner currently contemplated; current or, where applicable, proposed assumed industry conditions, laws and regulations will continue in effect or as anticipated; and the estimates of our production and reserves volumes and Aurora's production and reserve volumes and the assumptions related thereto (including commodity prices and development costs) are accurate in all material respects. You are cautioned that such assumptions, although considered reasonable by us at the time of preparation, may prove to be incorrect.

Actual results achieved during the forecast period will vary from the information provided in this short form prospectus and in the documents incorporated by reference herein, respectively, as a result of numerous known and unknown risks and uncertainties and other factors which are discussed in this short form prospectus and in the documents incorporated herein by reference. Such factors include, but are not limited to: the Acquisition may not be completed on the terms contemplated or at all; failure to realize the anticipated benefits of the Acquisition; closing of the Offering and/or the Acquisition could be delayed or not completed if we are not able to obtain the necessary stock exchange, shareholder and regulatory approvals or any other approvals required for completion or, unless waived, some other condition to closing is not satisfied; declines in oil and natural gas prices; variations in interest rates and foreign exchange rates; uncertainties in the credit markets; the cost of borrowing; refinancing risk for existing debt and debt service costs; access to external sources of capital; risks associated with our hedging activities; third party credit risk; risks associated with the exploitation of our properties and our ability to acquire reserves; government regulation and changes in governmental legislation; changes in income tax or other laws or government incentive programs; uncertainties associated with estimating petroleum and natural gas reserves; risks associated with acquiring, developing and exploring for oil and natural gas and other aspects of our operations; risks associated with properties operated by third parties; risks associated with delays in business operations; risks associated with the marketing of our petroleum and natural gas production; risks associated with large projects or expansion of our activities; the failure to realize anticipated benefits of acquisitions and dispositions or to manage growth; changes in climate change laws and other environmental, health and safety regulations; competition in the oil and gas industry for, among other things, acquisitions of reserves, undeveloped lands, skilled personnel and drilling and related equipment; the application of accounting policies; the activities of our Operating Entities and their key personnel; depletion of our reserves; risks associated with securing and maintaining title to our properties; seasonality; our permitted investments; risks associated with the ownership of our securities, including the discretionary nature of dividend payments and changes in market-based factors; risks for United States and other non-resident shareholders; closing of the Offering and/or the Acquisition could be delayed or not completed if we are not able to obtain the necessary stock exchange approvals or any other approvals required for completion or, unless waived, some other condition to the closing is not satisfied; and other factors, many of which are beyond our control. Statements relating to "reserves" and "contingent resources" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves and contingent resources described exist in the quantities predicted or estimated, and can be profitably produced in the future.

Readers are cautioned that the foregoing list of risk factors is not exhaustive. New risk factors emerge from time to time, and it is not possible for management to predict all of such factors and to assess in advance the impact of each such factor on our business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statements. Further information regarding these factors may be found under the heading "*Risk Factors*" in this short form prospectus and under the heading "*Risk Factors*" in the Annual Information Form.

We do not undertake any obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise, except as may be required by applicable securities law. The forward-looking statements contained in this short form prospectus and in certain documents incorporated by reference into this short form prospectus are expressly qualified by this cautionary statement. Information on, or connected to our website, even if referred to in a document incorporated by reference, does not constitute part of this short form prospectus.

WHERE YOU CAN FIND MORE INFORMATION

We have filed with the SEC a registration statement on Form F-10 relating to the Subscription Receipts, of which this short form prospectus forms a part. This short form prospectus does not contain all of the information contained in the registration statement, certain items of which are contained in the exhibits to the registration statement as permitted by the rules and regulations of the SEC. For further information about us and the Subscription Receipts, please refer to the registration statement.

We are subject to the information requirements of the Exchange Act and applicable Canadian securities legislation, and in accordance with those requirements, we file and furnish reports and other information with the SEC and with the securities regulatory authorities of the provinces of Canada. Under the multi-jurisdictional disclosure system adopted by the United States and Canada, we generally may prepare these reports and other information in accordance with the disclosure requirements of Canada. These requirements are different from those of the United States. As a foreign private issuer, we are exempt from the rules under the Exchange Act prescribing the furnishing and content of proxy statements and our officers and directors and our Shareholders holding 10% or more of our Common Shares are exempt from the beneficial ownership reporting and short-swing profit recovery provisions contained in Section 16 of the Exchange Act.

The reports and other information filed and furnished by us with the SEC may be read and copied at the SEC's public reference room at 100 F Street, N.E., Washington, D.C. 20549. Copies of the same documents can also be obtained from the public reference room of the SEC in Washington by paying a fee. Please call the SEC at 1-800-SEC-0330 for further information on the public reference room. The SEC also maintains a website at www.sec.gov that makes available reports and other information that we file electronically with it, including the registration statement that we have filed with respect to this Offering.

Copies of reports, statements and other information that we file with the Canadian provincial securities regulatory authorities are electronically available through the SEDAR website at www.sedar.com.

EXCHANGE RATES

The financial statements incorporated by reference herein are in Canadian dollars, unless otherwise indicated. The following tables set forth: (i) the rates of exchange for Canadian dollars, expressed in United States dollars in effect at the end of each of the periods indicated; and (ii) the average of exchange rates in effect on the last day of each month during such period, in each case based on the noon buying rate in the City of New York for cable transfers in Canadian dollars as certified for customs purposes by the Federal Reserve Bank of New York for United States Dollars.

United States Dollars

	Nine Months Ended September 30, 2013	Year Ended December 31, 2013	2012	2011
Average for the Period[(1)]	$ 0.9769	$ 0.9708	$ 1.0008	$ 1.0151
End of Period	$ 0.9723	$ 0.9402	$ 1.0051	$ 0.9833

Note:

(1) Determined by averaging the rates on the last business day of each month during the respective period.

On February 5, 2014, the rate of exchange for the Canadian dollar, expressed in United States dollars, based on the Bank of Canada noon rate for United States dollars, was CDN.$1.00=U.S.$0.9008.

RISK FACTORS

An investment in the Subscription Receipts, including the Underlying Common Shares, is subject to a number of risks. In addition to the risk factors set forth below, additional risk factors relating to our business are discussed in our Annual Information Form, our Annual MD&A and certain other documents incorporated by reference or deemed to be incorporated by reference herein, which risk factors are incorporated herein by reference. Prospective purchasers of the Subscription Receipts should consider carefully the risk factors set forth below, as well as the other information contained in and incorporated by reference in this short form prospectus before purchasing the Subscription Receipts. If any event arising from these risks occurs, our business, prospects, financial condition, results of operations or cash flows, or your investment in the Subscription Receipts could be materially adversely affected.

Forward Looking Statements May Prove Inaccurate

Purchasers are cautioned not to place undue reliance on forward looking statements. By their nature, forward looking statements involve numerous assumptions, known and unknown risks and uncertainties, of both a general and specific nature, that could cause actual results to differ materially from those suggested by the forward looking statements or contribute to the possibility that predictions, forecasts or projections will prove to be materially inaccurate.

Risks Relating to the Offering

There is currently no public market for the Subscription Receipts and there can be no assurance that an active trading market will develop.

There is currently no market through which the Subscription Receipts may be sold and there is no guarantee that an active trading market will develop. Accordingly, purchasers may not be able to resell the Subscription Receipts distributed under this short form prospectus. This may affect the pricing of the Subscription Receipts in the secondary market, the transparency and the availability of trading prices and the liquidity of the securities. There can be no assurance that an active trading market will develop for the Subscription Receipts after the Offering, or if developed, that such a market will be sustained at the price level of the Offering.

If the Escrow Condition is not satisfied on or prior to the Termination Time, the Subscription Receipts will not be exchanged into Common Shares.

The Subscription Receipts will be exchanged for Common Shares upon the satisfaction of the Escrow Condition. We may, in our sole discretion, waive certain closing conditions in our favor in the Implementation Agreement or agree with Aurora to amend the Implementation Agreement and consummate the Acquisition on terms that may be substantially different from those contemplated in this short form prospectus. Other events, many of which are beyond our control including the acceptance of a superior proposal by Aurora, could result in termination of the Implementation Agreement prior to the Termination Time. If the Acquisition is not completed by the Termination Time, or if we advise the Underwriters or announce to the public that we do not intend to proceed with the Acquisition, or if the Implementation Agreement has been terminated in accordance with its terms, holders of Subscription Receipts shall receive an amount equal to the full subscription price attributable to the Subscription Receipts and their *pro rata* entitlement to interest accrued on such amount. As a result, the expected benefits of the Acquisition may not be fully realized. See "*Recent Developments The Acquisition*" and "*About Aurora*". There can be no assurance that the Escrow Condition will be satisfied on or prior to the Termination Time. Until the Escrow Condition is satisfied and the Common Shares are delivered pursuant to the Subscription Receipt Agreement, holders of Subscription Receipts have the rights described under "*Details of the Offering*".

There can be no assurance that the Acquisition will close after the conditions for the release of the Escrowed Funds have been satisfied.

The Escrowed Funds will be held by the Escrow Agent, and invested in short-term obligations of, or guaranteed by, the Government of Canada (or other approved investments) pending delivery by us to the

Underwriters of a certificate on the third Business Day prior to the anticipated Effective Date to the effect that the Escrow Condition has been satisfied. Upon satisfaction of the Escrow Condition prior to the Termination Time, the Escrowed Funds will be released to us to enable us to convert these funds to Australian dollars and complete the Acquisition. Although we have been advised by our Australian counsel that the Acquisition is unconditional once the Final Order has been filed with the ASIC, there is a possibility that the Acquisition is not completed by the Termination Time. As a result, the expected benefits of the Acquisition may not be fully realized. See "*Recent Developments The Acquisition*" and "*About Aurora*".

Risks Relating to the Acquisition

We may not complete the Acquisition on the terms negotiated or at all.

The Acquisition is subject to satisfaction of the conditions described herein and normal commercial risk that the Acquisition may not be completed on the terms negotiated or at all. This could result from events which are beyond our control, including the acceptance of a superior proposal by Aurora. If closing of the Acquisition does not take place by the Termination Time, we will repay to holders of Subscription Receipts, commencing on or before the second Business Day following the Termination Time, an amount equal to the issue price of the Subscription Receipts plus a *pro rata* share of the interest earned on the Escrowed Funds. In that case, the total return that a purchaser of Subscription Receipts would be entitled to receive would be limited to the purchaser's *pro rata* share of interest earned on the subscription price for such purchaser's Subscription Receipts. The purchaser would not be entitled to participate in any growth in the trading price of our Common Shares. Further, the purchaser would be restricted from using the funds devoted to the acquisition of the Subscription Receipts for any other investment opportunities until the Escrowed Funds are returned to the purchaser. See "*Recent Developments The Acquisition*", "*About Aurora*" and "*Risk Factors Use of Proceeds*".

It is possible that we will fail to realize the anticipated benefits of the Acquisition.

We are proposing to complete the Acquisition to strengthen our position in the oil and natural gas industry and to create the opportunity to realize certain benefits. Achieving the benefits of the Acquisition depends in part on successfully consolidating functions and integrating operations, procedures and personnel in a timely and efficient manner, as well as our ability to realize the anticipated growth opportunities and synergies from integrating the Aurora Assets into our existing portfolio of properties. The integration of the Aurora Assets requires the dedication of substantial management effort, time and resources, which may divert management's focus and resources from other strategic opportunities and from operational matters during this process. The integration process may result in the loss of key employees and the disruption of ongoing business, customer and employee relationships that may adversely affect our ability to achieve the anticipated benefits of the Acquisition.

There may be potential undisclosed liabilities associated with the Acquisition.

In connection with the Acquisition, there may be liabilities that we failed to discover or were unable to quantify in our due diligence (which we conducted prior to the execution of the Implementation Agreement). The representations, warranties and indemnities contained in the Implementation Agreement are limited and our ability to seek remedies for breach of such provisions following completion of the Acquisition will be limited.

Acquisitions require engineering, title, environmental and economic assessments that may be materially incorrect.

Acquisitions of oil and gas properties or companies are based in large part on engineering, environmental and economic assessments made by the acquiror, independent engineers and consultants. These assessments include a series of assumptions regarding such factors as recoverability and marketability of oil and natural gas, environmental restrictions and prohibitions regarding releases and emissions of various substances, future prices of oil and gas and operating costs, future capital expenditures and royalties and other government levies which will be imposed over the producing life of the reserves. Many of these factors are subject to change and are beyond our control. All such assessments involve a measure of geologic, engineering, environmental and regulatory uncertainty that could result in lower production and reserves or higher operating or capital expenditures than anticipated or unanticipated difficulty in obtaining required permits.

Aurora typically has not incurred the expense of a title examination prior to ordinary course acquisitions by its operator of oil and natural gas leases or undivided interests in oil and natural gas leases or other developed rights. In addition, its practice has been to not to incur the expense of retaining lawyers to examine the title to the mineral interest to be acquired. Instead, it has relied upon the judgment of oil and natural gas lease brokers or landmen to perform the fieldwork in examining records in the appropriate governmental or county clerk's office before attempting to acquire a lease or other developed rights in a specific mineral interest.

Prior to drilling an oil or natural gas well, however, it is the normal practice in the oil and natural gas industry for the person or company acting as the operator of the well to obtain a preliminary title review of the spacing unit within which the proposed oil or natural gas well is to be drilled to ensure there are no obvious deficiencies in title to the well. Frequently, as a result of such examinations, certain curative work must be done to correct deficiencies in the marketability of the title, such as obtaining affidavits of heirship or causing an estate to be administered. Such curative work entails expense, and the operator may elect to proceed with a well despite defects to the title identified in the preliminary title opinion.

Aurora's failure to obtain perfect title to its leaseholds may adversely affect the production and reserves associated with the Aurora Assets and our ability in the future to increase production and reserves. Although select title and environmental reviews were conducted by us in connection with the Acquisition, this review cannot guarantee that any unforeseen defects in the chain of title will not arise to defeat our title to certain assets or that environmental defects, liabilities or deficiencies do not exist or are greater than anticipated.

We will not be the operator of a substantial majority of the drilling locations in Aurora's acreage following completion of the Acquisition, and, therefore, we will not be able to control the timing of development, associated costs, or the rate of production on that non-operated acreage.

All of Aurora's current AMIs in the Sugarkane Field are operated by Marathon and we will be reliant upon Marathon to successfully operate the Sugarkane Field AMIs. Marathon will make decisions based on its own best interests and the collective best interests of all of the owners of WIs in the Sugarkane Field in connection with their operation (subject to its contractual and legal obligations to other owners of WIs), which may not be in our best interests. If we are not willing or are unable to fund our capital expenditure requirements relating to our drilling locations when required by our single operator, our interests in our drilling locations may be diluted or forfeited.

As a substantial majority of Aurora's acreage is operated by Marathon, we expect that we will not be the operator of the identified gross and net drilling locations in the Aurora Reserves Reports. As we carry out our exploration and development programs with respect to the Aurora Assets, we may enter into additional arrangements with respect to existing or future drilling locations that result in additional locations being operated by others. As a result, we may have virtually no ability to exercise influence over the operational decisions of the operator, including the setting of capital expenditure budgets and drilling locations and schedules. Dependence on the operator could prevent us from realizing our target returns of those locations. The success and timing of development activities operated by our partners will depend on a number of factors that will largely be outside of our control, including:

- the timing and amount of capital expenditures;
- the operator's expertise and financial resources;
- approval of other participants in drilling wells;
- selection of technology; and
- the rate of production of reserves, if any.

Following completion of the Acquisition, we could experience periods of higher capital and operating costs as activity in the Eagle Ford accelerates or if commodity prices rise. These increases could reduce our profitability, cash flow and ability to complete development activities as scheduled and on budget.

Industry activity in the Eagle Ford has accelerated since late 2008 when only a few rigs were operating. As activity in the Eagle Ford region increases, competition for equipment, labour and supplies is also expected to

increase. In addition, capital and operating costs in the oil and gas industry have generally risen during periods of increasing commodity prices as producers seek to ramp-up production in order to capitalize on higher commodity prices. In situations where cost inflation exceeds price inflation, our profitability, cash flow and ability to complete development activities as scheduled and on budget may be negatively impacted.

In addition to rising costs, increasing activity in the Eagle Ford and the oil and gas industry in general may impact the availability of necessary equipment, including drilling equipment. As activity increases, so does demand for equipment, which may lengthen the lead time for obtaining the equipment or, in the most extreme cases, make obtaining the equipment unavailable at a cost we are able or willing to pay.

Availability of adequate transportation arrangements with third parties may increase operating costs.

For the transportation and relocation of Aurora's hydraulic fracturing equipment, sand and chemicals, it currently relies predominantly on truck transportation services operated by third parties. Truck carriers are subject to regulation as motor carriers by the U.S. Department of Transportation ("**DOT**") and by various state agencies, whose regulations include certain permit requirements of state highway and safety authorities. Increased costs of trucking services for the transport of hydraulic fracturing equipment, sand and chemicals would result in increased transportation expenses, which would negatively affect our results of operations.

A large proportion of the total estimated proved and probable reserves attributable to the Aurora Assets at December 31, 2013 were undeveloped. These reserves may not ultimately be developed.

At December 31, 2013, approximately 79% of the total estimated proved reserves, and substantially all of the probable reserves, attributable to the Aurora Assets as set forth in the Aurora 2013 Reserves Report, were undeveloped. Recovery of undeveloped reserves requires successful drilling and incurrence of significant capital expenditures. The Aurora Reserve Reports assume that these expenditures can and will be made and that these operations will be conducted successfully. These assumptions, however, may not prove correct. If we choose not to spend the capital to develop these reserves, or if we are not otherwise able to successfully develop these reserves, we will be required to write them off. Any such write-offs of these reserves could reduce our ability to borrow and adversely affect our liquidity. In addition, to the extent we do not operate these undeveloped properties, we will be subject to operational decisions of the operator that we may have a limited ability to influence in respect of the development of these reserves on any particular schedule, or at all.

Expiration of licenses and leases will have a negative effect on our business operations.

The properties comprising the Aurora Assets are held in the form of licenses and leases and WIs in licenses and leases. If we or the holder of the license or lease fails to meet the specific requirement of a license or lease to bring the acreage into production or otherwise, the license or lease may terminate or expire. There can be no assurance that any of the obligations required to maintain each license or lease will be met. The termination or expiration of such licenses or leases or the WIs relating to a license or lease may have a material adverse effect on our business, financial condition, results of operations and prospects.

A change in the jurisdictional characterization of some of the Aurora Assets by federal, state or local regulatory agencies or a change in policy by those agencies may result in increased regulation of the Aurora Assets, which may cause our revenues to decline and operating expenses to increase.

Section 1(b) of the *Natural Gas Act of 1938* (the "**Natural Gas Act**") exempts natural gas gathering facilities from regulation by the Federal Energy Regulatory Commission ("**FERC**") under that statute. Aurora believes that the gathering systems it operates meet the traditional tests FERC has used to establish a pipeline's status as a gathering. However, the distinction between FERC-regulated transmission pipelines and unregulated gathering services is the subject of ongoing litigation and may be determined by FERC on a case-by-case basis. Consequently, the classification and regulation of Aurora's gathering facilities are subject to change based on future determinations by FERC, the courts or the U.S. Congress ("**Congress**").

While Aurora's natural gas gathering pipelines are currently exempt from FERC regulation under the Natural Gas Act, we may be subject to certain FERC reporting requirements. Other FERC regulations may indirectly affect our businesses and the markets for products derived from these businesses, including, for example, FERC's requirements as to access transportation, natural gas quality, ratemaking, capacity release and market center promotion. A change in these requirements may affect our financial condition and results of operations.

Regulation of sales and transportation may impact the marketing of production from the Aurora Assets.

The sales prices of oil, natural gas liquids, and natural gas are presently not regulated, but rather are set by the market. We cannot predict, however, whether new legislation to regulate the price of energy commodities might be proposed, what proposals, if any, might actually be enacted by the U.S. Congress or the various state legislatures and what effect, if any, such proposals might have on the operations of the underlying properties.

The FERC regulates rates and service conditions for the transportation of natural gas in interstate commerce, which affects the marketing of natural gas we produce, as well as the revenues we receive for sales of such production. The FERC exercises its ratemaking authority by applying cost-of-service principles, allowing for the negotiation of rates where there is a cost-based alternative rate or granting market-based rates in certain circumstances, typically with respect to storage services. The FERC has also undertaken various initiatives to increase competition in the natural gas industry, which may indirectly affect our businesses and the markets for products derived from these businesses. These policies include regulations on open access transportation, natural gas quality, capacity release and market center promotion. We may be also indirectly subject to certain reporting requirements of the FERC based on the sale of gas from producing properties in which we have interest.

The prices and terms of access to intrastate pipeline transportation are subject to state regulation. The FERC and, to a lesser extent, the Railroad Commission of Texas have proposed and implemented new rules and regulations affecting gas transportation in recent years. We do not believe that we will be affected by any such rules or changes to existing rules in a manner materially different than any other similarly situated natural gas producer.

Rates and service conditions for the interstate transportation of oil and natural gas liquids are regulated by the FERC. In general, these rates must be cost-based or based on rates in effect in 1992, although the FERC has established an indexing system for such transportation rates that allows pipelines to take an annual inflation-based rate increase. Shippers may, however, contest rates that do not reflect costs of service. The FERC has also established market-based rates and settlement rates as alternative forms of ratemaking in certain circumstances. We cannot predict with any certainty what effect, if any, these regulations will have, but other factors being equal, the regulations may, over time ten to increase transportation costs which may have the effect of reducing net prices for oil and natural gas liquids.

Sales of oil and natural gas, and any hedging activities related to such energy commodities, expose us to potential regulatory risks.

The FERC, the Federal Trade Commission ("**FTC**") and the Commodity Futures Trading Commission ("**CFTC**") hold statutory authority to monitor certain segments of the physical and future energy commodities and derivatives markets relevant to the Aurora Assets. These agencies have issued broad regulations prohibiting fraud and manipulation in such markets. With regard to physical sales of oil and natural gas, any hedging activities related to these energy commodities and certain other activities, we will be required to observe the market-related regulations issued by these agencies, which hold substantial enforcement authority. Failure to comply with such regulations, as interpreted and enforced, could expose us to enforcement actions and penalties and thus materially and adversely affect our financial condition and results of operations.

Under the Natural Gas Act, as amended by the Domenici-Barton Energy Policy Act of 2005, the FERC is authorized to impose civil penalties of up to U.S.$1 million per day for each violation of the Natural Gas Act and the FERC's regulations thereunder, including market-related regulations. The FERC may also order disgorgement of profits associated with any violation. The FTC is authorized to seek the judicial imposition of penalties of up to U.S.$1 million per day for each violation of such law and its implementing regulations. The CFTC also has statutory authority to assess fines of up to U.S.$1 million for violations of the Commodity Exchange Act and its anti-market manipulation regulations.

We may be subject to new pipeline safety laws and regulations.

The Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2012, which President Obama signed into law on January 3, 2012, increases penalties for safety violations, establishes additional safety requirements for newly constructed pipelines, and requires studies of certain safety issues, such as the exemption of gathering systems from integrity management programs. These studies could result in the adoption of new regulatory requirements for existing pipelines, including gathering systems. DOT, through the U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration ("**PHMSA**") has also published an advanced notice of proposed rulemaking to solicit comments on the need for changes to its safety regulations, including whether to revise the integrity management requirements and add new regulations governing the safety of gathering lines. We cannot predict the effect of new regulatory initiatives on us or the Aurora Assets. Penalties for safety violations and potential regulatory changes could have a material effect on our operations, operating expenses, and revenues.

Certain federal income tax deductions currently available with respect to oil and natural gas development and exploration may be eliminated as a result of future legislation.

President Obama's budget proposal for the fiscal year 2014 recommended the elimination of certain key U.S. federal income tax preferences currently available to oil and natural gas exploration and production companies. These changes include, but are not limited to: (i) the repeal of the percentage depletion allowance for oil and natural gas properties; (ii) the elimination of current deductions for intangible drilling and development costs; (iii) the elimination of the deduction for certain U.S. production activities for oil and gas production; and (iv) an extension of the amortization period for certain geological and geophysical expenditures.

It is unclear whether any such changes will actually be enacted or, if enacted, how soon any such changes could become effective. The passage of any legislation as a result of the budget proposal or any other similar change in U.S. federal income tax law could materially affect certain tax deductions that are currently available with respect to oil and natural gas exploration and production and materially affect the economic return from the development of reserves attributed to the Aurora Assets.

The recent adoption of derivatives legislation by Congress could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with the Aurora Assets.

Congress recently adopted comprehensive financial reform legislation that establishes federal oversight and regulation of the over-the-counter derivatives market and entities that participate in that market. This legislation, known as the Dodd-Frank Wall Street Reform and Consumer Protection Act (the "**Dodd-Frank Act**"), was signed into law by President Obama on July 21, 2010 and requires the CFTC and the SEC to promulgate rules and regulations implementing the new legislation. In its rulemaking under the Dodd-Frank Act, the CFTC has proposed regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. Certain bona fide hedging transactions or positions would be exempt from these position limits. It is not possible at this time to predict when the CFTC will finalize these regulations. The financial reform legislation may also require us to comply with margin requirements and with certain clearing and trade execution requirements in connection with any future derivative activities, although the application of those provisions to us is uncertain at this time. The financial reform legislation may also require certain of our counterparties to any future derivative instruments to spin off some of their derivatives activities to a separate entity, which may not be as creditworthy as the current counterparty. The new legislation and any new regulations could significantly increase the cost of derivative contracts (including through requirements to post collateral which could adversely affect our available liquidity) and trigger changes in the terms and availability of derivatives to protect against risks we may encounter. If we reduce our use of derivatives with respect to the Aurora Assets as a result of the legislation and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures on the Aurora Assets. Any of these consequences could have a material adverse effect on us, our financial condition and the results of our operations.

Federal and state legislation and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons from tight geological formations. We routinely utilize hydraulic fracturing techniques in many of our drilling and completion programs. At present, the hydraulic fracturing process in the United States is typically regulated by state oil and gas commissions. However, the EPA has asserted federal regulatory authority over certain hydraulic fracturing activities involving diesel fuel under the Safe Drinking Water Act's (the "**SDWA**") Underground Injection Control Program and, in May 2012, issued a draft permitting guidance document addressing the performance of hydraulic fracturing activities using diesel fuel. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing activities and issued a progress report in December 2012, with a draft final report expected to be available this year for public comment and peer review. In October 2011, the EPA announced its intention to propose federal Clean Water Act regulations by 2014 governing wastewater discharges from hydraulic fracturing and certain other natural gas operations. In addition, in November 2011, the EPA announced that it would require record-keeping and reporting of the chemicals used by oil and natural gas exploration and production companies in hydraulic fracturing, which is intended to provide transparency with regard to the use of chemicals in hydraulic fracturing. Moreover, in May 2013, the Bureau of Land Management issued a proposed rule that would require public disclosure of chemicals used in hydraulic fracturing operations, and impose other operational requirements for all hydraulic fracturing operations on federal lands, including Native American trust lands.

Also, the White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices and a committee of the U.S. House of Representatives has conducted an investigation of hydraulic fracturing practices. Public interest in hydraulic fracturing and initiatives by environmental groups may also increase regulatory scrutiny and regulation. The results of government studies or heightened public interest could spur additional initiatives to regulate hydraulic fracturing under the SDWA or otherwise.

Congress has from time to time considered legislation to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process. In addition, some states in the U.S. have adopted, and other states are considering adopting, regulations that could impose more stringent permitting, disclosure and well construction, completion and operating requirements on hydraulic fracturing operations, including the states in which Aurora operates the Aurora Assets. For example, Texas requires the disclosure of information regarding the substances used in the hydraulic fracturing process to the Railroad Commission of Texas (the entity that regulates oil and natural gas production in Texas) and to the public. In addition, some local governments, including some found in Texas, have adopted ordinances within their jurisdictions regulating the time, place and manner of drilling activities in ground or hydraulic fracturing activities in general. The disclosure of information regarding the constituents of hydraulic fracturing fluids could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect the environment, including groundwater, soil or surface water. In addition, disclosure of our proprietary chemical formulas or disclosure of any chemicals used in such formulas to the public could diminish the value of those formulas to us and result in fewer innovations or reduced access to new technology. If new laws, regulations or ordinances that significantly restrict hydraulic fracturing are adopted, such laws could make it more difficult or costly for us to perform fracturing to stimulate production from tight formations on the Aurora Assets. In addition, if hydraulic fracturing becomes regulated at the federal level as a result of new federal legislation or regulatory initiatives by the EPA, our fracturing activities on the Aurora Assets could become subject to additional permitting requirements, and also to attendant permitting delays and cost increases. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that we are ultimately able to produce from reserves attributed to the Aurora Assets and have an adverse effect on our business, financial condition and results of operations.

Recently issued rules regulating air emissions from oil and natural gas operations could cause us to incur increased capital expenditures and operating costs.

In August 2012, the EPA published final rules that subject oil and natural gas production and natural gas processing operations to regulation under the New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants programs. With regards to production activities, the final rules require, among other things, the reduction of volatile organic compound emission from three subcategories of fractured and re-fractured gas wells for which well completion operations are conducted: wildcat (exploratory) and delineation gas wells; low reservoir pressure non-wildcat and non-delineation gas wells; and all "other" fractured and re-fractured gas wells. All three subcategories of wells must route flow back emissions to a gathering line or be captured and combusted using a combustion device such as a flare. However, the "other" wells used must reduced emission completions, also known as "green completions," with or without combustion devices, after January 1, 2015. These regulations also establish specific new requirements regarding emissions from production-related wet seal and reciprocating compressors, pneumatic controllers, and storage vessels. Compliance with these requirements could increase our costs of development and production and our capital expenditures, which costs and expenditures could be significant and adversely impact our business.

Following the Acquisition, we will have a substantial amount of indebtedness, which may adversely affect our cash flows and ability to operate our business, remain in compliance with the agreements governing our indebtedness and service our debt obligations as they become due.

Our high level of indebtedness following the Acquisition could have important consequences to investors, including the following:

- it may make it difficult for us to satisfy our obligations under our indebtedness and contractual and commercial commitments;
- it may increase our vulnerability to adverse economic and industry conditions;
- it may require us to dedicate a substantial portion of our cash flow from operations to payments on our indebtedness, thereby reducing the availability of our cash flow to fund working capital, capital expenditures and other general corporate purposes;
- it may limit our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate;
- it may restrict us from making strategic acquisitions or exploiting business opportunities;
- it may place us at a competitive disadvantage compared to our competitors that have less debt;
- it may limit our ability to borrow additional funds; and
- it may decrease our ability to compete effectively or operate successfully under adverse economic and industry conditions.

Subject to the restrictions in the agreements governing our indebtedness, we may incur substantial additional indebtedness (including secured indebtedness) in the future, which may exacerbate the risks described above. In addition, financial covenants in the Aurora Notes may restrict us from freely distributing cash to us from Aurora's operating subsidiaries.

Many of the operational, environmental and reserves risks set forth in the "Risk Factors" section of the Annual Information Form apply to the Aurora Assets.

In addition to the risk factors set forth above, many of the risk factors set forth in the Annual Information Form and in this short form prospectus relating to the oil and natural gas business, environmental and our operations and reserves apply in respect of the Aurora Assets that we are acquiring pursuant to the Acquisition.

SUMMARY DESCRIPTION OF OUR BUSINESS

Through our subsidiaries, we are engaged in the business of acquiring, developing, exploiting and holding interests in petroleum and natural gas properties and related assets in Canada (primarily in the provinces of British Columbia, Alberta and Saskatchewan) and in the United States (primarily in the states of North Dakota and Wyoming). We act as the primary financing vehicle for our subsidiaries by providing access to debt and equity capital markets. As at the date of this short form prospectus, our primary assets are the shares of Baytex Energy that we own and the Notes. Cash flow from the business carried on by our subsidiaries is flowed to us by way of dividends, interest and principal repayments on the Notes and intercompany loans.

We pay monthly cash dividends to holders of our Common Shares in accordance with our dividend policy. In the event that we do not comply with covenants under the Credit Facilities, the New Credit Facilities and the Debenture Indenture, our ability to pay dividends to Shareholders may be restricted. See *"Description of Common Shares Dividend Policy"*.

For a description of us and the general development of our business over the last three completed financial years, see "*Baytex Energy Corp.*", "*General Development of Our Business*" and "*Description of Our Business and Operations*" in the Annual Information Form, which is incorporated by reference herein.

RECENT DEVELOPMENTS

Operational Update

During the fourth quarter of 2013, our transportation operations were hampered by severe winter weather which impacted our ability to deliver crude oil from the field to sales delivery points. As inventory levels reached capacity, production was curtailed by up to 5,000 Bbls/d during the month of December. Based on field estimates, our average production during the fourth quarter of 2013 is estimated at 58,000 Boe/d, which brings full-year 2013 production to approximately 57,100 Boe/d. We drilled 24 gross (23.7 net) operated oil wells in the fourth quarter of 2013, including 11 cold multi-lateral wells at Peace River, the remaining five wells of our 15-well cyclic steam stimulation module at Cliffdale and seven horizontal wells at Lloydminster.

The Acquisition

The Acquisition Agreement

On February 6, 2014 we entered into the Implementation Agreement with Aurora, whereby it is proposed that we, or a wholly-owned subsidiary of us, will acquire all of the issued and outstanding Aurora Shares for A$4.10 per share for total consideration of approximately CDN$1.8 billion plus assumed debt of approximately CDN$744 million for a total transaction value of approximately CDN$2.6 billion.

With the Acquisition, we will obtain a significant position in the core of the liquids-rich Eagle Ford resource play. The Aurora Assets will provide material production, long-term growth and high quality reserves with upside potential and will provide us with a platform for further potential growth opportunities.

The Acquisition is to be carried out by way of a scheme of arrangement (the "**Scheme of Arrangement**") under Part 5.1 of the Corporations Act, subject to receipt of certain approvals. The Scheme of Arrangement shall be substantially in the form attached to the Implementation Agreement as Annexure 2, subject to any alterations or conditions required by the Australian Court or agreed between us and Aurora. Subject to approval of the Australian Court, the Acquisition must be approved by the Aurora Shareholders at a special meeting of Aurora Shareholders expected to be held in late April/early May 2014. The Acquisition must be approved by (i) at least 75% of the votes cast and (ii) by a majority in number of the Aurora Shareholders who casts votes.

The Aurora Board has unanimously approved the Acquisition and recommended that Aurora Shareholders vote in favour of the Scheme of Arrangement. All of the directors of Aurora controlling approximately 5.5% of the issued and outstanding Aurora Shares have agreed to vote their Aurora Shares in favour of the Acquisition. The Aurora Board's recommendation and stated voting intention are given in the absence of a Superior Proposal (as described below) and subject to an independent expert concluding that the Acquisition is in the best interests of Aurora Shareholders.

Acquisition Consideration

Pursuant to the Scheme of Arrangement, each Aurora Shareholder will receive, for each Aurora Share held, A$4.10 cash.

Pursuant to the Acquisition Agreement, the parties have agreed to use reasonable endeavours (acting co-operatively and in good faith) to procure that, as soon as practicable, each holder of Aurora Options or Aurora Performance Rights (the "**Unlisted Securities**") enters into an agreement with us and Aurora, in a form acceptable to both us and Aurora (each acting reasonably), under which each holder agrees to the cancellation of all of their Unlisted Securities in exchange for an amount per Unlisted Security equal to: (i) for the Aurora Options, the amount equal to the assessed value of each Aurora Option using a standard methodology, and (ii) for the Aurora Performance Rights $4.10 cash, with such transfer or cancellation to be subject to the Acquisition becoming effective and to take effect on the Implementation Date.

The Acquisition will constitute a "change of control" pursuant to the trust indenture dated February 8, 2012 governing the 2017 Aurora Notes between Aurora USA Oil & Gas, Inc., each of the guarantors party thereto and U.S. Bank National Association and the trust indenture dated March 31, 2013 governing the 2020 Aurora Notes between Aurora, each of the guarantors party thereto and U.S. Bank National Association (collectively, the "**Aurora Note Indentures**"). Pursuant to the Aurora Note Indentures, upon completion of the Acquisition, each holder of Aurora Notes will have the right to require us to repurchase all or any part of that holder's Aurora Notes pursuant to an offer ("**Change of Control Offer**") on the terms set forth in the Aurora Note Indentures. Within 30 days following completion of the Acquisition, we will be required to mail a notice to each holder of Aurora Notes describing the Acquisition and offering to repurchase Aurora Notes properly tendered prior to the expiration date specified in the notice, which date will be no earlier than 30 days and no later than 60 days from the date such notice is mailed, pursuant to the procedures required by the Aurora Note Indentures and described in such notice. In the Change of Control Offer, we will offer a payment ("**Change of Control Payment**") in cash equal to 101% of the aggregate principal amount of Aurora Notes repurchased, plus accrued and unpaid interest, if any, on Aurora Notes repurchased to the date of purchase (the "**Change of Control Purchase Date**"), subject to the rights of holders of Aurora Notes on the relevant record date to receive interest due on the relevant interest payment date. Promptly following the expiration of the Change of Control Offer, we will, to the extent lawful, accept for payment all Aurora Notes or portions of Aurora Notes properly tendered pursuant to the Change of Control Offer.

In the event that holders of not less than 90% in aggregate principal amount of either series of the outstanding Aurora Notes accept a Change of Control Offer and we purchase all of such series of Aurora Notes held by such holders, we will have the right, upon not less than 30 nor more than 60 days prior notice, given not more than 30 days following the purchase pursuant to the Change of Control Offer described above, to redeem all of such series of the Aurora Notes that remain outstanding following such purchase at a redemption price equal to the Change of Control Payment plus, to the extent not included in the Change of Control Payment, accrued and unpaid interest, if any, on such series of the Aurora Notes that remain outstanding, to the date of redemption (subject to the right of holders of record on the relevant record date to receive interest due on an interest payment date that is on or prior to the redemption date).

We have agreed to retain a Canadian chartered bank (or one or more of its affiliates as may be appropriate in the circumstances), of which Scotia is a wholly-owned subsidiary, to act as manager in connection with the Change of Control Offers required to be made by us to the holders of the Aurora Notes following completion of the Acquisition at prevailing market rates for a person acting in such a role. See "*Relationship between Us and Certain Underwriters*".

Aurora Non-Solicitation; Termination Fee

The Implementation Agreement provides, among other things, for a non-completion fee of A$18.8 million in the event the Acquisition is not completed in certain circumstances, including circumstances where Aurora may receive and accept a Superior Proposal. The Implementation Agreement also contains certain non-solicitation covenants of Aurora and a right to counter in favour of us. Aurora's non-solicitation covenants are subject to exceptions where the directors of Aurora determine such covenants may involve a breach of their fiduciary or statutory duties.

Covenants, Representations and Warranties

Aurora has agreed that prior to the Implementation Date (as defined in the Implementation Agreement), it shall, and shall cause each of its subsidiaries and affiliates to, conduct its business in the ordinary course and in substantially the same manner as previously conducted (subject to ongoing capital requirements being satisfied), and not to undertake certain types of restricted activities unless we otherwise agree or unless otherwise expressly contemplated or permitted by the Implementation Agreement.

We and Aurora have made certain representations and warranties relating to, among other things, corporate existence, corporate authorization, capitalization, no conflicts, shareholder and governmental approvals and absence of certain changes. Like many public company acquisition agreements, the representations, warranties and indemnities contained in the Implementation Agreement are limited and, other than in exceptional circumstances, we will not be able to seek remedies for breach of such provisions following completion of the Acquisition.

Conditions to Closing

The Acquisition is subject to a number of customary closing conditions, including the receipt of required regulatory approvals and court approvals, as well as the approval of Aurora Shareholders as described above. Regulatory approvals include approval of the Australian Foreign Investment Review Board and the applicable approvals required under the HSR Act.

The disclosure booklet that will be prepared in connection with the meeting of Aurora Shareholders to be called to consider and approve the Acquisition is expected to be mailed to Aurora Shareholders in April, 2014. The Acquisition is expected to close in late April/early May, 2014 or such other date as we and Aurora may agree but in any event, not later than June 30, 2014.

Strategic Benefits of the Acquisition

The Acquisition enhances our growth-and-income business model, delivers production and reserves per share growth and provides attractive capital efficiencies for future investment. The Acquisition is accretive to us on all metrics while maintaining a strong balance sheet.

The following are the key benefits of the Acquisition:

- ***Exposure to a World-Class Oil Resource Play:*** the Acquisition will diversify our asset base into the core of the liquids-rich Eagle Ford, one of the premier oil resource plays in the United States. Following completion of the Acquisition, our three key oil resource plays the Peace River oil sands, Lloydminster heavy oil and the Eagle Ford will represent three of the highest rate of return projects in North America.

- ***Attractive Acquisition Metrics:***[(1)(2)]

  - CDN$24.15 per Boe of proved reserves and CDN$15.46 per Boe of proved plus probable reserves

  - CDN$84,500 per Boe/d of estimated 2014 production

- ***Accretive to Reserves and Production:***[(1)(2)]

  - 37% accretive to proved reserves per share

  - 23% accretive to proved plus probable reserves per share

  - 18% accretive to production per share

Notes:

(1) Reserves and reserve accretion based on our reserves as at December 31, 2012 prepared by Sproule and our internal estimate of Aurora's reserves as at December 31, 2013, prepared by a non-independent qualified reserves evaluator in accordance with NI 51-101 and the COGE Handbook. Based on gross reserves.

(2) Production per share accretion (Boe/d) is based on: (i) Aurora's 2014 estimated gross production of 30,500 Boe/d; (ii) our 2014 estimated gross production of 61,000 Boe/d; (iii) our weighted average outstanding Common Shares for 2014 of approximately 127 million Common Shares (before giving effect to the Offering); and (iv) 162 million Common Shares

outstanding after giving effect to the Offering (and prior to giving effect to the exercise of the Over-Allotment Option).

Increases Scale and Diversity of Production: our total gross production upon closing of the Acquisition is forecast to be approximately 85,000 Boe/d, with a production weighting of 53% heavy oil, 34% light oil and liquids and 13% natural gas (previously 75% heavy oil, 14% light oil and liquids and 11% natural gas).

Material Current Production with Long-Term Growth Potential: Aurora's fourth quarter 2013 gross production averaged 24,678 Boe/d (82% liquids) and it has estimated 2014 average gross production of 29,000 to 32,000 Boe/d which at the mid-point of the forecast equates to a 43% production increase over 2013. Aurora also has a substantial inventory of potential well locations to support future production growth.

High Quality Reserve Base with Potential Upside: the Acquisition will add proved reserves of 106.7 MMboe and proved plus probable reserves of 166.6 MMboe (based on our internal estimate of Aurora's reserves as at December 31, 2013, and prepared by a non-independent qualified reserves evaluator in accordance with NI 51-101 and the COGE Handbook). We believe that attractive reserves upside is available by exploiting additional horizons in the Austin Chalk and Upper Eagle Ford formations, downspacing and through improving completion techniques.

Attractive Individual Well Economics: Aurora's historical internal rates of return (before tax) per well in the Sugarkane Field are in excess of 100% with an undiscounted payout of 1 to 2 years and capital efficiencies (based on 30-day initial production rates) of under $10,000 per daily Boe (based on an oil price of U.S.$90/Bbl, a natural gas price of U.S.$4.00/Mcf and a natural gas liquids price of U.S.$27/Bbl).

Premier and Committed Eagle Ford Partner: Marathon is the operator of a majority of Aurora's Eagle Ford acreage position. Marathon has a strong track record of driving leading well performance, reducing costs and growing its resource base. In addition to the strong improvement in estimated ultimate reserves and drilling performance over time, Aurora's production has grown significantly from 4,257 Boe/d in the fourth quarter of 2011 to 24,678 Boe/d in the fourth quarter of 2013.

Increasing Development Performance and Recovery: Continuous improvements in drilling completion design have increased 30-day initial production rates by approximately 45% since the first quarter of 2011 with 180-day cumulative recoveries increasing approximately 34% over the same time period. Drilling times have decreased by approximately 50% since the first quarter of 2011 resulting in reduced completed well costs.

Established Infrastructure and Acreage Held by Production: Extensive infrastructure is in place across the acreage position, including centralized processing facilities, disposal wells and infield gathering systems. Approximately 97% of the acreage position is held by production.

Attractive Operating Costs and Premium Pricing: Operating cost per barrel averaged U.S.$5.68 per Boe in the third quarter of 2013. Given the proximity of the Eagle Ford to the Henry Hub and Gulf Coast crude oil markets, established transportation systems for both crude oil and natural gas result in strong realized pricing. In addition, a portion of the produced crude oil benefits from premium Louisiana Light Sweet based pricing.

Pro Forma the Acquisition and the Offering

Selected Pro Forma Financial Information

The following tables set out certain pro forma financial information for: (i) us and Aurora as at December 31, 2012 before giving effect to the Acquisition; (ii) us as at and for the year ended December 31, 2012 after giving effect to the Acquisition; (iii) us and Aurora as at September 30, 2013 before giving effect to the Acquisition; and (iv) us as at and for the nine month period ended September 30, 2013 after giving effect to the Acquisition.

	As at and for the Year Ended December 31, 2012			As at and for the Nine Months Ended September 30, 2013		
(expressed in $000s, except per share amounts)	Baytex before giving effect to the Acquisition	Aurora before giving effect to the Acquisition	Baytex after giving effect to the Acquisition(1)	Baytex before giving effect to the Acquisition	Aurora before giving effect to the Acquisition	Baytex after giving effect to the Acquisition(1)
Petroleum and natural gas sales, net of royalties	1,024,949	207,548	1,232,497	846,063	289,983	
General and administrative expenses	44,646	15,148	59,794	33,060	17,337	
Operating and transportation expenses	439,615	24,530	464,145	327,534	30,022	
Net income	258,631	58,899	254,273	133,672	81,867	
Per share (basic)	2.16	13.60	1.65	1.08	18.27	
Per share (diluted)	2.12	13.35	1.63	1.07	17.95	

Total assets	2,741,169	1,561,721
Total liabilities	1,445,104	1,013,230
Shareholders' equity	1,296,065	548,491

Note:

(1) For pro forma adjustments, see Schedule "B" to this short form prospectus.

For additional pro forma financial information in respect of us, including our outstanding share capital, after giving effect to the Acquisition, see Schedule "B" "*Pro Forma Consolidated Financial Statements of Baytex*". Reference should also be made to the Annual Financial Statements, the Annual MD&A, the Interim Financial Statements and the Interim MD&A, which are incorporated by reference herein, and the audited financial statements of Aurora for the years ended December 31, 2012 and 2011, together with the notes thereto and the report of the auditors thereon, and the unaudited interim consolidated financial statements of Aurora as at September 30, 2013 and 2012 and for the three and nine month periods ended September 30, 2013 and 2012, together with the notes thereto, which are attached hereto as Schedule "A".

The Acquisition is a significant acquisition for us for the purposes of Part 8 of National Instrument 51-102 Continuous Disclosure Obligations.

Selected Combined Operational Information

The following table sets out certain combined operational information for the oil and natural gas assets which will be owned, directly or indirectly, on a consolidated basis by us following completion of the Acquisition, for the periods indicated. Important information concerning the oil and natural gas properties and operations of each of us and Aurora is contained elsewhere in, or incorporated by reference in, this prospectus. Readers are encouraged to carefully review such information and those documents as the information set forth in the table below is a summary only and is qualified in its entirety by such detailed information.

Pro Forma Production

	Twelve months ended December 31, 2012			**Nine months ended September 30, 2013**		
	Baytex before giving effect to the Acquisition	**Aurora before giving effect to the Acquisition**	**Baytex after giving effect to the Acquisition(1)**	**Baytex before giving effect to the Acquisition**	**Aurora before giving effect to the Acquisition**	**Baytex after giving effect to the Acquisition(1)**
Daily Natural Gas Production (Mcf/d)	43,100	11,548	54,648	41,979	24,176	66,155
Crude Oil and NGLs (Bbls/d)	46,807	8,754	55,561	49,827	16,139	65,966
Total (Boe/d)	53,986	10,678	64,664	56,823	20,167	76,990
Operating Netback ($/Boe)(2)	31.10	46.76	33.69	33.41	47.21	37.02

Pro Forma Reserves

	Baytex as at December 31, 2012 before giving effect to the Acquisition		**Aurora as at December 31, 2013 (Baytex Internal Estimate)**		**Pro Forma Baytex after giving effect to the Acquisition(1)**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Category of Reserves (Mboe)						
Total Proved	143,444	118,814	106,694	78,954	250,138	197,768
Total Probable	148,152	118,379	59,876	44,308	208,028	162,687
Total Proved plus Probable plus Possible	291,596	237,193	166,570	123,262	458,166	360,455

Notes:

(1) Reserves information provided herein is from the Sproule Report as at December 31, 2012 and our internal estimate of Aurora's reserves as at as at December 31, 2013, prepared by a non-independent qualified reserves evaluator in accordance with NI 51-101 and the COGE Handbook.

(2) Operating netback does not have a standardized meaning under Canadian GAAP. See "*Non-GAAP Financial Measures*".

The pro forma reserve information in the foregoing table is derived (i) in respect of our reserves as at December 31, 2012, from the Sproule Report and (ii) in respect of Aurora's reserves as at December 31, 2013, from estimates of our internal non-independent qualified reserves evaluator as at December 31, 2013 made in connection with our evaluation of the Acquisition. Our internal estimates of Aurora's reserves as at December 31, 2013 differ from the estimates contained in the Aurora 2013 Reserves Report. They were prepared for use by our management in the evaluation of the Acquisition. Since the estimates of our reserves

and our internal estimate of the reserves of Aurora reflected in the above table were estimated as at different dates, they have been generated based on different assumptions in respect of commodity pricing, development costs, development timing and the timing and amount of capital expenditures, among other metrics. In addition, our reserves as at December 31, 2012 have not been adjusted to account for exploration or development results, production, revisions, acquisitions, dispositions, pricing or any other changes after December 31, 2012. As a result, the above table and the disclosure elsewhere in this short form prospectus describing our reserves on a consolidated pro forma basis for the Acquisition is presented for hypothetical purposes, does not reflect the actual combined estimated of our reserves and those of Aurora at December 31, 2013 and should not necessarily be viewed as predictive of our reserves and future production once the Acquisition is completed.

For pro forma financial information in respect of us, including our outstanding share capital, after giving effect to the Acquisition, see Schedule "B" "*Pro Forma Consolidated Financial Statements of Baytex*".

New Credit Facilities

In connection with the Acquisition, we have entered into an agreement with a Canadian chartered bank (the "**Bank**") pursuant to which the Bank has agreed to fully underwrite and commit to provide us with new senior secured credit facilities in the aggregate principal amount of $2.5 billion (the "**New Credit Facilities**") which will replace our Credit Facilities. The New Credit Facilities are comprised of revolving facilities consisting of a $50 million revolving operating loan facility and a $950 million extendible syndicated loan facility with a syndicate of chartered banks (collectively the "**Revolving Facilities**") and non-revolving facilities consisting of a $200 million non-revolving syndicated term facility (the "**Term Loan A Facility**") and a $1.3 billion non-revolving syndicated equity bridge (the "**Equity Bridge**") (collectively, the "**Non-Revolving Facilities**"). The Revolving Facilities will be for a four year term extendible annually for a one, two, three or four year period (subject to a maximum four-year term at any time) and will contain standard commercial covenants for facilities of this nature. The Revolving Facilities will not require any mandatory principal payments during the four-year term. Advances (including letters of credit in connection with the Revolving Facilities only) under the New Credit Facilities can be drawn in either Canadian or U.S. funds and bear interest at the agent bank's prime lending rate, bankers' acceptance discount rates or London Interbank Offered Rates, plus applicable margins. The New Credit Facilities will be secured by a floating charge over all of our assets, excluding the Aurora Assets, and will be guaranteed by certain material restricted subsidiaries other than Aurora and its subsidiaries. The Revolving Facilities will not include a term-out feature or a borrowing base restriction but will restrict our ability to borrow through the use of customary financial covenants. The Revolving Facilities and the Term Loan A Facility will contain restrictions on our and our subsidiaries' ability to make distributions when (i) a default or event of default under the Revolving Facilities has occurred and is continuing, or (ii) distributions would be reasonably expected to have a material adverse effect on or impair our ability to fulfill our financial obligations under the Credit Facilities.

Each of the Term Loan A Facility and the Equity Bridge non-revolving facilities are single drawdown facilities and will be available solely to finance (directly or indirectly) the Acquisition together with reasonable transaction costs and expenses related thereto. The Term Loan A Facility will have a two year term and the Equity Bridge will have a one year term. Each of the Term Loan A Facility and the Equity Bridge provide for mandatory reductions and repayments for specified equity and debt issuances and dispositions. In addition, with respect to any proceeds arising in connection with the issuance of the Subscription Receipts, the Equity Bridge will be reduced by an amount equal to the gross proceeds received by us in connection with the Offering, once such proceeds are placed into escrow with the Escrow Agent. The Equity Bridge will prohibit us and our subsidiaries from making distributions, other than inter-company distributions or acquisitions and will impose additional financial covenant restrictions under the New Credit Facilities if and for long as there is any outstanding indebtedness under the Equity Bridge.

In connection with the Acquisition, we also expect to establish replacement credit facilities through Aurora's subsidiary, Aurora USA Oil & Gas, Inc, with the Bank for the Existing Target Facility of up to U.S.$300 million.

Dividend Increase

We are committed to a growth-and-income model and its three fundamental principles: delivering organic production growth, paying a meaningful dividend and maintaining capital discipline. Through the combination of an expanded inventory of high capital efficiency projects and an improved outlook for heavy oil differentials, we remain confident in our business plan going forward. Consequently, we intend increase the monthly dividend on our Common Shares by 9% to $0.24 from $0.22 per Common Share, subject to the completion of the Acquisition.

ABOUT AURORA

Except as otherwise indicated all information regarding Aurora and the Aurora Assets contained in this short form prospectus, including all reserves and related information, financial information and all pro forma financial information reflecting the pro forma effects of the Acquisition, has been derived in part from information provided by Aurora and other third parties. The Aurora Reserves Reports were prepared by Aurora. We were not given the opportunity to participate in the preparation of the Aurora Reserves Reports or to review the reserves data with management of Aurora or Ryder Scott in conjunction with the preparation of the Aurora Reserves Reports. As a result, we are unable to assess Aurora's procedures for providing information to Ryder Scott or for assembling and reporting other information to Ryder Scott associated with Aurora's oil and gas activities. See "*Risk Factors*" in this short form prospectus.

General

Aurora is an ASX and TSX listed oil and natural gas company active exclusively in the United States. Its primary asset is 22,200 net (80,200 gross) acres in the prolific Sugarkane Field located in South Texas in the core of the liquids-rich Eagle Ford. Aurora's 2013 fourth quarter gross production was 24,678 Boe/d (82% liquids) of predominantly light, high-quality crude oil. The Sugarkane Field has been largely delineated with infrastructure in place which will facilitate low-risk future annual production growth. In addition, these assets have significant future reserves upside potential from well downspacing, improving completion techniques and new development targets in additional zones. In addition, Aurora holds approximately 14,000 net acres in the Eaglebine play regionally on trend with the Eagle Ford.

Aurora is an Australian corporation with its head and registered office located at Level 1, 338 Barker Road, Subiaco, WA 6008, Australia. Aurora also has an operational office located in Houston, Texas at 1200 Smith Street, Suite 2300, Houston, TX 77002 USA. It has appointed Davies Ward Phillips & Vineberg LLP at 155 Wellington Street West, Toronto, Ontario M5Y 3J7, as its agent for service of process in Canada.

The following chart summarizes the material subsidiaries of Aurora.

Aurora's current principal focus of operation is on the development of its Sugarkane Field interests currently operated by Marathon. The Sugarkane Field covers an identified area exceeding 200,000 acres and is a reservoir that lies approximately 20 kilometers south of the main Texas Austin Chalk formation, located within South Texas.

Unconventional shale production is typically characterized by high initial production rates, followed by steep decline rates and prolonged "tail" production profiles. The majority of Aurora's acreage is located in the

central portion of the Eagle Ford trend, primarily within the condensate-rich window, extending into the volatile oil window to the northwest. The Sugarkane Field is over-pressured (generally having a pressure gradient of approximately 0.8 psi per foot), enhancing both the initial production rates and estimated ultimate recovery per well. The combination of high liquids content and high production rate results in attractive economics for development wells.

We believe that this is one of the fastest developing unconventional shale developments in North America. There is limited and predictable variation in geological and reservoir properties across the region, with respect to thickness, depth and hydrocarbon composition of shale intersected. Unlike conventional oil and natural gas traps where the target reservoir may fail to contain hydrocarbons, all of the wells drilled on Aurora's properties are expected to intersect the Eagle Ford formation. Furthermore, a high proportion of the hydrocarbons produced by Aurora from the Eagle Ford are condensate or light/medium oil, which have historically resulted in a higher price realization per unit than dry natural gas.

The diagram below is an indicative pictorial representation of Aurora's Sugarkane Field AMIs. It is not intended to be schematically definitive, to scale or reference ownership of mineral rights.

Aurora's Recent Developments

2013 Operational and Financial Update

Aurora's principal assets and the approximate associated gross and net land positions as of December 31, 2013, are shown in the table below:

	AVERAGE WORKING INTEREST	GROSS ACREAGE	NET ACREAGE
Sugarloaf AMI	28.1%	24,000	6,750
Longhorn AMI	31.9%	28,500	9,100
Ipanema AMI	36.4%	4,800	1,750
Excelsior AMI	9.1%	20,100	1,800
Operated Sugarkane Acreage (2013 Acquired Assets)	100.0%	2,800	2,800
Total Sugarkane Field		80,200	22,200
Eaglebine Operated	91.1%	15,000	14,000
Total		95,200	36,200

Based on realized commodity pricing achieved by Aurora for the year ended December 31, 2013, approximately 94% of Aurora's production revenue related to oil, condensate and NGL sales, with the balance being natural gas production revenue.

During the last three years, substantial drilling activity was undertaken across Aurora's Sugarkane Field AMIs. As of December 31, 2013, the total number of gross producing wells in which Aurora has an interest was 387, as compared to 216 gross wells as of December 31, 2012 and 71 gross wells as of December 31, 2011.

The following table summarizes the status of wells in which Aurora has a WI, categorized by Sugarkane Field AMI, as of December 31, 2013.

	SUGARLOAF	LONGHORN	IPANEMA	EXCELSIOR	AXLE TREE	HEARD RANCH	TOTAL
Producing	97	178	7	86	11	8	387
Workover							
Fracture Stimulation						2	2
Completions	3	13		10		1	27
Drilling	2	4		2		1	9
Total	**102**	**195**	**7**	**98**	**11**	**12**	**425**

2013 Reserves Update

On February 3, 2014, Aurora publicly announced that Ryder Scott had provided the Aurora 2013 Reserves Report to Aurora. Set out below is a summary of reserves estimates and the value of future net revenue of Aurora associated with such reserves with an effective date as of December 31, 2013 based on the Aurora 2013 Reserves Report.

The following tables provides a summary of the reserve estimates as at December 31, 2013 evaluated by Ryder Scott using forecast prices and costs contained in the Aurora 2013 Reserves Report.

SUMMARY OF OIL AND NATURAL GAS RESERVES
AS OF DECEMBER 31, 2013
FORECAST PRICES AND COSTS

	RESERVES							
	LIGHT AND MEDIUM OIL		NATURAL GAS LIQUIDS		NATURAL GAS		BOE	
RESERVES CATEGORY	Gross (MMbbls)	Net (MMbbls)	Gross (MMbbls)	Net (MMbbls)	Gross (Bcf)	Net (Bcf)	Gross (MMBoe)	Net (MMBoe)
PROVED:								
Developed Producing	14.1	10.4	13.1	9.7	42.9	31.7	34.4	25.4
Developed Non-Producing	0.6	0.5			0.2	0.2	0.7	0.5
Undeveloped	34.4	25.3	64.6	47.6	184.8	136.3	129.8	95.6
TOTAL PROVED	49.1	36.2	77.8	57.4	227.9	168.1	164.9	121.5
PROBABLE	11.6	8.6	31.0	23.0	98.3	73.0	58.9	43.8
TOTAL PROVED PLUS PROBABLE	60.7	44.8	108.8	80.3	326.2	241.0	223.8	165.3
POSSIBLE	1.4	1.0	32.3	23.8	87.8	64.4	48.4	35.5
TOTAL PROVED PLUS PROBABLE PLUS POSSIBLE[(1)]	62.1	45.8	141.1	104.1	414.0	305.4	272.2	200.8

Note:

(1) Possible reserves are those reserves that are less certain to be recovered than probable reserves. There is a 10% probability that the quantities actually recovered will equal or exceed the sum of proved plus probable plus possible reserves.

The table below shows the before tax net present value of future net revenue of Aurora's reserves on an undiscounted basis and with a 5%, 10%, 15% and 20% discount being applied:

SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE
AS OF DECEMBER 31, 2013
FORECAST PRICES AND COSTS

	NET PRESENT VALUES OF FUTURE NET REVENUE BEFORE INCOME TAXES DISCOUNTED AT (%/year)				
RESERVES CATEGORY	0%	5%	10%	15%	20%
	(in U.S.$ million)				
PROVED:					
Developed Producing	1,079	857	721	629	564
Developed Non-Producing	28	25	23	21	20
Undeveloped	2,610	1,645	1,101	766	546
TOTAL PROVED	3,717	2,527	1,845	1,416	1,130
PROBABLE	1,143	702	464	324	233
TOTAL PROVED PLUS PROBABLE	4,860	3,229	2,309	1,740	1,363

POSSIBLE[1]	701	371	205	111	55
TOTAL PROVED PLUS PROBABLE PLUS POSSIBLE[1]	5,561	3,600	2,514	1,851	1,418

Note:

(1) Possible reserves are those reserves that are less certain to be recovered than probable reserves. There is a 10% probability that the quantities actually recovered will equal or exceed the sum of proved plus probable plus possible reserves.

The forecast pricing parameters detailed in the table below were used in the Aurora 2013 Reserves Report by Ryder Scott. NGL pricing was estimated at 30% of the oil pricing. The figures were then adjusted for quality and regional price variations. Further adjustments were made for the calorific value of the gas.

SUMMARY OF PRICE ASSUMPTIONS
AS OF DECEMBER 31, 2013
FORECAST PRICES AND COSTS

Period ended	West Texas Intermediate Price (U.S.$/Bbl)	Natural Gas Price (U.S.$/MMbtu)
2014	94.49	4.23
2015	87.98	4.17
2016	83.74	4.13
Thereafter	83.74	4.13

Well costs are based on estimates provided by the operator of Aurora's non-operated acreage, together with internally generated estimates for its operated acreage. These estimates are then adjusted for horizontal well lengths accordingly. In general the well costs are based on a nominal 5,000 foot lateral design with a drill and complete cost of U.S.$7.5 million. This results in well costs ranging from U.S.$6.7 million to U.S.$10.5 million depending on location, depth, lateral length and artificial lift design.

Aurora's 2012 Oil and Gas Information and Reserves Data

The disclosure below and the Aurora 2012 Reserves Report are each based on Aurora's WIs in the Sugarkane Field as at December 31, 2012 and do not include any reserves, production or other oil and gas information since December 31, 2012. For more recent reserves and other information relating to Aurora, see "*Recent Information Respecting Aurora*" above.

Reserves and Future Net Revenue

The following table discloses, in aggregate, Aurora's gross and net reserves estimated using the Aurora 2012 Reserves Report forecast prices and costs, by product type.

SUMMARY OF OIL AND NATURAL GAS RESERVES
AS OF DECEMBER 31, 2012
FORECAST PRICES AND COSTS

	RESERVES							
	LIGHT AND MEDIUM OIL		NATURAL GAS LIQUIDS		NATURAL GAS		BOE	
RESERVES CATEGORY	Gross (Mbbls)	Net (Mbbls)	Gross (Mbbls)	Net (Mbbls)	Gross (MMcf)	Net (MMcf)	Gross (MBoe)	Net (MBoe)
PROVED:								
Developed Producing	7,752	5,710	8,778	6,490	30,133	22,258	21,552	15,909
Developed Non-Producing								
Undeveloped	23,694	17,436	30,656	22,653	112,722	83,263	73,137	53,967
TOTAL PROVED	31,446	23,146	39,433	29,143	142,885	105,522	94,688	69,876
PROBABLE	1,433	1,069	3,595	2,677	18,915	14,091	8,181	6,094
TOTAL PROVED PLUS PROBABLE	32,879	24,215	43,028	31,820	161,769	119,612	102,869	75,970
POSSIBLE	2,436	1,793	36,702	27,166	154,182	114,285	64,835	48,006
TOTAL PROVED PLUS PROBABLE PLUS POSSIBLE[(1)]	35,315	26,008	79,731	58,986	315,952	233,897	167,705	123,976

Note:

(1) Possible reserves are those reserves that are less certain to be recovered than probable reserves. There is a 10% probability that the quantities actually recovered will equal or exceed the sum of proved plus probable plus possible reserves.

The following tables disclose, in the aggregate, the net present value of Aurora's net revenue attributable to the reserves categories in the previous table, estimated using the Aurora 2012 Reserves Report forecast prices and costs, before deducting future income tax expenses and after deducting future income tax expenses, on an undiscounted basis and with a 5%, 10%, 15% and 20% discount.

SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE AS OF DECEMBER 31, 2012 FORECAST PRICES AND COSTS

RESERVES CATEGORY	NET PRESENT VALUES OF FUTURE NET REVENUE BEFORE INCOME TAXES DISCOUNTED AT (%/year) 0%	5%	10%	15%	20%
	(in U.S.$ million)				
PROVED:					
Developed Producing	801.5	606.7	500.7	434.1	388.0
Developed Non-Producing					
Undeveloped	1,512.5	845.1	506.2	311.4	189.5
TOTAL PROVED	2,314.0	1,451.8	1,006.9	745.5	577.5
PROBABLE	141.3	75.3	44.0	26.9	16.5
TOTAL PROVED PLUS PROBABLE	2,455.2	1,527.2	1,050.9	772.3	594.0
POSSIBLE(1)	1,133.5	552.1	308.0	183.3	112.0
TOTAL PROVED PLUS PROBABLE PLUS POSSIBLE(1)	3,588.8	2,079.3	1,358.9	955.6	706.0

Note:

(1) Possible reserves are those reserves that are less certain to be recovered than probable reserves. There is a 10% probability that the quantities actually recovered will equal or exceed the sum of proved plus probable plus possible reserves.

RESERVES CATEGORY	NET PRESENT VALUES OF FUTURE NET REVENUE AFTER INCOME TAXES DISCOUNTED AT (%/year) 0%	5%	10%	15%	20%
	(in U.S.$ million)				
PROVED:					
Developed Producing	658.2	520.1	445.8	397.8	363.2
Developed Non-Producing					
Undeveloped	1,026.5	551.2	319.9	188.5	105.5
TOTAL PROVED	1,684.7	1,071.3	765.7	586.3	468.7
PROBABLE	86.4	42.1	23.0	13.0	7.0
TOTAL PROVED PLUS PROBABLE	1,771.1	1,113.4	788.7	599.3	475.7
POSSIBLE(1)	681.8	278.9	286.9	169.4	102.5
TOTAL PROVED PLUS PROBABLE PLUS POSSIBLE(1)	2,452.9	1,392.3	1,075.6	768.7	578.2

Note:

(1)

Possible reserves are those reserves that are less certain to be recovered than probable reserves. There is a 10% probability that the quantities actually recovered will equal or exceed the sum of proved plus probable plus possible reserves.

The following table discloses, by production group, the net present value to Aurora of future net revenue attributable to its reserves, before deducting future income tax expenses, estimated using forecast prices and costs, and calculated using a 10% discount rate.

**FUTURE NET REVENUE
BY PRODUCTION GROUP
AS OF DECEMBER 31, 2012
FORECAST PRICES AND COSTS**

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year)	UNIT VALUE[1]	
		(U.S.$000s)	(U.S.$/Boe)	(U.S.$/Mcfe)
Proved	Light and Medium Crude Oil (including solution gas and other by-products)	495,077	21.39	
	Natural Gas Liquids	407,134	13.97	
	Natural Gas (including by-products)	104,655		0.99
	Total	1,006,866		
Proved plus Probable	Light and Medium Crude Oil (including solution gas and other by-products)	507,254	20.95	
	Natural Gas Liquids	427,241	13.43	
	Natural Gas (including by-products)	116,396		0.97
	Total	1,050,891		
Proved plus Probable plus Possible[2]	Light and Medium Crude Oil (including solution gas and other by-products)	482,192	18.54	
	Natural Gas Liquids	672,657	11.40	
	Natural Gas (including by-products)	203,992		0.87
	Total	1,358,841		

Notes:

(1) Unit values are based on net reserve volumes.

(2) Possible reserves are those reserves that are less certain to be recovered than probable reserves. There is a 10% probability that the quantities actually recovered will equal or exceed the sum of proved plus probable plus possible reserves.

Pricing and Cost Assumptions

The forecast pricing parameters used in the Aurora 2012 Reserves Report were accepted by Ryder Scott and were based on the December 31, 2012 forward strip NYMEX West Texas Intermediate prices for oil and condensate sales and Henry Hub prices for natural gas sales, without adjustment for inflation. NGL sales are referenced to Mt. Belvieu Texas Propane but were estimated at 30% of the oil pricing. These prices are shown in the following table and are then further adjusted for gravity, quality, local conditions and/or distance from market to calculate reserves.

SUMMARY OF PRICE ASSUMPTIONS
AS OF DECEMBER 31, 2012
FORECAST PRICES AND COSTS

Period ended	NYMEX West Texas Intermediate Price (U.S.$/Bbl)	Natural Gas Price (U.S.$/MMbtu)
Historical prices		
12-31-2012	94.10	2.71
Forecast prices		
12-31-2013	93.19	3.56
12-31-2014	92.36	4.03
12-31-2015	90.26	4.23
12-31-2016	88.29	4.42
12-31-2017 and thereafter	86.88	4.63

For the proved reserves lease and well operating costs were estimated at U.S.$7,000 per well, per month for the fixed costs and U.S.$4.00/Boe for the variable component. For the probable and possible reserve cases these figures were decreased to U.S.$6,000 per well per month for the fixed costs and U.S.$3.00/Boe for the variable. Gross capital development costs for a 5,000 foot lateral were estimated at U.S.$8.9 million per well for 2012 with adjustment for variation in horizontal section length, then U.S.$7.8 million for 2013 and thereafter again adjusting for horizontal section length. These capital costs include the drilling, stimulation, completion, production line tie-in and associated field infrastructure.

Reconciliation of Changes in Reserves

The following table sets forth a reconciliation of Aurora's total gross (before royalty) proved, probable and proved plus probable reserves from the Sugarkane Field as at December 31, 2012 against such reserves as at December 31, 2011, based on forecast price and cost assumptions.

	LIGHT AND MEDIUM OIL			NATURAL GAS LIQUIDS			NATURAL GAS		
FACTOR	Gross Proved (Mbbls)	Gross Probable (Mbbls)	Gross Proved Plus Probable (Mbbls)	Gross Proved (Mbbls)	Gross Probable (Mbbls)	Gross Proved Plus Probable (Mbbls)	Gross Proved (MMcf)	Gross Probable (MMcf)	Gross Proved Plus Probable (MMcf)
December 31, 2011	30,352	4,561	34,913	30,649	4,329	34,977	116,297	16,861	133,157
Extensions & Improved Recovery	4,229	850	5,079	5,037	291	5,328	18,895	2,275	21,170
Technical Revisions	(3,046)	(3,985)	(7,031)	(4,332)	(2,710)	(7,042)	(18,315)	(8,581)	(26,896)
Discoveries									
Acquisitions	1,806		1,806	9,380	1,681	11,061	30,198	8,337	38,535
Dispositions									
Economic Factors	8	7	15	1	4	5	6	23	29
Production	(1,902)		(1,902)	(1,301)		(1,301)	(4,226)		(4,226)
December 31, 2012	31,446	1,433	32,879	39,433	3,595	43,028	142,854	18,915	161,769

Additional Information Relating to Reserves Data

Undeveloped Reserves   Proved Undeveloped Reserves

The following table sets forth the volumes of net (after royalty interests) proved undeveloped reserves that were first attributed for the years ended December 31 2010, 2011 and 2012. These figures are net of royalties paid.

	LIGHT AND MEDIUM OIL (Mbbls)		NATURAL GAS LIQUIDS (Mbbls)		NATURAL GAS (MMcf)	
	First Attributed(1)	Cumulative at Year End	First Attributed(1)	Cumulative at Year End	First Attributed(1)	Cumulative at Year End
Year						
2010	271	271	5,381	5,381	24,101	24,101
2011	21,985	20,209	16,426	21,261	58,713	79,982
2012	890	17,436	6,702	22,653	20,284	83,263

Note:

(1) First Attributed is annual change in proved undeveloped reserves plus those that have been developed in the period.

Proved undeveloped reserves are generally those reserves related to wells that have been tested and not yet tied-in, wells drilled near the end of the fiscal year or wells further away from Aurora's gathering systems. In addition, such reserves may relate to planned infill drilling locations. The majority of these reserves are planned to be on stream within a five year timeframe.

Undeveloped Reserves   Probable Undeveloped Reserves

The following table sets forth the volumes of probable undeveloped reserves that were first attributed for the years ended December 31 2010, 2011 and 2012.

	LIGHT AND MEDIUM OIL (Mbbls)		NATURAL GAS LIQUIDS (Mbbls)		NATURAL GAS (MMcf)	
	First Attributed(1)	Cumulative at Year End	First Attributed(1)	Cumulative at Year End	First Attributed(1)	Cumulative at Year End
Year						
2010	290	290	5,903	5,903	31,171	31,171
2011	25,719	3,024	13,472	2,950	38,952	11,409
2012	(1,065)	1,069	6,430	2,677	22,966	14,091

Note:

(1) First Attributed is annual change in proved undeveloped reserves plus those that have been developed in the period.

Probable undeveloped reserves are generally those reserves tested or indicated by analogy to be productive, infill drilling locations and lands contiguous to production. The majority of these reserves are planned to be on stream within a five year timeframe.

Under the terms of the mineral leases in which Aurora holds an interest, there are requirements to drill and produce a well to hold the acreage past its primary terms. The joint operating arrangements in which Aurora has participated therefore focused the early drilling program on ensuring that all acreage was held by production, before infill drilling occurs. Thereafter, the drilling has been carried out in order to maximize the efficiency and minimize costs, with wells being drilled in batches from common surface locations.

Significant Factors or Uncertainties

The process of evaluating reserves is inherently complex. It requires significant judgments and decisions based on available geological, engineering and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change. The reserve estimates contained herein are based on the then-current production forecasts, geological evaluation, engineering data, prices and economic conditions. The reserves associated with the assets described in the Aurora 2012 Reserves Report have been evaluated by Ryder Scott and considering certain factors and assumptions. These factors and assumptions include among others: (i) historical production in the area compared with production rates from analogous producing areas; (ii) initial production rates; (iii) production decline rates; (iv) ultimate recovery of reserves; (v) success of future development activities; (vi) marketability of production; (vii) effects of government regulations; and (viii) other government levies imposed over the life of the reserves. See also, "*Risk Factors*".

As circumstances change and additional data becomes available, reserve estimates also change. Estimates are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, prices, economic conditions and governmental restrictions. Revisions to reserve estimates can arise from changes in year-end prices, reservoir performance and geologic conditions or production. These revisions can be either positive or negative.

Future Development Costs

The table below summarizes Aurora's share of the future development costs for the Sugarkane Field project based on the Ryder Scott development schedule used in the Aurora 2012 Reserves Report.

FUTURE DEVELOPMENT COSTS
AS OF DECEMBER 31, 2012
FORECAST PRICES

Year	Proved Reserves (U.S.$000s)	Proved Plus Probable Reserves (U.S.$000s)
2013	255,740.1	263,683.4
2014	252,159.5	255,731.5
2015	271,278.3	280,252.0
2016	239,310.8	300,199.3
2017	200,183.0	210,829.5
2018+	28,304.6	28,304.6
Total (Undiscounted)[(1)]	1,258,254.8	1,350,857.1

Note:

(1) Includes capital expenditure on abandonment obligations at end of field life.

Other Oil and Gas Information

Oil and Natural Gas Properties

All principal properties of Aurora are located in the Sugarkane Field in Texas, United States. There are no properties in which Aurora has an interest to which reserves have been attributed which are not planned to be developed.

Aurora's principal assets and the approximate associated gross and net land positions as of December 31, 2012, excluding the 2013 Acquired Assets, are shown in the table below:

	AVERAGE WORKING INTEREST	GROSS ACREAGE	NET ACREAGE
Sugarloaf AMI	28.1%	24,300	6,700
Longhorn AMI	31.9%	28,100	8,900
Ipanema AMI	36.4%	4,500	1,600
Excelsior AMI	9.1%	20,200	1,800
Total		77,000	19,100

Operating Arrangements for Aurora's Principal Properties

The operations within each of the four Sugarkane Field AMIs are governed by a JOA, under which Marathon is the designated operator. Aurora's interests within each of the Sugarloaf, Longhorn, and Ipanema AMIs are also subject to farmout arrangements. Aurora's interests and operations related within the acreage associated with the 2013 Acquired Assets are not subject to any JOA or farmout agreements.

Farmout arrangements provide an incentive to operators to drill a producing well in exchange for a WI in those wells and generally in the related AMI. Under Aurora's farmout arrangements, it has no WIs in the farmout wells until payout on each separate farmout program is achieved, but this does not impact Aurora's post-farmout WIs on any other wells in the same contract area. Payout occurs when the farminor receives from WI revenues, net of operating costs, an amount equal to the costs incurred by the farminor within each separate farmout program. The farminor is entitled to receive a 100% priority return from each farmout program until repayment of all costs plus an amount equal to a 12% internal rate of return on such costs. Aurora's WIs are presented above on the basis of interests in the contract area (on a post-farmout basis) and not on a per-well basis. Once each farmout program reaches payout, Aurora starts to receive an interest of production from the wells within that farmout program as per the farmout agreements.

The following two farmout programs had not reached payout as of December 31, 2013: three wells in Longhorn and one well in Ipanema. Payout has been achieved on all wells in Sugarloaf and Aurora is receiving revenue based on its WIs in each of these three wells.

A JOA grants authority to, and delineates the responsibilities of, the party acting as the operator in the AMI. A JOA also outlines the rights that WI holders are entitled to, including participation in wells, access to newly acquired leases within a specified area, revenue distributions and access to information. The terms of the JOA for each of Aurora's AMIs are substantially similar and are described in more detail below.

Cost and Production Sharing

Under each JOA, Marathon, as the operator, generally incurs the initial costs for drilling operations and related costs, including equipment expenses, labour expenses, royalties, expenses for title examinations, legal expenses, taxes and insurance expenses. The operator has the right to be reimbursed from the other parties to the relevant JOA who have elected to participate in proportion to their respective WIs and may request payment of certain expenses and estimated capital costs in advance. Similarly, production of oil and natural gas from the relevant AMI is shared among the participants in the AMI in proportion to each participant's WI in that AMI, subject to any farmout, royalty agreements or other agreements impacting a party's WI. The operator has no obligation under the JOA to provide a schedule of long-term future operations or expenses.

Operations by Parties and Forfeiture of WIs

The operator generally establishes the drilling program; however, each party to a JOA has the right at any time to propose the drilling of a new well or reworking of existing wells in the relevant AMI. The proposing party must consult with the other parties to the JOA at least 30 days prior to providing notice of such proposal to the other parties, which notice must include or be accompanied by an itemized report detailing, among other things, the estimated cost of the proposed operations. After notice of such a proposal, the other parties to the JOA have 30 days (or 24 hours, if a rig is on location) to consent to participating in the cost of the proposed operations. If a party does not consent or reply within the required time period, such party will not have to pay any costs associated with the proposed operations. However, such non-consenting party will relinquish its rights to the production of oil and gas from the proposed operations. Under the terms of the JOA, and subject to the following paragraph, such non-consenting party will relinquish its interest in the production until the consenting parties are reimbursed for their costs and expenses in the proposed operations, including costs for equipment, and for an additional amount, which generally ranges from one and one half times to four times the costs and expenses for the operations. Once these reimbursement amounts are paid, the WI of the non-consenting party is restored.

However, notwithstanding the previous paragraph, in the circumstances described below, any non-consenting party relinquishes all rights to the production of oil and gas from the proposed operations:

- under the Sugarloaf JOA and the Longhorn JOA, the non-consenting party will lose all operating rights and WIs in a proposed new well and in the 1,920 acres surrounding such well not otherwise held by production by the parties;

- under the Excelsior JOA, the non-consenting party will lose all operating rights and WIs in a proposed new well that is drilled outside a previously drilled unit or on acreage not held by production and in the 1,920 acres surrounding such well not otherwise held by production by the parties;

- under each JOA, the non-consenting party will lose all interests in farmout rights or leases if the proposed operations are "Obligatory Operations", being operations (such as the drilling of a new well) commenced to prevent the expiration of a lease or leases that would otherwise expire within six months; and

- under the Excelsior JOA and the Sugarloaf JOA, if a party elects not to participate in the acquisition of 3-D seismic data in an AMI (or fails to make timely payment of its share of the costs to acquire such data after having elected to participate), the participating parties will have the right to select 1,920 acres in the AMI, which is not already held by production, but which is covered by the seismic data. The non-participating party will be prohibited from participating in any drilling operations as long as the participating parties own any leasehold rights in such 1,920 acre tract and, once the acquisition of the seismic data is complete, will assign all of its operating rights and WI in such 1,920 tract to the participating parties.

The operator will perform all of the proposed work for the consenting parties where less than all parties participate in operations; provided, however, that if the operator is a non-consenting party and there is no drilling rig already present at the proposed location of the operations, the consenting parties must either formally request that the operator commence operations or designate one of the consenting parties as operator for such proposed work.

Failure of Title

Under each of the JOAs, any and all losses incurred through title failures are shared jointly between all parties to the JOA in proportion to their WIs. In effect, these provisions provide that even though Aurora was not a party to the original leases underlying a particular AMI, it will share in any loss of those leases that may occur as a result of title problems.

Acquisition of Additional Interests in an AMI

If a party to a JOA acquires or obtains the right to acquire from anyone not a party to the JOA any additional leasehold or other oil and gas interest within the AMI, that party must notify the other parties of the acquisition of such interests or a right to acquire such interests and the other parties may mutually agree to acquire such interests in proportion to their WIs. If all parties to the JOA agree to participate in such acquisition, in proportion to their WIs in the AMIs, such interests will become subject to the terms of the JOA. Further, if all parties to the JOA acquire additional interests that become subject to the JOA, the parties have agreed to assign or reserve for the party to the JOAs who was the original operator an overriding royalty with respect to the acquired interest (subject to a cap that ranges from 4% to 6% of the interest acquired).

Divestments

Aurora is generally able to divest its WIs in the JOAs; however, under the Sugarloaf, Ipanema and Longhorn JOAs, any assignment is subject to the written consent of the party to the JOA who was the original operator, which must not be unreasonably withheld upon receipt of proof that the proposed assignee is financially capable of fulfilling its obligations in respect of the WI. Additionally, under each of the Longhorn and Ipanema JOAs, Aurora must provide notice to the operator of any proposed divestment of WIs and the operator will have a pre-emptive right to acquire any such interests on the same terms as proposed, except in the case of assignments by way of mortgage or disposal of WIs by way of merger, reorganization, consolidation or sale of all or substantially all of Aurora's assets to a subsidiary or parent company or to a subsidiary of a parent company or to a third party in which any one party owns a majority of the stock.

Default

Under the JOAs, the operator and other parties in each JOA have a first priority lien in Aurora's oil and gas rights in the relevant AMI and a security interest in its share of oil and/or gas when extracted and in all equipment purchased under the relevant JOA. If Aurora fails to fully discharge its financial obligations, including making payments in advance to the operator as described above, it will be in default under the JOAs. Subject to certain cure periods, upon default, Aurora may be sued for damages, its production revenues may be directed to the operator and it may be deemed to be a non-consenting party with respect to certain wells. The operator grants a like lien and security interest to the non-operators to secure payment of operator's proportionate share of expense.

Resignation or Removal of Operator

Under each of the JOAs, the operator may resign at any time on written notice and will be deemed to resign if it terminates its legal existence, is no longer capable of serving as operator or it no longer owns an interest in the area subject to the JOA. The operator can be removed if it fails or refuses to carry out its duties under the JOA or becomes insolvent, bankrupt or is placed in receivership, by the affirmative vote of two or more of the non-operating parties owning a majority of the WIs in the relevant contract area. Such resignation or removal is effective on the first day of the calendar month following a 90-day period from the date of written notice or action by the non-operators, as applicable, unless a successor operator is selected prior to that date.

Where an operator has resigned or has been removed under the foregoing circumstances, the successor operator shall be selected from the parties holding WIs in the relevant contract area, by an affirmative vote of two or more parties owning a majority of the WIs. An operator that has been removed must participate in voting for a successor operator, but may be excluded from the vote if it fails to vote or votes only to succeed itself, at which point the successor operator shall be selected by the affirmative vote of two or more parties owning a majority interest based on ownership remaining after excluding the voting interest of the operator that was removed.

Wells

Aurora's wells produce light and medium oil, NGLs (including condensate) and natural gas, with the ratio of gas to liquids production varying by well. The gas to liquids ratio observed across the gas condensate wells varies between 60 and 400 Bbls per MMcf. The volatile oil wells produce at approximately 1,000 Mcf/Bbl. The following table sets out the number of producing and non-producing wells net to Aurora's WI, both before royalties and after royalties, in the Sugarkane Field as at December 31, 2012.

Net Wells as at December 31, 2012	**Before Royalties**	**After Royalties**
Producing	50.5	37.3
Drilled, not producing	4.4	3.2
Total Net Wells	54.9	40.5

The following table summarizes the status of wells in which Aurora had a gross WI, categorized by Sugarkane Field AMI, as of December 31, 2012.

	SUGARLOAF	LONGHORN	IPANEMA	EXCELSIOR	TOTAL
Farmout Wells(1)					
Producing subject to payout		3.0	1.0		4.0
Post-Farmout Wells					
Producing	57.5	19.2	6.0	60.0	216.0
On test					
Fracking		4.0		4.0	8.0
Drilled and Cased	3.5	5.5		3.0	12.0
Drilling	4.0	3.0			7.0
Total Gross Wells	65.0	108.0	7.0	67.0	243.0

Note:

(1) Once the farmout wells are paid out, Aurora will start to receive an interest of production from these farmout wells as per the farmout agreements.

Leasehold Interests and Royalties

In Texas, mineral rights may be held privately or by the government. In the Eagle Ford, substantially all of the mineral interests are owned and leased by private owners. To drill wells or produce oil and gas, a company must either own the mineral rights or lease them from the mineral rights holder. Generally, Aurora's leases are for a primary term of five years. Marathon, as operator, has responsibility of managing the lease administration for Aurora's Sugarkane AMIs.

Aurora has an interest in numerous individual leases from private lessors across its four AMIs and in the 2013 Acquired Assets within the Sugarkane Field, each of which is current (typically a cash bonus and delay rental was paid upon execution of the lease with no such additional payments being required within the primary term of the lease). The undeveloped portion of the leaseholds under these leases generally expire between 2014 and 2015. The leases contain provisions requiring that the acreage be developed within a specified lease period or else it must be re-leased. The development provisions of these leases generally require the drilling of one or more wells that produce hydrocarbons from which the mineral owners derive royalties. Each producing well will hold a certain amount of land while it is still producing, hence the reference to "land held by production". The specific details of each lease and royalty rate are different as they are individually negotiated but, in general, the net revenue interests for the WI participants, including Aurora, ranges from 70 to 75% with an average across Aurora's current acreage of approximately 74%.

Over time, each field designated by the Railroad Commission of Texas will have its own rules depending on the individual characteristics of the field. Approximately half of the Sugarkane Field has been designated as a natural gas field and the remainder as an oil field. Under these designations, operators are able to hold a certain number of acres around every producing well drilled (depending on the well length) per the specific field rules. The rules currently in effect for natural gas wells within the Sugarkane Field allow each well to hold up to 320 acres plus an additional 200 acres for each 1,000 feet of horizontal well. A typical 5,000 foot horizontal well is therefore able to hold up to 1,320 acres, although units are generally 600 to 900 acres. The northern half of the Sugarkane Field falls within two Railroad Commission designated fields: the Eagleville I Field and the Eagleville II Field. These fields have been designated as oil fields. Under the relevant field rules, operators are able to hold on average 320 acres for wells with lateral lengths of 5,000 feet plus additional acreage for longer laterals.

Properties With No Attributed Reserves

The following table sets forth the gross and net acres of unproved properties held by Aurora, as of December 31, 2012, and the net area of unproved property for which Aurora expects its rights to expire during the next year.

	UNDEVELOPED LAND (ACRES)		
	Gross	**Net**	**Net Area to Expire in 2013**
South Texas, Flour Bluff Field	1,400	280	
California, North Belridge	125	40	
South Texas, Pan de Azucar and Brioche	5,260	5,260	5,160
Total	6,785	5,580	5,160

Other than immaterial abandonment costs liability for two wells at North Belridge, Aurora does not have work commitments on the above lands.

Additional Information Concerning Abandonment and Reclamation Costs

Aurora estimates the costs associated with well abandonment and reclamation based on its previous experience, current regulations, costs, technology and industry standards area by area. Abandonment and reclamation costs are expected to be incurred on 785 gross (182 net) well locations for the proved full field development. These wells are comprised of currently producing, non-producing, planned production and service wells.

Aurora's share of the expected total abandonment and reclamation costs for wells with assigned reserves, non-producing and service wells and facilities, net of salvage value are summarized, without discount and using a discount rate of 10%, in the following table.

NET PRESENT VALUES OF FUTURE NET REVENUE BEFORE INCOME TAXES DISCOUNTED AT (%/year) USING FORECAST PRICING AND COSTS

CATEGORY	PROVED NET PRESENT VALUE		PROVED PLUS PROBABLE NET PRESENT VALUE	
	0%	**10%**	**0%**	**10%**
	(U.S.$000s)		**(U.S.$000s)**	
Abandonment and disconnect costs for wells with reserves assigned	9,023	382.5	9,486	402.1
Reclamation costs for wells with reserves assigned	2,256	95.6	2,371	100.5
Abandonment and reclamation costs for wells with no reserves assigned and facilities				
Total abandonment and reclamation cost provision	11,279	478.1	11,587	502.6
Portion of the above total:				
forecast to be paid during the next three years; and				
not included in the Aurora 2012 Reserves Report				

Notes:

(1) For the full field development at the effective date of the Aurora 2012 Reserves Report there are 182 net proved wells and 11 net probable wells.

(2) Well life has been modeled for 30 years and abandonment liability is discounted accordingly.

(3) For the purposes of this table, management's estimated aggregate abandonment and reclamation costs have been allocated 80% as to abandonment costs and 20% as to reclamation costs.

Costs Incurred

The following table summarizes Aurora's property acquisition costs, exploration costs and development costs (before property dispositions) incurred during the year ended December 31, 2012.

EXPENDITURE	YEAR ENDED DECEMBER 31, 2012 (U.S.$000s)
Property acquisition costs:	
Proved properties	13,900
Unproved properties	4,606
Drilling and completion:	
Proved properties	575,933
Unproved properties	1,473
Facilities and equipment:	
Proved properties	104,215
Unproved properties	
Exploration costs	
Development costs	
Total	700,127

Exploration and Development Activities

The following table sets forth the number and status of wells in which Aurora had a working interest as at December 31, 2012.

	DEVELOPMENT(1)		EXPLORATORY	
	Gross	Net	Gross	Net
Light and Medium Oil	100	23.64		
Natural Gas	56	15.16		
Service				
Stratigraphic Test				
Dry				
Total	156	38.80		

Note:

(1) These wells commenced production during 2012 or completed their farmout payout period.

Infrastructure

There has been considerable focus on the installation of the required infrastructure to allow for full field development in the Sugarkane Field. In the first quarter of 2011, Aurora agreed to the participation and installation of centralized processing facilities across the Sugarkane Field. In total, nine central processing facilities were installed and gathering system improvements made, which provide the following capability:

- infield gathering systems between well locations and these centralized facilities;
- processing equipment for the treatment of natural gas and compression allowing injection into the transportation system that moves the product to refineries for NGL processing;

processing equipment for oil treatment and on site storage in preparation for either injection into oil pipelines that have contracted volumes and run across the field or for export via trucks to local refineries;

saline water wells, centralized ponds, disposal wells and buried distribution pipework allowing water to be sent to fracture locations throughout Aurora's leasehold interests in the Sugarkane Field and produced fracturing water to be recovered and recycled for future wells; and natural gas lift capability for longer term production maintenance of shallower wells in the volatile oil window.

During 2012, the final three central processing facilities were installed and commissioned, the initial six central processing facilities were upgraded for increased capacity and operational efficiency, and the vast majority of the field gathering system was installed (over 300 miles of pipework), including the commissioning of the Three Rivers oil pipeline which crosses the Excelsior and Longhorn AMIs. We expect future production to be accommodated within the existing infrastructure and planned capacity upgrades as necessary.

It is anticipated that the efficiencies of these central processing facilities will lead to material savings on capital well costs as well as subsequent operating costs. The same central facilities have deep saline water wells and holding pits to allow water storage and real time distribution to fracture stimulation operations. Produced water is separated at the central processing facilities and then recycled back to the pits or disposed of via dedicated disposal wells.

The gas export system downstream of the central facilities was predominantly built in 2011, with the most recent central facilities having now been tied in. At the end of 2012, an additional interconnect allowed gas exports to a third processing facility and increased the field take away capacity to over 100 MMbtu/day.

In 2013 Aurora acquired assets in the Sugarkane Field complex known as Heard Ranch and Axle Tree ranch. During 2013/2014, these assets had central facilities and gathering systems installed to manage production expected from the development plans of these assets. In particular the Axle Tree development includes two amine treatment plants to process H_2S (up to 6000 ppm from some wells) out of the gas for sale or field use.

Marketing and Sales of Production

Production from Aurora's leases is moved from individual well test facilities via inter-field transfer lines to central processing facilities where oil, condensate, natural gas liquids and natural gas are treated to sales quality, products are metered and gas compressed up to pipeline inlet pressure specification. Afterwards, treated production is sold either at the lease or moved via truck or pipeline to the particular market for sale.

Currently, Aurora's share of production from the Sugarkane Field AMIs is marketed and sold on its behalf by Marathon, as operator. Under the terms of its JOAs, Aurora has the right to separately dispose of its share of hydrocarbon production from its AMIs under different arrangements, including, without limitation, through different agents. Aurora is responsible for marketing and sales of hydrocarbon production from its operated acreage.

Marathon sells oil, condensate, NGLs and natural gas under a variety of arrangements with the realised price in reference to a range of local prevailing spot markers adjusted for gravity, quality, local conditions and any relevant costs incurred.

Future production associated with Aurora's assets will require transportation, storage and processing capacity to be either constructed or contracted, as well as additional marketing efforts to commit products to sale. Significant regional processing and transportation infrastructure has been constructed or is under construction, with significant additional capacity expected in the area and prospective markets being examined and discussed.

Aurora's properties are accessible year round. Facilities through which its production is processed and/or delivered may be temporarily shut down for a short period of time during the year to conduct repair and maintenance operations.

Production Estimates

The following tables summarize Aurora's estimated future annual production volumes for the assets evaluated in the Aurora 2012 Reserves Report for the 12 months beginning January 1, 2013 and ending December 31, 2013 for each product type, which is reflected in the estimate of future net revenues disclosed earlier in this section using the forecast prices contained in the table entitled "*Summary of Price Assumptions as of December 31, 2012 (Forecast Prices and Costs)"*.

RESERVE CATEGORY	LIGHT AND MEDIUM OIL (Bbls/d)	NATURAL GAS LIQUIDS (Bbls/d)	NATURAL GAS (Mcf/d)	COMBINED (Boe/d)
Proved				
Developed producing	3,964	4,896	15,844	11,501
Developed Non-Producing				
Undeveloped	3,140	1,907	6,370	6,109
Total Proved	7,104	6,803	22,215	17,610
Probable		122	609	224
Total Proved plus Probable	7,104	6,926	22,824	17,834
Possible[1]				
Total Proved plus Probable plus Possible	7,104	6,926	22,824	17,834

Note:

(1) Possible reserves are those reserves that are less certain to be recovered than probable reserves. There is a 10% probability that the quantities actually recovered will equal or exceed the sum of proved plus probable plus possible reserves.

Production Volume

The following table discloses Aurora's net production volumes for the year ended December 31, 2012 based on 365 days for each product type from the Sugarkane Field.

Light and medium oil (Bbls)	Natural gas liquids (Bbls)	Natural gas (Mcf)	Combined (Boe)
1,395,904	963,415	3,115.8	2,878,612

Production History

The following table summarizes Aurora's share of average daily gross production for each of the periods indicated.

	Financial Year Ended December 31, 2012			
	Three Months Ended March 31, 2012	Three Months Ended June 30, 2012	Three Months Ended September 30, 2012	Three Months Ended December 31, 2012
Light and Medium Oil				
Average daily production (Bbls/d)	3,052	5,792	5,885	6,046
Prices received (U.S.$/Bbl)	110.41	94.70	101.29	95.46
Royalties paid (U.S.$/Bbl)	29.68	25.60	26.90	24.87
Production costs (U.S.$/Bbl)(1)	13.80	11.50	12.40	10.44
Resulting netback (U.S.$Bbl)(2)	66.93	57.60	61.98	60.15
Natural Gas Liquids				
Average daily production (Bbls/d)	541	939	1,934	2,656
Prices received (U.S.$/Bbl)	55.13	22.93	30.16	34.58
Royalties paid (U.S.$/Bbl)	13.53	6.33	7.95	9.03
Production costs (U.S.$/Bbl)	7.83	2.69	3.87	4.16
Resulting netback (U.S.$Bbl)(2)	33.77	13.91	18.33	21.39
Condensate Gas Liquids				
Average daily production (Bbls/d)	409	466	2,354	4,872
Prices received (U.S.$/Bbl)	124.22	101.72	101.32	98.35
Royalties paid (U.S.$/Bbl)	32.74	24.86	26.21	25.59
Production costs (U.S.$/Bbl)(1)	15.41	12.40	11.58	10.77
Resulting netback (U.S.$Bbl)(2)	76.07	64.46	63.53	61.99
Natural Gas				
Average daily production (MMcf/d)	4.91	7.00	14.15	20.00
Prices received (U.S.$/Mcf)	2.54	1.81	2.53	3.73
Royalties paid (U.S.$/Mcf)	0.58	0.50	0.67	0.98
Production costs (U.S.$/Mcf)(1)	0.35	0.15	0.33	0.39
Resulting netback (U.S.$/Mcf)(2)	1.61	1.16	1.54	2.36

Notes:

(1) The calculation of production costs allocates operating costs on a prorated basis from production volumes in Boes.

(2) Netbacks have been calculated as the price received subtracting royalties and production costs.

Although there were 220 producing wells on the Sugarloaf, Ipanema, Excelsior and Longhorn AMIs during the year ended December 31, 2012, due to its farm-out arrangements, Aurora did not have an interest in production in four of these wells during this entire period and did not have an interest in production of two other wells to the period ended March 31, 2012.

Other Interests and Investments

Aurora has a minor interest in undeveloped acreage in the Eagle Ford in two separate development areas in Fayette County, Washington and Burleson Counties, located in Southeast Texas and a small WI in producing acreage in Fayette County and in the associated producing Black Jack Springs Unit #1 well.

Aurora also has an immaterial interest in non-U.S. and offshore activities through its equity investment in Elixir. Elixir holds a diversified portfolio of oil and natural gas interests across the exploration, appraisal, development and production spectrum, including: oil and natural gas development and production from the shallow shelf in the Gulf of Mexico, United States; exploration and appraisal activities in the northern North

Sea, United Kingdom; and a very large acreage position of approximately 1.3 million acres onshore France in the East Paris Basin prospective for both conventional and unconventional hydrocarbon bearing formations.

USE OF PROCEEDS

The gross proceeds from the Offering will be held by the Escrow Agent, and invested in short-term obligations of, or guaranteed by, the Government of Canada (or other approved investments) pending the satisfaction of the Escrow Condition. Upon satisfaction of the Escrow Condition on or before the Termination Time, the Escrowed Funds and the interest earned thereon (less any amounts required to pay the Dividend Equivalent Amount upon the issuance of the Underlying Common Shares, if applicable) will be released to us to enable us to convert these funds to Australian dollars and complete the Acquisition. We will utilize the Escrowed Funds, together with funds available under the New Credit Facilities, to pay for Aurora Shares pursuant to the Acquisition. See "*Recent Developments New Credit Facilities*".

On the closing of the Acquisition, each holder of Subscription Receipts will receive one Underlying Common Share for each Subscription Receipt held, without payment of additional consideration or further action on the part of such holder, and such holder will also be entitled to receive an amount per Subscription Receipt equal to the Dividend Equivalent Amount. If the Acquisition is not completed by the Termination Time, or if we advise the Underwriters or announce to the public that we do not intend to proceed with the Acquisition, or if the Implementation Agreement has been terminated in accordance with its terms, holders of Subscription Receipts shall receive an amount equal to the full subscription price attributable to the Subscription Receipts and their *pro rata* entitlement to interest accrued on such amount up to and including the date of the Termination Time. See "*Details of the Offering*".

The following table sets forth the principal purposes to which we propose to use the net proceeds of the Offering:

Proceeds to Us	**Offering not including Over-allotment Option** ($000s)	**Offering including full exercise of Over-allotment Option** ($000s)
Gross proceeds raised pursuant to this Offering[(1)]		
Underwriters' Fee[(2)]	( )	( )
Expenses and costs relating to the Offering	( )	( )
Total estimated net proceeds to the Corporation		
Funds from the Offering used to fund the purchase price for Aurora Shares[(2)]		
Remaining portion of purchase price for Aurora Shares to be funded by the New Credit Facilities[(3)]		

Notes:

(1) The gross proceeds of the Offering will be held in escrow by the Escrow Agent pending satisfaction of the Escrow Condition on or before 5:00 p.m. (Calgary time) on June 30, 2014. See "*Details of the Offering*".

(2) The Underwriters' Fee is payable as to 50% upon the closing of the Offering and 50% upon the closing of the Acquisition. If the Acquisition has not occurred by the Termination Time, the Underwriters' Fee will be reduced to the amount payable upon closing of the Offering. See "*Details of the Offering*" and "*Plan of Distribution*".

(3) See "*Recent Developments The Acquisition*" and "*About Aurora*".

The use of the net proceeds of the Offering is consistent with our stated business objective of acquiring, developing, exploiting and holding interests in petroleum and natural gas properties and related assets in Canada and the United States. Other than the successful completion of the Offering, there is no particular significant event or milestone that must occur for this objective to be accomplished.

DESCRIPTION OF COMMON SHARES

Our authorized capital consists of an unlimited number of Common Shares without nominal or par value and 10,000,000 preferred shares, without nominal or par value, issuable in series.

Holders of Common Shares are entitled to notice of, to attend and to one vote per share held at any meeting of our Shareholders (other than meetings of a class or series of our shares other than the Common Shares as such).

Holders of Common Shares will be entitled to receive dividends as and when declared by the Board of Directors on the Common Shares as a class, subject to prior satisfaction of all preferential rights to dividends attached to shares of other classes of our shares ranking in priority to the Common Shares in respect of dividends.

Holders of Common Shares will be entitled in the event of any liquidation, dissolution or winding-up of us, whether voluntary or involuntary, or any other distribution of our assets among our shareholders for the purpose of winding-up our affairs, and subject to prior satisfaction of all preferential rights to return of capital on dissolution attached to all shares of other classes of our shares ranking in priority to the Common Shares in respect of return of capital on dissolution, to share ratably, together with the holders of shares of any other class of our shares ranking equally with the Common Shares in respect of return of capital on dissolution, in such of our assets as are available for distribution.

Dividend Policy

Our dividend policy is to pay a monthly dividend on our Common Shares on or about the 15th day following the end of each calendar month to Shareholders of record on or about the last business day of each such calendar month. Our dividend policy follows the general corporate philosophy of financial self sufficiency whereby, over the long term, development capital expenditures and dividend payments are planned to be financed from internally generated funds from operations. Unless otherwise indicated, all dividends paid or to be paid on our Common Shares are designated as "eligible dividends" for Canadian income tax purposes.

The amount of future cash dividends, if any, will be subject to the discretion of the Board of Directors and may vary depending on a variety of factors and conditions existing from time to time, including fluctuations in commodity prices, production levels, capital expenditure requirements, debt service requirements, operating costs, royalty burdens, foreign exchange rates, the satisfaction of the liquidity and solvency tests imposed by the ABCA for the declaration and payment of dividends and other factors beyond our control. Pursuant to the ABCA, after the payment of a dividend, we must be able to pay our liabilities as they become due and the realizable value of our assets must be greater than our liabilities and the legal stated capital of our outstanding securities. As at September 30, 2013, our stated capital was approximately $2 billion. Cash dividends to Shareholders are not assured or guaranteed and there can be no guarantee that we will maintain our dividend policy. See *"Dividends to Shareholders"* and *"Risk Factors"*.

The agreement governing the Credit Facilities, the New Credit Facilities and the Debenture Indenture restrict or will restrict our ability to pay cash dividends in certain circumstances and contain certain limitations on maximum cumulative dividends. See *"Dividends to Shareholders",* "*Consolidated Capitalization*" and "*Recent Developments New Credit Facilities*".

CONSOLIDATED CAPITALIZATION

The following table sets forth, as at September 30, 2013, our pro forma consolidated capitalization: (i) before giving effect to the Offering and Acquisition; (ii) after giving effect to the Offering and Acquisition (assuming the Over-allotment Option is not exercised); and (iii) after giving effect to the Offering and Acquisition (assuming the Over-allotment Option is exercised in full). There have been no material changes in our share and loan capital, on a consolidated basis, since September 30, 2013.

(amounts in $000s, except where noted)	As at September 30, 2013 before giving effect to the Offering and the Acquisition	As at September 30, 2013 after giving effect to the Offering and the Acquisition[1]	As at September 30, 2013 after giving effect to the Offering, the Acquisition and the Over-allotment Option[1]
Debt:			
Credit Facilities[2]	$244,651	$	
New Credit Facilities[1][3][4]			$
2021 Debentures[5]	U.S.$150,000	U.S.$150,000	U.S.$150,000
2022 Debentures[5]	$300,000	$300,000	$300,000
2017 Aurora Notes[5][6]		U.S.$365,000	U.S.$365,000
2020 Aurora Notes[6]		U.S.$300,000	U.S.$300,000
Shareholders' Capital:			
Common Shares (unlimited)[7]	$1,969,018 (124,497,000 Common Shares)	$ (Common Shares)	$ (Common Shares)
Preferred Shares (10,000,000)			

Notes:

(1) Based on the issuance of Underlying Common Shares pursuant to the exchange of Subscription Receipts for aggregate proceeds of $ less Underwriters' Fees of $ and expenses of the Offering estimated to be $3 million (exclusive of GST). If the Over-allotment Option is exercised in full, the aggregate gross proceeds, Underwriters' Fees, estimated expenses of the Offering and net proceeds will be $, $, $ and $, respectively. The aggregate net proceeds of the Offering will be used to finance a portion of the Acquisition with the balance of the Acquisition to be funded by cash on hand and advances under the New Credit Facilities. We will assume the Aurora Notes at closing. See "*Recent Developments The Acquisition*", "*About Aurora*", "*Use of Proceeds*" and "*Details of the Offering*" in this short form prospectus. See also the pro forma financial information in respect of us after giving effect to the Acquisition set forth in Schedule "B" "*Pro Forma Consolidated Financial Statements of Baytex*".

(2) As at September 30, 2013, Baytex Energy had a $40 million extendible operating loan facility with a chartered bank and a $810 million extendible syndicated loan facility with a syndicate of chartered banks, which is extendible annually for a one, two, three or four year period (subject to a maximum four-year term at any time) (the "**Credit Facilities**"). On June 4, 2013, the maturity date of the Credit Facilities was extended to June 14, 2017. The Credit Facilities contain standard commercial covenants for facilities of this nature. The Credit Facilities do not require any mandatory principal payments during the four-year term. Advances (including letters of credit) under the Credit Facilities can be drawn in either Canadian or U.S. funds and bear interest at the agent bank's prime lending rate, bankers' acceptance discount rates or London Interbank Offered Rates, plus applicable margins. The Credit Facilities are secured by a floating charge over all of Baytex Energy's assets and are guaranteed by us and certain material restricted subsidiaries. The Credit Facilities do not include a term-out feature or a borrowing base restriction. The Credit Facilities contain restrictions on Baytex Energy's ability to make distributions to us, including the declaration or payment of any dividend or distribution to us as the holder of the capital stock of Baytex Energy and the payment of interest or principal on subordinated debt owed to us. Baytex Energy and its subsidiaries are restricted from making distributions to us when (i) a default or event of default under the Credit Facilities has occurred and is continuing, or (ii) distributions would be reasonably expected to have a material adverse effect on or impair the ability of Baytex Energy to fulfill its financial obligations to its lenders under the Credit Facilities. Baytex Energy is in compliance in all material respects with the terms of the agreements governing the Credit Facilities.

(3)

In connection with the Acquisition, we have entered into an agreement with a Canadian chartered bank for new senior secured credit facilities in the aggregate principal amount of $2.5 billion which will replace our Credit Facilities. See "*Recent Developments New Credit Facilities*".

(4) Does not include working capital deficit of $57.7 million as at September 30, 2013.

(5) The 2021 Debentures were issued on February 17, 2011, bear interest at a rate of 6.75% and mature on February 17, 2021. The 2022 Debentures were issued on July 19, 2012, bear interest at a rate of 6.625% and mature on July 19, 2022. For information regarding the

2021 Debentures and 2022 Debentures, see the Annual Information Form and note 11 to the Annual Financial Statements, which are incorporated by reference herein.

(6) The 2017 Aurora Notes were issued on February 8, 2012 and the 2020 Aurora Notes were issued on March 21, 2013. Subject to Aurora's obligation to make a Change of Control Offer to the holders of the Aurora Notes as described under "*Recent Developments The Acquisition Acquisition Consideration*", the Aurora Notes will remain outstanding in accordance with their terms following completion of the Acquisition.

(7) As at September 30, 2013, we had 1,022,000 rights to acquire Common Shares (issued pursuant to our Common Share Rights Incentive Plan) outstanding. In addition, as at September 30, 2013, we had 733,000 restricted awards and 597,000 performance awards (granted pursuant to our Share Award Incentive Plan) outstanding.

DETAILS OF THE OFFERING

Subscription Receipts

The Offering consists of Subscription Receipts at a price of $ per Subscription Receipts. Each Subscription Receipt will entitle the holder thereof to receive without payment of additional consideration or further action on the part of such holder, one Common Share.

The following is a summary of the material attributes and characteristics of the Subscription Receipts. This summary does not purport to be complete and is subject to, and qualified in its entirety by, reference to the terms of the Subscription Receipt Agreement, which, following the Closing Date, will be available for inspection at our offices and will be filed on SEDAR at www.sedar.com and EDGAR at www.sec.gov.

The Escrowed Funds will be held by the Escrow Agent, and invested in short-term obligations of, or guaranteed by, the Government of Canada (or other approved investments) pending delivery by us to the Underwriters of a certificate on the third Business Day prior to the anticipated Effective Date to the effect that the Final Order has been filed with the ASIC and all other material conditions (other than payment of the purchase price) necessary to complete the Acquisition have been satisfied (the "**Escrow Condition**"). Upon satisfaction of the Escrow Condition on or before 5:00 p.m. (Calgary time) on June 30, 2014 (the "**Termination Time**"), the Escrowed Funds and the interest earned thereon (less any amounts required to pay the Dividend Equivalent Amount upon the issuance of the Underlying Common Shares, if applicable) will be released to us to enable us to convert these funds to Australian dollars and complete the Acquisition. Upon the closing of the Acquisition, each holder of Subscription Receipts will receive one Underlying Common Share for each Subscription Receipt held, without payment of additional consideration or further action on the part of such holder, and such holder will also be entitled to receive an amount per Subscription Receipt equal to the Dividend Equivalent Amount, being an amount per Subscription Receipt equal to the amount per Common Share of any cash dividends for which record date(s) have occurred during the period commencing on the closing of the Offering to the date immediately preceding the date the Underlying Common Shares are issued pursuant to the Subscription Receipts. All or a portion of the Dividend Equivalent Amount will be satisfied by the payment by the Escrow Agent to holders of Subscription Receipts of interest earned on the Escrowed Funds. The difference, if any, between the amount of interest earned on the Escrowed Funds and the Dividend Equivalent Amount will be paid by us as a partial refund of the subscription price of the Subscription Receipts. If holders of Subscription Receipts become entitled to receive Underlying Common Shares, we and the Escrow Agent will pay such amounts to holders on the later of the date the Underlying Common Shares are issued and the date such dividend(s) is paid to holders of Common Shares. See "*Certain Canadian Federal Income Tax Considerations*" and "*Certain United States Federal Income Tax Considerations*".

We will utilize the Escrowed Funds, together with funds available under the New Credit Facilities, to pay for Aurora Shares pursuant to the Acquisition. See "*Recent Developments The Acquisition*", "*About Aurora*" and "*Use of Proceeds*".

If the Acquisition is not completed by the Termination Time, or if we advise the Underwriters or announce to the public that we do not intend to proceed with the Acquisition, or if the Implementation Agreement has been terminated in accordance with its terms, holders of Subscription Receipts shall receive an amount equal to the full subscription price attributable to the Subscription Receipts and their *pro rata* entitlement to interest accrued on such amount up to and including the date of the Termination Time. In such event, the issuance of a cheque in payment of the subscription price for the Subscription Receipts and *pro rata* interest, if any, will require the surrender of the certificate(s), by the holder thereof, presenting the same at the principal office of the Escrow Agent in Calgary, Alberta. If any certificates representing Subscription Receipts have not been surrendered one year after the Termination Time, the Escrow Agent will mail the cheques that the holders thereof are entitled to receive to their last addresses of record.

Upon satisfaction of the Escrow Condition and the issuance of the Underlying Common Shares, we will issue a press release specifying that the Underlying Common Shares have been issued.

We have granted to the Underwriters the Over-allotment Option to purchase up to an additional Subscription Receipts at a price of $ per Subscription Receipt on the same terms and conditions as the Offering, exercisable from time to time, in whole or in part, for a period commencing at closing of the Offering and ending on the earlier of: (i) 30 days following closing of the Offering; and (ii) the Termination Time, to cover over-allotments, if any, and for market stabilization purposes.

Under the Subscription Receipt Agreement, original purchasers of Subscription Receipts under the Offering will have a contractual right of rescission against us both prior to and following the issuance of Underlying Common Shares to such purchaser upon the exchange of the Subscription Receipts to receive the amount paid for the Subscription Receipts if this short form prospectus (including the documents incorporated by reference herein) and any amendment contains a misrepresentation or is not delivered to such purchaser, provided such remedy for rescission is exercised within 180 days of closing of the Offering.

Holders of Subscription Receipts are not Shareholders. Holders of Subscription Receipts are entitled only to receive Underlying Common Shares on surrender of their Subscription Receipts to the Escrow Agent or to a return of the subscription price for the Subscription Receipts together with any payments of interest as described above.

The Subscription Receipts will be issued in "book-entry only" form and must be purchased or transferred through a Participant. See "*Details of the Offering Book-Entry Only System*".

In the event that, prior to the date the Underlying Common Shares become issuable pursuant to the Subscription Receipts, there is a subdivision, consolidation, reclassification or other change of the Common Shares or any reorganization, amalgamation, merger or sale of all or substantially all of our assets, the Subscription Receipts will thereafter evidence the right of the holder to receive the securities, property or cash deliverable in exchange for or on conversion of or in respect of the Underlying Common Shares to which the holder of a Subscription Receipt would have been entitled immediately after such event if it had been a holder of such Underlying Common Shares prior to such event. Similarly, any distribution to all or substantially all of the holders of Common Shares of rights, options, warrants, evidences of indebtedness or assets will result in an adjustment in the number of Underlying Common Shares to be issued to holders of Subscription Receipts. Alternatively, such securities, evidences of indebtedness or assets may, at our option, be issued to the Escrow Agent and delivered to holders of Subscription Receipts following the closing of the Acquisition.

The Subscription Receipt Agreement will provide for modifications and alterations thereto and to the Subscription Receipts issued thereunder by way of an extraordinary resolution. The term "extraordinary resolution" will be defined in the Subscription Receipt Agreement to mean, in effect, a resolution passed by the affirmative votes of the holders of not less than $66^2/_3\%$ of the number of outstanding Subscription Receipts represented and voted at a meeting of holders or an instrument or instruments in writing signed by the holders of not less than $66^2/_3\%$ of the number of outstanding Subscription Receipts.

Book-Entry Only System

The Subscription Receipts will be issued in "book-entry only" form and must be purchased or transferred through a Participant.

Except as otherwise provided herein, on the Closing Date, the Subscription Receipts will be registered and represented electronically through CDS, and will be deposited with CDS pursuant to the book-entry only system. Unless the book-entry only system is terminated as described below, a Subscription Receipt Beneficial Owner will not be entitled to receive a certificate for Subscription Receipts, or, unless requested, for the Underlying

Common Shares. Purchasers of Subscription Receipts will not be shown on the records maintained by CDS, except through a Participant.

Beneficial interests in Subscription Receipts will be represented solely through the book-entry only system and such interests will be evidenced by customer confirmations of purchase from the registered dealer from which the Subscription Receipts are purchased in accordance with the practices and procedures of that registered dealer. In addition, registration of interests in and transfers of the Subscription Receipts will be made only through the depository service of CDS.

As indirect holders of Subscription Receipts, investors should be aware that they (subject to the situations described below): (a) may not have Subscription Receipts registered in their name; (b) may not have physical certificates representing their interest in the Subscription Receipts; (c) may not be able to sell the Subscription Receipts to institutions required by law to hold physical certificates for securities they own; and (d) may be unable to pledge Subscription Receipts as security.

The Subscription Receipts will be issued to beneficial owners thereof in fully registered and certificate form (the "**Subscription Receipt Certificates**") only if: (a) required to do so by applicable law; (b) the book-entry only system ceases to exist; (c) we or CDS advises the Escrow Agent that CDS is no longer willing or able to properly discharge its responsibilities as depository with respect to the Subscription Receipts and we are unable to locate a qualified successor; or (d) we, at our option, decide to terminate the book-entry only system through CDS.

Upon the occurrence of any of the events described in the immediately preceding paragraph, the Escrow Agent must notify CDS, for and on behalf of Participants and Subscription Receipt Beneficial Owners of the availability through CDS of Subscription Receipt Certificates. Upon surrender by CDS of the global certificates representing the Subscription Receipts and receipt of instructions from CDS for the new registrations, the Escrow Agent will deliver the Subscription Receipts in the form of Subscription Receipt Certificates and thereafter we will recognize the holders of such Subscription Receipt Certificates as Subscription Receipt holders under the Subscription Receipt Agreement.

Neither we nor the Underwriters will assume any liability for: (a) any aspect of the records relating to the beneficial ownership of the Subscription Receipts held by CDS or any payments relating thereto; (b) maintaining, supervising or reviewing any records relating to the Subscription Receipts; or (c) any advice or representation made by or with respect to CDS and contained in this short form prospectus and relating to the rules governing CDS or any action to be taken by CDS or at the direction of a Participant. The rules governing CDS provide that it acts as the agent and depository for the Participants. As a result, Participants must look solely to CDS and Subscription Receipt Beneficial Owners must look solely to Participants for any payments relating to the Subscription Receipts paid by or on behalf of us to CDS.

PLAN OF DISTRIBUTION

Pursuant to the terms and conditions of the Underwriting Agreement among us and each of the Underwriters, we have agreed to sell and the Underwriters have severally agreed to purchase on the Closing Date, an aggregate of Subscription Receipts at a price of $ per Subscription Receipt payable in cash to us against delivery of such Subscription Receipts, subject to compliance with all necessary legal requirements and terms and conditions of the Underwriting Agreement. The Underwriting Agreement provides that we will pay the Underwriters' Fee of 4.0% of the gross proceeds of the Offering, or $ per Subscription Receipt. The Underwriters' Fee in respect of the Subscription Receipts is payable as to 50% upon the closing of the Offering and 50% on the closing of the Acquisition. If the Acquisition is not completed by the Termination Time, the Underwriters' Fee will be reduced to the amount payable upon closing of the Offering. The offering price of the Subscription Receipts was determined by negotiation between us and Scotia on behalf of itself and on behalf of the other Underwriters.

We have granted to the Underwriters the Over-allotment Option to purchase up to an additional Subscription Receipts at a price of $ per Subscription Receipt on the same terms and conditions as the Offering, exercisable from time to time, in whole or in part, for a period commencing at closing of the Offering and ending at 5:00 p.m. (Calgary time) on the earlier of: (i) 30 days following closing of the Offering; and (ii) the Termination Time, to cover over-allotments, if any, and for market stabilization purposes. A purchaser who acquires Subscription Receipts forming part of the Underwriters' over-allocation position acquires those Subscription Receipts under this short form prospectus, regardless of whether the over-allocation position is ultimately filled through the exercise of the Over-allotment Option or secondary market purchases. If the Over-allotment Option is exercised in full, the total Offering, the Underwriters' Fee and the net proceeds to us (before deducting expenses of the Offering) will be $, $ and $, respectively. This short form prospectus also qualifies the distribution of the Subscription Receipts issuable upon exercise of the Over-allotment Option.

The obligations of the Underwriters, under the Underwriting Agreement, are several, and not joint and several, and may be terminated on the occurrence of certain stated events, including, in the event that at or prior to closing of the Offering: (i) any order to cease or suspend trading in any of our securities, prohibiting or restricting the distribution of any of the Subscription Receipts or Underlying Common Shares, suspending the effectiveness of the registration statement filed by us with the SEC or preventing or suspending the use of any prospectus relating to the Subscription Receipts or Underlying Common Shares has been issued or made, or proceedings are announced, commenced or threatened for the making of any such order, by any securities commission or similar regulatory authority, the TSX, the NYSE or any other competent authority, and such order or proceeding has not been rescinded, revoked or withdrawn or such announced, commenced or threatened proceeding has not been terminated or withdrawn; (ii) any inquiry, action, suit, investigation or other proceeding (whether formal or informal) in relation to us or any of our directors or senior officers is announced, commenced or threatened by any federal, provincial, state, municipal, other governmental agency or by any securities commission or similar regulatory authority, the TSX, the NYSE or any other competent authority, or there is a change in law, regulation or policy or the interpretation or administration thereof, if, in the sole opinion of the Underwriters, or any one of them, acting reasonably, the change, announcement, commencement or threatening thereof, as the case may be adversely effects the distribution or trading of the Subscription Receipts and Underlying Common Shares; (iii) there should develop, occur or come into effect or existence any event, action, state, condition or major financial occurrence of national or international consequence, including, without limitation, any military conflict, civil insurrection, act of terrorism, war or like event, or a governmental action, law, regulation, inquiry or any occurrence of any nature whatsoever, which, in the sole opinion of the Underwriters, or any one of them, acting reasonably, seriously adversely affects or involves, or will seriously adversely affect or involve, the financial markets generally or our business, operations or affairs on a standalone basis or on a consolidated basis after giving effect to the Acquisition; (iv) there should occur any material adverse change or development in our operations, capital or condition (financial or otherwise), business on a standalone basis or on a consolidated basis after giving effect to the Acquisition or our properties, assets, prospects, liabilities or obligations (absolute, accrued, contingent or otherwise) on a standalone basis or on a consolidated basis after giving effect to the Acquisition which, in the sole opinion of the Underwriters, or any one of them, acting reasonably, has or could reasonably be expected to have a material adverse effect on the market price, value or marketability of the Subscription Receipts and Underlying Common Shares; (v) we are in breach of, default under or non-compliance with any covenant, term or condition of the Underwriting Agreement in any material respect, or any representation or warranty given by us in the Underwriting Agreement becomes or is false in any material respect; (vi) the Underwriters shall become aware of any material information with respect to us or the Acquisition which had not been publicly disclosed or disclosed in writing to the Underwriters prior to the date of the Underwriting Agreement which, in the sole opinion of the Underwriters or any one of them, acting reasonably, could be expected to have a material adverse effect on the market price or value of the Subscription Receipts, the Common Shares or any other of our securities; (vii) a general moratorium on commercial banking activities is declared by either United States federal, New York or state authorities or a material disruption in commercial banking or securities settlement or clearance services in Canada or in the United States occurs; (viii) the Implementation Agreement is terminated and not replaced by an amendment or restatement of such on substantially the same terms and satisfactory in form and containing terms and conditions acceptable to the Underwriters, acting reasonably, or we otherwise notify the Underwriters that the Acquisition will not occur; or (ix) the Termination Time has occurred.

In addition, the obligations of us and the Underwriters under the Underwriting Agreement to complete the purchase and sale of the Subscription Receipts will terminate automatically if the Acquisition is not completed by June 30, 2014, or if we advise the Underwriters or announce to the public that we do not intend to proceed with the Acquisition, or if the Implementation Agreement has been terminated in accordance with its terms. See "*Details of the Offering*". The closing of the Offering is conditional upon the Underwriters being advised by the Financial Industry Regulatory Authority that it has no objection to the proposed underwriting terms and arrangements among us and the Underwriters, as set forth in the Underwriting Agreement.

Under the Underwriting Agreement, we shall not be obliged to sell to the Underwriters, nor shall the Underwriters be obliged to purchase, less than all of the Subscription Receipts that the Underwriters have agreed to purchase. In certain circumstances, if an Underwriter fails to purchase the Subscription Receipts which it has agreed to purchase, the other Underwriters may, but are not obligated to, purchase such Subscription Receipts unless the number of Subscription Receipts which one or more of the Underwriters agreed but failed or refused to purchase is more than 5% of the total number of Subscription Receipts being offered, in which case the remaining Underwriters are obligated to purchase such Subscription Receipts on a pro-rata basis. The Underwriters are, however, obligated to take up and pay for all Subscription Receipts if any Subscription Receipts are purchased under the Underwriting Agreement.

We have agreed to indemnify each of the Underwriters and their respective affiliates and their respective directors, officers, employees, shareholders, agents and each person who controls the Underwriters within the meaning of Section 15 of the 1933 Act or Section 20 of the Exchange Act against certain liabilities, including liabilities under the U.S. securities laws and Canadian securities laws or to contribute to payments the Underwriters may be required to make because of any of these liabilities.

Subject to applicable laws, the Underwriters may, in connection with the Offering, effect transactions which stabilize or maintain the market price of the Common Shares at levels other than those that might otherwise prevail on the open market in accordance with applicable market stabilization rules. Such transactions, if commenced, may be discontinued at any time.

The public offering price for the Subscription Receipts offered in Canada and in the United States is payable in Canadian dollars only. The Underwriters propose to offer the Subscription Receipts initially at the offering price specified herein. After a reasonable effort has been made to sell all of the Subscription Receipts at the price specified, the Underwriters may subsequently reduce the selling price to investors from time to time in order to sell any of the Subscription Receipts remaining unsold. In the event the offering price of the Subscription Receipts is reduced, the compensation received by the Underwriters will be decreased by the amount the aggregate price paid by the purchasers for the Subscription Receipts is less than the gross proceeds paid by the Underwriters to us for the Subscription Receipts. Any such reduction will not affect the proceeds received by us.

Other than the Underlying Common Shares and in connection with the Acquisition, we have agreed not to directly or indirectly issue any Common Shares or securities or other financial instruments convertible into or having the right to acquire Common Shares (other than for purposes of issuing Common Shares pursuant to our dividend reinvestment plan, Share Award Incentive Plan and Common Share Rights Incentive Plan) or enter into any agreement or arrangement under which we acquire or transfer to another, in whole or in part, any of the economic consequences of ownership of Common Shares, whether that agreement or arrangement may be settled by the delivery of Common Shares or other securities or cash, or agree to become bound to do so, or disclose to the public any intention to do so, prior to 90 days after the Closing Date without the prior written consent of Scotia, on behalf of the Underwriters, which consent will not be unreasonably withheld or delayed.

There is currently no market through which the Subscription Receipts may be sold and purchasers may not be able to resell the Subscription Receipts purchased under this short form prospectus.

Subscriptions for Subscription Receipts will be received subject to rejection or allotment in whole or in part and the right is reserved to close the subscription books at any time without notice. The Closing Date is anticipated to occur on or about February 24, 2014 or such other date as may be agreed upon by us and the Underwriters, but in any event not later than March 28, 2014.

This Offering is being made concurrently in all of the provinces of Canada and in the United States pursuant to the multi-jurisdictional disclosure system implemented by the securities regulatory authorities in Canada and the United States. The Subscription Receipts will be offered in the United States and/or Canada through the Underwriters either directly or, if applicable, through their respective U.S. or Canadian registered broker-dealer affiliates.

Certain Underwriters and their affiliates have performed, and may in the future perform, various underwriting, financial advisory, investment banking, commercial lending and other services in the ordinary course of business with us and our affiliates, for which they receive or will receive customary compensation. See "*Relationship between Us and Certain Underwriters*".

RELATIONSHIP BETWEEN US AND CERTAIN UNDERWRITERS

Scotia is a wholly-owned subsidiary of a Canadian chartered bank which has agreed to fully underwrite and commit to provide us with the New Credit Facilities which will replace the Credit Facilities in connection with the Acquisition. See "*Recent Developments New Credit Facilities*" for a description of the New Credit Facilities. Each of Scotia and RBC Dominion Securities Inc. are wholly-owned subsidiaries of Canadian chartered banks (the "**Lenders**"), which are lenders to our subsidiary, Baytex Energy pursuant to the Credit Facilities, and to which Baytex Energy is indebted pursuant to the Credit Facilities. See Note 2 under the heading "*Consolidated Capitalization*" for a description of the Credit Facilities. In addition, Scotia acted as our financial advisor in connection with the Acquisition. Consequently, we may be considered to be a connected issuer of such Underwriters for the purposes of securities regulations in certain provinces.

As at September 30, 2013, an aggregate of approximately $244.7 million was outstanding under our Credit Facilities. We are in compliance with the Credit Facilities and the Lenders have not waived a breach of the Credit Facilities since they were executed. Our financial position has not substantially changed since the indebtedness under the Credit Facilities was incurred. We may be considered to be a "connected issuer" of each of these Underwriters for the purposes of securities regulations in certain provinces. The net proceeds received pursuant to this Offering will not be used to reduce our indebtedness.

The decision to offer the Subscription Receipts and the determination of the terms of the Offering were made through negotiations between us and Scotia, on behalf of the Underwriters. The Lenders did not have any involvement in such decision or determination; however, the Lenders have been advised of the Offering and the terms thereof. As a consequence of the Offering, each of the Underwriters will receive its share of the Underwriters' Fee payable by us to the Underwriters. See "*Use of Proceeds*".

We have agreed to retain a Canadian chartered bank (or one or more of its affiliates as may be appropriate in the circumstances), of which Scotia is a wholly-owned subsidiary, to act as manager in connection with the Change of Control Offers required to be made by us to the holders of the Aurora Notes following completion of the Acquisition as described under "***Recent Developments The Acquisition Acquisition Consideration" at prevailing market rates for a person acting in such a role.***

PRIOR SALES

The following is a description of prior sales of Common Shares and securities convertible into Common Shares during the twelve-month period ended January 31, 2014:

(a) 2,205,000 Common Shares were issued pursuant to the our Dividend Reinvestment Plan for aggregate consideration of approximately $89,366,000;

(b) 537,000 Common Shares were issued pursuant to outstanding awards granted under the Share Award Incentive Plan;

(c) 718,000 Common Shares were issued pursuant to outstanding rights granted under the Common Share Rights Incentive Plan for aggregate consideration of approximately $9,605,000; and

(d) 892,000 share awards were granted under the Share Award Incentive Plan.

MARKET FOR SECURITIES

The Common Shares are listed and posted for trading on the TSX and the NYSE under the trading symbol "BTE". The Common Shares commenced trading on the TSX on January 6, 2011 and on the NYSE on January 3, 2011. The following table sets forth certain trading information for the Common Shares in Canada and the United States for the periods indicated.

	Canada Composite Trading			United States Composite Trading		
	Price Range			Price Range		
	High ($)	Low ($)	Volume Traded	High ($US)	Low ($US)	Volume Traded
2013						
January	47.04	43.17	11,685,057	47.09	43.79	2,949,901
February	47.61	42.22	13,235,046	47.47	41.04	3,233,303
March	45.38	42.00	14,229,551	44.21	41.10	3,474,977
April	43.05	36.37	17,625,019	42.50	35.42	4,994,797
May	41.60	37.75	16,525,672	41.47	37.04	5,052,109
June	39.51	36.56	10,374,749	38.22	34.71	3,190,546
July	44.44	37.65	16,395,772	43.08	35.70	3,634,313
August	43.49	40.29	9,083,228	42.12	38.55	3,530,714
September	43.44	40.76	9,125,099	42.20	39.18	3,169,676
October	44.74	40.82	13,112,997	42.84	39.26	2,807,133
November	43.75	41.19	11,651,629	41.84	39.25	4,840,744
December	42.73	40.21	11,807,054	40.16	37.76	3,056,178
2014						
January	42.50	39.18	13,653,728	39.42	35.51	4,269,728
February (to 5)	41.23	39.83	1,910,902	37.20	35.99	634,431

On February 5, 2014, the last trading day prior to the date of this short form prospectus, the closing price of the Common Shares was $41.16 on the TSX and U.S.$37.16 on the NYSE (as reported by such stock exchanges).

DIVIDENDS TO SHAREHOLDERS

Our dividend policy is to pay a monthly dividend on our Common Shares on or about the 15th day following the end of each calendar month to Shareholders of record on or about the last business day of each such calendar month. See *"Description of Common Shares Dividend Policy"*.

Since we commenced operations on January 1, 2011, the following per Common Share dividends have been paid by us for the months indicated.

	Dividends per Common Share ($)			
Month	**2014**	**2013**	**2012**	**2011**
January	0.22	0.22	0.22	0.20
February		0.22	0.22	0.20
March		0.22	0.22	0.20
April		0.22	0.22	0.20
May		0.22	0.22	0.20
June		0.22	0.22	0.20
July		0.22	0.22	0.20
August		0.22	0.22	0.20
September		0.22	0.22	0.20
October		0.22	0.22	0.20
November		0.22	0.22	0.20
December		0.22	0.22	0.20
Total	$ 0.22	$ 2.64	$ 2.64	$ 2.40

In connection with the Acquisition, we intend increase the monthly dividend on our Common Shares by 9% to $0.24 from $0.22 per Common Share, subject to the completion of the Acquisition. See "*Recent Developments Dividend Increase*".

Pursuant to the Credit Facilities, we are restricted from paying dividends to Shareholders if a default or event of default has occurred and is continuing and, if no default or event of default has occurred which is continuing, where the dividend would or would reasonably be expected to have a material adverse effect on us or on our or our subsidiaries' ability to fulfill their obligations under the Credit Facilities or under any hedge agreements with lenders (or their affiliates) under the Credit Facilities. The New Credit Facilities will also contain restrictions on our ability to pay dividends. See "*Recent Developments New Credit Facilities*" for a description of the New Credit Facilities.

The Debenture Indenture also contains certain limitations on maximum cumulative dividends. Restricted payments include the declaration or payment of any dividend or distribution by us and the payment of interest or principal on subordinated debt owed by us. We and certain of our subsidiaries are restricted from making any restricted payments unless at the time of, and immediately after giving effect to, the proposed restricted payment, no default or event of default under the Debenture Indenture has occurred and is continuing, and either: (i) (a) we could incur at least $1.00 of additional indebtedness (other than certain permitted debt) in accordance with the "Limitation on Incurrence of Indebtedness and Issuance of Disqualified Stock" covenant in the Debenture Indenture; (b) the ratio of consolidated debt to consolidated cash flow from operations does not exceed 3.0 to 1.0; and (c) the aggregate amount of all restricted payments declared or made after August 26, 2009 (other than certain permitted restricted payments) does not exceed the sum of: (A) 80% of consolidated cash flow from operations accrued on a cumulative basis since August 26, 2009, plus (B) 100% of the aggregate net cash proceeds received by us after August 26, 2009 from (x) the issuance by us of convertible debentures, or (y) capital contributions in respect of certain permitted equity that we receive from any person; plus (C) the aggregate net proceeds, including the fair market value of property received after August 26, 2009 other than cash (as determined by the Board of Directors), received by us from any person, other than a subsidiary, from the issuance or sale of debt securities (including convertible debentures) or disqualified stock that have been converted into or exchanged for certain permitted equity of us, plus the aggregate net cash proceeds received by us at the time of such conversion or exchange; or (ii) the aggregate amount of all restricted payments declared or made pursuant to paragraph (i) does not exceed the sum of certain unpaid funds from restricted payments not previously expended under paragraph (i), plus $50,000,000. As at the date of this short form prospectus, we are in compliance with these covenants.

Cash dividends are not guaranteed. Our historical cash dividends may not be reflective of future cash dividends, which will be subject to review by the Board of Directors taking into account our prevailing financial circumstances at the relevant time. Although we intend to pay dividends to Shareholders, these cash dividends may be reduced or suspended. The actual amount distributed will depend on numerous factors, including fluctuations in commodity prices, production levels, capital expenditure requirements, debt service requirements, operating costs, royalty burdens, foreign exchange rates, the satisfaction of the liquidity and solvency tests imposed by the ABCA for the declaration and payment of dividends and other factors beyond our control. See *"Risk Factors"*.

As described above under "*Details of the Offering Subscription Receipts*", if the Acquisition is completed prior to the Termination Time, the holder of a Subscription Receipt, in addition to receiving a Common Share in exchange therefore, will be entitled to receive the Dividend Equivalent Amount which will be paid by way of a *pro rata* share of accrued interest on the Escrowed Funds. The difference, if any, between the amount of interest earned on the Escrowed Funds and the Dividend Equivalent Amount will be paid by us as a partial refund of the subscription price of the Subscription Receipts.

CERTAIN CANADIAN FEDERAL INCOME TAX CONSIDERATIONS

Prospective investors should be aware that the purchase of Subscription Receipts has tax consequences, which are not described in this short form prospectus. Accordingly, prospective investors are advised to consult their own tax advisors with respect to the tax aspects of investing in, holding and disposing of the Subscription Receipts and the Underlying Common Shares.

In the opinion of Burnet, Duckworth & Palmer LLP, counsel to the Corporation, and McCarthy Tétrault LLP, counsel to the Underwriters (collectively, "**Counsel**"), the following is a fair and adequate summary of the principal Canadian federal income tax considerations pursuant to the Tax Act generally applicable to a subscriber who acquires the Subscription Receipts pursuant to the Offering and who, for purposes of the Tax Act, holds the Subscription Receipts and will hold the Underlying Common Shares (collectively, the "**Securities**") as capital property and deals at arm's length with, and is not affiliated with us and the Underwriters. Generally, the Securities will be considered to be capital property to a holder provided the holder does not hold the Securities in the course of carrying on a business of trading or dealing in securities and has not acquired them in one or more transactions considered to be an adventure in the nature of trade. Certain holders resident in Canada who might not otherwise be considered to hold their Underlying Common Shares as capital property may, in certain circumstances, be entitled to have their Underlying Common Shares and every other "Canadian security" as defined in the Tax Act treated as capital property by making the irrevocable election permitted by subsection 39(4) of the Tax Act. This election is not available in respect of the Subscription Receipts.

This summary is not applicable to: (i) a holder that is a "financial institution", as defined in the Tax Act for purposes of the mark-to-market rules; (ii) a holder an interest in which would be a "tax shelter investment" as defined in the Tax Act; (iii) a holder that is a "specified financial institution" as defined in the Tax Act; (iv) a holder whose functional currency for the purposes of the Tax Act is the currency of a country other than Canada; or (v) that has or will enter into a "derivative forward agreement" as defined in the Tax Act, in respect of the Subscription Receipts or Underlying Common Shares. **Any such holder should consult its own tax advisor with respect to an investment in the Securities.**

This summary is based upon the provisions of the Tax Act in force as of the date hereof and Counsel's understanding of the current published administrative and assessing practices of the Canada Revenue Agency ("**CRA**"). Except for specifically proposed amendments (the "**Proposed Amendments**") to the Tax Act that have been publicly announced by the federal Minister of Finance prior to the date hereof, this summary does not take into account or anticipate changes in the income tax law, whether by legislative, governmental or judicial action, nor any changes in the administrative or assessing practices of the CRA. This summary does not take into account or anticipate provincial, territorial or foreign tax considerations, which may differ significantly from those discussed herein.

This summary is of a general nature only and is not intended to be, nor should it be construed to be, legal or tax advice to any prospective purchaser or holder of Securities, and no representations with respect to the income tax consequences to any prospective purchaser or holder are made. Consequently, prospective holders of Securities should consult their own tax advisors with respect to their particular circumstances.

Holders Resident in Canada

The following portion of the summary is applicable to a holder of Subscription Receipts who, for purposes of the Tax Act, is resident in Canada (a "**Resident Holder**").

Acquisition of Common Shares Pursuant to Terms of the Subscription Receipts

A Resident Holder will not realize a capital gain or loss on the issuance of an Underlying Common Share pursuant to a Subscription Receipt.

The cost of any such Underlying Common Shares will generally be equal to the amount paid by such Resident Holder to acquire the Subscription Receipt. However, such cost may be reduced by a portion of the Dividend Equivalent Amount, if any is received. See "*Holders Resident in Canada   Dividend Equivalent Amount*". The cost of Underlying Common Shares received will generally be averaged with the cost of all other Common Shares held by the Resident Holder as capital property to determine the adjusted cost base of each Common Share held by the Resident Holder.

Other Dispositions of Subscription Receipts

A disposition or deemed disposition by a Resident Holder of Subscription Receipts, other than on the exchange thereof for an Underlying Common Share, but including on the repayment of the issue price thereof by us in the event the Acquisition is not completed before the Termination Time, will generally result in the Resident Holder realizing a capital gain (or capital loss) equal to the amount, if any, by which the proceeds of disposition are greater (or less) than the aggregate of the Resident Holder's adjusted cost base thereof and any reasonable costs of disposition. The cost to a Resident Holder of a Subscription Receipt will generally be the amount paid to acquire the Subscription Receipt. Such capital gain (or capital loss) will be subject to the tax treatment described below under "*Holders Resident in Canada   Taxation of Capital Gains and Capital Losses*".

In the event that a Resident Holder becomes entitled to the repayment of the issue price of a Subscription Receipt, any amount that is paid to the holder as, or on account of, interest and that is included in the Resident Holder's income, will be excluded from the holder's proceeds of disposition.

Pro Rata Share of Interest

If the Acquisition is not completed by the Termination Time or if we advise the Underwriters or announce to the public that we do not intend to proceed with the Acquisition, or if the Implementation Agreement has been terminated in accordance with its terms, holders of Subscription Receipts shall be entitled to receive from the Escrow Agent an amount equal to the full subscription price thereof plus their *pro rata* share of interest accrued on the Escrowed Funds.

A Resident Holder that is a corporation, partnership, unit trust or any trust of which a corporation or a partnership is a beneficiary will be required to include in computing its income for a taxation year the amount of any such interest accrued to the Resident Holder on the Escrowed Funds to the end of the Resident Holder's taxation year, or that is receivable or received by the Resident Holder before the end of that taxation year, except to the extent that such interest was included in computing the Resident Holder's income for a preceding taxation year.

Any other Resident Holder that is entitled to receive its share of accrued interest will be required to include in computing income for a taxation year such interest that is receivable or received by the Resident Holder in that taxation year, depending upon the method regularly followed by the Resident Holder in computing income.

A Resident Holder that is, throughout the relevant taxation year, a "Canadian-controlled private Corporation" (as defined in the Tax Act) may be liable to pay a refundable tax of $6^{2}/_{3}$% on its certain investment income, including interest income.

Dividend Equivalent Amount

As described above under "*Details of the Offering — Subscription Receipts*", if the Acquisition is completed prior to the Termination Time, the holder of a Subscription Receipt, in addition to receiving a Common Share, will be entitled to receive the Dividend Equivalent Amount, if any, which will be first paid by way of a *pro rata* share of accrued interest on the Escrowed Funds. The amount of such interest will generally be included in computing the Resident Holder's income as described above under "*Holders Resident in Canada — Pro Rata Share of Interest*".

If the amount of accrued interest that is paid to the Resident Holder is less than the Dividend Equivalent Amount, we will pay to the Resident Holder the amount of any shortfall as a partial refund of the subscription price of the Subscription Receipts. Such shortfall amount generally will reduce the cost to the Resident Holder of the Common Shares acquired on the exchange of the Subscription Receipts.

For greater certainty, no part of the Dividend Equivalent Amount will benefit from the gross-up and dividend tax credit rules normally applicable in respect of taxable dividends received by individuals from "taxable Canadian corporations" (as defined in the Tax Act); and, where this amount is received by a corporation, the amount will not be deductible in computing the corporation's taxable income and will not result in the requirement to pay the refundable Part IV tax.

Disposition of Common Shares

A disposition or a deemed disposition of a Common Share by a Resident Holder (except to us) will generally result in the Resident Holder realizing a capital gain (or a capital loss) equal to the amount by which the proceeds of disposition of the Common Share exceeds (or are less than) the aggregate of the adjusted cost base to the Resident Holder thereof and any reasonable costs of disposition. Such capital gain (or capital loss) will be subject to the tax treatment described below under "*Holders Resident in Canada — Taxation of Capital Gains and Capital Losses*".

Taxation of Capital Gains and Capital Losses

Generally, one-half of any capital gain (a "taxable capital gain") realized by a Resident Holder in a taxation year must be included in the Resident Holder's income for the year, and one-half of any capital loss (an "allowable capital loss") realized by a Resident Holder in a taxation year must be deducted from taxable capital gains realized by the Resident Holder in that year. Allowable capital losses in excess of taxable capital gains realized in a taxation year generally may be carried back and deducted in any of the three preceding taxation years or carried forward and deducted in any subsequent taxation year against net taxable capital gains realized in such years, to the extent and under the circumstances described in the Tax Act.

The amount of any capital loss realized by a Resident Holder that is a corporation on the disposition of a Common Share may be reduced by the amount of dividends received or deemed to be received by it on such Common Share (or on a share for which the Common Share has been substituted) to the extent and under the circumstances described by the Tax Act. Similar rules may apply where a corporation is a member of a partnership or a beneficiary of a trust that owns Common Shares, directly or indirectly, through a partnership or a trust.

A Resident Holder that is, throughout the relevant taxation year, a "Canadian-controlled private corporation", as defined in the Tax Act, may be liable to pay a refundable tax of $6^{2}/_{3}$% on certain investment income, including taxable capital gains.

Capital gains realized by an individual (including certain trusts) may give rise to liability for alternative minimum tax as calculated under the detailed rules set out in the Tax Act. Resident Holders who are individuals should consult their own tax advisors in this regard.

Receipt of Dividends on Common Shares

Dividends received or deemed to be received on Common Shares held by a Resident Holder will be included in the Resident Holder's income for the purposes of the Tax Act.

Such dividends received by a Resident Holder that is an individual (other than certain trusts) will be subject to the gross-up and dividend tax credit rules in the Tax Act normally applicable to dividends received from taxable Canadian corporations, including the enhanced gross-up and dividend tax credit in respect of dividends designated by us as "eligible dividends". There may be limitations on our ability to designate dividends as "eligible dividends".

Taxable dividends received by a Resident Holder who is an individual (other than certain trusts) may result in such Resident Holder being liable for alternative minimum tax under the Tax Act. Resident Holders who are individuals should consult their own tax advisors in this regard.

A Resident Holder that is a corporation will include such dividends in computing its income and generally will be entitled to deduct the amount of such dividends in computing its taxable income. A Resident Holder that is a "private corporation" or "subject corporation" (as such terms are defined in the Tax Act) may be liable under Part IV of the Tax Act to pay a refundable tax of $33^{1}/_{3}$% of dividends received or deemed to be received on the Common Shares to the extent such dividends are deductible in computing the Resident Holder's taxable income.

Holders Not Resident in Canada

This portion of the summary applies to a holder of Subscription Receipts who, for purposes of the Tax Act, is not, and is not deemed to be, resident in Canada and is not an insurer who carries on an insurance business in Canada and elsewhere (a "**Non-Resident Holder**"). Prospective holders of Subscription Receipts who are not resident in Canada should consult their own tax advisors with respect to their particular circumstances in their country of residence.

Acquisition of Common Shares pursuant to terms of the Subscription Receipts

A Non-Resident Holder will not realize a capital gain or loss on the issuance of an Underlying Common Share pursuant to a Subscription Receipt.

Other Dispositions of Subscription Receipts

On a disposition of a Subscription Receipt (other than on the acquisition of a Common Share pursuant to the terms of Subscription Receipts as discussed above), a Non-Resident Holder will not be subject to tax under the Tax Act in respect of any capital gain realized by such Non-Resident Holder, unless the Subscription Receipt constitutes "taxable Canadian property" (as defined in the Tax Act) of the Non-Resident Holder at the time of disposition and the holder is not entitled to relief under an applicable income tax convention.

As long as the Common Shares are then listed on a designated stock exchange (which currently includes the TSX), Subscription Receipts will not constitute "taxable Canadian property" to a Non-Resident Holder at the time of the disposition or deemed disposition thereof unless at any particular time during the 60-month period immediately preceding the disposition the following two conditions have been met concurrently: (a) the Non-Resident Holder, persons with whom the Non-Resident Holder does not deal at arm's length (within the meaning of the Tax Act), partnerships in which the Non-Resident Holder or a person with whom the Non-Resident Holder does not deal at arm's length (within the meaning of the Tax Act) holds a membership interest directly or indirectly through one or more partnerships, or any combination thereof owned 25% or more of the issued Common Shares, and (b) more than 50% of the fair market value of the Common Shares was derived directly or indirectly from one or any combination of (i) real or immovable property situated in Canada, (ii) "Canadian resource properties" (as defined in the Tax Act), (iii) "timber resource properties" (as defined in the Tax Act) or (iv) an option, an interest or right in such property, whether or not such property exists (the conditions described in (a) and (b) are the "**TCP Conditions**"). A Non-Resident Holder contemplating a disposition of Subscription Receipts that may constitute taxable Canadian property should consult a tax advisor prior to such disposition.

Pro Rata Share of Interest

If the Acquisition is not completed by the Termination Time or if we advise the Underwriters or announce to the public that we do not intend to proceed with the Acquisition, or if the Implementation Agreement has been terminated in accordance with its terms, holders of Subscription Receipts shall be entitled to receive from the Escrow Agent an amount equal to the full subscription price thereof plus their *pro rata* share of accrued interest on the Escrowed Funds. A Non-Resident Holder will generally not be subject to Canadian withholding tax in respect of amounts paid or credited or deemed to have been paid or credited by us as, on account or in lieu of payment of, or in satisfaction of, any such interest.

Dividend Equivalent Amount

As described above under "*Details of the Offering Subscription Receipts*", if the Acquisition is completed prior to the Termination Time, the holder of a Subscription Receipt, in addition to receiving a Common Share, will be entitled to receive the Dividend Equivalent Amount, if any, which will be first paid by way of a *pro rata* share of accrued interest on the Escrowed Funds. The amount of such interest payable to a Non-Resident Holder will be subject to the Canadian federal tax considerations described above under "*Holders Not Resident in Canada Pro Rata Share of Interest*", unless such interest constitutes "participating debt interest" (within the meaning of the Tax Act). If such interest is considered to be participating debt interest, the amount paid to a Non-Resident Holder would be subject to Canadian withholding tax at the statutory rate of 25% (subject to reduction under an applicable income tax convention between Canada and the Non-Resident Holder's country of residence). In this respect, it is uncertain whether or not such interest would constitute "participating debt interest" for purposes of the Tax Act. We have advised Counsel that we intend to withhold at the statutory rate of 25% (subject to reduction under an applicable income tax convention between Canada and the Non-Resident Holder's country of residence) on the portion of any Dividend Equivalent Amount which is paid by way of a *pro rata* share of accrued interest on the Escrowed Funds that is paid to a Non-Resident Holder.

If the amount of accrued interest that is paid to the Non-Resident Holder is less than the Dividend Equivalent Amount, we will pay to the Non-Resident Holder the amount of any shortfall as a partial refund of the subscription price of the Subscription Receipts. Such shortfall amount generally will reduce the cost to the Non-Resident Holder of the Common Shares acquired on the exchange of the Subscription Receipts.

Disposition of Common Shares

A Non-Resident Holder will not be subject to tax under the Tax Act in respect of any capital gain realized by such Non-Resident Holder on a disposition of a Common Share issuable pursuant to the terms of the Subscription Receipts, unless the Common Shares constitute "taxable Canadian property" (as defined in the Tax Act) of the Non-Resident Holder at the time of disposition and the Non-Resident Holder is not entitled to relief under an applicable income tax convention.

As long as the Common Shares are then listed on a designated stock exchange (which currently includes the TSX), Common Shares will not constitute "taxable Canadian property" to a Non-Resident Holder at the time of the disposition or deemed disposition thereof unless at any particular time during the 60 month period immediately preceding the disposition, the TCP Conditions are met. A Non-Resident Holder contemplating a disposition of Subscription Receipts that may constitute taxable Canadian property should consult a tax advisor prior to such disposition.

Receipt of Dividends on Common Shares

Any dividends paid or credited, or deemed to be paid or credited, on the Common Shares to a Non-Resident Holder will be subject to Canadian withholding tax at the rate of 25% of the gross amount of the dividend unless the rate is reduced under the provisions of an applicable income tax convention between Canada and the Non-Resident Holder's country of residence. For instance, where the Non-Resident Holder is a resident of the United States that is entitled to full benefits under the *Canada United States Income Tax Convention (1980)* as amended and is the beneficial owner of the dividends, the rate of Canadian withholding tax applicable to dividends is generally reduced to 15%.

CERTAIN UNITED STATES FEDERAL INCOME TAX CONSIDERATIONS

General

The following is a discussion of certain United States federal income tax consequences to United States Holders (as defined below) relating to the acquisition, ownership and disposition of Subscription Receipts and Common Shares. This discussion is based on existing provisions of the United States Internal Revenue Code of 1986, as amended (the "Code"), its legislative history, existing final, temporary and proposed Treasury Regulations promulgated thereunder, administrative pronouncements or practice, judicial decisions, and interpretations of the foregoing, all as of the date hereof. Future legislative, judicial or administrative modifications, revocations or interpretations, which may or may not be retroactive, may result in United States federal income tax consequences significantly different from those discussed herein. This discussion is not binding on the Internal Revenue Service (the "IRS"). No ruling has been or will be sought or obtained from the IRS with respect to any of the United States federal income tax consequences discussed herein. There can be no assurance that the IRS will not challenge any of the conclusions described herein or that a United States court will not sustain such challenge.

For purposes of this discussion, a "United States Holder" is a beneficial owner of Subscription Receipts or Common Shares that is (i) an individual who is a citizen or a resident alien of the United States for U.S. federal income tax purposes, (ii) a corporation (or other entity treated as a corporation for United States federal income tax purposes) created or organized in or under the laws of the United States, any state thereof, or the District of Columbia, (iii) an estate the income of which is subject to United States federal income taxation regardless of its source, or (iv) a trust (A) if a court within the United States is able to exercise primary supervision over its administration and one or more United States persons have authority to control all substantial decisions of the trust, or (B) that has a valid election in effect under applicable Treasury regulations to be treated as a United States person.

If a partnership or other pass-through entity holds Subscription Receipts or Common Shares, the tax treatment of a partner in or owner of the partnership or pass-through entity will generally depend upon the status of the partner or owner and the activities of the entity. Partners, partnerships or other pass-through entities considering holding Subscription Receipts or Common Shares should consult their tax advisors regarding the tax consequences of the acquisition, ownership and disposition of Subscription Receipts and Common Shares.

This discussion does not address any United States federal alternative minimum tax, United States federal estate, gift, or other non-income tax; or state, local or non-United States tax consequences of the acquisition, ownership and disposition of Subscription Receipts and Common Shares. In addition, this discussion does not address the United States federal income tax consequences to certain categories of United States Holders subject to special rules, including United States Holders that are (i) banks, financial institutions or insurance companies; (ii) regulated investment companies or real estate investment trusts; (iii) brokers or dealers in securities or currencies or traders in securities that elect to use a mark-to-market method of accounting; (iv) tax-exempt organizations, qualified retirement plans, individual retirement accounts or other tax-deferred accounts; (v) holders that hold the Subscription Receipts or Common Shares as part of a hedge, straddle, conversion transaction or a synthetic security or other integrated transaction; (vi) holders that have a "functional currency" other than the U.S. dollar; (vii) holders that own directly, indirectly or constructively 10% or more of the voting power of our stock; (viii) United States expatriates; and (ix) holders that purchase or otherwise acquire Subscription Receipts or Common Shares other than through this Offering. Further, this discussion does not address the indirect consequences to holders of equity interests in entities that own the Subscription Receipts or Common Shares or to holders of the Subscription Receipts or Common Shares that are not United States Holders.

This discussion assumes that Subscription Receipts and Common Shares are held as "capital assets" (generally, property held for investment), within the meaning of Section 1221 of the Code, in the hands of a United States Holder at all relevant times and that we are not and will not become, a passive foreign investment company, or PFIC, as discussed under "*Certain United States Federal Income Tax Considerations   Passive Foreign Investment Company Considerations*."

The following discussion is for general information only and is not intended to be, nor should it be construed to be, legal or tax advice to any holder or prospective holder of Subscription Receipts or Common Shares and no opinion or representation with respect to the United States federal income tax consequences to any such holder or prospective holder is made. Prospective purchasers are urged to consult their tax advisors as to the particular consequences to them under Unites States federal, state and local, and applicable foreign, tax laws of the acquisition, ownership and disposition of Subscription Receipts and Common Shares.

Taxation of Subscription Receipts

Consequences if the Acquisition is Not Completed

If the Acquisition is not completed (see "*Details of the Offering*"), holders of Subscription Receipts shall receive an amount equal to the full subscription price attributable to the Subscription Receipts and their *pro rata* entitlement to interest accrued on such amount up to and including the date of the Termination Time. We intend to treat United States Holders of Subscription Receipts as subject to tax for United States federal income tax purposes in respect of amounts earned on the Escrowed Funds at the time, depending upon the holder's method of accounting, such holders are entitled to such amounts or such amounts are distributed to such holders (which income would include amounts withheld in respect of any Canadian withholding tax).

Consequences if the Acquisition is Completed

We do not intend to treat United States Holders of Subscription Receipts as subject to tax for United States federal income tax purposes in respect of amounts earned on the Escrowed Funds in the event that the Acquisition is completed. If the Acquisition is completed, the Escrowed Funds and the interest earned thereon (less any amounts required to pay the Dividend Equivalent Amount, if applicable) will be released to us. See "*Details of the Offering*". However, it is possible that the IRS could successfully assert that a United States Holder of Subscription Receipts is subject to tax with respect to the holder's share of the income earned on Escrowed Funds at or before relinquishment of such Subscription Receipts even if Common Shares rather than the holder's share of the Escrowed Funds are received. In all likelihood, the amount of any Dividend Equivalent Amount to which the United States holder is entitled (including amounts withheld in respect of any Canadian withholding tax) would be subject to tax for United States federal income tax purposes. It is unclear in such an event how and to what extent the overall taxable amount would be adjusted if the United States Holder were also taxable with respect to its share of the Escrowed Funds.

Notwithstanding any change in value of the Common Shares after the Closing Date, no gain or loss will be recognized upon any receipt of the Common Shares. In addition, a United States Holder's disposition of Subscription Receipts prior to relinquishment either for Common Shares or for the holder's share of Escrowed Funds will generally result in such holder realizing a capital gain (or capital loss) equal to the amount by which the proceeds of the disposition are greater (or less) then the aggregate of the adjusted cost basis in the Subscription Receipts (except that, possibly, ordinary income could arise with respect to entitlement to a Dividend Equivalent Amount).

Prospective purchasers of Subscription Receipts are urged to consult their own tax advisers regarding the United States federal income tax consequences of the Subscription Receipts.

Distributions on Common Shares

The gross amount of any distribution we pay will generally be subject to United States federal income tax as dividend income to the extent paid out of our current or accumulated earnings and profits, as determined under United States federal income tax principles. Such amount will be includable in gross income by a United States

Holder as ordinary income on the date such United States Holder actually or constructively receives the distribution.

Certain dividends received by non-corporate United States Holders from a qualified foreign corporation ("QFC") may be eligible for reduced rates of taxation ("qualified dividends"). A QFC includes a foreign corporation that is eligible for the benefits of a comprehensive income tax treaty with the United States that the United States Treasury Department determines to be satisfactory for these purposes and that includes an exchange of information provision. The United States Treasury has determined that the United States Canada Income Tax Convention meets these requirements, and we believe we are eligible for the benefits of the Tax Convention. A foreign corporation is also treated as a QFC with respect to dividends paid by that corporation on ordinary shares that are readily tradable on an established securities market in the United States. U.S. Treasury guidance indicates that our Common Shares are readily tradable on an established securities market in the United States; however, there can be no assurance that the Common Shares will be considered readily tradable on an established securities market in future years.

We believe that we are currently, and will continue to be, a QFC so as to allow all dividends we pay to be qualified dividends for United States federal income tax purposes. Distributions in excess of our current and accumulated earnings and profits will be treated first as a non-taxable return of capital reducing a United States Holder's tax basis in Common Shares. Any distribution in excess of such tax basis will be treated as capital gain and will be either long-term or short-term capital gain depending upon whether the United States Holder held the Common Shares for more than one year. See "*Certain United States Federal Income Tax Considerations Sale, Exchange, or Other Taxable Disposition of Common Shares*". Dividends we pay generally will not be eligible for the dividends-received deduction available to certain United States corporate shareholders.

The limitations on foreign taxes eligible for credit are calculated separately with respect to specific classes of income. For foreign tax credit purposes, dividends received by a United States Holder with respect to shares of a foreign corporation generally constitute foreign-source income and are treated as "passive category" or "general category" income. Subject to certain limitations, any Canadian tax withheld with respect to distributions made on the Common Shares may be treated as foreign taxes eligible for credit against a United States Holder's United States federal income tax liability. Alternatively, a United States Holder may, subject to applicable limitations, elect to deduct the otherwise creditable Canadian withholding taxes for United States federal income tax purposes. The rules governing the foreign tax credit are complex and their application depends on each taxpayer's particular circumstances. Accordingly, United States Holders are urged to consult their own tax advisors regarding the availability of the foreign tax credit under their particular circumstances.

The gross amount of distributions paid in any foreign currency will be included by each United States Holder in gross income in a U.S. dollar amount calculated by reference to the exchange rate in effect on the day the distributions are paid, regardless of whether the payment is in fact converted into U.S. dollars. If the foreign currency is converted into U.S. dollars on the date of the payment, the United States Holder should not be required to recognize any foreign currency gain or loss with respect to the receipt of the foreign currency distributions. If instead the foreign currency is converted at a later date, any currency gains or losses resulting from the conversion of the foreign currency will be treated as United States source ordinary income or loss.

Sale, Exchange, or Other Taxable Disposition of Common Shares

A United States Holder will generally recognize capital gain or loss upon the sale, exchange or other taxable disposition of the Common Shares measured by the difference between the amount received and the United States Holder's adjusted tax basis in the Common Shares which should generally equal the United States Holder's adjusted tax basis in the Subscription Receipts. Any gain or loss will be long-term capital gain or loss if the Common Shares have been held for more than one year and will generally be United States source gain or loss. For this purpose, the holding period in the Common Shares received upon relinquishment of the Subscription Receipts generally will begin on the day following such relinquishment. Long-term capital gains recognized by non-corporate United States Holders are generally subject to United States federal income tax at preferred rates. A holder's ability to deduct capital losses is subject to limitations.

For cash-basis United States Holders that receive foreign currency in connection with a sale or other taxable disposition of Common Shares, the amount realized will be based upon the U.S. dollar value of the foreign currency received with respect to such Common Shares as determined on the settlement date of such sale or other taxable disposition. Accrual-basis United States Holders may elect the same treatment required of cash-basis taxpayers with respect to a sale or other taxable disposition of Common Shares, provided that the election is applied consistently from year to year. Such election cannot be changed without the consent of the IRS. Accrual-basis United States Holders that do not elect to be treated as cash-basis taxpayers (pursuant to the Treasury Regulations applicable to foreign currency transactions) for this purpose may have a foreign currency gain or loss for United States federal income tax purposes because of differences between the U.S. dollar value of the foreign currency received prevailing on the date of such sale or other taxable disposition and the value prevailing on the date of payment. Any such currency gain or loss will generally be treated as ordinary income or loss that is United States source, in addition to the gain or loss, if any, recognized on the sale or other taxable disposition of Common Shares.

Passive Foreign Investment Company Considerations

Special, adverse, United States federal income tax rules apply to United States persons owning stock of a PFIC. A foreign corporation will be considered a PFIC for any taxable year in which (i) 75% or more of its gross income is passive income, or (ii) 50% or more of the average value (or, if elected, the adjusted tax basis) of its assets are considered "passive assets" (generally, assets that generate passive income). We believe we are not currently a PFIC for United States federal income tax purposes, and we do not expect to become a PFIC in the future. However, the determination of PFIC status for any year is very fact specific, and there can be no assurance in this regard. Accordingly, it is possible that we may become a PFIC in the current taxable year or in future years. If we are classified as a PFIC in any year during which a holder holds Common Stock, we generally will continue to be treated as a PFIC to such a holder in all succeeding years, regardless of whether we continue to meet the income or asset test discussed above. United States Holders are urged to consult their own tax advisors regarding the adverse tax consequences of owning the Common Shares were we to be a PFIC and certain elections that may be made that are designed to lessen those adverse consequences.

Additional Tax on Passive Income

An additional 3.8% tax will generally be imposed on the "net investment income" of individuals, estates and trusts whose income exceeds certain thresholds. "Net investment income" generally includes the following: (1) gross income from interest and dividends other than from the conduct of a non-passive trade or business; (2) other gross income from a passive trade or business; and (3) net gain attributable to the disposition of property other than property held in a non-passive trade or business. Therefore, dividends on, and capital gains from the sale or other taxable disposition of, the Common Shares and Subscription Receipts may be subject to this additional tax.

United States Information Reporting and Backup Withholding

Under United States federal income tax law and regulations, certain categories of United States Holders must file information returns with respect to their investment in, or involvement in, a foreign corporation. Penalties for failure to file certain of these information returns are substantial. In addition, new United States return disclosure obligations (and related penalties for failure to disclose) have also been imposed on United States individuals who hold certain specified foreign financial assets in excess of U.S.$50,000. The definition of specified foreign financial assets includes not only financial accounts maintained in foreign financial institutions, but also may include the Common Shares and Subscription Receipts. United States Holders of Common Shares and/or Subscription Receipts should consult with their own tax advisors regarding the requirements of filing any information returns.

Dividends on Common Shares, amounts earned on Escrowed Funds and/or the Dividend Equivalent Amount relating to Subscription Receipts and proceeds from the sale or other disposition of Common Shares and/or Subscription Receipts that are paid in the United States or by a United States-related financial intermediary will be subject to United States information reporting rules, unless a United States Holder is a corporation or other exempt recipient. In addition, payments that are subject to information reporting may be subject to backup withholding (currently at a 28% rate) if a United States Holder does not provide its taxpayer identification number and otherwise comply with the backup withholding rules. Backup withholding is not an additional tax. Amounts withheld under the backup withholding rules are available to be credited against a United States Holder's United States federal income tax liability and may be refunded to the extent they exceed such liability, provided the required information is provided to the IRS in a timely manner.

LEGAL MATTERS

Certain legal matters relating to Canadian law in connection with the Subscription Receipts offered hereby will be passed upon on our behalf by Burnet, Duckworth & Palmer LLP, Calgary, Alberta and on behalf of the Underwriters by McCarthy Tétrault LLP, Calgary, Alberta. Certain legal matters relating to United States law in connection with the Subscription Receipts offered hereby will be passed upon on our behalf by Paul, Weiss, Rifkind, Wharton & Garrison LLP, New York, New York and on behalf of the Underwriters by Vinson & Elkins LLP, Houston, Texas.

INTEREST OF EXPERTS

As of the date hereof, the partners and associates of each of Burnet, Duckworth & Palmer LLP and McCarthy Tétrault LLP each beneficially own, directly or indirectly, less than 1% of our outstanding Common Shares.

Deloitte LLP, our independent registered chartered accountants, are independent of us within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of Alberta.

BDO Audit (WA) Pty Ltd., Aurora's external auditor, has confirmed that they are independent of Aurora in accordance with Canadian Auditing Standards as adopted by the Canadian Auditing and Assurance Standards Board.

Information relating to our reserves included in this short form prospectus and in the Annual Information Form was calculated based on an evaluation of, and reports on, our crude oil and natural gas reserves conducted and prepared by Sproule, our independent qualified reserves evaluators. As of the date hereof Sproule does not have any registered or beneficial interest, direct or indirect, in any of our securities or other property or any of our associates or affiliates. For the purposes of this paragraph, Sproule shall be interpreted to include its designated professionals.

Information relating to Aurora's reserves included in this short form prospectus was calculated based on an evaluation of, and reports on, our crude oil and natural gas reserves conducted and prepared by Ryder Scott, Aurora's independent qualified reserves evaluators. As of the date hereof Ryder Scott does not have any registered or beneficial interest, direct or indirect, in any securities or other property of Aurora or any of Aurora's associates or affiliates. For the purposes of this paragraph, Ryder Scott shall be interpreted to include its designated professionals.

In addition, none of the aforementioned persons or companies, nor any director, officer or employee of any of the aforementioned persons or companies, is or is expected to be elected, appointed or employed as a director, officer or employee of us or of any of our associate or affiliate entities, except for John A. Brussa, one of our directors, who is a partner of Burnet, Duckworth & Palmer LLP.

DOCUMENTS FILED AS PART OF THE REGISTRATION STATEMENT

The following documents have been or will be filed with the SEC as part of the registration statement of which this short form prospectus forms a part: (i) the documents listed under the heading "*Documents Incorporated by Reference*"; (ii) consents of independent auditors and engineers and legal counsel; and (iii) powers of attorney pursuant to which amendments to the registration statement may be signed.

SCHEDULE "A"

FINANCIAL STATEMENTS OF AURORA

AURORA OIL & GAS LIMITED

ANNUAL FINANCIAL REPORT

For the year ended December 31, 2012

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MANAGEMENT REPORT

For the year ended December 31, 2012

Management, in accordance with Australian Accounting Standards including Australian equivalents to International Financial Reporting Standards (AIFRS), has prepared the accompanying consolidated financial statements of Aurora Oil and Gas Limited (Aurora). Financial and operating information presented throughout this report is consistent with that shown in the consolidated financial statements.

Management is responsible for the integrity of the financial information. Internal control systems are designed and maintained to provide reasonable assurance that assets are safeguarded from loss or unauthorized use and to produce reliable accounting records for financial reporting purposes.

BDO Audit (WA) Pty Ltd were appointed by the Company's Board of Directors to conduct an audit of the consolidated financial statements. Their examination included a review and evaluation of Aurora's internal control systems and included such tests and procedures, as they considered necessary, to provide a reasonable assurance that the consolidated financial statements are presented fairly in accordance with Australian Accounting Standards including Australian equivalents to compliance with AIFRS ensures that the financial statements of Aurora comply with International Financial Reporting Standards.

The Board of Directors is responsible for ensuring that management fulfils its responsibilities for financial reporting and internal control. The Board exercises this responsibility through the Audit and Risk Management Committee, with assistance from the Reserves Committee regarding the annual evaluation of our petroleum and natural gas reserve. The Audit and Risk Management Committee meets regularly with management and the independent auditors to ensure that management's responsibilities are properly discharged, to review the consolidated financial statements and recommend that the consolidated financial statements be presented to the Board of Directors for approval. The Audit and Risk Management Committee also considers the independence of the external auditors and reviews their fees. The external auditors have access to the Audit and Risk Management Committee without the presence of management.

Signed Jonathan Stewart	*Signed* Graham Dowland
Jonathan Stewart Executive Chairman	Graham Dowland Finance Director

February 27, 2013

INDEPENDENT AUDIT REPORT

For the year ended December 31, 2012

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Australia

INDEPENDENT AUDITOR'S REPORT
TO THE MEMBERS OF AURORA OIL & GAS LIMITED

Report on the Financial Report

We have audited the accompanying financial report of Aurora Oil & Gas Limited, which comprises the consolidated statement of financial position as at 31 December 2012 and 31 December 2011, the consolidated statement of profit or loss and other comprehensive income, the consolidated statement of changes in equity and the consolidated statement of cash flows for the years then ended, notes comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Report

Management is responsible for the preparation and fair presentation of the financial report in accordance with International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of the financial report that is free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express an opinion on the financial report based on our audit. We conducted our audit in accordance with international generally accepted auditing standards. Those standards require that we comply with relevant ethical requirements relating to audit engagements and plan and perform the audit to obtain reasonable assurance about whether the financial report is free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial report. The procedures selected depend on the auditor's judgement, including the assessment of the risks of material misstatement of the financial report, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the company's preparation of the financial report that gives a true and fair view in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the company's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial report.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial report presents fairly, in all material respects the consolidated financial position of Aurora Oil & Gas Limited as at 31 December 2012 and 31 December 2011 and its performance for the years then ended in accordance with *International Financial Reporting Standards* as disclosed in Note 1.

/s/ BDO Audit (WA) Pty Ltd

Glyn O'Brien
Director

Perth, Western Australia
Dated this 27th day of February 2013

AURORA OIL & GAS LIMITED

CONSOLIDATED STATEMENT OF PROFIT OR LOSS AND OTHER COMPREHENSIVE INCOME

For the year ended December 31, 2012

	Note	Consolidated December 31, 2012 US$'000	December 31, 2011 US$'000
Revenue from continuing operations	(5)	**295,059**	75,969
Other income	(6)	**5,008**	1,052
Total income		**300,067**	77,021
Expenses			
Royalties	(7)	**(77,625)**	(20,067)
Production and operating expenses	(7)	**(34,581)**	(6,737)
Depletion, depreciation and amortisation expense	(7)	**(39,161)**	(4,367)
Exploration and evaluation costs	(7)	**(4,939)**	(652)
Finance Costs	(7)	**(28,027)**	(136)
Administrative expenses		**(15,134)**	(8,783)
Share-based payment expenses	(7)	**(4,398)**	(4,052)
Profit from continuing operations before income tax expense		**96,202**	32,227
Income tax expense	(8)	**(37,356)**	(1,643)
Net profit attributable to owners of the Company		**58,846**	30,584
Other comprehensive income			
Changes in fair value on equity instruments measured at fair value through other comprehensive income	(11)	**957**	(1,302)
Change in fair value of cash flow hedges	(19)	**(1,154)**	
Other comprehensive (expenses) for the year net of tax		**(197)**	(1,302)
Total comprehensive income for the year attributable to owners of the Company		**58,649**	29,282
Earnings / (loss) per share attributable to owners of the Company			
Basic earnings per share (US cents per share)	(25)	**13.60**	7.49
Diluted earnings per share (US cents per share)	(25)	**13.35**	7.37

The above consolidated statement of profit or loss and other comprehensive income should be read in conjunction with the accompanying notes.

AURORA OIL & GAS LIMITED

CONSOLIDATED STATEMENT OF FINANCIAL POSITION

As at December 31, 2012

	Note	Consolidated December 31, 2012 US$'000	December 31, 2011 US$'000
Current assets			
Cash and cash equivalents	(9)	**67,584**	70,246
Trade and other receivables	(10)	**89,535**	14,626
Total current assets		**157,119**	84,872
Non-current assets			
Other financial assets	(11)	**842**	2,507
Property, plant and equipment	(12)	**71,063**	21,319
Exploration and evaluation expenditure	(13)		
Oil and gas properties	(14)	**882,373**	272,128
Total non-current assets		**954,278**	295,954
Total assets		**1,111,397**	380,826
Current liabilities			
Trade and other payables	(15)	**180,619**	73,434
Derivative financial instruments	(19)	**1,535**	
Provisions	(16)	**334**	92
Total current liabilities		**182,488**	73,526
Non-current liabilities			
Borrowings	(17)	**390,453**	30,000
Deferred tax liabilities	(18)	**83,523**	1,643
Derivative financial instrument	(19)	**114**	
Provisions	(20)	**1,705**	565
Total non-current liabilities		**475,795**	32,208
Total liabilities		**658,283**	105,734
Net assets		**453,114**	275,092
Equity			
Contributed equity	(21)	**405,169**	290,194
Share-based payment reserve	(24)	**12,165**	7,767
Fair value reserve	(24)	**(7,054)**	(8,011)
Foreign exchange reserve	(24)	**(7,505)**	(7,505)
Cash flow hedge reserve	(24)	**(1,154)**	
Retained earnings / (accumulated losses)	(24)	**51,493**	(7,353)
Total equity		**453,114**	275,092

The above consolidated statement of financial position should be read in conjunction with the accompanying notes.

On behalf of the Board of Directors:

Signed Jonathan Stewart	*Signed* Graham Dowland
Jonathan Stewart Executive Chairman	Graham Dowland Finance Director

AURORA OIL & GAS LIMITED

CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

For the year ended December 31, 2012

	Contributed Equity	Other Reserve	Accumulated Profits / (Losses)	Total
	US$'000	US$'000	US$'000	US$'000
Balance at January 1, 2011	**222,730**	**10,738**	**(30,609)**	**202,859**
Adjustment arising from change in functional currency on January 1, 2011	28,565	(21,237)	(7,328)	
Balance as at January 1, 2011 restated	**251,295**	**(10,499)**	**(37,937)**	**202,859**
Profit for the year			30,584	30,584
Other comprehensive income				
Change in fair value of equity instruments measured at fair value through other comprehensive income		(1,302)		(1,302)
Total comprehensive income for the year		(1,302)	30,584	29,282
Transactions with owners, in their capacity as owners				
Contributed equity net of transaction costs	38,899			
Options and performance rights expense recognised during the year		4,052		
Balance as at December 31, 2011	**290,194**	**(7,749)**	**(7,353)**	**275,092**
Profit for the year			58,846	58,846
Other comprehensive income				
Change in fair value of equity instruments measured at fair value through other comprehensive income		916		916
Change in fair value of cash flow hedges net of tax		(1,154)		(1,154)
Recognition of fair value of equity instruments measured at fair value through other comprehensive income on disposal		41		41
Total comprehensive income for the year		(197)	58,846	58,649
Transactions with owners, in their capacity as owners				
Contributed equity net of transaction costs	114,975			114,975
Options and performance rights expense recognised during the year		4,398		4,398
Balance as at December 31, 2012	**405,169**	**(3,548)**	**51,493**	**453,114**

The above consolidated statement of changes in equity should be read in conjunction with the accompanying notes.

AURORA OIL & GAS LIMITED

CONSOLIDATED STATEMENT OF CASH FLOWS

For the year ended December 31, 2012

		Consolidated	
		December 31, 2012	**December 31, 2011**
		US$'000	**US$'000**
Cash flows from operating activities			
Receipts from oil and gas sales		**221,539**	62,315
Payments to suppliers and employees		**(67,433)**	(27,368)
Other revenue		**1,167**	
Interest paid		**(11,151)**	
Net cash inflow from operating activities	(32)	**144,122**	34,947
Cash flows from investing activities			
Payments for capitalised oil and gas assets		**(452,635)**	(64,514)
Payment for property, plant and equipment		**(51,352)**	(12,226)
Transaction costs		**(4,939)**	
Payment for other financial assets		**(252)**	(1,614)
Payment for acquisition of subsidiary, net of cash acquired	(22)	**(98,765)**	
Interest received		**247**	711
Net cash (outflow) from investing activities		**(607,696)**	(77,643)
Cash flows from financing activities			
Proceeds from issues of shares		**120,138**	42,130
Share issue costs		**(5,163)**	(3,231)
Proceeds from borrowings		**394,579**	30,000
Repayment of borrowings		**(39,000)**	
Borrowing costs		**(11,558)**	(2,328)
Net cash inflow from financing activities		**458,996**	66,571
Net increase / (decrease) in cash and cash equivalents		**(4,578)**	23,875
Cash and cash equivalents at the beginning of the financial year		**70,246**	45,997
Effect of exchange rates on cash holdings in foreign currencies		**1,916**	374
Cash and cash equivalents at the end of the financial year	(9)	**67,584**	70,246

The above consolidated statement of cash flows should be read in conjunction with the accompanying notes.

AURORA OIL & GAS LIMITED

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

For the year ended December 31, 2012

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Aurora Oil and Gas Limited ("Company" or "Aurora") is a company incorporated in Australia whose shares are publically listed on the Australian Securities Exchange (ASX) and Toronto Stock Exchange (TSX). Aurora is the ultimate parent entity in the group.

The consolidated financial report of the Company for the year ended December 31, 2012 comprises the financial statements for Aurora Oil and Gas Limited and its controlled entities ("Group" or "Consolidated Entity").

Statement of Compliance

This general purpose financial report has been prepared in accordance with Australian Accounting Standards, Accounting Interpretations and other authoritative pronouncements of the Australian Accounting Standards Board, Urgent Issues Group Interpretations and the Corporations Act 2001.

The financial statements of Aurora Oil and Gas Limited also comply with International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board (IASB).

Basis of Preparation

The financial report of the Consolidated Entity is presented in US dollars.

The principal accounting policies adopted in the preparation of the financial report are set out below. These policies have been applied consistently to all the periods presented, unless otherwise stated.

Historical cost convention

These financial statements have been prepared under the historical cost convention, as modified by the revaluation of financial assets at fair value through other comprehensive income.

Changes in accounting policy and disclosures

Subsequent to the change in functional currency of the US subsidiaries from Australian dollars to US dollars, which occurred for the year ended June 30, 2010, the Company announced on December 24, 2010 that it had elected to change its presentational currency from Australian dollars to US dollars effective July 1, 2010. The operational activities of the Group are conducted through US subsidiaries and these activities contribute to all of the Company's revenue (other than interest) and the majority of the groups' expenditure is denominated in US dollars. As a result, the Board considered that the change in presentational currency provided shareholders with a more consistent and meaningful reflection of the Group's underlying performance.

Effective January 1, 2011 the functional currency of Aurora, the parent entity, has changed from Australian dollars to US dollars as the trend in the source currency of the majority of the revenue and costs of the parent entity from Australian dollars to US dollars was not considered temporary. The effects of the change have been disclosed in the Consolidated Statement of Changes in Equity.

Critical accounting estimates and significant judgements

The preparation of financial statements requires the use of certain critical accounting estimates. It also requires management to exercise its judgment in the process of applying the Group's accounting policies. The areas involving a higher degree of judgment or complexity, or areas where assumptions and estimates are significant to the financial statements are disclosed in note 2.

Adoption of new and revised accounting standards

In the current year, the Group has adopted all of the new and revised Standards and Interpretations issued by the Australian Accounting Standards Board that are relevant to its operations and effective for the current reporting period. There is no impact on any amounts recognised in the current periods or any prior periods.

Accounting Policies

(a) Principles of consolidation

The consolidated financial statements incorporate the assets and liabilities of Aurora Oil and Gas Limited and its controlled entities as at December 31, 2012 and the financial performance of the Company and its controlled entities for the period then ended.

AURORA OIL & GAS LIMITED

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

For the year ended December 31, 2012

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

Controlled entities are all those entities (including special purpose entities) over which the group has the power to govern the financial and operating policies, generally accompanying a shareholding of more than one-half of the voting rights. The existence and effect of potential voting rights that are currently exercisable or convertible are considered when assessing whether the Company controls another entity.

Controlled entities are consolidated from the date on which control is transferred to the Company. They are de-consolidated from the date that control ceases.

The acquisition method of accounting is used to account for the acquisition of subsidiaries by the Group.

Intercompany transactions, balances and unrealised gains or losses on transactions between Group entities are eliminated. Unrealised losses are eliminated unless the transaction provides evidence of the impairment of the assets transferred. Accounting policies of subsidiaries have been changed where necessary to ensure consistency with the policies adopted by the Consolidated Entity.

Non-controlling interests in the results and equity of subsidiaries are shown separately in the consolidated statement of profit or loss and other comprehensive income, consolidated statement of changes in equity and consolidated statement of financial position.

(b) Joint ventures

The Group's share of the assets, liabilities, revenues and expenses of joint venture operations have been incorporated into the financial statements in the appropriate items of the consolidated statement of comprehensive income and consolidated statement of financial position. Details of joint ventures are set out in note 29.

(c) Segment reporting

Operating segments are reported in a manner consistent with the internal reporting provided to the chief operating decision maker. The chief operating decision maker, who is responsible for allocating resources and assessing performance of the operating segments, has been identified as the CEO.

The CEO reviews the information within the internal management reports on a monthly basis which is consistent with the information provided in the consolidated financial statements. As a result no reconciliation is required, because the information as presented is used by the CEO to make strategic decisions.

Management has determined, based on the reports reviewed by the CEO and used to make strategic decisions, that the Group has one reportable segment being oil and gas exploration and production in the United States of America. The Group's management and administration office is located in Australia. There has been no other impact on the measurement of the company's assets and liabilities.

(d) Foreign currency translation

(i) Functional and presentational currency

Items included in the financial statements of the Group companies are measured using the currency of the primary economic environment in which each company operates ('the functional currency'). Effective January 1, 2011 the functional currency of the parent entity changed from Australian dollars to US dollars as the trend in the source currency of the majority of the revenue and costs of the parent entity from Australian dollars to US dollars was not considered temporary. The functional currency of the US subsidiaries is US dollars.

The consolidated financial statements are presented in US dollars, which is the Group's presentation currency.

The change in functional currency of the parent entity was implemented by translating the assets and liabilities of the parent entity at the spot rate at the date of the change.

(ii) Translation and balances

Foreign currency transactions are translated into functional currency using the exchange rates prevailing at the dates of the transactions.

Foreign currency monetary assets and liabilities at the reporting date are translated into USD at the exchange rate existing at reporting date.

Exchange differences are recognised in profit or loss in the period in which they arise.

AURORA OIL & GAS LIMITED

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

For the year ended December 31, 2012

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

(iii) *Group companies*

The results and financial position of all the Group companies that have a functional currency different from the presentation currency are translated into the presentation currency as follows:

- assets and liabilities for each statement of financial position presented are translated at the closing rate at the date of the statement of financial position;
- income and expense for each statement of profit or loss and other comprehensive income balance are translated at average exchange rates; and
- exchange differences arising on translation of intercompany payables and / or receivables of foreign operations, in a currency that is not the same as the parent's functional currency, are recognised in the foreign currency translation reserve, as a separate component of equity. These differences are only recognised in the profit or loss upon disposal of the foreign operations.

(e) Revenue recognition

Revenue is recognised at the fair value of consideration received or receivable to the extent that it is probable that economic benefits will flow to the Group and the revenue can be reliably measured.

(i) *Oil and Gas Sales*

Revenue from the sale of oil / condensate, gas and natural gas liquids produced is recognised when the Consolidated Entity has transferred to the buyer the significant risks and rewards of ownership of the products from the following product streams:

- Dry Gas upon transfer into a third party's sales pipeline, typically at the exit of a third party processing facility;
- Natural Gas Liquids (NGL's) upon transfer into a third party's sales pipeline, typically at the exit of a third party processing facility;
- Oil / Condensate upon transfer of product to purchasers transportation mode, either truck or pipeline.

(ii) *Other revenue*

Dividend revenue is recognised on a receivable basis. Interest revenue is recognised on a time proportionate basis that takes into account the effective yield on the financial asset.

(iii) *Service income*

Revenue from the provision of services is recognised when an entity has a legally enforceable right to receive payment for services rendered.

(f) Income tax

The income tax benefit/(expense) for the period is the tax payable on the current period's taxable income/(loss) based on the applicable income tax rate for each jurisdiction adjusted by changes in deferred tax assets and liabilities attributable to temporary differences and for unused tax losses.

Deferred income tax is provided in full, using the liability method, on temporary differences arising between the tax bases of assets and liabilities and their carrying amounts in the consolidated financial statements. However, the deferred income tax is not accounted for if it arises from initial recognition of an asset or liability in a transaction other than a business combination that at the time of the transaction affects neither accounting nor taxable profit or loss. Deferred income tax is determined using tax rates (and laws) that have been enacted or substantially enacted at the reporting date and are expected to apply when the related deferred income tax assets is realised or the deferred income tax liability is settled.

Deferred tax assets are recognised for deductible temporary differences and unused tax losses only if it is probable that future taxable amounts will be available to utilise those temporary differences and losses.

Deferred tax liabilities and assets are not recognised for temporary differences between the carrying amount and tax bases of investments in controlled entities where the Company is able to control the timing of the reversal of the temporary differences and it is probable that the differences will not reverse in the foreseeable future.

AURORA OIL & GAS LIMITED

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

For the year ended December 31, 2012

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

Deferred tax assets and liabilities are offset when there is a legally enforceable right to offset current tax assets and liabilities and when the deferred tax balances relate to the same taxation authority. Current tax assets and tax liabilities are offset where the entity has a legally enforceable right to offset and intends either to settle on a net basis or to realise the asset and settle the liability simultaneously.

Current and deferred tax balances attributable to amounts recognised directly in other comprehensive income / equity are also recognised directly in other comprehensive income / equity.

(g) Impairment of assets

Assets are tested for impairment whenever events or changes in circumstances indicate that the carrying amount may not be fully recoverable. An impairment loss is recognised for the amount by which the asset's carrying amount exceeds its recoverable amount. The recoverable amount is the higher of an asset's fair value less costs to sell and value in use. For the purposes of assessing impairment, assets are grouped at the lowest levels for which there are separately identifiable cash inflows which are largely independent of the cash inflows from other assets or groups of assets (cash-generating units). Non-financial assets, other than goodwill, which have been previously impaired, are reviewed for possible reversal of the impairment at each reporting date.

(h) Business combinations

The acquisition method of accounting is used to account for all business combinations, regardless of whether equity instruments or other assets are acquired. The consideration transferred for the acquisition of a subsidiary comprises the fair values of the assets transferred, the liabilities incurred and the equity interests issued by the group. The consideration transferred also includes the fair value of any pre-existing equity interest in the subsidiary. Acquisition-related costs are expensed as incurred. Identifiable assets acquired and liabilities and contingent liabilities assumed in a business combination are, with limited exceptions, measured initially at their face value at the acquisition date. On an acquisition-by-acquisition basis, the group recognises any non-controlling interest in the acquiree's net identifiable assets.

The excess of the consideration transferred and the amount of any non-controlling interest in the acquiree over the fair value of the net identifiable assets acquired is recorded as goodwill. If those amounts are less than the fair value of net identifiable assets of the subsidiary acquired and the measurement of all amounts has been reviewed, the difference is recognised directly in profit or loss as a bargain purchase.

Where settlement of any part of cash consideration is deferred, the amounts payable in the future are discounted to their present value as at the date of exchange. The discount rate used is the entity's incremental borrowing rate, being the rate at which a similar borrowing could be obtained from an independent financier under comparable terms and conditions.

Contingent consideration is classified either as equity or a financial liability. Amounts classified as a financial liability are subsequently remeasured to fair value with changes in fair value recognised in profit or loss.

(i) Cash and cash equivalents

For cash flow statement presentation purposes, cash and cash equivalents includes cash on hand, deposits held at call with financial institutions and other short-term highly liquid investments with original maturities of three months or less.

(j) Trade receivables

Trade receivables are recognised initially at fair value and subsequently measured at amortised cost using the effective interest method, less provision for impairment. An allowance for trade receivables is established where there is objective evidence that the Group will not be able to collect all amounts.

Collectability of trade receivables is reviewed on a monthly basis. Where there is objective evidence that the Group will not be able to collect all amounts due according to the original terms of the receivables, an allowance for impairment of trade receivables is raised. Debts which are known to be uncollectable are written off by reducing the carrying amount directly. Significant financial difficulties of the debtor, probability that the debtor will enter bankruptcy or financial reorganisation, and default or delinquency in payment are considered indicators that the trade receivable is impaired. The amount of the impairment allowance is the difference between the asset's carrying amount and the present value of estimated future cash flows, discounted at the original effective interest rate. Cash flows relating to short-term receivables are not discounted if the effect of discounting is immaterial.

The amount of the impairment loss is recognised in profit or loss within other expenses. When a trade receivable for which an impairment allowance had been recognised becomes uncollectible in a subsequent period, it is written off against the allowance account. Subsequent recoveries of amounts previously written off are credited against other expenses in profit or loss.

AURORA OIL & GAS LIMITED

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

For the year ended December 31, 2012

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

(k) Financial assets

(i) Classification

The Group classifies its financial assets in the following categories: 'financial assets at fair value through other comprehensive income', and 'loans and receivables'. The classification depends on the purpose for which the financial assets were acquired. Management determines the classification of its financial assets at initial recognition.

(ii) Trade and other receivables

Trade and other receivables are recognised initially at fair value and subsequently measured at amortised cost using the effective interest rate method, less provision for impairment. Trade receivables are generally due for settlement within 30 days.

(iii) Financial assets at fair value through other comprehensive income

At initial recognition the Group may make an irrevocable election (on an instrument-by-instrument basis) to recognise the change in fair value of investments in equity instruments in other comprehensive income. This election is permitted for equity instruments that are not held for trading purposes.

These instruments are initially recognised at fair value plus transaction costs. Subsequent to initial recognition, they are measured at fair value and changes therein are recognised in other comprehensive income and presented within equity in the fair value reserve. When an instrument is derecognised, the cumulative gain or loss is transferred directly to retained earnings and is not recognised in profit or loss.

Dividends or other distributions received from these investments are still recognised in profit or loss as part of finance income.

(iv) Recognition and de-recognition

Regular purchases and sales of financial assets are recognised on trade date being the date on which the Group commits to purchase or sell the asset. Investments are initially recognised at fair value plus transaction costs for all financial assets not carried at fair value through profit or loss. Financial assets are derecognised when the rights to receive cash flows from the financial assets have expired or have been transferred and the Group has transferred substantially all the risks and rewards of ownership.

(v) Subsequent measurement

Loans and receivables are carried at amortised cost less impairment using the effective interest method.

Details on how the fair value of financial instruments is determined are disclosed in note 2(a)(ii).

(vi) Impairment

The Group assesses at each reporting date whether there is objective evidence that a financial asset or group of financial assets is impaired.

If there is evidence of impairment for any of the Group's financial assets carried at amortised cost, the loss is measured as the difference between the assets carrying amount and the present value of estimated future cash flows, excluding future credit losses that have not been incurred. The cash flows are discounted at the financial asset's original effective interest rate. The loss is recognised in the consolidated statement of profit or loss and other comprehensive income.

(l) Derivatives and hedging activities

Derivatives are initially recognised at fair value on the date a derivative contract is entered into and are subsequently measured to their fair value at the end of each reporting period. The accounting for subsequent changes in fair value depends on whether the derivative is designated as a hedging instrument, and if so, the nature of the item being hedged. The group designates certain derivatives as hedges of a particular risk associated with the cash flow of recognised assets and liabilities and highly probable forecast transactions (cash flow hedges).

The group documents at the inception of the hedging transaction the relationship between hedging instruments and hedged items, as well as its risk management objective and strategy for undertaking various hedge transactions. The group also documents its assessment, both at hedge inception and on an ongoing basis, of whether the derivatives that are used in hedging transactions have been and will continue to be highly effective in offsetting changes in fair value or cash flows of hedged items.

AURORA OIL & GAS LIMITED

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

For the year ended December 31, 2012

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

The full fair value of a hedging derivative is classified as a non-current asset or liability when the remaining maturity of the hedged item is more than 12 months; it is classified as a current asset or liability when the remaining maturity of the hedged item is less than 12 months.

(i)
Cash flow hedge

The effective portion of changes in the fair value of derivatives that are designated and qualify as cash flow hedges is recognised in other comprehensive income and accumulated in reserves in equity. The gain or loss relating to the ineffective portion is recognised immediately in profit or loss within other income or other expense.

Amounts accumulated in equity are reclassified to profit or loss in the periods when the hedged item affects profit or loss (for instance when the forecast sale that is hedged takes place). When the forecast transaction that is hedged results in the recognition of a non-financial asset (for example, inventory or fixed assets) the gains and losses previously deferred in equity are reclassified from equity and included in the initial measurement of the cost of the asset. The deferred amounts are ultimately recognised in profit or loss as cost of goods sold in the case of inventory, or as depreciation or impairment in the case of fixed assets.

When a hedging instrument expires or is sold or terminated, or when a hedge no longer meets the criteria for hedge accounting, any cumulative gain or loss existing in equity at that time remains in equity and is recognised when the forecast transaction is ultimately recognised in profit or loss. When a forecast transaction is no longer expected to occur, the cumulative gain or loss that was reported in equity is immediately reclassified to profit or loss.

(ii)
Derivatives that do not qualify for hedge accounting

Certain derivative instruments do not qualify for hedge accounting. Changes in the fair value of any derivative instrument that does not qualify for hedge accounting are recognised immediately in profit or loss and are included in other income or other expenses.

(m)
Inventories

Inventories consist of hydrocarbon stocks. Inventories are valued at the lower of cost and net realisable value. Cost is determined on a weighted average basis and includes direct costs and an appropriate portion of fixed and variable production overheads where applicable.

(n)
Property, plant and equipment (other than oil and gas properties)

Property, plant and equipment is stated at cost less accumulated depreciation and impairment. Cost includes expenditure that is directly attributable to the acquisition of the item. In the event that settlement of all or part of the purchase consideration is deferred, cost is determined by discounting the amounts payable in the future to their present value as at the date of acquisition.

Depreciation is provided on property, plant and equipment. Depreciation is calculated on a reducing balance basis so as to write down the net cost or fair value of each asset over its expected useful life to its estimated residual value.

The estimated useful lives, residual values and depreciation method are reviewed at the end of each annual reporting period.

The following estimated useful lives are used in the calculation of depreciation:

Fixtures and fittings	5 years
Plant and equipment	5 15 years

(o)
Non-operator interests in oil and gas properties

(i)

Exploration and evaluation expenditure

Expenditure on exploration and evaluation is accounted for in accordance with the area of interest method which is closely aligned to the US GAAP based successful efforts method of accounting for oil and gas exploration and evaluation expenditure.

This approach is strongly linked to the Company's oil and gas reserves determination and reporting process and is considered to most fairly reflect the results of the Company's exploration and evaluation activity because only assets with demonstrable value are carried on the statement of financial position.

AURORA OIL & GAS LIMITED

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

For the year ended December 31, 2012

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

Once a well commences producing commercial quantities of oil and gas, capitalised exploration and evaluation costs are transferred to Oil and Gas Properties Producing Projects and amortisation commences.

This method allows the costs associated with the acquisition, exploration and evaluation of a prospect to be aggregated on the Consolidated Statement of Financial Position and matched against the benefits derived from commercial production once this commences.

(ii) *Costs*

Exploration lease acquisition costs relating to greenfield oil and gas exploration provinces are expensed as incurred while the costs incurred in relation to established or recognised oil and gas provinces are initially capitalised and then amortised over the shorter term of the lease or the expected life of the project.

All other exploration and evaluation costs, including general permit activity, geological and geophysical costs and new venture activity costs are charged as expenses as incurred except where:

- the expenditure relates to an exploration discovery that, at the reporting date, had not been recognised as an area of interest as an assessment of the existence or otherwise of economically recoverable reserves has not yet been completed; or

- where there exists an economically recoverable reserve, and it is expected that the capitalised expenditure will be recouped through exploitation of the area of interest, or alternatively, by its sale.

Areas of Interest are recognised at field level. Subsequent to the recognition of an Area of Interest, all further costs relating to the Area of Interest are initially capitalised. Each Area of Interest is reviewed at least bi-annually to determine whether economic quantities of reserves exist or whether further exploration and evaluation work is required to support the continued carry forward of capitalised costs. To the extent it is considered that the relevant expenditure will not be recovered, it is written off.

The costs of drilling exploration and evaluation wells are initially capitalised pending the results of the well. Costs are expensed where the well does not result in the discovery of economically recoverable hydrocarbons. To the extent that it is considered that the relevant expenditure will not be recovered, it is immediately expensed.

In the statement of cash flows, those cash flows associated with the capitalised exploration and evaluation expenditure are classified as cash flows used in investing activities. Exploration and evaluation expenditure expensed is classified as cash flows used in operating activities.

(iii) *Prepaid drilling and completion costs*

Where the Company has a non-operator interest in an oil or gas property, it may periodically be required to make a cash contribution for its share of the operator's estimated drilling and / or completion costs, in advance of these operations taking place.

Where these contributions relate to a prepayment for exploratory or early stage drilling activity, prior to a decision on the commerciality of a well having been made, the costs are capitalised as prepaid drilling costs within Exploration and Evaluation and / or Development Projects.

Where these contributions relate to a prepayment for well completion, these costs are capitalised as prepaid completion costs within Exploration and Evaluation.

As the operator notifies the Company as to how funds have been expended, the costs are reclassified from prepaid costs to the appropriate expenditure category.

(iv) *Transfer of capitalised exploration and evaluation expenditure to producing projects (oil and gas properties)*

When a well comes into commercial production, accumulated exploration and evaluation expenditure for the relevant Area of Interest is transferred to producing projects and amortised on a units of production basis.

(v) *Producing projects*

Producing projects are stated at cost less accumulated amortisation and impairment charges. Producing projects include construction, installation or completion of production and infrastructure facilities such as pipelines, transferred exploration and evaluation assets, development wells and the provision for restoration.

AURORA OIL & GAS LIMITED

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

For the year ended December 31, 2012

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

(vi)

Amortisation and depreciation of producing projects

The Consolidated Entity uses the "units of production" ("UOP") approach when amortising and depreciating field-specific assets. Using this method of amortisation and depreciation requires the Consolidated Entity to compare the actual volume of production to the reserves and then to apply this determined rate of depletion to the carrying value of depreciable asset.

Capitalised producing projects costs relating to commercially producing wells are depreciated/amortised using the UOP basis once commercial quantities are being produced within an area of interest. The reserves used in these calculations are the Proved plus Probable reserves and are reviewed at least annually.

(vii)

Future restoration costs

The Consolidated Entity's aim is to avoid or minimise environmental impact resulting from its operations.

Provision is made in the statement of financial position for the estimated cost of legal and constructive obligations to restore operating locations in the period in which the obligation arises. The estimated costs are capitalised as part of the cost of the related project where recognition occurs upon acquisition of an interest in the operating locations. The carrying amount capitalised is amortised on a unit of production basis during the production phase of the project.

Work scope and cost estimates for restoration are reviewed annually and adjusted to reflect the expected cost of restoration.

Restoration costs are based on the latest estimated future costs, determined on a discounted basis, which are re-assessed regularly and exclude any allowance for potential changes in technology or material changes in legislative requirements.

The Group accounts for changes in cost estimates on a prospective basis.

(p)

Trade and other payables

Trade payables and other accounts payable are recognised when the Consolidated Entity becomes obliged to make future payments resulting from the purchase of goods and services. They are initially recognised at fair value and subsequently at amortised cost using the effective interest rate method.

(q)

Employee benefits

Provision is made for benefits accruing to employees in respect of employee entitlements when it is probable that settlement will be required and these benefits can be measured reliably. These benefits include wages, salaries, annual leave and long service leave.

Provisions made in respect of employee benefits expected to be settled within 12 months are measured at their nominal values using the remuneration rate expected to apply at the time of settlement.

Provisions made in respect of employee entitlements which are not expected to be settled within 12 months are measured as the present value of the estimated future cash outflows to be made by the consolidated entity in respect of services provided by employees up to reporting date.

(r)

Provisions

Provisions are recognised when the Consolidated Entity has a present obligation as a result of a past event, the future sacrifice of economic benefits is probable, and the amount of the provision can be reliably estimated.

The amount recognised as a provision is the best estimate of the consideration required to settle the present obligation at reporting date, taking into account the risks and uncertainties surrounding the obligation. Where a provision is measured using the cash flows estimated to settle the present obligation, its carrying amount is the present value of those cash flows.

When some or all of the economic benefits required to settle a provision are expected to be recovered from a third party, the receivable is recognised as an asset if it is virtually certain that recovery will be received and the amount of the receivable can be measured reliably.

An onerous contract is considered to exist where the Consolidated Entity has a contract under which the unavoidable cost of meeting the contractual obligations exceeds the economic benefits estimated to be received. Present obligations arising under onerous contracts are recognised as a provision to the extent that the present obligation exceeds the economic benefits estimated to be received.

AURORA OIL & GAS LIMITED

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

For the year ended December 31, 2012

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

(s) Borrowings

Borrowings are initially recognised at fair value, net of transaction costs incurred. Borrowings are subsequently measured at amortised cost. Borrowings are classified as current liabilities unless the Consolidated Entity has an unconditional right to deferred settlement for at least 12 months after the reporting date.

(t) Contributed equity

Ordinary shares are classified as equity.

Incremental costs directly attributable to the issue of new shares or options are shown in equity as a deduction, net of tax, from the proceeds. Incremental costs directly attributable to the issue of new shares or options for the acquisition of a business are not included in the cost of the acquisition as part of the purchase consideration.

If the Company reacquires its own equity instruments, e.g. as the result of a share buy-back, those instruments are deducted from equity and the associated shares are cancelled. No gain or loss is recognised in the profit or loss and the consideration paid, including any directly attributable incremental costs (net of income taxes), is recognised directly in equity.

(u) Borrowing costs

Borrowing costs are expensed in the period in which they are incurred, except to the extent to which they are directly attributable to the acquisition, construction or production of a qualifying asset and it is probable that they will result in future economic benefits to the entity and the costs can be measured reliably.

(v) Good and services tax

Revenues, expenses and assets are recognised net of the amount of goods and services tax (GST), except:

- where the amount of GST incurred is not recoverable from the taxation authority, it is recognised as part of the cost of acquisition of an asset or as part of an item of expense; or

- for receivables and payables which are recognised inclusive of GST.

The net amount of GST recoverable from, or payable to, the taxation authority is included as part of receivables or payables. Cash flows are included in the cash flow statement on a gross basis. The GST component of cash flows arising from investing and financing activities which is recoverable from, or payable to, the taxation authority is classified as operating cash flows.

(w) Earnings per share

(i) Basic earnings per share

Basic earnings per share is calculated by dividing the profit (or loss) attributable to equity holders of the company, excluding any costs of servicing equity other than ordinary shares, by the weighted average number of ordinary shares outstanding during the financial year, adjusted for bonus elements in ordinary shares issued during the year.

(ii) Diluted earnings per share

Diluted earnings per share adjusts the figures used in the determination of basic earnings per share to take into account the after income tax effect of interest and other financing costs associated with dilutive potential ordinary shares and the weighted average number of shares assumed to have been issued for no consideration in relation to dilutive potential ordinary shares.

(x) Share-based payments

The Group has provided benefits to its employees (including key management personnel) in the form of share-based payments, whereby services were rendered partly or wholly in exchange for shares or rights over shares. The Remuneration Committee has also approved the grant of options or performance rights as incentives to attract executives and to maintain their long term commitment to the Company. These benefits were awarded at the discretion of the board, or following approval by shareholders.

The costs of these equity-settled transactions are measured by reference to the fair value of the equity instruments at the date on which they are granted. The fair value of performance rights granted under the Aurora Oil & Gas Limited performance rights plan is determined using a risked statistical analysis. The fair value of performance rights granted under the Aurora Oil & Gas Limited long

AURORA OIL & GAS LIMITED

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

For the year ended December 31, 2012

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

term incentive plan is determined using binomial tree and Monte-Carlo simulation valuation models. Further details of performance rights granted under each plan are disclosed in note 27. The fair value of options granted is determined by using a Black-Scholes option pricing technique.

The costs of these equity-settled transactions is recognised, together with a corresponding increase in equity, over the period in which the performance and / or service conditions are fulfilled (the vesting period).

At each subsequent reporting date until vesting, the cumulative charge to the income statement is the product of (i) the fair value at grant date of the award; (ii) the current best estimate of the number of equity instruments that will vest, taking into account such factors as the likelihood of employee turnover during the vesting period and the likelihood of non-market performance conditions being met and (iii) the expired portion of the vesting period.

The charge to the income statement for the period is the cumulative amount as calculated above less the amounts already charged in previous periods. There is a corresponding credit to equity.

Until an equity instrument has vested, any amounts recorded are contingent and will be adjusted if more or fewer equity instruments vest than were originally anticipated to do so. Any equity instrument subject to a market condition is considered to vest irrespective of whether or not that market condition is fulfilled, provided that all other conditions are satisfied.

If the terms of an equity-settled award are modified, as a minimum, an expense is recognised as if the terms had not been modified. An additional expense is recognised for any modification that increases the total fair value of the share based payment arrangement, or is otherwise beneficial to the recipient of the award, as measured at the date of modification.

If an equity-settled transaction is cancelled (other than a grant cancelled by forfeiture when the vesting conditions are not satisfied), it is treated as if it had vested on the date of cancellation, and any expense not yet recognised for the award is recognised immediately. However, if a new equity instrument is substituted for the cancelled award and designated as a replacement award on the date that it is granted, the cancelled and new equity instrument are treated as if they were a modification of the original award, as described in the preceding paragraph.

The dilutive effect, if any, of outstanding options is reflected as additional share dilution in the computation of diluted earnings per share (see note 25).

(y)

Rounding of amounts

The Company is of a kind referred to in Class order 98/100, issued by the Australian Securities and Investments Commission, relating to the "rounding off" of amounts in the financial statements. Amounts in the financial statements have been rounded off in accordance with the Class Order to the nearest thousand dollars, or in certain cases, the nearest dollar.

(z)

New accounting standards and interpretations

The Group has chosen not to early-adopt any accounting standards that have been issued, but are not yet effective. Set out below is a summary of issued accounting standards, relevant to the Group, which are not yet effective and a description of their expected effect on the Group's financial statements (if any).

(i)

AASB 2010-2 Amendments to Australian Accounting Standards arising from the Reduced Disclosure Requirements *(effective for annual reporting periods commencing on or after July 1, 2013)*

Entities classified as Tier 2 entities in AASB 1053 Application of Tiers of Australian Accounting Standards that currently apply full IFRSs as adopted in Australia are able to adopt the Reduced Disclosure Requirements.

The entity is a Tier 1 entity and therefore is not eligible to apply the Reduced Disclosure Requirements of AASB 2010-2.

(aa)

New accounting standards and interpretations

(ii)

AASB 2011-6 Amendments to Australian Accounting Standards Extending Relief from Consolidation, Equity Method and Proportionate Consolidation Reduced Disclosure Requirements **[AASB 127, AASB 128 & AASB 131]** *(effective for annual reporting periods commencing on or after July 1, 2013).*

In July 2011, the AASB extended relief from preparing consolidated financial statements to entities applying the Reduced Disclosure Requirements wanting to apply the consolidation exemption in paragraph 10 of AASB 127 (or exemption from equity accounting or proportionate consolidation under equivalent paragraphs in AASB 128 and AASB 131) where the ultimate parent entity prepares consolidated financial statements using the Reduced Disclosure requirements, rather than using full IFRS.

AURORA OIL & GAS LIMITED

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

For the year ended December 31, 2012

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

When this standard is first adopted, there will be no impact on presentation because the group has always qualified for relief from preparing consolidated financial statements because its parent entity produces consolidated financial statements in accordance with IFRS.

(iii)

AASB 9 Financial Instruments and AASB 2009-11 Amendments to Australian Accounting Standards arising from AASB 9 and AASB 2010-7 Amendments to Australian Accounting Standards arising from AASB 9 (December 2010) *(effective for annual reporting periods beginning on or after January 1, 2015).*

AASB 9 addresses the classification, measurement and derecognition of financial assets and financial liabilities. The standard is not applicable until January 1, 2015 but is available for early adoption. The Group is continuing to assess its full impact.

(iv)

AASB 10 Consolidated Financial Statements *(effective for annual reporting periods commencing on or after January 1, 2013)*

Issued May 2011, AASB 10 introduces a single 'control model' for all entities, including special purpose entities (SPEs), whereby all of the following conditions must be present:

Power over investee (whether or not power used in practice)

Exposure, or rights, to variable returns from investee

Ability to use power over investee to affect the entity's returns from investee.

When this standard is first adopted for the year ended December 31, 2013, there will be no impact on transactions and balances recognised in the financial statements because the entity does not have any special purpose entities.

(v)

AASB 11 Joint Arrangements *(effective for the annual reporting periods commencing on or after January 1, 2013).*

AASB 11 introduces certain changes to the accounting for joint arrangements. Joint arrangements will be classified as either joint operations (where parties with joint control have rights to assets and obligations for liabilities) or joint ventures (where parties with joint control have rights to the net assets of the arrangement).

Joint arrangements structured as a separate vehicle will generally be treated as joint ventures and accounted for using the equity method. The Group is continuing to assess the impact of the standard.

(vi)

AASB 12 Disclosure of Interests in Other Entities *(effective for annual reporting periods commencing on or after January 1, 2013)*

Issued August 2011, AASB 12 combines existing disclosures from AASB 127 Consolidated and Separate Financial Statements, AASB 128 Investments in Associates and AASB 131 Interests in Joint Ventures and introduces new disclosure requirements for interests in associates and joint arrangements, as well as new requirements for unconsolidated structured entities.

As this is a disclosure standard only, there will be no impact on amounts recognised in the financial statements. However, additional disclosures will be required for interests in joint arrangements, as well as for unconsolidated structured entities.

(vii)

AASB 13 Fair Value Measurement *(effective from January 1, 2013)*

Issued May 2011 requires additional disclosures for items measured at fair value in the statement of financial position, as well as items merely disclosed at fair value in the notes to the financial statements. Extensive additional disclosure requirements for items measured at fair value that are 'level 3' valuations in the fair value hierarchy that are not financial instruments, for example land and buildings and investment properties.

(viii)

AASB 1053 Application of Tiers of Australian Accounting Standards and AASB 2010-2 Amendments to Australian Accounting Standards arising from Reduced Disclosure Requirements *(effective from July 1, 2013).*

On June 30, 2010 the AASB officially introduced a revised differential reporting framework in Australia. Under this framework, a two-tier differential reporting regime applies to all entities that prepare general purpose financial statements.

Aurora is listed on the ASX and TSX and is not eligible to adopt the new Australian Accounting Standards   Reduced Disclosure Requirements. The two standards will therefore have no impact on the financial statements of the entity.

AURORA OIL & GAS LIMITED

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

For the year ended December 31, 2012

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

(ix)

AASB 119 Employee Benefits *(effective from January 1, 2013).*

Employee benefits expected to be settled (as opposed to due to settle under contract) wholly within 12 months after the end of the reporting period are short-term benefits, and therefore not discounted when calculating leave liabilities. Annual leave not expected to be used wholly within 12 months of end of reporting period will in future be discounted when calculating leave liability.

When this standard is first adopted for December 31, 2013 year end, a portion of annual leave liabilities will be recalculated on January 1, 2012 as long term benefits because they are not expected to be settled wholly within 12 months after the end of the reporting period. This will result in a reduction of the annual leave liabilities recognised on January 1, 2012, and a corresponding increase in retained earnings at that date.

2. CRITICAL ACCOUNTING ESTIMATES AND JUDGEMENTS

In preparing these financial statements the Group has been required to make certain estimates and assumptions concerning future occurrences. There is an inherent risk that the resulting accounting estimates will not equate exactly with actual events and results.

(a)

Critical accounting estimates

The carrying amounts of certain assets and liabilities are often determined based on estimates and assumptions of future events. The key estimates and assumptions that have a significant risk of causing a material adjustment to the carrying amounts of assets and liabilities within the next financial year are discussed below.

(i)

Share-based payment transactions

The Group measures the cost of equity-settled transactions with employees by reference to the fair value of the equity instruments at the date at which they are granted. The fair value is determined using a risked statistical analysis, or binomial tree and Monte-Carlo simulation valuation techniques or a Black Scholes Option Pricing Model, using the assumptions detailed in note 27.

(ii)

Rehabilitation and decommissioning obligations

The Group estimates the future rehabilitation costs of production facilities, wells and pipelines at different stages of the development and construction of assets or facilities. In most instances, removal of assets occurs many years into the future. This requires judgemental assumptions regarding removal date, future environmental legislation, the extent of restoration activities and the future removal technology available and liability specific discount rates to determine the present value of these cash flows. As at December 31, 2012 rehabilitation obligations have a carrying value of US$1,705,000 (December 31, 2011: US$565,000).

(iii)

Reserves estimates

Estimation of reported recoverable quantities of Proven and Probable reserves include judgemental assumptions regarding commodity prices, exchange rates, discount rates and production and transportation costs for future cash flows. It also requires interpretation of complex geological and geophysical models in order to make an assessment of the size, shape, depth and quality of reservoirs and their anticipated recoveries. These factors used to estimate reserves may change from period to period.

Reserve estimates are prepared in accordance with assumption and methodology guidelines outlined in the Canadian Oil and Gas Evaluation Handbook and in accordance with National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities.

Reserve estimates are used to calculate amortisation of producing assets and therefore a change in reserve estimates impacts the carrying value of assets and the recognition of deferred tax assets due to the changes in expected future cash flows (see below).

(iv)

Depletion and depreciation

In relation to the depletion of capitalised exploration and evaluation expenditure and the depreciation of property plant and equipment related to producing oil and gas properties, the Consolidated Entity uses a unit of production reserve depletion model to calculate amortisation and depreciation. This method of amortisation and depreciation necessitates the estimation of the oil and gas reserves over which the carrying value of the relevant assets will be expensed to the profit or loss. The calculation of oil and gas reserves is extremely complex and requires management to make judgements about commodity prices, future production costs and geological structures. The nature of reserve estimation is such that reserves are not intended to be 100% accurate but rather provide a statistically probable outcome in relation to the economically recoverable reserve. As the actual reserve can only be accurately determined once production has ceased, amortisation and depreciation expensed during the production may not on a year to year basis accurately reflect the actual

AURORA OIL & GAS LIMITED

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

For the year ended December 31, 2012

2. CRITICAL ACCOUNTING ESTIMATES AND JUDGEMENTS (Continued)

percentage of reserve depleted. However, over the entire life of the producing assets all capitalised costs will be expensed to the profit or loss.

(v)

Impairment of assets

In the absence of readily available market prices, the recoverable amounts of assets are determined by discounting the expected future net cash flows from production and comparing these to the carrying value of the relevant asset or group of assets to determine the asset's net present value. The calculation of net present value is based on assumptions concerning discount rates, reserves, future production profiles, commodity prices and costs.

3. FINANCIAL RISK MANAGEMENT

The financial risks that arise during the normal course of Aurora's operations comprise market risk, credit risk and liquidity risk. In managing financial risk, it is Aurora's policy to seek a balance between the potential adverse effects of financial risks on Aurora's financial performance and position, and the "upside" potential made possible by exposure to these risks and by taking into account the costs and expected benefits of the various risk management methods available to manage them.

General objectives, policies and processes

Aurora's board of directors (Board) is responsible for approving Aurora's policies on risk oversight and management and ensuring management has developed and implemented effective risk management and internal control. Whilst maintaining ultimate responsibility for financial risk management, the Board has delegated the responsibility for ensuring that management has designed processes that ensure the effective implementation of the objectives and policies to the Audit and Risk Management Committee. The Audit and Risk Management Committee receives reports as required from the Chief Financial Officer and other relevant Executives in which they review the effectiveness of the processes implemented and the appropriateness of the objectives and policies it sets.

Aurora's Audit and Risk Management Committee oversees how management monitors compliance with the Group's risk management policies and procedures and reviews the adequacy of the risk management framework in relation to the risks faced by Aurora.

These disclosures are not, nor are they intended to be an exhaustive list of risks to which Aurora is exposed.

Financial instruments

The group holds the following financial instruments:

	Consolidated	
	December 31, 2012	**December 31, 2011**
	US$'000	**US$'000**
Financial assets		
Cash and cash equivalents	**67,584**	70,246
Trade receivables	**89,535**	14,626
Financial assets at fair value through other comprehensive income	**842**	2,507
	157,961	87,379
Financial liabilities		
Trade and other payables	**180,619**	73,434
Borrowings	**390,453**	30,000
Derivative financial instruments	**1,649**	
	572,721	103,434

(a)

Market risk

Market risk arises from Aurora's exposure to commodity price risk and the use of interest bearing and foreign currency financial instruments. It is a risk that the fair value of future cash flows of a financial instrument will fluctuate because of changes in interest rates (interest rate risk), foreign exchange rates (currency risk) or natural gas, condensate and oil prices (commodity price risk).

AURORA OIL & GAS LIMITED

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

For the year ended December 31, 2012

3. FINANCIAL RISK MANAGEMENT (Continued)

(i)

Commodity price risk

The Group is exposed to commodity price risk arising from fluctuations in the prices of natural gas, condensate and oil. The demand for, and prices of, natural gas, condensate and oil are dependent on a variety of factors, including:

Supply and demand;

Weather conditions;

The price and availability of alternative fuels;

Actions taken by governments and international cartels; and

Global economic and political developments.

The Board recognises that through the normal course of its business activities, the Company is exposed to various market risks, including commodity risk. To manage commodity price risk the Board established a hedging committee during the year ended December 31, 2012 to implement and manage effective hedges of commodity price pursuant to Board approved levels. To manage the Group's commodity price risk exposure during the year ended December 31, 2012, the Group entered into cash settled commodity swap and zero cost collar hedging arrangements with financial institutions, as disclosed at note 19 Derivative financial instruments.

Sensitivity analysis change in US$ oil price

The following table demonstrates the estimated sensitivity to a US$10 increase / decrease in the oil price, with all variables held constant, on post tax profit and equity. These sensitivities should not be used to forecast the future effect of movement in the oil price on future cash flows.

	December 31, 2012	December 31, 2011
	US$'000	US$'000
Impact on post-tax profits		
US$ oil / condensate price + $10	**26,470**	10,431
US$ oil / condensate price - $10	**(26,470)**	(10,431)
Impact on equity		
US$ oil / condensate price + $10	**26,470**	10,431
US$ oil / condensate price - $10	**(26,470)**	(10,431)

The impact on post-tax profits and equity resulting from a $10 movement in Gas or NGL prices is not considered material.

(ii)

Foreign exchange risk

The functional currency of the Group is US dollars and the Group operates in the US, however maintains corporate listings in Australia and in Canada. The Group is exposed to foreign exchange risk arising from fluctuations in the US dollar and Australian dollar, and US dollar and Canadian dollar at parent entity level on cash balances.

Foreign exchange risk arises from future commercial transactions and recognised assets and liabilities denominated in a currency that is not the entity's functional currency. The exposure to risks is measured using sensitivity analysis and cash flow forecasting.

The Board has formed the view that it would not be beneficial for the Group to purchase forward contracts or other derivative financial instruments to hedge this foreign exchange risk, other than on an ad hoc basis for significant foreign currency transactions. Factors which the Board considered in arriving at this position included, the expense of purchasing such instruments and the inherent difficulties associated with forecasting the timing and quantum of Australian and Canadian dollar cash inflows and outflows, compared to the relatively low volume and value of commercial transactions and recognised assets and liabilities denominated in a currency which is not US dollars.

AURORA OIL & GAS LIMITED

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

For the year ended December 31, 2012

3. FINANCIAL RISK MANAGEMENT (Continued)

The Group's exposure to foreign currency risk at the end of the reporting period, expressed in US dollars, was as follows:

	December 31, 2012		
	AUD	CAD	Total
	US$'000	US$'000	US$'000
Financial assets			
Cash and cash equivalents	924	1,111	2,035
Trade and other receivables	320	4	324
Other financial assets	842		842
Total financial assets	**2,086**	**1,115**	**3,201**
Financial liabilities			
Trade and other payables	2,359	48	2,407
Total financial liabilities	**2,359**	**48**	**2,407**

	December 31, 2011		
	AUD	CAD	Total
	US$'000	US$'000	US$'000
Financial assets			
Cash and cash equivalents	1,134	465	1,599
Trade and other receivables	93		93
Other financial assets	2,507		2,507
Total financial assets	**3,734**	**465**	**4,199**
Financial liabilities			
Trade and other payables	403	590	933
Total financial liabilities	**403**	**590**	**933**

Sensitivity analysis change in Australian / US dollar exchange rate and Canadian / US dollar exchange rate

The following table demonstrates the estimated sensitivity to a 10% increase / decrease in the Australian / US dollar exchange rate and a 10% increase / decrease in the Canadian / US dollar exchange rate, with all variables held consistent, on post tax profit and equity. These sensitivities should not be used to forecast the future effect of movement in the US dollar exchange rate on future cash flows.

	December 31, 2012	December 31, 2011
	US$'000	US$'000
Impact on post-tax profits		
AUD / US$ + 10%	**(39)**	397
AUD / US$ - 10%	**18**	(281)
CAD / US$ + 10%	**110**	83
CAD / US$ - 10%	**(104)**	(124)
Impact on equity		
AUD / US$ + 10%	**(39)**	397

AUD / US$ - 10%	**18**	(281)
CAD / US$ + 10%	**110**	83
CAD / US$ - 10%	**(104)**	(124)

AURORA OIL & GAS LIMITED

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

For the year ended December 31, 2012

3. FINANCIAL RISK MANAGEMENT (Continued)

A hypothetical change of 10% in the Australian dollar and Canadian dollar exchange rates was used to calculate the Group's sensitivity to foreign exchange rate movements as this is management's estimate of possible rate movements over the coming year taking into account current market conditions and past volatility (December 31, 2011: 10%).

(iii) *Interest rate risk*

As at and during the year ended December 31, 2012 the Group had interest-bearing assets and liabilities, being liquid funds on deposit, a drawn down balance from the senior secured revolving credit facility and senior unsecured notes. As such, the Group's income and operating cash flows (other than interest income from funds on deposit and interest expense from the senior secured revolving credit facility) are somewhat dependent on changes in market interest rates. The Board manages the Group's exposure to interest rate risk by regularly assessing the company's exposure, taking into account funding requirements and selecting appropriate investments to manage its exposure.

Sensitivity analysis change in interest rates

Based on the financial instruments held at reporting date, with all other variables assumed to be held constant, the table below sets out the notional effect on consolidated profit after tax for the year and on equity at reporting date under varying hypothetical changes in prevailing interest rates:

	Consolidated	
	December 31, 2012	December 31, 2011
	US$'000	US$'000
Impact on post-tax profit		
Hypothetical 90 basis points[1] increase in interest	**2,677**	(362)
Hypothetical 90 basis points[1] decrease in interest	**(2,677)**	362
Impact on equity		
Hypothetical 90 basis points[1] increase in interest	**2,677**	362
Hypothetical 90 basis points[1] decrease in interest	**(2,677)**	(362)

(1) A hypothetical change of 90 basis points was used to calculate the Group's sensitivity to future interest rate movements as this figure approximates the movement in bond yields published by the Reserve Bank of Australia for bonds with a 12 month maturity (December 31, 2011: 0.90%).

The weighted average effective interest rate of funds on deposit is 0.08% (December 31, 2011: 0.32%).

(iv) *Price risk*

The Group is exposed to equity securities price risk in relation to its financial assets at fair value through other comprehensive income. The carrying value of investments at December 31, 2012 is US$842,000 (December 31, 2011: US$2,507,000). The impact of fluctuations in the fair value of these investments on post-tax profit for the year would depend on whether such fluctuations were as a result of impairment or of short-term market movements.

AURORA OIL & GAS LIMITED

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

For the year ended December 31, 2012

3. FINANCIAL RISK MANAGEMENT (Continued)

Sensitivity analysis change in share price

In the table below movements in share price are assumed to be short-term market movement related and the movement in the fair value would be recognised in the statement of profit or loss and other comprehensive income.

	Consolidated	
	December 31, 2012	December 31, 2011
	US$'000	US$'000
Impact on post-tax profit		
Hypothetical 50%[1] increase in price		
Hypothetical 20%[1] decrease in price		
Impact on equity		
Hypothetical 50%[1] increase in price	**421**	1,254
Hypothetical 20%[1] decrease in price	**(168)**	(501)

(1) Management has determined that the above hypothetical outcomes are the most appropriate estimation of share price movements given the current market and economic conditions.

(b) Credit risk

Credit risk arises from cash and cash equivalents and deposits with financial institutions, as well as trade receivables and non-current oil and gas assets as these assets consist of interests in projects operated by a single US public company.

The Board are of the opinion that the credit risk arising as a result of this concentration of the Group's assets is more than offset by the potential benefits to be gained through continuing to build on the Group's relationship with the operator of its existing projects.

The maximum exposure to credit risk at the reporting date is the carrying amount of the assets as summarised below, none of which are impaired or past due. The Group has a number of recourse options available in the event of counterparty default, including but not limited to de facto security over jointly held assets.

	Consolidated	
	December 31, 2012	December 31, 2011
	US$'000	US$'000
Cash and cash equivalents	**67,584**	70,246
Trade receivables	**89,535**	14,045
Prepaid exploration, development and lease acquisition expenses		12,560
Total	**157,119**	96,851

To manage exposure to credit risk from cash and cash equivalent financial assets, it was the Group's policy during 2012 to deposit only with banks and financial institutions with a minimum independent rating of 'AA'. Due to the current prevailing market conditions in the US, depositing of cash and cash equivalents for US domicile subsidiaries with banks or financial institutions with a minimum 'AA' rating

AURORA OIL & GAS LIMITED

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

For the year ended December 31, 2012

3. FINANCIAL RISK MANAGEMENT (Continued)

was not achievable. To mitigate this risk, cash and cash equivalents have been deposited in the US with products carrying the 100% Government guarantee.

	Consolidated	
	December 31, 2012	**December 31, 2011**
	US$'000	**US$'000**
Cash at bank and short-term bank deposits		
Held with Australian banks and financial institutions		
AA Rated	**2,080**	7,774
Held with US banks and financial institutions		
AA Rated		
A- Rated	**65,278**	62,472
BBB Rated	**226**	
Total	**67,584**	70,246

(c) Liquidity risk

Prudent liquidity management involves the maintenance of sufficient cash, marketable securities, committed credit facilities and access to capital markets. It is the policy of the Board to ensure that the Group is able to meet its financial obligations and maintain the flexibility to pursue attractive investment opportunities through ensuring the Group has sufficient working capital, available credit lines and preserving the 15% share issue limit available to the Company under the ASX Listing Rules.

(i) Financing arrangements

On November 8, 2011, Aurora USA Oil and Gas Inc. ("Aurora USA"), a wholly owned subsidiary of the Company, signed a credit agreement with a syndicate of banks, pursuant to which up to US$300 million may be available on a revolving basis (refer to note 17 Borrowings).

(ii) Maturities of financial liabilities

As at December 31, 2012 the Group had total financial liabilities of US$572,721,000 (December 31, 2011: US$103,433,480). This comprised non interest bearing trade creditors and accruals with a maturity of less than 6 months, interest bearing borrowings with maturities between 1 and 5 years and derivative financial instruments with maturities between 1 and 2 year.

AURORA OIL & GAS LIMITED

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

For the year ended December 31, 2012

3. FINANCIAL RISK MANAGEMENT (Continued)

The table below analyses the Group's financial liabilities into relevant maturity groupings. The amounts disclosed in the table are the contractual undiscounted cash flows. Balance due within 12 months equal the carrying amount as the impact of discounting is not significant.

	Consolidated			
Contractual maturities of financial liabilities	**Less than 12 months**	**Between 1 and 5 years**	**Total contractual cash flows**	**Carrying Amount**
	US$'000	**US$'000**	**US$'000**	**US$'000**
At December 31, 2012				
Non derivative				
Non-interest bearing	**180,619**		**180,620**	**180,619**
Borrowings fixed rate		**365,000**	**513,125**	**360,453**
Borrowings variable rate		**30,000**	**33,071**	**30,000**
Total non derivative	**180,619**	**395,000**	**726,816**	**571,072**
Derivatives				
Gross settled forward commodity price contracts				
cash flow hedges:				
(inflow)	**(534)**		**(534)**	**(534)**
outflow	**2,069**	**114**	**2,183**	**2,183**
Total derivative	**1,535**	**114**	**1,649**	**1,649**
At December 31, 2011				
Non derivative				
Non-interest bearing	73,433		73,433	73,433
Variable rate(1)		30,000	30,121	30,000
Total non derivative	73,433	30,000	103,554	103,433

(1) Subsequent to December 31, 2011, the Group repaid 100% of the variable rate non-derivative financial liability. The balance of US$30,121,617, under total contractual cash flows, is the actual interest paid and the non-derivative variable rate loan balance repaid subsequent to December 31, 2011. The facility retention fee, payable on a quarterly basis, has not been included as a contractual cash flow.

(d) Fair value estimation

The fair value of financial assets and liabilities held by the Group must be estimated for recognition, measurement and / or disclosure purposes. The Group measures fair values by level, per the following fair value measurement hierarchy:

i. quoted prices (unadjusted) in active markets for identical assets or liabilities (level 1);

ii. inputs other than quoted prices included within level 1 that are observable for the asset or liability, either directly (as prices) or indirectly (derived from prices) (level 2); and

iii. inputs for the asset or liability that are not based on observable market data (unobservable inputs) (level 3).

The Group's investment in equity securities is measured under level 1 disclosure requirements. The fair value of US$842,000 (December 31, 2011: US$2,507,000) was determined based on the securities quoted market closing bid price.

The fair value of financial instruments traded in active markets (such as financial assets at fair value through other comprehensive income) is based on quoted market prices at the reporting date. The quoted market price used for financial assets held by the Group is the current bid price.

AURORA OIL & GAS LIMITED

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

For the year ended December 31, 2012

3. FINANCIAL RISK MANAGEMENT (Continued)

The carrying values (net of any applicable impairment provision) of trade receivables and payables are assumed to approximate their fair values due to their short-term nature. The Group has considered the fair value of borrowings and have determined that carrying amount is a reasonable approximation of fair value.

(e) Capital risk management

The Group manages its capital to ensure entities in the Group will be able to continue as a going concern while maximising the potential return to shareholders.

The capital structure of the Group is considered to include the total equity plus borrowings, which at December 31, 2012 was US$844 million (December 31, 2011: US$575 million). In determining the funding mix of debt and equity (total borrowings / total equity), consideration is given to the relative impact of the gearing ratio on the ability of the Group to service loan interest and repayment schedules, credit facility covenants and also to generate adequate free cash available for corporate and oil and gas production and development activities. The debt to equity ratio was 46% as at December 31, 2012 (December 31, 2011: 5%).

The capital of Group subsidiary entities is subject to externally imposed guarantees for the senior secured revolving credit facility (refer to note 17 Borrowings).

4. SEGMENT INFORMATION

Management has determined, based on the reports reviewed by the CEO and Executive Chairman and used to make strategic decisions, that the Group has one reportable segment being oil and gas exploration and production in the United States of America. The Group's management and administration office is located in Australia.

The CEO and Executive Chairman reviews internal management reports on a monthly basis that are consistent with the information provided in the statement of profit or loss and other comprehensive income, statement of financial position and statement of cash flows. As a result no reconciliation is required, because the information as presented is used by the CEO and Executive Chairman to make strategic decisions.

Reportable segment revenue

Revenue, including interest income, is disclosed below based on the reportable segment:

	December 31, 2012 US$'000	December 31, 2011 US$'000
Revenue from oil and gas exploration and production	**294,812**	75,079
Revenue from other corporate activities	**5,255**	1,942
	300,067	77,021

Reportable segment assets

Assets are disclosed below based on the reportable segment:

	December 31, 2012 US$'000	December 31, 2011 US$'000
Assets from oil and gas exploration and production	**1,041,143**	306,173
Assets from corporate activities:		
Cash and cash equivalents	**67,584**	70,246
Other corporate assets	**2,670**	4,407

	1,111,397	380,826

AURORA OIL & GAS LIMITED

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

For the year ended December 31, 2012

4. SEGMENT INFORMATION (Continued)

Reportable segment liabilities

Liabilities are disclosed below based on the reportable segment:

	December 31, 2012	December 31, 2011
	US$'000	US$'000
Liabilities from oil and gas exploration and production	**655,090**	102,100
Liabilities from corporate activities	**3,193**	3,634
	658,283	105,734

Reportable segment profit

Profit / (loss) is disclosed below based on the reportable segment:

	December 31, 2012	December 31, 2011
	US$'000	US$'000
Profit from oil and gas exploration and production	**74,016**	40,980
(Loss) from other corporate activities	**(15,170)**	(10,396)
	58,846	30,584

5. REVENUE

	Consolidated	
	December 31, 2012	December 31, 2011
	US$'000	US$'000
From continuing operations		
Sales revenue		
Oil and gas sales	**294,936**	75,079
Realised profit / (loss) on forward commodity price contracts	**(124)**	
	294,812	75,079
Other revenue		
Interest	**247**	649
Other		241
	247	890
Total revenue from continuing operations	**295,059**	75,969

6. OTHER INCOME

		Consolidated	
	Notes	December 31, 2012	December 31, 2011

		US$'000	US$'000
Foreign exchange gain	(i)	**3,042**	989
Net gain on financial assets		**770**	
Net gain on foreign currency derivatives not qualifying as hedges		**1,167**	
Other		**29**	63
Total other income		**5,008**	1,052

(i) During the year ended December 31, 2012 and the comparable year ended December 31, 2011, the Consolidated Entity recognised a foreign exchange gain in relation to the retranslation of Australian and Canadian dollar denominated cash and cash equivalents.

AURORA OIL & GAS LIMITED

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

For the year ended December 31, 2012

7. EXPENSES

Profit before income tax includes the following specific expenses:

	Notes	Consolidated December 31, 2012 US$'000	December 31, 2011 US$'000
Royalties expense	(i)	**77,625**	20,067
Production and operating expense			
Sales taxes	(ii)	**10,073**	2,822
Operating expenses	(iii)	**24,508**	3,915
Total production and operating expenses		**34,581**	6,737
Deprecation and depletion expense			
Depreciation	(iv)	**3,202**	929
Depletion	(v)	**35,959**	3,438
Total depletion and depreciation expense		**39,161**	4,367
Share-based payment expenses			
Options		**3,857**	3,969
Performance rights		**541**	83
Total share-based payment expense	(vi)	**4,398**	4,052
Finance costs			
Interest expense		**24,539**	70
Amortisation of borrowing costs		**2,638**	66
Amortisation of debt premium and debt discount		**289**	
Other financing fees		**561**	
Total finance costs	(vii)	**28,027**	136
Exploration and evaluation costs written off	(viii)	**4,939**	652

(i) Aurora pays royalties to the owners of the petroleum rights on the land in which the Group owns lease interests. Royalties, as a percentage of production revenue, are payable in accordance with the terms of individual leasehold agreements and are generally payable for the production life of each well within the leasehold area.

(ii) Sales taxes include local state tax expense and severance tax payable in the State of Texas, USA.

(iii) Operating expenses include field operating costs and transportation of production.

(iv) Depreciation is calculated using the reducing balance method to allocate the cost of property, plant and equipment over their useful lives.

(v)

Depletion is calculated based on estimated remaining Proven and Probable reserves.

(vi) The Group issued performance rights to key management personnel on February 19, 2010 and to executives under Aurora's Long Term Incentive Plan ("LTIP") on May 29, 2012, and October 18, 2012 and to employees only on February 1, 2012 and December 31, 2012. The Group issued options to executive management personnel between November 2010 and June 2011 and on October 18, 2012. For the year ended December 31, 2012 a performance right expense of US$540,602 (December 31, 2011: US$83,000) and an option expense of US$3,857,063 (December 31, 2011: US$3,969,000) was recognised.

(vii) Finance costs were incurred in respect of the senior secured revolving credit facility entered into on November 7, 2011 and the senior unsecured notes issued on February 8, 2012 and the follow on notes issued on July 31, 2012.

(viii) Transaction costs written off during the year ended December 31, 2012 consisted of ancillary costs incurred in relation to the on market bid for the issued share capital of Australian Securities Exchange (ASX) listed Eureka Energy Limited ("Eureka") and evaluation expenditure that could not be directly attributable to the acquisition, construction or production of a qualifying asset providing probable future economic benefits to the entity.

AURORA OIL & GAS LIMITED

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

For the year ended December 31, 2012

8. INCOME TAX EXPENSE

	Consolidated	
	December 31, 2012	December 31, 2011
	US$'000	US$'000
(a) Income tax expense		
Current tax		
Deferred tax	**37,356**	1,643
Income tax expense	**37,356**	1,643
(b) Reconciliation of income tax expense to prima facie tax payable		
Profit from continuing operations before income tax expense	**96,202**	32,227
Tax at the Australian statutory tax rate of 30% (December 31, 2011: 30%)	**28,861**	9,668
Tax effect of amounts that are not deductible (taxable) in calculating taxable income		
Share-based payment expense	**1,157**	1,041
Foreign exchange gains not assessable	**(1,026)**	(321)
Revenue losses not previously recognised now brought to account	**(357)**	(426)
(Expense) / benefit from a previously unrecognised temporary difference now recognised	**3,205**	(8,833)
Income tax rate differences	**5,359**	456
Other non-allowable deductions	**157**	58
Income tax expense	**37,356**	1,643
(c) Tax expense (income) relating to items of other comprehensive income		
Financial assets at fair value through other comprehensive income	**1,509**	
Cash flow hedges	**495**	
	2,004	

9. CASH AND CASH EQUIVALENTS

	Consolidated	
	December 31, 2012	December 31, 2011
	US$'000	US$'000
Held with Australian banks and financial institutions		
Cash at bank and in hand	**1,976**	7,137
Deposits at call	**104**	637
Held with US banks and financial institutions		
Cash at bank and in hand	**65,504**	62,472
	67,584	70,246

(a)

Risk exposure

The Group's exposure to interest rate risk is discussed at Note 3 Financial Risk Management. The maximum exposure to credit risk at the end of the reporting period is the carrying amount of each class of cash and cash equivalents mentioned above.

(b)

Deposits at call

Deposits at call held with Australian banks and financial institutions earn interest at 4.40% floating rate (December 31, 2011: 4.50%).

Cash held with US banks earn interest at rates between 0% and 0.50%.

AURORA OIL & GAS LIMITED

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

For the year ended December 31, 2012

10. TRADE AND OTHER RECEIVABLES

	Consolidated	
	December 31, 2012	December 31, 2011
	US$'000	US$'000
Trade receivables	**89,535**	14,626

(a)
Trade receivables

Trade receivables represents revenue earned but not yet received from the production and sale of oil, natural gas and natural gas liquids.

(b)
Impaired trade receivables
No Group trade receivables were past due or impaired as at December 31, 2012 (December 31, 2011: Nil) and there is no indication that amounts recognised as trade and other receivables will not be recovered in the normal course of business.

11. OTHER FINANCIAL ASSETS

	Consolidated	
	December 31, 2012	December 31, 2011
	US$'000	US$'000
Financial assets at fair value through other comprehensive income	**842**	2,507

(a)
Significant interest in other financial assets

An interest in a financial asset is considered 'significant' when Aurora holds 5% or more of issued share capital.

Aurora holds a significant interest in Elixir Petroleum Ltd. As at December 31, 2012, Aurora held 33,833,334 fully paid ordinary shares in Elixir Petroleum Ltd (December 31, 2011: 29,000,000), representing approximately 12.20% of its total issued capital. The market value of these securities at December 31, 2012 was US$842,000 (December 31, 2011: US$2,507,000).

Included in the statement of profit or loss and other comprehensive income is US$957,000 (December 31, 2011: US$(1,302,000)) which represents the movement in the financial assets at fair value through other comprehensive income.

AURORA OIL & GAS LIMITED

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

For the year ended December 31, 2012

12. PROPERTY, PLANT AND EQUIPMENT

	Consolidated	
	December 31, 2012	December 31, 2011
	US$'000	US$'000
Production facilities and field equipment		
Production facilities and field equipment at cost	**73,685**	21,468
Production facilities and field equipment accumulated depreciation	**(3,876)**	(880)
Total production facilities and field equipment	**69,809**	20,588
Reconciliation of movement in production facilities and field equipment		
Balance at the beginning of the financial period	**20,588**	
Additions	**52,217**	21,297
Transfer from oil and gas properties		171
Depreciation expense	**(2,996)**	(880)
Total production facilities and field equipment	**69,809**	20,588
Office equipment		
Office equipment at cost	**1,509**	780
Office equipment accumulated depreciation	**(256)**	(49)
Total office equipment	**1,253**	731
Reconciliation of movement in office equipment		
Balance at the beginning of the financial period	**731**	
Additions	**729**	780
Depreciation expense	**(206)**	(49)
Total office equipment	**1,254**	731
Total property, plant and equipment	**71,063**	21,319

AURORA OIL & GAS LIMITED

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

For the year ended December 31, 2012

13. EXPLORATION AND EVALUATION EXPENDITURE

	Consolidated	
	December 31, 2012	**December 31, 2011**
	US$'000	**US$'000**
Balance at the beginning of the financial period		71
Transfer to Producing Projects		
Capitalised expenditure		
Exploration and evaluation expenditure written off		(71)
Total exploration and evaluation expenditure		

No exploration and evaluation expenditure was capitalised during the year ended December 31, 2012. During the year ended December 31, 2011 management conducted a review of exploration and evaluation projects for indicators of impairment, and expensed an amount of US$71,000.

14. OIL AND GAS PROPERTIES

	Consolidated	
	December 31, 2012	**December 31, 2011**
	US$'000	**US$'000**
Producing projects		
At cost	**917,501**	275,671
Accumulated depletion	**(41,207)**	(3,543)
Net carrying value	**876,294**	272,128
Development projects		
At cost	**6,079**	
Net carrying value	**6,079**	
Total	**882,373**	272,128

AURORA OIL & GAS LIMITED

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

For the year ended December 31, 2012

14. OIL AND GAS PROPERTIES (Continued)

A reconciliation of movements in oil and gas properties during the year ended December 31, 2012 is as follows:

	Tangible Costs US$'000	Intangible Costs US$'000	Prepaid Drilling, Completion and Lease Acquisition Costs US$'000	Total US$'000
PRODUCING PROJECTS				
Cost				
Balance at January 1, 2011	2,174	109,121	5,866	117,161
Transfer from development projects		38,508		38,508
Additions	10,422	98,718		109,140
Increase in restoration provision		565		565
Transfer to property, plant and equipment	(171)			(171)
Capitalised borrowing costs(1)		3,774		3,774
Net movement in prepaid costs			6,694	6,694
Balance at December 31, 2011	**12,425**	**250,686**	**12,560**	**275,671**
Additions	51,998	595,602		647,600
Increase in restoration provision		1,140		1,140
Capitalised borrowing costs(1)		5,650		5,650
Net movement in prepaid costs			(12,560)	(12,560)
Balance at December 31, 2012	**64,423**	**853,078**		**917,501**
Accumulated depletion				
Balance at January 1, 2011	(1)	(38)		(39)
Depletion charge	(161)	(3,277)		(3,438)
Amortisation(2)		(66)		(66)
Balance at December 31, 2011	**(162)**	**(3,381)**		**(3,543)**
Depletion charge	(2,525)	(33,434)		(35,959)
Amortisation(2)		(1,705)		(1,705)
Balance at December 31, 2012	**(2,687)**	**(38,520)**		**(41,207)**
Net carrying value				
Balance at December 31, 2011	**12,263**	**247,305**		**272,128**
Balance at December 31, 2012	**61,736**	**814,558**		**876,294**

(1) In accordance with the Group's policy at note 1(u), borrowing costs are capitalised where it is probable that they will result in future economic benefits to the entity and the costs can be measured reliably. Borrowing costs have been specifically capitalised in respect of oil and gas properties as the intended use of funding provided from the senior secured revolving credit facility and the first issue of high yield bonds is the Group's drilling program at the Sugarkane field.

(2) Borrowing costs are amortised to profit or loss over the term of the loan facility.

AURORA OIL & GAS LIMITED

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

For the year ended December 31, 2012

14. OIL AND GAS PROPERTIES (Continued)

	Tangible Costs	Intangible Costs	Prepaid Drilling, Completion and Lease Acquisition Costs	Total
	US$'000	US$'000	US$'000	US$'000
DEVELOPMENT PROJECTS				
Cost				
Balance at January 1, 2011		38,508		38,508
Transfer to producing projects		(38,508)		(38,508)
Balance at December 31, 2011				
Additions		**6,079**		**6,079**
Balance at December 31, 2012		**6,079**		**6,079**
Net carrying value				
Balance at December 31, 2011				
Balance at December 31, 2012		**6,079**		**6,079**

15. TRADE AND OTHER PAYABLES

	Consolidated	
	December 31, 2012	December 31, 2011
	US$'000	US$'000
Trade payable and accruals	**180,619**	73,434

Trade and other payables are normally settled within 30 days from receipt of invoice. Information about the Group's exposure to foreign exchange risk on financial instruments is provided in Note 3. All amounts recognised as trade and other payables are expected to be settled within the next 12 months.

16. PROVISIONS CURRENT

	Consolidated	
	December 31, 2012	December 31, 2011
	US$'000	US$'000
Employee Benefits	**334**	92

AURORA OIL & GAS LIMITED

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

For the year ended December 31, 2012

17. BORROWINGS NON CURRENT

		Consolidated	
		December 31, 2012	**December 31, 2011**
		US$'000	**US$'000**
Secured			
Senior secured syndicated facility	(a)	**30,000**	30,000
Unsecured			
Senior unsecured notes	(b)	**360,453**	
		390,453	30,000

(a)

Senior Secured Revolving Credit facility

On November 8, 2011, Aurora USA Oil and Gas Inc. ("Aurora USA"), a wholly owned subsidiary of the Company, signed a credit agreement with a syndicate of banks, pursuant to which up to US$300 million may be available on a revolving basis at a margin of between 2 and 4 per cent over the floating LIBOR rate. The Facility ("Facility") contains negative and affirmative covenants and matures on November 7, 2016.

The funding under the Facility will be provided with availability determined, at a minimum on a semi-annual basis, relative to a borrowing base calculated by reference to proved reserves. The Facility is designed for the borrowing base to increase with Aurora's increased proved reserves, subject to and in accordance with the terms of the credit agreement. At December 31, 2012 the borrowing base is US$150 million (December 31, 2011: US$85 million) and $30 million has been drawn (December 31, 2011: US$30 million).

Aurora USA's obligations under the Facility are guaranteed by pledged security from the parent entity, Aurora, and the subsidiaries of Aurora USA. At December 31, 2012, the following investment property was pledged as security:

Owner / Grantor	**Issuer**	**Percentage Owned**	**Percentage Pledged**	**Class of stock**
Aurora Oil and Gas Limited	Aurora USA Oil and Gas Inc.	100%	100%	Common Stock
Aurora USA Oil and Gas Inc.	Wardanup Oil and Gas Inc.	100%	100%	Common Stock
Aurora USA Oil and Gas Inc.	Sugarloaf Oil and Gas Inc.	100%	100%	Common Stock
Aurora USA Oil and Gas Inc.	Yallingup Oil and Gas Inc.	100%	100%	Common Stock
Aurora USA Oil and Gas Inc.	Trigg Oil and Gas Inc.	100%	100%	Common Stock

The carrying value of assets pledged as securities for non-current borrowings is US$307,910,000 (December 31, 2011: US$268,619,000).

In addition to investment property pledged, a negative pledge imposes that certain financial covenants be maintained by Aurora, Aurora USA and its subsidiaries.

On November 17, 2011, US$30 million was drawn down under the Facility. During the quarter ended March 31, 2012, the Group repaid 100% of the Facility outstanding balance upon closing of the senior unsecured note offering described in (c) below. On November 28, 2012, US$30 million was drawn down under the Facility.

(b)

Senior unsecured notes

On February 8, 2012 Aurora USA, a wholly owned subsidiary of the Company, completed a private offering of unsecured notes ("Senior Note Offering"). Under the Senior Note Offering, Aurora USA issued an aggregate principal amount of $200 million 9.875% senior unsecured notes due February 2017 at an issue price of 98.552% of their face value, resulting in net proceeds of approximately $192 million after deduction of the original discount and commissions. The senior notes were issued pursuant to an indenture dated February 8, 2012 by and amongst Aurora USA, the guarantor parties thereto and US Bank National Association, as trustee.

On July 31, 2012 Aurora USA completed a follow on offering of the senior unsecured notes, issuing an aggregate principal amount of US$165 million 9.875% senior unsecured notes due in February 2017 at a premium of 101.5% of their face value, resulting in net proceeds of approximately $164 million after addition of premium and deduction of commissions.

AURORA OIL & GAS LIMITED

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

For the year ended December 31, 2012

17. BORROWINGS NON CURRENT (Continued)

(c) Senior Secured Term Debt Facility

On May 18, 2012 Eureka Energy Limited ("Eureka"), prior to becoming a subsidiary of the Company, signed a Term Debt Facility agreement with Macquarie Bank Limited, pursuant to which US$15 million was available at a margin of 7 per cent over the floating LIBOR rate. The Term Debt Facility contained negative and affirmative covenants and was to mature on May 18, 2015. On May 23, 2012, US$9 million was drawn down under the Term Debt Facility. Subsequent to June 30, 2012, Eureka became a wholly owned subsidiary and the Term Debt Facility was repaid and terminated.

18. DEFERRED TAX LIABILITIES

	Consolidated	
	December 31, 2012	**December 31, 2011**
	US$'000	**US$'000**
(a) Deferred tax asset		
Arising from temporary differences attributable to:		
Tax losses[1]		
Australia	**216**	284
United States	**142,967**	42,623
Share issue expense	**464**	239
Other	**8,492**	7,406
Total deferred tax asset	**152,139**	50,552
Less set off of deferred tax liabilities under set-off provisions (b)	**(152,139)**	(50,552)
(b) Deferred tax liability		
Arising from temporary differences attributable to:		
Financial assets through other comprehensive income	**1,509**	
Cash flow hedge	**495**	
Oil and gas properties	**(232,547)**	(52,189)
Management fees and borrowing costs	**(5,119)**	(7)
Total deferred tax liabilities	**(235,662)**	(52,195)
Less set off of deferred tax asset under set-off provisions (a)	**152,139**	50,552
Net deferred tax liabilities	**(83,523)**	(1,643)
Deferred tax liabilities expected to be settled within 12 months		
Deferred tax liabilities expected to be settled after more than 12 months	**(83,523)**	(1,643)

(1) The deferred taxes arising from accumulated tax losses for US taxpaying entities and on US based oil and gas properties have been calculated at the marginal tax rate of 35%.

19. DERIVATIVE FINANCIAL INSTRUMENTS

Consolidated	
December 31, 2012	**December 31, 2011**

	US$'000	US$'000
Forward commodity contracts cash flow hedges		
Current	**1,535**	
Non-current	**114**	
Total derivative financial instrument liabilities	**1,649**	

AURORA OIL & GAS LIMITED

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

For the year ended December 31, 2012

19. DERIVATIVE FINANCIAL INSTRUMENTS (Continued)

Instruments used by the group

The Group is a party to derivative financial instruments entered into in the normal course of business in order to hedge exposure to fluctuations in commodity prices in accordance with the Group's financial risk management policies.

Forward commodity price contracts cash flow hedges

At December 31, 2012, the Group has various oil commodity contacts designated as hedges of expected future oil sales. These contracts are all designated as cash flow hedges and are used to reduce the exposure to a future decrease in the value of oil sales. The outstanding contracts held by the Group at December 31, 2012 are as follows:

					Weighted average US$ / barrel			
Year of delivery	**Subject of contract**	**Reference**	**Option traded**	**Barrels**	**Strike price**	**Floor price**	**Ceiling price**	**Fair value**
								US$'000
2013	Oil	Nymex WTI	Swap	102,000	92.15			(111)
2013	Oil	LLS	Swap	108,000	95.40			(1,144)
2013	Oil	Nymex WTI	Zero Cost Collar	210,000		77.86	102.89	(280)
2014	Oil	Nymex WTI	Swap	78,000	90.66			(114)
Total				**498,000**				**(1,649)**

The hedge contracts are to be settled at a rate of between 6,000 to 10,000 barrels per month in 2013 and 2014.

The portion of the gain or loss on the hedging instrument that is determined to be an effective hedge is recognised in other comprehensive income. When the cash flows occur, the Group adjusts the initial measurement of the component recognised in the statement of financial position by removing the related amount from other comprehensive income.

20. PROVISIONS NON-CURRENT

	Consolidated	
	December 31, 2012	**December 31, 2011**
	US$'000	**US$'000**
Restoration provision	**1,705**	565
Reconciliation of movement in restoration provision		
Balance at the beginning of the financial period	**565**	
Provision made during the year	**1,140**	565
Balance at the end of the financial year	**1,705**	565

Provisions for future removal and restoration costs are recognised where there is a present obligation as a result of exploration, development, production, transportation or storage activities having been undertaken, and it is probable that an outflow of economic benefits will be required to settle the obligation. The estimated future obligations include the costs of removing facilities, abandoning wells and restoring the affected areas.

21. CONTRIBUTED EQUITY

	December 31, 2012 Securities	December 31, 2011 Securities	December 31, 2012 US$'000	December 31, 2011 US$'000
Share capital				
Ordinary shares	**447,885,778**	411,655,353	**405,169**	290,194
Total contributed equity	**447,885,778**	411,655,353	**405,169**	290,194

AURORA OIL & GAS LIMITED

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

For the year ended December 31, 2012

21. CONTRIBUTED EQUITY (Continued)

(a) Ordinary shares

Ordinary shares entitle the holder to participate in dividends and the proceeds on winding up of the Company in proportion to the number of shares held. On a show of hands every holder of ordinary shares present at a meeting or by proxy, is entitled to one vote. Upon poll every holder is entitled to one vote per share held.

(b) Movements in contributed equity:

	Date	Number of Securities		Issue Price	US$'000
Balance at December 31, 2010		**383,455,342**			**222,730**
Adjustment to reflect change in functional currency on January 1, 2011					**28,565**
Balance January 1, 2011 restated		**383,455,342**			**251,295**
Placement	25-Jan-11	**23,399,480**	A$	1.60	**37,212**
Placement	25-Jan-11	**2,760,520**	C$	1.60	**4,433**
Options exercised	01-Apr-11	**250,000**	A$	0.50	**129**
Prospectus share issue	09-Jun-11	**1**	A$	3.00	
Performance rights exercised	26-Aug-11	**1,290,000**			
Options exercised	17-Nov-11	**500,000**	A$	0.70	**356**
Share issue costs					**(3,231)**
Balance at December 31, 2011		**411,655,343**			**290,194**
Placement	16-May-12	**15,802,816**	A$	3.55	**54,721**
Placement	16-May-12	**18,000,000**	C$	3.55	**61,359**
Placement	28-Jun-12	**1,137,619**	A$	3.55	**4,058**
Performance rights exercised	15-Aug-12	**390,000**			
Performance rights exercised	20-Aug-12	**900,000**			
Share issue costs					**(5,163)**
Balance at December 31, 2012		**447,885,778**			**405,169**

22. BUSINESS COMBINATION

(a) Summary of acquisition

On April 30, 2012 Aurora Oil and Gas Limited ("Aurora") announced an unconditional on-market cash offer of A$0.45 per share for all issued ordinary shares of ASX listed Eureka Energy Limited ("Eureka"). On June 30, 2012 Aurora had acquired 75.03% of the issued share capital of Eureka, and it was determined that control existed on this date. On August 13, 2012 Aurora completed the compulsory acquisition of Eureka on the same terms as the on market offer dated April 30, 2012, and is now the registered holder of 100% of Eureka's issued share capital. On August 23, 2012 Eureka was removed from the official list of ASX Limited.

Details of the purchase consideration, the net assets acquired and the fair value of net assets acquired are as follows:

	US$'000
Purchase consideration (refer to (b) below):	
Cash paid	**106,136**
Fair value of shares owned prior to the on-market cash offer	**3,405**

Total purchase consideration	**109,541**

AURORA OIL & GAS LIMITED

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

For the year ended December 31, 2012

22. BUSINESS COMBINATION (Continued)

The assets and liabilities provisionally recognised from the unaudited financial statements of the acquiree as a result of the acquisition are as follows:

	Fair value US$'000
Cash and cash equivalents	7,371
Trade and other receivables	1,636
Property, plant and equipment	360
Oil and gas properties	164,664
Trade and other payables	(8,830)
Borrowings	(9,000)
Deferred tax liability	(46,526)
Provisions	(134)
Net identifiable assets acquired	109,541

Revenue and profit contribution

If the acquisition had occurred on January 1, 2012, consolidated revenue and profit for the year ended December 31, 2012 would have been US$299,805,000 and US$61,055,000 respectively. These amounts have been calculated using the group's accounting policies and by adjusting the results of the subsidiary to reflect the additional depletion that would have been charged assuming the fair value adjustments to oil and gas properties had been applied from January 1, 2012, together with the consequential tax effects.

(b) Purchase consideration

	December 31, 2012 US$'000	December 31, 2011 US$'000
Outflow of cash to acquire subsidiary, net of cash acquired		
Cash consideration	106,136	
Less: Balances acquired		
Cash	7,371	
Outflow of cash investing activity	98,765	

Acquisition related costs

Acquisition related costs $1,892,000 are included in evaluation expenses in the Statement of profit or loss and other comprehensive Income and in operating cash flows in the Statement of Cash Flows.

AURORA OIL & GAS LIMITED

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

For the year ended December 31, 2012

23. OPTIONS AND PERFORMANCE RIGHTS

As at reporting date the Group has the following classes of options and performance rights on issue:

		December 31, 2012 Number	December 31, 2011 Number	Exercise Price		Expiry
Type 18	AUTAZ	**900,000**	2,190,000		n/a	19-Feb-15
Type 19	AUTAI	**150,000**	150,000	A$	1.60	9-Nov-15
Type 20	AUTAI	**150,000**	150,000	A$	1.85	9-Nov-15
Type 21	AUTAI	**150,000**	150,000	A$	2.10	9-Nov-15
Type 22	AUTAZ	**600,000**	600,000	A$	1.60	24-Jan-16
Type 23	AUTAZ	**600,000**	600,000	A$	1.85	24-Jan-16
Type 24	AUTAZ	**600,000**	600,000	A$	2.10	24-Jan-16
Type 25	AUTAK	**250,000**	250,000	A$	3.00	30-Apr-15
Type 26	AUTAK	**250,000**	250,000	A$	3.50	30-Apr-16
Type 27	AUTAK	**250,000**	250,000	A$	4.00	30-Apr-17
Type 28	AUTAK	**500,000**	500,000	A$	3.28	30-May-16
Type 29	AUTAK	**250,000**	250,000	A$	3.28	30-May-16
Type 30	AUTAK	**500,000**	500,000	A$	3.58	30-May-16
Type 31	AUTAK	**250,000**	250,000	A$	3.58	30-May-16
Type 32	AUTAK	**300,000**	300,000	A$	3.76	30-Sep-15
Type 33	AUTAK	**350,000**	350,000	A$	4.10	30-Sep-16
Type 34	AUTAK	**350,000**	350,000	A$	4.45	30-Sep-17
Type 35	AUTAM	**49,396**			n/a	01-Jan-15
Type 36	AUTAM	**98,795**			n/a	01-Jan-15
Type 37	AUTAM	**197,586**			n/a	01-Jan-15
Type 38	AUTAO	**100,000**			n/a	19-Oct-15
Type 39	AUTAO	**100,000**			n/a	19-Oct-15
Type 40	AUTAO	**100,000**			n/a	19-Oct-15
Type 41	AUTAK	**250,000**		A$	4.00	19-Oct-17
Type 42	AUTAK	**250,000**		A$	4.50	19-Oct-18
Type 43	AUTAK	**250,000**		A$	5.00	19-Oct-19
Type 44	AUTAO	**5,962**			n/a	01-Jan-15
Type 45	AUTAO	**11,923**			n/a	01-Jan-15
Type 46	AUTAO	**23,847**			n/a	01-Jan-15
Total		**7,837,509**	7,690,000			

(a)

Options and performance rights

The options and performance rights are not listed and carry no dividend or voting rights. Upon exercise, each option or performance right is convertible into one ordinary share to rank pari passu in all respects with the Company's existing fully paid ordinary shares.

AURORA OIL & GAS LIMITED

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

For the year ended December 31, 2012

23. OPTIONS AND PERFORMANCE RIGHTS (Continued)

Movements in the number of options and performance rights on issue during the year:

	Date			Number
Balance at December 31, 2010				4,890,000
Granted during the year:	24-Jan-11	Type 22	AUTAZ	600,000
	24-Jan-11	Type 23	AUTAZ	600,000
	24-Jan-11	Type 24	AUTAZ	600,000
	29-Apr-11	Type 25	AUTAK	250,000
	29-Apr-11	Type 26	AUTAK	250,000
	29-Apr-11	Type 27	AUTAK	250,000
	30-May-11	Type 28	AUTAK	500,000
	30-May-11	Type 29	AUTAK	250,000
	30-May-11	Type 30	AUTAK	500,000
	30-May-11	Type 31	AUTAK	250,000
	3-Jun-11	Type 32	AUTAK	300,000
	3-Jun-11	Type 33	AUTAK	350,000
	3-Jun-11	Type 34	AUTAK	350,000
Exercised during the year:	31-Mar-11	Type 8	AUTAQ	(250,000)
	26-Aug-11	Type 18	AUTAZ	(1,290,000)
	18-Nov-11	Type 16	AUTAM	(500,000)
Lapsed during the year:	7-Oct-11	Type 18	AUTAZ	(210,000)
Balance at December 31, 2011				7,690,000
Granted during the year:	1-Feb-12	Type 35	AUTAM	**49,796**
	1-Feb-12	Type 36	AUTAM	**99,593**
	1-Feb-12	Type 37	AUTAM	**199,185**
	18-Oct-12	Type 38	AUTAO	**100,000**
	18-Oct-12	Type 39	AUTAO	**100,000**
	18-Oct-12	Type 40	AUTAO	**100,000**
	18-Oct-12	Type 41	AUTAK	**250,000**
	18-Oct-12	Type 42	AUTAK	**250,000**
	18-Oct-12	Type 43	AUTAK	**250,000**
	31-Dec-12	Type 44	AUTAO	**5,962**
	31-Dec-12	Type 45	AUTAO	**11,923**
	31-Dec-12	Type 46	AUTAO	**23,847**
Exercised during the year:	15-Aug-12	Type 18	AUTAZ	**(390,000)**
	20-Aug 12	Type 18	AUTAZ	**(900,000)**
Lapsed during the year:	20-Apr-12	Type 35, 36, 37	AUTAM	**(1,987)**
	17-May-12	Type 35, 36, 37	AUTAM	**(810)**
Balance at December 31, 2012				**7,837,509**

AURORA OIL & GAS LIMITED

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

For the year ended December 31, 2012

24. RESERVES AND RETAINED EARNINGS

	Consolidated	
	December 31, 2012	December 31, 2011
	US$'000	US$'000
(a) Share based payment reserve		
Balance at the beginning of the financial period	**7,767**	2,969
Adjustment arising from change in functional currency on January 1, 2011		746
Restated opening balance	**7,767**	3,715
Share-based payment expense	**4,398**	4,052
Closing balance	**12,165**	7,767
(b) Fair value reserve		
Balance at the beginning of the financial period	**(8,011)**	(5,196)
Adjustment arising from change in functional currency on January 1, 2011		(1,513)
Restated opening balance	**(8,011)**	(6,709)
Change in financial assets at fair value through other comprehensive income	**(593)**	(1,302)
Recognition of fair value of equity instruments measured at fair value through other comprehensive income on disposal	**41**	
Deferred tax	**1,509**	
Closing balance	**(7,054)**	(8,011)
(c) Foreign exchange reserve		
Balance at the beginning of the financial period	**(7,505)**	12,965
Adjustment arising from change in functional currency on January 1, 2011		(20,470)
Restated opening balance	**(7,505)**	(7,505)
Currency translation differences arising during the period / year		
Closing balance	**(7,505)**	(7,505)
(d) Cash flow hedge reserve		
Balance at the beginning of the financial period		
Change in derivative financial instruments at fair value through other comprehensive income	**(1,649)**	
Deferred tax	**495**	
Closing balance	**(1,154)**	
(e) Retained earnings / (accumulated losses)		
Balance at the beginning of the financial period	**(7,353)**	(30,609)
Adjustment arising from change in functional currency on January 1, 2011		(7,328)
Restated opening balance	**(7,353)**	(37,937)
Net profit for the year	**58,846**	30,584
Closing balance	**51,493**	(7,353)

25. EARNINGS PER SHARE

	Consolidated	
	December 31, 2012	December 31, 2011
	US Cents	US Cents
(a) Earnings per share attributable to members of the Company		
Basic earnings per share	**13.60**	7.49
Diluted earnings per share	**13.35**	7.37

AURORA OIL & GAS LIMITED

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

For the year ended December 31, 2012

25. EARNINGS PER SHARE (Continued)

	US$'000	US$'000
(b) Earnings used in calculation of basic / diluted earnings per share		
Net Profit after tax	**58,846**	30,584

	Shares	Shares
(c) Weighted average number of ordinary shares used as the denominator in calculating:		
Basic earnings per share	**432,588,491**	408,518,986
Diluted earnings per share	**439,407,647**	415,017,754

26. DIVIDENDS

No dividend has been paid or is proposed in respect of the year ended December 31, 2012 (2011: None).

27. SHARE BASED PAYMENTS

(a)

Performance rights

The Company currently has in existence two long term incentive plans, the Aurora Oil and Gas Limited Performance Rights Plan (PRP) which was approved by shareholders at the general meeting held on February 19, 2010, and the Aurora Oil & Gas Limited Long Term Incentive Plan (LTIP) which was established in 2011 and approved by the shareholders at the annual general meeting on May 29, 2012.

Awards of performance rights are no longer made under the PRP and the Company intends to terminate the PRP once all awards granted there under have otherwise terminated.

(i)

Performance Rights Plan (PRP)

The PRP was designed to align the interests of executives with shareholders by providing direct participation in the benefits of future Company performance over the medium to long term.

The participants of the plan during 2012 were:

Jonathan Stewart

Ian Lusted

Under the PRP, participants were granted performance rights which only vest if certain performance standards (as disclosed in the Remuneration Report) are met and the executive remains employed by the Company to the end of the vesting period. The selection of suitable performance benchmarks was considered critical to securing the objective of the PRP, and hurdles were set at significantly higher levels than those prevailing at the time of structuring the PRP.

The fair value of performance rights granted was calculated using a risked statistical analysis. This expense has been apportioned pro-rata to reporting periods where vesting periods apply.

Key inputs to the model used in the calculation were as follows:

Grant date:	Type 18 AUTAZ 19-Feb-10
Expected price volatility[(1)]	85%
Exercise price	Nil
Expiry date	19-Feb-2015
Share price at grant date	A$0.29
Risk free interest rate[(2)]	4.8%

(1) Expected price volatility was 85% (based on the historical volatility adjusted for any expected changes to future volatility due to publicly available information).

(2) Risk free rate of securities with comparable terms to maturity.

AURORA OIL & GAS LIMITED

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

For the year ended December 31, 2012

27. SHARE BASED PAYMENTS (Continued)

Performance rights can only be exercised if they have vested and can be exercised at any time until their expiry. The exercise of any vested performance right may only be effected in such form and manner as the Board prescribed.

Participants will not be required to make any payment for the grant of the performance rights or on the exercise of a vested performance right. The maximum number of performance rights that could vest in future periods and hence be exercised by the Participants are as follows:

Earliest exercise date:	**July 31, 2013**
Jonathan Stewart	900,000

For the full entitlement of these performance rights to vest, the top range of the Performance Hurdle would need to be met in the last 15 trading days in July 2013. On this basis the weighted average fair value of each of the performance rights at the date of grant (February 19, 2010) is as follows:

Vesting date:	**July 31, 2013**
Weighted average fair value	A$ 0.03

Movement in the number of performance rights granted under the PRP:

Grant Date	**Expiry Date**	**Balance at start of the year**	**Granted during the year**	**Exercised during the year**	**Net other changes[1]**	**Balance at end of the year**	**Vested and exercisable at end of the year**
		Number	**Number**	**Number**	**Number**	**Number**	**Number**
At December 31, 2012							
19-Feb-2010	**19-Feb-2015**	**2,190,000**		**(1,290,000)**		**900,000**	
At December 31, 2011							
19-Feb-2010	19-Feb-2015	3,690,000		(1,290,000)	(210,000)	2,190,000	

(1) Included as net other changes are 210,000 performance rights that lapsed as a result of failure to meet the employment vesting condition. No performance rights expired during the year (December 31, 2011: Nil).

The weighted average share price at the date of exercise during the year ended December 31, 2012 was A$3.48 (December 31, 2011: A$3.25).

The weighted average remaining contractual life of performance rights outstanding at the end of the year was 2.14 years (December 31, 2011: 3.14 years).

(ii) Long Term Incentive Plan (LTIP)

The objectives of the LTIP are to align the interest of shareholders and employees, and as an incentive to attract and retain key management, including Executive KMP's. Participants' invitation to participate in the LTIP, the awards granted, and their terms and conditions, are determined by the Board on the recommendation of the Remuneration and Nomination Committee (RNC). The terms of LTI's awarded to executive management include specific performance hurdles in order to match such awards with the actual circumstances of the Company at a given point in time.

Vesting of performance rights is dependent upon the participant remaining in employment until the vesting date. The number of performance rights that will vest to executive management level participants is also dependent upon Aurora Oil & Gas Limited's total return to shareholders (TSR) ranking within a peer group determined on an annual basis by the RNC, over the test period. The peer group for 2012 represented 11 Australian energy companies (ASX listed) and 4 Canadian oil and gas companies (TSX listed). Performance rights are granted under the plan for no consideration.

Upon vesting it is at the Board's discretion on the recommendation of the RNC as to whether each performance right is converted into one ordinary share or settled in cash. The cash settled value of each performance right is determined as the volume weighted average trading price of Shares sold on the ASX over the last 5 trading days immediately before the relevant settlement date. The settlement date is determined by the Board, and must be within 30 days of vesting date.

AURORA OIL & GAS LIMITED

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

For the year ended December 31, 2012

27. SHARE BASED PAYMENTS (Continued)

Fair value of LTIP performance rights was calculated using binomial tree and Monte-Carlo simulation valuation models. This expense has been apportioned pro-rata to reporting periods where vesting periods apply.

Key inputs to the binomial tree and Monte-Carlo simulation valuation models used in the calculation of each grant of long term incentive performance rights during the year ended December 31, 2012 were as follows:

	Expected price volatility[1]	Exercise price	Vest date	Expiry date	Share price at grant date		Risk free interest rate[2]	Fair value per performance right	
Grant date: February 1, 2012	**valuation grant date: May 29, 2012[3]**								
Type 35A: AUTAM	55%	N/a	15-Feb-12	1-Jan-15	A$	3.42	2.74%	US$	3.47
Type 35B: AUTAM	N/a	N/a	15-Feb-12	1-Jan-15	A$	3.42	N/a	US$	2.46
Type 36A: AUTAM[4]	45%	N/a	1-Jan-14	1-Jan-15	A$	3.89	2.79%	US$	2.84
Type 36B: AUTAM[4]	N/a	N/a	1-Jan-14	1-Jan-15	A$	3.89	N/a	US$	4.05
Type 37A: AUTAM[4]	45%	N/a	1-Jan-15	1-Jan-15	A$	3.89	2.65%	US$	2.83
Type 37B: AUTAM[4]	N/a	N/a	1-Jan-15	1-Jan-15	A$	3.89	N/a	US$	4.05
Grant date: May 29, 2012[5]									
Type 35A: AUTAM	55%	N/a	15-Feb-12	1-Jan-15	A$	3.42	2.74%	US$	3.47
Type 35B: AUTAM	N/a	N/a	15-Feb-12	1-Jan-15	A$	3.42	N/a	US$	2.46
Type 36A: AUTAM[4]	45%	N/a	1-Jan-14	1-Jan-15	A$	3.89	2.79%	US$	2.84
Type 36B: AUTAM[4]	N/a	N/a	1-Jan-14	1-Jan-15	A$	3.89	N/a	US$	4.05
Type 37A: AUTAM[4]	45%	N/a	1-Jan-15	1-Jan-15	A$	3.89	2.65%	US$	2.83
Type 37B: AUTAM[4]	N/a	N/a	1-Jan-15	1-Jan-15	A$	3.89	N/a	US$	4.05
Grant date: October 18, 2012									
Type 38: AUTAO	N/a	N/a	18-Oct-13	19-Oct-15	A$	3.94	N/a	US$	4.09
Type 39: AUTAO	N/a	N/a	18-Oct-14	19-Oct-15	A$	3.94	N/a	US$	4.09
Type 40: AUTAO	N/a	N/a	18-Oct-15	19-Oct-15	A$	3.94	N/a	US$	4.09
Grant date: December 31, 2012									
Type 44A: AUTAO	45%	N/a	1-Jan-13	1-Jan-16	A$	3.63	2.63%	US$	1.89
Type 45A: AUTAO	45%	N/a	1-Jan-14	1-Jan-16	A$	3.63	2.62%	US$	2.07
Type 46A: AUTAO	45%	N/a	1-Jan-15	1-Jan-16	A$	3.63	2.66%	US$	2.27

(1) Expected price volatility is based on the historical volatility adjusted for any expected changes to future volatility due to publicly available information.

(2) Risk free rate of securities with comparable terms to maturity.

(3) The LTIP was approved by shareholder at the Annual General Meeting held on May 29, 2012. LTIP performance rights were granted to employees and executive employees on February 1, 2012, however in accordance AASB 2: Share-based Payments, grant date for valuation purposes is determined with reference to the date of shareholder approval for the incentive plan.

(4) On November 8, 2012 a modification was made to the vesting conditions of type 36 and type 37 performance rights, to extend the test dates for the performance hurdle, to ensure the TSR hurdle is tested over the full vesting period. In accordance with AASB 2: Share-based Payments, type 36 and type 37 performance rights were revalued immediately prior and immediately subsequent to the modification being made. The resultant value increment is recognised over the remaining vesting period.

(5) Both the LTIP and the number of performance rights granted under the LTIP to directors were approved by shareholder at the Annual General Meeting held on May 29, 2012.

AURORA OIL & GAS LIMITED

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

For the year ended December 31, 2012

27. SHARE BASED PAYMENTS (Continued)

Movement in the number of performance rights granted under LTIP:

Grant Date	Expiry Date	Exercise Price	Balance at start of the year	Granted during the year	Exercised during the year	Forfeited during the year	Balance at end of the year	Vested and exercisable at end of the year
		A$	Number	Number	Number	Number	Number	Number
At December 31, 2012								
1-Feb-2012	1-Jan-2015	N/a		99,674		(2,797)	**96,877**	
29-May-2012	1-Jan-2015	N/a		248,900			**248,900**	
18-Oct-2012	18-Oct-2015	N/a		300,000			**300,000**	
31-Dec-2012	1-Jan-2015	N/a		41,732			**41,732**	
Total				690,306		(2,797)	**687,509**	

The weighted average remaining contractual life of performance rights outstanding at December 31, 2012 was 2.27 years.

(b)

Options

Options over ordinary shares in Aurora Oil and Gas Limited were granted as remuneration, with shareholder approval where required, to the following non-executive directors, executive directors and other executives as follows:

	December 31, 2012		December 31, 2011	
Recipient	Grant date	Number of options granted	Grant date	Number of options granted
Gren Schoch			24-Jan-2011	750,000
Graham Dowland			24-Jan-2011	1,050,000
Darren Wasylucha			29-Apr-2011	750,000
Fiona Harris			30-May-2011	500,000
Alan Watson			30-May-2011	500,000
William Molson			30-May-2011	500,000
Michael Verm			3-Jun-2011	1,000,000
Douglas Brooks[(1)]	**18-Oct-12**	**750,000**		

(1) Mr. Brooks was appointed Chief Executive Officer on October 18, 2012.

The fair value of options granted during the year was calculated using the Black Scholes options pricing model. The expense is apportioned pro-rata to reporting periods where vesting periods apply. Key inputs to the Black Scholes options pricing model used in the calculation of each grant of options during the year ended December 31, 2012 were as follows:

	Expected price volatility[(i)]	Exercise price	Vest date	Expiry date	Share price at grant date	Risk free interest rate[(ii)]	Fair value per option
Grant date: October 18, 2012							
Type 41: AUTAK	50%	A$4.00	19-Oct-13	19-Oct-17	A$3.94	2.50%	US$ 1.60
Type 42: AUTAK	50%	A$4.50	19-Oct-14	19-Oct-18	A$3.94	2.50%	US$ 1.67

Type 43:								
AUTAK	50%	A$5.00	19-Oct-15	19-Oct-19	A$3.94	2.50%	US$	1.74

AURORA OIL & GAS LIMITED

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

For the year ended December 31, 2012

27. SHARE BASED PAYMENTS (Continued)

Key inputs to the Black Scholes options pricing model used in the calculation of each grant of options during the year ended December 31, 2011 were as follows:

	Expected price volatility(1)	Exercise price	Vest date	Expiry date	Share price at grant date	Risk free interest rate(2)	Fair value per option
Grant date: January 24, 2011							
Type 22: AUTAZ	85%	A$1.60	24-Jan-12	24-Jan-16	A$2.70	5.29%	US$ 1.41
Type 23: AUTAZ	85%	A$1.85	24-Jan-13	24-Jan-16	A$2.70	5.29%	US$ 1.56
Type 24: AUTAZ	85%	A$2.10	24-Jan-14	24-Jan-16	A$2.70	5.29%	US$ 1.68
Grant date: April 29, 2011							
Type 25: AUTAK	85%	A$3.00	30-Apr-12	30-Apr-15	A$2.65	5.24%	US$ 1.45
Type 26: AUTAK	85%	A$3.50	30-Apr-13	30-Apr-16	A$2.65	5.24%	US$ 1.60
Type 27: AUTAK	85%	A$4.00	30-Apr-14	30-Apr-17	A$2.65	5.24%	US$ 1.73
Grant date: May 30, 2011							
Type 28: AUTAK	85%	A$3.28	30-May-12	30-May-16	A$3.19	5.00%	US$ 1.93
Type 29: AUTAK	85%	A$3.28	30-Sep-12	30-May-16	A$3.19	5.00%	US$ 1.98
Type 30: AUTAK	85%	A$3.58	30-May-13	30-May-16	A$3.19	5.00%	US$ 2.00
Type 31: AUTAK	85%	A$3.58	30-Sep-13	30-May-16	A$3.19	5.00%	US$ 2.04
Grant date: June 3, 2011							
Type 32: AUTAK	85%	A$3.76	30-Sep-12	30-Sep-15	A$3.40	5.09%	US$ 1.94
Type 33: AUTAK	85%	A$4.10	30-Sep-13	30-Sep-16	A$3.40	5.09%	US$ 2.16
Type 34: AUTAK	85%	A$4.45	30-Sep-14	30-Sep-17	A$3.40	5.09%	US$ 2.34

(1) Expected price volatility is based on the historical volatility adjusted for any expected changes to future volatility due to publicly available information.

(2) Risk free rate of securities with comparable terms to maturity.

AURORA OIL & GAS LIMITED

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

For the year ended December 31, 2012

27. SHARE BASED PAYMENTS (Continued)

Movement in the number of options on issue:

Grant Date	Expiry Date	Exercise Price	Balance at start of the year	Granted during the year	Exercised during the year	Forfeited during the year	Balance at end of the year	Vested and exercisable at end of the year
		A$	Number	Number	Number	Number	Number	Number
At December 31, 2012								
18-Oct-12	19-Oct-17 to 19-Oct-19	4.00 - 5.00		750,000			**750,000**	
3-Jun-11	30-Sept-15 to 30-Sept-17	3.76 - 4.45	1,000,000				**1,000,000**	300,000
30-May-11	30-May-16	3.28 - 3.58	1,500,000				**1,500,000**	750,000
29-Apr-11	30-April-15 to 30-Apr-17	3.00 - 4.00	750,000				**750,000**	250,000
24-Jan-11	24-Jan-16	1.60 - 2.10	1,800,000				**1,800,000**	600,000
9-Nov-10	9-Nov-15	1.60 - 2.10	450,000				**450,000**	300,000
Total			**5,500,000**	**750,000**			**6,250,000**	**2,200,000**
Weighted average exercise price			**A$2.92**	**A$4.50**	**N/a**	**N/a**	**A$3.11**	**A$2.64**
At December 31, 2011								
3-Jun-11	30-Sept-15 to 30-Sept-17	3.76 - 4.45		1,000,000			1,000,000	
30-May-11	30-May-16	3.28 - 3.58		1,500,000			1,500,000	
29-Apr-11	30-April-15 to 30-Apr-17	3.00 - 4.00		750,000			750,000	
24-Jan-11	24-Jan-16	1.60 - 2.10		1,800,000			1,800,000	
9-Nov-10	9-Nov-15	1.60 - 2.10	450,000				450,000	150,000
Total			450,000	5,050,000			5,500,000	150,000
Weighted average exercise price			A$1.85	A$3.01	N/a	N/a	A$2.92	A$1.60

No options were exercised or expired during the year ended December 31, 2012 (December 31, 2011: nil).

The weighted average remaining contractual life of share options outstanding at the end of the year was 3.49 years.

(c) Expense arising from share-based payment transactions

The total expense arising from share-based payment transactions recognised during the reporting period as part of employee benefit expense were as follows:

Consolidated

	December 31, 2012	December 31, 2011
	US$'000	**US$'000**
Options issued	**3,857**	3,969
Performance rights issued under PRP	**32**	83
Performance rights issued under LTIP	**509**	
	4,398	4,052

AURORA OIL & GAS LIMITED

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

For the year ended December 31, 2012

28. KEY MANAGEMENT PERSONNEL DISCLOSURE

(a) Key management personnel of Aurora Oil and Gas Limited

Name and positions held of key management personnel at any time during the financial year are as follows:

Aurora Oil and Gas Limited

Name	Position
Mr. Jonathan Stewart(1)	Executive Chairman
Mr. Graham Dowland	Finance Director
Mr. Ian Lusted	Technical Director
Mr. Gren Schoch	Non-Executive Director
Ms. Fiona Harris	Non-Executive Director
Mr. Alan Watson	Non-Executive Director
Mr. William Molson	Non-Executive Director

Aurora USA Oil and Gas Inc

Name	Position
Mr. Douglas E Brooks(2)	Chief Executive Officer
Mr. Michael Verm	Chief Operating Officer

(1) Mr Stewart resigned as Chief Executive Officer on October 18, 2012.

(2) Mr Brooks was appointed as Chief Executive Officer on October 18, 2012.

(b) Key management personnel compensation

	Consolidated	
	December 31, 2012	December 31, 2011
	US$'000	US$'000
Short-term employee benefits	**4,023**	2,385
Post-employment benefits	**222**	107
Share-based payments	**3,735**	3,412
	7,980	5,904

Information regarding individual directors and executives' compensation and some equity instruments disclosures as permitted by Corporations Regulation 2M.3.03 is provided in the remuneration report section of the directors' report.

Apart from the details disclosed in this note, no director has entered into a material contract with Aurora or the consolidated entity since the end of the previous financial year and there were no material contracts involving directors' interests existing at year end. For details of other transactions with key management personnel, refer to note 33 Related Party transactions.

(c) Equity instrument disclosure relating to key management personnel

(i)

Options and performance rights provided as remuneration and shares issued on exercise of such options

Details of options and performance rights provided as remuneration and shares issued on the exercise of such options, together with terms and conditions of the options and performance rights, can be found at note 27.

AURORA OIL & GAS LIMITED

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

For the year ended December 31, 2012

28. KEY MANAGEMENT PERSONNEL DISCLOSURE (Continued)

(ii)

Option and performance right holdings

The number of options and performance rights over ordinary shares in the company held during the financial year by each director of Aurora Oil and Gas Limited and other key management personnel of the group, including their personally related parties, are set out below:

December 31, 2012	Balance at start of the year	Granted as compensation	Exercised	Net other changes	Balance at the end of year	Vested and exercisable	Unvested
Directors of Aurora Oil and Gas Limited							
Jonathan Stewart							
Performance rights PRP	1,800,000		(900,000)		900,000		900,000
Performance rights LTIP		152,279			152,279		152,279
Balance at December 31, 2012	**1,800,000**	**152,279**	**(900,000)**		**1,052,279**		**1,052,279**
Graham Dowland							
Options	1,050,000				1,050,000	350,000	700,000
Performance rights LTIP		48,088			48,088		48,088
Balance at December 31, 2012	**1,050,000**	**48,088**			**1,098,088**	**350,000**	**748,088**
Ian Lusted							
Performance rights PRP	390,000		(390,000)				
Performance rights LTIP		48,533			48,533		48,533
Balance at December 31, 2012	**390,000**	**48,533**	**(390,000)**		**48,533**		**48,533**
Gren Schoch							
Options	750,000				750,000	250,000	500,000
Balance at December 31, 2012	**750,000**				**750,000**	**250,000**	**500,000**
Fiona Harris							
Options	500,000				500,000	250,000	250,000
Balance at December 31, 2012	**500,000**				**500,000**	**250,000**	**250,000**
Alan Watson							
Options	500,000				500,000	250,000	250,000
Balance at December 31, 2012	**500,000**				**500,000**	**250,000**	**250,000**
William Molson							
Options	500,000				500,000	250,000	250,000
Balance at							

December 31, 2012	**500,000**			**500,000**	**250,000**	**250,000**

AURORA OIL & GAS LIMITED

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

For the year ended December 31, 2012

28. KEY MANAGEMENT PERSONNEL DISCLOSURE (Continued)

December 31, 2012	Balance at start of the year	Granted as compensation	Exercised	Net other changes	Balance at the end of year	Vested and exercisable	Unvested
Other key management personnel of the Group							
Michael Verm							
Performance rights LTIP		22,103			22,103		22,103
Options	1,000,000				1,000,000	300,000	700,000
Balance at December 31, 2012	**1,000,000**	**22,103**			**1,022,103**	**300,000**	**722,103**
Douglas E Brooks[(1)]							
Performance rights LTIP		300,000			300,000		300,000
Options		750,000			750,000		750,000
Balance at December 31, 2012		**1,050,000**			**1,050,000**		**1,050,000**

(1) Mr Brooks was appointed as Chief Executive Officer on October 18, 2012.

December 31, 2011	Balance at start of the year	Granted as compensation	Exercised	Net other changes	Balance at the end of year	Vested and exercisable	Unvested
Directors of Aurora Oil and Gas Limited							
Jonathan Stewart							
Performance rights PRP	2,550,000		(750,000)		1,800,000		1,800,000
Balance at December 31, 2011	**2,550,000**		**(750,000)**		**1,800,000**		**1,800,000**
Graham Dowland							
Options		1,050,000			1,050,000		1,050,000
Balance at December 31, 2011		**1,050,000**			**1,050,000**		**1,050,000**
Ian Lusted							
Performance rights PRP	750,000		(360,000)		390,000		390,000
Balance at December 31, 2011	**750,000**		**(360,000)**		**390,000**		**390,000**
Gren Schoch							
Options		750,000			750,000		750,000
Balance at December 31, 2011		**750,000**			**750,000**		**750,000**
Fiona Harris							
Options		500,000			500,000		500,000

Balance at December 31, 2011	**500,000**	**500,000**	**500,000**

AURORA OIL & GAS LIMITED

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

For the year ended December 31, 2012

28. KEY MANAGEMENT PERSONNEL DISCLOSURE (Continued)

December 31, 2011	Balance at start of the year	Granted as compensation	Exercised	Net other changes	Balance at the end of year	Vested and exercisable	Unvested
Alan Watson							
Options		500,000			500,000		500,000
Balance at December 31, 2011		**500,000**			**500,000**		**500,000**
William Molson[1]							
Options		500,000			500,000		500,000
Balance at December 31, 2011		**500,000**			**500,000**		**500,000**
Other key management personnel of the Group							
Michael Verm[2]							
Options		1,000,000			1,000,000		1,000,000
Balance at December 31, 2011		**1,000,000**			**1,000,000**		**1,000,000**

(1) Mr Molson was appointed as Non-executive Director on April 5, 2011.

(2) Mr Verm was appointed as Chief Operating Officer on June 3, 2011.

(iii) *Share holdings*

The numbers of shares in the Company held during the financial year by each director of Aurora Oil and Gas Limited and other key management personnel of the Group, including their personally related parties, are set out below. No shares were granted during the year ended December 31, 2012 as compensation (December 31, 2011: nil).

Year ended December 31, 2012	Balance at start of the year	Exercise of options / performance rights	On-market trade	Net other changes	Balance at the end of year
Directors of Aurora Oil and Gas Limited					
Jonathan Stewart[1]	18,446,321	900,000		400,000	19,746,321
Graham Dowland	2,203,828				2,203,828
Ian Lusted	1,031,950	390,000			1,421,950
Gren Schoch[1]	5,396,554		100,000	500,000	5,996,554
Fiona Harris[1]	100,000		10,000	40,000	150,000
Alan Watson[1]	952,381			97,619	1,050,000
William Molson[1]	1,412,390			100,000	1,512,390
Other key management personnel of the Group					
Michael Verm	14,700				14,700

Douglas E Brooks[2]	14,000	14,000

(1) On June 28, 2012, shareholder approval was granted for the purchase of 1,137,619 ordinary shares by certain directors of the Company, at an issue price of A$3.55 per share.

AURORA OIL & GAS LIMITED

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

For the year ended December 31, 2012

28. KEY MANAGEMENT PERSONNEL DISCLOSURE (Continued)

(2) Mr Brooks was appointed as Chief Executive Officer on October 18, 2012.

Year ended December 31, 2011	Balance at start of the year	Exercise of options / performance rights	On-market trade	Net other changes	Balance at the end of year
Directors of Aurora Oil and Gas Limited					
Jonathan Stewart	17,696,321	750,000			18,446,321
Graham Dowland	2,203,828				2,203,828
Ian Lusted	971,950	360,000	(300,000)		1,031,950
Gren Schoch[(1)]	4,196,554		200,000	1,000,000	5,396,554
Fiona Harris[(2)]				100,000	100,000
Alan Watson	952,381				952,381
William Molson[(3)]			100,000	1,312,390	1,412,390
Other key management personnel of the Group					
Michael Verm[(4)]			14,700		14,700

(1) On January 24, 2011, shareholder approval was granted for the purchase of 1,000,000 special warrants by Mr Schoch, convertible into shares at an issue price of C$1.60 each, via the underwritten shares and special warrants offer, also approved by shareholders on this date. On June 9, 2011, special warrants were quoted as ordinary fully paid shares of Aurora Oil and Gas Limited.

(2) On January 24, 2011, shareholder approval was granted for the purchase of 100,000 ordinary shares by Ms Harris, at an issue price of A$1.60 each, via the underwritten shares and special warrants offer, also approved by shareholders on this date.

(3) Mr Molson was appointed as Non-executive Director on April 5, 2011.

(4) Mr Verm was appointed as Chief Operating Officer on June 3, 2011.

(d) Highest paid executive personnel

The following are the five highest paid executives of the consolidated company, excluding executive directors:

Name	Position
Mr. Douglas Brooks	Chief Executive Officer (appointed October 18, 2012)
Mr. Michael Verm	Chief Operating Officer
Mr. Darren Wasylucha	Executive Vice President, Corporate Affairs
Ms. Julie Foster	Company Secretary and Financial Controller
Mr. Barclay Ridge	Vice President, Land

There were no options granted to the highest paid executives during or subsequent to the year ended December 31, 2012, other than 750,000 options granted to Mr. Douglas E Brooks on commencement of employment. Refer to note 27 for share based payment terms and conditions.

AURORA OIL & GAS LIMITED

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

For the year ended December 31, 2012

29. CONSOLIDATED ENTITIES

(a) Significant investments in subsidiaries

The consolidated financial statements incorporate the assets, liabilities and results of the following subsidiaries in accordance with the accounting policy described in note 1(a).

Name of Entity	Jurisdiction of Incorporation / Formation	Class of Equity Interest	December 31, 2012	December 31, 2011
			Equity Holding	
			%	%
Aurora USA Oil and Gas, Inc. (*formerly Corpus Christi Gas, Inc.*)	Delaware	Common	**100**	100
Wardanup Oil and Gas, Inc.	Delaware	Common	**100**	100
Sugarloaf Oil and Gas, Inc.	Delaware	Common	**100**	100
West Black Lake Oil and Gas, Inc.(1)	Delaware	Common		100
Aurora West Coast Oil and Gas, Inc.(1)	California	Common		100
Meelup Oil and Gas, Inc.(2)	Delaware	Common		100
Mullaloo Oil and Gas, Inc.(3)	Delaware	Common		100
Yallingup Oil and Gas, Inc.	Delaware	Common	**100**	100
Trigg Oil and Gas, Inc.	Delaware	Common	**100**	100
Aurora USA Development, LLC.	Texas	Membership interest	**100**	
AWT Exploration Oil and Gas, Inc.	Delaware	Common	**100**	
Eureka Energy Limited	Australia	Ordinary	**100**	
Kiana Projects Pty Ltd	Australia	Ordinary	**100**	
Hosston Holdings Pty Ltd	Australia	Ordinary	**100**	
Hosston Oil and Gas, Inc.	Delaware	Common	**100**	
EKA 002, Inc.	Delaware	Common	**100**	
EKA 003, Inc.	Delaware	Common	**100**	
EKA 003, LLC.	Delaware	Membership interest	**100**	

(1) On December 31, 2012 West Black Lake Oil and Gas, Inc. and Aurora West Coast Oil and Gas, Inc. merged with and into Sugarloaf Oil and Gas, Inc.

(2) On December 31, 2012 Meelup Oil and Gas, Inc. merged with and into Yallingup Oil and Gas, Inc.

(3) On December 31, 2012 Mullaloo Oil and Gas, Inc. merged with and into Trigg Oil and Gas, Inc.

During the year ended December 31, 2012 Aurora Oil and Gas Limited (Aurora) commenced a multi-step restructure of certain indirect US subsidiaries with the ultimate aim to continue to streamline the administration of the Aurora Group structure, by reducing the number of Aurora entities based in the US that hold interests in identical wells and other assets. On December 31, 2012 West Black Lake Oil and Gas, Inc. and Aurora West Coast Oil and Gas, Inc., merged with and into Sugarloaf Oil and Gas, Inc., Meelup Oil and Gas, Inc. merged with and into Yallingup Oil and Gas, Inc. and Mullaloo Oil and Gas, Inc. merged with and into Trigg Oil and Gas, Inc.

During the year ended December 31, 2011, Aurora Oil and Gas Limited undertook a restructuring of its wholly owned subsidiaries. The initial phase of the restructure was the change of name of Corpus Christi Gas, Inc. to Aurora USA Oil and Gas, Inc. ("Aurora USA") and the incorporation by Aurora USA of Wardanup Oil and Gas, Inc. as a wholly owned subsidiary, followed by the transfer of all membership interests in Corpus Christi Gas General LLC and Corpus Christi Gas Limited LLC to Wardanup Oil and Gas, Inc.

Under the second phase of the restructure each limited partnership and each limited liability company was merged with its parent corporation, with the resulting surviving entity being the parent corporations.

Delaware legislation provides that when a partnership or limited liability company is merged into another entity, the real, personal and mixed property of the partnership or limited liability company becomes vested in the surviving entity.

The third phase of the restructure involved the transfer by the Company to Aurora USA of all common shares it held in all US corporations in exchange for additional common shares of Aurora USA.

AURORA OIL & GAS LIMITED

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

For the year ended December 31, 2012

29. CONSOLIDATED ENTITIES (Continued)

The rationale for the restructure was to simplify the corporate structure to reflect the fact that changes in tax legislation over time meant that there was no longer any economic rationale for the existence of the limited liability companies and the limited partnerships.

(b)

Transactions with controlled entities

Aurora Oil and Gas Limited provides working capital to its controlled entities. Transactions between Aurora and other controlled entities in the wholly owned Group during the year ended December 31, 2012 consisted of:

Working capital advanced by Aurora Oil and Gas Limited;

Provision of services by Aurora Oil and Gas Limited; and

Expenses paid by Aurora Oil and Gas Limited on behalf of its controlled entities.

The above transactions were made interest free with no fixed terms for the repayment of principal on amounts advanced by Aurora Oil and Gas Limited.

Details of transactions with controlled entities during the year are as follows:

	Company	
	December 31, 2012	**December 31, 2011**
	US$'000	**US$'000**
Sale of goods and services		
Management fees and expense recharges to subsidiaries	**6,811**	2,034
Loans to subsidiaries		
Balance at beginning of the year	**1,688**	193,850
Loans advanced	**26,828**	69,540
Loans repaid	**(2,600)**	(261,702)
Balance at end of year	**25,916**	1,688

During the year ended December 31, 2011, Aurora Oil and Gas Limited resolved to convert the total indebtedness of wholly owned subsidiary, Aurora USA Oil and Gas Inc, of US$261,701,921 into common shares in the capital of Aurora USA Oil and Gas Inc, having a fair market value equal to the face value of the total indebtedness, and Aurora USA Oil and Gas Inc agreed to issue such common shares to Aurora Oil and Gas Limited in exchange for the extinguishment of all liability relating to the total indebtedness.

30. JOINTLY CONTROLLED ASSETS

At reporting date, the Group has non-operating working interests in joint operating agreements for the following projects:

		Working Interest*	
Project	**Activity**	**December 31, 2012**	**December 31, 2011**
Sugarloaf	Sugarkane field development (USA)	28.1%	15.7%
Ipanema	Sugarkane field development (USA)	36.4%	36.4%
Longhorn	Sugarkane field development (USA)	31.9%	31.9%
Excelsior	Sugarkane field development (USA)	9.14%	9.14%

* Working interest denotes the percentage share of costs to be borne by the Group in relation to its interest in projects. The Working interest and Net Revenue Interests (working interests after the deduction of royalty interests) are subject to varying terms in the relevant agreements for each project.

AURORA OIL & GAS LIMITED

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

For the year ended December 31, 2012

30. JOINTLY CONTROLLED ASSETS (Continued)

During the year ended December 31, 2012 Aurora acquired additional working interests in the Sugarloaf project through a corporate transaction and a separate asset transaction.

Project	Activity	Working Interest* December 31, 2012	December 31, 2011
Flour Bluff	Gas field development and production project (USA)	**20%**	20%
North Belridge	Oil wells (USA)	**32.5%**	32.5%
Pan De Azucar	Oil exploration and development (USA)	**100%**	
Black Jack Springs	Oil exploration and development (USA)	**9.4%**	
Brioche	Oil exploration and development (USA)	**100%**	

Interests in the Pan De Azcar, Black Jack Springs and Brioche projects were acquired as part of the corporate transaction completed during the year ended December 31, 2012.

The total carrying value of Aurora's interest in assets held by jointly controlled projects at reporting date is US$952,182,000 (December 31, 2011: US$264,228,000).

31. PARENT ENTITY FINANCIAL INFORMATION

Select financial information of the parent entity, Aurora Oil and Gas Limited, is set out below:

(a)

Summary financial information

The individual financial statements for the parent entity show the following aggregate amounts:

	Company December 31, 2012	December 31, 2011
	US$'000	US$'000
Current assets	**3,018**	7,874
Total assets	**353,981**	236,499
Current liabilities	**2,877**	1,981
Total liabilities	**2,877**	1,981
Contributed equity	**405,169**	290,195
Share-based payment reserve	**13,004**	7,767
Fair value reserve	**(7,054)**	(8,011)
Accumulated losses	**(60,015)**	(55,433)
Total equity	**351,104**	234,518
(Loss) for the year	**(4,583)**	(9,991)
Total comprehensive (loss) for the year	**(3,626)**	(11,293)

(b)

Guarantees entered into by the parent entity

The parent entity has provided a guarantee by way of pledged security, in respect of a senior secured revolving credit facility entered into by Aurora USA Oil and Gas Inc. with a syndicate of banks on November 8, 2011. The parent entity has pledged its 100 per cent ownership interest in Aurora USA Oil and Gas Inc. (refer to note 17 Borrowings).

(c) Contingent liabilities of the parent entity

The parent entity did not have any contingent liabilities as at December 31, 2012 (December 31, 2011: nil).

AURORA OIL & GAS LIMITED

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

For the year ended December 31, 2012

31. PARENT ENTITY FINANCIAL INFORMATION (Continued)

(d)

Expenditure commitments

The parent entity has contracted the following amounts for expenditure at December 31, 2012, for which no amounts have been provided for in the financial statements:

	Company	
	December 31, 2012	**December 31, 2011**
	US$'000	**US$'000**
Rent		
Payable:		
Within one year	**615**	178
Later than one year but not later than five years	**1,890**	185
Later than five years		
	2,505	363

32. RECONCILIATION OF PROFIT AFTER INCOME TAX TO NET CASH INFLOW FROM OPERATING ACTIVITIES

	Consolidated	
	December 31, 2012	**December 31, 2011**
	US$'000	**US$'000**
Net Profit for the year	**58,846**	30,584
(i) Add / (less) non-cash items		
Depreciation, depletion and amortisation	**39,161**	4,367
Amortisation of borrowing costs	**2,927**	66
Transaction costs expensed	**4,939**	652
Share based payment expense	**4,398**	4,052
Net gain on sale of available for sale assets	**(770)**	
Net foreign exchange (gains)	**(3,146)**	(989)
(ii) Add / (less) items classified as investment / financing activities:		
Net interest	**(247)**	(641)
Borrowing costs	**563**	
(iii) Change in assets and liabilities during the financial year		
Increase in receivables	**(73,273)**	(12,912)
Increase in payables	**73,126**	8,217
Increase in deferred tax liability	**37,356**	1,643
Increase in employee provisions	**242**	(92)
Net cash provided by operating activities	**144,122**	34,947

As at December 31, 2012, the undrawn balance available to the Group under the senior secured revolving credit facility current borrowing base was US$120,000,000 (December 31, 2011: US$55,000,000) (refer to note 17).

33. RELATED PARTY TRANSACTIONS

Transactions with related parties are on normal commercial terms and conditions no more favourable than those available to other parties unless otherwise stated.

(a)

Key management personnel

Disclosures relating to key management personnel are set out in Note 28.

(b) Subsidiaries

Interests in subsidiaries are set out in Note 29.

AURORA OIL & GAS LIMITED

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

For the year ended December 31, 2012

33. RELATED PARTY TRANSACTIONS (Continued)

(c) Transactions with wholly-owned controlled entities

Aurora advanced interest free loans to wholly-owned controlled entities. In addition to these loans, Aurora paid expenses on behalf of its controlled entities and provided support services to Aurora USA Oil and Gas Limited and Eureka Energy Limited on commercial terms. These additional advances were made interest free with no fixed terms for repayment.

(d) Transactions with other related parties

Details of other transactions with related parties during the financial year ended December 31, 2012 are set out below:

	Consolidated	
	December 31, 2012	**December 31, 2011**
	US$'000	**US$'000**
Payment for services		125

During the year ended December 31, 2011, an amount of US$125,297 was paid on commercial terms for office accommodation (rental and outgoings), car parking and office equipment to Epicure Administration Pty Ltd, a company of which Mr Stewart, Executive Chairman, is also a director and beneficial shareholder. The outstanding balance payable at year end was nil (December 31, 2011: nil).

34. REMUNERATION OF AUDITORS

During the year the following fees were paid or payable for services provided by the auditor of the Consolidated Entity, its related practices and non-related audit firms:

	Consolidated	
	December 31, 2012	**December 31, 2011**
	US$'000	**US$'000**
(a) BDO Audit (WA) Pty Ltd for:		
(i) Audit and assurance services		
Audit and review of financial statements	**345**	101
Due diligence services	**87**	75
Total remuneration of BDO Audit (WA) Pty Ltd	**432**	176
(b) BDO Corporate Finance (WA) Pty Ltd for:		
(i) Tax services		
Notice of meeting disclosure consulting	**2**	
Total remuneration of BDO Corporate Finance (WA) Pty Ltd	**2**	
(c) BDO Canada LLP for:		
(i) Other services		
Financial Statement language translation services	**58**	31
Total remuneration of BDO Canada LLP	**58**	31

Total auditors' remuneration	**492**	207

It is the Group's policy to engage BDO on assignments additional to their statutory audit duties where BDO's expertise and experience with the Group are important. These assignments are principally due diligence reporting on acquisitions, language translation services, notice of meeting disclosure services or where BDO is awarded assignments on a competitive basis. It is the Group's policy to seek competitive tenders for all major consulting projects.

35. CONTINGENCIES

The Consolidated Entity has no material contingent assets or liabilities as at reporting date.

AURORA OIL & GAS LIMITED

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

For the year ended December 31, 2012

36. COMMITMENTS

Capital expenditure contracted for at the reporting date but not recognised as a liability is as follows:

	Consolidated	
	December 31, 2012	December 31, 2011
	US$'000	US$'000
Oil and gas properties		
Payable:		
Within one year	**38,912**	15,007
Later than one year but not later than five years		
Later than five years		
	38,912	15,007
Property, plant and equipment		
Payable:		
Within one year	**2,484**	205
Later than one year but not later than five years		
Later than five years		
	2,484	205
Rent		
Payable:		
Within one year	**845**	316
Later than one year but not later than five years	**2,077**	358
Later than five years		
	2,922	674
Total commitments	**44,318**	15,886

37. EVENTS OCCURRING AFTER BALANCE SHEET DATE

The following events occurred subsequent to the end of the year:

(a) On February 27, 2013, Aurora Oil and Gas Limited announced that the borrowing base of its senior secured revolving credit facility had been increased to $275 million.

Other than as disclosed above, no event has occurred since reporting date that would materially affect the operations of the Consolidated Entity, the results of the Consolidated Entity or the state of affairs of the Consolidated Entity not otherwise disclosed in the Consolidated Entity's financial statements.

AURORA OIL & GAS LIMITED

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UNAUDITED INTERIM FINANCIAL REPORT

For the three and nine months ended September 30, 2013

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AURORA OIL & GAS LIMITED

ABN 90 008 787 988

CONSOLIDATED STATEMENT OF PROFIT OR LOSS AND OTHER COMPREHENSIVE INCOME

For the three and nine months ended September 30, 2013 and 2012

		Consolidated			
		Three months ended		Nine months ended	
	Note	September 30, 2013	September 30, 2012	September 30, 2013	September 30, 2012
		US$'000	US$'000	US$'000	US$'000
Revenue from continuing operations	4	**143,626**	85,483	**405,388**	182,540
Other income	4	**146**	27	**99**	4,994
Total income		**143,772**	85,510	**405,487**	187,534
Expenses					
Royalties	4	**(38,717)**	(22,528)	**(108,575)**	(48,323)
Production and operating expenses	4	**(15,970)**	(10,342)	**(42,846)**	(22,199)
Administrative expenses		**(8,041)**	(2,666)	**(17,036)**	(8,862)
Depletion, depreciation and amortisation expense	4	**(24,978)**	(14,117)	**(65,344)**	(24,125)
Share-based payment expense	4	**(1,462)**	(991)	**(4,325)**	(3,296)
Finance costs	4	**(16,269)**	(9,056)	**(43,115)**	(17,811)
Exploration and evaluation costs	4		(887)	**(282)**	(3,930)
Foreign exchange loss	4			**(282)**	
Profit from continuing operations before income tax expense		**38,335**	24,923	**123,682**	58,988
Income tax (expense)	5	**(13,661)**	(8,910)	**(43,703)**	(23,940)
Net profit attributable to owners of the Company		**24,674**	16,013	**79,979**	35,048
Other comprehensive income					
Items that may be reclassified to profit or loss:					
Changes in fair value on equity instruments measured at fair value through other comprehensive income		**(58)**	(1,601)	**(208)**	957
Change in fair value of cash flow hedges		**(4,249)**	(1,982)	**(3,510)**	(909)
Other comprehensive income for the period net of tax		**(4,307)**	(3,583)	**(3,718)**	48
Total comprehensive income for the period attributable to owners of the Company		**20,367**	12,430	**76,261**	35,096
Earnings per share attributable to owners of the Company					
Basic earnings per share (US cents per share)		**5.50**	3.58	**17.85**	8.20
Diluted earnings per share (US cents per share)		**5.39**	3.52	**17.53**	8.05

The above consolidated statement of profit or loss and other comprehensive income should be read in conjunction with the accompanying notes.

AURORA OIL & GAS LIMITED

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CONSOLIDATED STATEMENT OF FINANCIAL POSITION

As at September 30, 2013

		Consolidated	
	Note	September 30, 2013	December 31, 2012
		US$'000	US$'000
Current assets			
Cash and cash equivalents		**105,517**	67,584
Trade and other receivables	6	**58,375**	89,535
Total current assets		**163,892**	157,119
Non-current assets			
Other financial assets	7	**504**	842
Property, plant and equipment	8	**119,851**	71,063
Oil and gas properties	9	**1,234,198**	882,373
Total non-current assets		**1,354,553**	954,278
Total assets		**1,518,445**	1,111,397
Current liabilities			
Trade and other payables	11	**188,024**	180,619
Derivative financial instruments	10	**6,235**	1,535
Provisions	12	**542**	334
Total current liabilities		**194,801**	182,488
Non-current liabilities			
Borrowings	13	**660,653**	390,453
Deferred tax liabilities	14	**126,240**	83,523
Derivative financial instruments	10	**428**	114
Provisions	15	**3,031**	1,705
Total non-current liabilities		**790,352**	475,795
Total liabilities		**985,153**	658,283
Net assets		**533,292**	453,114
Equity			
Contributed equity	16	**405,148**	405,169
Share-based payment reserve		**16,103**	12,165
Fair value reserve		**(7,262)**	(7,054)
Foreign exchange reserve		**(7,505)**	(7,505)
Cash flow hedges reserve		**(4,664)**	(1,154)
Retained earnings		**131,472**	51,493
Total equity		**533,292**	453,114

The above consolidated statement of financial position should be read in conjunction with the accompanying notes.

AURORA OIL & GAS LIMITED

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CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

For the three and nine months ended September 30, 2013 and 2012

	For the nine months ended September 30, 2013			
	Contributed Equity	Other Reserve	Accumulated Profits / (Losses)	Total
	US$'000	US$'000	US$'000	US$'000
Balance at January 1, 2012	290,194	(7,749)	(7,353)	275,092
Profit for the period			35,048	35,048
Other comprehensive income				
Change in fair value of equity instruments measured at fair value through other comprehensive income		916		916
Change in fair value of cash flow hedges		(909)		(909)
Recognition of fair value of equity instruments measured at fair value through other comprehensive income on disposal		41		41
Total comprehensive income for the period		48	35,048	35,096
Transactions with owners, in their capacity as owners				
Contributed equity net of transaction costs	115,116			115,116
Options and performance rights expense recognised during the period		3,297		3,297
Balance as at September 30, 2012	405,310	(4,404)	27,695	428,601
Balance as at January 1, 2013	**405,169**	**(3,548)**	**51,493**	**453,114**
Profit for the period			**79,979**	**79,979**
Other comprehensive income				
Change in fair value of equity instruments measured at fair value through other comprehensive income		**(208)**		**(208)**
Change in fair value of cash flow hedges		**(3,510)**		**(3,510)**
Total comprehensive income for the period		**(3,718)**	**79,979**	**76,261**
Transactions with owners, in their capacity as owners				
Contributed equity net of transaction costs	**(21)**			**(21)**
Options and performance rights expense recognised during the period		**3,938**		**3,938**
Balance as at September 30, 2013	**405,148**	**(3,328)**	**131,472**	**533,292**

The above consolidated statement of changes in equity should be read in conjunction with the accompanying notes.

AURORA OIL & GAS LIMITED

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CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

For the three and nine months ended September 30, 2013 and 2012

	For the three months ended September 30, 2013				
	Contributed Equity	Other Reserve	Accumulated Profits / (Losses)	Non-Controlling Interests	Total
	US$'000	US$'000	US$'000	US$'000	US$'000
Balance at July 1, 2012	405,325	(1,812)	11,682	27,349	442,544
Profit for the period			16,013		16,013
Other comprehensive income					
Change in fair value of equity instruments measured at fair value through other comprehensive income		(1,642)			(1,642)
Change in fair value of cash flow hedges		(1,982)			(1,982)
Recognition of fair value of equity instruments measured at fair value through other comprehensive income on disposal		41			41
Total comprehensive income for the period		(3,583)	16,013		12,430
Transactions with owners, in their capacity as owners					
Contributed equity net of transaction costs	(15)				(15)
Options and performance rights expense recognised during the period		991			991
Non-controlling interest on acquisition of subsidiary				(27,349)	(27,349)
Balance as at September 30, 2012	405,310	(4,404)	27,695		428,601
Balance as at July 1, 2013	**405,156**	**(482)**	**106,798**		**511,472**
Profit for the period			**24,674**		**24,674**
Other comprehensive income					
Change in fair value of equity instruments measured at fair value through other comprehensive income		**(58)**			**(58)**
Change in fair value of cash flow hedges		**(4,249)**			**(4,249)**
Total comprehensive income for the period		**(4,307)**	**24,674**		**20,367**
Transactions with owners, in their capacity as owners					
Contributed equity net of transaction costs	**(8)**				**(8)**
Options and performance rights expense recognised during the period		**1,461**			**1,461**
Balance as at September 30, 2013	**405,148**	**(3,328)**	**131,472**		**533,292**

The above consolidated statement of changes in equity should be read in conjunction with the accompanying notes.

AURORA OIL & GAS LIMITED

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CONSOLIDATED STATEMENT OF CASH FLOWS

For the three and nine months ended September 30, 2013 and 2012

	Consolidated			
	Three months ended		Nine months ended	
	September 30, 2013	September 30, 2012	September 30, 2013	September 30, 2012
	US$'000	US$'000	US$'000	US$'000
Cash flows from operating activities				
Receipts from oil and gas sales	**152,718**	45,786	**436,504**	95,878
Payments to suppliers and employees	**(64,254)**	(14,558)	**(173,180)**	(36,657)
Other revenue	**22**		**99**	1,167
Interest paid	**(29,641)**	(10,978)	**(48,148)**	(11,098)
Net cash inflow from operating activities	**58,845**	20,250	**215,275**	49,290
Cash flows from investing activities				
Payments for capitalised oil and gas assets	**(107,097)**	(117,539)	**(395,208)**	(286,758)
Payment for property, plant and equipment	**(10,860)**	(4,263)	**(41,468)**	(22,282)
Payment for other financial assets				(252)
Payment for acquisition of subsidiary, net of cash acquired		(27,349)		(98,765)
Interest received	**11**	31	**44**	224
Net cash (outflow) from investing activities	**(117,946)**	(149,120)	**(436,632)**	(407,833)
Cash flows from financing activities				
Proceeds from issues of shares				120,138
Share issue costs	**(8)**	(15)	**(21)**	(5,022)
Proceeds from borrowings		167,475	**330,000**	364,579
Repayment of borrowings		(9,000)	**(60,000)**	(39,000)
Borrowing costs	**(737)**	(5,453)	**(10,632)**	(11,102)
Net cash inflow / (outflow) from financing activities	**(745)**	153,007	**259,347**	429,593
Net increase / (decrease) in cash and cash equivalents	**(59,846)**	24,137	**37,990**	71,050
Cash and cash equivalents at the beginning of the financial period	**165,222**	118,930	**67,584**	70,246
Effect of exchange rates on cash holdings in foreign currencies	**141**	152	**(57)**	1,923
Cash and cash equivalents at the end of the financial period	**105,517**	143,219	**105,517**	143,219

The above consolidated statement of cash flows should be read in conjunction with the accompanying notes.

AURORA OIL & GAS LIMITED
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NOTES TO THE FINANCIAL STATEMENTS

For the three and nine months ended September 30, 2013

1. BASIS OF PREPARATION

The financial report consists of consolidated financial statements for Aurora Oil & Gas Limited and its subsidiaries ("Group" or "Consolidated Entity").

These general purpose financial statements for the period ended September 30, 2013 have been prepared in accordance with Australian Accounting Standard 134 *Interim Financial Reporting* and the *Corporations Act 2001.*

The interim financial report does not include all the notes of the type normally included in annual financial statements. Accordingly, this financial report should be read in conjunction with the most recent annual financial report for the year ended December 31, 2012 and any public announcements made by the Company during the interim period in accordance with the disclosure requirements of the *Corporations Act 2001*.

The accounting policies adopted are consistent with those of the previous financial period. All references in this report are to US dollars unless otherwise stated.

The Company has considered the impact of new standards not yet effective and does not consider that they would have a material impact on the Company's financial statements.

2. SEGMENT INFORMATION

Management has determined, based on the reports reviewed by the CEO and Executive Chairman and used to make strategic decisions, that the Group has one reportable segment being oil and gas exploration and production in the United States of America. The Group's management and administration office is located in Australia.

The CEO and Executive Chairman review internal management reports on a monthly basis that are consistent with the information provided in the statement of profit or loss and other comprehensive income, statement of financial position and statement of cash flows. As a result no reconciliation is required, because the information as presented is used by the CEO and Executive Chairman to make strategic decisions.

Reportable segment revenue

Revenue, including interest income, is disclosed below based on the reportable segment:

	Three months ended		**Nine months ended**	
	September 30, 2013	**September 30, 2012**	**September 30, 2013**	**September 30, 2012**
	US$'000	**US$'000**	**US$'000**	**US$'000**
Revenue from oil and gas exploration and production	**143,615**	85,452	**405,344**	182,316
Revenue from other corporate activities	**157**	58	**143**	5,218
	143,772	85,510	**405,487**	187,534

Reportable segment assets

Assets are disclosed below based on the reportable segment:

	September 30, 2013	**December 31, 2012**
	US$'000	**US$'000**
Assets from oil and gas exploration and production	**1,409,962**	1,041,143
Assets from corporate activities:		
Cash and cash equivalents	**105,517**	67,584

Other corporate assets	**2,966**	2,670
	1,518,445	1,111,397

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NOTES TO THE FINANCIAL STATEMENTS (Continued)

For the three and nine months ended September 30, 2013

2. SEGMENT INFORMATION (Continued)

Reportable segment liabilities

Liabilities are disclosed below based on the reportable segment:

	September 30, 2013	December 31, 2012
	US$'000	US$'000
Liabilities from oil and gas exploration and production	**982,829**	655,090
Liabilities from other corporate activities	**2,324**	3,193
	985,153	658,283

Reportable segment profit

Profit / (loss) is disclosed below based on the reportable segment:

	Three months ended		Nine months ended	
	September 30, 2013	September 30, 2012	September 30, 2013	September 30, 2012
	US$'000	US$'000	US$'000	US$'000
Profit from oil and gas exploration and production	**32,781**	19,674	**99,822**	41,840
Profit/(Loss) from other corporate activities	**(8,107)**	(3,661)	**(19,843)**	(6,792)
	24,674	16,013	**79,979**	35,048

3. DIVIDENDS

No dividend has been paid or is proposed in respect of the period ended September 30, 2013 (September 30, 2012: None).

4. PROFIT FOR THE PERIOD

Profit for the period ended September 30, 2013 includes the following items which are significant because of their nature, size or incidence:

	Note	Three months ended		Nine months ended	
		September 30, 2013	September 30, 2012	September 30, 2013	September 30, 2012
		US$'000	US$'000	US$'000	US$'000
Income					
Revenue from continuing operations					
Oil and gas sales		**145,481**	85,550	**408,381**	182,581
Realised (loss) on forward commodity price contract		**(1,866)**	(98)	**(3,037)**	(265)
Interest		**11**	31	**44**	224
		143,626	85,483	**405,388**	182,540
Other income					
Foreign exchange gain	*(i)*	**124**	27		3,056
Net gain on sale of available-for-sale financial assets					770
					1,167

Net gain on foreign currency derivatives not qualifying as hedges				
Other	**22**		**99**	1
	146	27	**99**	4,994

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NOTES TO THE FINANCIAL STATEMENTS (Continued)

For the three and nine months ended September 30, 2013

4. PROFIT FOR THE PERIOD (Continued)

	Note	Three months ended September 30, 2013	Three months ended September 30, 2012	Nine months ended September 30, 2013	Nine months ended September 30, 2012
		US$'000	US$'000	US$'000	US$'000
Expenses					
Royalties expense	*(ii)*	**(38,717)**	(22,528)	**(108,575)**	(48,323)
Production and operating expenses					
Production taxes	*(iii)*	**(4,773)**	(2,925)	**(13,516)**	(6,214)
Operating expenses	*(iv)*	**(11,197)**	(7,417)	**(29,330)**	(15,985)
Total production and operating expenses		**(15,970)**	(10,342)	**(42,846)**	(22,199)
Depletion and depreciation					
Depletion	*(v)*	**(22,758)**	(13,558)	**(59,446)**	(22,871)
Depreciation	*(vi)*	**(2,220)**	(559)	**(5,898)**	(1,254)
Total depletion and depreciation expense		**(24,978)**	(14,117)	**(65,344)**	(24,125)
Share-based payment expense					
Options		**(567)**	(841)	**(1,909)**	(3,077)
Performance Rights		**(895)**	(150)	**(2,416)**	(219)
Total share-based payment expense	*(vii)*	**(1,462)**	(991)	**(4,325)**	(3,296)
Finance costs					
Interest expense		**(14,804)**	(7,637)	**(39,092)**	(15,420)
Amortisation of borrowing costs		**(1,159)**	(1,085)	**(3,253)**	(1,831)
Amortisation of debt premium / discount		**(8)**	(55)	**(24)**	(281)
Other financing fees		**(298)**	(279)	**(746)**	(279)
Total finance costs	*(viii)*	**(16,269)**	(9,056)	**(43,115)**	(17,811)
Exploration and evaluation costs written off	*(ix)*		(887)	**(282)**	(3,930)
Foreign exchange loss	*(i)*			**(282)**	

(i)

During the three month period ended September 30, 2012 the Consolidated Entity recognised a foreign exchange gain in relation to the retranslation of Australian and Canadian dollar denominated cash and cash equivalents. For the nine month period ended September 30, 2013 the Consolidated Entity recognised a foreign exchange loss on the retranslation of these balances.

(ii)

Aurora pays royalties to the owners of the petroleum rights on the land in which the Group owns lease interests. Royalties, as a percentage of production revenue, are payable in accordance with the terms of individual leasehold agreements and are generally payable for the production life of each well within the leasehold area.

(iii)

Production taxes include local tax expense and severance tax payable in the State of Texas, USA.

(iv)

Operating expenses include field operating costs and transportation of production.

(v)

Depletion is calculated based on estimated remaining Proven and Probable reserves.

(vi)

Depreciation is calculated using the reducing balance method to allocate the cost of property, plant and equipment over their useful lives.

(vii)

The Group issued performance rights to key management personnel on February 19, 2010 and to directors and employees under Aurora's Long Term Incentive Plan ("LTIP") on May 29, 2012, and October 18, 2012, to employees on December 31, 2012, to key management during January 2013, and to directors on May 29, 2013 subsequent to shareholder approval being obtained at the 2013 Annual General Meeting. The group issued options to executive management personnel between November 2010 and June 2011, on October 18, 2012 and on May 30, 2013. For the nine months to September 30, 2013 a performance right expense of US$2,415,496 (September 30, 2012: US$219,224) and an option expense of US$1,909,347 (September 30, 2012: US$3,076,995) was recognised.

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NOTES TO THE FINANCIAL STATEMENTS (Continued)

For the three and nine months ended September 30, 2013

4. PROFIT FOR THE PERIOD (Continued)

(viii) Finance fees were incurred in respect of the senior secured revolving credit facility entered into on November 8, 2011 and the senior unsecured notes issued on February 8, 2012, the follow on notes issued on July 31, 2012 and the senior unsecured notes issued on March 21, 2013.

(ix) Evaluation costs written off during the period ended September 30, 2013 consisted of evaluation expenditure that could not be directly attributable to the acquisition, construction or production of a qualifying asset providing probable future economic benefits to the entity.

5. INCOME TAX

	Three months ended		Nine months ended	
	September 30, 2013	September 30, 2012	September 30, 2013	September 30, 2012
	US$'000	US$'000	US$'000	US$'000
(a) Income tax expense				
Current tax				
Deferred tax	**13,661**	8,910	**43,703**	23,940
Income tax expense	**13,661**	8,910	**43,703**	23,940
(b) Reconciliation of income tax expense to prima facie tax payable				
Profit from continuing operations before income tax expense	**38,335**	24,923	**123,682**	58,988
Tax at the Australian statutory tax rate of 30% (September 30, 2012: 30%)	**11,501**	7,476	**37,105**	17,696
Tax effect of amounts that are not deductible (taxable) in calculating taxable income				
Share-based payment expense	**194**	217	**603**	757
Foreign exchange gains/(losses) not assessable	**16**	(6)	**75**	(913)
Revenue losses not previously recognised now brought to account	**(330)**	(4)	**(157)**	(294)
(Expense)/benefit from a previously unrecognised temporary difference now recognised	**(248)**	484	**(611)**	1,150
Income tax rate differences	**2,043**	286	**6,337**	3,502
Other non-allowable deductions	**485**	457	**351**	2,042
Income tax expense	**13,661**	8,910	**43,703**	23,940
(c) Tax expense (income) relating to items of other comprehensive income				
Financial assets at fair value through other comprehensive income	**(681)**	(829)	**(519)**	1,509
Cash flow hedges	**1,814**	849	**1,504**	389
	1,133	20	**985**	1,898

6. TRADE AND OTHER RECEIVABLES

		Consolidated	
		September 30, 2013	December 31, 2012
		US$'000	US$'000
Trade receivables	*(i)*	**58,375**	89,535

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NOTES TO THE FINANCIAL STATEMENTS (Continued)

For the three and nine months ended September 30, 2013

6. TRADE AND OTHER RECEIVABLES (Continued)

(i)

Trade receivable
Trade receivables represent revenue earned but not yet received from the production and sale of oil, natural gas and natural gas liquids.

(ii)

Impaired trade receivables

No Group trade receivables were past due or impaired as at September 30, 2013 (December 31, 2012: Nil) and there is no indication that amounts recognised as trade and other receivables will not be recovered in the normal course of business.

7. OTHER FINANCIAL ASSETS

	Consolidated	
	September 30, 2013	December 31, 2012
	US$'000	US$'000
Non-current		
Financial assets at fair value through other comprehensive income	**504**	842

Significant interest in other financial assets

An interest in a financial asset is considered 'significant' when Aurora holds 5% or more of issued share capital.

Aurora holds a significant interest in Elixir Petroleum Ltd. As at September 30, 2013, Aurora held 33,833,334 fully paid ordinary shares in Elixir Petroleum Ltd (December 31, 2012: 33,833,334), representing approximately 7.84% of its total issued capital. The market value of these securities at September 30, 2013 was US$504,000 (December 31, 2012: US$842,000).

Included in the statement of comprehensive income is (US$208,000) (December 31, 2012: US$957,000) which represents the movement in the financial assets at fair value through other comprehensive income.

8. PROPERTY, PLANT AND EQUIPMENT

	Consolidated	
	September 30, 2013	December 31, 2012
	US$'000	US$'000
Production facilities and field equipment		
Production facilities and field equipment at cost	**126,944**	73,685
Production facilities and field equipment accumulated depreciation	**(9,472)**	(3,876)
Net production facilities and field equipment	**117,472**	69,809
Office equipment		
At cost	**2,926**	1,510
Accumulated depreciation	**(547)**	(256)
Net office equipment	**2,379**	1,254
Total property, plant and equipment	**119,851**	71,063

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NOTES TO THE FINANCIAL STATEMENTS (Continued)

For the three and nine months ended September 30, 2013

9. OIL AND GAS PROPERTIES

	Consolidated September 30, 2013 US$'000	Consolidated December 31, 2012 US$'000
Producing projects		
At cost	**1,258,801**	917,501
Accumulated depletion	**(102,728)**	(41,207)
Net carrying value	**1,156,073**	876,294
Development projects		
At cost	**78,125**	6,079
Net carrying value	**78,125**	6,079
Total	**1,234,198**	882,373

A reconciliation of movements in oil and gas properties during the nine months ended September 30, 2013 is as follows:

	Consolidated September 30, 2013 US$'000	Consolidated December 31, 2012 US$'000
Producing projects		
Cost		
Opening balance	**917,501**	275,671
Additions	**331,903**	653,250
Increase in restoration provision	**1,326**	1,140
Net movement in prepaid costs	**8,071**	(12,560)
Closing balance	**1,258,801**	917,501
Accumulated depletion and amortisation		
Opening balance	**(41,207)**	(3,543)
Depletion charge	**(61,521)**	(37,664)
Closing balance	**(102,728)**	(41,207)
Net carrying value		
Opening carrying value	**876,294**	272,128
Closing carrying value	**1,156,073**	876,294
Development projects		
Cost		
Opening balance	**6,079**	
Additions	**72,046**	6,079
Closing balance	**78,125**	6,079

Net carrying value		
Opening carrying value	**6,079**	
Closing carrying value	**78,125**	6,079

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NOTES TO THE FINANCIAL STATEMENTS (Continued)

For the three and nine months ended September 30, 2013

10. DERIVATIVE FINANCIAL INSTRUMENTS

	Consolidated	
	September 30, 2013	December 31, 2012
	US$'000	US$'000
Forward commodity contracts cash flow hedges		
Current	**6,235**	1,535
Non current	**428**	114
Total derivative financial instrument liabilities	**6,663**	1,649

Instruments used by the group

The Group is a party to derivative financial instruments entered into in the normal course of business in order to hedge exposure to fluctuations in commodity prices in accordance with the group's financial risk management policies.

Forward commodity price contracts cash flow hedges

At September 30, 2013, the Group has various oil commodity contacts designated as hedges of expected future oil sales. These contracts are all designated as cash flow hedges and are used to reduce the exposure to a future decrease in the value of oil sales. The outstanding contracts held by the Group at September 30, 2013 are as follows:

					Weighted average US$ / barrel			
Year of delivery	Subject of contract	Reference	Option traded	Barrels	Strike price	Floor price	Ceiling price	Fair value US$'000
2013	Oil	Nymex WTI	Swap	363,100	98.69			1,045
2013	Oil	LLS	Swap	27,000	95.40			255
2013	Oil	Nymex WTI	Zero Cost Collar	112,500		79.00	103.35	236
2014	Oil	Nymex WTI	Swap	1,158,300	91.81			4,348
2014	Oil	Nymex WTI	Zero Cost Collar	270,000		80.00	98.67	892
2015	Oil	Nymex WTI	Swap	186,000	91.40			(113)
Total				2,116,900				6,663

The hedge contracts are to be settled at a rate of between 97,100 to 178,400 barrels per month in 2013 and 2014 and between 16,000 to 115,000 barrels per month in 2015.

The portion of the gain or loss on the hedging instrument that is determined to be an effective hedge is recognised in other comprehensive income. When the cash flows occur, the Group adjusts the initial measurement of the component recognised in the statement of financial position by removing the related amount from other comprehensive income.

11. TRADE AND OTHER PAYABLES

Consolidated

	September 30, 2013	December 31, 2012
	US$'000	US$'000
Trade payables and accruals	**188,024**	180,619

Trade and other payables are normally settled within 30 days from receipt of invoice. All amounts recognised as trade and other payables, but not yet invoiced, are expected to be settled within the next 12 months.

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NOTES TO THE FINANCIAL STATEMENTS (Continued)

For the three and nine months ended September 30, 2013

12. PROVISIONS CURRENT

	Consolidated	
	September 30, 2013	December 31, 2012
	US$'000	US$'000
Employee benefits	**542**	334

13. BORROWINGS

		Consolidated	
		September 30, 2013	December 31, 2012
		US$'000	US$'000
Secured			
Senior secured syndicated facility	(a)		30,000
Unsecured			
Senior unsecured notes	(b)	**660,653**	360,453
		660,653	390,453

(a)

Senior Secured Revolving Credit facility

On November 8, 2011, Aurora USA Oil and Gas Inc. ("Aurora USA"), a wholly owned subsidiary of the Company, signed a US$300 million credit agreement with a syndicate of banks, pursuant to which funds are available on a revolving basis up to an established amount at a margin of between 2 and 3 per cent over the floating LIBOR rate. The Facility ("Facility") contains negative and affirmative covenants and matures on November 7, 2016.

The funding under the Facility will be provided with availability determined, at a minimum on a semi-annual basis, relative to a borrowing base calculated by reference to proved reserves. The Facility is designed for the borrowing base to increase with Aurora's increased proved reserves, subject to and in accordance with the terms of the credit agreement. During September 2013 the borrowing base was re-determined following the 2013 mid-year reserves update from US$200 million to US$300 million (September 30, 2012: US$150 million).

On November 28, 2012, US$30 million was drawn down under the Facility and a further US$30 million was drawn down on February 21, 2013. On March 25, 2013 a total of US$60 million was re-paid, leaving the full borrowing base of US$300 million undrawn as at September 30, 2013.

Aurora USA's obligations under the Facility are guaranteed by pledged security from the parent entity, Aurora, and the subsidiaries of Aurora USA. At September 30, 2013, the following investment property remained pledged as security:

Owner / Grantor	Issuer	Percentage Owned	Percentage Pledged	Class of stock
Aurora Oil and Gas Limited	Aurora USA Oil and Gas, Inc.	100%	100%	Common Stock
Aurora USA Oil and Gas, Inc.	Wardanup Oil and Gas, Inc.	100%	100%	Common Stock
Aurora USA Oil and Gas, Inc.	Sugarloaf Oil and Gas, Inc.	100%	100%	Common Stock
Aurora USA Oil and Gas, Inc.	Yallingup Oil and Gas, Inc.	100%	100%	Common Stock
Aurora USA Oil and Gas, Inc.	Trigg Oil and Gas, Inc.	100%	100%	Common Stock
Aurora USA Oil and Gas, Inc.	Aurora USA Development, LLC.	100%	100%	Membership Interest

Aurora USA Oil and Gas, Inc.	ATW Exploration Oil and Gas, Inc.	100%	100%	Common Stock
Aurora USA Oil and Gas, Inc.	Aurora EF Production Company	100%	100%	Common Stock
Aurora USA Oil and Gas, Inc.	EKA 002, Inc.	100%	100%	Common Stock
Aurora USA Oil and Gas, Inc.	EKA 003, Inc.	100%	100%	Common Stock
EKA 003, Inc.	EKA 003, LLC.	100%	100%	Membership Interest

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NOTES TO THE FINANCIAL STATEMENTS (Continued)

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13. BORROWINGS (Continued)

The carrying value of assets pledged as securities for non-current borrowings is US$527,694,000 (December 31, 2012: US$307,910,000).

In addition to investment property pledged, a negative pledge imposes that certain financial covenants be maintained by Aurora, Aurora USA and its subsidiaries.

(b)

Senior unsecured note

On February 8, 2012 Aurora USA, a wholly owned subsidiary of the Company, completed a private offering of unsecured notes ("2017 Senior Note Offering"). Under the 2017 Senior Note Offering, Aurora USA issued an aggregate principal amount of US$200 million 9.875% senior unsecured notes ("2017 Senior Notes") due February 2017 at an issue price of 98.552% of their face value, resulting in net proceeds of approximately US$192 million after deduction of the original discount and commissions. The 2017 Senior Notes were issued pursuant to an indenture dated February 8, 2012 by and amongst Aurora USA, the guarantor parties thereto and US Bank National Association, as trustee.

On July 31, 2012 Aurora USA completed a follow on offering of the 2017 Senior Notes, issuing an aggregate principal amount of US$165 million 9.875% senior unsecured notes due in February 2017 at a premium of 101.5% of their face value, resulting in net proceeds of approximately US$164 million after addition of premium and deduction of commissions.

On March 21, 2013 Aurora USA completed a new offering of senior unsecured notes ("2020 Senior Note Offering"), issuing an aggregate principal amount of US$300 million 7.50% senior unsecured notes ("2020 Senior Notes"), due in April 2020 at par, resulting in net proceeds of approximately US$293 million after deductions of commissions. The 2020 Senior Notes will bear interest at 7.50% per annum and will be payable semi-annually in arrears, beginning October 1, 2013.

14. DEFERRED TAX

	Consolidated	
	September 30, 2013	**December 31, 2012**
	US$'000	**US$'000**
(a) Deferred tax asset		
Arising from temporary differences attributable to:		
Tax losses[1]		
Australia	**902**	216
United States	**177,355**	142,967
Share issue expense	**620**	464
Other	**9,344**	8,492
Financial assets through other comprehensive income	**990**	1,509
Cash flow hedge	**1,999**	495
Total deferred tax asset	**191,210**	154,143
Less set off against deferred tax liabilities under set-off provisions (b)	**(191,210)**	(154,143)
(b) Deferred tax liability		
Arising from temporary differences attributable to:		
Oil and gas properties	**(312,411)**	(232,547)
Management fees and borrowing costs	**(5,039)**	(5,119)
Total deferred tax liabilities	**(317,450**	(237,666)
Less set off of deferred tax asset under set-off provisions (a)	**191,210**	154,143
Net deferred tax liabilities	**(126,240)**	(83,523)
Deferred tax liabilities expected to be settled within 12 months		

Deferred tax liabilities expected to be settled after more than 12 months	**(126,240)**	(83,523)

(1) The deferred tax assets arising from accumulated tax losses for US taxpaying entities and on US based oil and gas properties have been calculated at the marginal tax rate of 35%.

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15. PROVISIONS NON-CURRENT

	Consolidated	
	September 30, 2013	December 31, 2012
	US$'000	US$'000
Restoration provision	**3,031**	1,705

Provisions for future removal and restoration costs are recognised where there is a present obligation as a result of exploration, development, production, transportation or storage activities having been undertaken, and it is probable that an outflow of economic benefits will be required to settle the obligation. The estimated future obligations include the costs of removing facilities, abandoning wells and restoring the affected areas.