



**FOR THE YEAR ENDED DECEMBER 31, 2012**

## **MANAGEMENT'S DISCUSSION AND ANALYSIS**

The following Management's Discussion and Analysis ("MD&A") of Parex Resources Inc. ("Parex" or the "Company") of the Company's financial condition and operating results for the three months and years ended December 31, 2012 and 2011 is dated March 13, 2013 and should be read in conjunction with the audited consolidated financial statements for the years ended December 31, 2012 and 2011. The audited consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS" or "GAAP") as issued by the International Accounting Standards Board.

Additional information related to Parex is available in the Annual Information Form dated March 28, 2012 on the Canadian Securities Administrators' website at [www.sedar.com](http://www.sedar.com).

All financial amounts are in United States (US) dollars unless otherwise stated.

### **Company Profile**

Parex is an oil and gas exploration and production company active in Colombia and onshore Trinidad & Tobago. Headquartered in Calgary, Canada, Parex through its foreign subsidiaries holds interests in onshore exploration blocks totaling approximately 1,567,662 gross acres. The common shares of the Company trade on the Toronto Stock Exchange ("TSX") under the symbol PXT. The Company's 5.25 percent convertible unsecured subordinated Debentures (the "Debentures") trade on the TSX under the symbol PXT.DB.

### **Accounting Policies**

On January 1, 2011, Parex adopted IFRS for financial reporting purposes, using a transition date of January 1, 2010. The audited consolidated financial statements for the years ended December 31, 2012 and 2011 have been prepared in accordance with IFRS, as issued by the International Accounting Standards Board ("IASB").

### **Advisory on Forward-Looking Statements**

Certain information regarding Parex set forth in this MD&A, including assessments by the Company's management of the Company's plans and future operations, contains forward-looking statements that involve substantial known and unknown risks and uncertainties. The use of any of the words "plan", "expect", "forecast", "project", "intend", "believe", "anticipate", "estimate" or other similar words, or statements that certain events or conditions "may" or "will" occur are intended to identify forward-looking statements. Such statements represent the Company's internal projections, estimates or beliefs concerning, among other things, future growth, results of operations, production, future capital and other expenditures (including the amount, nature and sources of funding thereof), competitive advantages, plans for and results of drilling activity, environmental matters, business prospects and opportunities. These statements are only predictions and actual events or results may differ materially. Although the Company's management believes that the expectations reflected in the forward-looking statements are reasonable, it cannot guarantee future results, levels of activity, performance or achievement since such expectations are inherently subject to significant business, economic, competitive, political and social uncertainties and contingencies. Many factors could cause the Company's actual results to differ materially from those expressed or implied in any forward-looking statements made by, or on behalf of, Parex. In particular, forward-looking statements contained in this MD&A include, but are not limited to, statements with respect to:

- the Company's average production range for 2013;
- terms of the Company's Debentures;
- terms of the Company's secured credit facility;
- the Company's operational strategy, including targeted jurisdictions and technologies used to execute its strategy;
- the Company's approach to manage subsurface and commercial risks;
- activities to be undertaken in various areas including the fulfillment of exploration commitments;
- terms of exploration and production contracts and the timing of release of exploration property deemed non-commercial in respect of the exploration contracts;

- terms of the PSCs (as defined herein) on the Central Range Shallow and Central Range Deep Blocks and the timing of release of exploration property deemed non commercial;
- the Company's expected capital expenditures for 2013;
- the status of the Company's review of transportation and marketing alternatives in an effort to maximize the net proceeds from production in Colombia;
- expected royalty rates and effect of increased production and pricing on the Company's royalty rates;
- expected average production costs and effect of additional productive fields on such costs;
- anticipated effect of implementation of gas powered electrification facilities on energy costs in the Kona field;
- anticipated effect of increased production volumes in the non-operated fields on the Company's operating costs;
- terms of stock based compensation plans, including option plan and restricted share unit plan, and share appreciation rights;
- the Company's plans with respect to granting securities under its stock based compensation plans;
- foreign currency risk;
- ability to reverse unrealized foreign exchange gains and losses in the future;
- the Company's risk management strategy, terms of the Company's risk management contracts and the anticipated effect of derivative contracts on managing cash flow;
- expected effective Colombian corporate income tax rate for 2012 and in the future;
- status of lawsuit brought in Texas against Parex and certain foreign subsidiaries and Parex' plans to defend such lawsuit;
- planned capital expenditures, the timing thereof and the method of funding;
- the Company's ability to fund its capital program and meet its financial obligations;
- terms of joint venture agreement with Niko (as defined herein);
- drilling plans and timing of drilling, completion and tie-in of wells;
- impact of new and revised accounting pronouncements and critical accounting estimates;
- effect of business environment and risks on the Company; and
- financial and business prospects and financial outlook.

In addition, statements relating to "reserves" or "resources" are by their nature forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions that the resources and reserves described can be profitably produced in the future. The recovery and reserve estimates of Parex' reserves provided herein or used in critical accounting assumptions are estimates only and there is no guarantee that the estimated reserves will be recovered. As a consequence, actual results may differ materially from those anticipated in the forward-looking statements.

These forward-looking statements are subject to numerous risks and uncertainties, including but not limited to: the impact of general economic conditions in Canada, Colombia and Trinidad & Tobago; industry conditions including changes in laws and regulations including adoption of new environmental laws and regulations, and changes in how they are interpreted and enforced, in Canada, Colombia and Trinidad & Tobago; competition; lack of availability of qualified personnel; the results of exploration and development drilling and related activities; partner approval of capital work programs and other matters requiring approval; imprecision in reserve and resource estimates; the production and growth potential of Parex' assets; obtaining required approvals of regulatory authorities in Canada, Colombia and Trinidad & Tobago; risks associated with negotiating with foreign governments as well as country risk associated with conducting international activities; volatility in market prices for oil and natural gas; fluctuations in foreign exchange or interest rates; environmental risks; changes in income tax laws or changes in tax laws and incentive programs relating to the oil and natural gas industry; ability to access sufficient capital from internal and external sources; risk that the Company will not be able to obtain contract extensions or fulfill the contractual obligations required to retain its rights to explore, develop and exploit any of its undeveloped properties; risks related to the lawsuit brought in Texas against Parex and certain foreign subsidiaries; failure of counterparties to perform under the terms of their contracts; the risks discussed under "Risk Factors" in the Company's Annual Information Form dated March 28, 2012; the risks described under the heading "Business Environment and Risks" in this MD&A, and other factors, many of which are beyond the control of the Company. Readers are cautioned that the foregoing list of factors is not exhaustive. Additional information on these and other factors that could affect the Company's operations and financial results are included in reports on file with Canadian securities regulatory authorities and may be accessed through the SEDAR website ([www.sedar.com](http://www.sedar.com)).

Although the forward-looking statements contained in this MD&A are based upon assumptions which management believes to be reasonable, the Company cannot assure investors that actual results will be consistent with these forward-looking statements. With respect to forward-looking statements contained in this MD&A, Parex has made assumptions regarding, among other things: current commodity prices and royalty regimes; availability of skilled labour; timing and amount of capital expenditures; uninterrupted access to infrastructure; future exchange rates; the price of oil; the impact of increasing competition; conditions in general economic and financial markets; availability of drilling and related equipment; effects of regulation by governmental agencies; recoverability of reserves and future production rates; royalty rates; future operating costs; foreign exchange rates; the status of litigation; timing of drilling and completion of wells; that the Company will have sufficient cash flow, debt or equity sources or other financial resources required to fund its capital and operating expenditures and requirements as needed; that the Company's conduct and results of operations will be consistent with its expectations; that the Company will have the ability to develop the Company's oil and gas properties in the manner currently contemplated; current or, where applicable, proposed industry conditions, laws and regulations will continue in effect or as anticipated as described herein; that the estimates of the Company's reserves volumes and the assumptions related thereto (including commodity prices and development costs) are accurate in all material respects; that the Company will be able to obtain contract extensions or fulfill the contractual obligations required to retain its rights to explore, develop and exploit any of its undeveloped properties; and other matters. The ability of the Company to carry out its business plan is primarily dependent upon the continued support of its shareholders, the discovery of economically recoverable reserves and the ability of the Company to obtain financing to develop such reserves.

Forward-looking statements and other information contained in this MD&A concerning the oil and natural gas industry in the countries in which it operates and the Company's general expectations concerning this industry are based on estimates prepared by Management using data from publicly available industry sources as well as from resource reports, market research and industry analysis and on assumptions based on data and knowledge of this industry which the Company believes to be reasonable. However, this data is inherently imprecise, although generally indicative of relative market positions, market shares and performance characteristics. While the Company is not aware of any material misstatements regarding any industry data presented herein, the oil and natural gas industry involves numerous risks and uncertainties and is subject to change based on various factors.

Management has included the above summary of assumptions and risks related to forward-looking information provided in this MD&A in order to provide shareholders with a more complete perspective on the Company's current and future operations and such information may not be appropriate for other purposes. The Company's actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking statements and, accordingly, no assurance can be given that any of the events anticipated by the forward-looking statements will transpire or occur, or if any of them do, what benefits Parex will derive there from. These forward-looking statements are made as of the date of this MD&A and Parex disclaims any intent or obligation to update publicly any forward-looking statements, whether as a result of new information, future events or results or otherwise, other than as required by applicable securities laws.

## **Non-GAAP Terms**

Funds flow used in, or from operations, working capital, operating netback per barrel and adjusted net income may from time to time be used by the Company, but do not have any standardized meaning under IFRS and may not be comparable to similar measures presented by other companies. Funds flow used in, or from operations includes all cash generated from operating activities and is calculated before changes in non-cash working capital. Funds flow used in, or from operations is reconciled with net income in the Consolidated Statements of Cash Flows. Funds flow per share is calculated by dividing funds flow from operations by the weighted average number of shares outstanding. Working capital includes current assets less current liabilities but may not include changes in non-cash working capital from one period to the next and does not include any undrawn credit facility amount. Adjusted net income is determined by adding back any losses or deducting any gains associated with the Company's derivative financial liability. Operating netback per barrel equals sales revenue, less royalties, production expense and transportation expense, divided by total equivalent sales volume excluding purchased oil volumes. Management uses these non-GAAP measures for its own performance measurement and to provide shareholders and investors with additional measurements of the Company's efficiency and its ability to fund a portion of its future capital expenditures.

## **Abbreviations**

Refer to the end of the MD&A for commonly used abbreviations in the document.

## 2012 Highlights

- Achieved annual average oil production in 2012 of 11,407 bbls/d an increase of 113% over 2011;
- Realized Brent referenced sales price of \$109.18 per bbl and an operating netback of \$73.41 per bbl;
- Generated year end funds flow from operations of \$241.6 million (\$2.23 per share basic) and adjusted net income of \$32.6 million (\$0.30 per share basic). Funds flow has increased due to continued strong operating netbacks, production growth and exploration success;
- The Company participated in drilling 33 gross wells in Colombia and 2 in Trinidad, resulting in 25 oil wells, 6 disposal wells and 4 dry and abandoned, for a success rate of 87 percent;
- The Company began 2012 with interests in 6 blocks in Colombia and production primarily from the Kona field, and exited 2012 with interests in 14 blocks in Colombia and a diversified production base of ten fields;
- Closed a Colombian corporate acquisition which assets primarily consist of interests in four exploration blocks located in the Llanos Basin, one block located in the Middle Magdalena Basin and 2.3 mmbbl of probable reserves for net cash consideration of \$71.8 million.
- Independent reserve evaluation for Colombia as prepared by GLJ Petroleum Consultants Ltd. (“GLJ”) reported proved plus probable reserve growth of 50 percent, increasing from 10.7 million barrels of oil to 16.1 million barrels of oil (net company working interest) at December 31, 2012;

## Three months ended December 31, 2012 (“fourth quarter or Q4”) Highlights

- Achieved a record quarterly oil production of 12,743 bbls/d, an 18% increase over the three months ending September 30, 2012;
- Realized sales price in Colombia averaged \$105.75 per barrel generating an operating netback of \$68.94 per barrel;
- Generated funds flow from operations of \$54.4 million (\$0.50 per share basic);
- Generated adjusted net loss of \$13.5 million (\$0.12 per share basic) primarily due to an impairment of Trinidad Moruga Block exploration and evaluation assets;
- Drilled six oil wells in Colombia (3.3 net) including the La Casona light oil and natural gas discovery;
- Continued to increase monthly production with January and February production of approximately 14,250 bopd primarily driven by production increases from Kona, Cumbre and Las Maracas fields in Colombia.

## Financial Summary

| (Financial figures in 000s except per share amounts)             | For the three months<br>ended December 31, |            | For the year<br>ended December 31, |            | 2010        |
|------------------------------------------------------------------|--------------------------------------------|------------|------------------------------------|------------|-------------|
|                                                                  | 2012                                       | 2011       | 2012                               | 2011       |             |
| Average daily oil production ( bopd)                             | 12,743                                     | 11,342     | 11,407                             | 5,345      | 86          |
| Realized sales price (/bbl)                                      | \$ 105.75                                  | \$ 102.15  | \$ 109.18                          | \$ 100.43  | \$ 83.51    |
| Operating netback (/bbl)                                         | \$ 68.94                                   | \$ 71.24   | \$ 73.41                           | \$ 69.48   | \$ 50.08    |
| Oil and natural gas sales                                        | \$ 149,614                                 | \$ 96,169  | \$ 523,514                         | \$ 171,170 | \$ 2,621    |
| Funds flow from operations <sup>(1)</sup>                        | \$ 54,446                                  | \$ 63,135  | \$ 241,569                         | \$ 97,916  | \$ (7,699)  |
| Per share – basic                                                | 0.50                                       | 0.58       | 2.23                               | 1.05       | (0.12)      |
| Per share – diluted <sup>(6)</sup>                               | 0.50                                       | 0.56       | 1.96                               | 1.03       | (0.12)      |
| Adjusted net income (loss) <sup>(1)(2)(8)</sup>                  | \$ (13,450)                                | \$ 6,470   | \$ 32,628                          | \$ 10,545  | \$ (13,531) |
| Per share – basic                                                | (0.12)                                     | 0.06       | 0.30                               | 0.11       | (0.20)      |
| Per share – diluted                                              | (0.12)                                     | 0.06       | 0.26                               | 0.11       | (0.20)      |
| Net Income (loss) <sup>(8)</sup>                                 | \$ (15,840)                                | \$ 4,477   | \$ 39,922                          | \$ 15,635  | \$ (13,531) |
| Per share – basic                                                | (0.15)                                     | 0.04       | 0.37                               | 0.17       | (0.20)      |
| Per share – diluted <sup>(7)</sup>                               | (0.15)                                     | 0.04       | 0.31                               | 0.17       | (0.20)      |
| Capital Expenditures, excluding corporate acquisitions           | \$ 64,877                                  | \$ 53,677  | \$ 267,688                         | \$ 149,643 | \$ 42,765   |
| Total assets (end of period)                                     | \$ 821,201                                 | \$ 660,177 | \$ 821,201                         | \$ 660,177 | \$ 210,702  |
| Working capital (deficit) surplus <sup>(5)</sup> (end of period) | (12,640)                                   | 92,893     | (12,640)                           | 92,893     | 115,136     |
| Debenture (end of period) <sup>(3)</sup>                         | 65,657                                     | 60,001     | 65,657                             | 60,001     | -           |
| Bank debt (end of period)                                        | 9,100                                      | -          | 9,100                              | -          | -           |
| Weighted average shares outstanding (000s)                       |                                            |            |                                    |            |             |
| Basic                                                            | 108,440                                    | 108,287    | 108,403                            | 92,996     | 65,516      |
| Diluted                                                          | 109,508                                    | 117,423    | 125,711                            | 98,067     | 67,284      |
| Outstanding shares (end of period) (000s)                        |                                            |            |                                    |            |             |
| Basic                                                            | 108,476                                    | 108,300    | 108,476                            | 108,300    | 76,968      |
| Diluted <sup>(4)</sup>                                           | 126,477                                    | 124,963    | 126,477                            | 124,963    | 82,608      |

<sup>(1)</sup> Non GAAP measure. See “Non GAAP Measures”.

<sup>(2)</sup> Adjusted net income has been adjusted for the IFRS accounting effects of changes in the derivative financial liability. For the three months and year ended December 31, 2012 adjusted net income excludes a \$2.4 million addition and \$7.3 million reduction of the gain (loss) upon revaluation of the derivative liability associated with the Company’s Debentures (three months and year ended December 31, 2011 includes a \$2.0 million addition and \$5.1 million reduction of the loss (gain) upon revaluation of the derivative liability).

<sup>(3)</sup> Debentures will accrete up to the face value amount of Cdn \$85.0 million over the remaining term to June 30, 2016.

<sup>(4)</sup> Diluted outstanding shares include all potential common shares including potential dilution in respect of the Debentures.

<sup>(5)</sup> Working capital calculation does not take into consideration the undrawn \$65.9 million available under the secured credit facility.

<sup>(6)</sup> Includes cash interest in the funds flow from operations balance.

<sup>(7)</sup> Net income diluted has been adjusted for the IFRS accounting effects of changes in the Debentures. For the three months ended December 31, 2012 the effect of the debenture is anti dilutive and for the year ended December 31, 2012 there is a \$1.3 million reduction relating to accretion, interest, foreign exchange and gain upon revaluation of the derivative liability (three month and year ended December 31, 2011 is nil).

<sup>(8)</sup> For the three months and year ended December 31, 2012 the Company recognized a \$23.5 million impairment relating to the Trinidad and Tobago exploration and evaluation assets on the Moruga Block (three months and year ended December 31, 2011–nil).

## Strategy

The Company’s strategy is to leverage Latin American and Caribbean onshore experience and capability to create shareholder value. Jurisdictions will be targeted that have stable fiscal regimes coupled with oil-prone hydrocarbon-rich basins in under-explored areas. Parex will apply proven technology used in the Western Canada Sedimentary Basin in basins with large oil-in-place potential. The Company will focus on short cycle time from discovery to bringing new reserves on-stream and use a portfolio approach to manage subsurface and commercial risks.

## Principal Properties

As at December 31, 2012, the Company's principal land holdings and interests in exploration blocks held by its subsidiaries were as follows:

|                                             | Working Interest | Gross Acres      | Net Acres        |
|---------------------------------------------|------------------|------------------|------------------|
| <b>Colombia Llanos Basin</b>                |                  |                  |                  |
| <u>Operated Properties</u>                  |                  |                  |                  |
| Blocks LLA-16, 20, 29 and 30 <sup>(1)</sup> | 100%             | 489,137          | 489,137          |
| Block LLA-57 <sup>(2)</sup>                 | 100%             | 104,532          | 104,532          |
| Block Los Ocarros <sup>(3)</sup>            | 50%              | 110,436          | 55,218           |
| Block LLA-17 <sup>(4)</sup>                 | 40%              | 108,726          | 43,490           |
| Block El Eden <sup>(5)</sup>                | 60%              | 109,249          | 65,549           |
| Block Cabrestero <sup>(6)</sup>             | 50%              | 29,562           | 14,781           |
| Block LLA-40 <sup>(7)</sup>                 | 50%              | 163,090          | 81,545           |
| <u>Non-Operated Properties</u>              |                  |                  |                  |
| Block LLA-32 <sup>(4)</sup>                 | 30%              | 100,325          | 30,097           |
| Block LLA-34 <sup>(4)</sup>                 | 45%              | 82,286           | 37,029           |
| <b>Colombia Middle Magdalena</b>            |                  |                  |                  |
| <u>Non-Operated Properties</u>              |                  |                  |                  |
| Morpho <sup>(4)</sup>                       | 50%              | 51,398           | 25,699           |
| <b>Trinidad &amp; Tobago</b>                |                  |                  |                  |
| <u>Operated Properties</u>                  |                  |                  |                  |
| CRBs <sup>(8)</sup>                         | 50%              | 211,478          | 105,739          |
| Moruga Block <sup>(9)</sup>                 | 83.8%            | 7,443            | 6,237            |
| <b>Total</b>                                |                  | <b>1,567,662</b> | <b>1,059,053</b> |

Exploration properties that are deemed non-commercial will be released in due course. Accordingly, the gross vs. net acres described above may decrease over time as lands deemed non-commercial are released.

- <sup>(1)</sup> The initial exploration phase under these exploration and production ("E&P") contracts is 36 months. Subsequent to this period, there is an option to enter into a second 36-month exploration phase. The initial exploration phase commenced on July 2, 2009 for Block LLA-16, July 29, 2009 for Block LLA-20, and October 20, 2009 for Blocks LLA-29 and LLA-30. All commitments have been fulfilled on Block LLA-16 and Block LLA-20. Extensions for the initial phase were granted on Blocks LLA-29 and LLA-30 to April 20, 2013 and June 8, 2013 respectively. The Company has entered into the second phase in LLA-16 and LLA-20 on July 2, 2012 and July 29, 2012 respectively.
- <sup>(2)</sup> The E&P contract has an initial exploration phase of 36 months, with an option to enter into a second 36-month exploration phase, subsequent to this period. The initial exploration phase commenced on March 23, 2011.
- <sup>(3)</sup> Parex has a working interest of 50 percent in the block and has a commitment of one exploratory well in the next year.
- <sup>(4)</sup> Block LLA-17, Block LLA-32, Block LLA-34, and Morpho have had their initial exploration commitments satisfied as of July 31, 2012.
- <sup>(5)</sup> Parex has a working interest of 60 percent in the block and has a commitment of one exploratory well in the next year.
- <sup>(6)</sup> Parex has a working interest of 50 percent in the block and has a commitment of one exploratory well in the next year.
- <sup>(7)</sup> Remaining obligations for Block LLA-40 in the initial exploration phase of the E&P contract is to drill four exploration wells. Parex has acquired 308 kilometers of 3D seismic. The initial phase is a period of 36 months, with an option to enter into a second 36 month exploration phase. The initial exploration phase commenced June 14, 2011.
- <sup>(8)</sup> Working interests noted are for the exploration phase of the Production Sharing Contracts ("PSCs"). The Petroleum Company of Trinidad & Tobago ("Petrotrin") has the right to participate at a 35 percent working interest in any development on the Central Range Shallow Block and at a 20 percent interest in any development on the Central Range Deep Block. The initial exploration phase under the Company's PSCs has been extended to September 18, 2014.
- <sup>(9)</sup> The Moruga Block had the final earning confirmed on April 27, 2011. All exploration commitments are satisfied. The Moruga block initial exploration term is scheduled to end on August 29, 2013.

## 2013 Outlook

Building on our 2012 operational and exploration success, Parex plans a self funding 2013 capital investment program of approximately \$210 million balanced between exploration and development in Colombia and certain exploration and appraisal activities in Trinidad. The Company is forecasting a 2013 average production range of approximately 14,000-14,500 bopd as compared to the 2012 average production of 11,407 bopd and the 2011 average production of 5,345 bopd.

## Financial and Operational Results

### Consolidated Results of Operations

Parex' operations are conducted in Colombia, Trinidad & Tobago and Canada which are the Company's reportable segments.

|                                            | For the three months<br>ended December 31, |           | For the year<br>ended December 31, |            |
|--------------------------------------------|--------------------------------------------|-----------|------------------------------------|------------|
|                                            | 2012                                       | 2011      | 2012                               | 2011       |
| Average daily production                   |                                            |           |                                    |            |
| Colombia – oil (bopd)                      | 12,743                                     | 11,342    | 11,407                             | 5,345      |
| Total (bopd)                               | 12,743                                     | 11,342    | 11,407                             | 5,345      |
| Average daily sales                        |                                            |           |                                    |            |
| Colombia – oil (bopd) <sup>(1)</sup>       | 12,592                                     | 10,233    | 11,800                             | 4,670      |
| Total (bopd)                               | 12,592                                     | 10,233    | 11,800                             | 4,670      |
| Operating netback (000s)                   |                                            |           |                                    |            |
| Oil and natural gas sales                  | \$ 149,614                                 | \$ 96,169 | \$ 523,514                         | \$ 171,170 |
| Royalties                                  | (9,359)                                    | (7,572)   | (35,890)                           | (13,929)   |
| Net revenue                                | 140,255                                    | 88,597    | 487,624                            | 157,241    |
| Production expense                         | (12,122)                                   | (6,558)   | (36,286)                           | (11,219)   |
| Transportation expense                     | (25,853)                                   | (14,971)  | (91,397)                           | (27,604)   |
| Purchased oil expense                      | (19,749)                                   | -         | (37,158)                           | -          |
| Operating netback                          | \$ 82,531                                  | \$ 67,068 | \$ 322,783                         | \$ 118,418 |
| Operating netback (per bbl) <sup>(1)</sup> |                                            |           |                                    |            |
| Oil and natural gas sales                  | \$ 105.75                                  | \$ 102.15 | \$ 109.18                          | \$ 100.43  |
| Royalties                                  | (8.08)                                     | (8.04)    | (8.31)                             | (8.17)     |
| Net revenue                                | 97.67                                      | 94.11     | 100.87                             | 92.26      |
| Production expense                         | (10.46)                                    | (6.97)    | (8.40)                             | (6.58)     |
| Transportation expense                     | (18.27)                                    | (15.90)   | (19.06)                            | (16.20)    |
| Operating netback                          | \$ 68.94                                   | \$ 71.24  | \$ 73.41                           | \$ 69.48   |

<sup>(1)</sup> Average daily sales and the operating netback calculation includes the Company's working interest sales volumes and excludes purchased oil sales volumes.

The Company's operating netback on a per barrel basis for the three months and year ended December 31, 2012 was \$68.94 (\$71.24—three months ended December 31, 2011) and \$73.41 (\$69.48—year ended December 31, 2011) compared to \$70.57 for the third quarter of 2012. The average realized sales price in Colombia for the three months and year ended was \$105.75/bbl (\$102.15—three months ended December 31, 2011) and \$109.18/bbl (\$100.43—year ended December 31, 2011) compared to \$107.53/bbl for the third quarter of 2012. Royalty charges for the three months and year ended December 31, 2012 were \$8.08/bbl (\$8.04—three months ended December 31, 2011) and \$8.31/bbl (\$8.17—year ended December 31, 2011) in comparison to \$8.07/bbl for the third quarter of 2012. Royalty charge per barrel is calculated by applying the royalty percentage on produced oil sold and is valued at the realized price net of transportation costs. Production expense for the three months and year ended was \$10.46/bbl (\$6.97—three months ended December 31, 2011) and \$8.40/bbl (\$6.58—year ended December 31, 2011) compared to \$9.27/bbl for the third quarter of 2012. Increase is mainly related to non-operated partner production and associated higher costs. Transportation expense per barrel for the three months and year end was \$18.27/bbl (\$15.90—three months ended December 31, 2011) and \$19.06/bbl (\$16.20—year ended December 31, 2011) compared to \$19.62/bbl for the third quarter of 2012. Transportation and marketing alternatives continue to be examined by the Company in an effort to maximize the net proceeds from production in Colombia.

Overall the price of the Company's benchmark Brent price increased by \$0.52/bbl in the fourth quarter as compared to the third quarter of 2012 while the operating netback declined by \$1.63/bbl in the same period, mainly a result of increased production costs on non-operated fields.

Comparative fourth quarter of 2011 figures have a marginally higher operating netback on a per barrel basis due to the higher operating and transportation costs in 2012 relating to our non operated properties acquired in 2012.

## Colombian Oil Sales

### a) Average Daily Crude Oil Production and Sales Volumes (bopd)

|                                                       | For the three months<br>ended December 31, |               | For the year<br>ended December 31, |              |
|-------------------------------------------------------|--------------------------------------------|---------------|------------------------------------|--------------|
|                                                       | 2012                                       | 2011          | 2012                               | 2011         |
| Block LLA-16 (Kona, Sulawesi, Java and Malawi fields) | 6,473                                      | 11,342        | 8,551                              | 5,345        |
| Block LLA-20 (Cumbre field)                           | 661                                        | -             | 612                                | -            |
| Block Los Ocarros (Las Maracas field)                 | 3,131                                      | -             | 1,233                              | -            |
| Block Cabrestero (Kitaro field)                       | 478                                        | -             | 243                                | -            |
| Block LLA-32 (Maniceno field)                         | 840                                        | -             | 350                                | -            |
| Block LLA-34 (Max & Tua fields)                       | 1,144                                      | -             | 408                                | -            |
| Other                                                 | 16                                         | -             | 10                                 | -            |
| <b>Total Production</b>                               | <b>12,743</b>                              | <b>11,342</b> | <b>11,407</b>                      | <b>5,345</b> |
| Inventory changes                                     | (151)                                      | (1,109)       | 393                                | (675)        |
| Colombia average daily oil sales of produced oil      | 12,592                                     | 10,233        | 11,800                             | 4,670        |

Production for the fourth quarter of the year averaged 12,743 bopd, an increase of approximately 18 percent from the third quarter average of 2012. Production in the fourth quarter includes increased production attributable to Block LLA-32, Block LLA-34 and Los Ocarros offset by a decrease in production in Block LLA-16 related to natural declines and shutting in production when doing field optimization. During the three months ended December 31, 2012, inventory in transit including purchased oil inventory decreased by an average of approximately 438 bopd as ending September 30, 2012 inventory volumes were cleared in October and November 2012.

The increase in oil sales in the fourth quarter of 2012 compared to the reported Colombian oil sales of 10,233 bopd for the three months ended December 31, 2011 was primarily a result of drilling success at Cumbre, Las Maracas, Block 34 and Cabrestero fields and an increase in oil inventory sold in the period.

Production in January and February 2013 has increased by approximately 1,200 bopd from the fourth quarter and has averaged approximately 14,250 bopd. The production increase in 2013 is primarily a result of net new volumes being added at Kona, Cumbre, and Las Maracas.

### b) Average Reference and Realized Prices

|                                                      | For the three months<br>ended December 31, |        | For the year<br>ended December 31, |        |
|------------------------------------------------------|--------------------------------------------|--------|------------------------------------|--------|
|                                                      | 2012                                       | 2011   | 2012                               | 2011   |
| WTI (\$/bbl)                                         | 88.01                                      | 94.02  | 94.05                              | 94.88  |
| Brent (\$/bbl)                                       | 110.15                                     | 109.42 | 111.63                             | 111.26 |
| Realized sales price (\$/bbl)                        | 105.75                                     | 102.15 | 109.18                             | 100.43 |
| Realized oil hedging gain (\$/bbl)                   | 0.77                                       | -      | 0.13                               | -      |
| Realized price after hedging (\$/bbl)                | 106.52                                     | 102.15 | 109.31                             | 100.43 |
| Realized price (discount) as percentage of Brent (%) | (3.9)                                      | (6.6)  | (2.2)                              | (9.7)  |
| Realized price premium as percentage of WTI (%)      | 20.2                                       | 8.6    | 16.1                               | 5.8    |

The Company's oil sales contracts during the period ended December 31, 2012 were referenced to Brent. The discount to Brent was four percent in the fourth quarter compared to two percent in the third quarter of 2012. The differential to Brent in the fourth quarter increased as a result of an increased differential between Brent and the Colombia Vasconia crude reference.

The table below provides a quarter-by-quarter view of Parex' historical pricing in Colombia:

| Average price for the period                               | Q4 2012 | Q3 2012 | Q2 2012 | Q1 2012 | Q4 2011 |
|------------------------------------------------------------|---------|---------|---------|---------|---------|
| Brent (\$/bbl)                                             | 110.15  | 109.63  | 108.04  | 118.71  | 109.42  |
| Parex realized sales price (\$/bbl)                        | 105.75  | 107.46  | 107.54  | 116.90  | 102.15  |
| Parex realized price (discount) as percentage of Brent (%) | (3.9)   | (2.0)   | (1.9)   | (1.5)   | (6.6)   |

### c) Oil Revenue

Fourth quarter 2012 oil revenue increased \$53.5 million or 56 percent as reconciled in the table below to the fourth quarter of 2011:

(\$000s)

|                                                                 |    |                |
|-----------------------------------------------------------------|----|----------------|
| Oil revenue, three months ended December 31, 2011               | \$ | <b>96,169</b>  |
| Sales volume of produced oil, an increase of 23% (2,359 bopd)   |    | <b>22,245</b>  |
| Sales volume of purchased oil, an increase of 100% (2,876 bopd) |    | <b>26,272</b>  |
| Sales price increase of 4%                                      |    | <b>4,928</b>   |
| Oil revenue, three months ended December 31, 2012               | \$ | <b>149,614</b> |

Oil sales increased in the three months ended December 31, 2012 compared to the same period in 2011 due an increase in production volumes and the Company purchasing and selling third party oil. Oil sales for the three months ended December 31, 2012 included a crude oil inventory drawdown of 40,300 bbls from the third quarter of 2012, see "Colombian Crude Oil Inventory in Transit" below.

### d) Colombian Crude Oil Inventory in Transit

(\$000s)

|                                  |    |              |    |        |
|----------------------------------|----|--------------|----|--------|
| For the years ended December 31, |    | <b>2012</b>  |    | 2011   |
| Crude oil in transit             | \$ | <b>7,474</b> | \$ | 17,321 |

As at December 31, 2012, the Company had 98,800 bbls of crude oil inventory in transit, which was injected into the Colombian Ocesa and ODC pipelines. The inventory was valued based on direct and indirect expenditures (including production costs, certain transportation costs, depletion expense and royalty expense) at approximately \$75/bbl incurred in bringing the crude oil to its existing condition and location. A reconciliation of the crude oil inventory in transit volumes is provided below:

(mbbls)

|                                                          |  |                  |  |           |
|----------------------------------------------------------|--|------------------|--|-----------|
| For the periods ended December 31,                       |  | <b>2012</b>      |  | 2011      |
| Crude oil inventory in transit - beginning of the period |  | <b>281.5</b>     |  | 35.0      |
| Oil production                                           |  | <b>4,177.2</b>   |  | 1,951.0   |
| Oil sales                                                |  | <b>(4,825.5)</b> |  | (1,704.5) |
| Purchased oil                                            |  | <b>465.6</b>     |  | -         |
| Crude oil inventory in transit— end of the period        |  | <b>98.8</b>      |  | 281.5     |

A reconciliation of quarter to quarter crude oil inventory movements is provided below:

(mbbls)

|                                                          |                      |                |               |               |
|----------------------------------------------------------|----------------------|----------------|---------------|---------------|
| For the periods ended                                    | <b>Dec. 31, 2012</b> | Sept. 30, 2012 | June 30, 2012 | Mar. 31, 2012 |
| Crude oil inventory in transit - beginning of the period | <b>139.1</b>         | 164.8          | 232.3         | 281.5         |
| Oil production                                           | <b>1,172.4</b>       | 1,000.4        | 945.3         | 1,062.8       |
| Oil sales                                                | <b>(1,453.2)</b>     | (1,216.7)      | (1,051.6)     | (1,112.0)     |
| Purchased oil                                            | <b>240.5</b>         | 190.6          | 38.8          | -             |
| Crude oil inventory in transit— end of the period        | <b>98.8</b>          | 139.1          | 164.8         | 232.3         |

The Company is experiencing, on average, two-thirds of period ending crude oil inventory being sold within the following month, however build and draw down of crude oil inventory from period to period are subject to factors that the Company does not control such as timing of the number of shipments from storage to export.

### e) Purchased Oil

|                                       |                                         |      |                                 |      |
|---------------------------------------|-----------------------------------------|------|---------------------------------|------|
|                                       | For the three months ended December 31, |      | For the year ended December 31, |      |
| (mbbls)                               | <b>2012</b>                             | 2011 | <b>2012</b>                     | 2011 |
| Oil purchased                         | <b>240.5</b>                            | -    | <b>465.6</b>                    | -    |
| Purchased oil sales                   | <b>(256.4)</b>                          | -    | <b>(465.6)</b>                  | -    |
| Purchased oil net change in inventory | <b>(15.9)</b>                           | -    | -                               | -    |

From time to time the Company will purchase crude oil from partners. The purchases are done as a service as some partners have difficulty selling to other third parties. The preceding table shows the effect of purchased oil on ending crude oil inventory balances.

|                                |    | For the three months<br>ended December 31, |      |    | For the year<br>ended December 31, |      |
|--------------------------------|----|--------------------------------------------|------|----|------------------------------------|------|
|                                |    | 2012                                       | 2011 |    | 2012                               | 2011 |
| Purchased oil expense (\$000s) | \$ | 19,749                                     | -    | \$ | 37,158                             | -    |

Purchased oil expense for the three months and year ended December 31, 2012 was \$19.7 million and \$37.2 million as compared to \$15.9 million in the preceding quarter and nil for the comparative periods. At December 31, 2012 the Company had no third party purchased oil in inventory. Transportation costs are incurred by the Company to transport purchased oil to sale delivery points.

### Colombian Royalties

|                                       |    | For the three months<br>ended December 31, |          |    | For the year<br>ended December 31, |           |
|---------------------------------------|----|--------------------------------------------|----------|----|------------------------------------|-----------|
|                                       |    | 2012                                       | 2011     |    | 2012                               | 2011      |
| Royalties (\$000s)                    | \$ | 9,359                                      | \$ 7,572 | \$ | 35,890                             | \$ 13,929 |
| Per unit (\$/bbl)                     |    | 8.08                                       | 8.04     |    | 8.31                               | 8.17      |
| Percentage of sales <sup>(1)(2)</sup> |    | 9.7%                                       | 9.3%     |    | 8.3%                               | 9.7%      |

<sup>(1)</sup> Calculated based on Company working interest sales volumes excluding purchased oil volumes sold

<sup>(2)</sup> Net of transportation costs

The Company's Colombian government royalties are generally comprised of a fixed rate of 8 percent, supplemented with an x-factor based upon the E&P contract terms. Parex has an additional 1 percent x-factor on Blocks LLA -16, 20,29,30,57,17,32,34 and 40. Las Maracas and Cabrestero blocks have a fixed 8% royalty rate. Royalties are paid in kind and valued at the realized sales price less transportation expenses incurred. Should monthly average daily production exceed 5,000 bopd, the Company's royalty rate will increase by 1 percent for each incremental 10,000 bopd of production per field. In addition, as accumulated production of any production area, inclusive of royalty volumes, exceeds 5 million barrels, and in the event international reference prices are exceeded by pricing determined in the contract such as a WTI price of \$90 per bbl, the production area's royalty percentage will increase by approximately 22 percent and total approximately 31 percent. At December 31, 2012 the Kona Production Area had produced 4.9 million bbls. The 5.0 million barrel threshold was reached in January of 2013 and accordingly, the expected new Kona Field royalty charge is to be approximately 31%.

### Colombian Production Expense

|                             |    | For the three months<br>ended December 31, |          |    | For the year<br>ended December 31, |           |
|-----------------------------|----|--------------------------------------------|----------|----|------------------------------------|-----------|
|                             |    | 2012                                       | 2011     |    | 2012                               | 2011      |
| Production expense (\$000s) | \$ | 12,122                                     | \$ 6,558 | \$ | 36,286                             | \$ 11,219 |
| Per unit (\$/bbl)           |    | 10.46                                      | 6.97     |    | 8.40                               | 6.58      |

A breakdown of the production expense on a per bbl basis between operated and non-operated fields are provided below:

|                                                                          |  | For the three months<br>ended December 31, |      |  | For the year<br>ended December 31, |      |
|--------------------------------------------------------------------------|--|--------------------------------------------|------|--|------------------------------------|------|
|                                                                          |  | 2012                                       | 2011 |  | 2012                               | 2011 |
| Per unit (\$/bbl) – based on sales volumes – operated <sup>(1)</sup>     |  | 9.49                                       | 6.97 |  | 7.92                               | 6.58 |
| Per unit (\$/bbl) – based on sales volumes – non-operated <sup>(1)</sup> |  | 17.15                                      | -    |  | 16.72                              | -    |

<sup>(1)</sup> Calculated based on Company working interest sales volumes excluding purchased oil volumes sold.

Production expense includes the cost of activities in the field to operate wells and facilities, lift to surface, gather, process, treat and store production. Production expense for the fourth quarter on a per barrel basis of \$10.46/bbl is higher in comparison of the third quarter of \$9.27/bbl. Operated properties production expense in the fourth quarter was \$9.49/bbl compared to \$8.58/bbl for the third quarter and non-operated properties production expense was \$17.15/bbl for the fourth quarter compared to \$16.84 for the third quarter. The increase in the operated properties production expense relate to increased energy costs in the Kona field, which we expect to be reduced in 2013 with the implementation of gas powered electrification facilities currently being introduced. Further, as production volumes in the non-operated fields increase as expected in 2013, the operating costs on a per barrel basis will decrease.

Production expense for the year ended December 31, 2012 on a per barrel basis is \$8.40/bbl in comparison to \$6.58/bbl for the year ended December 31, 2011. The increase is due to higher non-operated property expenses and increased energy costs associated with the Kona field.

### Colombian Transportation Expense

|                                 |    | For the three months<br>ended December 31, |           |    | For the year<br>ended December 31, |           |
|---------------------------------|----|--------------------------------------------|-----------|----|------------------------------------|-----------|
|                                 |    | 2012                                       | 2011      |    | 2012                               | 2011      |
| Transportation expense (\$000s) | \$ | 25,853                                     | \$ 14,971 | \$ | 91,397                             | \$ 27,604 |
| Per unit (\$/bbl)               |    | 18.27                                      | 15.90     |    | 19.06                              | 16.20     |

Transportation expense includes trucking costs incurred to transport production to several offloading stations for sale and in some instances an oil transportation tariff from delivery point to the buyer's facility. For the three months ended December 31, 2012, the cost of transportation on a per barrel basis has decreased to \$18.27/bbl (\$15.90 three months ended December 31, 2011) from the third quarter of \$19.62/bbl. For the year ended December 31, 2012, the cost of transportation on a per barrel basis has increased to \$19.06/bbl from year ended December 31, 2011 of \$16.20/bbl. The main reason for the increases/decreases relate to new oil contracts entered into with changes in delivery points.

### General and Administrative Expense ("G&A")

| (\$000s)        |    | For the three months<br>ended December 31, |          |    | For the year<br>ended December 31, |           |
|-----------------|----|--------------------------------------------|----------|----|------------------------------------|-----------|
|                 |    | 2012                                       | 2011     |    | 2012                               | 2011      |
| Gross G&A       | \$ | 13,403                                     | \$ 6,782 | \$ | 40,183                             | \$ 22,608 |
| G&A recoveries  |    | (553)                                      | (211)    |    | (1,367)                            | (2,108)   |
| Capitalized G&A |    | (1,918)                                    | (2,144)  |    | (7,798)                            | (4,719)   |
| Net G&A expense | \$ | 10,932                                     | \$ 4,427 | \$ | 31,018                             | \$ 15,781 |

Net G&A was \$31.0 million for the twelve months ended December 31, 2012 compared to \$15.8 million for the same period in 2011. These costs primarily consist of management and administrative salaries, legal and professional fees, office rent, insurance, travel and other administrative expense and employee costs. Costs were higher than the comparative period as a result of increased activity levels. For the fourth quarter of 2012 net G&A was mainly comprised of \$7.0 million relating to staff, consultants and professional services, \$0.9 million relating to office costs, \$1.0 million relating to legal fees and \$2.0 million relating to various other expenses. The Company engages local in-country staff at the earliest opportunity and local professional services to improve execution and manage costs. A total of 185 full-time-equivalents in three locations were working for Parex as at December 31, 2012 and throughout the fourth quarter compared to 122 as at December 31, 2011.

### Share Based Compensation Expense

| (\$000s)                          |    | For the three months<br>ended December 31, |          |    | For the year<br>ended December 31, |          |
|-----------------------------------|----|--------------------------------------------|----------|----|------------------------------------|----------|
|                                   |    | 2012                                       | 2011     |    | 2012                               | 2011     |
| Stock-based compensation expense  | \$ | 1,358                                      | \$ 1,141 | \$ | 6,907                              | \$ 5,179 |
| Share appreciation rights expense |    | 1,139                                      | 1,078    |    | 1,068                              | 1,299    |
| Restricted share units expense    |    | 140                                        | -        |    | 140                                | -        |
|                                   | \$ | 2,637                                      | 2,219    | \$ | 8,115                              | \$ 6,478 |

Share-based compensation expense was \$8.1 million for the twelve months ended December 31, 2012 compared to \$6.5 million for the same period in 2011. The primary reason for the increase relates to a higher number of options outstanding period over period. As at December 31, 2012, stock options outstanding were 9,626,515 equaling nine percent of the common shares outstanding at the end of the fourth quarter. A total of 176,083 options were exercised and 1,750,470 options were granted during the twelve months ended December 31, 2012. As at December 31, 2012, the weighted average fair value upon grant date of the options outstanding based upon the Black Scholes option value methodology was Cdn\$1.68 per option (December 31, 2011 – Cdn\$2.53 per option). The weighted average grant price for the twelve months ended December 31, 2012 was Cdn\$4.85 per option (December 31, 2011 – Cdn\$7.48).

Share appreciation rights ("SARs") expense was \$1.1 million for the twelve months ended December 31, 2012 compared to \$1.3 million for the same period in 2011. As at December 31, 2012, 2,741,143 SARs were outstanding all of which were granted to employees in Colombia and Trinidad & Tobago. The weighted average exercise price at December 31, 2012 of the SARs outstanding was Cdn\$6.26 per SAR (December 31, 2011 – Cdn\$7.10 per SAR).

As at December 31, 2012, the total SARs liability accrued is \$2.9 million (December 31, 2011 - \$1.8 million).

Parex Canada has a restricted share unit (“RSUs”) plan, for which the Company may grant restricted shares to directors, officers and certain employees. The plan is subject to shareholder approval. The restricted shares vest at 33 percent on each of the first, second and third anniversaries of the grant date. The determination of fair value for recording share-based compensation expense is based on the then current Parex share price. Restricted share unit expense was \$0.1 million for the twelve months ended December 31, 2012 compared to nil for the same period in 2011 as the plan commenced on October 19, 2012. A total of 240,800 units were granted during the twelve months ended December 31, 2012 (December 31, 2011 –nil). As at December 31, 2012 the fair value upon grant date of the units outstanding was \$4.72 per unit (December 31, 2011 –nil). In the future the Company is expected to issue more RSU’s and less stock options than prior compensation practice.

### **Depletion, Depreciation and Amortization Expense (“DD&A”)**

|                   |    | For the three months ended December 31, |           | For the year ended December 31, |           |
|-------------------|----|-----------------------------------------|-----------|---------------------------------|-----------|
|                   |    | 2012                                    | 2011      | 2012                            | 2011      |
| DD&A (\$000s)     | \$ | 48,836                                  | \$ 36,343 | \$ 181,149                      | \$ 53,772 |
| Per unit (\$/bbl) |    | 41.66                                   | 34.83     | 43.37                           | 27.60     |

<sup>(1)</sup> DDA per unit (\$/bbl) is calculated using Company working interest production volumes.

DD&A is primarily associated with production assets in Colombia and also includes the depreciation and amortization of corporate assets such as computer equipment, office furniture and leasehold improvements. The net carrying value of production assets are depleted using the unit-of-production method by determining the ratio of production in the period to the related proved plus probable reserves, while also taking into account estimated future development costs necessary to bring those reserves into production. For the fourth quarter, future development costs of \$113.1 million (three months ended December 31 2011- \$76.2 million) were included in the depletion calculation. Fourth quarter 2012 depletion was \$48.1 million compared to \$36.0 million for the same period in 2011. Year to date depletion expense of \$179.7 million (\$43.04/bbl) is attributable to the ten producing fields in comparison to two producing fields for the twelve month period ended December 31, 2011. Fourth quarter 2012 DD&A of \$41.66/bbl is lower than Q3, 2012 rate of \$41.96/bbl due to an increase in proved and probable reserves and a change in the CGU production mix. The remaining DD&A relates to seismic equipment and office equipment which is depreciated over the assets estimated useful lives.

### **Foreign Exchange Loss (Gain)**

| (\$000s)                     |    | For the three months ended December 31, |          | For the year ended December 31, |          |
|------------------------------|----|-----------------------------------------|----------|---------------------------------|----------|
|                              |    | 2012                                    | 2011     | 2012                            | 2011     |
| Foreign exchange loss (gain) | \$ | 157                                     | \$ (787) | \$ 2,446                        | \$ 3,146 |

The Company’s main exposure to foreign currency risk relates to the pricing of foreign currency denominated in Canadian dollars, Colombian pesos and Trinidad & Tobago dollars, as the Company’s functional currency is the US dollar. The Company also has exposure in Canada, Colombia and Trinidad & Tobago on costs, such as capital expenditures, local wages, royalties and income taxes, all of which may be denominated in local currencies. The Company holds Canadian dollars to meet head-office general and administrative expenditures. The Company’s convertible debenture is held in Canadian dollars. All cash balances in Colombia must be held in Colombian pesos due to local currency exchange requirements. During the twelve months ended December 31, 2012, the total foreign exchange loss was \$2.4 million due primarily to the Canadian dollar exchange rate at December 31, 2012 being higher than the opening January 1, 2012 exchange rate with the main driver being the conversion for reporting purposes of the CAD denominated Debenture to USD. For the three month period ended December 31, 2012 the Canadian dollar strengthened resulting in a \$0.1 million loss as a result of the Company’s Canadian dollar denominated monetary liabilities exceeding its Canadian dollar monetary assets. The Trinidad & Tobago dollar was relatively stable against the US dollar during the fourth quarter of 2012.

For the twelve month period ended December 31, 2011, a foreign exchange gain of \$3.1 million was recognized as a result of the depreciation of the Colombian peso and the Canadian dollar versus the US dollar. Unrealized foreign exchange gains and losses may be reversed in the future as a result of fluctuations in exchange rates and are recorded in the Company’s consolidated statement of comprehensive income.

As of December 30, 2012 the Company put into place a cross currency interest rate swap (CCRIS) for the principal balance of Cdn 85.0 million relating to the Debenture in order to minimize the fluctuations in exchange rates and to capitalize on fixed USD denominated interest rates being lower than comparable

CDN denominated interest rates. The Company does review its exposure to foreign currency variations on an ongoing basis and maintains foreign denominated deposits in Canada, Colombia and Trinidad & Tobago.

### **Net Finance Expense (Income)**

| (\$000s)                                      | For the three months<br>ended December 31, |          | For the year<br>ended December 31, |            |
|-----------------------------------------------|--------------------------------------------|----------|------------------------------------|------------|
|                                               | 2012                                       | 2011     | 2012                               | 2011       |
| Interest expense                              | \$ 1,211                                   | \$ 1,099 | \$ 4,602                           | \$ 2,800   |
| Bank fees                                     | 367                                        | -        | 643                                | -          |
| Accretion on debentures                       | 1,026                                      | 882      | 3,744                              | 1,738      |
| Accretion on decommissioning liability        | 110                                        | 50       | 359                                | 97         |
| Loss (gain) on derivative financial liability | 2,389                                      | 1,992    | (7,294)                            | (5,091)    |
| Amortization of debt issuance costs           | 155                                        | 133      | 564                                | 262        |
| Interest and other income                     | (1,416)                                    | (414)    | (1,925)                            | (1,334)    |
| Net finance expense (income)                  | \$ 3,842                                   | \$ 3,742 | \$ 693                             | \$ (1,528) |

Derivatives are carried at fair value on the balance sheet, with any changes in fair value being recorded to the statement of comprehensive income.

Under IFRS, the conversion feature of the Debenture issued on June 29, 2011 is classified as a derivative financial liability given that, if converted, the Company has the option to deliver either common shares or cash equal to the market value. In the three months ended December 31, 2012, a \$2.4 million loss on the derivative financial liability was recognized (December 31, 2012- gain of \$7.3 million). An equivalent non-cash derivative gain/loss was recorded in comprehensive income. The gain/loss is a result of fair valuing the derivative liability at December 31, 2012 and specifically the decrease/increase in the Company's stock price from December 31, 2011, September 30, 2012 to December 31, 2012.

Interest expense on Debentures for the three months ended December 31, 2012 was \$1.1 million (three months ended December 31, 2011 -\$1.1 million). Interest expense on Debenture for the year ended December 31, 2012 was \$4.5 million (December 31, 2011 – \$2.8 million). The interest expense relates to the annual 5.25 percent coupon on the outstanding Debentures. The accretion expense for the debentures for the three months ended December 31, 2012 was \$1.0 million (three months ended December 31, 2011 – \$0.9 million). The debenture accretion expense was \$3.7 million for the year ended December 31, 2012 (December 31, 2011 – \$1.7 million). The accretion is related to the Debenture liability portion being accreted under the effective interest rate method. The liability portion of the Debentures is measured at amortized cost and will accrete up to the principal balance at maturity using the effective interest rate method. The resulting accretion is charged to finance expense in the consolidated statement of comprehensive income.

### **Derivatives**

Management of cash flow variability is an integral component of Parex' business strategy. Changing business conditions are monitored regularly and, where material, reviewed with the Board of Directors to establish risk management guidelines used by management in carrying out the Company's strategic risk management program. The risk exposure inherent in movements in the price of crude oil, fluctuations in the US/Cdn dollar exchange rate and interest rate movements on the Debenture are all proactively reviewed by Parex and as considered appropriate may be managed through the use of derivatives with financial institutions that are members of Parex' credit facility. The Company considers these derivative contracts to be an effective means to manage cash flow.

#### **a) Risk Management Contracts- Brent Crude**

The following is a summary of the risk management contracts in place as at December 31, 2012:

| Period Hedged                        | Type        | Volume bbls/d | Price/bbl      |
|--------------------------------------|-------------|---------------|----------------|
| September 1 2012 - December 31, 2012 | Fixed price | 2000 bbl/d    | \$111.70       |
| November 1, 2012 - March 31, 2013    | Collar      | 2000 bbl/d    | \$100 to \$123 |

Subsequent to December 31, 2012 Parex entered into the following contracts:

| Oil Period Hedged               | Type        | Volume bbls/d | Price/bbl |
|---------------------------------|-------------|---------------|-----------|
| January 1, 2013 – June 30, 2013 | Fixed price | 2000 bbl/d    | \$108.50  |
| April 30, 2013 – June 30, 2013  | Fixed Price | 2000 bbl/d    | \$110.10  |

## b) Cross Currency Interest Rate Swap ("CCIRS") contract

The following is a summary of the CCIRS in place as at December 31, 2012:

|                                   | Type | Receive Notional<br>Principal (Cdn\$) | Fixed annual<br>rate (Cdn%) | Pay Notional<br>Principal (US\$) | Fixed annual rate<br>(US%) |
|-----------------------------------|------|---------------------------------------|-----------------------------|----------------------------------|----------------------------|
| December 30, 2012 – June 30, 2016 | Swap | 85,000,000                            | 5.25%                       | 85,685,565                       | 4.45%                      |

The table below summarizes the (gain) loss on risk management contracts:

| (\$000s)                                         |    | For the three months<br>ended December 31, |        | For the year<br>ended December 31, |        |
|--------------------------------------------------|----|--------------------------------------------|--------|------------------------------------|--------|
|                                                  |    | 2012                                       | 2011   | 2012                               | 2011   |
| Realized (gain) loss on risk management contract | \$ | (230)                                      | \$ 432 | \$ (234)                           | \$ 432 |
| Unrealized gain on risk management contract      |    | (90)                                       | -      | (90)                               | -      |
| Unrealized loss on CCIRS                         |    | 992                                        | -      | 992                                | -      |
| Net loss on derivative contracts                 | \$ | 672                                        | \$ 432 | \$ 668                             | \$ 432 |

The realized gain represents the risk management contracts settled during the period. The unrealized (gain) loss represents the fair value change of the underlying risk management contracts and CCIRS to be settled in the future.

The Company's net unrealized derivative loss for the year ended December 31, 2012 was \$902,000 (December 31, 2011-nil). The increase is primarily due to an unrealized gain on crude oil contracts, offset by an unrealized loss on the Company's CCIRS contract. The unrealized oil derivative gain for the year ended December 31, 2012 is primarily attributable to the decrease in the Brent forward benchmark price at December 31, 2012. The unrealized CCIRS for the year ended December 31, 2012 is primarily attributable to the increase in the forward Cdn dollar exchange rate at December 31, 2012 versus the US dollar rate.

The Company has not designated any of its derivative contracts as accounting hedges under International Accounting Standard 39, *Financial Instruments: Recognition and Measurement* and, accordingly, has fair valued its derivatives.

## Income Tax

The components of tax expense for the three and twelve months ended December 31, 2012 and 2011 were as follows:

| (\$000s)                       |    | For the three months<br>ended December 31, |            | For the year<br>ended December 31, |           |
|--------------------------------|----|--------------------------------------------|------------|------------------------------------|-----------|
|                                |    | 2012                                       | 2011       | 2012                               | 2011      |
| Current equity tax expense     | \$ | 17,049                                     | \$ (2,610) | \$ 42,999                          | \$ 424    |
| Deferred tax expense (benefit) |    | (9,265)                                    | 16,926     | (8,847)                            | 28,443    |
| Total tax expense              | \$ | 7,784                                      | \$ 14,316  | \$ 34,152                          | \$ 28,867 |

The Company has losses available to reduce future taxable income, as well as other cumulative tax deductions in excess of book value in Canada, Colombia and Trinidad & Tobago. Only the Colombian benefit associated with these losses and deductions has been recognized in the financial statements as the recoverability of the tax benefit in Trinidad & Tobago and Canada is uncertain. Losses can be carried forward indefinitely in Colombia and Trinidad & Tobago, while in Canada they expire after 20 years. Amounts denominated in foreign currency have been translated at the December 31, 2012 exchange rate.

The current and future tax expense relates to the Company's operations in Colombia. The increase in current tax expense in the fourth quarter of 2012 is a result of non-operating losses being substantially utilized as of December 31, 2012. Future tax expense in the fourth quarter of 2012 was a recovery of \$9.3 million, mainly a result of a narrowing between the book and tax basis in Colombian subsidiaries. The calculation of current and future income tax in Colombia is based on a number of variables which can cause swings in current and future income tax. These variables include the year end producing reserves used in calculating depletion for tax purposes and the timing and number of dry hole write offs permissible for Colombian tax purposes. Accordingly estimating tax expense during the year is inherently difficult. The effective current tax rate for the twelve months ended December 31, 2012 on Colombian segmented operating cash flows was 14%.

## Capital Expenditures

| (\$000s)                           | Colombia <sup>(1)</sup> |         | Trinidad & Tobago |           | Canada |          | Total      |            |
|------------------------------------|-------------------------|---------|-------------------|-----------|--------|----------|------------|------------|
| For the year ended December 31,    | 2012                    | 2011    | 2012              | 2011      | 2012   | 2011     | 2012       | 2011       |
| Geological and geophysical         | \$ 12,880               | 8,407   | \$ 9,715          | \$ 172    | \$ -   | \$ -     | \$ 22,595  | \$ 8,579   |
| Acquisition of unproved properties | 20,848                  | 1,085   | 16,480            | 2,940     | -      | -        | 37,328     | 4,025      |
| Drilling and completion            | 170,835                 | 109,021 | 13,476            | 10,419    | -      | -        | 184,311    | 119,440    |
| Well equipment and facilities      | 21,162                  | 13,254  | (28)              | 865       | -      | -        | 21,134     | 14,119     |
| Other                              | 1,833                   | 825     | 241               | 64        | 246    | 2,591    | 2,320      | 3,480      |
|                                    | \$ 227,558              | 132,592 | \$ 39,884         | \$ 14,460 | \$ 246 | \$ 2,591 | \$ 267,688 | \$ 149,643 |

<sup>(1)</sup> Excludes corporate acquisition costs.

| (\$000s)                                | Colombia <sup>(1)</sup> |        | Trinidad & Tobago |          | Canada |          | Total     |           |
|-----------------------------------------|-------------------------|--------|-------------------|----------|--------|----------|-----------|-----------|
| For the three months ended December 31, | 2012                    | 2011   | 2012              | 2011     | 2012   | 2011     | 2012      | 2011      |
| Geological and geophysical              | \$ 9,849                | 1,523  | \$ 421            | \$ (22)  | \$ -   | \$ -     | \$ 10,270 | \$ 1,501  |
| Acquisition of unproved properties      | 8,271                   | 10     | 1,480             | 2,209    | -      | -        | 9,751     | 2,219     |
| Drilling and completion                 | 35,064                  | 40,046 | 1,851             | 2,669    | -      | -        | 36,915    | 42,715    |
| Well equipment and facilities           | 7,058                   | 4,051  | (71)              | 42       | -      | -        | 6,987     | 4,093     |
| Other                                   | 711                     | 683    | 209               | 43       | 34     | 2,423    | 954       | 3,149     |
|                                         | \$ 60,953               | 46,313 | \$ 3,890          | \$ 4,941 | \$ 34  | \$ 2,423 | \$ 64,877 | \$ 53,677 |

<sup>(1)</sup> Excludes corporate acquisition costs.

### a) Capital Expenditures Summary

During the twelve months ended December 31, 2012 the Company incurred \$267.7 million of capital expenditures compared to \$149.6 million in the same period of 2011. The majority of the increase is attributed to increased drilling activity in Colombia and Trinidad compared to the prior year and a higher average working interest. During 2012 the Company drilled 35 wells (23 net), compared to 18 wells (15 net) in 2011.

In the fourth quarter of 2012 the Company drilled 6 wells (3.3 net) in Colombia. Total drilling and completion costs during the fourth quarter totaled \$36.9 million of which \$35.1 million related to drilling and completion and capitalized workover costs in Colombia and \$1.8 million related to drilling and completion costs incurred in Trinidad. Spending on well equipment and facilities was \$7.0 million in the quarter, primarily all focused in Colombia.

In the fourth quarter of 2012 the Company's Colombian operations utilized three drilling rigs and two service rigs. The level of activity increased in the fourth quarter of 2012 from the third quarter of 2012 as Parex invested \$64.9 million in the fourth quarter as compared to \$50.1 million in the previous third quarter of 2012. The drilling and completion costs in the fourth quarter include \$4.5 million of recompletion costs relating to Kona field. The acquisition of unproved properties of \$8.3 million relate to costs associated with the closing of purchased working interest on the Cabrestero, El Eden, and Los Ocarros Blocks.

Minor capital expenditures in Canada during the twelve months ended December 31, 2012 related to office and other equipment.

### b) Exploration and Evaluation Impairment

The Company completed an impairment review for the exploration and evaluation assets in Trinidad & Tobago, due to unfavorable testing results in the fourth quarter relating to the Green Hermit and Fire Crown wells on the Moruga Block. The impairment review compared the carrying value of the Moruga Block to the recoverable amount. The recoverable amount of the Block was estimated using fair value less cost based on offers and indications from third parties in the Company's interest in the Moruga Block. It was determined that the impairment amount on the Moruga Block was \$23.5 million which was recorded in the statement of comprehensive income for the year ended December 31, 2012. The impairment is not income tax affected as the Company is currently not taxable in Trinidad.

## Business Combination

### Ramshorn

On April 12, 2012 Parex, through a foreign subsidiary, acquired Ramshorn International Limited (“Ramshorn”) which assets primarily consist of interests in four exploration blocks located in Colombia’s Llanos Basin and one block located in Colombia’s Middle Magdalena Basin (the Ramshorn “Acquisition”). Total net consideration paid was \$71.8 million in cash and the assumption of a working capital deficiency at close, primarily relating to post effective date capital expenditures. The Ramshorn Acquisition was funded from existing cash. The Company’s independent reserve engineers ascribed probable oil reserves of 2.3 million barrels to the properties effective March 31, 2012.

The statement of comprehensive income includes Ramshorn’s results of operation since the Ramshorn Acquisition closing date of April 12, 2012 and expensed transaction costs associated with the Ramshorn Acquisition of \$1.1 million.

This transaction has been accounted for using the acquisition method whereby the assets acquired and the liabilities assumed, excluding goodwill, are recorded at fair values. No goodwill was recorded on this transaction. The following table summarizes the recognizable assets acquired and consideration paid pursuant to this acquisition:

|                                                |    |               |
|------------------------------------------------|----|---------------|
| (\$000s)                                       |    |               |
| <b>Assets acquired and liabilities assumed</b> |    |               |
| Property, plant and equipment                  | \$ | 66,382        |
| Exploration and evaluation assets              |    | 34,312        |
| Working capital deficiency                     |    | (13,269)      |
| Deferred tax liability                         |    | (14,946)      |
| Decommissioning liabilities                    |    | (705)         |
|                                                | \$ | <b>71,774</b> |

|                                                      |    |               |
|------------------------------------------------------|----|---------------|
| (\$000s)                                             |    |               |
| <b>Consideration for the acquisition</b>             |    |               |
| Cash paid                                            | \$ | 72,636        |
| Cash acquired                                        |    | (862)         |
| <b>Total consideration paid net of cash acquired</b> | \$ | <b>71,774</b> |

### Remora

On June 29, 2011, Parex acquired Remora Energy Colombia Ltd. (“Remora”) which held the other 50 percent interest Parex did not already own in four Llanos Basin blocks in Colombia, including Block LLA-16 and the Kona discovery (the “Remora Acquisition”). The Remora Acquisition was funded through a bought deal public offering of Cdn\$217.35 million of subscription receipts and Cdn\$85.0 million of extendible convertible unsecured subordinated debentures (the “Offering”). With the close of the Remora Acquisition, Parex has increased its working interest from 50 percent to 100 percent. The Remora Acquisition is underpinned by the Kona multi-zone light oil field and an inventory of exploration prospects.

The statement of comprehensive income (loss) includes Remora’s results of operation since the Remora Acquisition date June 29, 2011 and expensed transaction costs of \$2.1 million.

This transaction has been accounted for using the acquisition method whereby the assets acquired and the liabilities assumed, excluding goodwill, are recorded at fair values. The following table summarizes the recognizable assets acquired and consideration transferred pursuant to this acquisition:

|                                                |    |                |
|------------------------------------------------|----|----------------|
| (\$000s)                                       |    |                |
| <b>Assets acquired and liabilities assumed</b> |    |                |
| PP&E                                           | \$ | 197,706        |
| E&E assets                                     |    | 80,146         |
| Working capital deficiency                     |    | (21,246)       |
| Deferred tax liability                         |    | (64,401)       |
| Goodwill                                       |    | 61,252         |
| Decommissioning liabilities                    |    | (470)          |
|                                                | \$ | <b>252,987</b> |

(\$000s)

| <b>Consideration for the acquisition</b>             |                   |
|------------------------------------------------------|-------------------|
| Cash paid                                            | \$ 254,335        |
| Cash acquired                                        | (1,348)           |
| <b>Total consideration paid net of cash acquired</b> | <b>\$ 252,987</b> |

## Summary of Quarterly Results (Unaudited)

| Three months ended (\$000s)                                      | Dec. 31, 2012 | Sep. 30, 2012 | June 30, 2012 | March 31, 2012 |
|------------------------------------------------------------------|---------------|---------------|---------------|----------------|
| Average daily production volumes (bopd)                          | 12,743        | 10,874        | 10,389        | 11,679         |
| Realized sales price volumes (\$/bbl)                            | 105.75        | 107.53        | 107.54        | 116.90         |
| Financial (000s except per share amounts)                        |               |               |               |                |
| Oil Sales                                                        | \$ 149,614    | \$ 130,824    | \$ 113,087    | \$ 129,989     |
| Funds flow from operations <sup>(2)</sup>                        | \$ 54,446     | \$ 42,012     | \$ 61,357     | \$ 83,754      |
| Per share – basic                                                | 0.50          | 0.39          | 0.57          | 0.77           |
| Per share – diluted                                              | 0.50          | 0.39          | 0.53          | 0.72           |
| Adjusted net income (loss) <sup>(2)(3)</sup>                     | \$ (13,450)   | \$ 7,490      | \$ 11,654     | \$ 26,934      |
| Per share – basic                                                | (0.12)        | 0.07          | 0.11          | 0.25           |
| Per share – diluted                                              | (0.12)        | 0.07          | 0.10          | 0.25           |
| Net income (loss)                                                | \$ (15,840)   | \$ 7,538      | \$ 20,920     | \$ 27,304      |
| Per share – basic                                                | (0.15)        | 0.07          | 0.19          | 0.25           |
| Per share – diluted                                              | (0.15)        | 0.07          | 0.09          | 0.25           |
| Total assets (end of period)                                     | \$ 821,201    | \$ 789,546    | \$ 768,498    | \$ 703,343     |
| Working capital surplus (deficit) (end of period) <sup>(2)</sup> | \$ (12,640)   | \$ (9,014)    | \$ (555)      | \$ 116,277     |
| Debentures (end of period) <sup>(4)</sup>                        | \$ 65,657     | \$ 65,251     | \$ 61,940     | \$ 62,148      |
| Bank debt (end of period)                                        | \$ 9,100      | \$ -          | \$ -          | \$ -           |

| Three months ended (\$000s)                            | Dec. 31, 2011 | Sep. 30, 2011 | June 30, 2011 | March 31, 2011 |
|--------------------------------------------------------|---------------|---------------|---------------|----------------|
| Average daily production volumes (bopd)                | 11,342        | 7,031         | 1,619         | 1,146          |
| Realized sales price volumes (\$/bbl)                  | 102.15        | 97.64         | 104.67        | 95.54          |
| Financial (000s except per share amounts)              |               |               |               |                |
| Oil Sales                                              | \$ 96,169     | \$ 54,429     | \$ 10,719     | \$ 9,853       |
| Funds flow from operations <sup>(2)</sup>              | \$ 63,135     | \$ 31,814     | \$ 334        | \$ 2,960       |
| Per share – basic                                      | 0.58          | 0.29          | 0.00          | 0.04           |
| Per share – diluted                                    | 0.56          | 0.27          | 0.00          | 0.04           |
| Adjusted net income (loss) <sup>(2)(3)</sup>           | \$ 6,470      | \$ 7,740      | \$ (4,688)    | \$ 1,023       |
| Per share – basic                                      | 0.06          | 0.07          | (0.06)        | 0.01           |
| Per share – diluted                                    | 0.06          | 0.07          | (0.06)        | 0.01           |
| Net income (loss)                                      | \$ 4,477      | \$ 14,823     | \$ (4,688)    | \$ 1,023       |
| Per share – basic                                      | 0.04          | 0.14          | (0.06)        | 0.01           |
| Per share – diluted                                    | 0.04          | 0.13          | (0.06)        | 0.01           |
| Total assets (end of period)                           | \$ 660,177    | \$ 619,240    | \$ 593,699    | \$ 220,521     |
| Working capital surplus (end of period) <sup>(2)</sup> | \$ 92,893     | \$ 77,890     | \$ 101,422    | \$ 101,672     |
| Debentures (end of period) <sup>(4)</sup>              | \$ 60,001     | \$ 57,226     | \$ 61,200     | \$ -           |
| Bank debt (end of period)                              | \$ -          | \$ -          | \$ -          | \$ -           |

<sup>(1)</sup> Non GAAP measure. See “Non GAAP Measures” above.

<sup>(2)</sup> The December 31, 2012 working capital deficiency does not include the undrawn \$65.9 million available from the credit facility.

<sup>(3)</sup> Net income has been adjusted for the IFRS accounting effects of changes in the derivative financial liability.

<sup>(4)</sup> Debentures will accrete up to the face value amount of Cdn \$85.0 million over the remaining term of the Debenture to June 30, 2016.

## Fourth Quarter Results (Unaudited)

An unaudited income statement for the three months ended December 31, 2012 is set out below:

| (\$000s)                                              | For the three month period ended December 31, |  | 2012     |    | 2011    |
|-------------------------------------------------------|-----------------------------------------------|--|----------|----|---------|
| Oil sales                                             | \$                                            |  | 149,614  | \$ | 96,169  |
| Royalties                                             |                                               |  | (9,359)  |    | (7,572) |
| Revenue                                               |                                               |  | 140,255  |    | 88,597  |
| Risk management contracts                             |                                               |  | (672)    |    | (432)   |
|                                                       |                                               |  | 139,583  |    | 88,165  |
| <b>Expenses</b>                                       |                                               |  |          |    |         |
| Production                                            |                                               |  | 12,122   |    | 6,558   |
| Transportation                                        |                                               |  | 25,853   |    | 14,971  |
| Purchased oil                                         |                                               |  | 19,749   |    | -       |
| General and administrative                            |                                               |  | 10,932   |    | 4,427   |
| Share-based compensation                              |                                               |  | 2,637    |    | 2,219   |
| Transaction costs                                     |                                               |  | -        |    | 326     |
| Depletion, depreciation and amortization              |                                               |  | 48,836   |    | 36,343  |
| Foreign exchange loss                                 |                                               |  | 157      |    | 786     |
| Exploration and evaluation impairment                 |                                               |  | 23,511   |    | -       |
|                                                       |                                               |  | 143,797  |    | 65,630  |
| Finance income                                        |                                               |  | (1,413)  |    | 6,675   |
| Finance expense                                       |                                               |  | 5,255    |    | (2,933) |
| <b>Net finance expense (income)</b>                   |                                               |  | 3,842    |    | 3,742   |
| <b>Net income (loss) before taxes</b>                 |                                               |  | (8,056)  |    | 18,793  |
| <b>Income tax expense</b>                             |                                               |  |          |    |         |
| Current tax expense (recovery)                        |                                               |  | 17,049   |    | (2,610) |
| Deferred tax expense (recovery)                       |                                               |  | (9,265)  |    | 16,926  |
|                                                       |                                               |  | 7,784    |    | 14,316  |
| <b>Net comprehensive income (loss) for the period</b> | \$                                            |  | (15,840) | \$ | 4,477   |

## Reconciliation of Non-GAAP terms

### Funds Flow from Operations

| (\$000s)                                    | For the three months ended December 31, |           | For the year ended December 31, |           |
|---------------------------------------------|-----------------------------------------|-----------|---------------------------------|-----------|
|                                             | 2012                                    | 2011      | 2012                            | 2011      |
| <b>Operating activities</b>                 |                                         |           |                                 |           |
| Net income (loss)                           | \$ (15,840)                             | \$ 4,477  | \$ 39,922                       | \$ 15,635 |
| Add (deduct) non-cash items                 |                                         |           |                                 |           |
| Depletion, depreciation and amortization    | 48,836                                  | 36,343    | 181,149                         | 53,772    |
| Non-cash finance (income) loss              | 3,672                                   | 3,050     | (2,633)                         | (2,999)   |
| Share-based compensation                    | 2,637                                   | 2,219     | 8,115                           | 6,478     |
| Deferred tax expense (recovery)             | (9,265)                                 | 16,926    | (8,847)                         | 28,443    |
| Equity tax expense                          | -                                       | -         | -                               | -         |
| Unrealized foreign exchange gain            | (88)                                    | 588       | 1,030                           | (2,712)   |
| Exploration and evaluation impairment       | 23,511                                  | -         | 23,511                          | -         |
| Unrealized loss on risk management contract | 983                                     | -         | 902                             | -         |
| Decommissioning expenditures                | -                                       | (467)     | -                               | (467)     |
| Colombia equity tax paid                    | -                                       | -         | (1,580)                         | (234)     |
| <b>Funds flow from (used in) operations</b> | \$ 54,446                               | \$ 63,135 | \$ 241,569                      | \$ 97,916 |

The following table shows the variables used in the calculation of diluted funds flow from operations per share:

| (\$000s)                                                                        | For the three months<br>ended December 31, |                  | For the year<br>ended December 31, |                   |
|---------------------------------------------------------------------------------|--------------------------------------------|------------------|------------------------------------|-------------------|
|                                                                                 | 2012                                       | 2011             | 2012                               | 2011              |
| <b>Funds flow from operations</b>                                               |                                            |                  |                                    |                   |
| Funds flow from (used in) operations for the purpose of basic funds flow        | \$ 54,446                                  | \$ 63,135        | \$ 241,569                         | \$ 97,916         |
| Debt interest expense                                                           | 1,125                                      | 2,800            | 4,466                              | 2,800             |
| <b>Funds flow from operations for diluted funds flow</b>                        | <b>\$ 55,571</b>                           | <b>\$ 65,935</b> | <b>\$ 246,035</b>                  | <b>\$ 100,716</b> |
| Weighted average number of shares for the purposes of basic funds flow (\$000s) | 108,440                                    | 108,287          | 108,403                            | 92,956            |
| Dilutive effect of share options on potential common shares                     | 1,068                                      | 763              | 1,324                              | 889               |
| Dilutive effect of Debentures on potential common shares <sup>(1)</sup>         | -                                          | 8,374            | 15,984                             | 4,222             |
| <b>Weighted average number of shares for the purposes of diluted funds</b>      | <b>109,508</b>                             | <b>117,424</b>   | <b>125,711</b>                     | <b>98,067</b>     |

<sup>(1)</sup> For the three months ended December 31, 2012 the effect of the Debenture is antidilutive.

In the fourth quarter of 2012, funds flow from operations was lower than capital expenditures by \$10.5 million as compared to the prior year's fourth quarter when capital expenditures exceeded funds flow from operations by \$9.5 million.

## Adjusted net income

The following table reconciles net income to adjusted net income:

| (\$000s)                                               | For the three months<br>ended December 31, |                 | For the year<br>ended December 31, |                  |
|--------------------------------------------------------|--------------------------------------------|-----------------|------------------------------------|------------------|
|                                                        | 2012                                       | 2011            | 2012                               | 2011             |
| Net income (GAAP)                                      | \$ (15,840)                                | \$ 4,477        | \$ 39,922                          | \$ 15,635        |
| Non cash (gain) loss on derivative financial liability | 2,390                                      | 1,993           | (7,294)                            | (5,090)          |
| <b>Adjusted net income (Non-GAAP)</b>                  | <b>\$ (13,450)</b>                         | <b>\$ 6,470</b> | <b>\$ 32,628</b>                   | <b>\$ 10,545</b> |

## Liquidity and Capital Resources

As at December 31, 2012, the Company had a working capital deficiency of \$12.6 million, excluding amounts available under the credit facility, as compared to working capital deficit at September 30, 2012 of \$9.0 million. The decrease in working capital is mainly related to the higher Colombian corporate tax accrual and additional working interest purchase costs being recorded. As at December 31, 2012 the Company had a \$75 million senior credit facility available of which \$9.1 million was drawn. The undrawn facility and estimated positive operating cashflows are expected to be in excess of any commitments due in 2013. At December 31, 2012 Parex held \$31.9 million of cash, compared to \$26.5 million at September 30, 2012. The Company's cash balances reside in current accounts and term deposits, the majority of which are held on account in Canada and Barbados.

The Company values its crude oil inventory on hand using weighted average cost for the inventoried barrels. On a fair market value basis the inventory on hand would have a value of approximately \$10.9 million or a fair value adjustment of approximately \$3.5 million.

Parex entered into a \$200 million senior secured credit facility ("credit facility") with a syndicate of banks led by a major Canadian bank during 2012. Key covenants include a current ratio test of 1:1 adjusted for undrawn amounts on the facility plus the fair value of inventoried oil, and a rolling four quarters total funded debt to EBITDA test of 3:50:1, and other standard business operating covenants. As at December 31, 2012, the Company is in compliance with all covenants.

## Debentures

On June 29, 2011, Parex issued Cdn\$85.0 million of Debentures with an annual coupon of 5.25 percent maturing on June 30, 2016. The Debentures have a face value of \$1,000 per Debenture and are convertible into common shares at the holder's option at a conversion price of Cdn\$10.15 per Common Share, representing a conversion rate of approximately 98.52 Common Shares per Debenture. The Debentures pay interest semi-annually in arrears on June 30 and December 31 of each year, commencing on December 31, 2011. In the event that a holder of Debentures exercises the conversion feature, such holder shall be

entitled to receive accrued and unpaid interest, in addition to the applicable number of common shares to be received on conversion, for the period from the latest interest payment date to the date of conversion.

The company has entered into a “CCRIS” contract in order to reduce the risk exposure relating to the, fluctuation in the US/Cdn dollar exchange rate relating to the Debenture. Refer to the derivative section of the document for details on the “CCRIS” contract.

The following table summarizes the accounting for the Debentures:

|                                                                                  | Liability | Derivative<br>financial liability | Total     |
|----------------------------------------------------------------------------------|-----------|-----------------------------------|-----------|
| Issuance of Debentures on June 29, 2011 (net of \$3.5 million of issuance costs) | \$ 60,809 | \$ 23,266                         | \$ 84,075 |
| Accretion                                                                        | 1,738     | -                                 | 1,738     |
| Amortization of debt issuance costs                                              | 262       | -                                 | 262       |
| Derivative gain                                                                  | -         | (5,091)                           | (5,091)   |
| Foreign exchange gain                                                            | (2,808)   | (1,354)                           | (4,162)   |
| Balance at December 31, 2011                                                     | \$ 60,001 | \$ 16,821                         | \$ 76,822 |
| Accretion                                                                        | 3,744     | -                                 | 3,744     |
| Amortization of debt issuance costs                                              | 564       | -                                 | 564       |
| Derivative gain                                                                  | -         | (7,294)                           | (7,294)   |
| Foreign exchange loss                                                            | 1,348     | 372                               | 1,720     |
| Balance at December 31, 2012                                                     | \$ 65,657 | \$ 9,899                          | \$ 75,556 |

## Outstanding Share Data

Parex is authorized to issue an unlimited number of voting common shares without nominal or par value. As at December 31, 2012 the Company had 108,476,451 common shares outstanding.

The Company has a stock option and RSU plan. The plans provide for the issuance of options to the Company’s directors, officers and certain employees to acquire common shares. The maximum number of options and RSU’s reserved for issuance under the two plans may not exceed 10 percent of the number of common shares issued and outstanding.

As at March 13, 2013 Parex has the following securities outstanding:

|                                       | Number      | %     |
|---------------------------------------|-------------|-------|
| Common shares                         | 108,574,251 | 91.7% |
| Stock options                         | 9,626,515   | 8.1%  |
| Restricted share units <sup>(1)</sup> | 240,800     | 0.2%  |
|                                       | 118,440,566 | 100%  |

<sup>(1)</sup> Restricted share unit plan is subject to shareholder approval.

As of the date of this MD&A, total stock options and RSU’s outstanding represent approximately 9.1 percent of the total issued and outstanding common shares.

## Contractual Obligations, Commitments and Guarantees

In the normal course of business, Parex has entered into arrangements and incurred obligations that will affect the Company’s future operations and liquidity. These commitments primarily relate to exploration work commitments including seismic and drilling activities. The Company has discretion regarding the timing of capital spending for exploration work commitments, provided that the work is completed by the end of the exploration periods specified in the contracts or the Company can negotiate extensions of the exploration periods. The Company’s exploration commitments are described under “Description of Business – Principal Properties”. These obligations and commitments are considered in assessing cash requirements in the discussion of future liquidity.

In Colombia, the Company has provided guarantees to the Colombian energy regulator (“ANH”) which on December 31, 2012 are approximately \$50.0 million to support the exploration work commitments on its Blocks. The guarantees have been provided in the form of letters of credit for varying terms. Export Development Canada (“EDC”) has provided the Company’s bank with performance security guarantees to support 100 percent of the letters of credit issued on behalf of Parex. The letters of credit issued to the ANH are reduced from time to time to reflect the work performed on the various blocks.

In Trinidad & Tobago, under the initial exploration phase of the Central Range Block PSCs the joint ventures remaining work commitment is to drill an exploration well to 12,000 feet and acquire 340 kilometers of 2D seismic. The obligations under the PSCs are to perform the exploration work commitments, irrespective of actual cost. In the event of a default by the Company's joint venture partner Niko Resources Ltd. ("Niko"), the joint venture agreement provides that Niko's working interest shall vest in Parex.

The following table summarizes the Company's estimated commitments as at December 31, 2012:

| (\$000s)                                 |           | <b>Total</b>   | <b>&lt;1 year</b> | <b>1 – 3 years</b> | <b>3 – 4 years</b> | <b>&gt;5 years</b> |
|------------------------------------------|-----------|----------------|-------------------|--------------------|--------------------|--------------------|
| Exploration <sup>(1)</sup>               | \$        | 79,042         | \$ 45,997         | \$ 33,045          | \$ -               | \$ -               |
| Office and accommodations <sup>(2)</sup> |           | 1,860          | 1,145             | 715                | -                  | -                  |
| Decommissioning expenditures             |           | 17,500         | -                 | -                  | -                  | 17,500             |
| Other                                    |           | 4,318          | 2,465             | 1,853              | -                  | -                  |
| <b>Total</b>                             | <b>\$</b> | <b>102,720</b> | <b>\$ 49,607</b>  | <b>\$ 35,613</b>   | <b>\$ -</b>        | <b>\$ 17,500</b>   |

<sup>(1)</sup> Exploration commitments do not include production bonuses and other payments that will vary depending on production levels due to the uncertainty of their amount and timing.

<sup>(2)</sup> Includes minimum lease payment obligations associated with leases for office space and accommodations.

The Company has entered into contracts for drilling rigs in Colombia and Trinidad & Tobago. Rig contracts in both countries include commitments to use the rigs for a minimum period on terms consistent with normal industry practice.

## Contingencies

As announced by Parex on April 12, 2012, Parex and its wholly owned subsidiaries Parex Resources (Bermuda) Ltd. ("Parex Bermuda") and Ramshorn International, Limited ("Ramshorn") have been named as defendants along with Nabors Industrial Ltd. and Nabors Global Holdings II Limited in a lawsuit (the "Lawsuit") filed in the 61st Judicial District Court of Harris County, Texas (the "Texas Court") by a Texas based private company (the "Plaintiff"). The Lawsuit relates to a share purchase agreement entered into by the Plaintiff and a third party seller (the "Seller") (prior to the agreement entered into by Parex Bermuda and the Seller for the purchase of Ramshorn) respecting the proposed purchase by the Plaintiff of the shares of Ramshorn, which prior agreement the Plaintiff claims was improperly terminated by the Seller. The Plaintiff is seeking specific performance remedies or in the alternative, actual, consequential, and exemplary damages. Each of Parex, Parex Bermuda and Ramshorn specially appeared in the Lawsuit to challenge the jurisdiction of the Texas Court and to seek dismissal of the claims against them.

A hearing on the jurisdictional aspects of the case took place on November 19 and 20, 2012 and the decision of the Texas Court on these jurisdictional matters has now been received. The Texas Court found that it does not have jurisdiction over Parex Bermuda and ordered that all of the Plaintiff's claims against Parex Bermuda be dismissed. The Texas Court overruled Parex and Ramshorn's jurisdictional challenges such that the Plaintiff's claims against Parex and Ramshorn have not been dismissed. Parex and Ramshorn have filed a Notice of Appeal of the Texas Court's rulings in this regard. Additionally, the Texas Court has entered an order staying all discovery between the Plaintiff and Parex/Ramshorn pending the outcome of the appeal on these jurisdictional matters. Parex and Ramshorn believe that the Lawsuit and the Plaintiff's claims against it are baseless and without merit and will continue to vigorously defend the Lawsuit, including by way of appealing the Texas Court's recent jurisdictional rulings against Parex and Ramshorn.

Based on input from counsel received to date and on managements' understanding of the facts, risks and uncertainties at the date of authorization of this management discussion and analysis management has determined it is not more likely than not that an economic outflow will occur given these uncertainties.

## Impairment Test of Goodwill

The Company performed its annual test for goodwill impairment at the balance sheet date and no goodwill impairment was recorded. The goodwill balance at December 31, 2011 was \$61.3 million and relates to the Remora acquisition which closed on June 29, 2011. The Company has allocated goodwill to the Colombia operating segment.

The estimated fair value less cost to sell of the Colombia operating segment exceeded the carrying value.

### Valuation Techniques

The recoverable amount of the group of cash generating units (“CGUs”) in which the goodwill was assigned is based on fair value less cost to sell. The technique used in determining the recoverable amount is based on the net present value of the after-tax cash flows from oil and gas reserves of the group of CGUs based on reserves estimated by Parex’ independent reserve evaluator and the fair value of undeveloped land based on estimates with consideration given to acquisition metrics of recent transactions completed on similar assets to those contained within the relevant group of CGUs. The discounting process uses a rate of return that is commensurate with the risk associated with the assets and the time value of money. This approach requires assumptions about revenue, future oil prices, tax rates and discount rates.

### Significant Assumptions

#### Oil Reserves

Assumptions that are valid at the time of reserve estimation may change significantly when new information becomes available. Changes in forward price estimates, production costs or recovery rates may change the economic status of reserves and may ultimately result in reserves being restated.

#### Future Oil Prices

Oil forward price estimates are used in the cash flow model. Commodity prices have fluctuated widely in recent years due to global and regional factors including supply and demand fundamentals, inventory levels, exchange rates, weather, economic and geopolitical factors.

The future oil prices used in the model are based on forecast crude oil prices from Parex’ independent reserve evaluator. Prices used are as follows:

|                  | 2013   | 2014   | 2015   | 2016   | 2017   | Thereafter           |
|------------------|--------|--------|--------|--------|--------|----------------------|
| Brent (\$US/bbl) | 105.00 | 102.50 | 102.50 | 102.50 | 100.00 | 2% increase per year |

#### Discount Rate

The Company assumed a discount rate in order to calculate the present value of its projected cash flows. The discount rate represented a weighted average cost of capital (“WACC”) for comparable companies operating in similar industries, based on publicly available information. The WACC is an estimate of the overall required rate of return on an investment for both debt and equity owners and serves as the basis for developing an appropriate discount rate. Its determination requires separate analysis of the cost of equity and debt, and considers a risk premium based on an assessment of risks related to the projected cash flows of the group of Colombia CGUs. The discount rate used in performing the impairment test was 11 percent.

The fair value was in excess of its carrying value. Based on sensitivity analysis, no reasonably possible change in assumptions would cause the carrying amount of the group of Colombia CGUs to exceed its recoverable amount.

### Decommissioning Liabilities

(\$000s)

| For the years ended December 31,             | 2012      | 2011     |
|----------------------------------------------|-----------|----------|
| Balance, beginning of the year               | \$ 5,105  | \$ 651   |
| Additions                                    | 5,465     | 4,253    |
| Corporate Acquisition                        | 705       | 470      |
| Settlements of obligations during the period | -         | (467)    |
| Change in estimates                          | 445       | 101      |
| Accretion expense                            | 359       | 97       |
| Balance, end of the year                     | \$ 12,079 | \$ 5,105 |

The total decommissioning liability is estimated based on the Company’s net ownership in wells drilled as at December 31, 2012, the estimated costs to abandon and reclaim the wells and the estimated timing of the costs to be paid in future periods. The total undiscounted amount of cash flows required to settle Parex’ decommissioning liability is approximately \$17.5 million as at December 31, 2012 (December 31, 2011 – \$11.9 million) with the majority of these costs relate to Colombia operations and are anticipated to occur 2020 or later. A risk-free discount factor of 4.0 percent and an inflation rate of 4.0 percent were used in the valuation of the liabilities (December 31, 2011 – 4.0 percent risk free discount factor and a 3.0 percent inflation rate). The discount rates used are a blend of US, Colombia and Trinidad & Tobago risk free rates.

Decommissioning liabilities are considered critical accounting estimates. There are significant uncertainties related to decommissioning expenditures and the impact on the financial statements could be material. The eventual timing of and costs for these expenditures could differ from current estimates. The main factors that can cause expected estimated cash flows in respect of decommissioning liabilities to change are:

- Changes in laws and legislation;
- Construction of new facilities;
- Change in commodity price;
- Change in the estimate of oil reserves and the resulting amendment to the life of reserves; and
- Changes in technology.

## **Business Environment and Risks**

Parex is exposed to a variety of risks including but not limited to operational, financial, competitive, political and environmental risks. As a participant in the oil and natural gas industry, Parex is exposed to operational risks such as: unsuccessful exploration and exploitation activities, the inability to find new reserves that are commercially and economically feasible, premature declines of reservoirs, well blow-outs and other operating hazards, and lack of infrastructure or transportation to access markets and monetize reserves. The Company works to mitigate these risks by employing highly skilled personnel and utilizing available technology. The Company also maintains a corporate insurance program consistent with industry practices to protect against insurable losses.

The Company is exposed to normal financial risks inherent in the oil and natural gas industry including: commodity price risk, exchange rate risk, interest rate risk and credit risk. From time to time, the Company may have to raise additional funds to finance business development activities. Depending on market conditions at the time, however, there can be no assurance that the Company will be able to arrange debt or equity financing on satisfactory terms. The Company continuously monitors opportunities to use financial instruments to manage exposure to fluctuations in commodity prices, foreign currency rates and interest rates. Parex operates the majority of its properties and, therefore, has significant control over the timing, direction and costs related to exploration commitments and development opportunities.

The oil and natural gas industry is intensely competitive, with Parex competing against companies that may have greater technical and financial resources. There is competition for new exploration and development properties, for infrastructure and sales contracts, for drilling and other specialized technical equipment and for experienced key human resources. As appropriate, Parex seeks to enter into joint venture arrangements with large and/or experienced industry players in each country to improve its access to resources.

Parex is focused on international oil and natural gas activities, currently with interests in Colombia and Trinidad & Tobago. As such, the Company is subject to political risks such as: changes in policies and regulation related to changes in government, price controls, renegotiation of land tenure agreements, nationalization, changes in tax regulations, amendments or changes to legal systems, and complex regulatory regimes. The Company focuses its foreign operations in countries where management has prior experience and/or engages local in-country staff as soon as possible. The Company engages local, Canadian and international advisors. The Company may also, from time to time, arrange for insurance to mitigate specific risks. The Company is also exposed to potential delay of its operations due to waiting on permits or obtaining surface access to drilling locations.

The oil and natural gas industry is subject to extensive and varying environmental regulations imposed by governments in all countries in which Parex operates. The Company adopts prudent and industry-recommended field operating procedures in all of its operations, as well as maintaining a health, safety and environment program.

The Company is exposed to a high level of exploration risk. The Company's current and future (to the extent discovered or acquired) proved reserves will decline as reserves are produced from its properties unless the Company is able to acquire or develop new reserves. The business of exploring for, developing or acquiring reserves is capital-intensive and is subject to numerous estimates and interpretations of geological and geophysical data. There can be no assurance the Company's future exploration, development and acquisition activities will result in material additions of proved reserves. To manage this risk, to the extent possible, Parex employs highly experienced geologists and geophysicists, uses technology such as 3D seismic as a primary exploration tool and focuses exploration efforts in known hydrocarbon-producing basins. In addition, the Company takes a portfolio approach to exploration by dispersing drilling

locations among different exploration blocks and geological basins and by targeting multiple play-types. The Company may also choose to mitigate exploration risk through acquisitions that may require raising funds.

## Internal Controls over Financial Reporting

Disclosure controls and procedures (“DC&P”), as defined in National Instrument 52-109 *Certification of Disclosure in Issuers’ Annual and Interim Filings*, are designed to provide reasonable assurance that information required to be disclosed in annual filings, interim filings or other reports filed, or submitted by the Company under securities legislation authorities is recorded, processed, summarized and reported within the time periods specified in the securities legislation and include controls and procedures designed to ensure that information required to be disclosed by the Company in its annual filings, interim filings or other reports filed or submitted under securities legislation is accumulated and communicated to the Company’s management, including the Chief Executive Officer and the Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. The Chief Executive Officer and the Chief Financial Officer of Parex evaluated the effectiveness of the design and operation of the Company’s DC&P. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded Parex DC&P were effective as at December 31, 2012.

Internal control over financial reporting (“ICFR”), as defined in National Instrument 52-109, includes those policies and procedures that:

- 1) Pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect transactions and dispositions of assets of Parex;
- 2) Are designed to provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles and that receipts and expenditures of Parex are being made in accordance with authorizations of management and Directors of Parex; and
- 3) Are designed to provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the Company’s assets that could have a material effect on the annual financial statements or interim financial reports.

The Chief Executive Officer and the Chief Financial Officer are responsible for establishing and maintaining ICFR for Parex. They have, as at the financial year ended December 31, 2012, designed ICFR, or caused it to be designed under their supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. The control framework Parex officers used to design the Company’s ICFR is the Internal Control - Integrated Framework (“COSO Framework”) published by The Committee of Sponsoring Organizations of the Treadway Commission (“COSO”). Under the supervision of the Chief Executive Officer and the Chief Financial Officer, Parex conducted an evaluation of the effectiveness of the Company’s ICFR as at December 31, 2012 based on the COSO Framework. Based on this evaluation, the officers concluded that as of December 31, 2012, Parex maintained effective ICFR. It should be noted that while Parex officers believe that the Company’s controls provide a reasonable level of assurance with regard to their effectiveness, they do not expect that the DC&P and ICFR will prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, but not absolute, assurance that the objectives of the control system are met. There were no changes in Parex ICFR during the year ended December 31, 2012, except for the Ramshorn corporate acquisition in 2012. The Company has integrated Ramshorn into the existing internal controls and procedures of Parex.

## Off-Balance-Sheet Arrangements

The Company did not enter into any off-balance-sheet arrangements during the twelve months ended December 31, 2012.

## Financial Instruments and Other Instruments

The Company’s non-derivative financial instruments recognized in the balance sheet include cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities, current income and equity tax payable and Debentures (excluding the derivative financial liability associated with the Debentures). Non-derivative financial instruments are recognized initially at fair value. The fair values of the current financial instruments approximate their carrying value due to their short-term maturity.

## Accounting Policies and Estimates

The Company’s IFRS accounting policies are provided below. The accounting policies set out below have been applied consistently to all years presented in these consolidated financial statements, and have been applied consistently by the Company and its subsidiaries.

The accounting policies set out below have been applied consistently to all years presented in these consolidated financial statements, and have been applied consistently by the Company and its subsidiaries.

**a) Consolidation**

The consolidated financial statements include the accounts of Parex and its subsidiaries. Inter-company balances and transactions are eliminated on consolidation. Interests in jointly controlled assets are accounted for using the proportionate consolidation method, whereby Parex' proportionate share of revenues, expenses, assets and liabilities are included in the accounts.

**b) Foreign Currency Translation**

**(i) Functional and presentation currency**

Items included in the consolidated financial statements are measured using the currency of the primary economic environment in which the entity operates (the "functional currency"). The consolidated financial statements are presented in United States dollars, which is Parex' functional currency.

**(ii) Transactions and balances**

Foreign currency transactions are translated into the functional currency using the exchange rates prevailing at the date of the transaction. Generally, foreign exchange gains and losses resulting from the settlement of foreign currency transactions and from the translation at period-end exchange rates of monetary assets and liabilities denominated in currencies other than an operation's functional currency are recognized in the statement of comprehensive income (loss).

**c) Financial Instruments**

The Company initially measures financial instruments at estimated fair value. The Company's loans and receivables are comprised of cash and cash equivalents and trade receivables are included in current assets due to their short-term nature. Financial liabilities are categorized as "other financial liabilities" consisting of accounts payable and accrued liabilities, and the convertible debentures.

**(i) Loans and receivables**

Loans and receivables are non-derivative financial assets with fixed or determinable payments that are not quoted in an active market and with no intention of being traded. They are included in current assets, except for maturities greater than 12 months after the statement of financial position date, which are classified as non-current assets. Loans and receivables are recognized at the amount expected to be received less, any discount or rebate to reduce the loan and receivables to estimated fair value. Loans and receivables are subsequently measured at amortized cost using the effective interest method. Loans and receivables are included in cash and cash equivalents and accounts receivable in the consolidated balance sheet.

**(ii) Other financial liabilities**

Other financial liabilities are financial liabilities that are not quoted on an active market and with no intention of being traded. They are included in current liabilities, except for the convertible debentures as it has a maturity greater than 12 months after the statement of financial position date and is classified as a non-current liability. Financial liabilities include accounts payable and accrued liabilities and the convertible debentures. Accounts payable are initially recognized at the amount required to be paid less any discount or rebates to reduce the payables to estimated fair value. Accounts payable are subsequently measured at amortized cost using the effective interest method. The convertible debentures was recognized initially at fair value, net of any transaction costs incurred, and subsequently at amortized cost using the effective interest method.

**(iii) Derivative instruments**

Derivatives may be used by the Company to manage economic exposure to market risk relating to commodity prices, foreign exchange rates and interest rates. Parex's policy is not to utilize derivative financial instruments for speculative purposes. The Company does not designate its financial derivative contracts as hedges, and as such does not apply hedge accounting. As a result, all financial derivative contracts are classified at fair value through comprehensive income (loss) and are recorded on the balance sheet at fair value.

Financial derivative contracts are initially recognized at fair value on the date a derivative contract is entered into and are remeasured at their fair value at each subsequent reporting date.

Financial derivative instruments are included in current assets/liabilities except for those with maturities greater than 12 months after the end of the reporting period, which are classified as non-current assets/liabilities.

## *Convertible Debenture*

On issuance, the Debenture was split between the financial liability and the equity conversion feature. The convertible debenture represents a liability in its entirety, as the conversion feature fails the fixed-for-fixed requirement for equity classification as the convertible debenture is denominated in Canadian dollars, whereas the functional currency of Parex is US dollars. The convertible feature of the convertible debenture is required to be fair-valued at each balance sheet date. As a result, the convertible debenture is classified at fair value through comprehensive income and is recorded on the Balance Sheet at fair value.

### **d) Capital Assets**

#### **(i) Exploration and evaluation**

All costs directly associated with the exploration and evaluation of oil and natural gas reserves are initially capitalized. E&E costs are those expenditures for an area where technical feasibility and commercial viability have not yet been determined. These costs include unproved property acquisition costs, exploration costs, geological and geophysical costs, asset retirement costs, E&E drilling, sampling and appraisals. Costs incurred prior to acquiring the legal rights to explore an area are charged directly to net income (loss) as E&E expense.

When an area is determined to be technically feasible and commercially viable the accumulated costs are transferred to PP&E, where they are depleted. When an area is determined not to be technically feasible and commercially viable or the Company decides not to continue with its activity, the unrecoverable costs are charged to net income (loss) as E&E expense.

#### **(ii) Property, plant and equipment**

All costs directly associated with the development of oil and natural gas reserves are capitalized on an area-by-area basis. Development costs include expenditures for areas where technical feasibility and commercial viability has been determined. These costs include proved property acquisitions, development drilling, completion of wells, gathering facilities and infrastructure, asset retirement costs and transfers of E&E assets.

Costs accumulated within each CGU are depleted using the unit-of-production method based on proved plus probable reserves incorporating estimated future prices and costs. Costs subject to depletion include estimated future costs to be incurred in developing proved plus probable reserves. Costs of major development projects are excluded from the costs subject to depletion until they are available for use.

Costs associated with office furniture, fixtures and leasehold improvements are carried at cost and depreciated on a straight-line basis over the estimated service lives of the assets, which range from 1 to 5 years.

### **e) Impairment of Long-term Assets**

The carrying amounts of the Company's long-term assets, other than E&E assets and deferred tax assets, are reviewed at each reporting date to determine whether there is any indication of impairment. If an indication of impairment exists, then the asset's recoverable amount is estimated. E&E assets are assessed for impairment when they are reclassified to PP&E, and if facts and circumstances suggest that the carrying amount exceeds the recoverable amount.

For the purpose of impairment testing, assets are grouped into the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets. The recoverable amount of an asset or a CGU is the greater of its value in use and its fair value less costs to sell ("FVLCTS").

Value in use is determined by estimating the present value of the pre-tax future net cash flows expected to be derived from the continued use of the asset or CGU. FVLCTS is based on available market information, where applicable. In the absence of such information, FVLCTS is determined using discounted future after tax net cash flows of proved plus probable reserves using forecast prices and costs.

E&E assets related to Blocks are assessed for impairment upon their eventual reclassification to PP&E. E&E assets not reclassified to PP&E are assessed for impairment on a Block basis.

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses are recognized in net income (loss). Impairment losses recognized in respect of CGUs are allocated first to reduce the carrying amount of any goodwill allocated to the units and then to reduce the carrying amounts of the other assets in the unit (group of units) on a pro-rata basis.

Impairment losses recognized in prior years are assessed at each reporting date for any indications that the loss has decreased or no longer exists. An impairment loss is reversed if there has been a change in the estimates used to determine the recoverable amount. An impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depletion and depreciation or amortization, if no impairment loss had been recognized.

**f) Crude Oil Inventory**

Crude oil inventory consists of crude oil in transit at the balance sheet date and is valued at the lower of cost, using the weighted average cost method and net realizable value. Costs include direct and indirect expenditures incurred in bringing the crude oil to its existing condition and location.

**g) Purchased Oil**

Purchased oil includes costs to buy third party oil. These costs are initially recorded in inventory until the crude oil title is transferred.

**h) Goodwill**

Goodwill is recorded on a business acquisition when the purchase price is in excess of the fair values assigned to assets acquired and liabilities assumed. Goodwill is not amortized and an impairment test is performed annually or as events occur that could indicate impairment. To test for impairment, goodwill is allocated to each of the Company's CGUs, groups of CGUs, or an operating segment expected to benefit from the acquisition. Goodwill is tested by combining the carrying amounts of property, plant and equipment and exploration and evaluation assets and goodwill and comparing this to the recoverable amount. Fair value, less costs to sell, is derived by estimating the discounted after-tax future net cash flows as described in the property, plant and equipment impairment test, plus the fair market value of undeveloped land, seismic and inventory. Value-in-use is assessed using the present value of the expected future cash flows. Any excess of the carrying amount over the recoverable amount is recorded as impairment. Impairment charges, which are not tax affected, are recognized in net income (loss) and are not reversed. Goodwill is reported at cost less any impairment.

**i) Revenue Recognition**

Revenue from the sale of oil and natural gas is recorded when the significant risks and rewards of ownership of the product are transferred to the buyer which is usually when legal title passes to the external party.

**j) Share-based Compensation**

The Company has an incentive stock option plan for officers, directors, and certain employees. The Company records share-based compensation expense using the fair value method. The fair value of an option is calculated at the grant date using the Black-Scholes pricing model, and expensed over the vesting period of the option. The Company determines an appropriate forfeiture rate by examining the history of its forfeitures. The Company records the cumulative share-based compensation as contributed surplus. When options are exercised, contributed surplus is reduced and share capital is increased by the amount of accumulated share-based compensation for the exercised option. Any consideration received on the exercise of stock options is credited to share capital.

Obligations for payments of cash under the subsidiaries' SARs plan are accrued as compensation expense over the vesting period based on the fair value of SARs, subject to appreciation limits specified in the plan. The fair value of SARs is measured using the Black-Scholes pricing model. In accordance with the fair value method, increases or decreases in the fair value of the SARs result in a corresponding change in the recorded liability. The accrued compensation for a right that is forfeited is adjusted by decreasing compensation cost in the period of forfeiture.

Restricted share units ("RSUs") are accrued as compensation expense over the vesting period based on the fair value of RSUs. The fair value of RSUs is measured using the Black-Scholes pricing model, and expensed over the vesting period of the option.

**k) Provisions**

A provision is recognized if, as a result of a past event, the Company has a current legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are determined by discounting the expected future cash flows at a pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the liability. Provisions are not recognized for future operating losses.

### ***l) Decommissioning Liabilities***

The Company's activities give rise to dismantling, decommissioning, abandonment and site disturbance remediation activities. Provision is made for the estimated cost of the future site restoration and capitalized in the relevant asset category.

Decommissioning liabilities are measured at the present value of management's best estimate of the expenditure required to settle the present obligation at the balance sheet date using a risk-free discount rate. Subsequent to the initial measurement, the obligation is adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation. The increase in the provision due to the passage of time is recognized as a finance expense whereas increases/decreases due to changes in the estimated future cash flows are capitalized. Actual costs incurred upon settlement of the decommissioning liabilities are charged against the provision to the extent the provision was established.

### ***m) Finance Income and Expense***

Finance expense comprises interest expense on borrowings, accretion on decommissioning liabilities, revaluation of derivative financial liabilities and impairment losses recognized on financial assets. Finance income comprises interest earned on cash and cash equivalents and other income.

### ***n) Cash and Cash Equivalents***

Cash and cash equivalents are comprised of cash in the bank and term deposits held with banks with original maturities of 3 months or less.

### ***o) Income Taxes***

Income tax expense comprises current and deferred tax. Income tax expense is recognized in comprehensive income (loss) except to the extent that it relates to items recognized directly in equity, in which case it is recognized in equity.

Current tax is the expected tax payable on taxable income for the year, using tax rates enacted or substantively enacted at the reporting date, and any adjustment to tax payable in respect of previous years.

In general, deferred tax is recognized in respect of temporary differences arising between the tax basis of assets and liabilities and their carrying amounts in the consolidated financial statements. Deferred tax is determined on a non-discounted basis using tax rates and laws enacted or substantively enacted by the balance sheet date and expected to apply when the deferred tax asset or liability is settled. Deferred tax assets are recognized to the extent that it is probable that the assets can be recovered. Deferred tax is provided on temporary differences arising on investments in subsidiaries except, in the case of subsidiaries, where the timing of the reversal of the temporary difference is controlled by the Company and it is probable that the temporary difference will not be reversed in the foreseeable future. Deferred tax assets and liabilities are presented as non-current.

### ***p) Per Share Information***

Basic net income (loss) per share is calculated by dividing the income or loss attributable to common shareholders of the Company by the weighted average number of common shares outstanding during the period. Diluted net income (loss) per share is determined by adjusting the income or loss attributable to common shareholders and the weighted average number of common shares outstanding for the effects of dilutive instruments such as options granted to employees and convertible debentures, except when the effect would be anti-dilutive.

### **Recent Pronouncements Issued**

Unless otherwise noted, the following revised standards and amendments are effective for annual periods beginning on or after January 1, 2013 with earlier application permitted.

(i) IFRS 9, *Financial Instruments (effective for annual periods beginning on or after January 1, 2015)*, was issued in November 2009 and addresses classification and measurement of financial assets. It replaces the multiple category and measurement models in IAS 39 for debt instruments with a new mixed measurement model having only two categories: amortized cost and fair value through net income (loss). IFRS 9 also replaces the models for measuring equity instruments. Such instruments are either recognized at fair value through net income (loss) or at fair value through other comprehensive income. Where equity instruments are measured at fair value through other comprehensive income, dividends are recognized in net income (loss) to the extent that they do not clearly represent a return of investment; however, other gains and losses (including impairments) associated with such instruments remain in accumulated comprehensive income indefinitely. Requirements for financial liabilities were added to IFRS 9 in October 2010 and they largely carried forward existing requirements in IAS 39, *Financial Instruments – Recognition and Measurement*, except that fair value changes due to credit risk for liabilities

designated at fair value through net income (loss) are generally recorded in other comprehensive income. *The Company does not expect IFRS 9 to have a material impact on its financial position.*

(ii) IFRS 10, *Consolidated Financial Statements*, requires an entity to consolidate an investee when it has power over the investee, is exposed, or has rights, to variable returns from its involvement with the investee and has the ability to affect those returns through its power over the investee. Under existing IFRS, consolidation is required when an entity has the power to govern the financial and operating policies of an entity so as to obtain benefits from its activities. IFRS 10 replaces SIC-12, *Consolidation—Special Purpose Entities* and parts of IAS 27, *Consolidated and Separate Financial Statements*. *The Company does not expect IFRS 10 to have a material impact of its financial position. The Company has determined that IFRS 10 will not have a material impact on its financial position.*

(iii) IFRS 11, *Joint Arrangements*, requires a venturer to classify its interest in a joint arrangement as a joint venture or joint operation. Joint ventures will be accounted for using the equity method of accounting whereas for a joint operation the venturer will recognize its share of the assets, liabilities, revenue and expenses of the joint operation. Under existing IFRS, entities have the choice to proportionately consolidate or equity account for interests in joint ventures. IFRS 11 supersedes IAS 31, *Interests in Joint Ventures*, and SIC-13, *Jointly Controlled Entities—Non-monetary Contributions by Venturers*. *The Company has determined that IFRS 11 will not have a material impact on its financial position.*

(iv) IFRS 13, *Fair Value Measurement*, is a comprehensive standard for fair value measurement and disclosure for use across all IFRS standards. The new standard clarifies that fair value is the price that would be received to sell an asset, or paid to transfer a liability in an orderly transaction between market participants, at the measurement date. Under existing IFRS, guidance on measuring and disclosing fair value is dispersed among the specific standards requiring fair value measurements and does not always reflect a clear measurement basis or consistent disclosures. *The Company has determined that IFRS 13 will not have a material impact on its financial position.*

(v) There have been amendments to existing standards, including IAS 27, *Separate Financial Statements* (IAS 27), and IAS 28, *Investments in Associates and Joint Ventures* (IAS 28). IAS 27 addresses accounting for subsidiaries, jointly controlled entities and associates in non-consolidated financial statements. IAS 28 has been amended to include joint ventures in its scope and to address the changes in IFRS 10 – 12. *The Company has determined that IFRS 27 will not have a material impact on its financial position.*

(vi) IAS 12, *Income Taxes*, was amended to introduce an exception to the existing principle for the measurement of deferred tax assets or liabilities arising on investment property measured at fair value. As a result of the amendment, there is a rebuttable presumption that the carrying amount of the investment property will be recovered through sale when considering the expected manner or recovery or settlement. SIC 21, *Income Taxes - Recovery of Revalued Non-Depreciable Assets*, will no longer apply to investment properties carried at fair value. The amendment also incorporates into IAS 12 the remaining guidance previously contained in SIC 21, which is withdrawn. The amendment is effective for annual periods beginning on or after July 1, 2012 with earlier application permitted. *The Company has determined that IAS 12 will not have a material impact on its financial position.*

## **Critical Accounting Estimates**

The preparation of consolidated financial statements in accordance with IFRS requires management to make judgments, assumptions and estimates that affect the financial results of the Company. The following discussion outlines the accounting policies and practices involving the use of estimates that the Company believes are critical in determining Parex' financial results.

### ***Oil and natural gas reserves***

The Company retains qualified independent reserves evaluators to evaluate the Company's proved and probable oil and natural gas reserves. As at December 31, 2012, Parex' reserves were evaluated by GLJ Petroleum Consultants Ltd., who are a firm of qualified independent reserves evaluators. The evaluation was conducted in accordance with National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities. The Operations and Reserves Committee of the Company's Board of Directors is comprised of independent directors whose mandate is to steward the reserves evaluation process.

The estimation of reserves involves the exercise of judgment. Forecasts are based on engineering data, expected rates of production and the timing of future capital expenditures, all of which are subject to major uncertainties and interpretations. The Company expects that over time its reserve estimates will be revised upward or downward based on updated information such as the results of future drilling, testing and production levels. Reserve estimates can have a significant impact on net income (loss), as they are a key component in the calculation of DD&A and for determining potential asset impairment. A downward revision in reserves estimates or an increase in estimated future development costs could result in the recognition of a higher DD&A charge to net income (loss).

Oil and natural gas assets (development and producing costs) are aggregated into CGUs based on their ability to generate largely independent cash flows. If the carrying value of the CGU exceeds the recoverable amount, the CGU is written down with an impairment recognized in net income (loss). The recoverable amount of an asset or CGU is the greater of its fair value less costs to sell and its value in use. Fair value less costs to sell may be determined using discounted future net cash flows of proved plus probable reserves using forecast prices and costs. A downward revision in reserves estimates could result in the recognition of impairments charged to net income (loss).

Reversals of impairments are recognized when there has been a subsequent increase in the recoverable amount. In this event, the carrying amount of the asset or CGU is increased to its revised recoverable amount with an impairment reversal recognized in net income (loss).

### ***Decommissioning liabilities***

The Company is required to recognize a liability for future dismantling, decommissioning, abandoning and site disturbance remediation costs associated with the Company's oil and natural gas properties in accordance with existing laws, contracts or other policies. The fair value of the estimated decommissioning liability is recorded as a long-term liability, with a corresponding increase in the carrying amount of the related long-lived asset, which is depleted on a unit-of-production basis over the life of the reserves. The liability is adjusted each reporting period to reflect the passage of time, with the accretion charged to net income (loss), and for revisions to the estimated future cash flows. Actual costs incurred upon settlement of the obligations are charged against the liability.

Decommissioning liabilities are determined by using management's best estimate of costs, taking into account the anticipated method and extent of restoration consistent with legal requirements, technological advances, industry practices and the possible use of the site. Since these estimates are specific to the sites involved, there are many individual assumptions underlying the Company's total decommissioning liability. These individual assumptions can be subject to change based on experience. Restoration technologies and costs are constantly changing, as are regulatory, political, environmental, safety and public relations considerations. The Company estimates future decommissioning costs based on current estimates adjusted for inflation. This estimate for inflation is also subject to management uncertainty.

### ***Deferred tax***

The Company follows the liability method of accounting for income taxes. Under this method, future tax assets and liabilities are determined based on differences between the financial reporting and tax basis of assets and liabilities and are measured using substantially enacted tax rates and laws that will be in effect when the differences are expected to reverse. The effect of a change in income tax rates on deferred tax liabilities and assets is recognized in net income (loss) in the period that the change occurs. Deferred tax assets are only recognized to the extent that it is more likely than not that sufficient future taxable income will be available in the applicable jurisdiction to allow the deferred tax assets to be realized.

The determination of the Company's income and other tax liabilities requires interpretation of complex laws and regulations from multiple jurisdictions. Rates are also affected by legislative changes. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, the actual income tax liability may differ significantly from that estimated and recorded in the financial statements. Estimates of Colombian current income tax for interim periods are also subject to additional uncertainty. A variety of factors cannot be known until year-end and, therefore, estimates are used for interim period current tax provisions.

### ***Share-based compensation***

The Company records stock-based compensation expense using the fair value method. The fair value of an option is calculated at the grant date, and expensed equally over the vesting term of the option. The Company records the cumulative stock-based compensation as contributed surplus. When options are exercised, contributed surplus is reduced and share capital is increased by the amount of accumulated stock-based compensation for the exercised option. Any consideration received on the exercise of stock options is credited to share capital.

The determination of stock-based compensation expense is based on assumptions regarding stock volatility, risk-free interest rates and the expected life of the options. These assumptions, by their nature, are subject to measurement uncertainty.

Obligations for payments of cash under the subsidiaries' SARs plan are accrued as compensation expense over the vesting period based on the fair value of SARs, subject to appreciation limits specified in the plan. The fair value of SARs is measured using the Black-Scholes pricing model. In accordance with the fair value method, increases or decreases in the fair value of the SARs result in a corresponding change in the recorded liability. The accrued compensation for a right that is forfeited is adjusted by decreasing compensation cost in the period of forfeiture.

The determination of SARs expense is based on assumptions regarding stock volatility, risk-free interest rates and the expected life of the SAR. These assumptions, by their nature, are subject to measurement uncertainty.

The fair value of stock RSUs is measured using the Black-Scholes option pricing model. Measurement inputs include the share price on measurement date, exercise price of the option, expected future share price volatility, weighted average expected life of the instruments (based on historical experience and general option-holder behavior), expected dividends and the risk-free interest rate (based on Government of Canada Bonds) for the relevant expected life.

The determination of RSUs expense is based on assumptions regarding stock volatility, risk-free interest rates and the expected life of the SAR. These assumptions, by their nature, are subject to measurement uncertainty.

### ***Goodwill***

Goodwill represents the excess of purchase price over fair value of net assets acquired, and is assessed for impairment annually at December 31 of each year. To test for impairment, goodwill is allocated to each of the Company's CGUs, or groups of CGUs, that are expected to benefit from the acquisition and is tested as described above in the Company's impairment policy. The recoverable amount of an asset or a CGU is the greater of its value in use and its FVLCTS.

Value in use is determined by estimating the present value of the future net cash flows expected to be derived from the continued use of the asset or CGU. FVLCTS is based on available market information, where applicable. In the absence of such information, FVLCTS is determined using discounted future net cash flows of proved plus probable reserves using forecast prices and costs. A downward revision in reserves estimates could result in the recognition of a goodwill impairment charge to net earnings.

These calculations require the use of estimates and assumptions and are subject to changes as new information becomes available including information on future commodity prices, expected production volumes, quantity of reserves and discount rates as well as future development and operating costs. Changes in assumptions used in determining the recoverable amount could affect the carrying value of the related assets and CGUs.

### ***Derivative liabilities***

The convertible feature of the convertible debentures is required to be fair-valued at each balance sheet date. The fair value of this derivative liability is calculated using the Black-Scholes pricing model which is based on significant assumptions such as volatility of the market price of Parex' shares, the risk free interest rate (based on government of Canada Bonds), and the share price of Parex' stock at the measurement date.

Risk management contracts are initially recognized at fair value on the date a derivative contract is entered into and are remeasured at their fair value at each subsequent reporting date. The fair value of the risk management contract on initial recognition is normally the transaction price. Subsequent to initial recognition, the fair value are based on quoted market price where available from active markets, otherwise fair values are estimated based on market prices at the reporting date for similar assets or liabilities with similar terms and conditions.

### ***Legal, environmental remediation and other contingent matters***

In respect of these matters, the Company is required to determine both whether a loss is probable based on judgment and interpretation of laws and regulations and if such a loss can reasonably be estimated. When any such loss is determined, it is charged to net income (loss). Management continually monitors known and potential contingent matters and makes appropriate provisions by charges to net income (loss) when warranted by circumstances.

## MANAGEMENT'S REPORT

Management is responsible for the reliability and integrity of the consolidated financial statements, the notes to the consolidated financial statements, and other financial information presented elsewhere in this annual report.

The consolidated financial statements were prepared by management in accordance with International Financial Reporting Standards. Since a precise determination of many assets and liabilities is dependent on future events, the timely preparation of financial statements requires that management make estimates and assumptions and use judgment. When alternative accounting methods exist, management has chosen those that it deems most appropriate in the circumstances.

PricewaterhouseCoopers LLP were appointed by the Company's shareholders to express an audit opinion on the consolidated financial statements. Their examination included such tests and procedures as they considered necessary to provide reasonable assurance that the consolidated financial statements are in accordance with International Financial Reporting Standards.

The Board of Directors is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal control. The Board exercises this responsibility through the Finance & Audit Committee. The Finance & Audit Committee recommends appointment of the external auditors to the Board ensures their independence and approves their fees. The Finance & Audit Committee meets regularly with management and the external 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 for approval. The external auditors have full and unrestricted access to the Finance & Audit Committee to discuss their audit and their findings.



Wayne K. Foo  
President, Chief Executive Officer



Kenneth G. Pinsky  
VP Finance, Chief Financial Officer

March 13, 2013

March 13, 2013

## Independent Auditor's Report

**To the Shareholders of  
Parex Resources Inc.**

We have audited the accompanying consolidated financial statements of Parex Resources Inc. and its subsidiaries, which comprise the consolidated balance sheets as at December 31, 2012 and December 31, 2011 and the consolidated statements of comprehensive income, changes in equity and cash flows for the years then ended, and the related notes, which comprise a summary of significant accounting policies and other explanatory information.

### **Management's Responsibility for the Consolidated Financial Statements**

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

### **Auditor's Responsibility**

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

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

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

### **Opinion**

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Parex Resources Inc. and its subsidiaries as at December 31, 2012 and December 31, 2011 and their financial performance and their cash flows for the years ended in accordance with International Financial Reporting Standards.

*PricewaterhouseCoopers LLP*

**Chartered Accountants**

## CONSOLIDATED FINANCIAL STATEMENTS

### Consolidated Balance Sheets

| As at<br>(thousands of United States dollars) | NOTE | December 31,<br>2012 | December 31,<br>2011 |
|-----------------------------------------------|------|----------------------|----------------------|
| <b>ASSETS</b>                                 |      |                      |                      |
| Current assets                                |      |                      |                      |
| Cash and cash equivalents                     | 5    | \$ 31,950            | \$ 103,884           |
| Accounts receivable                           | 6    | 102,442              | 35,947               |
| Prepays and other current assets              |      | 6,279                | 5,202                |
| Crude oil inventory                           | 7    | 7,474                | 17,321               |
|                                               |      | 148,145              | 162,354              |
| Goodwill                                      | 11   | 61,252               | 61,252               |
| Exploration and evaluation                    | 8    | 145,172              | 136,715              |
| Property, plant and equipment                 | 9    | 466,632              | 299,856              |
|                                               |      | \$ 821,201           | \$ 660,177           |
| <b>LIABILITIES AND SHAREHOLDERS' EQUITY</b>   |      |                      |                      |
| Current liabilities                           |      |                      |                      |
| Accounts payable and accrued liabilities      |      | \$ 116,116           | \$ 68,398            |
| Current income and equity tax payable         | 18   | 44,669               | 1,063                |
|                                               |      | 160,785              | 69,461               |
| Long-term debt                                | 12   | 9,100                | -                    |
| Convertible debenture                         | 17   | 65,657               | 60,001               |
| Derivative financial liability                | 17   | 9,899                | 16,821               |
| Other long-term liabilities                   | 14   | 3,071                | 1,816                |
| Decommissioning liabilities                   | 15   | 12,079               | 5,105                |
| Deferred tax liability                        | 18   | 95,214               | 89,114               |
|                                               |      | 355,805              | 242,318              |
| Shareholders' equity                          |      |                      |                      |
| Share capital                                 | 16   | 412,736              | 411,921              |
| Contributed surplus                           |      | 16,015               | 9,215                |
| Retained earnings (deficit)                   |      | 36,645               | (3,277)              |
|                                               |      | 465,396              | 417,859              |
|                                               |      | \$ 821,201           | \$ 660,177           |

Commitments (note 25)

Contingencies (note 26)

Subsequent event (note 28)

See accompanying Notes to the Consolidated Financial Statements

Approved by the Board:



Paul Wright  
Director



Ron Miller  
Director

## Consolidated Statements of Comprehensive Income

For the year ended December 31,

| (thousands of United States dollars, except per share amounts) | NOTE | 2012       | 2011       |
|----------------------------------------------------------------|------|------------|------------|
| Oil sales                                                      |      | \$ 523,514 | \$ 171,170 |
| Royalties                                                      |      | (35,890)   | (13,929)   |
| Revenue                                                        |      | 487,624    | 157,241    |
| Risk management contracts                                      | 23   | (668)      | (432)      |
|                                                                |      | 486,956    | 156,809    |
| <b>Expenses</b>                                                |      |            |            |
| Production                                                     |      | 36,286     | 11,219     |
| Transportation                                                 |      | 91,397     | 27,604     |
| Purchased oil                                                  |      | 37,158     | -          |
| General and administrative                                     |      | 31,018     | 15,781     |
| Share-based compensation                                       | 16   | 8,115      | 6,478      |
| Transaction costs                                              | 10   | 1,109      | 2,127      |
| Depletion, depreciation and amortization                       | 9    | 181,149    | 53,772     |
| Foreign exchange loss (gain)                                   |      | 2,446      | (3,146)    |
| Exploration and evaluation impairment                          | 8    | 23,511     | -          |
|                                                                |      | 412,189    | 113,835    |
| Finance income                                                 | 13   | (2,399)    | (1,364)    |
| Finance expense                                                | 13   | 3,092      | (164)      |
| <b>Net finance expense (income)</b>                            |      | 693        | (1,528)    |
| <b>Net income before taxes</b>                                 |      | 74,074     | 44,502     |
| <b>Income tax expense</b>                                      |      |            |            |
| Current tax expense                                            | 18   | 42,999     | 424        |
| Deferred tax expense (recovery)                                | 18   | (8,847)    | 28,443     |
|                                                                |      | 34,152     | 28,867     |
| <b>Net income and comprehensive income for the year</b>        |      | \$ 39,922  | \$ 15,635  |
| Basic net income per common share                              | 19   | \$ 0.37    | \$ 0.17    |
| Diluted net income per common share                            | 19   | \$ 0.31    | \$ 0.11    |

See accompanying Notes to the Consolidated Financial Statements

## Consolidated Statements of Changes in Equity

| For the year ended December 31,<br>(thousands of United States dollars) | 2012 |         | 2011 |          |
|-------------------------------------------------------------------------|------|---------|------|----------|
| <b>Share Capital</b>                                                    |      |         |      |          |
| Balance, beginning of year                                              | \$   | 411,921 | \$   | 198,857  |
| Issuance of common shares under option plans                            |      | 815     |      | 1,249    |
| Issuance of common shares                                               |      | -       |      | 211,815  |
| Balance, end of year                                                    | \$   | 412,736 | \$   | 411,921  |
| <b>Contributed Surplus</b>                                              |      |         |      |          |
| Balance, beginning of year                                              | \$   | 9,215   | \$   | 4,000    |
| Share-based compensation                                                |      | 7,047   |      | 5,594    |
| Options exercised                                                       |      | (247)   |      | (379)    |
| Balance, end of year                                                    | \$   | 16,015  | \$   | 9,215    |
| <b>Retained Earnings (deficit)</b>                                      |      |         |      |          |
| Balance, beginning of year                                              | \$   | (3,277) | \$   | (18,912) |
| Net income for the year                                                 |      | 39,922  |      | 15,635   |
| Balance, end of year                                                    | \$   | 36,645  | \$   | (3,277)  |

See accompanying Notes to the Consolidated Financial Statements

## Consolidated Statements of Cash Flows

For the year ended December 31,  
(thousands of United States dollars)

|                                                                                 | NOTE | 2012             | 2011              |
|---------------------------------------------------------------------------------|------|------------------|-------------------|
| <b>Operating activities</b>                                                     |      |                  |                   |
| Net income                                                                      |      | \$ 39,922        | \$ 15,635         |
| Add (deduct) non-cash items                                                     |      |                  |                   |
| Depletion, depreciation and amortization                                        | 9    | 181,149          | 53,772            |
| Non-cash finance (income) loss                                                  | 13   | (2,633)          | (2,999)           |
| Share-based compensation                                                        | 16   | 8,115            | 6,478             |
| Deferred tax expense (recovery)                                                 | 18   | (8,847)          | 28,443            |
| Unrealized foreign exchange gain                                                |      | 1,030            | (2,712)           |
| Unrealized loss (gain) on risk management contracts                             | 23   | 902              | -                 |
| Exploration and evaluation impairment                                           | 8    | 23,511           | -                 |
| Decommissioning expenditures                                                    | 15   | -                | (467)             |
| Colombia equity tax paid                                                        |      | (1,580)          | (234)             |
| Funds flow from (used in) operations                                            |      | 241,569          | 97,916            |
| Net change in non-cash working capital                                          | 20   | 12,948           | 22,337            |
|                                                                                 |      | 254,517          | 120,253           |
| <b>Investing activities</b>                                                     |      |                  |                   |
| Capital expenditures                                                            |      | (267,688)        | (149,643)         |
| Acquisition                                                                     | 10   | (71,774)         | (252,987)         |
| Net change in non-cash working capital                                          | 20   | 2,466            | (33,102)          |
|                                                                                 |      | (336,996)        | (435,732)         |
| <b>Financing activities</b>                                                     |      |                  |                   |
| Issuance of common shares                                                       | 16   | 568              | 224,828           |
| Share issuance costs                                                            | 16   | -                | (12,143)          |
| Convertible debenture                                                           | 17   | -                | 84,244            |
| Long-term debt issued                                                           | 12   | 9,100            | -                 |
| Net change in non-cash working capital                                          | 20   | -                | (116)             |
|                                                                                 |      | 9,668            | 296,813           |
| <b>Decrease in cash and cash equivalents for the year</b>                       |      | <b>(72,811)</b>  | <b>(18,666)</b>   |
| <b>Impact of foreign exchange on foreign currency-denominated cash balances</b> |      | <b>877</b>       | <b>(989)</b>      |
| <b>Cash and cash equivalents, beginning of year</b>                             |      | <b>103,884</b>   | <b>123,539</b>    |
| <b>Cash and cash equivalents, end of year</b>                                   |      | <b>\$ 31,950</b> | <b>\$ 103,884</b> |

Supplemental Disclosure of Cash Flow Information (note 20)

See accompanying Notes to the Consolidated Financial Statements

## Notes to the Consolidated Financial Statements

For the year ended December 31, 2012

(Tabular amounts in thousands of United States dollars, unless otherwise stated. Amounts in text are in United States dollars unless otherwise stated.)

### 1. Corporate Information

Parex Resources Inc. and its subsidiaries (“Parex” or “the Company”) are in the business of the exploration, development, production and marketing of oil and natural gas.

Parex Resources Inc. is a publicly traded company, incorporated and domiciled in Canada. Its registered office is at 2400, 525-8th Avenue S.W., Calgary, Alberta T2P 1G1. The Company was incorporated as 1485196 Alberta Ltd. on August 17, 2009, pursuant to the Business Corporations Act (Alberta). On September 29, 2009 it filed Articles of Amendment to change its name to Parex Resources Inc.

The consolidated financial statements were approved and authorized for issuance by the Board of Directors on March 13, 2013.

### 2. Basis of Preparation, Critical Accounting Estimates and Judgements

#### a) Statement of compliance

These consolidated financial statements have been prepared in accordance with IFRS, as issued by the International Accounting Standard Boards (“IASB”).

The policies applied in these consolidated financial statements are based on IFRS issued and outstanding as of December 31, 2012. On March 13, 2013 the Board of Directors approved the consolidated financial statements.

#### b) Basis of measurement

The consolidated financial statements have been prepared under the historical cost convention except for derivative financial instruments and share-based compensation transactions which are measured at fair value. The methods used to measure fair values are discussed in note 4 - Determination of Fair Values.

#### c) Use of management estimates, judgments and measurement uncertainty

The timely preparation of the consolidated financial statements requires that management make estimates and use judgment regarding the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities as at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the period. Such estimates primarily relate to unsettled transactions and events as at the date of the consolidated financial statements. Accordingly, actual results could differ from estimated amounts as future confirming events occur. Significant estimates and judgments made by management in the preparation of these consolidated financial statements are outlined below:

##### (i) Depletion, depreciation and reserves

Depletion is based on the proved plus probable reserves as evaluated in accordance with National Instrument 51-101, *Standards of Disclosure for Oil and Gas Activities* (“NI 51-101”) and incorporating the estimated future cost of developing and extracting those. The process of estimating reserves is complex. It requires significant judgments and decisions based on available geological, geophysical, 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 are based on current production forecasts, prices and economic conditions. As circumstances change and additional data becomes available, reserve estimates also change. Estimates made 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.

Although every reasonable effort is made to ensure that reserve estimates are accurate, reserve estimation is an inferential science. As a result, subjective decisions, new geological or production information and a changing environment may impact these estimates. Revisions to reserve estimates can arise from changes in year-end oil and gas prices and reservoir performance. Such revisions can be either positive or negative. Changes in reserve estimates impact the financial results of the Company as reserves and estimated future development costs are used to calculate depletion and are also used in measuring fair value less costs to sell of property, plant and equipment for impairment calculations (see note 9).

**(ii) Determination of cash-generating units (“CGU”)**

The determination of CGUs requires judgment in defining a group of assets that generate cash inflows that are largely independent of the cash inflows from other assets or groups of assets. CGUs are determined by similar geological structure, shared infrastructure, geographical proximity, commodity type, similar exposure to market risks and materiality.

**(iii) Exploration and evaluation (“E&E”)**

The decision to transfer assets from E&E to property, plant and equipment (“PP&E”) is based on the estimated proved plus probable reserves used in the determination of an area’s technical feasibility and commercial viability.

**(iv) Decommissioning liabilities**

Decommissioning and restoration costs will be incurred by the Company at the end of the operating life of certain of its assets. The ultimate decommissioning and restoration costs are uncertain and cost estimates can vary in response to many factors including changes to relevant legal and regulatory requirements, the emergence of new restoration techniques or experience at other production sites. The expected timing and amount of expenditure can also change in response to changes in reserves or changes in laws and regulations or their interpretation. As a result, there could be significant adjustments to the provisions established which would affect future financial results. In the Company’s judgment, the most appropriate discount rate to use is a risk free rate.

**(v) Impairment indicators and discount rate**

The recoverable amounts of CGUs and individual assets have been determined as the greater of an asset’s or CGU’s value-in-use and fair value less costs to sell. These calculations require the use of estimates and assumptions and are subject to changes as new information becomes available including information on future commodity prices, expected production volumes, quantity of reserves and discount rates as well as future development and operating costs. It is reasonably possible that the commodity price assumptions may change, which may impact the estimated life of the field and economical reserves recoverable and may require a material adjustment to the carrying value of oil and natural gas assets. The Company monitors internal and external indicators of impairment relating to its tangible assets.

**(vi) Share - based compensation**

Compensation costs accrued for share-based compensation plans, the Company’s Share Appreciation Rights (“SAR”) plan and Share Restricted Share Unit (“RSU”) are subject to the estimation of what the ultimate payout will be using the Black-Scholes pricing model which is based on significant assumptions such as the future volatility of the market price of Parex shares and expected term of the issued stock option or SAR.

**(vii) Derivative financial asset/liability**

The estimated fair value of derivative instruments resulting derivative assets and liabilities, by their nature is subject to measurement uncertainty.

**(viii) Income taxes**

Tax interpretations, regulations and legislation in the various jurisdictions in which the Company and its subsidiaries operate are subject to change and interpretation. As such, income taxes are subject to measurement uncertainty. The Company follows the liability method for calculating deferred taxes. Assessing the recoverability of deferred tax assets requires the Company to make significant estimates related to the expectations of future cash flows from operations and the application of existing tax laws. To the extent that future cash flows and taxable income differ significantly from estimates, the ability of the Company to realize the deferred tax assets and liabilities recorded at the balance sheet date could be impacted. Additionally, changes in tax laws could limit the ability of the Company to obtain tax deductions in the future.

**(ix) Business combinations**

Business combinations are accounted for using the acquisition method of accounting. The determination of fair value often requires management to make assumptions and estimates about future events. The assumptions and estimates with respect to determining the fair value of E&E assets and oil and natural gas assets acquired generally require the most judgment and include estimates of reserves acquired, forecast benchmark commodity prices and discount rates. Changes in any of the assumptions or estimates used in determining the fair value of acquired assets and liabilities could impact the amounts assigned to assets, liabilities and goodwill in the purchase price allocation. Future net earnings can be affected as a result of changes in future depletion and depreciation, asset impairment or goodwill impairment.

### 3. Summary of Significant Accounting Policies

The accounting policies set out below have been applied consistently to all years presented in these consolidated financial statements, and have been applied consistently by the Company and its subsidiaries.

#### **a) Consolidation**

The consolidated financial statements include the accounts of Parex and its subsidiaries. Inter-company balances and transactions are eliminated on consolidation. Interests in jointly controlled assets are accounted for using the proportionate consolidation method, whereby Parex' proportionate share of revenues, expenses, assets and liabilities are included in the accounts.

#### **b) Foreign currency translation**

##### **(i) Functional and presentation currency**

Items included in the consolidated financial statements are measured using the currency of the primary economic environment in which the entity operates (the "functional currency"). The consolidated financial statements are presented in United States dollars, which is Parex' functional currency.

##### **(ii) Transactions and balances**

Foreign currency transactions are translated into the functional currency using the exchange rates prevailing at the date of the transaction. Generally, foreign exchange gains and losses resulting from the settlement of foreign currency transactions and from the translation at period-end exchange rates of monetary assets and liabilities denominated in currencies other than an operation's functional currency are recognized in the statement of comprehensive income.

#### **c) Financial instruments**

The Company initially measures financial instruments at estimated fair value. The Company's loans and receivables are comprised of cash and cash equivalents and trade receivables are included in current assets due to their short-term nature. Financial liabilities are categorized as "other financial liabilities" consisting of accounts payable and accrued liabilities, current income and equity tax payable and the convertible debentures.

##### *Loans and receivables*

Loans and receivables are non-derivative financial assets with fixed or determinable payments that are not quoted in an active market and with no intention of being traded. They are included in current assets, except for maturities greater than 12 months after the statement of financial position date, which are classified as non-current assets. Loans and receivables are recognized at the amount expected to be received less any discount or rebate to reduce the loan and receivables to estimated fair value. Loans and receivables are subsequently measured at amortized cost using the effective interest method. Loans and receivables are included in cash and cash equivalents and accounts receivable in the consolidated balance sheet.

##### *Other financial liabilities*

Other financial liabilities are financial liabilities that are not quoted on an active market and with no intention of being traded. They are included in current liabilities, except for the convertible debentures and long term equity tax payable as it has a maturity greater than 12 months after the statement of financial position date and is classified as a non-current liability. Financial liabilities include accounts payable and accrued liabilities, current income and equity tax payable and the convertible debentures. Accounts payable are initially recognized at the amount required to be paid less any discount or rebates to reduce the payables to estimated fair value. Accounts payable are subsequently measured at amortized cost using the effective interest method. The convertible debentures was recognized initially at fair value, net of any transaction costs incurred, and subsequently at amortized cost using the effective interest rate method.

##### *Derivative instruments*

Derivatives may be used by the Company to manage economic exposure to market risk relating to commodity prices, foreign exchange rates and interest rates. Parex' policy is not to utilize derivative financial instruments for speculative purposes. The Company does not designate its financial derivative contracts as hedges, and as such does not apply hedge accounting. As a result, all financial derivative contracts are classified at fair value through Comprehensive Income and are recorded on the Balance Sheet at fair value.

Financial derivative contracts are initially recognized at fair value on the date a derivative contract is entered into and are remeasured at their fair value at each subsequent reporting date.

Financial derivative instruments are included in current assets (liabilities) except for those with maturities greater than 12 months after the end of the reporting period, which are classified as non-current assets (liabilities).

#### *Convertible Debenture*

On issuance, the Debenture was split between the financial liability and the equity conversion feature. The convertible debenture represents a liability in its entirety, as the conversion feature fails the fixed-for-fixed requirement for equity classification as the convertible debenture is denominated in Canadian dollars, whereas the functional currency of Parex is US dollars. The convertible feature of the convertible debenture is required to be fair-valued at each balance sheet date. As a result, the convertible debenture is classified at fair value through comprehensive income and is recorded on the Balance Sheet at fair value.

### **d) Capital assets**

#### **(iii) Exploration and evaluation**

All costs directly associated with the exploration and evaluation of oil and natural gas reserves are initially capitalized. E&E costs are those expenditures for an area where technical feasibility and commercial viability have not yet been determined. These costs include unproved property acquisition costs, exploration costs, geological and geophysical costs, asset retirement costs, E&E drilling, sampling and appraisals. Costs incurred prior to acquiring the legal rights to explore an area are charged directly to net income as exploration and evaluation impairment.

When an area is determined to be technically feasible and commercially viable the accumulated costs are transferred to PP&E, where they are depleted. When an area is determined not to be technically feasible and commercially viable or the Company decides not to continue with its activity, the unrecoverable costs are charged to net income as exploration and evaluation impairment.

#### **(iv) Property, plant and equipment**

All costs directly associated with the development of oil and natural gas reserves are capitalized on an area-by-area basis. Development costs include expenditures for areas where technical feasibility and commercial viability has been determined. These costs include proved property acquisitions, development drilling, completion of wells, gathering facilities and infrastructure, asset retirement costs and transfers of E&E assets.

Costs accumulated within each CGU are depleted using the unit-of-production method based on proved plus probable reserves incorporating estimated future prices and costs. Costs subject to depletion include estimated future costs to be incurred in developing proved plus probable reserves. Costs of major development projects are excluded from the costs subject to depletion until they are available for use.

Costs associated with office furniture, fixtures and leasehold improvements are carried at cost and depreciated on a straight-line basis over the estimated service lives of the assets, which range from 1 to 5 years.

### **e) Impairment of long-term assets**

The carrying amounts of the Company's long-term assets, other than E&E assets and deferred tax assets, are reviewed at each reporting date to determine whether there is any indication of impairment. If an indication of impairment exists, then the asset's recoverable amount is estimated. E&E assets are assessed for impairment when they are reclassified to PP&E, and if facts and circumstances suggest that the carrying amount exceeds the recoverable amount.

For the purpose of impairment testing, assets are grouped into the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets. The recoverable amount of an asset or a CGU is the greater of its value in use and its fair value less costs to sell ("FVLCTS").

Value in use is determined by estimating the present value of the pre-tax future net cash flows expected to be derived from the continued use of the asset or CGU. FVLCTS is based on available market information, where applicable. In the absence of such information, FVLCTS is determined using discounted future after tax net cash flows of proved plus probable reserves using forecast prices and costs.

E&E assets are allocated to related CGUs where they are assessed for impairment upon their eventual reclassification to PP&E. E&E assets not reclassified to PP&E are assessed for impairment on a Block basis.

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses are recognized in net income. Impairment losses recognized in respect of CGUs are allocated first to reduce the carrying amount of any goodwill allocated to the units and then to reduce the carrying amounts of the other assets in the unit (group of units) on a pro-rata basis.

Impairment losses recognized in prior years are assessed at each reporting date for any indications that the loss has decreased or no longer exists. An impairment loss is reversed if there has been a change in the estimates used to determine the recoverable amount. An impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depletion and depreciation or amortization, if no impairment loss had been recognized.

**f) Crude oil inventory**

Crude oil inventory consists of crude oil in transit at the balance sheet date and is valued at the lower of cost, using the weighted average cost method and net realizable value. Costs include direct and indirect expenditures incurred in bringing the crude oil to its existing condition and location.

**g) Purchased oil**

Purchased oil includes costs to buy third party oil. These costs are initially recorded in inventory until the crude oil title is transferred.

**h) Goodwill**

Goodwill is recorded on a business acquisition when the purchase price is in excess of the fair values assigned to assets acquired and liabilities assumed. Goodwill is not amortized and an impairment test is performed annually or as events occur that could indicate impairment. To test for impairment, goodwill is allocated to each of the Company's CGUs, groups of CGUs, or an operating segment expected to benefit from the acquisition. Goodwill is tested by combining the carrying amounts of property, plant and equipment and exploration and evaluation assets and goodwill and comparing this to the recoverable amount. Fair value, less cost to sell, is derived by estimating the discounted after-tax future net cash flows as described in the property, plant and equipment impairment test, plus the fair market value of undeveloped land, seismic and inventory. Value-in-use is assessed using the present value of the expected future cash flows. Any excess of the carrying amount over the recoverable amount is recorded as impairment. Impairment charges, which are not tax affected, are recognized in net income and are not reversed. Goodwill is reported at cost less any impairment.

**i) Revenue recognition**

Revenue from the sale of oil and natural gas is recorded when the significant risks and rewards of ownership of the product are transferred to the buyer which is usually when legal title passes to the external party.

**j) Share-based compensation**

The Company has an incentive stock option plan and a restricted unit plan for certain employees, officers and directors as described in note 16. The Company records share-based compensation expense using the fair value method. The fair value of an option is calculated at the grant date using the Black-Scholes pricing model, and expensed over the vesting period of the option. The Company determines an appropriate forfeiture rate by examining the history of its forfeitures. The Company records the cumulative share-based compensation as contributed surplus. When options are exercised, contributed surplus is reduced and share capital is increased by the amount of accumulated share-based compensation for the exercised option. Any consideration received on the exercise of stock options is credited to share capital.

Obligations for payments of cash under the subsidiaries' SARs plan are accrued as compensation expense over the vesting period based on the fair value of SARs, subject to appreciation limits specified in the plan. The fair value of SARs is measured using the Black-Scholes pricing model. In accordance with the fair value method, increases or decreases in the fair value of the SARs result in a corresponding change in the recorded liability. The accrued compensation for a right that is forfeited is adjusted by decreasing compensation cost in the period of forfeiture.

#### **k) Provisions**

A provision is recognized if, as a result of a past event, the Company has a current legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are determined by discounting the expected future cash flows at a pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the liability. Provisions are not recognized for future operating losses.

#### **l) Decommissioning liabilities**

The Company's activities give rise to dismantling, decommissioning, and abandonment and site disturbance remediation activities. Provision is made for the estimated cost of the future site restoration and capitalized in the relevant asset category.

Decommissioning liabilities are measured at the present value of management's best estimate of the expenditure required to settle the present obligation at the balance sheet date using a risk-free discount rate. Subsequent to the initial measurement, the obligation is adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation. The increase in the provision due to the passage of time is recognized as a finance expense whereas increases (decreases) due to changes in the estimated future cash flows are capitalized. Actual costs incurred upon settlement of the decommissioning liabilities are charged against the provision to the extent the provision was established.

#### **m) Finance income and expense**

Finance expense comprises interest expense on borrowings, accretion on decommissioning liabilities, revaluation of derivative financial liabilities and impairment losses recognized on financial assets. Finance income comprises interest earned on cash and cash equivalents and other income.

#### **n) Cash and cash equivalents**

Cash and cash equivalents are comprised of cash in the bank and term deposits held with banks with original maturities of 3 months or less.

#### **o) Income taxes**

Income tax expense comprises current and deferred tax. Income tax expense is recognized in comprehensive income.

Current tax is the expected tax payable on taxable income for the year, using tax rates enacted or substantively enacted at the reporting date, and any adjustment to tax payable in respect of previous years.

In general, deferred tax is recognized in respect of temporary differences arising between the tax basis of assets and liabilities and their carrying amounts in the consolidated financial statements. Deferred tax is determined on a non-discounted basis using tax rates and laws enacted or substantively enacted by the balance sheet date and expected to apply when the deferred tax asset or liability is settled. Deferred tax assets are recognized to the extent that it is probable that the assets can be recovered. Deferred tax is provided on temporary differences arising on investments in subsidiaries except, in the case of subsidiaries, where the timing of the reversal of the temporary difference is controlled by the Company and it is probable that the temporary difference will not be reversed in the foreseeable future. Deferred tax assets and liabilities are presented as non-current.

#### **p) Per share information**

Basic net income per share is calculated by dividing the income or loss attributable to common shareholders of the Company by the weighted average number of common shares outstanding during the period. Diluted net income per share is determined by adjusting the income or loss attributable to common shareholders and the weighted average number of common shares outstanding for the effects of dilutive instruments such as options granted to employees and convertible debentures, except when the effect would be anti-dilutive.

#### **q) New standards and interpretations not yet adopted**

Unless otherwise noted, the following revised standards and amendments are effective for annual periods beginning on or after January 1, 2013 with earlier application permitted..

(i) IFRS 9, *Financial Instruments (effective for annual periods beginning on or after January 1, 2015)*, was issued in November 2009 and addresses classification and measurement of financial assets. It replaces the multiple category and measurement models in IAS 39 for debt instruments with a new

mixed measurement model having only two categories: amortized cost and fair value through profit or loss. IFRS 9 also replaces the models for measuring equity instruments. Such instruments are either recognized at fair value through net income or at fair value through other comprehensive income. Where equity instruments are measured at fair value through other comprehensive income, dividends are recognized in net income to the extent that they do not clearly represent a return of investment; however, other gains and losses (including impairments) associated with such instruments remain in accumulated comprehensive income indefinitely. Requirements for financial liabilities were added to IFRS 9 in October 2010 and they largely carried forward existing requirements in IAS 39, *Financial Instruments – Recognition and Measurement*, except that fair value changes due to credit risk for liabilities designated at fair value through net income are generally recorded in other comprehensive income. *The Company does not expect IFRS 9 to have a material impact on its financial position.*

(ii) IFRS 10, *Consolidated Financial Statements*, requires an entity to consolidate an investee when it has power over the investee, is exposed, or has rights, to variable returns from its involvement with the investee and has the ability to affect those returns through its power over the investee. Under existing IFRS, consolidation is required when an entity has the power to govern the financial and operating policies of an entity so as to obtain benefits from its activities. IFRS 10 replaces SIC-12, *Consolidation—Special Purpose Entities* and parts of IAS 27, *Consolidated and Separate Financial Statements*. *The Company has determined that IFRS 10 will not have a material impact on its financial position.*

(iii) IFRS 11, *Joint Arrangements*, requires a venturer to classify its interest in a joint arrangement as a joint venture or joint operation. Joint ventures will be accounted for using the equity method of accounting whereas for a joint operation the venturer will recognize its share of the assets, liabilities, revenue and expenses of the joint operation. Under existing IFRS, entities have the choice to proportionately consolidate or equity account for interests in joint ventures. IFRS 11 supersedes IAS 31, *Interests in Joint Ventures*, and SIC-13, *Jointly Controlled Entities—Non-monetary Contributions by Venturers*. *The Company has determined that IFRS 11 will not have a material impact on its financial position.*

(v) IFRS 13, *Fair Value Measurement*, is a comprehensive standard for fair value measurement and disclosure for use across all IFRS standards. The new standard clarifies that fair value is the price that would be received to sell an asset, or paid to transfer a liability in an orderly transaction between market participants, at the measurement date. Under existing IFRS, guidance on measuring and disclosing fair value is dispersed among the specific standards requiring fair value measurements and does not always reflect a clear measurement basis or consistent disclosures. *The Company has determined that IFRS 13 will not have a material impact on its financial position.*

(vi) There have been amendments to existing standards, including IAS 27, *Separate Financial Statements* (IAS 27), and IAS 28, *Investments in Associates and Joint Ventures* (IAS 28). IAS 27 addresses accounting for subsidiaries, jointly controlled entities and associates in non-consolidated financial statements. IAS 28 has been amended to include joint ventures in its scope and to address the changes in IFRS 10 – 12. *The Company has determined that IFRS 27 will not have a material impact on its financial position.*

(vii) IAS 12, *Income Taxes*, was amended to introduce an exception to the existing principle for the measurement of deferred tax assets or liabilities arising on investment property measured at fair value. As a result of the amendment, there is a rebuttable presumption that the carrying amount of the investment property will be recovered through sale when considering the expected manner or recovery or settlement. SIC 21, *Income Taxes - Recovery of Revalued Non-Depreciable Assets*, will no longer apply to investment properties carried at fair value. The amendment also incorporates into IAS 12 the remaining guidance previously contained in SIC 21, which is withdrawn. The amendment is effective for annual periods beginning on or after July 1, 2012 with earlier application permitted. *The Company has determined that IAS 12 will not have a material impact on its financial position.*

#### 4. Determination of Fair Values

A number of the Company's accounting policies and disclosures require the determination of fair value for financial and non-financial assets and liabilities. Fair values have been determined for measurement and/or disclosure purposes based on the methods below. When applicable, further information about the assumptions made in determining fair values is disclosed in the notes specific to that asset or liability.

##### a) PP&E and intangible exploration assets

The fair value of PP&E is the estimated amount for which PP&E could be exchanged on the acquisition date between a willing buyer and a willing seller in an arm's-length transaction after proper marketing wherein the parties had each acted knowledgeably, prudently and without compulsion. The fair value of oil

and natural gas assets (included in PP&E) is estimated with reference to the discounted cash flows expected to be derived from oil and natural gas production based on externally prepared reserve reports. The risk-adjusted discount rate is specific to the asset with reference to general market conditions. The fair value of PP&E and intangible exploration assets are determined if there are indicators of impairment.

**b) Cash and cash equivalents, accounts receivable, and accounts payable**

The fair value of cash and cash equivalents, accounts receivable and accounts payable is estimated as the present value of future cash flows, discounted at the market rate of interest at the reporting date. At December 31, 2012 and December 31, 2011 the fair value of these balances approximated their carrying value due to their short term to maturity.

**c) Stock options**

The fair value of stock options is measured using the Black-Scholes option pricing model. Measurement inputs include the share price on measurement date, exercise price of the option, expected future share price volatility, weighted average expected life of the instruments (based on historical experience and general option-holder behavior), expected dividends and the risk-free interest rate (based on Government of Canada Bonds) for the relevant expected life as described in note 16.

**d) Share appreciation rights**

The fair value of SARs is measured using the Black-Scholes option pricing model. Measurement inputs include the share price on each balance sheet date, expected future share price volatility, weighted average expected life of the instruments (based on historical experience and general SAR-holder behavior), expected dividends and the risk-free interest rate (based on Government of Canada Bonds) for the relevant expected life as described in note 16.

**e) Restricted share units**

The fair value of stock RSUs is measured using the Black-Scholes option pricing model. Measurement inputs include the share price on measurement date, exercise price of the option, expected future share price volatility, weighted average expected life of the instruments (based on historical experience and general option-holder behavior), expected dividends and the risk-free interest rate (based on Government of Canada Bonds) for the relevant expected life as described in note 16.

**f) Derivative financial asset /liability**

The convertible feature of the convertible debentures is required to be fair-valued at each balance sheet date. The fair value of this derivative liability is calculated using the Black-Scholes pricing model which is based on significant assumptions such as volatility of the market price of Parex' shares, the risk free interest rate (based on government of Canada Bonds), and the share price of Parex' stock at the measurement date.

Risk management contracts are initially recognized at fair value on the date a derivative contract is entered into and are remeasured at their fair value at each subsequent reporting date. The fair value of the risk management contract on initial recognition is normally the transaction price. Subsequent to initial recognition, the fair value are based on quoted market price where available from active markets, otherwise fair values are estimated based on market prices at the reporting date for similar assets or liabilities with similar terms and conditions.

## 5. Cash and Cash Equivalents

|                              | December 31, 2012 |        | December 31, 2011 |         |
|------------------------------|-------------------|--------|-------------------|---------|
| Bank balances                | \$                | 31,950 | \$                | 74,134  |
| Term deposits <sup>(1)</sup> |                   | -      |                   | 29,750  |
| Cash and cash equivalents    | \$                | 31,950 | \$                | 103,884 |

(1) Term deposits are all less than 3 months duration.

## 6. Accounts Receivable

|                                  | December 31, 2012 |         | December 31, 2011 |        |
|----------------------------------|-------------------|---------|-------------------|--------|
| Trade receivables                | \$                | 58,435  | \$                | 26,360 |
| Colombia income taxes receivable |                   | 21,147  |                   | 5,368  |
| Receivables from partners        |                   | 16,109  |                   | 2,502  |
| Value added taxes (VAT)          |                   | 6,751   |                   | 1,717  |
|                                  | \$                | 102,442 | \$                | 35,947 |

Trade receivables consist primarily of oil sale receivables related to the Company's oil sales. Colombia income tax receivable is a result of withholding tax incurred on Colombia oil sales. The balance can either be received in cash or applied to Colombian cash income tax payable. Receivables from partners consist of cash calls outstanding from joint venture partners in Colombia and in Trinidad & Tobago to recover ongoing capital costs and operating costs, or overhead recoveries outstanding from joint venture partners. Receivables from partners in Colombia are \$10.5 million and in Trinidad & Tobago the amount is \$5.6 million. VAT receivable is \$6.7 million as at December 31, 2012 and is recoverable in 2013. All accounts receivable are expected to be received in 2013 and are thus recognized as current assets.

## 7. Inventory

|                     | December 31, 2012 |       | December 31, 2011 |        |
|---------------------|-------------------|-------|-------------------|--------|
| Crude oil inventory | \$                | 7,474 | \$                | 17,321 |

Crude oil inventory relates to produced oil in-transit in Colombia. During 2012 \$9.8 million (December 31, 2011 - \$13.4 million) of crude oil inventory cost was expensed to the income statement.

## 8. Exploration and Evaluation Assets

|                                       | Colombia |           | Trinidad & Tobago |          | Total      |
|---------------------------------------|----------|-----------|-------------------|----------|------------|
| <b>Cost</b>                           |          |           |                   |          |            |
| Balance at December 31, 2010          | \$       | 25,790    | \$                | 30,062   | \$ 55,852  |
| Additions                             |          | 39,349    |                   | 14,496   | 53,845     |
| Transfers to PP&E                     |          | (53,404)  |                   | -        | (53,404)   |
| Abandonment costs                     |          | 93        |                   | 183      | 276        |
| Corporate acquisition – note 10 (b)   |          | 80,146    |                   | -        | 80,146     |
| Balance at December 31, 2011          | \$       | 91,974    | \$                | 44,741   | \$ 136,715 |
| Additions                             |          | 66,438    |                   | 39,858   | 106,296    |
| Transfers to PP&E                     |          | (109,440) |                   | -        | (109,440)  |
| Abandonment costs                     |          | 168       |                   | 632      | 800        |
| Corporate acquisition – note 10 (a)   |          | 34,312    |                   | -        | 34,312     |
| Exploration and evaluation impairment |          | -         |                   | (23,511) | (23,511)   |
| Balance at December 31, 2012          | \$       | 83,452    |                   | 61,720   | 145,172    |

E&E assets consist of the Company's exploration projects which are pending either the determination of proved or probable reserves or impairment. Additions represent the Company's share of costs incurred on E&E assets during the period. Amounts transferred to PP&E of \$109.4 million for the year ended December 31, 2012 and \$53.4 million for the year ended December 31, 2011 are primarily associated with the Kona, Sulawesi, Tua and Las Maracas fields. E&E increased by \$34.3 million for the year ended December 31, 2012 and \$80.1 million for the year ended December 31, 2011 relating to the fair values of the E&E assets acquired in the corporate acquisitions (see note 10 - Business Combination).

At December 31, 2012 and December 31, 2011 the Company did not have E&E assets in Canada.

The Company completed an impairment review for the exploration and evaluation assets in Trinidad & Tobago due to unfavorable testing results in late 2012 relating to the Green Hermit and Fire Crown wells on the Morgua Block. The impairment review compared the carrying value of the Morgua Block to the recoverable amount. The recoverable amount of the Block was estimated using fair value less cost based on offers and indications from third parties in the Company's interest in the Morgua Block. It was determined that the impairment on the Morgua Block is \$23.5 million which is recorded in the Statement of Comprehensive Income for the year ended December 31, 2012.

## 9. Property, Plant and Equipment

|                                                             | Canada |       | Colombia |         | Trinidad&<br>Tobago |     | Total      |
|-------------------------------------------------------------|--------|-------|----------|---------|---------------------|-----|------------|
| <b>Cost</b>                                                 |        |       |          |         |                     |     |            |
| Balance at December 31, 2010                                | \$     | 1,813 | \$       | 11,751  | \$                  | 229 | \$ 13,793  |
| Additions                                                   |        | 2,594 |          | 93,141  |                     | 63  | 95,798     |
| Transfer from E&E assets                                    |        | -     |          | 53,404  |                     | -   | 53,404     |
| Abandonment costs                                           |        | -     |          | 4,080   |                     | -   | 4,080      |
| Corporate acquisition – note 10                             |        | -     |          | 197,706 |                     | -   | 197,706    |
| Balance at December 31, 2011                                | \$     | 4,407 | \$       | 360,082 | \$                  | 292 | \$ 364,781 |
| Additions                                                   |        | 246   |          | 161,120 |                     | 26  | 161,392    |
| Transfer from E&E assets                                    |        | -     |          | 109,440 |                     | -   | 109,440    |
| Abandonment costs                                           |        | -     |          | 5,078   |                     | -   | 5,078      |
| Corporate acquisition – note 10                             |        | -     |          | 66,382  |                     | -   | 66,382     |
| Balance at December 31, 2012                                | \$     | 4,653 | \$       | 702,102 | \$                  | 318 | \$ 707,073 |
| <b>Accumulated Depreciation, Depletion and Amortization</b> |        |       |          |         |                     |     |            |
| Balance at December 31, 2010                                | \$     | 578   | \$       | 781     | \$                  | 69  | \$ 1,428   |
| Depletion and depreciation for the year                     |        | 598   |          | 53,101  |                     | 73  | 53,772     |
| DD&A transferred from crude oil inventory costing           |        | -     |          | 9,725   |                     | -   | 9,725      |
| Balance at December 31, 2011                                | \$     | 1,176 | \$       | 63,607  | \$                  | 142 | \$ 64,925  |
| Depletion and depreciation for the year                     |        | 867   |          | 180,243 |                     | 39  | 181,149    |
| DD&A transferred to crude oil inventory costing             |        | -     |          | (5,633) |                     | -   | (5,633)    |
| Balance at December 31, 2012                                | \$     | 2,043 |          | 238,217 |                     | 181 | 240,441    |
| <b>Net book value:</b>                                      |        |       |          |         |                     |     |            |
| At December 31, 2010                                        |        | 1,235 |          | 10,970  |                     | 160 | 12,365     |
| At December 31, 2011                                        |        | 3,231 |          | 296,475 |                     | 150 | 299,856    |
| At December 31, 2012                                        | \$     | 2,610 | \$       | 463,885 | \$                  | 137 | \$ 466,632 |

During 2012, additions mainly relate to development expenditures in the amount of \$161.1 million in Colombia. Amounts transferred from E&E are \$109.4 million for the year ended December 31, 2012 and \$53.4 million for the year ended December 31, 2011. PP&E increased by \$66.4 million for the year ended December 31, 2012 and \$197.7 million for the year ended December 31, 2011 relating to the fair values of the assets acquired in the corporate acquisitions (see note 10 – Business Combination).

## 10. Business Combination

### a) Ramshorn

On April 12, 2012 Parex, through a foreign subsidiary, acquired Ramshorn International Limited (“Ramshorn”) which assets primarily consist of interests in four exploration blocks located in Colombia’s Llanos Basin and one block located in Colombia’s Middle Magdalena Basin (the “Ramshorn Acquisition”). Total net consideration paid was \$71.8 million in cash, and the assumption of a working capital deficiency at close, primarily relating to post effective date adjustments. The Acquisition was funded from existing cash.

The statement of comprehensive income includes Ramshorn’s results of operation since the Acquisition closing date of April 12, 2012 and expensed transaction costs associated with the Acquisition of \$1.1 million.

This transaction has been accounted for using the acquisition method whereby the assets acquired and the liabilities assumed, excluding goodwill, are recorded at fair values. As the fair value of the identifiable assets was determined to equal the purchase price, no goodwill arose on the transaction. The following table summarizes the recognizable assets acquired and consideration paid pursuant to the acquisition:

| <b>Assets acquired and liabilities assumed</b> |                  |
|------------------------------------------------|------------------|
| PP&E                                           | \$ 66,382        |
| E&E assets                                     | 34,312           |
| Working capital deficiency                     | (13,269)         |
| Deferred tax liability                         | (14,946)         |
| Decommissioning liabilities                    | (705)            |
|                                                | <b>\$ 71,774</b> |

| <b>Consideration for the acquisition</b>             |           |               |
|------------------------------------------------------|-----------|---------------|
| Cash paid                                            | \$        | 72,636        |
| Cash acquired                                        |           | (862)         |
| <b>Total consideration paid net of cash acquired</b> | <b>\$</b> | <b>71,774</b> |

Included in the working capital deficiency of assets acquired are accounts receivable of \$5.8 million. The receivables are joint venture and trade receivables for which the fair value approximates its carrying value.

The pro forma results for year ended December 31, 2012 are shown below, as if the Acquisition had occurred on January 1, 2012. Pro forma results are not indicative of actual results or future performance.

|           |    |        |
|-----------|----|--------|
| Oil sales | \$ | 28,787 |
|-----------|----|--------|

The pro forma net income and pro forma net income per share, basic and diluted, are considered impracticable to calculate and therefore not included.

The statement of comprehensive income for the year ended December 31, 2012 includes \$20.7 million of oil sales attributable to the assets acquired since the Ramshorn Acquisition. Net income for the year ended December 31, 2012 attributable to the assets acquired since the Acquisition is considered impracticable to calculate.

#### **b) Remora**

On June 29, 2011, Parex acquired Remora Energy Colombia Ltd. ("Remora") which held the other 50 percent interest Parex did not already own in four Llanos Basin blocks in Colombia, including Block LLA-16 and the Kona discovery (the "Remora Acquisition"). The Remora Acquisition was funded through a bought deal public offering of Cdn\$217.35 million of subscription receipts and Cdn\$85.0 million of extendible convertible unsecured subordinated debentures (the "Offering").

The statement of comprehensive income includes Remora's results of operation since the Remora Acquisition date June 29, 2011 and expensed transaction costs associated with the acquisition of \$2.1 million.

This transaction has been accounted for using the acquisition method whereby the assets acquired and the liabilities assumed, excluding goodwill, are recorded at fair values. The following table summarizes the recognizable assets acquired and consideration transferred pursuant to the acquisition:

| <b>Assets acquired and liabilities assumed</b> |           |                |
|------------------------------------------------|-----------|----------------|
| PP&E                                           | \$        | 197,706        |
| E&E assets                                     |           | 80,146         |
| Working capital deficiency                     |           | (21,246)       |
| Deferred tax liability                         |           | (64,401)       |
| Goodwill                                       |           | 61,252         |
| Decommissioning liabilities                    |           | (470)          |
|                                                | <b>\$</b> | <b>252,987</b> |

| <b>Consideration for the acquisition</b>             |           |                |
|------------------------------------------------------|-----------|----------------|
| Cash paid                                            | \$        | 254,335        |
| Cash acquired                                        |           | (1,348)        |
| <b>Total consideration paid net of cash acquired</b> | <b>\$</b> | <b>252,987</b> |

Included in the working capital deficiency of assets acquired are accounts receivable of \$2.0 million. The receivables are trade receivables for which the fair value approximates its carrying value.

The goodwill recognized on acquisition is attributed to the strategic benefit of the significant undeveloped land in the Llanos Basin. The goodwill recognized is not deductible for tax purposes.

The pro forma results for the year ended December 31, 2011 are shown below, as if the Remora Acquisition had occurred on January 1, 2011. Pro forma results are not indicative of actual results or future performance.

|                                      |    |         |
|--------------------------------------|----|---------|
| For the year ended December 31, 2011 |    |         |
| Oil sales                            | \$ | 191,531 |

The pro forma net income and pro forma net income per share, basic and diluted, are considered impracticable to calculate and therefore not included.

The statement of comprehensive income for the year ended December 31, 2011 includes \$75.1 million of oil sales attributable to the assets acquired since the Remora Acquisition. Net income for the year ended December 31, 2011 since the Acquisition is considered impracticable to calculate.

## 11. Goodwill

|          | December 31, 2012 |        | December 31, 2011 |        |
|----------|-------------------|--------|-------------------|--------|
| Goodwill | \$                | 61,252 | \$                | 61,252 |

### *Impairment test of goodwill*

The Company performed its annual test for goodwill impairment at the balance sheet date in accordance with its policy described in note 2. The Company has allocated goodwill to the Colombia operating segment.

The estimated fair value less cost to sell of the Colombia operating segment exceeded the carrying value. As a result, no goodwill impairment was recorded.

### *Valuation Techniques*

The recoverable amount of the group of CGUs in which the goodwill was assigned is based on fair value less cost to sell. The technique used in determining the recoverable amount is based on the net present value of the after-tax cash flows from oil and gas reserves of the group of CGU's based on reserves estimated by Parex' independent reserve evaluator and the fair value of undeveloped land based on estimates with consideration given to acquisition metrics of recent transactions completed on similar assets to those contained within the relevant group of CGU's. The discounting process uses a rate of return that is commensurate with the risk associated with the assets and the time value of money. This approach requires assumptions about revenue, future oil prices, tax rates and discount rates.

### *Significant Assumptions*

#### *Oil Reserves*

Assumptions that are valid at the time of reserve estimation may change significantly when new information becomes available. Changes in forward price estimates, production costs or recovery rates may change the economic status of reserves and may ultimately result in reserves being restated.

#### *Future Oil Prices*

Oil forward price estimates are used in the cash flow model. Commodity prices have fluctuated widely in recent years due to global and regional factors including supply and demand fundamentals, inventory levels, exchange rates, weather, economic and geopolitical factors. The future oil prices used in the model are based on a forecast of crude oil prices by Parex' independent reserve evaluator. Prices used are as follows:

|                  | 2013   | 2014   | 2015   | 2016   | 2017   | Thereafter           |
|------------------|--------|--------|--------|--------|--------|----------------------|
| Brent (\$US/bbl) | 105.00 | 102.50 | 102.50 | 102.50 | 100.00 | 2% increase per year |

### *Discount Rate*

The Company assumed a discount rate in order to calculate the present value of its projected cash flows. The discount rate represented a weighted average cost of capital ("WACC") for comparable companies operating in similar industries, based on publicly available information. The WACC is an estimate of the overall required rate of return on an investment for both debt and equity owners and serves as the basis for developing an appropriate discount rate. Its determination requires separate analysis of the cost of equity and debt, and considers a risk premium based on an assessment of risks related to the projected cash flows of the group of Colombia CGU's. The discount rate used in performing the impairment test was 11 percent.

The fair value was in excess of its carrying value. Based on sensitivity analysis, no reasonably possible change in assumptions would cause the carrying amount of the group of Colombia CGUs to exceed its recoverable amount.

## 12. Long-term debt

|                                            | December 31, 2012 | December 31, 2011 |
|--------------------------------------------|-------------------|-------------------|
| Long-term debt (syndicate credit facility) | \$ 9,100          | \$ -              |

On May 23, 2012, Parex entered into a \$200 million senior secured credit facility (“credit facility”) with a syndicate of banks led by a major Canadian bank. The facility currently consists of a reserve-based revolving facility of \$75 million including an operating line of \$5 million. The revolving facility has a two year term, maturing on May 23, 2014, and may be extended for an additional 365 days. The facility is subject to re-determination of the borrowing base semi-annually on November 30 and May 31 of each year, beginning on November 30, 2012. The borrowing base is determined based on, among other things, the Company’s current reserve report, results of operations, the lenders view of the current and forecasted commodity prices and the current economic environment. US base rate and LIBOR base rate loan advances under the revolving facility bear interest at rates ranging from US base rate or LIBOR plus 2.75% - 3.50% per annum, depending on utilization. Canadian prime rate loan advances, drawn on the operating line only, bear interest at rates ranging from Canadian prime plus 1.75% - 2.50% per annum, dependent on utilization. Undrawn amounts under the revolving facility bear a commitment fee ranging from 0.5% to 0.75% per annum, dependent on utilization.

Repayments of principal are not required provided that the borrowings under the facility do not exceed the authorized borrowing amount and the Company is in compliance with all covenants, representations and warranties. Key covenants include a current ratio test of 1:1 adjusted for undrawn amounts on the credit facility plus fair value of inventoried oil, a rolling four quarter total funded debt to EBITDA test of 3:50: 1, and other standard business operating covenants. The authorized borrowing amount is subject to an interim review as discussed above. As at December 31, 2012, the Company is in compliance with all covenants. Security is provided for by a first fixed and floating charge debenture over all assets of Parex Resources Inc., a pledge of the shares of material subsidiaries and general assignment of book debts.

## 13. Net Finance Expense (Income)

|                                                  |            |            |
|--------------------------------------------------|------------|------------|
| For the year ended December 31,                  | 2012       | 2011       |
| Interest expense                                 | \$ 4,602   | \$ 2,800   |
| Bank fees                                        | 643        | -          |
| Accretion on convertible debentures              | 3,744      | 1,738      |
| Accretion on decommissioning liability           | 359        | 97         |
| Gain on derivative financial liability (Note 17) | (7,294)    | (5,091)    |
| Amortization of debt issuance costs              | 564        | 262        |
| Interest and other income                        | (1,925)    | (1,334)    |
| Net finance expense (income)                     | \$ 693     | \$ (1,528) |
| For the year ended December 31,                  | 2012       | 2011       |
| Non-cash finance expense (income)                | \$ (2,633) | \$ (2,999) |
| Cash finance expense                             | 3,326      | 1,471      |
| Net finance expense (income)                     | \$ 693     | \$ (1,528) |

## 14. Other Long-Term Liabilities

Other long-term liabilities are comprised of the following:

|                                                                                           | December 31, 2012 | December 31, 2011 |
|-------------------------------------------------------------------------------------------|-------------------|-------------------|
| Long-term SARs payable                                                                    | \$ 511            | \$ 502            |
| Long-term equity tax payable                                                              | 1,574             | 1,314             |
| Financial derivative liability related to the cross currency interest rate swap (“CCIRS”) | 986               | -                 |
|                                                                                           | \$ 3,071          | \$ 1,816          |

The outstanding amount of the equity tax provision is \$3.1 million. Included in this amount is \$1.6 million which is classified as long term, as the equity tax is payable over a four year period.

## 15. Decommissioning Liabilities

|                                              | December 31, 2012 | December 31, 2011 |
|----------------------------------------------|-------------------|-------------------|
| Balance, beginning of period                 | \$ 5,105          | \$ 651            |
| Additions                                    | 5,465             | 4,253             |
| Corporate acquisition                        | 705               | 470               |
| Settlements of obligations during the period | -                 | (467)             |
| Change in estimates                          | 445               | 101               |
| Accretion expense                            | 359               | 97                |
| Balance, end of period                       | \$ 12,079         | \$ 5,105          |

The total decommissioning liability is estimated based on the Company's net ownership in wells drilled as at December 31, 2012, the estimated costs to abandon and reclaim the wells and the estimated timing of the costs to be paid in future periods. The total undiscounted amount of cash flows required to settle the Company's decommissioning liability is approximately \$17.5 million as at December 31, 2012 (December 31, 2011 – \$11.9 million) with the majority of these costs anticipated to occur in 2030 or later. A risk-free discount rate of 4 percent and an inflation rate of 4 percent were used in the valuation of the liabilities (December 31, 2011 – 4 percent risk free discount rate and a 3 percent inflation rate). The discount rates used are a blend of US, Colombia and Trinidad & Tobago risk free rates.

## 16. Share Capital

### a) Issued and outstanding common shares

|                                                         | Number of shares | Amount     |
|---------------------------------------------------------|------------------|------------|
| Balance, December 31, 2010                              | 76,968,285       | \$ 198,857 |
| Issued for cash                                         | 31,050,000       | 223,958    |
| Issued for cash – exercise of options                   | 282,083          | 870        |
| Allocation of contributed surplus – exercise of options | -                | 379        |
| Share issuance costs                                    | -                | (12,143)   |
| Balance, December 31, 2011                              | 108,300,368      | \$ 411,921 |
| Issued for cash – exercise of options                   | 176,083          | 568        |
| Allocation of contributed surplus – exercise of options | -                | 247        |
| Balance, December 31, 2012                              | 108,476,451      | \$ 412,736 |

The Company has authorized an unlimited number of voting common shares without nominal or par value.

In 2012, a total of 176,083 options were exercised for \$568,000.

On June 29, 2011, Parex closed the Remora corporate acquisition (see note 10) for total consideration of \$255.0 million, before closing adjustments. The Acquisition was effective January 1, 2011 and was funded through a bought deal public offering with a syndicate of underwriters which closed on May 17, 2011. Pursuant to the offering, the Company issued 31,050,000 subscription receipts at Cdn\$7.00 each for gross proceeds of Cdn\$217.35 million (Cdn\$206.5 million net) and Cdn\$85.0 million (Cdn\$81.6 million net) of 5.25 percent extendible convertible unsecured subordinated debentures for total combined gross proceeds of Cdn\$302.35 million (Cdn\$288.1 million net). Upon closing of the Remora acquisition each subscription receipt was automatically exchanged for one Parex common share.

### b) Stock options

The Company has a stock option plan which provides for the issuance of options to the Company's directors, officers, certain employees and certain consultants to acquire common shares. The maximum number of options reserved for issuance under the option plan may not exceed 10 percent of the number of common shares issued and outstanding. The options typically vest over a three-year period and expire 5 years from the date of grant.

|                            | Number of options | Weighted average exercise price Cdn\$/option |
|----------------------------|-------------------|----------------------------------------------|
| Balance, December 31, 2011 | 8,288,242         | 5.79                                         |
| Granted                    | 1,750,470         | 4.85                                         |
| Exercised                  | (176,083)         | 3.22                                         |
| Forfeited                  | (236,114)         | 6.76                                         |
| Balance, December 31, 2012 | 9,626,515         | 5.64                                         |

Stock options outstanding and the weighted average remaining life of the stock options at December 31, 2012 are as follows:

| Exercise price Cdn\$ | Options outstanding |                                         |                                              | Options vested    |                                         |                                              |
|----------------------|---------------------|-----------------------------------------|----------------------------------------------|-------------------|-----------------------------------------|----------------------------------------------|
|                      | Number of options   | Weighted average remaining life (years) | Weighted average exercise price Cdn\$/option | Number of options | Weighted average remaining life (years) | Weighted average exercise price Cdn\$/option |
| \$3.04 - \$3.55      | 2,653,084           | 1.8                                     | 3.04                                         | 2,653,084         | 1.8                                     | 3.04                                         |
| \$3.56 - \$4.77      | 1,755,470           | 4.2                                     | 4.43                                         | 269,166           | 2.1                                     | 4.35                                         |
| \$4.78 - \$7.50      | 1,001,666           | 3.2                                     | 6.22                                         | 408,324           | 2.8                                     | 6.02                                         |
| \$7.51 - \$7.62      | 2,532,374           | 3.9                                     | 7.56                                         | 864,483           | 3.9                                     | 7.56                                         |
| \$7.63 - \$7.95      | 1,683,921           | 3.0                                     | 7.76                                         | 1,037,854         | 2.9                                     | 7.76                                         |
|                      | 9,626,515           | 3.1                                     | 5.64                                         | 5,232,911         | 2.5                                     | 5.02                                         |

The fair value of each option granted is estimated on the date of grant using the Black-Scholes option pricing model with the following weighted average assumptions:

| For the year ended December 31, | 2012 | 2011 |
|---------------------------------|------|------|
| Risk-free interest rate (%)     | 1.14 | 1.13 |
| Expected life (years)           | 3    | 3    |
| Expected volatility (%)         | 50   | 49   |
| Expected dividends              | -    | -    |

The weighted average fair value at the grant date for the year ended December 31, 2012 was Cdn\$1.68 per option (year ended December 31, 2011 – Cdn\$2.53 per option). The weighted average share price on the exercise date for options exercised in 2012 was Cdn\$6.67 (year ended December 31, 2011 – Cdn\$8.59)

### c) *Share appreciation rights*

Parex Trinidad and Parex Colombia initiated a SARs plan that provides for the issuance of SARs to certain employees. The plan entitles the holders to receive a cash payment equal to the excess of the market price of the Company's common shares at the time of exercise over the grant price. At any time, if the current market price of the Company's common shares exceeds four times the grant price, Parex has the option to require the holders to exercise all vested SARs. SARs typically vest over a three-year period and expire 5 years from the date of grant. The SARs liability cannot be settled by the issuance of common shares.

|                            | Number of SARs | Weighted average exercise price Cdn\$/SAR |
|----------------------------|----------------|-------------------------------------------|
| Balance, December 31, 2011 | 1,817,422      | \$ 7.10                                   |
| Granted                    | 1,109,490      | 5.78                                      |
| Forfeited                  | (185,769)      | 6.72                                      |
| Balance, December 31, 2012 | 2,741,143      | \$ 6.26                                   |

As at December 31, 2012, 783,472 SARs were vested (year ended December 31, 2011 – 631,376).

Obligations for payments of cash under the SARs plan are accrued as compensation expense over the vesting period based on the fair value of SARs, subject to appreciation limits specified in the plan. The fair value of SARs is measured using the Black-Scholes pricing model at each reporting date based on weighted average pricing assumptions noted below:

| For the year ended December 31, | 2012 | 2011 |
|---------------------------------|------|------|
| Risk-free interest rate (%)     | 1.24 | 1.08 |
| Expected life (years)           | 3    | 3    |
| Expected volatility (%)         | 49   | 48   |
| Expected dividends              | -    | -    |

As at December 31, 2012, the total SARs liability accrued is \$2.9 million (December 31, 2011 - \$1.8 million) of which \$511,000 (December 31, 2011 - \$502,000) is classified as long-term in accordance with the three year vesting period. For the year ended December 31, 2012, Parex recorded \$1.1 million of compensation costs related to the outstanding SARs (year ended December 31, 2011 – \$0.8 million). The intrinsic value of vested SARs at December 31, 2012 was \$147,104 (December 31, 2011 – \$245,000).

#### **d) Restricted share units**

On October 19, 2012, The Company put into place a restricted share unit plan pursuant to which the Company may grant restricted shares to directors and certain employees. The plan is subject to shareholder approval. The restricted shares vest at 33 percent on each of the first, second and third anniversaries of the grant date and expire five years from date of grant.

|                            | Number of RSU's | Weighted average exercise price Cdn\$/RSU |
|----------------------------|-----------------|-------------------------------------------|
| Balance, December 31, 2011 | -               | -                                         |
| Granted                    | 240,800         | 0.01                                      |
| Exercised                  | -               | -                                         |
| Forfeited                  | -               | -                                         |
| Balance, December 31, 2012 | 240,800         | 0.01                                      |

The fair value of each RSU granted is estimated on the date of grant using the Black-Scholes option pricing model with the following weighted average assumptions:

| For the year ended December 31, | 2012 | 2011 |
|---------------------------------|------|------|
| Risk-free interest rate (%)     | 1.19 | -    |
| Expected life (years)           | 3    | -    |
| Expected volatility (%)         | 50   | -    |
| Expected dividends              | -    | -    |

#### **e) Stock-based compensation and SARs expense**

| For the year ended December 31,  | 2012     | 2011     |
|----------------------------------|----------|----------|
| Stock-based compensation expense | \$ 6,907 | \$ 5,594 |
| SARs expense                     | 1,068    | 884      |
| Restricted share unit expense    | 140      | -        |
| Total                            | \$ 8,115 | \$ 6,478 |

### **17. Convertible Debenture**

On June 29, 2011, Parex issued Cdn\$85.0 million of convertible unsecured subordinated debentures (the "Debentures") with an annual coupon of 5.25 percent maturing on June 30, 2016. The Debentures have a face value of \$1,000 per debenture, are convertible into common shares at the option of the holder at a conversion price of Cdn\$10.15 per common share and represent a conversion rate of approximately 98.52 common shares per Debenture. The Debentures pay interest semi-annually in arrears on June 30 and December 31 of each year, commencing on December 31, 2011. In the event that a holder of Debentures exercises the conversion feature, such holder shall be entitled to receive accrued and unpaid interest, in addition to the applicable number of common shares to be received on conversion, for the period from the latest interest payment date to the date of conversion.

On issuance, the Debentures were split between the financial liability and the equity conversion feature (which is classified as a derivative financial liability under IFRS). The financial liability portion was determined by subtracting issuance costs and the fair value of the conversion feature from the principal of the Debenture. As at June 29, 2011, the \$87.5 million (Cdn\$85.0 million) net issuance proceeds resulted in \$60.8 million (Cdn\$62.4 million) being classified as a liability and \$23.3 million (Cdn\$22.6 million) being classified as a derivative financial liability. The fair value of the conversion feature is estimated every balance sheet date with changes in the fair value estimate between periods recognized in the statement of comprehensive income as finance expense.

The following table summarizes the accounting for the debentures:

|                                                                                  | Liability | Derivative<br>financial liability | Total     |
|----------------------------------------------------------------------------------|-----------|-----------------------------------|-----------|
| Issuance of Debentures on June 29, 2011 (net of \$3.5 million of issuance costs) | \$ 60,809 | \$ 23,266                         | \$ 84,075 |
| Accretion                                                                        | 1,738     | -                                 | 1,738     |
| Amortization of debt issuance costs                                              | 262       | -                                 | 262       |
| Derivative gain                                                                  | -         | (5,091)                           | (5,091)   |
| Foreign exchange gain                                                            | (2,808)   | (1,354)                           | (4,162)   |
| Balance at December 31, 2011                                                     | \$ 60,001 | \$ 16,821                         | \$ 76,822 |
| Accretion                                                                        | 3,744     | -                                 | 3,744     |
| Amortization of debt issuance costs                                              | 564       | -                                 | 564       |
| Derivative gain                                                                  | -         | (7,294)                           | (7,294)   |
| Foreign exchange loss                                                            | 1,348     | 372                               | 1,720     |
| Balance at December 31, 2012                                                     | \$ 65,657 | \$ 9,899                          | \$ 75,556 |

The liability portion is measured at amortized cost and will accrete up to the principal balance at maturity using the effective interest rate method. The accretion and the interest paid are charged to finance expense in the consolidated statement of comprehensive income. The derivative financial liability is measured at fair value through profit or loss, with changes to the fair value being recorded in finance expense.

The fair value of the derivative financial liability is determined using the Black Scholes valuation model and the following assumptions were used:

| For the year ended December 31, | 2012 | 2011 |
|---------------------------------|------|------|
| Risk-free interest rate (%)     | 1.24 | 1.08 |
| Expected life (years)           | 3.5  | 4.5  |
| Expected volatility (%)         | 49   | 48   |
| Expected dividends              | -    | -    |

## 18. Income Tax

The components of tax expense for 2012 and 2011 were as follows:

| For the year ended December 31, | 2012      | 2011      |
|---------------------------------|-----------|-----------|
| Current equity tax expense      | \$ 42,999 | \$ 424    |
| Deferred tax expense (recovery) | (8,847)   | 28,443    |
| Total tax expense               | \$ 34,152 | \$ 28,867 |

### Factors affecting tax expense for the year

The standard Colombian corporate income tax rate for 2011 was 33 percent. The following is a reconciliation of income taxes calculated at the Colombian corporate tax rate to the tax expense for 2012 and 2011:

| For the year ended December 31,                                                                  | 2012             | 2011             |
|--------------------------------------------------------------------------------------------------|------------------|------------------|
| Income before tax                                                                                | \$ 74,074        | \$ 44,502        |
| Income before tax multiplied by the standard rate of Colombian corporate tax of 33% (2011 – 33%) | 24,445           | 14,686           |
| Effects of:                                                                                      |                  |                  |
| Income taxes recorded at rates different from the Colombian tax rate                             | (2,835)          | 2,281            |
| Expenses not deductible for tax purposes                                                         | (1,592)          | 439              |
| Current equity tax expense                                                                       | -                | 424              |
| Share based compensation                                                                         | 2,325            | 1,846            |
| Deferred tax assets not recognized                                                               | 20,352           | 2,623            |
| Foreign exchange effects and other                                                               | (8,543)          | 6,568            |
| <b>Total tax expense</b>                                                                         | <b>\$ 34,152</b> | <b>\$ 28,867</b> |

The analysis of deferred income tax (assets) liabilities as follows:

|                                                                  | December 31, 2012 | December 31, 2011 |
|------------------------------------------------------------------|-------------------|-------------------|
| Deferred tax liabilities (assets) to be settled within 12 months | \$ -              | \$ -              |
| Deferred tax liabilities to be settled after more than 12 months | 95,214            | 89,114            |
| Net deferred income tax liability (asset)                        | \$ 95,214         | \$ 89,114         |

For the purposes of the above table, deferred income tax liabilities are shown net of offsetting deferred income tax assets where these occur in the same entity and jurisdiction. The deferred income tax liabilities and assets to be settled (recovered) within 12 months represents management's estimate of the timing of the reversal of temporary differences and does not correlate to the current income tax expense of the subsequent year.

The movement during the year in the deferred income tax (assets) liabilities and the net components is as follows:

| Deferred Tax (Liability)<br>Asset | December 31,<br>2012 | (Charged)<br>credited to the<br>statement of<br>comprehensive<br>income | Corporate<br>Acquisition | December<br>31, 2011 | (Charged)<br>credited to the<br>statement of<br>comprehensive<br>income (loss) | Corporate<br>Acquisition<br>and Other |
|-----------------------------------|----------------------|-------------------------------------------------------------------------|--------------------------|----------------------|--------------------------------------------------------------------------------|---------------------------------------|
| PP&E                              | \$ (106,025)         | \$ 14,399                                                               | \$ (21,876)              | \$ (98,548)          | \$ (26,222)                                                                    | \$ (71,326)                           |
| Loss carry forwards               | 6,187                | (10,419)                                                                | 6,929                    | 9,677                | (1,573)                                                                        | 7,925                                 |
| Decommissioning liability         | 4,807                | 3,978                                                                   | -                        | 829                  | 829                                                                            | -                                     |
| SARs                              | 1,636                | 882                                                                     | -                        | 754                  | 754                                                                            | -                                     |
| Other                             | (1,819)              | 7                                                                       | -                        | (1,826)              | (2,231)                                                                        | 405                                   |
| <b>Balance, end of period</b>     | <b>\$ (95,214)</b>   | <b>\$ 8,847</b>                                                         | <b>\$ (14,947)</b>       | <b>\$ (89,114)</b>   | <b>\$ (28,443)</b>                                                             | <b>\$ (63,996)</b>                    |

The Company has losses available to reduce future taxable income, as well as other cumulative tax deductions in excess of book value in Canada, Colombia and Trinidad & Tobago. Only the Colombian benefit has been recognized in the financial statements since the recoverability of the tax benefit in Trinidad & Tobago and Canada is uncertain. Losses can be carried forward indefinitely in Colombia and Trinidad & Tobago, while in Canada they expire in 20 years. Amounts denominated in foreign currency have been translated at the December 31, 2012 exchange rate. At December 31, 2012 the Company had the following non-capital losses:

|               | Canada           | Colombia         | Trinidad & Tobago |
|---------------|------------------|------------------|-------------------|
| <b>Expiry</b> |                  |                  |                   |
| 2029          | \$ 1,387         | \$ -             | \$ -              |
| 2030          | 6,333            | -                | -                 |
| 2031          | 4,843            | -                | -                 |
| 2032          | 13,569           | -                | -                 |
| Indefinitely  | -                | 24,747           | 53,721            |
| <b>Total</b>  | <b>\$ 26,132</b> | <b>\$ 24,747</b> | <b>\$ 53,721</b>  |

Earnings retained by subsidiaries amounted to \$98.5 million at December 31, 2012 (December 31, 2011 - \$10.4 million). No provision has been made for withholding and other taxes that would become payable on the distribution of these earnings as it is not expected that they will be remitted in the foreseeable future.

### Colombian Equity Tax

Parex' Colombian subsidiaries were subject to a one-time tax which was calculated based on the subsidiary's net taxable equity as at January 1, 2011 at a rate of 6 percent. The equity tax is payable over four years (1.5 percent per year) in eight equal installments every May and September starting in 2011. A total of \$1.6 million was paid during the year ended December 31, 2012 (December 31, 2011 \$657,000). The outstanding amount is \$3.1 million (December 31, 2011 - 2.0 million), to be paid over the remaining four installments of which \$1.6 million is due within one year (December 31, 2011 - \$657,000). Equity tax expense recorded in 2012 was nil (December 31, 2011 - \$424,000).

## 19. Net Income per Share

### a) Basic net income per share

| For the year ended December 31,                                                                 | 2012           | 2011    |
|-------------------------------------------------------------------------------------------------|----------------|---------|
| <b>Net income</b>                                                                               |                |         |
| Net income for the purpose of basic net income per share                                        | \$ 39,922      | 15,635  |
| <b>Weighted average number of shares for the purposes of basic net income per share (000's)</b> | <b>108,403</b> | 92,956  |
| <b>Basic net income per share</b>                                                               | <b>\$ 0.37</b> | \$ 0.17 |

### b) Adjusted diluted net income per share

| For the year ended December 31,                                                                                                                                            | 2012             | 2011             |
|----------------------------------------------------------------------------------------------------------------------------------------------------------------------------|------------------|------------------|
| <b>Net income</b>                                                                                                                                                          |                  |                  |
| Net income for the purpose of basic net income per share                                                                                                                   | \$ 39,922        | \$ 15,635        |
| Elimination of interest and accretion expense and the gain on changes in fair value and foreign exchange, net of tax, on the Debentures and derivative financial liability | (1,266)          | (4,715)          |
| <b>Net income used to calculate diluted net income per share</b>                                                                                                           | <b>\$ 38,656</b> | <b>\$ 10,920</b> |
| <b>Weighted average number of shares for the purposes of basic net income per share (000's)</b>                                                                            | <b>108,403</b>   | 92,956           |
| Dilutive effect of share options on potential common shares                                                                                                                | 1,324            | 885              |
| Dilutive effect of Debentures on potential common shares                                                                                                                   | 15,984           | 4,226            |
| <b>Weighted average number of shares for the purposes of diluted net income per share</b>                                                                                  | <b>125,711</b>   | 98,067           |
| <b>Diluted net income per share</b>                                                                                                                                        | <b>\$ 0.31</b>   | \$ 0.11          |

At December 31, 2012, 4,848,961 (December 31, 2011 – 2,199,987) share options had an exercise price in excess of the average market value of the shares from the option grant date to the end of the period. As a result, these share options are excluded from the calculation of diluted earnings per share.

## 20. Supplemental Disclosure of Cash Flow Information

### a) Net change in non-cash working capital

| For the year ended December 31,               | 2012             | 2011               |
|-----------------------------------------------|------------------|--------------------|
| Accounts receivable                           | \$ (66,495)      | \$ (21,069)        |
| Prepays and other current assets              | (1,077)          | (4,458)            |
| Oil inventory                                 | 9,847            | (17,321)           |
| Accounts payable and accrued liabilities      | 92,041           | 43,488             |
| Depletion related to oil inventory            | (5,633)          | 9,725              |
| Net non-cash working capital on acquisition   | (13,269)         | (21,246)           |
| <b>Net change in non-cash working capital</b> | <b>\$ 15,414</b> | <b>\$ (10,881)</b> |
| Operating                                     | \$ 12,948        | \$ 22,337          |
| Investing                                     | 2,466            | (33,102)           |
| Financing                                     | -                | (116)              |
| <b>Net change in non-cash working capital</b> | <b>\$ 15,414</b> | <b>\$ (10,881)</b> |

### b) Interest and taxes paid

| For the year ended December 31,   | 2012     | 2011     |
|-----------------------------------|----------|----------|
| Cash interest paid                | \$ 4,602 | \$ 2,800 |
| Cash income and equity taxes paid | \$ 1,580 | \$ 656   |

## 21. Employee Salaries and Benefit Expenses

| For the year ended December 31,                 | 2012 |        | 2011 |        |
|-------------------------------------------------|------|--------|------|--------|
| Salaries, bonuses and other short term benefits | \$   | 21,985 | \$   | 6,761  |
| Stock-based compensation expense                |      | 7,047  |      | 5,594  |
| SARs expense                                    |      | 1,068  |      | 884    |
|                                                 | \$   | 30,100 | \$   | 13,239 |

Employee salaries, bonuses and short term benefits are included in general and administrative expenses in the statement of comprehensive income. Stock-based compensation and SARs and RSUs expense is included in share based compensation expense in the statement of comprehensive income.

## 22. Capital Management

The Company's policy is to maintain a strong capital base in order to provide flexibility in the future development of the business and maintain the confidence of investors and capital markets.

The Company manages its capital to achieve the following:

- Maintain balance sheet strength in order to meet the Company's strategic growth objectives; and
- Ensure financial capacity is available to fund the Company's exploration commitments.

Parex has secured a senior credit facility (see note 12 - long- term debt) in the amount of \$75 million of which \$9.1 million was drawn as at December 31, 2012. The facility is intended to serve as means to increase liquidity and fund short term cash needs as they arise.

The Company has also provided a general security agreement to Export Development Canada ("EDC") in connection with the performance security guarantees that support letters of credit provided to the Colombian National Hydrocarbon Agency ("ANH") related to the exploration work commitments on its Colombian concessions (see note 25 - Commitments).

As at December 31, 2012, the Company's net working capital deficit was \$12.6 million excluding amounts available under the credit facility of \$65.9 million (December 31, 2011 – \$92.9 million working capital surplus), which was primarily attributable to the close of the Corporate Acquisition (see note 10 – Business Combination) and Parex becoming taxable in Colombia in 2012. The net working capital deficit also reflects the Company's crude oil inventory recorded at cost which is less than its fair value at December 31, 2012.

Parex has the ability to adjust its capital structure by issuing new equity or debt and making adjustments to its capital expenditure program to the extent the capital expenditures are not committed. The Company considers its capital structure at this time to include shareholders equity plus debentures (excluding the associated derivative financial liability and the credit facility). As at December 31, 2012 shareholders' equity was \$465.4 million (December 31, 2011 - \$417.9 million) and the Debentures' face value balance was Cdn\$85.0 million (December 31, 2011 - Cdn\$85.0 million).

## 23. Financial Instruments and Risk Management

The Company's non-derivative financial instruments recognized in the balance sheet consist of cash and cash equivalents, accounts receivable, and accounts payable and accrued liabilities, current income and equity tax payable and the liability portion of the Debentures. Non-derivative financial instruments are recognized initially at fair value. The fair values of the current financial instruments approximate their carrying value due to their short-term maturity.

Financial instruments of the Company carried on the balance sheet are carried at amortized cost with the exception of cash and financial derivative instruments, specifically fixed price contracts and CCIRS contract, which are carried at fair value. There are no significant differences between the carrying amount of financial instruments and their estimated fair values as at December 31, 2012.

The conversion feature associated with Debentures is a derivative financial liability. Derivative financial liabilities are recorded upon recognition and subsequently at each balance sheet date at fair value, with changes in fair value being recognized in the statement of comprehensive income.

The fair value of the Company's cash and financial derivative instruments are quoted in active markets. The Company classifies the fair value of these transactions according to the following hierarchy.

Level 1 – quoted prices in active markets for identical financial instruments.

Level 2 – quoted prices for similar instruments in active markets; quoted prices for identical or similar instruments in markets that are not active; and model-derived valuations in which all significant inputs and significant value drivers are observable in active markets.

Level 3 – valuations derived from valuation techniques in which one or more significant inputs or significant value drivers are unobservable.

The Company's cash has been classified as level 1 and financial derivative instruments have been classified as level 2 based on the fair value hierarchy described above.

#### **a) Credit risk**

Credit risk is the risk of loss associated with the inability of a third party to fulfill its payment obligations. The Company is exposed to the risk that third parties that owe it money do not meet their obligations. The Company assesses the financial strength of its joint venture partners and oil marketing counterparties in its management of credit exposure.

The Company for the year ended December 31, 2012 had the majority of its oil sales to nine counterparties. Accounts receivable balance at December 31, 2012 are substantially made up of receivables with customers in the oil and gas industry and are subject to normal industry credit risks. Trade accounts receivable reported in the Company's balance sheet are aged at or under ninety days. The Company historically has not experienced any collection issues with its crude oil customers. None of the Company's receivables are impaired as at December 31, 2012. The maximum credit risk exposure associated with accounts receivable is the total carrying value.

#### **b) Liquidity risk**

The Company's approach to managing liquidity risk is to have sufficient cash and/or credit facilities to meet its obligations when due. Management typically forecasts cash flows for a period of 12 to 36 months to identify any financing requirements. Liquidity is managed through daily and longer-term cash, debt and equity management strategies. These include estimating future cash generated from operations based on reasonable production and pricing assumptions, estimating future discretionary and non-discretionary capital expenditures and assessing the amount of equity or debt financing available. In the current year the Company has completed a corporate acquisition and maintained a robust capital program. The Company's Debentures are unsecured and subordinated with expiry on June 30, 2016.

The following are the contractual maturities of financial liabilities at December 31, 2012:

|                                                | Less than 1<br>year | 2-3<br>Years | 4-5<br>Years | Thereafter | Total      |
|------------------------------------------------|---------------------|--------------|--------------|------------|------------|
| Accounts payable and accrued liabilities       | \$ 113,730          | \$ -         | \$ -         | \$ -       | \$ 113,730 |
| SARs payable                                   | 2,386               | 511          | -            | -          | 2,897      |
| Current income tax payable <sup>(1)</sup>      | 23,522              | -            | -            | -          | 23,522     |
| Equity tax payable                             | 1,572               | 1,573        | -            | -          | 3,145      |
| Credit Facility <sup>(2)</sup>                 | -                   | 9,100        | -            | -          | 9,100      |
| Interest on the credit facility <sup>(2)</sup> | 273                 | 273          | -            | -          | 546        |
| Debentures <sup>(2)</sup>                      | -                   | -            | 85,434       | -          | 85,434     |
| Interest on Debentures <sup>(2)</sup>          | 4,485               | 8,970        | 2,243        | -          | 15,698     |
| Total                                          | \$ 145,968          | \$ 20,427    | \$ 87,677    | \$ -       | \$ 254,072 |

<sup>(1)</sup> Net of withholding tax receivable

<sup>(2)</sup> Balances denominated in Canadian dollars have been translated at the December 31, 2012 exchange rate.

The following are the contractual maturities of financial liabilities at December 31, 2011:

|                                          | Less than 1<br>year | 2-3<br>Years | 4-5<br>Years | Thereafter | Total      |
|------------------------------------------|---------------------|--------------|--------------|------------|------------|
| Accounts payable and accrued liabilities | \$ 68,398           | \$ -         | \$ -         | \$ -       | \$ 68,398  |
| SARs payable                             | 1,328               | 502          | -            | -          | 1,830      |
| Debentures <sup>(1)</sup>                | -                   | -            | 83,581       | -          | 83,581     |
| Interest on Debentures <sup>(1)</sup>    | 4,463               | 8,925        | 6,693        | -          | 20,081     |
| Total                                    | \$ 74,189           | \$ 9,427     | \$ 90,274    | \$ -       | \$ 173,890 |

<sup>(1)</sup> Balances denominated in Canadian dollars have been translated at the December 31, 2011 exchange rate.

### c) Commodity price risk

The Company is exposed to commodity price movements as part of its operations, particularly in relation to the prices received for its oil production. Crude oil is sensitive to numerous worldwide factors, many of which are beyond the Company's control. Changes in global supply and demand fundamentals in the crude oil market and geopolitical events can significantly affect crude oil prices. Consequently, these changes could also affect the value of the Company's properties, the level of spending for exploration and development and the ability to meet obligations as they come due. The Company's oil production is sold under short-term contracts, exposing it to the risk of near-term price movements.

As at December 31, 2012, The Company entered into a fixed and swap contract which manages its exposure to fluctuations in the price of crude oil.

The following is a summary of the Brent crude oil risk management contracts in place as at December 31, 2012:

| Oil Period Hedged                  | Type        | Volume bbls/d | Price (\$/bbl) |
|------------------------------------|-------------|---------------|----------------|
| September 1- December 31, 2012     | Fixed price | 2000 bbl/d    | \$111.70       |
| November 1, 2012 to March 31, 2013 | Collar      | 2000 bbl/d    | \$100 to \$123 |

The table below summarizes (gain) loss on the commodity risk management contracts:

| For the year ended December 31,                  | 2012     | 2011   |
|--------------------------------------------------|----------|--------|
| Realized (gain)loss on risk management contracts | \$ (234) | \$ 432 |
| Unrealized gain on risk management contracts     | (90)     | -      |
| Total                                            | \$ (324) | \$ 432 |

As at December 31, 2012, Parex had committed to the future sale of 180,000 barrels of oil with a collar of \$100/bbl to \$123/bbl. The following sensitivity shows the resulting unrealized (gain) loss and impact on income before tax for the oil hedged contract if Brent oil price were to increase/ decrease by \$10/bbl as at December 31, 2012.

| Brent Price         | Impact on Income before tax for the year ended<br>December 31, 2012 |                    |        |
|---------------------|---------------------------------------------------------------------|--------------------|--------|
|                     | Increase of 10/bbl                                                  | Decrease of 10/bbl |        |
| Oil hedged contract | Year end                                                            | \$ (506)           | \$ 410 |
| Total               |                                                                     | \$ (506)           | \$ 410 |

Subsequent to December 31, 2012 Parex entered into the following contracts:

| Oil Period Hedged               | Type        | Volume bbls/d | Price/bbl |
|---------------------------------|-------------|---------------|-----------|
| January 1, 2013 – June 30, 2013 | Fixed price | 2000 bbl/d    | \$108.50  |
| April 30, 2013 – June 30, 2013  | Fixed Price | 2000 bbl/d    | \$110.10  |

**d) Foreign currency risk**

The Company is exposed to foreign currency risk as various portions of its cash balances are held in Canadian dollars (Cdn\$), Colombian pesos (COP\$) and Trinidad & Tobago dollars (TT\$) while its committed capital expenditures are expected to be primarily denominated in US dollars.

Associated with the Cdn\$85.0 million of convertible debentures, on December 30, 2012, the Company entered into a Cross Currency Interest Rate Swap (“CCIRS”) with two financial institutions who are members of the Company’s credit facility. Under the terms of the CCIRS, The US dollar amount of the debenture was fixed for purposes of interest and principal repayment at a notional amount of \$85.7 million.

The following is a summary of the CCIRS contract in place as at December 31, 2012:

|                                   | Type | Receive Notional<br>Principal (Cdn\$) | Fixed annual rate<br>(Cdn%) | Pay Notional<br>Principal (US\$) | Fixed annual rate<br>(US%) |
|-----------------------------------|------|---------------------------------------|-----------------------------|----------------------------------|----------------------------|
| December 30, 2012 – June 30, 2016 | Swap | 85,000,000                            | 5.25%                       | 85,685,565                       | 4.45%                      |

The table below summarizes the loss on the CCIRS contract:

| For the year ended December 31,   | 2012   | 2011 |
|-----------------------------------|--------|------|
| Unrealized loss on CCIRS contract | \$ 992 | -    |
| Total                             | \$ 992 | \$ - |

The following sensitivity show the resulting unrealized (gain) loss and impact on income before tax for the CCIRS contract for the respective changes in the period end foreign exchange rates at December 31, 2012.

| Exchange Rate | Impact on Income before tax for the year ended<br>December 31, 2012 |                     |
|---------------|---------------------------------------------------------------------|---------------------|
|               | Increase of 5 cents                                                 | Decrease of 5 cents |
|               | \$ (4,300)                                                          | \$ 4,300            |
| Total         | \$ (4,300)                                                          | \$ 4,300            |

**e) Interest rate risk**

The Company is exposed to interest rate risk in relation to interest expense on its credit facility. Currently the Company has not entered into any agreements to manage this risk. The following sensitivity shows the resulting impact on income before tax if the interest expense increased /decreased by 1% as at December 31, 2012.

| Interest rate | Impact on Income before tax for the year ended<br>December 31, 2012 |                |
|---------------|---------------------------------------------------------------------|----------------|
|               | Increase of 1%                                                      | Decrease of 1% |
|               | \$ 32                                                               | \$ (32)        |
| Total         | \$ 32                                                               | \$ (32)        |

## 24. Segmented Information

The Company has foreign subsidiaries and the following segmented information is provided:  
For the year ended December 31, 2012

|                                                        | Canada |          | Colombia |          | Trinidad & Tobago |          | Total      |
|--------------------------------------------------------|--------|----------|----------|----------|-------------------|----------|------------|
| Oil sales                                              | \$     | -        | \$       | 523,514  | \$                | -        | \$ 523,514 |
| Royalties                                              |        | -        |          | (35,890) |                   | -        | (35,890)   |
| Revenue                                                |        | -        |          | 487,624  |                   | -        | 487,624    |
| Risk management contracts                              |        | (668)    |          | -        |                   | -        | (668)      |
|                                                        |        | (668)    |          | 487,624  |                   | -        | 486,956    |
| Expenses                                               |        |          |          |          |                   |          |            |
| Production                                             |        | -        |          | 36,286   |                   | -        | 36,286     |
| Transportation                                         |        | -        |          | 91,397   |                   | -        | 91,397     |
| Purchased oil                                          |        | -        |          | 37,158   |                   | -        | 37,158     |
| General and administrative                             |        | 8,088    |          | 19,521   |                   | 3,409    | 31,018     |
| Transaction costs                                      |        | -        |          | 1,109    |                   | -        | 1,109      |
| Share-based compensation                               |        | 6,684    |          | 986      |                   | 445      | 8,115      |
| Depletion, depreciation and amortization               |        | 867      |          | 180,243  |                   | 39       | 181,149    |
| Foreign exchange loss (gain)                           |        | 1,382    |          | 1,081    |                   | (17)     | 2,446      |
| Exploration and evaluation impairment                  |        | -        |          | -        |                   | 23,511   | 23,511     |
|                                                        |        | 17,021   |          | 367,781  |                   | 27,387   | 412,189    |
| Finance income                                         |        | (1,005)  |          | (2,357)  |                   | 963      | (2,399)    |
| Finance expense                                        |        | 2,738    |          | 332      |                   | 22       | 3,092      |
|                                                        |        | 1,733    |          | (2,025)  |                   | 985      | 693        |
| Net income (loss) before taxes                         |        | (19,422) |          | 121,868  |                   | (28,372) | 74,074     |
| Current and equity tax expense                         |        | -        |          | 42,999   |                   | -        | 42,999     |
| Deferred tax expense                                   |        | -        |          | (8,847)  |                   | -        | (8,847)    |
| Net income (loss)                                      | \$     | (19,422) | \$       | 87,716   | \$                | (28,372) | \$ 39,922  |
| Capital assets (end of year)                           | \$     | 2,610    | \$       | 547,337  | \$                | 61,857   | \$ 611,804 |
| Capital expenditures, excluding corporate acquisitions | \$     | 246      | \$       | 227,558  | \$                | 39,884   | \$ 267,688 |
| Total assets (end of year)                             | \$     | 9,216    | \$       | 735,497  | \$                | 76,488   | \$ 821,201 |

For the year ended December 31, 2011

|                                                        | Canada |         | Colombia |          | Trinidad & Tobago |         | Total      |
|--------------------------------------------------------|--------|---------|----------|----------|-------------------|---------|------------|
| Oil sales                                              | \$     | -       | \$       | 171,170  | \$                | -       | \$ 171,170 |
| Royalties                                              |        | -       |          | (13,929) |                   | -       | (13,929)   |
| Revenue                                                |        | -       |          | 157,241  |                   | -       | 157,241    |
| Risk management contracts                              |        | (432)   |          | -        |                   | -       | (432)      |
|                                                        |        | (432)   |          | 157,241  |                   | -       | 156,809    |
| Expenses                                               |        |         |          |          |                   |         |            |
| Production                                             |        | -       |          | 11,219   |                   | -       | 11,219     |
| Transportation                                         |        | -       |          | 27,604   |                   | -       | 27,604     |
| General and administrative                             |        | 7,024   |          | 6,858    |                   | 1,899   | 15,781     |
| Transaction costs                                      |        | -       |          | 2,127    |                   | -       | 2,127      |
| Share-based compensation                               |        | 5,318   |          | 779      |                   | 381     | 6,478      |
| Depletion, depreciation and amortization               |        | 598     |          | 53,101   |                   | 73      | 53,772     |
| Foreign exchange loss (gain)                           |        | (2,649) |          | (499)    |                   | 2       | (3,146)    |
|                                                        |        | 10,291  |          | 101,189  |                   | 2,355   | 113,835    |
| Finance income                                         |        | (901)   |          | (274)    |                   | (189)   | (1,364)    |
| Finance expense                                        |        | (725)   |          | 517      |                   | 44      | (164)      |
|                                                        |        | (1,626) |          | 243      |                   | (145)   | (1,528)    |
| Net income (loss) before taxes                         |        | (9,097) |          | 55,809   |                   | (2,210) | 44,502     |
| Current and equity tax expense                         |        | -       |          | 424      |                   | -       | 424        |
| Deferred tax expense                                   |        | -       |          | 28,443   |                   | -       | 28,443     |
| Net income (loss)                                      | \$     | (9,097) | \$       | 26,942   | \$                | (2,210) | \$ 15,635  |
| Capital assets (end of year)                           | \$     | 3,231   | \$       | 388,449  | \$                | 44,891  | \$ 436,571 |
| Capital expenditures, excluding corporate acquisitions | \$     | 2,594   | \$       | 132,490  | \$                | 14,559  | \$ 149,643 |
| Total assets (end of year)                             | \$     | 54,356  | \$       | 541,439  | \$                | 64,382  | \$ 660,177 |

In Colombia in the years 2012 and 2011 the majority of oil sales are with four customers in the oil and gas industry and are subject to normal industry credit risks.

## 25. Commitments

### a) Colombia

At December 31, 2012 guarantees in place with ANH are in the form of issued letters of credit totaling \$50.0 million (December 31, 2011 - \$45 million) to support the exploration work commitments in respect of the 15 blocks in Colombia.

EDC has provided the Company's bank with performance security guarantees to support 100 percent of the letters of credit issued on behalf of Parex. The EDC guarantees have been secured by a general security agreement issued by Parex in favour of EDC. The letters of credit issued to the ANH are reduced to reflect completed work on an ongoing basis.

The value of the Company's exploration commitments as at December 31, 2012 in respect of the Colombia blocks are estimated to be as follows:

| (000s)     |           |
|------------|-----------|
| 2013       | 29,250    |
| 2014       | 11,000    |
| Thereafter | 22,045    |
|            | \$ 62,295 |

### b) Central Range Blocks and Moruga Block (Trinidad & Tobago)

The Company's share of exploration and financial obligation in respect of the Central Range Blocks Production Sharing Contracts includes the remaining carry for its partners and minor annual financial obligations in the Moruga block remaining at December 31, 2012, are estimated to be as follows:

| (000s)     | Exploration | Other    | Total     |
|------------|-------------|----------|-----------|
| 2013       | 16,747      | 2,465    | 19,212    |
| 2014       | -           | 1,853    | 1,853     |
| Thereafter | -           | -        | -         |
|            | \$ 16,747   | \$ 4,318 | \$ 21,065 |

In Trinidad & Tobago, under the initial exploration phase of the Central Range Block PSCs the joint ventures' remaining work commitment is to drill an exploration well to 12,000 feet and acquire 340 kilometers of 2D seismic. The obligations under the PSCs are to perform the exploration work commitments, irrespective of actual cost. In the event of a default by the Company's joint venture partner Niko Resources Ltd. ("Niko"), the joint venture agreement provides that Niko's working interest shall vest in Parex.

These amounts do not include production bonuses and other payments that will vary depending on production levels due to the uncertainty of their amount and timing.

### c) Operating leases

In the normal course of business, Parex has entered into arrangements and incurred obligations that will impact the Company's future operations and liquidity. These commitments include leases for office space and accommodations.

The existing minimum lease payments for office space and accommodations at December 31, 2012 are as follows:

| (000s)                    | Total    | 2013     | 2014   | 2015   | 2016 |
|---------------------------|----------|----------|--------|--------|------|
| Office and accommodations | \$ 1,860 | \$ 1,145 | \$ 575 | \$ 140 | \$ - |

#### **d) Drilling rig contracts**

The Company has entered into contracts for drilling rigs in Colombia and Trinidad & Tobago on terms consistent with normal industry practice for a minimum period of time. The drilling rig commitments have been entered into to fulfill the exploration drilling commitments in both Colombia and Trinidad and Tobago as described above along with the companies 2013 budgeted work program. The commitment amount has been calculated above in points a) and b).

## **26. Contingencies**

As announced by Parex on April 12, 2012, Parex and its wholly owned subsidiaries Parex Resources (Bermuda) Ltd. ("Parex Bermuda") and Ramshorn International, Limited ("Ramshorn") have been named as defendants along with Nabors Industrial Ltd. and Nabors Global Holdings II Limited in a lawsuit (the "Lawsuit") filed in the 61st Judicial District Court of Harris County, Texas (the "Texas Court") by a Texas based private company (the "Plaintiff"). The Lawsuit relates to a share purchase agreement entered into by the Plaintiff and a third party seller (the "Seller") (prior to the agreement entered into by Parex Bermuda and the Seller for the purchase of Ramshorn) respecting the proposed purchase by the Plaintiff of the shares of Ramshorn, which prior agreement the Plaintiff claims was improperly terminated by the Seller. The Plaintiff is seeking specific performance remedies or in the alternative, actual, consequential, and exemplary damages. Each of Parex, Parex Bermuda and Ramshorn specially appeared in the Lawsuit to challenge the jurisdiction of the Texas Court and to seek dismissal of the claims against them.

A hearing on the jurisdictional aspects of the case took place on November 19 and 20, 2012 and the decision of the Texas Court on these jurisdictional matters has now been received. The Texas Court found that it does not have jurisdiction over Parex Bermuda and ordered that all of the Plaintiff's claims against Parex Bermuda be dismissed. The Texas Court overruled Parex and Ramshorn's jurisdictional challenges such that the Plaintiff's claims against Parex and Ramshorn have not been dismissed. Parex and Ramshorn have filed a Notice of Appeal of the Texas Court's rulings in this regard. Additionally, the Texas Court has entered an order staying all discovery between the Plaintiff and Parex/Ramshorn pending the outcome of the appeal on these jurisdictional matters. Parex and Ramshorn believe that the Lawsuit and the Plaintiff's claims against it are baseless and without merit and will continue to vigorously defend the Lawsuit, including by way of appealing the Texas Court's recent jurisdictional rulings against Parex and Ramshorn.

Based on input from counsel received to date and on managements' understanding of the facts, risks and uncertainties at the date of authorization of these financial statements management has determined it is not more likely than not that an economic outflow will occur given these uncertainties.

## **27. Related Party Disclosures**

#### **a) Significant Subsidiaries**

The consolidated financial statements include the financial statements of Parex Resources Inc. at December 31, 2012. Transactions between subsidiaries are eliminated upon consolidation. The Company did not have any material related party transactions with entities outside the consolidated group for the years ended December 31, 2012 and 2011.

#### **b) Compensation of Key Management Personnel**

Key management personnel compensation, including directors, is as follows:

| For the year ended December 31,             |    | 2012  |    | 2011  |
|---------------------------------------------|----|-------|----|-------|
| Salaries, directors fees and other benefits | \$ | 2,754 | \$ | 2,276 |
| Stock-based compensation <sup>(1)</sup>     |    | 2,883 |    | 1,901 |
|                                             | \$ | 5,637 | \$ | 4,177 |

<sup>(1)</sup> Non-cash stock-based compensation expense for the year.

Key management personnel are comprised of the Company's directors and five executive officers. As at December 31, 2012, there is a \$4.5 million commitment (December 31, 2011 \$3.7 million) relating to change of control or termination of employment of the key management personnel.

## 28. Subsequent Event

Subject to the approval of the Toronto Stock Exchange (TSX) and the Company's credit facility bank syndicate, Parex intends to commence a normal course issuer bid (the "Bid") to purchase, from time to time, as it considers advisable, common shares on the open market through the facilities of the TSX. The price that Parex will pay for any common shares under the Bid will be the prevailing market price on the TSX at the time of such purchase. Common shares acquired under the Bid will be cancelled. The Bid will terminate one year from the date of acceptance by the TSX of the Form 12 Notice of Intention to Make a Normal Course Issuer Bid to be filed by the Company with the TSX or such earlier time as the Bid is completed or terminated at the option of Parex.

## DIRECTORS

**Norman F. McIntyre**  
*Chairman of the Board*

**Curtis D. Bartlett**

**John F. Bechtold**

**Robert J. Engbloom**

**Wayne K. Foo**

**Ron D. Miller**

**W. A. (Alf) Peneycad**

**Paul D. Wright**

## OFFICERS AND SENIOR EXECUTIVES

**Wayne K. Foo**  
*President, Chief Executive Officer*

**David R. Taylor**  
*Executive VP Exploration & Business  
Development*

**Stu R. Davie**  
*VP Human Resources & Administration*

**Barry B. Larson**  
*Chief Operating Officer*

**Kenneth G. Pinsky**  
*Chief Financial Officer*

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## AUDITORS

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Calgary, Alberta

## LEGAL COUNSEL

**Burnet, Duckworth & Palmer LLP**  
Calgary, Alberta

## TRANSFER AGENT AND REGISTRAR

**Valiant Trust Company**  
Calgary, Alberta

## RESERVES EVALUATORS

**GLJ Petroleum Consultants Ltd.**  
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## INVESTOR RELATIONS

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## ABBREVIATIONS

### Oil and Natural Gas Liquids

bbls  
mbbls  
mmmbbls  
NGLs  
bbls/d  
mbbls/d

barrels  
one thousand barrels  
one million barrels  
natural gas liquids  
barrels of oil per day  
one thousand barrels per day

### Other

BOE or boe  
mboe  
mmboe  
bfpd  
boe/d  
WTI  
Brent

barrel of oil equivalent, using the conversion factor of 6 Mcf: 1 bbl  
one thousand barrels of oil equivalent  
one million barrels of oil equivalent  
barrels of fluid per day  
barrels of oil equivalent per day  
West Texas Intermediate  
Brent Ice

"BOEs" may be misleading, particularly if used in isolation. A BOE conversion ratio of nine thousand cubic feet of natural gas to one barrel of oil equivalent (6 mcf: 1 bbl) is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.