

# PEYTO

**Exploration & Development Corp.**

# 2012



*Annual Report*

## Chairman's Message

This past year marks Peyto's 14th year in the business of finding oil and gas. What a profitable 14 years it has been. Since inception, our team has consistently delivered results that have led the industry. Our ability to execute our strategy has built high quality energy assets and delivered exceptional returns to our shareholders.

A few months ago, our President and CEO, Darren Gee, was recognized by Alberta Oil as "CEO of the Year" for 2012. As a large shareholder and founder of Peyto, it is very satisfying to see what Darren and the team have accomplished. When I stepped down in 2007, some suggested that Peyto's day had come and gone - that I was selling all of my shares and leaving the shareholders high and dry. In fact, it was the opposite. I felt that eight years at the helm was enough for me and that some new blood was in order. I knew that I was stepping away at a time when Peyto's assets had never been stronger and the talent pool behind me was very deep. When I announced my retirement in August 2006, I said the following: "I take a lot of pride in knowing that we have not only built great assets but we have also empowered future leaders. I'm confident and excited about Peyto's future." To be a truly great company, you should not be reliant on any one person for your success. You should be able to deliver top-tier results consistently and do so without compromising the long term health of the enterprise. Under Darren's leadership, Peyto continues to be one of Canada's truly great companies. I am very happy that I continue to be a large shareholder of Peyto.

In my time as Peyto's President and CEO I prepared slides that compared Peyto's operational performance to its industry peers. These comparisons of our actual results to other industry participants had two effects. First, it objectively focused the Peyto team on how we were doing relative to others in the industry and second, it offended those whose results were shown in my slides because it showed their actual results did not measure up. I still think these comparisons are a very important tool, no different than the feedback you get when you shoot an arrow at a target and then see where the arrow actually ended up. When I look at Peyto's results for 2012 and compare them to the top stories in the North American energy space, I'm very pleased with what the team has been able to achieve. I think it is reasonable to suggest that 2012 was the bottom for the natural gas sector. During the year Peyto was faced with a stiff headwind and still manage to gain substantial ground for its shareholders. I think as this headwind dies down the shareholders of Peyto will see even more clearly how well the team is performing.

At Peyto we do not rely on hope and hype to move us forward; we rely on our skills and ability and with this we create real value for our shareholders. I'm very pleased to report that our company is stronger than ever and our outlook continues to look excellent, just the way we planned it.

Don T. Gray  
Chairman of the Board

## Report from the President

Peyto Exploration & Development Corp. (“Peyto” or the “Company”) is pleased to report operating and financial results for the fourth quarter and the 2012 fiscal year. Peyto grew production and reserves per share to record levels in 2012 while delivering a 76% operating margin<sup>1</sup> and a 23% profit margin<sup>2</sup>. An 8% return on capital and an 8% return on equity were achieved despite historically low natural gas prices. Highlights for 2012 include:

- **Production per share up 17%.** Annual production increased 26% or 17% per share to 267 MMCFe/d (44,527 boe/d) in 2012 from 213 MMCFe/d (35,465 boe/d) in 2011. Q4 2012 production was also up 26% to 49,754 boe/d.
- **Reserves per share up 15%.** Proved Producing (“PP”), Total Proved (“TP”) and Proved plus Probable Additional (“P+P”) reserves increased 24%, 23%, and 22% (15%, 14%, and 13% per share) to 0.9, 1.7, and 2.4 TCFe, respectively.
- **Reduced cash costs 22%.** Royalties, operating costs, transportation, G&A and interest expense totaled \$1.05/MCFe (\$6.30/boe) in 2012 down from \$1.35/MCFe (\$8.10/boe) in 2011. Industry leading operating costs were just \$0.32/MCFe (\$1.92/boe) in 2012.
- **Funds from Operations per share of \$2.19.** Generated \$309 million in Funds from Operations (“FFO”) in 2012, down 7% from \$2.36/share in 2011 despite a 27% drop in realized commodity prices.
- **Capital investments up 63%.** Invested a record \$452 million to build 25,700 boe/d at a cost of \$17,600/boe/d and invested \$166 million to acquire Open Range Energy Corp. (“Open Range”), which produced 4,300 boe/d at year end, for a cost of \$38,600/boe/d. Average cost to add new production was \$20,600/boe/d.
- **P+P FD&A half the field netback.** All in FD&A cost for PP, TP and P+P reserves was \$2.22/MCFe, \$2.04/MCFe and \$1.68/MCFe (\$10.07/boe), respectively including changes in Future Development Capital (“FDC”), while the average field netback was \$3.46/MCFe (\$20.75/boe).
- **NAV per share of \$34.** Net Asset Value or the Net Present Value per share, debt adjusted (discounted at 5%) of the P+P reserves was \$20/share of developed reserves and \$14/share of undeveloped reserves.
- **Earnings of \$0.67/share and dividends of \$0.72/share.** A total of \$94 million in earnings were generated and \$102 million in dividends were paid to shareholders. Cumulative dividend/distribution payments made by Peyto to date total \$1.3 Billion (\$12.31/share).

### 2012 in Review

The year 2012 was an historic year for Peyto. With the largest capital program in the Company’s history, coupled with its first major corporate acquisition, Peyto added a record 30,000 boe/d of new production. Peyto again led the industry as the lowest cost producer and with this advantage was able to generate a 23% profit margin despite natural gas prices that dropped to their lowest level in Company history. In addition to growing production and reserves per share, Peyto increased its ownership and control of processing infrastructure by 100 mmcf/d or 30%, ensuring this low cost advantage can continue in the future. Peyto’s land position in the Alberta Deep Basin also grew by more than 30% resulting in the addition of 1.6 new booked horizontal drilling locations for every well drilled in 2012. Production revenues were maximized with the installation of Peyto’s enhanced NGL extraction facilities at the Company’s Oldman gas plant. Peyto’s profitable, returns driven strategy once again delivered an attractive total return on shareholder’s capital in 2012.

(1) Operating Margin is defined as Funds from Operations divided by Revenue before Royalties but including realized hedging gains (losses).

(2) Profit Margin is defined as Net Earnings for the year divided by Revenue before Royalties but including realized hedging gains (losses).

Natural gas volumes recorded in thousand cubic feet (mcf) are converted to barrels of oil equivalent (boe) using the ratio of six (6) thousand cubic feet to one (1) barrel of oil (bbl). Natural gas liquids and oil volumes in barrel of oil (bbl) are converted to thousand cubic feet equivalent (mcf) using a ratio of one (1) barrel of oil to six (6) thousand cubic feet. This could be misleading if used in isolation as it is based on an energy equivalency conversion method primarily applied at the burner tip and does not represent a value equivalency at the wellhead.

|  | 3 Months Ended December 31 |             | %<br>Change | 12 Months Ended December 31 |             | %<br>Change |
|--|----------------------------|-------------|-------------|-----------------------------|-------------|-------------|
|  | 2012                       | 2011        |             | 2012                        | 2011        |             |
| <b>Operations</b>  |                            |             |             |                             |             |             |
| Production   |                            |             |             |                             |             |             |
| Natural gas (mcf/d)  | 266,808                    | 212,715     | 25%         | 238,490                     | 189,653     | 26%         |
| Oil & NGLs (bbl/d)   | 5,286                      | 3,947       | 34%         | 4,778                       | 3,856       | 24%         |
| Thousand cubic feet equivalent (mcf/d @ 1:6)                               | 298,522                    | 236,394     | 26%         | 267,160                     | 212,789     | 26%         |
| Barrels of oil equivalent (boe/d @ 6:1)                                    | 49,754                     | 39,399      | 26%         | 44,527                      | 35,465      | 26%         |
| Product prices   |                            |             |             |                             |             |             |
| Natural gas (\$/mcf)   | 3.45                       | 4.21        | (18)%       | 3.23                        | 4.47        | (28)%       |
| Oil & NGLs (\$/bbl)  | 73.01                      | 88.04       | (17)%       | 73.92                       | 81.67       | (9)%        |
| Operating expenses (\$/mcf)  | 0.31                       | 0.35        | (11)%       | 0.32                        | 0.35        | (9)%        |
| Transportation (\$/mcf)  | 0.11                       | 0.12        | (8)%        | 0.12                        | 0.13        | (8)%        |
| Field netback (\$/mcf)   | 3.62                       | 4.32        | (16)%       | 3.46                        | 4.46        | (22)%       |
| General & administrative expenses (\$/mcf)                                 | 0.02                       | 0.05        | (60)%       | 0.04                        | 0.06        | (33)%       |
| Interest expense (\$/mcf)  | 0.32                       | 0.35        | (9)%        | 0.26                        | 0.28        | (7)%        |
| <b>Financial (\$000, except per share)</b>                                 |                            |             |             |                             |             |             |
| Revenue  | 120,310                    | 114,263     | 5%          | 411,400                     | 424,560     | (3)%        |
| Royalties  | 9,205                      | 9,870       | (7)%        | 30,754                      | 41,064      | (25)%       |
| Funds from operations  | 90,078                     | 80,410      | 12%         | 308,865                     | 314,622     | (2)%        |
| Funds from operations per share  | 0.62                       | 0.60        | 3%          | 2.19                        | 2.36        | (7)%        |
| Total dividends  | 26,178                     | 24,245      | 8%          | 101,593                     | 96,068      | 6%          |
| Total dividends per share  | 0.18                       | 0.18        | -           | 0.72                        | 0.72        | -           |
| Payout ratio (%)   | 28                         | 30          | (7)%        | 33                          | 31          | 6%          |
| Earnings   | 25,823                     | 26,036      | (1)%        | 93,951                      | 128,183     | (27)%       |
| Earnings per share   | 0.18                       | 0.19        | (5)%        | 0.67                        | 0.96        | (30)%       |
| Capital expenditures   | 156,847                    | 94,688      | 66%         | 617,985                     | 379,061     | 63%         |
| Weighted average shares outstanding  | 145,449,651                | 133,913,301 | 9%          | 141,093,829                 | 133,196,301 | 6%          |
| <b>As at December 31</b>   |                            |             |             |                             |             |             |
| Net debt (before future compensation expense and unrealized hedging gains) |                            |             |             | 662,461                     | 465,391     | 42%         |
| Shareholders' equity   |                            |             |             | 1,210,067                   | 1,015,708   | 19%         |
| Total assets   |                            |             |             | 2,203,524                   | 1,800,252   | 22%         |

| (\$000)  | 3 Months Ended December 31 |          | 12 Months Ended December 31 |         |
|--|----------------------------|----------|-----------------------------|---------|
|  | 2012                       | 2011     | 2012                        | 2011    |
| Cash flows from operating activities                   | 78,878                     | 85,592   | 284,309                     | 289,995 |
| Change in non-cash working capital                     | 4,457                      | (19,139) | 12,920                      | 3,085   |
| Change in provision for performance based compensation | (7,712)                    | (8,739)  | (2,819)                     | (1,154) |
| Income tax paid on account of 2003 reassessment        | 1,868                      | -        | 1,868                       | -       |
| Performance based compensation                         | 12,587                     | 22,696   | 12,587                      | 22,696  |
| Funds from operations                                  | 90,078                     | 80,410   | 308,865                     | 314,622 |
| Funds from operations per share                        | 0.62                       | 0.60     | 2.19                        | 2.36    |

(1) Funds from operations - Management uses funds from operations to analyze the operating performance of its energy assets. In order to facilitate comparative analysis, funds from operations is defined throughout this report as earnings before performance based compensation, non-cash and non-recurring expenses. Management believes that funds from operations is an important parameter to measure the value of an asset when combined with reserve life. Funds from operations is not a measure recognized by Canadian generally accepted accounting principles ("GAAP") and does not have a standardized meaning prescribed by GAAP. Therefore, funds from operations, as defined by Peyto, may not be comparable to similar measures presented by other issuers, and investors are cautioned that funds from operations should not be construed as an alternative to net earnings, cash flow from operating activities or other measures of financial performance calculated in accordance with GAAP. Funds from operations cannot be assured and future dividends may vary.

## The Peyto Strategy

The Peyto strategy has long been one of building enduring shareholder value by focusing on generating the maximum possible returns on invested capital. This disciplined model has been tested during times of high commodity prices and record industry activity levels as well as low commodity prices and low activity levels. As with any commodity business, a focus on keeping costs low at all times yields significant advantages over the competition and contributes to generating the best return on the capital invested. Peyto has successfully executed this strategy, aggressively investing capital during opportunistic periods in the cycle while at other times restricting investment, but at all times focusing on cost control. In total, over \$2.9 billion has been invested in developing producing reserves that to date have sold for over 1.75 times the total average cost to develop and produce them. The following table illustrates the profitability of the Peyto strategy with the average sales price far exceeding Peyto's historic costs of development and production.

| (\$/Mcf)                     | 2002          | 2003          | 2004          | 2005          | 2006          | 2007          | 2008          | 2009          | 2010          | 2011          | 2012            |
|------------------------------|---------------|---------------|---------------|---------------|---------------|---------------|---------------|---------------|---------------|---------------|-----------------|
| Sales Price                  | \$4.78        | \$7.21        | \$7.32        | \$8.87        | \$8.76        | \$8.93        | \$9.54        | \$6.75        | \$6.15        | \$5.47        | <b>\$4.21</b>   |
| Cost to develop <sup>1</sup> | (\$0.84)      | (\$1.33)      | (\$1.60)      | (\$2.39)      | (\$2.95)      | (\$2.11)      | (\$2.88)      | (\$2.26)      | (\$2.10)      | (\$2.12)      | <b>(\$2.22)</b> |
| Cost to produce <sup>2</sup> | (\$1.59)      | (\$2.16)      | (\$2.21)      | (\$2.76)      | (\$2.66)      | (\$2.75)      | (\$3.01)      | (\$1.75)      | (\$1.63)      | (\$1.35)      | <b>(\$1.05)</b> |
| <b>"Profit"</b>              | <b>\$2.35</b> | <b>\$3.72</b> | <b>\$3.51</b> | <b>\$3.72</b> | <b>\$3.15</b> | <b>\$4.07</b> | <b>\$3.65</b> | <b>\$2.74</b> | <b>\$2.42</b> | <b>\$2.00</b> | <b>\$0.94</b>   |
| Payout                       |               | \$1.36        | \$2.28        | \$2.81        | \$3.47        | \$3.92        | \$4.25        | \$4.03        | \$3.37        | \$1.24        | <b>\$1.04</b>   |

1. Cost to develop is the PDP FD&A

2. Cost to produce is the total cash costs including Royalties, Operating costs, Transportation, G&A and Interest.

3. Payout is the annual distribution or dividend in \$/mcf of production.

In total, over \$1.3 billion in profit has been returned to shareholders. As illustrated above, these payments have come from the ongoing profitable development and production of reserves. The success and sustainability of the Peyto strategy continues to be evident.

## Capital Expenditures

Peyto deployed a record amount of capital in 2012, with an exploration and development program comprising \$452 million and a corporate acquisition costing \$166 million, after associated dispositions.

The 2012 exploration and development program was 19% larger than the 2011 program making it the largest in the Company's 14 year history. In total, \$338 million was invested into the drilling and completion of 86 gross (76 net) horizontal wells, while \$47 million was invested into pipelines and wellsite equipment to bring those wells on production. An additional \$11 million was invested into expanding Peyto's natural gas processing capacity while \$26 million was invested in the Oldman plant enhanced liquids extraction facility.

Peyto spent \$29 million adding to its extensive inventory of profitable, high quality drilling locations with a minor property acquisition in the Sundance area and the successful purchase of 72 new sections of crown land at an average price of \$232/acre.

On August 14, 2012, Peyto closed the acquisition of Open Range for an effective total capital cost of \$187.2 million. The acquisition was conducted pursuant to a plan of arrangement with Peyto exchanging 0.0723 Peyto shares for each Open Range share (5.4 million Peyto shares total) and assuming \$75 million in net debt (inclusive of transaction costs). On December 1, 2012, Peyto disposed of some minor non-core Open Range assets in the Waskahigan area for total proceeds of \$20.9 million, which effectively reduced the cost of the acquisition to \$166.3 million.

The following table summarizes the increased capital expenditures for the fourth quarter and 2012 year.

| (\$000)                                      | Three Months ended Dec. 31 |         | Twelve Months ended Dec. 31 |         |
|--|----------------------------|---------|-----------------------------|---------|
|  | 2012                       | 2011    | 2012                        | 2011    |
| Land   | 5,206                      | 5,910   | 10,770                      | 21,002  |
| Seismic                                      | 612                        | 1,245   | 1,741                       | 2,859   |
| Drilling – Exploratory & Development         | 123,778                    | 77,570  | 337,988                     | 279,446 |
| Production Equipment, Facilities & Pipelines | 48,015                     | 10,644  | 84,482                      | 72,079  |
| Acquisition of Open Range Energy Corp.       | -                          | -       | 187,187                     | -       |
| Property Acquisitions                        | 75                         | 527     | 17,841                      | 5,581   |
| Dispositions                                 | (16,969)                   | (1,208) | (17,646)                    | (1,906) |
| (Gains) Losses on Dispositions               | (3,870)                    | (1,126) | (4,378)                     | (1,634) |
| Total Capital Expenditures                   | 156,847                    | 93,562  | 617,985                     | 377,427 |

## Reserves

Peyto was successful growing reserves and values in all categories in 2012. The following table illustrates the change in reserve volumes and Net Present Value (“NPV”) of future cash flows, discounted at 5%, before income tax and using forecast pricing.

|  | As at December 31<br>2012 | 2011    | % Change | % Change, debt<br>adjusted per share <sup>†</sup> |
|--|---------------------------|---------|----------|---|
| <b>Reserves (BCFe)</b>                                 |                           |         |          |   |
| Proved Producing                                       | 945                       | 765     | 24%      | 10%   |
| Total Proved   | 1,659                     | 1,352   | 23%      | 9%  |
| Proved + Probable Additional                           | 2,353                     | 1,935   | 22%      | 8%  |
| <b>Net Present Value (\$millions) Discounted at 5%</b> |                           |         |          |   |
| Proved Producing                                       | \$2,806                   | \$2,624 | 7%       | -8%   |
| Total Proved   | \$4,166                   | \$3,972 | 5%       | -7%   |
| Proved + Probable Additional                           | \$5,732                   | \$5,484 | 5%       | -6%   |

<sup>†</sup>Per share reserves are adjusted for changes in net debt by converting debt to equity using the Dec 31 share price of \$22.99 for 2012 and share price of \$24.39 for 2011. Net Present Values are adjusted for debt by subtracting net debt from the value prior to calculating per share amounts. Note: based on the InSite Petroleum Consultants (“InSite”) report effective December 31, 2012. The InSite price forecast is available at [www.InSitepc.com](http://www.InSitepc.com). For more information on Peyto’s reserves, refer to the Press Releases dated February 13, 2013 and February 14, 2013 announcing the 2012 Year End Reserve Report which is available on the website at [www.peyto.com](http://www.peyto.com). The complete statement of reserves data and required reporting in compliance with NI 51-101 will be included in Peyto’s Annual Information Form to be released in March 2013.

## Performance Ratios

The following table highlights additional annual performance indicators, to be used for comparative purposes, but it is cautioned that in isolation they do not measure investment success.

|                         | 2012   | 2011   | 2010   | 2009   | 2008   | 2007   |
|-------------------------|--------|--------|--------|--------|--------|--------|
| <b>Proved Producing</b> |        |        |        |        |        |        |
| FD&A (\$/mcf)           | \$2.22 | \$2.12 | \$2.10 | \$2.26 | \$2.88 | \$2.11 |
| RLI (yrs)               | 9      | 9      | 11     | 14     | 14     | 13     |
| Recycle Ratio           | 1.6    | 1.9    | 2.0    | 1.8    | 2.3    | 2.8    |
| Reserve Replacement     | 284%   | 230%   | 239%   | 79%    | 110%   | 127%   |
| <b>Total Proved</b>     |        |        |        |        |        |        |
| FD&A (\$/mcf)           | \$2.04 | \$2.13 | \$2.35 | \$1.73 | \$3.17 | \$1.57 |
| RLI (yrs)               | 15     | 16     | 17     | 21     | 17     | 16     |
| Recycle Ratio           | 1.7    | 1.9    | 1.8    | 2.3    | 2.1    | 3.7    |

|  |                |         |         |        |        |        |
|--|----------------|---------|---------|--------|--------|--------|
| <b>Reserve Replacement</b>               | <b>414%</b>    | 452%    | 456%    | 422%   | 139%   | 175%   |
| <b>Future Development Capital (\$MM)</b> | <b>\$1,318</b> | \$1,111 | \$741   | \$446  | \$222  | \$169  |
| <b>Proved plus Probable Additional</b>   |                |         |         |        |        |        |
| <b>FD&amp;A (\$/mcf)</b>                 | <b>\$1.68</b>  | \$1.90  | \$2.19  | \$1.47 | \$3.88 | \$1.56 |
| <b>RLI (yrs)</b>                         | <b>22</b>      | 22      | 25      | 29     | 23     | 21     |
| <b>Recycle Ratio</b>                     | <b>2.1</b>     | 2.1     | 1.9     | 2.8    | 1.7    | 3.7    |
| <b>Reserve Replacement</b>               | <b>527%</b>    | 585%    | 790%    | 597%   | 122%   | 117%   |
| <b>Future Development Capital (\$MM)</b> | <b>\$2,041</b> | \$1,794 | \$1,310 | \$672  | \$390  | \$321  |

- FD&A (finding, development and acquisition) costs are used as a measure of capital efficiency and are calculated by dividing the capital costs for the period, including the change in undiscounted future development capital ("FDC"), by the change in the reserves, incorporating revisions and production, for the same period (eg. Total Proved  $(\$618+\$207)/(1,659-1,352+98) = \$2.04/\text{mcf}$  or  $\$12.24/\text{boe}$ ).
- The reserve life index (RLI) is calculated by dividing the reserves (in boes) in each category by the annualized average production rate in boe/year (eg. Proved Producing  $157,491/(49.754 \times 365) = 8.7$ ). Peyto believes that the most accurate way to evaluate the current reserve life is by dividing the proved developed producing reserves by the actual fourth quarter average production. In Peyto's opinion, for comparative purposes, the proved developed producing reserve life provides the best measure of sustainability.
- The Recycle Ratio is calculated by dividing the field netback per MCFe, before hedging, by the FD&A costs for the period (eg. Proved Producing  $(\$3.46)/\$2.22=1.6$ ). The recycle ratio is comparing the netback from existing reserves to the cost of finding new reserves and may not accurately indicate investment success unless the replacement reserves are of equivalent quality as the produced reserves.
- The reserve replacement ratio is determined by dividing the yearly change in reserves before production by the actual annual production for the year (eg. Total Proved  $((1,659-1,352+98)/98) = 4.14$ ).

## Value Creation/Reconciliation

In order to measure the success of all of the capital invested in 2012, it is necessary to quantify the total amount of value added during the year and compare that to the total amount of capital invested. As requested, Insite has run last year's reserve evaluation with this year's price forecast to remove the change in value attributable to both commodity prices and changing royalties. This approach isolates the value created by the Peyto team from the value created (or lost) by those changes outside of their control. Since the capital investments in 2012 were funded from a combination of cash flow, debt and equity, it is necessary to include the change in debt and the change in shares outstanding to determine if the change in value is truly accretive to shareholders.

At year end 2012, Peyto's estimated net debt had increased by \$196.8 million to \$662.4 million while the number of shares outstanding had increased by 10.3 million shares to 148.7 million shares. The change in debt includes all of the capital expenditures, as well as acquisitions, and the total fixed and performance based compensation paid out during the year.

Based on this reconciliation of changes in BT NPV, the Peyto team was able to create \$963 million of Proved Producing, \$1.36 billion of Total Proved, and \$2.0 billion of Proved plus Probable Additional undiscounted reserve value, with a \$618 million capital investment. The ratio of value creation to capital expenditure is what Peyto refers to as the NPV recycle ratio, which is simply the undiscounted value addition, resulting from the capital program, divided by the capital investment. For 2012, the Proved Producing NPV recycle ratio is 1.6. Refer to the value reconciliation table in the February 14, 2013 Reserve Press Release for additional details on the value creation determination.

## Performance Measures

There are a number of performance measures that are used in the oil and gas industry in an attempt to evaluate how profitably capital has been invested. Peyto believes that the value analysis and reconciliation presented above is the best determination of profitability as it compares the value of what was created relative to what was invested. This is because the NPV of an oil and gas asset takes into consideration the reserves, the production forecast, the future royalties and operating costs, future capital and the current commodity price outlook. In 2012, the Proved Producing NPV recycle ratio was 1.6 times. This means for each dollar invested, the Peyto team was able to create 1.6 new dollars of Proved Producing reserve value. The average NPV Recycle Ratio over the last 5 years is 3.0 times for undiscounted future values or 2.2 times for future values discounted at 10%. The historic NPV recycle ratios are presented in the following table.

| <b>Value Creation</b>          | <b>Dec 31,<br/>2012</b> | Dec 31,<br>2011 | Dec 31,<br>2010 | Dec 31, 2009 | Dec 31, 2008 | Dec 31, 2007 | Dec 31, 2006 |
|--------------------------------|-------------------------|-----------------|-----------------|--------------|--------------|--------------|--------------|
| NPV <sub>0</sub> Recycle Ratio |                         |                 |                 |              |              |              |              |
| Proved Producing               | <b>1.6</b>              | 2.4             | 3.5             | 5.4          | 2.1          | 4.7          | 2.9          |
| Total Proved                   | <b>2.2</b>              | 4.7             | 6.1             | 18.9         | 2.5          | 5.5          | 2.9          |
| Proved + Probable Additional   | <b>3.2</b>              | 6.6             | 10.3            | 27.1         | 2.2          | 3.8          | 3.8          |

- NPV<sub>0</sub> (net present value) recycle ratio is calculated by dividing the undiscounted NPV of reserves added in the year by the total capital cost for the period (eg. Proved Producing (\$963/\$618) = 1.6).

## Quarterly Review

Activity in the fourth quarter of 2012 included the drilling of 28 gross (27.2 net) horizontal wells, the completion of 33 gross (29.6 net) wells and the installation of wellsite equipment and tie in of 34 gross (30.4 net) wells. Capital expenditures in Q4 totaled \$156.8 million with \$78 million spent on drilling, \$47 million on completions, and \$22 million on wellsite equipment and pipelines. Installation of the enhanced liquids extraction facilities at the Oldman gas plant was responsible for the majority of the \$25 million invested in facilities. In the quarter, 30.5 sections of new land was purchased at crown land sales for \$5.2 million or \$267/ac.

On December 1, 2012 Peyto disposed of some minor non-core Open Range assets in the Waskahigan area for total proceeds of \$20.9 million reflected in the previous capital summary as a disposition and gain on disposition.

Production for Q4 2012 was up 26% from Q4 2011 to 49,754 boe/d including 299 mmcf/d of natural gas and 5,286 bbl/d of oil and natural gas liquids. Fourth quarter production was less than expected, however, due to an unanticipated outage at Peyto's Oldman gas processing facility. The cause of the outage was a faulty piece of equipment installed during the new Oldman Deep Cut plant expansion. The defective equipment prevented the operation of approximately two thirds, or 80 mmcf/d, of the processing capacity at the facility. This equipment has been repaired and the impacted processing capacity was brought back online on January 7, 2013 with the Deep Cut plant operation commencing January 25, 2013. Approximately 10,700 boe/d of net production was offline for the final 13 days in December.

Peyto's natural gas price in the fourth quarter 2012 of \$3.45/mcf was 18% lower than the previous year, while the realized oil and natural gas liquids price of \$73.01/bbl was 17% lower. These prices combined for a realized price of \$4.38/mcfe including \$0.13/mcfe of realized hedging gain. Q4 2012 total cash costs of \$1.10/mcfe included \$0.34/mcfe for royalties, \$0.31/mcfe for operating costs, \$0.11/mcfe for transportation, \$0.02/mcfe for G&A and \$0.32/mcfe for interest. Realized prices less cash costs resulted in cash netbacks for the quarter of \$3.28/mcfe or a 75% operating margin.

Peyto incurred a one-time tax charge of \$1.9 million or \$0.12/mcfe in the quarter due to the reassessment of Peyto's 2003 Alberta income tax return. The reassessment related to the treatment of the payout of stock options for income tax purposes upon conversion to an income trust in 2003. The federal reassessment was paid to Canada Revenue Agency in 2008, however, the Alberta Government subsequently reassessed the 2003 Alberta income tax return in January, 2013 which was paid in the same month and accrued as a one-time charge in the 2012 financial results.

## Marketing

The current natural gas price outlook is substantially better than this time last year. Although storage volumes are at the high end of historical levels, growing demand and flat to declining North American natural gas supply is supporting prices at \$3.00/GJ CND\$ and \$3.50/MMBTU US\$. With current supplies matching demand, weather should continue to play a significant role in future prices. In addition, natural gas is playing an increasing role for summer power generation, particularly in light of the current projections for decreased hydro power this coming spring and ongoing retirement of coal fired power plants.

Natural gas liquids prices have, in general, remained substantially higher than the equivalent price in gaseous form. Recent industry trends to extract more Propane and Ethane from the natural gas production have increase supplies and filled available liquefied petroleum gas ("LPG") fractionation plant capacity. This has put significant downward pressure on the price for these specific products which will likely continue for the near future. The majority of Peyto's LPG is under long term contract for transportation and fractionation.

Approximately 50% of Peyto's natural gas production in the fourth quarter had been pre-sold in forward sales done over the previous year at an average price of \$3.17/GJ. The remaining balance of production was subject to AECO monthly spot prices that averaged \$2.90/GJ. On a blended basis, Peyto's realized gas price was \$3.04/GJ or \$3.45/mcf, reflective of Peyto's high heat content natural gas production.

The Company's hedging practice of layering in future sales in the form of fixed price swaps, in order to smooth out the volatility in natural gas price, continued throughout the quarter and into 2013. The following table summarizes the remaining hedged volumes and prices for the upcoming years, effective March 6, 2013:

|       | Future Sales |            | Average Price (CAD) |        |
|-------|--------------|------------|---------------------|--------|
|       | GJ           | Mcf        | \$/GJ               | \$/Mcf |
| 2013  | 54,842,500   | 46,873,932 | \$3.20              | \$3.74 |
| 2014  | 27,575,000   | 23,568,376 | \$3.24              | \$3.79 |
| Total | 82,417,500   | 70,442,308 | \$3.21              | \$3.76 |

As illustrated in the following table, Peyto's annual realized natural gas liquids prices<sup>(1)</sup> were approximately 10% lower on a year over year basis, due primarily to realized Propane prices which were 45% lower than the price realized in 2011.

|                     | Three Months ended Dec. 31 |        | Twelve Months ended Dec. 31 |       |
|---------------------|----------------------------|--------|-----------------------------|-------|
|                     | 2012                       | 2011   | 2012                        | 2011  |
| Condensate (\$/bbl) | 91.22                      | 101.08 | 94.78                       | 94.47 |
| Propane (\$/bbl)    | 25.58                      | 46.03  | 24.12                       | 44.00 |
| Butane (\$/bbl)     | 63.38                      | 67.46  | 64.05                       | 63.41 |
| Pentane (\$/bbl)    | 94.34                      | 104.03 | 98.93                       | 96.63 |

(1) Liquids prices are Peyto realized prices in Canadian dollars adjusted for fractionation and transportation.

Peyto's hedging practice with respect to propane and butane also continued throughout the fourth quarter. The following table summarizes the hedged volumes and prices for the upcoming years, effective March 6, 2013.

|      | Propane             |                           | Butane              |                           |
|------|---------------------|---------------------------|---------------------|---------------------------|
|      | Future Sales (bbls) | Average Price (\$USD/bbl) | Future Sales (bbls) | Average Price (\$USD/bbl) |
| 2013 | 213,972             | \$33.95                   | 15,345              | \$65.88                   |

## Activity Update

Peyto has continued its record level of activity into the first quarter of 2013. Nine rigs are drilling and four completions crews are following behind the drilling rigs. To the end of February, 17 gross (16.9 net) wells have been rig released and 14 gross (13.2 net) wells have been brought on production.

Current production is approximately 57,000 boe/d which includes 4,300 boe/d of new additions since early January. Over 5,000 boe/d of production awaits tie-in of 8.0 net wells that have been completed but are not yet onstream.

Over the first two months of 2013, two compressor expansion projects were completed. An additional 10 MMcf/d of compression was added to the Nosehill Plant taking the facility capacity to 120 MMcf/d. In addition, another 10 MMcf/d of compression was added to the Wildhay Plant taking it to a capacity of 70 MMcf/d.

Three plant construction projects are in the early stage of equipment fabrication with field work anticipated for the summer of 2013 and start-ups ranging from late summer to fall. The first project is a 30 MMcf/d addition to the Swanson Plant (taking it to 60 MMcf/d) for the accommodation of Ansell area growth volumes. In addition to the plant expansion, a 50 km strategic pipeline from Ansell to Swanson is currently under construction with targeted completion after breakup. The second project is a new Oldman North Plant to be located adjacent to the existing 125 MMcf/d Oldman Plant and initially designed for 40 MMcf/d. This plant will handle ongoing Cardium and Falher horizontal well development. A third new facility is planned for mid-fall for a new step-out area of Wilrich development that is presently undergoing early stage delineation drilling.

The Oldman Deep Cut facility built at the end of 2012 was successfully brought online in mid-January. The plant is currently running just below its 80 MMcfd raw gas capacity as some final re-compression tuning occurs for the four new compressors. The overall Oldman LPG recovery level has increased from a pre-Deep Cut level of 1,600 bbl/d to a present level of 2,400 bbl/d at the current -75°C operating level for the Deep Cut train. With continued tuning of the re-compression, throughput will be brought up and chilling will be dropped towards the -80°C design level to realize the full 2,600 bbl/d of LPG.

As in most past years, Peyto tentatively plans to shut down its drilling operations over spring break-up which is contemplated to occur from early April to mid-May and resume its drilling program with nine rigs. Post break-up drilling will focus in the traditional Greater Sundance area with volumes filling the new Oldman North Plant, the Ansell area with volumes pipelined to the expanded Swanson Plant, and with some additional Northern Cardium drilling. The \$450 to \$500 million capital program is on pace and it is expected that target 2013 exit production levels of 62,000 to 67,000 boe/d will be reached.

### **2013 Outlook**

2013 is forecast to be the most active in the Company's history. It also comes at a time when the majority of natural gas producers in North America are challenged by low natural gas prices and high costs, rendering many plays uneconomic. Over its history, Peyto has maintained a unique low cost advantage that allows the Company to profitably grow its asset base, despite lower commodity prices, taking advantage of lower service and material costs. In effect, Peyto can be "greedy when others are fearful" and capture new opportunities when others are cutting capital budgets and rationalizing assets. This prevailing economic condition is forecast to continue throughout 2013 allowing Peyto the opportunity to deliver the same superior total returns to shareholders as in the past. Peyto's expertise in the Alberta Deep Basin will serve it well in this regard. The company's financial flexibility, quality asset base and strong balance sheet position Peyto to continue to be opportunistic. As always, capital investments will only be pursued if Peyto's high return objectives can be met.

### **Annual General Meeting**

Peyto's Annual General Meeting of Shareholders is scheduled for 3:00 p.m. on Wednesday, June 5, 2013 at Livingston Place Conference Centre, +15 level, 222-3<sup>rd</sup> Avenue SW, Calgary, Alberta. Shareholders are encouraged to visit the Peyto website at [www.peyto.com](http://www.peyto.com) where there is a wealth of information designed to inform and educate investors. A monthly President's Report can also be found on the website which follows the progress of the capital program and the ensuing production growth, along with video and audio commentary from Peyto's senior management.



Darren Gee  
President and CEO  
March 6, 2013

## Management's discussion and analysis

This Management's Discussion and Analysis ("MD&A") should be read in conjunction with the audited consolidated financial statements of Peyto Exploration & Development Corp. ("Peyto" or the "Company", successor issuer to Peyto Energy Trust, the "Trust") for the years ended December 31, 2012 and 2011. The financial statements have been prepared in accordance with the International Accounting Standards Board ("IASB") most current International Financial Reporting Standards ("IFRS" or "GAAP") and International Accounting Standards ("IAS").

This discussion provides management's analysis of Peyto's historical financial and operating results and provides estimates of Peyto's future financial and operating performance based on information currently available. Actual results will vary from estimates and the variances may be significant. Readers should be aware that historical results are not necessarily indicative of future performance. This MD&A was prepared using information that is current as of March 5, 2013. Additional information about Peyto, including the most recently filed annual information form is available at [www.sedar.com](http://www.sedar.com) and on Peyto's website at [www.peyto.com](http://www.peyto.com).

Certain information set forth in this MD&A, including management's assessment of the Company's future plans and operations, contains forward-looking statements. By their nature, forward-looking statements are subject to numerous risks and uncertainties, some of which are beyond these parties' control, including the impact of general economic conditions, industry conditions, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other industry participants, the lack of availability of qualified personnel or management, stock market volatility and ability to access sufficient capital from internal and external sources. Readers are cautioned that the assumptions used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be imprecise and, as such, undue reliance should not be placed on forward-looking statements. Peyto'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 so, what benefits that Peyto will derive there from. Other than is required pursuant to applicable securities legislation, Peyto does not undertake to update forward looking statements at any particular time.

All references are to Canadian dollars unless otherwise indicated. Natural gas liquids and oil volumes are recorded in barrels of oil (bbl) and are converted to a thousand cubic feet equivalent (mcf) using a ratio of six (6) thousand cubic feet to one (1) barrel of oil (bbl). Natural gas volumes recorded in thousand cubic feet (mcf) are converted to barrels of oil equivalent (boe) using the ratio of six (6) thousand cubic feet to one (1) barrel of oil (bbl).

### CORPORATE ACQUISITION

On August 14, 2012 Peyto closed the acquisition of Open Range Energy Corp. ("Open Range") for an effective total capital cost of \$187.2 million. The acquisition was conducted pursuant to a plan of arrangement with Peyto exchanging 0.0723 Peyto common shares for each Open Range common share (5.4 million Peyto common shares total) and assuming \$75 million in net debt (inclusive of transaction costs), see Note 3 to the Financial Statements. Peyto and Open Range amalgamated on January 1, 2013.

### OVERVIEW

Peyto is a Canadian energy company involved in the development and production of natural gas in Alberta's deep basin. As at December 31, 2012, the total Proved plus Probable reserves were 2,353 billion cubic feet equivalent (392.2 million barrels of oil equivalent) as evaluated by the independent petroleum engineers. Production is weighted approximately 89% to natural gas and 11% to natural gas liquids and oil.

The Peyto business model is designed to deliver a superior total return and, over time, growth in value, assets, production and income, all on a debt adjusted per share basis. The model is built around three key principles:

- Use technical expertise to achieve the best return on capital employed, through the development of internally generated drilling projects.
- Build an asset base which is made up of high quality, long life natural gas reserves.
- Balance dividends to shareholders and funding for the capital program with cash flow and available bank lines.

Operating results over the last fourteen years indicate that these principles have been successfully implemented. This business model makes Peyto a truly unique energy company.

## ANNUAL FINANCIAL INFORMATION

The following is a summary of selected financial information of the Company for the periods indicated. Reference should be made to the audited consolidated financial statements of the Company, which are available at [www.sedar.com](http://www.sedar.com).

| Year Ended December 31           | 2012             | 2011      | 2010      |
|----------------------------------|------------------|-----------|-----------|
| (\$000 except per share amounts) |                  |           |           |
| Total revenue (before royalties) | <b>411,400</b>   | 424,560   | 319,426   |
| Funds from operations            | <b>308,865</b>   | 314,622   | 236,956   |
| Per share – basic and diluted    | <b>2.19</b>      | 2.36      | 1.94      |
| Earnings                         | <b>93,951</b>    | 128,183   | 121,838   |
| Per share – basic and diluted    | <b>0.67</b>      | 0.96      | 1.01      |
| Total assets                     | <b>2,203,524</b> | 1,800,252 | 1,454,575 |
| Total long-term debt             | <b>580,000</b>   | 470,000   | 355,000   |
| Dividends per share              | <b>0.72</b>      | 0.72      | 1.44      |

### Funds from Operations

“Funds from operations” is a non-GAAP measure which represents cash flows from operating activities before changes in non-cash operating working capital and provision for future performance based compensation. Management considers funds from operations and per share calculations of funds from operations to be key measures as they demonstrate the Company’s ability to generate the cash necessary to pay dividends, repay debt and make capital investments. Management believes that by excluding the temporary impact of changes in non-cash operating working capital, funds from operations provides a useful measure of Peyto’s ability to generate cash that is not subject to short-term movements in operating working capital. The most directly comparable GAAP measure is cash flows from operating activities.

## QUARTERLY FINANCIAL INFORMATION

| (\$000 except per share amounts) | 2012           |        |        |        | 2011    |        |        |        |
|----------------------------------|----------------|--------|--------|--------|---------|--------|--------|--------|
|                                  | Q4             | Q3     | Q2     | Q1     | Q4      | Q3     | Q2     | Q1     |
| Total revenue (net of royalties) | <b>111,105</b> | 95,409 | 80,471 | 93,661 | 104,394 | 98,261 | 91,186 | 89,655 |
| Funds from operations            | <b>90,078</b>  | 76,918 | 64,732 | 77,645 | 80,410  | 82,506 | 77,010 | 74,696 |
| Per share – basic and diluted    | <b>0.62</b>    | 0.54   | 0.47   | 0.56   | 0.60    | 0.62   | 0.58   | 0.56   |
| Earnings                         | <b>25,823</b>  | 23,058 | 18,201 | 26,868 | 26,036  | 37,741 | 32,718 | 31,688 |
| Per share – basic and diluted    | <b>0.18</b>    | 0.16   | 0.13   | 0.19   | 0.19    | 0.28   | 0.25   | 0.24   |
| Dividends                        | <b>26,178</b>  | 25,576 | 24,927 | 24,912 | 24,245  | 23,951 | 23,951 | 23,921 |
| Per share – basic and diluted    | <b>0.18</b>    | 0.18   | 0.18   | 0.18   | 0.18    | 0.18   | 0.18   | 0.18   |

## RESULTS OF OPERATIONS

### Production

|  | Three Months ended Dec. 31 |        | Twelve Months ended Dec. 31 |        |
|--|----------------------------|--------|-----------------------------|--------|
|  | 2012                       | 2011   | 2012                        | 2011   |
| Natural gas (mmcf/d)                     | <b>266.8</b>               | 212.7  | <b>238.5</b>                | 189.7  |
| Oil & natural gas liquids (bbl/d)        | <b>5,286</b>               | 3,947  | <b>4,778</b>                | 3,856  |
| Barrels of oil equivalent (boe/d)        | <b>49,754</b>              | 39,399 | <b>44,527</b>               | 35,465 |
| Thousand cubic feet equivalent (mmcfe/d) | <b>298.5</b>               | 236.4  | <b>267.2</b>                | 212.8  |

Natural gas production averaged 266.8 mmcf/d in the fourth quarter of 2012, 25% higher than the 212.7 mmcf/d reported for the same period in 2011. Oil and natural gas liquids production averaged 5,286 bbl/d, up 34% from 3,947 bbl/d reported in the prior year. Production for the year increased 26% from 212.8 mmmcfe/d to 267.2 mmmcfe/d (35,465 boe/d to 44,527 boe/d). The production increases are attributable to Peyto’s increased capital program and resulting production additions.

**Oil & Natural Gas Liquids Production by Component**

|   | Three Months ended Dec. 31 |       | Twelve Months ended Dec. 31 |       |
|---|----------------------------|-------|-----------------------------|-------|
|   | 2012                       | 2011  | 2011                        | 2011  |
| Condensate (bbl/d)                      | 1,847                      | 1,464 | 1,675                       | 1,432 |
| Propane (bbl/d)                         | 872                        | 659   | 832                         | 657   |
| Butane (bbl/d)                          | 962                        | 701   | 876                         | 703   |
| Pentane (bbl/d)                         | 1,380                      | 1,014 | 1,181                       | 955   |
| Other NGL's (bbl/d)                     | 225                        | 109   | 214                         | 109   |
| Oil & natural gas liquids (bbl/d)       | 5,286                      | 3,947 | 4,778                       | 3,856 |
| Thousand cubic feet equivalent (mmcf/d) | 31.7                       | 23.7  | 28.7                        | 23.1  |

**Commodity Prices**

|  | Three Months ended Dec. 31 |       | Twelve Months ended Dec. 31 |       |
|--|----------------------------|-------|-----------------------------|-------|
|  | 2012                       | 2011  | 2012                        | 2011  |
| Oil and natural gas liquids (\$/bbl)                 | 73.12                      | 88.04 | 73.96                       | 81.67 |
| Hedging – ngl (\$/bbl)                               | (0.11)                     | -     | (0.04)                      | -     |
| Oil and natural gas liquids – after hedging (\$/mcf) | 73.01                      | 88.04 | 73.92                       | 81.67 |
| Natural gas (\$/mcf)                                 | 3.31                       | 3.70  | 2.61                        | 3.93  |
| Hedging – gas (\$/mcf)                               | 0.14                       | 0.51  | 0.62                        | 0.54  |
| Natural gas – after hedging (\$/mcf)                 | 3.45                       | 4.21  | 3.23                        | 4.47  |
| Total Hedging (\$/mcf)                               | 0.13                       | 0.46  | 0.55                        | 0.48  |
| Total Hedging (\$/boe)                               | 0.77                       | 2.74  | 3.29                        | 2.88  |

Peyto's natural gas price, before hedging gains, averaged \$3.31/mcf during the fourth quarter of 2012, a decrease of 11 percent from \$3.70/mcf reported for the equivalent period in 2011. Oil and natural gas liquids prices before hedging averaged \$73.12/bbl, a decrease of 17 percent from \$88.04/bbl a year earlier. Average natural gas prices for the year were down 34% to \$2.61/mcf while oil and natural gas liquids prices were down 9% to \$73.96/bbl. Hedging activity increased Peyto's achieved price/mcfe by 3% from \$4.25 to \$4.38 per mcfe for the fourth quarter and 15% from \$3.66 to \$4.21 per mcfe for the year.

**Oil & Natural Gas Liquids Prices by Component**

|                     | Three Months ended Dec. 31 |        | Twelve Months ended Dec. 31 |       |
|---------------------|----------------------------|--------|-----------------------------|-------|
|                     | 2012                       | 2011   | 2012                        | 2011  |
| Condensate (\$/bbl) | 91.22                      | 101.08 | 94.78                       | 94.47 |
| Propane (\$/bbl)    | 25.58                      | 46.03  | 24.12                       | 44.00 |
| Butane (\$/bbl)     | 63.38                      | 67.46  | 64.05                       | 63.41 |
| Pentane (\$/bbl)    | 94.34                      | 104.03 | 98.93                       | 96.63 |

**Revenue**

| (\$000)                     | Three Months ended Dec. 31 |         | Twelve Months ended Dec. 31 |         |
|-----------------------------|----------------------------|---------|-----------------------------|---------|
|                             | 2012                       | 2011    | 2012                        | 2011    |
| Natural gas                 | 81,249                     | 72,382  | 228,398                     | 272,297 |
| Oil and natural gas liquids | 35,557                     | 31,964  | 129,335                     | 114,943 |
| Hedging gain                | 3,504                      | 9,917   | 53,667                      | 37,320  |
| Total revenue               | 120,310                    | 114,263 | 411,400                     | 424,560 |

For the three months ended December 31, 2012, gross revenue increased 5% to \$120.3 million from \$114.3 million for the equivalent period in 2011. Revenue for 2012 decreased 3% to \$411.4 million from \$424.6 million in 2011. The increase in revenue for the quarter (decrease for the year) was a result of increased production volumes and offset by lower realized natural gas, oil and NGL prices as detailed in the following table:

|                                  | Three Months ended Dec. 31 |         |               | Twelve Months ended Dec. 31 |         |                |
|----------------------------------|----------------------------|---------|---------------|-----------------------------|---------|----------------|
|                                  | 2012                       | 2011    | \$million     | 2012                        | 2011    | \$million      |
| Total Revenue, December 31, 2011 |                            |         | <b>114.3</b>  |                             |         | <b>424.6</b>   |
| Revenue change due to:           |                            |         |               |                             |         |                |
| <b>Natural gas</b>               |                            |         |               |                             |         |                |
| Volume (mmcf)                    | 24,546                     | 19,570  | <b>21.0</b>   | 87,487                      | 69,223  | <b>80.8</b>    |
| Price (\$/mcf)                   | \$3.45                     | \$4.21  | <b>(18.7)</b> | \$3.23                      | \$4.47  | <b>(108.3)</b> |
| <b>Oil &amp; NGL</b>             |                            |         |               |                             |         |                |
| Volume (mdbl)                    | 486                        | 363     | <b>10.9</b>   | 1,749                       | 1,408   | <b>27.9</b>    |
| Price (\$/bbl)                   | \$73.01                    | \$88.04 | <b>(7.2)</b>  | \$73.92                     | \$81.67 | <b>(13.6)</b>  |
| Total Revenue, December 31, 2012 |                            |         | <b>120.3</b>  |                             |         | <b>411.4</b>   |

### Royalties

Royalties are paid to the owners of the mineral rights with whom leases are held, including the provincial government of Alberta. Alberta Natural Gas Crown royalties are invoiced on the Crown's share of production based on a monthly established Alberta Reference Price. The Alberta Reference Price is a monthly weighted average price of gas consumed in Alberta and gas exported from Alberta reduced for transportation and marketing allowances.

| (\$000 except per share amounts) | Three Months ended Dec. 31 |       | Twelve Months ended Dec. 31 |        |
|----------------------------------|----------------------------|-------|-----------------------------|--------|
|                                  | 2012                       | 2011  | 2012                        | 2011   |
| Royalties                        | <b>9,205</b>               | 9,870 | <b>30,754</b>               | 41,064 |
| % of sales before hedging        | <b>8</b>                   | 10    | <b>9</b>                    | 11     |
| % of sales after hedging         | <b>8</b>                   | 9     | <b>8</b>                    | 10     |
| \$/mcf                           | <b>0.34</b>                | 0.46  | <b>0.31</b>                 | 0.53   |
| \$/boe                           | <b>2.01</b>                | 2.72  | <b>1.89</b>                 | 3.17   |

For the fourth quarter of 2012, royalties averaged \$0.34/mcfe or approximately 8% of Peyto's total petroleum and natural gas sales, a 26% decrease from the fourth quarter 2011. Royalties for 2012 were 42% lower at \$0.31/mcfe than 2011.

Substantially all of Peyto's production is in the Province of Alberta. Under the Alberta Royalty Framework ("ARF") the Crown royalty rate varies with production rates and commodity prices. The royalty rate expressed as a percentage of sales revenue will fluctuate from period to period due to the fact that the Alberta Reference Price can differ significantly from the commodity prices realized by Peyto and that hedging gains and losses are not subject to royalties.

In addition to the basic underlying royalty structure (the ARF), Alberta has instituted additional features that impact the royalty paid on gas, particularly for newly drilled wells. These additional features include:

1. A drilling royalty credit program that terminated on March 31, 2011. Under this program credits were earned at a rate of \$200 per meter of newly drilled well depth and could be applied with certain limitations to the earning company's corporate royalty bill.
2. A one year flat 5% royalty period (18 months for horizontal wells) for each new well but capped at a cumulative production level of 500 MMcf for each new well, and
3. A Natural Gas Deep Drilling Holiday program that provides a royalty holiday value for new wells based on meterage drilled. This holiday feature further reduces the royalty for new wells to a minimum of 5% for a maximum 5 year period from on-stream date. This benefit sequentially follows the benefit under point (2) above.

From the combination of these royalty programs, Peyto has experienced a decrease in overall corporate royalty rates. This, in part, can be attributed to a decline in commodity prices and the dependence of royalty rates on commodity prices. In its 14 year history, Peyto has invested \$2.9 billion in capital projects, found and developed 1.9 TCFe of gas reserves, and paid over \$600 million in royalties.

## Operating Costs & Transportation

Peyto's operating expenses include all costs with respect to day-to-day well and facility operations.

|                         | Three Months ended Dec. 31 |       | Twelve Months ended Dec. 31 |        |
|-------------------------|----------------------------|-------|-----------------------------|--------|
|                         | 2012                       | 2011  | 2012                        | 2011   |
| Operating costs (\$000) | <b>8,513</b>               | 7,707 | <b>31,260</b>               | 27,379 |
| \$/mcf                  | <b>0.31</b>                | 0.35  | <b>0.32</b>                 | 0.35   |
| \$/boe                  | <b>1.86</b>                | 2.13  | <b>1.92</b>                 | 2.12   |
| Transportation (\$000)  | <b>3,124</b>               | 2,667 | <b>11,275</b>               | 9,754  |
| \$/mcf                  | <b>0.11</b>                | 0.12  | <b>0.12</b>                 | 0.13   |
| \$/boe                  | <b>0.68</b>                | 0.74  | <b>0.69</b>                 | 0.75   |

Operating costs were \$8.5 million in the fourth quarter of 2012 compared to \$7.7 million for the equivalent period in 2011. On a unit-of-production basis, operating costs decreased 11% to \$0.31/mcf in the fourth quarter of 2012 compared to \$0.35/mcf for the equivalent period in 2011. Operating costs decreased 9% from 0.35/mcf in 2011 to \$0.32/mcf in 2012. Transportation expenses were 8% lower in 2012 quarter over quarter and year over year on a per mcf basis.

## General and Administrative Expenses

|                      | Three Months ended Dec. 31 |         | Twelve Months ended Dec. 31 |         |
|----------------------|----------------------------|---------|-----------------------------|---------|
|                      | 2012                       | 2011    | 2012                        | 2011    |
| G&A expenses (\$000) | <b>3,742</b>               | 3,165   | <b>12,822</b>               | 11,402  |
| Overhead recoveries  | <b>(3,265)</b>             | (2,049) | <b>(8,976)</b>              | (6,491) |
| Net G&A expenses     | <b>477</b>                 | 1,116   | <b>3,846</b>                | 4,911   |
| \$/mcf               | <b>0.02</b>                | 0.05    | <b>0.04</b>                 | 0.06    |
| \$/boe               | <b>0.10</b>                | 0.31    | <b>0.24</b>                 | 0.38    |

For the fourth quarter, general and administrative expenses before overhead recoveries were up 18% over the same quarter of 2011 and up 12% on an annual basis primarily due to costs associated with the acquisition of Open Range. Capital overhead recoveries increased 59% for the fourth quarter from \$2.0 million to \$3.3 million and 38% on an annual basis due to the increased capital program.

## Interest Expense

|   | Three Months ended Dec. 31 |       | Twelve Months ended Dec. 31 |        |
|---|----------------------------|-------|-----------------------------|--------|
|   | 2012                       | 2011  | 2012                        | 2011   |
| Interest expense (\$000)  | <b>8,914</b>               | 7,546 | <b>25,401</b>               | 21,881 |
| \$/mcf  | <b>0.32</b>                | 0.35  | <b>0.26</b>                 | 0.28   |
| \$/boe  | <b>1.95</b>                | 2.08  | <b>1.56</b>                 | 1.69   |
| Average interest rate   | <b>5.5%</b>                | 5.9%  | <b>4.7%</b>                 | 4.8%   |
| Average interest rate excluding interest associated with 2003 income tax reassessment | <b>4.5%</b>                | 4.3%  | <b>4.7%</b>                 | 4.2%   |

Fourth quarter 2012 interest expense was \$8.9 million or \$0.32/mcf compared to \$7.5 million or \$0.35/mcf for the equivalent period in 2011. 2012 interest expense was \$25.4 million or \$0.26/mcf compared to \$21.9 million or \$0.28/mcf a year earlier. 2012 interest expense was increased by the \$1.4 million paid to the Alberta Government and 2011 interest expense was increased by the \$2.2 million paid to the Federal Government due to the inclusion of interest charges related to the reassessment of the 2003 income tax return filed at the date of conversion to an income trust. If those items were excluded, the average interest rate would have been 4.5% for the fourth quarter 2012 and 4.72% for the year. For additional information, see discussion in Current Taxes Paid section.

## Netbacks

| (\$/mcfe)                  | Three Months ended Dec. 31 |       | Twelve Months ended Dec. 31 |       |
|----------------------------|----------------------------|-------|-----------------------------|-------|
|                            | 2012                       | 2011  | 2012                        | 2011  |
| Gross Sale Price           | 4.25                       | 4.79  | 3.66                        | 4.99  |
| Hedging gain               | 0.13                       | 0.46  | 0.55                        | 0.48  |
| Net Sale Price             | 4.38                       | 5.25  | 4.21                        | 5.47  |
| Less: Royalties            | 0.34                       | 0.46  | 0.31                        | 0.53  |
| Operating costs            | 0.31                       | 0.35  | 0.32                        | 0.35  |
| Transportation             | 0.11                       | 0.12  | 0.12                        | 0.13  |
| Field netback              | 3.62                       | 4.32  | 3.46                        | 4.46  |
| General and administrative | 0.02                       | 0.05  | 0.04                        | 0.06  |
| Interest on long-term debt | 0.32                       | 0.35  | 0.26                        | 0.28  |
| Cash netback (\$/mcfe)     | 3.28                       | 3.92  | 3.16                        | 4.12  |
| Cash netback (\$/boe)      | 19.68                      | 23.55 | 18.96                       | 24.69 |

Netbacks are a non-GAAP measure that represents the profit margin associated with the production and sale of petroleum and natural gas. Netbacks are per unit of production measures used to assess the Company's performance and efficiency. The primary factors that produce Peyto's strong netbacks and high margins are a low cost structure and the high heat content of its natural gas that results in higher commodity prices.

The impact of cash taxes paid as a result of the reassessment of Peyto's 2003 income tax return have not been included in the cash netback. This was a one-time item related to the treatment of the payout of stock options for income tax upon conversion to an income trust. The reassessment was paid in 2008. The Alberta Government subsequently reassessed the 2003 Alberta income tax return in January, 2013 which was paid in the same month and accrued in the 2012 financial results.

### Depletion, Depreciation and Amortization

The 2012 provision for depletion, depreciation and accretion totaled \$172.3 million compared to \$130.7 million in 2011. On a unit-of-production basis, depletion, depreciation and amortization costs for 2012 averaged \$1.76/mcfe compared to \$1.68/mcfe for 2011.

### Income Taxes

The current provision for deferred income tax expense is \$34.3 million (2011 – \$35.0 million). Resource pools are generated from the capital program, which are available to offset current and deferred income tax liabilities.

| Income Tax Pool type<br>(\$ millions) | December 31,<br>2012 | December 31,<br>2011 | Annual deductibility                         |
|---------------------------------------|----------------------|----------------------|--|
| Canadian Oil and Gas Property Expense | 263.4                | 179.5                | 10% declining balance                        |
| Canadian Development Expense          | 575.6                | 457.3                | 30% declining balance                        |
| Canadian Exploration Expense          | 181.0                | 163.0                | 100%   |
| Undepreciated Capital Cost            | 228.4                | 156.8                | Primarily 25% declining balance              |
| Non-capital loss carry forward        | 42.1                 | -                    | 100%   |
| Other                                 | 39.5                 | 41.5                 | Various, 7% declining balance to 20%         |
| <b>Total Federal Tax Pools</b>        | <b>1,330.0</b>       | <b>998.1</b>         |  |
| <b>Additional Alberta Tax Pool</b>    | 41.3                 | 56.5                 | Various rates, 25% declining balance to 100% |

Canada Revenue Agency ("CRA") conducted an audit of Peyto's restructuring costs incurred in the 2003 trust conversion. On September 25, 2008, the CRA reassessed on the basis that \$41 million of these costs were not deductible and treated them as an eligible capital amount. Peyto filed a notice of objection and the CRA confirmed the reassessment. Examinations for discovery were completed. The Tax Court of Canada had agreed to both parties' request to hold Peyto's appeal in abeyance pending a decision of the Supreme Court of Canada to hear another taxpayer's appeal. As the other taxpayer's appeal was unsuccessful with the Federal Court of Appeal, Peyto filed a discontinuance and expensed the income tax of \$4.9 million and interest charges of \$2.2 million assessed and paid in 2008. In January 2013 the Alberta Government reassessed the 2003 Alberta Income Tax return on the same basis. This reassessment was accrued in the year-end financial records of the Company and paid in January 2013.

**Current Taxes Paid**

|                            | Three Months ended Dec. 31 |       | Twelve Months ended Dec. 31 |       |
|----------------------------|----------------------------|-------|-----------------------------|-------|
|                            | 2012                       | 2011  | 2012                        | 2011  |
| Current taxes (\$000)      | 1,890                      | 4,949 | 1,890                       | 4,949 |
| Interest and penalties     | 1,333                      | 2,225 | 1,333                       | 2,225 |
| Amount due on reassessment | 3,223                      | 7,174 | 3,223                       | 7,174 |
| \$/mcf                     | 0.12                       | 0.33  | 0.03                        | 0.09  |
| \$/boe                     | 0.72                       | 1.98  | 0.18                        | 0.55  |
| \$/share                   | 0.02                       | 0.05  | 0.02                        | 0.05  |

**MARKETING****Commodity Price Risk Management**

The Company is a party to certain off balance sheet derivative financial instruments, including fixed price contracts. The Company enters into these forward contracts with well established counterparties for the purpose of protecting a portion of its future revenues from the volatility of oil and natural gas prices. In order to minimize counterparty risk, these marketing contracts are executed with financial institutions that are members of Peyto's loan syndicate. During 2012, a realized hedging gain of \$53.7 million was recorded as compared to \$37.3 million in 2011. A summary of contracts outstanding in respect of the hedging activities are as follows:

| <b>Propane</b>                      |             |                       |                    |
|-------------------------------------|-------------|-----------------------|--------------------|
| <b>Period Hedged</b>                | <b>Type</b> | <b>Monthly Volume</b> | <b>Price (USD)</b> |
| September 1, 2012 to March 31, 2013 | Fixed Price | 2,000 bbl             | \$49.56/bbl        |
| September 1, 2012 to March 31, 2013 | Fixed Price | 2,000 bbl             | \$44.10/ bbl       |
| September 1, 2012 to March 31, 2013 | Fixed Price | 2,000 bbl             | \$32.34/ bbl       |
| September 1, 2012 to March 31, 2013 | Fixed Price | 2,000 bbl             | \$33.60/ bbl       |
| September 1, 2012 to March 31, 2013 | Fixed Price | 2,000 bbl             | \$32.97/ bbl       |
| October 1, 2012 to March 31, 2013   | Fixed Price | 2,000 bbl             | \$34.01/ bbl       |
| October 1, 2012 to March 31, 2013   | Fixed Price | 2,000 bbl             | \$34.65/ bbl       |
| October 1, 2012 to March 31, 2013   | Fixed Price | 2,000 bbl             | \$36.96/ bbl       |
| January 1, 2013 to March 31, 2013   | Fixed Price | 4,000 bbl             | \$36.12/bbl        |
| April 1, 2013 to June 30, 2013      | Fixed Price | 4,000 bbl             | \$34.86/bbl        |
| April 1, 2013 to December 31, 2013  | Fixed Price | 4,000 bbl             | \$30.66/bbl        |
| April 1, 2013 to December 31, 2013  | Fixed Price | 4,000 bbl             | \$32.34/bbl        |
| April 1, 2013 to December 31, 2013  | Fixed Price | 4,000 bbl             | \$34.86/bbl        |
| April 1, 2013 to December 31, 2013  | Fixed Price | 4,000 bbl             | \$35.39/bbl        |

| <b>Butane</b>                       |             |                       |                    |
|-------------------------------------|-------------|-----------------------|--------------------|
| <b>Period Hedged</b>                | <b>Type</b> | <b>Monthly Volume</b> | <b>Price (USD)</b> |
| September 1, 2012 to March 31, 2013 | Fixed Price | 2,000 bbl             | \$80.64/bbl        |
| September 1, 2012 to March 31, 2013 | Fixed Price | 2,000 bbl             | \$58.38/bbl        |
| September 1, 2012 to March 31, 2013 | Fixed Price | 2,000 bbl             | \$60.06/bbl        |
| September 1, 2012 to March 31, 2013 | Fixed Price | 2,000 bbl             | \$60.06/bbl        |
| October 1, 2012 to March 31, 2013   | Fixed Price | 2,000 bbl             | \$66.36/bbl        |

| <b>Iso-Butane</b>                   |             |                       |                    |
|-------------------------------------|-------------|-----------------------|--------------------|
| <b>Period Hedged</b>                | <b>Type</b> | <b>Monthly Volume</b> | <b>Price (USD)</b> |
| September 1, 2012 to March 31, 2013 | Fixed Price | 1,000 bbl             | \$82.32/bbl        |
| September 1, 2012 to March 31, 2013 | Fixed Price | 1,000 bbl             | \$60.48/bbl        |
| September 1, 2012 to March 31, 2013 | Fixed Price | 1,000 bbl             | \$62.58/bbl        |
| September 1, 2012 to March 31, 2013 | Fixed Price | 1,000 bbl             | \$62.58/bbl        |
| October 1, 2012 to March 31, 2013   | Fixed Price | 1,000 bbl             | \$69.30/bbl        |

| <b>Natural Gas</b>              |             |                     |                    |
|---------------------------------|-------------|---------------------|--------------------|
| <b>Period Hedged</b>            | <b>Type</b> | <b>Daily Volume</b> | <b>Price (CAD)</b> |
| April 1, 2011 to March 31, 2013 | Fixed Price | 5,000 GJ            | \$4.055/GJ         |
| April 1, 2011 to March 31, 2013 | Fixed Price | 5,000 GJ            | \$3.80/GJ          |
| June 1, 2011 to March 31, 2013  | Fixed Price | 5,000 GJ            | \$4.17/GJ          |
| June 1, 2011 to March 31, 2013  | Fixed Price | 5,000 GJ            | \$4.10/GJ          |

|                                      |             |          |             |
|--------------------------------------|-------------|----------|-------------|
| June 1, 2011 to March 31, 2013       | Fixed Price | 5,000 GJ | \$4.10/GJ   |
| November 1, 2011 to March 31, 2013   | Fixed Price | 5,000 GJ | \$4.00/GJ   |
| April 1, 2012 to October 31, 2013    | Fixed Price | 5,000 GJ | \$4.00/GJ   |
| April 1, 2012 to October 31, 2013    | Fixed Price | 5,000 GJ | \$4.00/GJ   |
| April 1, 2012 to October 31, 2013    | Fixed Price | 5,000 GJ | \$4.00/GJ   |
| April 1, 2012 to October 31, 2013    | Fixed Price | 5,000 GJ | \$4.00/GJ   |
| April 1, 2012 to March 31, 2013      | Fixed Price | 5,000 GJ | \$2.20/GJ   |
| April 1, 2012 to March 31, 2013      | Fixed Price | 5,000 GJ | \$2.31/GJ   |
| April 1, 2012 to October 31, 2013    | Fixed Price | 5,000 GJ | \$2.52/GJ   |
| April 1, 2012 to March 31, 2014      | Fixed Price | 5,000 GJ | \$3.00/GJ   |
| May 1, 2012 to October 31, 2013      | Fixed Price | 5,000 GJ | \$2.30/GJ   |
| August 1, 2012 to March 31, 2014     | Fixed Price | 5,000 GJ | \$3.00/GJ   |
| August 1, 2012 to October 31, 2014   | Fixed Price | 5,000 GJ | \$3.10/GJ   |
| November 1, 2012 to October 31, 2013 | Fixed Price | 5,000 GJ | \$2.60/GJ   |
| November 1, 2012 to October 31, 2013 | Fixed Price | 5,000 GJ | \$3.005/GJ  |
| November 1, 2012 to October 31, 2013 | Fixed Price | 5,000 GJ | \$3.00/GJ   |
| November 1, 2012 to March 31, 2014   | Fixed Price | 5,000 GJ | \$2.81/GJ   |
| November 1, 2012 to March 31, 2014   | Fixed Price | 5,000 GJ | \$3.00/GJ   |
| November 1, 2012 to March 31, 2014   | Fixed Price | 5,000 GJ | \$3.05/GJ   |
| November 1, 2012 to March 31, 2014   | Fixed Price | 5,000 GJ | \$3.02/GJ   |
| November 1, 2012 to October 31, 2014 | Fixed Price | 5,000 GJ | \$3.0575/GJ |
| January 1, 2013 to October 31, 2013  | Fixed Price | 5,000 GJ | \$3.42/GJ   |
| January 1, 2013 to December 31, 2013 | Fixed Price | 5,000 GJ | \$3.105/GJ  |
| January 1, 2013 to March 31, 2013    | Fixed Price | 5,000 GJ | \$3.32/GJ   |
| January 1, 2013 to March 31, 2014    | Fixed Price | 5,000 GJ | \$3.00/GJ   |
| January 1, 2013 to March 31, 2014    | Fixed Price | 5,000 GJ | \$3.02/GJ   |
| April 1, 2013 to October 31, 2013    | Fixed Price | 5,000 GJ | \$3.205/GJ  |
| April 1, 2013 to March 31, 2014      | Fixed Price | 5,000 GJ | \$3.105/GJ  |
| April 1, 2013 to March 31, 2014      | Fixed Price | 5,000 GJ | \$3.53/GJ   |
| April 1, 2013 to March 31, 2014      | Fixed Price | 5,000 GJ | \$3.45/GJ   |
| April 1, 2013 to March 31, 2014      | Fixed Price | 5,000 GJ | \$3.50/GJ   |
| April 1, 2013 to March 31, 2014      | Fixed Price | 5,000 GJ | \$3.08/GJ   |
| April 1, 2013 to March 31, 2014      | Fixed Price | 5,000 GJ | \$3.17GJ    |
| November 1, 2013 to October 31, 2014 | Fixed Price | 5,000 GJ | \$3.50/GJ   |

As at December 31, 2012, Peyto had committed to the future sale of 261,000 barrels of natural gas liquids at an average price of \$39.86 USD per barrel and 59,810,000 gigajoules (GJ) of natural gas at an average price of \$3.19 per GJ or \$3.74 per mcf. Had these contracts been closed on December 31, 2012, Peyto would have realized a gain in the amount of \$7.7 million. If the AECO gas price on December 31, 2012 were to increase by \$1/GJ, the unrealized gain would decrease by approximately \$59.8 million. An opposite change in commodity prices rates would result in an opposite impact on other comprehensive income.

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

| <b>Propane</b>                     |             |                       | <b>Price</b> |
|------------------------------------|-------------|-----------------------|--------------|
| <b>Period Hedged</b>               | <b>Type</b> | <b>Monthly Volume</b> | <b>(USD)</b> |
| April 1, 2013 to December 31, 2013 | Fixed Price | 4,000 bbl             | \$34.44/bbl  |

  

| <b>Natural Gas</b>                 |             |                     | <b>Price</b> |
|------------------------------------|-------------|---------------------|--------------|
| <b>Period Hedged</b>               | <b>Type</b> | <b>Daily Volume</b> | <b>(CAD)</b> |
| April 1, 2013 to March 31, 2014    | Fixed Price | 5,000 GJ            | \$3.10/GJ    |
| April 1, 2013 to October 31, 2014  | Fixed Price | 5,000 GJ            | \$3.25/GJ    |
| April 1, 2013 to October 31, 2014  | Fixed Price | 5,000 GJ            | \$3.30/GJ    |
| April 1, 2013 to October 31, 2014  | Fixed Price | 5,000 GJ            | \$3.33/GJ    |
| April 1, 2013 to October 31, 2014  | Fixed Price | 7,500 GJ            | \$3.20/GJ    |
| April 1, 2013 to October 31, 2014  | Fixed Price | 5,000 GJ            | \$3.22/GJ    |
| April 1, 2013 to October 31, 2014  | Fixed Price | 5,000 GJ            | \$3.20/GJ    |
| April 1, 2013 to October 31, 2014  | Fixed Price | 5,000 GJ            | \$3.1925/GJ  |
| April 1, 2013 to October 31, 2014  | Fixed Price | 5,000 GJ            | \$3.25/GJ    |
| April 1, 2013 to October 31, 2014  | Fixed Price | 5,000 GJ            | \$3.30/GJ    |
| November 1, 2013 to March 31, 2015 | Fixed Price | 5,000 GJ            | \$3.6025/GJ  |

### Commodity Price Sensitivity

Peyto's earnings are largely determined by commodity prices for crude oil and natural gas including the US/Canadian dollar exchange rate. Volatility in these oil and gas prices can cause fluctuations in Peyto's earnings over which the Company has no control. Low operating costs and a long reserve life reduce Peyto's sensitivity to changes in commodity prices.

### Currency Risk Management

The Company is exposed to fluctuations in the Canadian/US dollar exchange ratio since commodities are effectively priced in US dollars and converted to Canadian dollars. In the short term, this risk is mitigated indirectly as a result of a commodity hedging strategy that is conducted in a Canadian dollar currency. Over the long term, the Canadian dollar tends to rise as commodity prices rise. There is a similar correlation between oil and gas prices. Currently Peyto has not entered into any agreements to further manage its currency risks.

### Interest Rate Risk Management

The Company is exposed to interest rate risk in relation to interest expense on its revolving demand facility. Currently there are no agreements to manage this risk. At December 31, 2012, the increase or decrease in earnings for each 100 bps (1%) change in interest rate paid on the outstanding revolving demand loan amounts to approximately \$1.1 million per quarter or \$4.2 million per annum. Average debt outstanding was \$641.3 million for the fourth quarter and \$535.4 million for 2012.

## LIQUIDITY AND CAPITAL RESOURCES

Funds from operations is reconciled to cash flows from operating activities below:

| (\$000)   | 3 Months Ended December 31 |          | 12 Months Ended December 31 |         |
|---|----------------------------|----------|-----------------------------|---------|
|   | 2012                       | 2011     | 2012                        | 2011    |
| Cash flows from operating activities                          | <b>78,878</b>              | 85,592   | <b>284,309</b>              | 289,995 |
| Change in non-cash working capital                            | <b>4,457</b>               | (19,139) | <b>12,920</b>               | 3,085   |
| Change in provision for future performance based compensation | <b>(7,712)</b>             | (8,739)  | <b>(2,819)</b>              | (1,154) |
| Income tax paid on account of 2003 reassessment               | <b>1,868</b>               | -        | <b>1,868</b>                | -       |
| <b>Performance based compensation</b>                         | <b>12,587</b>              | 22,696   | <b>12,587</b>               | 22,696  |
| Funds from operations   | <b>90,078</b>              | 80,410   | <b>308,865</b>              | 314,622 |
| Funds from operations per share                               | <b>0.62</b>                | 0.60     | <b>2.19</b>                 | 2.36    |

For the fourth quarter ended December 31, 2012, funds from operations totaled \$90.1 million or \$0.62 per share, as compared to \$80.4 million, or \$0.60 per share during the same quarter in 2011. Funds from operation for the year was down 2% to \$308.9 million.

Peyto's policy is to balance dividends to shareholders and funding for a capital program with cash flow and available bank lines. Earnings and cash flow are sensitive to changes in commodity prices, exchange rates and other factors that are beyond Peyto's control. Current volatility in commodity prices creates uncertainty as to the funds from operations and capital expenditure budget. Accordingly, results are assessed throughout the year and operational plans revised as necessary to reflect the most current information.

Revenues will be impacted by drilling success and production volumes as well as external factors such as the market prices for commodities and the exchange rate of the Canadian dollar relative to the US dollar.

### Long-Term Debt

|                                   | December 31, 2012 | December 31, 2011 |
|-----------------------------------|-------------------|-------------------|
| Bank credit facility              | 430,000           | 470,000           |
| Senior secured notes              | 150,000           | -                 |
| <b>Balance, end of the period</b> | <b>580,000</b>    | <b>470,000</b>    |

Peyto has a syndicated \$730 million extendible revolving credit facility with a stated term date of April 28, 2013. The facility is made up of a \$30 million working capital sub-tranche and a \$700 million production line. The facilities are available on a revolving basis for a period of at least 364 days and upon the term out date may be extended for a further 364 day period at the request of Peyto, subject to approval by the lenders. In the event that the revolving period is not extended, the facility is available on a non-revolving basis for a one year term, at the end of which time the facility would be due and

payable. The loan has therefore been classified as long-term on the balance sheet. The average borrowing rate for the three months ended December 31, 2012 was 5.5% (2011 – 5.0%). Outstanding amounts on this facility will bear interest at rates ranging from prime plus 1.0% to prime plus 2.5% determined by Peyto's debt to earnings before interest, taxes, depreciation, depletion and amortization (EBITDA) ratios ranging from less than 1:1 to greater than 2.5:1. A General Security Agreement with a floating charge on land registered in Alberta is held as collateral by the bank.

At December 31, 2012, \$430 million was drawn under the facility. Working capital liquidity is maintained by drawing from and repaying the unutilized credit facility as needed. At December 31, 2012, the working capital deficit was \$74.9 million (including a non-cash current asset for an unrealized mark to market future hedging gain of \$10.3 million).

On January 3, 2012, Peyto issued CDN \$100 million of senior secured notes pursuant to a note purchase and private shelf agreement with Prudential Investment Management, Inc. The notes were issued by way of private placement and rank equally with Peyto's obligations under its bank facility. The notes have a coupon rate of 4.39% and mature on January 3, 2019. Interest will be paid semi-annually in arrears. Proceeds from the notes were used to repay a portion of Peyto's outstanding bank debt.

On September 6, 2012, Peyto issued CDN \$50 million of senior secured notes pursuant to a note purchase and private shelf agreement with Prudential Investment Management, Inc. The notes were issued by way of private placement and rank equally with Peyto's obligations under its credit facility. The notes have a coupon rate of 4.88% and mature on September 6, 2022. Interest will be paid semi-annually in arrears. Proceeds from the notes were used to repay a portion of Peyto's outstanding bank debt.

Upon the issuance of the senior secured notes January 3, 2012, Peyto became subject to the following financial covenants as defined in the credit facility and note purchase and private shelf agreements:

- Senior Debt to EBITDA Ratio will not exceed 3.0 to 1.0.
- Total Debt to EBITDA Ratio will not exceed 4.0 to 1.0.
- Interest Coverage Ratio will not be less than 3.0 to 1.0
- Total Debt to Capitalization Ratio will not exceed 0.55:1.0

Peyto is in compliance with all financial covenants.

Peyto's total borrowing capacity is \$880 million and Peyto's net credit facility is \$730 million.

Peyto believes funds generated from operations, together with borrowings under the credit facility will be sufficient to maintain dividends, finance current operations, and fund the planned capital expenditure program of \$450 to \$500 million for 2013. The total amount of capital invested in 2013 will be driven by the number and quality of projects generated. Capital will only be invested if it meets the long term objectives of the Company. The majority of the capital program will involve drilling, completion and tie-in of lower risk development gas wells. Peyto's rapidly scaleable business model has the flexibility to match planned capital expenditures to actual cash flow.

#### **Net Debt**

"Net debt" is a non-GAAP measure that is the sum of long-term debt and working capital excluding the current financial derivative instruments and current provision for future performance based compensation. It is used by management to analyze the financial position and leverage of the Company. Net debt is reconciled below to long-term debt which is the most directly comparable GAAP measure:

| (\$000)   | <b>As at<br/>December 31, 2012</b> | As at<br>December 31, 2011 |
|---|------------------------------------|----------------------------|
| Bank credit facility                                | <b>430,000</b>                     | 470,000                    |
| Senior secured notes                                | <b>150,000</b>                     | -                          |
| Working capital deficit (surplus)                   | <b>74,884</b>                      | 38,818                     |
| Financial derivative instruments                    | <b>10,254</b>                      | 38,530                     |
| Provision for future performance based compensation | <b>(2,677)</b>                     | (4,321)                    |
| Net debt  | <b>662,461</b>                     | 465,391                    |

## Capital

**Authorized:** Unlimited number of voting common shares

### Issued and Outstanding

| <b>Common Shares (no par value)</b>       | <b>Number of<br/>Common<br/>Shares/Units</b> | <b>Amount<br/>\$</b> |
|---|--|----------------------|
| <b>Balance, December 31, 2010</b>         | <b>131,875,382</b>                           | <b>755,831</b>       |
| Common shares issued                      | 4,899,000                                    | 115,126              |
| Common share issuance costs (net of tax)  | -  | (3,854)              |
| Common shares issued by private placement | 906,196                                      | 17,150               |
| Common shares issued pursuant to DRIP     | 113,527                                      | 1,973                |
| Common shares issued pursuant to OTUPP    | 166,196                                      | 2,889                |
| <b>Balance, December 31, 2011</b>         | <b>137,960,301</b>                           | <b>889,115</b>       |
| Common shares issued                      | 4,628,750                                    | 115,024              |
| Common shares issued for acquisitions     | 5,404,007                                    | 112,187              |
| Common share issuance costs (net of tax)  | -  | (3,896)              |
| Common shares issued by private placement | 525,655                                      | 11,952               |
| <b>Balance, December 31, 2012</b>         | <b>148,518,713</b>                           | <b>1,124,382</b>     |

Peyto reinstated its amended distribution reinvestment and optional trust unit purchase plan (the "Amended DRIP Plan") effective with the January 2010 distribution whereby eligible unitholders could elect to reinvest their monthly cash distributions in additional trust units at a 5 percent discount to market price. The DRIP plan incorporated an Optional Trust Unit Purchase Plan ("OTUPP") which provided unitholders enrolled in the DRIP with the opportunity to purchase additional trust units from treasury using the same pricing as the DRIP. The DRIP and the OTUPP plans were cancelled December 31, 2010 with the final shares issued under the plan January 14, 2011.

On December 31, 2010, Peyto completed a private placement of 655,581 common shares to employees and consultants for net proceeds of \$12.4 million (\$18.95 per share). These common shares were issued on January 6, 2011.

On January 14, 2011, 279,723 common shares (113,527 pursuant to the DRIP and 166,196 pursuant to the OTUPP) were issued for net proceeds of \$4.9 million.

On March 25, 2011, Peyto completed a private placement of 250,615 common shares to employees and consultants for net proceeds of \$4.7 million (\$18.86 per share).

On December 16, 2011, Peyto closed an offering of 4,899,000 common shares at a price of \$23.50 per common share, receiving proceeds of \$110.1 million (net of issuance costs).

On December 31, 2011 Peyto completed a private placement of 397,235 common shares to employees and consultants for net proceeds of \$9.7 million (\$24.52 per share). These common shares were issued on January 13, 2012.

On March 23, 2012 Peyto completed a private placement of 128,420 common shares to employees and consultants for net proceeds of \$2.2 million (\$17.22 per share).

On August 14, 2012 Peyto issued 5,404,007 common shares which were valued at \$112.2 million (net of issuance costs) (\$20.76 per share) in relation to the closing of a corporate acquisition (Note 3).

On December 11, 2012, Peyto closed an offering of 4,628,750 common shares at a price of \$24.85 per common share, receiving proceeds of \$110.0 million (net of issuance costs).

### Shares to be issued

On December 31, 2012 the Company completed a private placement of 154,550 common shares to employees and consultants for net proceeds of \$3.5 million (\$22.38 per share). These common shares were issued on January 7, 2013.

### Performance Based Compensation

The Company awards performance based compensation to employees and key consultants annually. The performance based compensation is comprised of market and reserve value based components.

The reserve value based component is 4% of the incremental increase in value, if any, as adjusted to reflect changes in debt, equity and dividends, of proved producing reserves calculated using a constant price at December 31 of the current year

and a discount rate of 8%. This methodology can generate interim results which vary significantly from the final compensation paid. Compensation expense of \$4.8 million was recorded for the year ended December 31, 2012.

| (\$millions except per share values)   | 2012    | 2011    | Change     |
|--|---------|---------|------------|
| Net present value of proved producing reserves @ 8% based on constant InSite 2013 price forecast | 1,575.9 | 1,335.1 |            |
| Net debt before performance based compensation   | (653.3) | (465.4) |            |
| 2012 dividends, G&A and interest   |         | (130.8) |            |
| Net value  | 922.6   | 738.9   |            |
| Shares outstanding (millions)  | 148.519 | 138.358 |            |
| Net value per share  | 6.212   | 5.340   | 0.872      |
| Shares outstanding at beginning of year (millions)   |         |         | 138.358    |
| Equity adjusted increase in value  |         |         | 120.6      |
| <b>2012 reserve value based compensation @ 4%</b>  |         |         | <b>4.8</b> |

Under the market based component, rights with a three year vesting period are allocated to employees and key consultants. The number of rights outstanding at any time is not to exceed 6% of the total number of common shares outstanding. At December 31 of each year, all vested rights are automatically cancelled and, if applicable, paid out in cash. Compensation is calculated as the number of vested rights multiplied by the total of the market appreciation (over the price at the date of grant) and associated dividends of a common share for that period. The 2012 market based component was based on i) 0.5 million vested rights at an average grant price of \$13.50, average cumulative distributions of \$1.44 and a ten day weighted average closing price of \$18.83, ii) 0.6 million vested rights at an average grant price of \$19.13, average cumulative distributions of \$0.72 and a ten day weighted average price of \$24.75 and iii) 0.07 million vested rights at an average grant price of \$20.63, average cumulative dividends of \$0.48 and a ten day weighted average price of \$22.58.

The total amount expensed under these plans was as follows:

| (\$000)   | 2012          | 2011          |
|---|---------------|---------------|
| Market based compensation                           | 7,762         | 17,486        |
| Reserve based compensation                          | 4,825         | 5,210         |
| <b>Total market and reserves based compensation</b> | <b>12,587</b> | <b>22,696</b> |

For the future market based component, compensation costs as at December 31, 2012 were a recovery of \$2.8 million related to 0.6 million non-vested rights with an average grant price of \$19.13, average cumulative dividends of \$0.72 and 0.1 million non-vested rights with an average grant price of \$20.63 and average cumulative dividends of \$0.48. (2011 – 0.6 million non-vested rights with an average grant price of \$13.50 and 1.3 million non-vested rights with an average grant price of \$19.13 were \$1.2 million). The cumulative provision for future performance based compensation as at December 31, 2012 was \$2.7 million (2011 - \$5.6 million).

Subsequent to December 31, 2012, 3.0 million rights were granted at a price of \$22.58 to be valued at the ten day weighted average market price at December 31, 2013 and vesting 1/3 on each of December 31, 2013, December 31, 2014 and December 31, 2015.

#### Stock Appreciation Rights Outstanding

| Vesting Date      | To be Valued December 31, 2013 |            |    | To be Valued December 31, 2014 |                          |
|-------------------|--------------------------------|------------|----|--------------------------------|--------------------------|
|                   | Number of Rights               | Value (\$) |    | Number of Rights               | Average Grant Price (\$) |
| December 31, 2013 | 632,833                        | 3,979,033  | *  | 1,000,000                      | 22.58                    |
|                   | 71,667                         | 174,000    | ** |                                |                          |
| December 31, 2014 | 71,667                         | 174,000    | ** | 1,000,000                      | 22.58                    |
| December 31, 2015 | -                              | -          |    | 1,000,000                      | 22.58                    |

\*Valued on December 31, 2011 at \$24.75

\*\*Valued on December 31, 2012 at \$22.58

#### Capital Expenditures

Net capital expenditures for the fourth quarter of 2012 totaled \$156.8 million. Exploration and development related activity represented \$123.8 million (79% of total), while expenditures on facilities, gathering systems and equipment totaled \$48.0 million (31% of total) land, seismic and acquisitions totaled \$5.9 million (4% of total), reduced by

dispositions and gain on dispositions of \$20.9 million (14% of total). Capital expenditures of \$618.0 million for 2012 were 64% higher than 2011 capital expenditures. The following table summarizes capital expenditures for the year:

| (\$000)                                      | Three Months ended Dec. 31 |               | Twelve Months ended Dec. 31 |                |
|--|----------------------------|---------------|-----------------------------|----------------|
|  | 2012                       | 2011          | 2012                        | 2011           |
| Land   | 5,206                      | 5,910         | 10,770                      | 21,002         |
| Seismic                                      | 612                        | 1,245         | 1,741                       | 2,859          |
| Drilling – Exploratory & Development         | 123,778                    | 77,570        | 337,988                     | 279,446        |
| Production Equipment, Facilities & Pipelines | 48,015                     | 10,644        | 84,482                      | 72,079         |
| Acquisition of Open Range                    | -                          | -             | 187,187                     | -              |
| Acquisitions                                 | 75                         | 527           | 17,841                      | 5,581          |
| Dispositions                                 | (16,969)                   | (1,208)       | (17,646)                    | (1,906)        |
| (Gains) Losses on Dispositions               | (3,870)                    | (1,126)       | (4,378)                     | (1,634)        |
| <b>Total Capital Expenditures</b>            | <b>156,847</b>             | <b>93,562</b> | <b>617,985</b>              | <b>377,427</b> |

### Dividends

|                                | Three Months ended Dec. 31 |        | Twelve Months ended Dec. 31 |         |
|--------------------------------|----------------------------|--------|-----------------------------|---------|
|                                | 2012                       | 2011   | 2012                        | 2011    |
| Funds from operations (\$000)  | 90,078                     | 80,410 | 308,865                     | 314,622 |
| Total dividends (\$000)        | 26,178                     | 24,245 | 101,593                     | 96,068  |
| Total dividends per share (\$) | 0.18                       | 0.18   | 0.72                        | 0.72    |
| Payout ratio (%)               | 28                         | 30     | 33                          | 31      |

Peyto's policy is to balance dividends to shareholders and funding for a capital program with cash flow and available bank lines. The Board of Directors is prepared to adjust the payout ratio levels (dividends declared divided by funds from operations) to achieve the desired dividends while maintaining an appropriate capital structure.

### CONTRACTUAL OBLIGATIONS

Peyto has contractual obligations and commitments as follows:

|                                  | 2013          | 2014          | 2015          | 2016          | 2017         | Thereafter     |
|----------------------------------|---------------|---------------|---------------|---------------|--------------|----------------|
| Note repayment <sup>(1)</sup>    | -             | -             | -             | -             | -            | 150,000        |
| Interest payments <sup>(2)</sup> | 4,635         | 6,830         | 6,830         | 6,830         | 6,830        | 18,785         |
| Transportation commitments       | 14,033        | 13,077        | 9,749         | 4,575         | 1,221        | 924            |
| Operating lease                  | 1,678         | 1,694         | 522           | -             | -            | -              |
| <b>Total</b>                     | <b>20,346</b> | <b>21,601</b> | <b>17,101</b> | <b>11,405</b> | <b>8,051</b> | <b>169,709</b> |

<sup>(1)</sup> Long-term debt repayment on senior secured notes

<sup>(2)</sup> Fixed interest payments on senior secured notes

### RELATED PARTY TRANSACTIONS

An officer and director of the Company is a partner of a law firm that provides legal services to the Company. For the year ended December 31, 2012, legal fees totaled \$1.2 million (2011 - \$0.8 million). As at December 31, 2012, an amount due to this firm of \$1.2 million was included in accounts payable (2011 - \$0.7 million).

### RISK MANAGEMENT

Investors who purchase shares are participating in the total returns from a portfolio of western Canadian natural gas producing properties. As such, the total returns earned by investors and the value of the shares are subject to numerous risks inherent in the oil and natural gas industry.

Expected returns depend largely on the volume of petroleum and natural gas production and the price received for such production, along with the associated costs. The price received for oil depends on a number of factors, including West Texas Intermediate oil prices, Canadian/US currency exchange rates, quality differentials and Edmonton par oil prices. The price received for natural gas production is primarily dependent on current Alberta market prices. Peyto's marketing strategy is designed to smooth out short term fluctuations in the price of natural gas through future sales. It is meant to be methodical and consistent and to avoid speculation.

Although Peyto's focus is on internally generated drilling programs, any acquisition of oil and natural gas assets depends on an assessment of value at the time of acquisition. Incorrect assessments of value can adversely affect dividends to shareholders and the value of the shares. Peyto employs experienced staff and performs appropriate levels of due diligence on the analysis of acquisition targets, including a detailed examination of reserve reports; if appropriate, re-engineering of reserves for a large portion of the properties to ensure the results are consistent; site examinations of facilities for environmental liabilities; detailed examination of balance sheet accounts; review of contracts; review of prior year tax returns and modeling of the acquisition to attempt to ensure accretive results to the shareholders.

Inherent in development of the existing oil and gas reserves are the risks, among others, of drilling dry holes, encountering production or drilling difficulties or experiencing high decline rates in producing wells. To minimize these risks, Peyto employs experienced staff to evaluate and operate wells and utilize appropriate technology in operations. In addition, prudent work practices and procedures, safety programs and risk management principles, including insurance coverage protect the Company against certain potential losses.

The value of Peyto's shares is based on among other things, the underlying value of the oil and natural gas reserves. Geological and operational risks can affect the quantity and quality of reserves and the cost of ultimately recovering those reserves. Lower oil and gas prices increase the risk of write-downs on oil and gas property investments. In order to mitigate this risk, proven and probable oil and gas reserves are evaluated each year by a firm of independent reservoir engineers. The reserves committee of the Board of Directors reviews and approves the reserve report.

Access to markets may be restricted at times by pipeline or processing capacity. These risks are minimized by controlling as much of the processing and transportation activities as possible and ensuring transportation and processing contracts are in place with reliable cost efficient counterparties.

The petroleum and natural gas industry is subject to extensive controls, regulatory policies and income and resource taxes imposed by various levels of government. These regulations, controls and taxation policies are amended from time to time. Peyto has no control over the level of government intervention or taxation in the petroleum and natural gas industry. The Company operates in such a manner to ensure, to the best of its knowledge that it is in compliance with all applicable regulations and are able to respond to changes as they occur.

The petroleum and natural gas industry is subject to both environmental regulations and an increased environmental awareness. Peyto has reviewed its environmental risks and is, to the best of its knowledge, in compliance with the appropriate environmental legislation and have determined that there is no current material impact on operations. Peyto employs environmentally responsible business operations, and looks to both Alberta provincial authorities and Canada's federal authorities for direction and regulation regarding environmental and climate change legislation.

Peyto is subject to financial market risk. In order to maintain substantial rates of growth, the Company must continue reinvesting in, drilling for or acquiring petroleum and natural gas. The capital expenditure program is funded primarily through funds from operations, debt and, if appropriate, equity.

## **CONTROLS AND PROCEDURES**

### **Disclosure Controls and Procedures**

The Company's Chief Executive Officer and Chief Financial Officer have designed, or caused to be designed under their supervision, disclosure controls and procedures to provide reasonable assurance that: (i) material information relating to the Company is made known to the Company's Chief Executive Officer and Chief Financial Officer by others, particularly during the period in which the annual and interim filings are being prepared; and (ii) information required to be disclosed by the Company in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time period specified in securities legislation. Such officers have evaluated, or caused to be evaluated under their supervision, the effectiveness of the Company's disclosure controls and procedures at the year end of the Company and have concluded that the Company's disclosure controls and procedures are effective at the financial period end of the Company for the foregoing purposes.

### **Internal Control over Financial Reporting**

The Company's Chief Executive Officer and Chief Financial Officer have designed, or caused to be designed under their supervision, internal control over financial reporting to provide reasonable assurance regarding the reliability of the Company's financial reporting and the preparation of financial statements for external purposes in accordance with GAAP. Such officers have evaluated, or caused to be evaluated under their supervision, the effectiveness of the Company's internal control over financial reporting at the financial period end of the Company and concluded that the Company's internal control over financial reporting is effective, at the financial period end of the Company, for the foregoing purpose.

The Company is required to disclose herein any change in the Company's internal control over financial reporting that occurred during the year ended December 31, 2012 that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting. No material changes in the Company's internal control over financial reporting were identified during such period that has materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

It should be noted that a control system, including the Company's disclosure and internal controls and procedures, no matter how well conceived, can provide only reasonable, but not absolute, assurance that the objectives of the control system will be met and it should not be expected that the disclosure and internal controls and procedures will prevent all errors or fraud.

## **CRITICAL ACCOUNTING ESTIMATES**

### **Reserve Estimates**

Estimates of oil and natural gas reserves, by necessity, are projections based on geologic and engineering data, and there are uncertainties inherent to the interpretation of such data as well as the projection of future rates of production and the timing of development expenditures. Reserve engineering is an analytical process of estimating underground accumulations of oil and natural gas that can be difficult to measure. The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation and judgment. Estimates of economically recoverable oil and natural gas reserves and future net cash flows necessarily depend upon a number of variable factors and assumptions, such as historical production from the area compared with production from other producing areas, the assumed effects of regulations by governmental agencies and assumptions governing future oil and natural gas prices, future royalties and operating costs, development costs and workover and remedial costs, all of which may in fact vary considerably from actual results. For these reasons, estimates of the economically recoverable quantities of oil and natural gas attributable to any particular group of properties, classifications of such reserves based on risk recovery, and estimates of the future net cash flows expected therefrom may vary substantially. Any significant variance in the assumptions could materially affect the estimated quantity and value of the reserves, which could affect the carrying value of the Company's oil and natural gas properties and the rate of depletion of the oil and natural gas properties as well as the calculation of the reserve value based compensation. Actual production, revenues and expenditures with respect to the Company's reserves will likely vary from estimates, and such variances may be material.

The Company's estimated quantities of proved and probable reserves at December 31, 2012 were audited by independent petroleum engineers InSite Petroleum Consultants Ltd. InSite has been evaluating reserves in this area and for Peyto for 14 consecutive years.

### **Depletion and Depreciation Estimate**

All costs of exploring for and developing petroleum and natural gas reserves, together with the costs of production equipment, are capitalized and then depleted and depreciated on the unit-of-production method based on estimated gross proven reserves. Petroleum and natural gas reserves and production are converted into equivalent units based upon estimated relative energy content (6 mcf to 1 barrel of oil). Costs for gas plants and other facilities are capitalized and depreciated on a declining balance basis.

### **Impairment of Long-Lived Assets**

Impairment is indicated if the carrying value of the long-lived asset or oil and gas cash generating unit exceeds its recoverable amount under IFRS. If impairment is indicated, the amount by which the carrying value exceeds the estimated fair value of the long-lived asset is charged to earnings. The determination of the recoverable amount for impairment purposes under IFRS involves the use of numerous assumptions and judgments including future net cash flows from oil and gas reserves, future third-party pricing, inflation factors, discount rates and other uncertainties. Future revisions to these assumptions impact the recoverable amount.

### **Decommissioning Provision**

The decommissioning provision is estimated based on existing laws, contracts or other policies. The fair value of the obligation is based on estimated future costs for abandonment and reclamation discounted at a credit adjusted risk free rate. The liability is adjusted each reporting period to reflect the passage of time and for revisions to the estimated future cash flows, with the accretion charged to earnings. By their nature, these estimates are subject to measurement uncertainty and the impact on the financial statements could be material.

### **Future Market Performance Based Compensation**

The provision for future market based compensation is estimated based on current market conditions, distribution history and on the assumption that all outstanding rights will be paid out according to the vesting schedule. The conditions at the time of vesting could vary significantly from the current conditions and may have a material effect on the calculation.

### **Reserve Value Performance Based Compensation**

The reserve value based compensation is calculated using the year end independent reserves evaluation which was completed in February 2013. A quarterly provision for the reserve value based compensation is calculated using estimated proved producing reserve additions adjusted for changes in debt, equity and dividends. Actual proved producing reserves additions and forecasted commodity prices could vary significantly from those estimated and may have a material effect on the calculation.

### **Income Taxes**

The determination of the Company's income and other tax liabilities requires interpretation of complex laws and regulations often involving multiple jurisdictions. 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.

### **Accounting Changes**

Voluntary changes in accounting policy are made only if they result in financial statements which provide more reliable and relevant information. Accounting policy changes are applied retrospectively unless it is impractical to determine the period or cumulative impact of the change. Corrections of prior period errors are applied retrospectively and changes in accounting estimates are applied prospectively by including these changes in earnings. When the Company has not applied a new primary source of GAAP that has been issued, but is not effective, the Company will disclose the fact along with information relevant to assessing the possible impact that application of the new primary source of GAAP will have on the financial statements in the period of initial application.

## **CHANGES IN ACCOUNTING POLICIES**

### **Presentation of Financial Statements**

As of January 1, 2012, the Company adopted IAS 1, "Presentation of Items of OCI: Amendments to IAS 1 Presentation of Financial Statements." The amendments stipulate the presentation of net earnings and OCI and also require the Company to group items within OCI based on whether the items may be subsequently reclassified to profit or loss. The adoption of the amendments to this standard is not expected to have a material impact on the Company's financial position or results.

Peyto has reviewed new and revised accounting pronouncements that have been issued but are not yet effective and determined that the following may have an impact on the Company:

In May 2011, the IASB released the following new standards: IFRS 10, "Consolidated Financial Statements", IFRS 11, "Joint Arrangements", IFRS 12, "Disclosures of Interests in Other Entities" and IFRS 13, "Fair Value Measurement". Each of these standards is to be adopted for fiscal years beginning January 1, 2013 with earlier adoption permitted. A brief description of each new standard follows below:

- IFRS 10, "Consolidated Financial Statements" supercedes IAS 27 "Consolidation and Separate Financial Statements" and SIC-12 "Consolidation – Special Purpose Entities". This standard provides a single model to be applied in control analysis for all investees including special purpose entities. The adoption of this standard is not expected to have any impact on Peyto's financial statements.
- IFRS 11, "Joint Arrangements" divides joint arrangements into two types, joint operations and joint ventures, each with their own accounting model. All joint arrangements are required to be reassessed on transition to IFRS 11 to determine their type to apply the appropriate accounting. The adoption of this standard is not expected to have any impact on Peyto's financial statements.
- IFRS 12, "Disclosure of Interests in Other Entities" combines in a single standard the disclosure requirements for subsidiaries, associates and joint arrangements as well as unconsolidated structured entities. The adoption of this standard is not expected to have a material impact on Peyto's financial statements.
- IFRS 13, "Fair Value Measurement" defines fair value, establishes a framework for measuring fair value and sets out disclosure requirements for fair value measurements. This standard defines fair value as 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. The adoption of this standard is not expected to have a material impact on Peyto's financial statements.

As of January 1, 2015, Peyto will be required to adopt IFRS 9 "Financial Instruments", which is the result of the first phase of the International Accounting Standards Board ("IASB") project to replace IAS 39 "Financial Instruments: Recognition and Measurement". The new standard replaces the current multiple classification and measurement models for financial

assets and liabilities with a single model that has only two classification categories: amortized cost and fair value. Portions of the standard remain in development and the full impact of the standard on Peyto's Consolidated Financial Statements will not be known until the project is complete.

#### **ADDITIONAL INFORMATION**

Additional information relating to Peyto Exploration & Development Corp. can be found on SEDAR at [www.sedar.com](http://www.sedar.com) and [www.peyto.com](http://www.peyto.com).

## Quarterly information

|  | 2012        |             |             |             | 2011        |
|--|-------------|-------------|-------------|-------------|-------------|
|  | Q4          | Q3          | Q2          | Q1          | Q4          |
| <b>Operations</b>                            |             |             |             |             |             |
| Production                                   |             |             |             |             |             |
| Natural gas (mcf/d)                          | 266,808     | 244,784     | 221,176     | 220,811     | 212,715     |
| Oil & NGLs (bbl/d)                           | 5,286       | 5,236       | 4,480       | 4,101       | 3,947       |
| Barrels of oil equivalent (boe/d @ 6:1)      | 49,754      | 46,033      | 41,343      | 40,903      | 39,399      |
| Thousand cubic feet equivalent (mcf/d @ 6:1) | 298,522     | 276,200     | 248,058     | 245,417     | 236,394     |
| Average product prices                       |             |             |             |             |             |
| Natural gas (\$/mcf)                         | 3.45        | 3.06        | 2.86        | 3.53        | 4.21        |
| Oil & natural gas liquids (\$/bbl)           | 73.01       | 68.62       | 71.27       | 84.83       | 88.04       |
| \$/MCFE                                      |             |             |             |             |             |
| Average sale price (\$/mcf)                  | 4.38        | 4.01        | 3.83        | 4.59        | 5.25        |
| Average royalties paid (\$/mcf)              | 0.34        | 0.26        | 0.26        | 0.39        | 0.46        |
| Average operating expenses (\$/mcf)          | 0.31        | 0.35        | 0.29        | 0.33        | 0.35        |
| Average transportation costs (\$/mcf)        | 0.11        | 0.11        | 0.12        | 0.12        | 0.12        |
| Field netback (\$/mcf)                       | 3.62        | 3.29        | 3.16        | 3.75        | 4.32        |
| General & administrative expense (\$/mcf)    | 0.02        | 0.03        | 0.07        | 0.04        | 0.05        |
| Interest expense (\$/mcf)                    | 0.32        | 0.25        | 0.23        | 0.23        | 0.35        |
| Cash netback (\$/mcf)                        | 3.28        | 3.01        | 2.86        | 3.48        | 3.92        |
| <b>Financial (\$000 except per share)</b>    |             |             |             |             |             |
| Revenue                                      | 120,310     | 102,042     | 86,553      | 102,496     | 114,263     |
| Royalties                                    | 9,205       | 6,632       | 6,082       | 8,835       | 9,870       |
| Funds from operations                        | 90,078      | 76,918      | 64,732      | 77,645      | 80,410      |
| Funds from operations per share              | 0.62        | 0.54        | 0.47        | 0.56        | 0.60        |
| Total dividends                              | 26,178      | 25,576      | 24,927      | 24,912      | 24,245      |
| Total dividends per share                    | 0.18        | 0.18        | 0.18        | 0.18        | 0.18        |
| Payout ratio                                 | 28%         | 33%         | 39%         | 32%         | 30%         |
| Earnings                                     | 25,823      | 23,058      | 18,201      | 26,868      | 26,036      |
| Earnings per diluted share                   | 0.18        | 0.16        | 0.13        | 0.19        | 0.19        |
| Capital expenditures                         | 156,847     | 317,089     | 45,924      | 98,632      | 94,688      |
| Weighted average shares outstanding          | 145,449,651 | 142,069,048 | 138,485,956 | 138,312,078 | 133,913,301 |



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## INDEPENDENT AUDITOR'S REPORT

To the Shareholders of Peyto Exploration & Development Corp.:

We have audited the accompanying consolidated financial statements of Peyto Exploration & Development Corp., which comprise the consolidated balance sheets as at December 31, 2012 and December 31, 2011, and the consolidated income statements, consolidated statements of comprehensive income, consolidated statements of changes in equity and consolidated statements of cash flows for the years then ended, and 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 Peyto Exploration & Development Corp. as at December 31, 2012 and December 31, 2011, and its financial performance and its cash flows for the years then ended in accordance with International Financial Reporting Standards.

Chartered Accountants  
March 5, 2013  
Calgary, Alberta

# Peyto Exploration & Development Corp.

## Consolidated Balance Sheet

(Amount in \$ thousands)

|   | December 31<br>2012 | December 31<br>2011 |
|---|---------------------|---------------------|
| <b>Assets</b>   |                     |                     |
| <b>Current assets</b>   |                     |                     |
| Cash  | -                   | 57,224              |
| Accounts receivable   | 85,677              | 53,829              |
| Due from private placement (Note 7)                           | 3,459               | 9,740               |
| Derivative financial instruments (Note 13)                    | 10,254              | 38,530              |
| Prepaid expenses  | 4,150               | 3,991               |
|   | <b>103,540</b>      | <b>163,314</b>      |
| Long-term derivative financial instruments (Note 13)          | -                   | 6,304               |
| Prepaid capital   | 3,714               | 1,414               |
| Property, plant and equipment, net (Note 4)                   | 2,096,270           | 1,629,220           |
|   | <b>2,099,984</b>    | <b>1,636,938</b>    |
|   | <b>2,203,524</b>    | <b>1,800,252</b>    |
| <b>Liabilities</b>  |                     |                     |
| <b>Current liabilities</b>                                    |                     |                     |
| Accounts payable and accrued liabilities                      | 164,946             | 110,483             |
| Current income tax  | 1,890               | -                   |
| Dividends payable (Note 7)                                    | 8,911               | 8,278               |
| Provision for future performance based compensation (Note 11) | 2,677               | 4,321               |
|   | <b>178,424</b>      | <b>123,082</b>      |
| Long-term debt (Note 5)                                       | 580,000             | 470,000             |
| Long-term derivative financial instruments (Note 13)          | 2,532               | -                   |
| Provision for future performance based compensation (Note 11) | 59                  | 1,235               |
| Decommissioning provision (Note 6)                            | 58,201              | 38,037              |
| Deferred income taxes (Note 12)                               | 174,241             | 152,190             |
|   | <b>815,033</b>      | <b>661,462</b>      |
| <b>Shareholders' equity</b>                                   |                     |                     |
| Shareholders' capital (Note 7)                                | 1,124,382           | 889,115             |
| Shares to be issued (Note 7)                                  | 3,459               | 9,740               |
| Retained earnings   | 75,247              | 82,889              |
| Accumulated other comprehensive income (Note 7)               | 6,979               | 33,964              |
|   | <b>1,210,067</b>    | <b>1,015,708</b>    |
|   | <b>2,203,524</b>    | <b>1,800,252</b>    |

Approved by the Board of Directors



(signed) "Michael MacBean"  
Director



(signed) "Darren Gee"  
Director

# Peyto Exploration & Development Corp.

## Consolidated Income Statement

(Amount in \$ thousands)

|  | Year ended December 31 |                    |
|--|------------------------|--------------------|
|  | 2012                   | 2011               |
| <b>Revenue</b>   |                        |                    |
| Oil and gas sales  | 357,734                | 387,240            |
| Realized gain on hedges (Note 13)                                    | 53,667                 | 37,320             |
| Royalties  | (30,754)               | (41,064)           |
| <b>Petroleum and natural gas sales, net</b>                          | <b>380,647</b>         | <b>383,496</b>     |
| <b>Expenses</b>  |                        |                    |
| Operating (Note 8)   | 31,260                 | 27,379             |
| Transportation   | 11,275                 | 9,754              |
| General and administrative (Note 9)                                  | 3,846                  | 4,911              |
| Market and reserves based bonus (Note 11)                            | 12,587                 | 22,696             |
| Future performance based compensation (Note 11)                      | (2,819)                | (1,154)            |
| Interest (Note 10)   | 25,401                 | 21,881             |
| Accretion of decommissioning provision (Note 10)                     | 1,044                  | 840                |
| Depletion and depreciation (Note 4)                                  | 172,338                | 130,678            |
| Gain on disposition of assets (Note 4)                               | (4,378)                | (1,634)            |
|  | <b>250,554</b>         | <b>215,351</b>     |
| <b>Earnings before taxes</b>   | <b>130,093</b>         | <b>168,145</b>     |
| <b>Income tax</b>  |                        |                    |
| Deferred income tax expense (recovery) (Note 12)                     | 34,274                 | 35,013             |
| Income tax expense (Note 12)   | 1,868                  | 4,949              |
|  |                        |                    |
| <b>Earnings for the year</b>   | <b>93,951</b>          | <b>128,183</b>     |
| <b>Earnings per share (Note 7)</b>                                   |                        |                    |
| <b>Basic and diluted</b>   | <b>\$ 0.67</b>         | <b>\$ 0.96</b>     |
| <b>Weighted average number of common shares outstanding (Note 7)</b> |                        |                    |
| <b>Basic and diluted</b>   | <b>141,093,829</b>     | <b>133,196,103</b> |

# Peyto Exploration & Development Corp.

## Consolidated Statement of Comprehensive Income

(Amount in \$ thousands)

|  | Year ended December 31 |          |
|--|------------------------|----------|
|  | 2012                   | 2011     |
| <b>Earnings for the year</b>                         | <b>93,951</b>          | 128,183  |
| <b>Other comprehensive income</b>                    |                        |          |
| Change in unrealized gain (loss) on cash flow hedges | 17,687                 | 54,243   |
| Deferred tax recovery (expense)                      | 8,995                  | (3,852)  |
| Realized gain on cash flow hedges                    | (53,667)               | (37,320) |
| <b>Comprehensive Income</b>                          | <b>66,966</b>          | 141,254  |

# Peyto Exploration & Development Corp.

## Consolidated Statement of Changes in Equity

(Amount in \$ thousands)

|   | Year ended December 31 |                  |
|---|------------------------|------------------|
|   | 2012                   | 2011             |
| <b>Shareholders' capital, Beginning of Year</b>                         | <b>889,115</b>         | <b>755,831</b>   |
| Common shares issued  | 115,024                | 115,126          |
| Common shares issued pursuant to acquisition of Open Range Energy Corp. | 112,187                | -                |
| Common shares issued by private placement                               | 11,952                 | 17,150           |
| Common shares issuance costs (net of tax)                               | (3,896)                | (3,854)          |
| Common shares issued pursuant to DRIP                                   | -                      | 1,973            |
| Common shares issued pursuant to OTUPP                                  | -                      | 2,889            |
| <b>Shareholders' capital, End of Year</b>                               | <b>1,124,382</b>       | <b>889,115</b>   |
| <b>Common shares to be issued, Beginning of Year</b>                    | <b>9,740</b>           | <b>17,285</b>    |
| Common shares issued  | (9,740)                | (17,285)         |
| Common shares to be issued  | 3,459                  | 9,740            |
| <b>Common shares to be issued, End of Year</b>                          | <b>3,459</b>           | <b>9,740</b>     |
| <b>Retained earnings, Beginning of Year</b>                             | <b>82,889</b>          | <b>50,774</b>    |
| Earnings for the year   | 93,951                 | 128,183          |
| Dividends ( <i>Note 7</i> )   | (101,593)              | (96,068)         |
| <b>Retained earnings, End of Year</b>                                   | <b>75,247</b>          | <b>82,889</b>    |
| <b>Accumulated other comprehensive income, Beginning of Year</b>        | <b>33,964</b>          | <b>20,893</b>    |
| Other comprehensive income (loss)                                       | (26,985)               | 13,071           |
| <b>Accumulated other comprehensive income, End of Year</b>              | <b>6,979</b>           | <b>33,964</b>    |
| <b>Total Shareholders' Equity</b>                                       | <b>1,210,067</b>       | <b>1,015,708</b> |

# Peyto Exploration & Development Corp.

## Consolidated Statement of Cash Flows

(Amount in \$ thousands)

|  | Year ended December 31 |                  |
|--|------------------------|------------------|
|  | 2012                   | 2011             |
| <b>Cash provided by (used in)</b>                                  |                        |                  |
| <b>Operating activities</b>  |                        |                  |
| Earnings   | 93,951                 | 128,183          |
| Items not requiring cash:  |                        |                  |
| Deferred income tax  | 34,274                 | 35,013           |
| Gain on disposition of assets                                      | (4,378)                | (1,634)          |
| Depletion and depreciation   | 172,338                | 130,678          |
| Accretion of decommissioning provision                             | 1,044                  | 840              |
| Change in non-cash working capital related to operating activities | (12,920)               | (3,085)          |
|  | <b>284,309</b>         | <b>289,995</b>   |
| <b>Financing activities</b>  |                        |                  |
| Issuance of common shares  | 126,976                | 132,276          |
| Issuance costs   | (5,195)                | (5,137)          |
| Dividends  | (100,960)              | (103,615)        |
| Increase (decrease) in bank debt                                   | (40,000)               | 115,000          |
| Repayment of Open Range bank debt                                  | (72,000)               | -                |
| Issuance of long term notes  | 150,000                | -                |
|  | <b>58,821</b>          | <b>138,524</b>   |
| <b>Investing activities</b>  |                        |                  |
| Additions to property, plant and equipment                         | (400,354)              | (382,189)        |
| Dispositions of property, plant and equipment                      | -                      | 3,000            |
|  | <b>(400,354)</b>       | <b>(379,189)</b> |
| <b>Net increase in cash</b>  | <b>(57,224)</b>        | <b>49,330</b>    |
| <b>Cash, beginning of year</b>                                     | <b>57,224</b>          | <b>7,894</b>     |
| <b>Cash, end of year</b>   | <b>-</b>               | <b>57,224</b>    |

The following amounts are included in Cash flows from operating activities:

|                    |        |        |
|--------------------|--------|--------|
| Cash interest paid | 23,460 | 19,656 |
| Cash taxes paid    | -      | -      |

# **Peyto Exploration & Development Corp.**

## **Notes to Consolidated Financial Statements**

**As at December 31, 2012 and 2011**

(Amount in \$ thousands, except as otherwise noted)

### **1. Nature of operations**

Peyto Exploration & Development Corp. and its wholly owned subsidiary Open Range Energy Corp. (“Open Range”), (collectively “Peyto” or the “Company”) are Calgary based oil and natural gas companies. Peyto and Open Range amalgamated on January 1, 2013. Peyto conducts exploration, development and production activities in Canada. Peyto is incorporated and domiciled in the Province of Alberta, Canada. The address of its registered office is 1500, 250 – 2nd Street SW, Calgary, Alberta, Canada, T2P 0C1.

These financial statements were approved and authorized for issuance by the Board of Directors of Peyto on March 5, 2013.

### **2. Basis of presentation**

These consolidated financial statements (“financial statements”) for the years ended December 31, 2012 and December 31, 2011 represent the Company’s results and financial position in accordance with International Financial Reporting Standards (“IFRS”). The consolidated financial statements include the accounts of Peyto Exploration & Development Corp. and its subsidiary. Subsidiaries are defined as any entities, including unincorporated entities such as partnerships, for which the Company has the power to govern their financial and operating policies to obtain benefits from their activities. Intercompany balances, net earnings and unrealized gains and losses arising from intercompany transactions are eliminated in preparing the consolidated financial statements.

#### **a) Summary of significant accounting policies**

The precise determination of many assets and liabilities is dependent upon future events and the preparation of periodic financial statements necessarily involves the use of estimates and approximations. Accordingly, actual results could differ from those estimates. The financial statements have, in management’s opinion, been properly prepared within reasonable limits of materiality and within the framework of the Company’s basis of presentation as disclosed.

#### **b) Significant accounting estimates and judgements**

The timely preparation of the financial statements in conformity with IFRS requires that management make estimates and assumptions and use judgment regarding the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the period. Such estimates primarily relate to unsettled transactions and events as of the date of the financial statements. Accordingly, actual results may differ from estimated amounts as future confirming events occur.

Amounts recorded for depreciation, depletion and amortization, decommissioning costs and obligations and amounts used for impairment calculations are based on estimates of gross proved plus probable reserves and future costs required to develop those reserves. By their nature, these estimates of reserves, including the estimates of future prices and costs, and the related future cash flows are subject to measurement uncertainty, and the impact in the financial statements of future periods could be material.

The amount of compensation expense accrued for future performance based compensation arrangements are subject to management’s best estimate of whether or not the performance criteria will be met and what the ultimate payout will be.

Tax interpretations, regulations and legislation in the various jurisdictions in which the Company operates are subject to change. As such, income taxes are subject to measurement uncertainty.

#### **c) Presentation currency**

All amounts in these financial statements are expressed in Canadian dollars, as this is the functional and presentation currency of the Company.

#### **d) Cash Equivalents**

Cash equivalents include term deposits or a similar type of instrument, with a maturity of three months or less when purchased.

**e) Jointly controlled assets**

A jointly controlled asset involves joint control and offers joint ownership by the Company and other partners of assets contributed to or acquired for the purpose of the jointly controlled assets, without the formation of a corporation, partnership or other entity.

The Company accounts for its share of the jointly controlled assets, any liabilities it has incurred, its share of any liabilities jointly incurred with its partners, income from the sale or use of its share of the joint asset's output, together with its share of the expenses incurred by the jointly controlled asset and any expenses it incurs in relation to its interest in the jointly controlled asset.

**f) Exploration and evaluation assets**

**Pre-license costs**

Costs incurred prior to obtaining the legal right to explore for hydrocarbon resources are expensed in the period in which they are incurred. The Company has no pre-license costs.

**Exploration and evaluation costs**

Once the legal right to explore has been acquired, costs directly associated with an exploration well are capitalized as exploration and evaluation intangible assets until the drilling of the well is complete and the results have been evaluated. All such costs are subject to technical feasibility, commercial viability and management review as well as review for impairment at least once a year to confirm the continued intent to develop or otherwise extract value from the discovery. The Company has no exploration or evaluation assets.

**g) Property, plant and equipment**

Oil and gas properties and other property, plant and equipment are stated at cost, less accumulated depreciation and accumulated impairment losses.

The initial cost of an asset comprises its purchase price or construction cost, any costs directly attributable to bringing the asset into operation, the initial estimate of the decommissioning provision and borrowing costs for qualifying assets. The purchase price or construction cost is the aggregate amount paid and the fair value of any other consideration given to acquire the asset. Costs include expenditures on the construction, installation or completion of infrastructure such as well sites, pipelines and facilities including activities such as drilling, completion and tie-in costs, equipment and installation costs, associated geological and human resource costs, including unsuccessful development or delineation wells.

**Oil and natural gas asset swaps**

For exchanges or parts of exchanges that involve assets, the exchange is accounted for at fair value. Assets are then de-recognized at their current carrying amount.

**Depletion and depreciation**

Oil and natural gas properties are depleted on a unit-of-production basis over the proved plus probable reserves. All costs related to oil and natural gas properties (net of salvage value) and estimated costs of future development of proved plus probable undeveloped reserves are depleted and depreciated using the unit-of-production method based on estimated gross proved plus probable reserves as determined by independent reservoir engineers. For purposes of the depletion and depreciation calculation, relative volumes of petroleum and natural gas production and reserves are converted at the energy equivalent conversion rate of six thousand cubic feet of natural gas to one barrel of crude oil.

Other property, plant and equipment are depreciated using a declining balance method over useful life of 20 years.

**h) Corporate assets**

Corporate assets not related to oil and natural gas exploration and development activities are recorded at historical costs and depreciated over their useful life. These assets are not significant or material in nature.

**i) Impairment of non-financial assets**

The Company assesses at each reporting date whether there is an indication that an asset may be impaired. If any indication exists, or when annual impairment testing for an asset is required, the Company estimates the asset's recoverable amount. An asset's recoverable amount is the higher of fair value less costs to sell or value-in-use and is determined for an individual asset, unless the asset does not generate cash inflows that are largely independent of those from other assets or groups of assets, in which case the recoverable amount is assessed as part of a cash generating unit ("CGU"). If the carrying amount of an asset or CGU exceeds its recoverable amount, the asset or CGU is considered

impaired and is written down to its recoverable amount. In assessing value-in-use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. In determining fair value less costs to sell, recent market transactions are taken into account, if available. If no such transactions can be identified, an appropriate valuation model is used. These calculations are corroborated by valuation multiples, quoted share prices for publicly traded securities or other available fair value indicators.

Impairment losses of continuing operations are recognized in the income statement.

An assessment is made at each reporting date as to whether there is any indication that previously recognized impairment losses may no longer exist or may have decreased. If such indication exists, the Company estimates the asset's or cash-generating unit's recoverable amount. A previously recognized impairment loss is reversed only if there has been a change in the assumptions used to determine the asset's recoverable amount since the last impairment loss was recognized. The reversal is limited so that the carrying amount of the asset does not exceed its recoverable amount, nor exceed the carrying amount that would have been determined, net of depreciation, had no impairment loss been recognized for the asset in prior years.

**j) Leases**

Leases or other arrangements entered into for the use of an asset are classified as either finance or operating leases. Finance leases transfer to the Company substantially all of the risks and benefits incidental to ownership of the leased asset. Assets under finance lease are amortized over the shorter of the estimated useful life of the assets and the lease term. All other leases are classified as operating leases and the payments are amortized on a straight-line basis over the lease term.

**k) Financial instruments**

Financial instruments within the scope of IAS 39 *Financial Instruments: Recognition and Measurement* ("IAS 39") are initially recognized at fair value on the balance sheet. The Company has classified each financial instrument into the following categories: "fair value through profit or loss"; "loans & receivables"; and "other liabilities". Subsequent measurement of the financial instruments is based on their classification. Unrealized gains and losses on fair value through profit or loss financial instruments are recognized in earnings. The other categories of financial instruments are recognized at amortized cost using the effective interest rate method. The Company has made the following classifications:

| <b>Financial Assets &amp; Liabilities</b>           | <b>Category</b>                   |
|---|-----------------------------------|
| Cash  | Fair value through profit or loss |
| Accounts Receivable                                 | Loans & receivables               |
| Due from Private Placement                          | Loans & receivables               |
| Accounts Payable and Accrued Liabilities            | Other liabilities                 |
| Provision for Future Performance Based Compensation | Other liabilities                 |
| Dividends Payable                                   | Other liabilities                 |
| Long Term Debt                                      | Other liabilities                 |
| Derivative Financial Instruments                    | Fair value through profit or loss |

**Derivative instruments and risk management**

Derivative instruments are utilized by the Company to manage market risk against volatility in commodity prices. The Company's policy is not to utilize derivative instruments for speculative purposes. The Company has chosen to designate its existing derivative instruments as cash flow hedges. The Company assesses, on an ongoing basis, whether the derivatives that are used as cash flow hedges are highly effective in offsetting changes in cash flows of hedged items. All derivative instruments are recorded on the balance sheet at their fair value. The effective portion of the gains and losses is recorded in other comprehensive income until the hedged transaction is recognized in earnings. When the earnings impact of the underlying hedged transaction is recognized in the income statement, the fair value of the associated cash flow hedge is reclassified from other comprehensive income into earnings. Any hedge ineffectiveness is immediately recognized in earnings. The fair values of forward contracts are based on forward market prices.

**Embedded derivatives**

An embedded derivative is a component of a contract that causes some of the cash flows of the combined instrument to vary in a way similar to a stand-alone derivative. This causes some or all of the cash flows that otherwise would be required by the contract to be modified according to a specified variable, such as interest rate, financial instrument

price, commodity price, foreign exchange rate, a credit rating or credit index, or other variables to be treated as a financial derivative. The Company has no contracts containing embedded derivatives.

#### **Normal purchase or sale exemption**

Contracts that were entered into and continue to be held for the purpose of the receipt or delivery of a non-financial item in accordance with the Company's expected purchase, sale or usage requirements fall within the exemption from IAS 32 *Financial Instruments: Presentation* ("IAS 32") and IAS 39, which is known as the 'normal purchase or sale exemption'. The Company recognizes such contracts in its balance sheet only when one of the parties meets its obligation under the contract to deliver either cash or a non-financial asset.

#### **l) Hedging**

The Company uses derivative financial instruments from time to time to hedge its exposure to commodity price fluctuations. All derivative financial instruments are initiated within the guidelines of the Company's risk management policy. This includes linking all derivatives to specific assets and liabilities on the balance sheet or to specific firm commitments or forecasted transactions. The Company enters into hedges of its exposure to petroleum and natural gas commodity prices by entering into natural gas fixed price contracts, when it is deemed appropriate. These derivative contracts, accounted for as hedges, are recognized on the balance sheet. Realized gains and losses on these contracts are recognized in revenue and cash flows in the same period in which the revenues associated with the hedged transaction are recognized. For financial derivative contracts settling in future periods, a financial asset or liability is recognized in the balance sheet and measured at fair value, with changes in fair value recognized in other comprehensive income.

#### **m) Inventories**

Inventories are stated at the lower of cost and net realizable value. Cost of producing oil and natural gas is accounted on a weighted average basis. This cost includes all costs incurred in the normal course of business in bringing each product to its present location and condition.

#### **n) Provisions**

##### **General**

Provisions are recognized when the Company has a present obligation (legal or constructive) as a result of a past event, it is probable that an outflow of resources embodying economic benefits will be required to settle the obligation and a reliable estimate can be made of the amount of the obligation. Where the Company expects some or all of a provision to be reimbursed, the reimbursement is recognized as a separate asset but only when the reimbursement is virtually certain. The expense relating to any provision is presented in the income statement net of any reimbursement. If the effect of the time value of money is material, provisions are discounted using a current pre-tax rate that reflects, where appropriate, the risks specific to the liability. Where discounting is used, the increase in the provision due to the passage of time is recognized as a finance cost.

##### **Decommissioning provision**

Decommissioning provision is recognized when the Company has a present legal or constructive obligation as a result of past events, and it is probable that an outflow of resources will be required to settle the obligation, and a reliable estimate of the amount of obligation can be made. A corresponding amount equivalent to the provision is also recognized as part of the cost of the related property, plant and equipment. The amount recognized is the estimated cost of decommissioning, discounted to its present value using a risk-free rate. Changes in the estimated timing of decommissioning or decommissioning cost estimates are dealt with prospectively by recording an adjustment to the provision, and a corresponding adjustment to property, plant and equipment. The accretion of the discount on the decommissioning provision is included as a finance cost.

#### **o) Taxes**

##### **Current income tax**

Current income tax assets and liabilities for the current and prior periods are measured at the amount expected to be recovered from or paid to the taxation authorities. The tax rates and tax laws used to compute the amount are those that are enacted or substantively enacted, at the reporting date, in Canada.

Current income tax relating to items recognized directly in equity is recognized in equity and not in the income statement. Management periodically evaluates positions taken in the tax returns with respect to situations in which applicable tax regulations are subject to interpretation and establishes provisions where appropriate.

**Deferred income tax**

The Company follows the liability method of accounting for income taxes. Under this method, income tax assets and liabilities are recognized for the estimated tax consequences attributable to differences between the amounts reported in the financial statements and their respective tax bases, using enacted or substantively enacted tax rates expected to apply when the asset is realized or the liability settled. Deferred income tax assets are only recognized to the extent it is probable that sufficient future taxable income will be available to allow the deferred income tax asset to be realized. Accumulated deferred income tax balances are adjusted to reflect changes in income tax rates that are enacted or substantively enacted with the adjustment being recognized in earnings in the period that the change occurs, except for items recognized in shareholders' equity.

**p) Revenue recognition**

Revenue from the sale of oil, natural gas and natural gas liquids is recognized when the significant risks and rewards of ownership have been transferred, which is when title passes to the purchaser. This generally occurs when product is physically transferred into a pipe or other delivery system.

**Gains and losses on disposition**

For all dispositions, either through sale or exchange, gains and losses are calculated as the difference between the sale or exchange value in the transaction and the carrying amount of the assets disposed. Gains and losses on disposition are recognized in earnings in the same period as the transaction date.

**q) Borrowing costs**

Borrowing costs directly relating to the acquisition, construction or production of a qualifying capital project under construction are capitalized and added to the project cost during construction until such time the assets are substantially ready for their intended use, which is, when they are capable of commercial production. Where the funds used to finance a project form part of general borrowings, the amount capitalized is calculated using a weighted average of rates applicable to relevant general borrowings of the Company during the period. All other borrowing costs are recognized in the income statement in the period in which they are incurred.

**r) Share-based payments**

Liability-settled share-based payments to employees are measured at the fair value of the liability award at the grant date. A liability equal to fair value of the payments is accrued over the vesting period measured at fair value using the Black-Scholes option pricing model.

The fair value determined at the grant date of the liability-settled share-based payments is expensed on a graded basis over the vesting period, based on the Company's estimate of liability instruments that will eventually vest. At the end of each reporting period, the Company revises its estimate of the number of liability instruments expected to vest. The impact of the revision of the original estimates, if any, is recognized in the income statement such that the cumulative expense reflects the revised estimate, with a corresponding adjustment to the related liability on the balance sheet.

**s) Earnings per share**

Basic and diluted earnings per share is computed by dividing the net earnings available to common shareholders by the weighted average number of shares outstanding during the reporting period. The Company has no dilutive instruments outstanding which would cause a difference between the basic and diluted earnings per share.

**t) Shareholders' capital**

Common shares are classified within Shareholders' equity. Incremental costs directly attributable to the issuance of shares are recognized as a deduction from Shareholders' capital.

**u) Standards issued but not yet effective**

Peyto has reviewed new and revised accounting pronouncements that have been issued but are not yet effective and determined that the following may have an impact on the Company:

In May 2011, the IASB released the following new standards: IFRS 10, "Consolidated Financial Statements", IFRS 11, "Joint Arrangements", IFRS 12, "Disclosures of Interests in Other Entities" and IFRS 13, "Fair Value Measurement". Each of these standards is to be adopted for fiscal years beginning January 1, 2013 with earlier adoption permitted. A brief description of each new standard follows below:

- IFRS 10, "Consolidated Financial Statements" supercedes IAS 27 "Consolidation and Separate Financial Statements" and SIC-12 "Consolidation – Special Purpose Entities". This standard provides a single model to

be applied in control analysis for all investees including special purpose entities. The adoption of this standard is not expected to have any impact on Peyto's financial statements.

- IFRS 11, "Joint Arrangements" divides joint arrangements into two types, joint operations and joint ventures, each with their own accounting model. All joint arrangements are required to be reassessed on transition to IFRS 11 to determine their type to apply the appropriate accounting. The adoption of this standard is not expected to have any impact on Peyto's financial statements.
- IFRS 12, "Disclosure of Interests in Other Entities" combines in a single standard the disclosure requirements for subsidiaries, associates and joint arrangements as well as unconsolidated structured entities. The adoption of this standard is not expected to have a material impact on Peyto's financial statements.
- IFRS 13, "Fair Value Measurement" defines fair value, establishes a framework for measuring fair value and sets out disclosure requirements for fair value measurements. This standard defines fair value as 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. The adoption of this standard is not expected to have a material impact on Peyto's financial statements.

As of January 1, 2015, Peyto will be required to adopt IFRS 9 "Financial Instruments", which is the result of the first phase of the International Accounting Standards Board ("IASB") project to replace IAS 39 "Financial Instruments: Recognition and Measurement". The new standard replaces the current multiple classification and measurement models for financial assets and liabilities with a single model that has only two classification categories: amortized cost and fair value. Portions of the standard remain in development and the full impact of the standard on Peyto's Consolidated Financial Statements will not be known until the project is complete.

### 3. Corporate Acquisition

On August 14, 2012, Peyto completed the acquisition, by plan of arrangement, of all issued and outstanding common shares of Open Range. The total consideration of approximately \$187.2 million was paid for by the issuance of 5.4 million common shares of Peyto and the assumption of Open Range's long-term debt and working capital deficiency (\$190.4 million was allocated to Property, plant & equipment). Transaction costs of approximately \$0.7 million are included in general and administrative expenses in the Consolidated Income Statement.

| <b>Fair value of net assets acquired</b> |                |
|--|----------------|
| Working capital                          | (1,868)        |
| Property, plant and equipment            | 190,385        |
| Financial derivative instruments         | (1,132)        |
| Bank debt                                | (72,000)       |
| Decommissioning provision                | (5,127)        |
| Deferred income taxes                    | 1,929          |
| <b>Total net assets acquired</b>         | <b>112,187</b> |
| <b>Consideration</b>                     |                |
| Shares issued (5,404,007 shares)         | 112,187        |
| <b>Total purchase price</b>              | <b>112,187</b> |

The above amounts are estimates, which were made by management at the time of the preparation of these consolidated financial statements based on information then available. Amendments may be made as amounts subject to estimates are finalized.

If Peyto had acquired Open Range on January 1, 2012, the pro-forma results of the oil and gas sales, net income and comprehensive income for the period ended December 31, 2012 would have been as follows;

|                      | <b>As Stated<br/>December 31, 2012</b> | <b>Open Range<br/>January 1, 2012 to<br/>August 14, 2012</b> | <b>Pro Forma<br/>December 31, 2012</b> |
|----------------------|--|--|--|
| Oil and gas sales    | 380,647                                | 27,756   | 408,403                                |
| Net income           | 93,951                                 | 1,134  | 95,085                                 |
| Comprehensive income | 66,966                                 | 1,134  | 68,100                                 |

#### 4. Property, plant and equipment, net

| <b>Cost</b>                                   |                  |
|---|------------------|
| At December 31, 2010                          | 1,452,242        |
| Additions                                     | 392,309          |
| Dispositions                                  | (785)            |
| At December 31, 2011                          | 1,843,766        |
| Acquisitions through business combinations    | 190,385          |
| Additions                                     | 466,506          |
| Dispositions                                  | (17,649)         |
| At December 31, 2012                          | 2,483,008        |
| <b>Accumulated depletion and depreciation</b> |                  |
| At December 31, 2010                          | (84,373)         |
| Depletion and depreciation                    | (130,678)        |
| Dispositions                                  | 505              |
| At December 31, 2011                          | (214,546)        |
| Depletion and depreciation                    | (172,338)        |
| Dispositions                                  | 146              |
| At December 31, 2012                          | (386,738)        |
| <b>Carrying amount at December 31, 2012</b>   | <b>2,096,270</b> |

Proceeds received for assets disposed of during 2012 were \$21.9 million (2011 - \$3.0 million).

In September 2012, Peyto acquired producing properties for net proceeds of \$16.7 million, which were allocated to property, plant and equipment of \$17.4 million and decommissioning liabilities of \$0.7 million. The properties are in Peyto's core area of production. The impact on revenue and net income is not significant.

During 2012 Peyto capitalized \$7.8 million (2011 - \$5.5 million) of general and administrative expense directly attributable to exploration and development activities.

The Company did not have any indicators of impairment in the current or prior years.

#### 5. Long-term debt

|                                 | <b>December 31, 2012</b> | <b>December 31, 2011</b> |
|---------------------------------|--------------------------|--------------------------|
| Bank credit facility            | 430,000                  | 470,000                  |
| Senior secured notes            | 150,000                  | -                        |
| <b>Balance, end of the year</b> | <b>580,000</b>           | <b>470,000</b>           |

The Company has a syndicated \$730 million extendible revolving credit facility with a stated term date of April 28, 2013. The bank facility is made up of a \$30 million working capital sub-tranche and a \$700 million production line. The facilities are available on a revolving basis for a period of at least 364 days and upon the term out date may be extended for a further 364 day period at the request of the Company, subject to approval by the lenders. In the event that the revolving period is not extended, the facility is available on a non-revolving basis for a further one year term, at the end of which time the facility would be due and payable. Outstanding amounts on this facility will bear interest at rates ranging from prime plus 1.0% to prime plus 2.5% determined by the Company's debt to earnings before interest, taxes, depreciation, depletion and amortization (EBITDA) ratios ranging from less than 1:1 to greater than 2.5:1. A General Security Agreement with a floating charge on land registered in Alberta is held as collateral by the bank.

On January 3, 2012, Peyto issued CDN \$100 million of senior secured notes pursuant to a note purchase and private shelf agreement. The notes were issued by way of private placement and rank equally with Peyto's obligations under its bank facility. The notes are secured under the General Security Agreement with a floating charge on land registered in Alberta is held as collateral. The notes have a coupon rate of 4.39% and mature on January 3, 2019. Interest will be paid semi-annually in arrears.

On September 6, 2012, Peyto issued CDN \$50 million of senior secured notes pursuant to a note purchase and private shelf agreement. The notes were issued by way of private placement and rank equally with Peyto's obligations under its bank facility. The notes are secured under the General Security Agreement with a floating charge on land registered in Alberta is held as collateral. The notes have a coupon rate of 4.88% and mature on September 6, 2022. Interest will be paid semi-annually in arrears.

Upon the issuance of the senior secured notes January 3, 2012, Peyto became subject to the following financial covenants as defined in the credit facility and note purchase and private shelf agreements:

- Senior Debt to EBITDA Ratio will not exceed 3.0 to 1.0
- Total Debt to EBITDA Ratio will not exceed 4.0 to 1.0
- Interest Coverage Ratio will not be less than 3.0 to 1.0
- Total Debt to Capitalization Ratio will not exceed 0.55:1.0

Peyto is in compliance with all financial covenants at December 31, 2012.

Peyto's total borrowing capacity is \$880 million and Peyto's net credit facility is \$730 million.

The fair value of all senior notes as at December 31, 2012, is \$149.9 million compared to a carrying value of \$150.0 million.

Total interest expense for 2012 was \$25.4 million (2011 - \$21.9 million) and the average borrowing rate for 2012 was 4.7% (2011 - 4.8%).

## 6. Decommissioning provision

The Company makes provision for the future cost of decommissioning wells, pipelines and facilities on a discounted basis based on the commissioning of these assets.

The decommissioning provision represents the present value of the decommissioning costs related to the above infrastructure, which are expected to be incurred over the economic life of the assets. The provisions have been based on the Company's internal estimates on the cost of decommissioning, the discount rate, the inflation rate and the economic life of the infrastructure. Assumptions, based on the current economic environment, have been made which management believes are a reasonable basis upon which to estimate the future liability. These estimates are reviewed regularly to take into account any material changes to the assumptions. However, actual decommissioning costs will ultimately depend upon the future market prices for the necessary decommissioning work required which will reflect market conditions at the relevant time. Furthermore, the timing of the decommissioning is likely to depend on when production activities ceases to be economically viable. This in turn will depend and be directly related to the current and future commodity prices, which are inherently uncertain.

The following table reconciles the change in decommissioning provision:

|                                       |               |
|---------------------------------------|---------------|
| <b>Balance, December 31, 2010</b>     | <b>24,734</b> |
| New or increased provisions           | 4,764         |
| Accretion of discount                 | 840           |
| Change in discount rate and estimates | 7,699         |
| <b>Balance, December 31, 2011</b>     | <b>38,037</b> |
| New or increased provisions           | 13,908        |
| Accretion of discount                 | 1,044         |
| Change in discount rate and estimates | 5,212         |
| <b>Balance, December 31, 2012</b>     | <b>58,201</b> |
| Current                               | -             |
| Non-current                           | 58,201        |

The Company has estimated the net present value of its total decommissioning provision to be \$58.2 million as at December 31, 2012 (\$38.0 million at December 31, 2011) based on a total future undiscounted liability of \$127.9 million (\$101.2 million at December 31, 2011). At December 31, 2012 management estimates that these payments are expected to be made over the next 50 years with the majority of payments being made in years 2041 to 2062. The Bank

of Canada's long term bond rate of 2.36 per cent (2.49 per cent at December 31, 2011) and an inflation rate of 2.0 per cent (2.0 per cent at December 31, 2011) were used to calculate the present value of the decommissioning provision.

## 7. Shareholders' capital

**Authorized:** Unlimited number of voting common shares

### Issued and Outstanding

| <b>Common Shares (no par value)</b>       | <b>Number of<br/>Common<br/>Shares</b> | <b>Amount<br/>\$</b> |
|---|--|----------------------|
| <b>Balance, December 31, 2010</b>         | <b>131,875,382</b>                     | <b>755,831</b>       |
| Common shares issued                      | 4,899,000                              | 115,126              |
| Common share issuance costs (net of tax)  | -                                      | (3,854)              |
| Common shares issued by private placement | 906,196                                | 17,150               |
| Common shares issued pursuant to DRIP     | 113,527                                | 1,973                |
| Common shares issued pursuant to OTUPP    | 166,196                                | 2,889                |
| <b>Balance, December 31, 2011</b>         | <b>137,960,301</b>                     | <b>889,115</b>       |
| Common shares issued                      | 4,628,750                              | 115,024              |
| Common shares issued for acquisition      | 5,404,007                              | 112,187              |
| Common share issuance costs (net of tax)  | -                                      | (3,896)              |
| Common shares issued by private placement | 525,655                                | 11,952               |
| <b>Balance, December 31, 2012</b>         | <b>148,518,713</b>                     | <b>1,124,382</b>     |

Peyto reinstated its amended distribution reinvestment and optional trust unit purchase plan (the "Amended DRIP Plan") effective with the January 2010 distribution whereby eligible unitholders could elect to reinvest their monthly cash distributions in additional trust units at a 5 percent discount to market price. The DRIP plan incorporated an Optional Trust Unit Purchase Plan ("OTUPP") which provided unitholders enrolled in the DRIP with the opportunity to purchase additional trust units from treasury using the same pricing as the DRIP. The DRIP and the OTUPP plans were cancelled December 31, 2010 with the final shares issued under the plan January 14, 2011.

On December 31, 2010, Peyto completed a private placement of 655,581 common shares to employees and consultants for net proceeds of \$12.4 million (\$18.95 per share). These common shares were issued on January 6, 2011.

On January 14, 2011, 279,723 common shares (113,527 pursuant to the DRIP and 166,196 pursuant to the OTUPP) were issued for net proceeds of \$4.9 million.

On March 25, 2011, Peyto completed a private placement of 250,615 common shares to employees and consultants for net proceeds of \$4.7 million (\$18.86 per share).

On December 16, 2011, Peyto closed an offering of 4,899,000 common shares at a price of \$23.50 per common share, receiving proceeds of \$110.1 million (net of issuance costs).

On December 31, 2011 Peyto completed a private placement of 397,235 common shares to employees and consultants for net proceeds of \$9.7 million (\$24.52 per share). These common shares were issued on January 13, 2012.

On March 23, 2012 Peyto completed a private placement of 128,420 common shares to employees and consultants for net proceeds of \$2.2 million (\$17.22 per share).

On August 14, 2012 Peyto issued 5,404,007 common shares which were valued at \$112.2 million (net of issuance costs) (\$20.76 per share) in relation to the closing of a corporate acquisition (Note 3).

On December 11, 2012, Peyto closed an offering of 4,628,750 common shares at a price of \$24.85 per common share, receiving proceeds of \$110.0 million (net of issuance costs).

### Shares to be issued

On December 31, 2012 the Company completed a private placement of 154,550 common shares to employees and consultants for net proceeds of \$3.5 million (\$22.38 per share). These common shares were issued on January 7, 2013.

### Per share amounts

Earnings per share or unit have been calculated based upon the weighted average number of common shares outstanding for the year ended December 31, 2012 of 141,093,829 (2011 – 133,196,103). There are no dilutive instruments outstanding.

### Dividends

During the year ended December 31, 2012, Peyto declared and paid dividends of \$0.72 per common share or \$0.06 per common share per month, totaling \$101.6 million (2011 - \$0.72 or \$0.06 per share per month, \$96.1 million).

On January 15, 2013 Peyto declared dividends of \$0.06 per common share paid on February 15, 2013. On February 15, 2013, Peyto declared dividends of \$0.06 per common share to be paid to shareholders of records February 28, 2013. These dividends will be paid March 15, 2013.

### Comprehensive income

Comprehensive income consists of earnings and other comprehensive income (“OCI”). OCI comprises the change in the fair value of the effective portion of the derivatives used as hedging items in a cash flow hedge. “Accumulated other comprehensive income” is an equity category comprised of the cumulative amounts of OCI.

### Accumulated hedging gains

Gains and losses from cash flow hedges are accumulated until settled. These outstanding hedging contracts are recognized in earnings on settlement with gains and losses being recognized as a component of net revenue. Further information on these contracts is set out in Note 13.

## 8. Operating expenses

The Company’s operating expenses include all costs with respect to day-to-day well and facility operations. Processing and gathering recoveries related to jointly controlled assets and third party natural gas reduce operating expenses.

|                                     | Years ended December 31 |               |
|-------------------------------------|-------------------------|---------------|
|                                     | 2012                    | 2011          |
| Field expenses                      | 46,591                  | 38,240        |
| Processing and gathering recoveries | (15,331)                | (10,861)      |
| <b>Total operating expenses</b>     | <b>31,260</b>           | <b>27,379</b> |

## 9. General and administrative expenses

General and administrative expenses are reduced by operating and capital overhead recoveries from operated properties.

|  | Years ended December 31 |              |
|--|-------------------------|--------------|
|  | 2012                    | 2011         |
| General and administrative expenses            | 12,822                  | 11,402       |
| Overhead recoveries                            | (8,976)                 | (6,491)      |
| <b>Net general and administrative expenses</b> | <b>3,846</b>            | <b>4,911</b> |

## 10. Finance costs

|                                     | Years ended December 31 |               |
|-------------------------------------|-------------------------|---------------|
|                                     | 2012                    | 2011          |
| Interest expense                    | 25,401                  | 21,881        |
| Accretion of discount on provisions | 1,044                   | 840           |
|                                     | <b>26,445</b>           | <b>22,721</b> |

## 11. Future performance based compensation

The Company awards performance based compensation to employees annually. The performance based compensation is comprised of reserve and market value based components.

### Reserve based component

The reserves value based component is 4% of the incremental increase in value, if any, as adjusted to reflect changes in debt, equity, dividends, general and administrative costs and interest, of proved producing reserves calculated using a

constant price at December 31 of the current year and a discount rate of 8%.

### Market based component

Under the market based component, rights with a three year vesting period are allocated to employees and key consultants. The number of rights outstanding at any time is not to exceed 6% of the total number of common shares outstanding. At December 31 of each year, all vested rights are automatically cancelled and, if applicable, paid out in cash. Compensation is calculated as the number of vested rights multiplied by the total of the market appreciation (over the price at the date of grant) and associated dividends of a common share for that period. The 2012 market based component was based on i) 0.5 million vested rights at an average grant price of \$13.50, average cumulative distributions of \$1.44 and a ten day weighted average closing price of \$18.83, ii) 0.6 million vested rights at an average grant price of \$19.13, average cumulative distributions of \$0.72 and a ten day weighted average price of \$24.75 and iii) 0.07 million vested rights at an average grant price of \$20.63, average cumulative dividends of \$0.48 and a ten day weighted average price of \$22.58.

The total amount expensed under these plans was as follows:

| (\$000)   | <b>2012</b>   | 2011          |
|---|---------------|---------------|
| Market based compensation                           | 7,762         | 17,486        |
| Reserve based compensation                          | 4,825         | 5,210         |
| <b>Total market and reserves based compensation</b> | <b>12,587</b> | <b>22,696</b> |

For the future market based component, compensation costs as at December 31, 2012 were a recovery of \$2.8 million related to 0.6 million non-vested rights with an average grant price of \$19.13, average cumulative dividends of \$0.72 and 0.1 million non-vested rights with an average grant price of \$20.63 and average cumulative dividends of \$0.48. (2011 – 0.6 million non-vested rights with an average grant price of \$13.50 and 1.3 million non-vested rights with an average grant price of \$19.13 were \$1.2 million). The cumulative provision for future performance based compensation as at December 31, 2012 was \$2.7 million (2011 - \$5.6 million).

The fair values were calculated using a Black-Scholes valuation model. The principal inputs to the option valuation model were:

|                         | <b>December 31<br/>2012</b> | <b>December 31<br/>2011</b> |
|-------------------------|-----------------------------|-----------------------------|
| Share price             | \$22.58                     | \$24.75                     |
| Exercise price          | \$18.41 - \$19.91           | \$12.06 - \$18.41           |
| Expected volatility     | 0%                          | 0%                          |
| Option life             | 1 - 2 years                 | 1 - 2 years                 |
| Dividend yield          | 0%                          | 0%                          |
| Risk-free interest rate | 1.08%                       | 0.97%                       |

Subsequent to December 31, 2012, 3.0 million rights were granted at a price of \$22.58 to be valued at the ten day weighted average market price at December 31, 2013 and vesting one third on each of December 31, 2013, December 31, 2014 and December 31, 2015.

## 12. Income taxes

| (\$000)                                    | <b>2012</b>   | <b>2011</b>   |
|--|---------------|---------------|
| Earnings before income taxes               | 130,093       | 168,145       |
| Statutory income tax rate                  | 25.00%        | 26.50%        |
| Expected income taxes                      | 32,523        | 44,558        |
| Increase (decrease) in income taxes from:  |               |               |
| Corporate income tax rate change           | -             | (2,429)       |
| True-up tax pools                          | 1,634         | (7,706)       |
| Resolution of reassessment and other       | 1,985         | 5,539         |
| <b>Total income tax expense (recovery)</b> | <b>36,142</b> | <b>39,962</b> |
| Deferred income tax expense (recovery)     | 34,274        | 35,013        |
| Current tax expense                        | 1,868         | 4,949         |
| <b>Total income tax expense (recovery)</b> | <b>36,142</b> | <b>39,962</b> |

|  |                |                |
|--|----------------|----------------|
| Differences between tax base and reported amounts for depreciable assets | 207,805        | 167,282        |
| Derivative financial instruments   | 1,930          | 11,208         |
| Share issuance costs   | (3,095)        | (3,083)        |
| Future performance based bonuses   | (684)          | (1,389)        |
| Provision for decommission provision                                     | (14,550)       | (9,509)        |
| Cumulative eligible capital  | (6,599)        | (7,096)        |
| Attributable crown royalty income carryforward                           | -              | (4,964)        |
| Tax loss carry-forwards recognized                                       | (10,566)       | (259)          |
| <b>Deferred income taxes</b>   | <b>174,241</b> | <b>152,190</b> |

At December 31, 2012 the Company has tax pools of approximately \$1,288.0 million (2011 - \$998.1 million) available for deduction against future income. The Company has approximately \$42.1 million in loss carry-forwards (2011 - \$0.4 million) available to reduce future taxable income.

Canada Revenue Agency ("CRA") conducted an audit of restructuring costs incurred in the 2003 trust conversion. On September 25, 2008, the CRA reassessed on the basis that \$41 million of these costs were not deductible and treated them as an eligible capital amount. The Company filed a notice of objection and the CRA confirmed the reassessment. Examinations for discovery have been completed. The Tax Court of Canada had agreed to both parties' request to hold the Company's appeal in abeyance pending a decision of the Supreme Court of Canada to hear another taxpayer's appeal. The other appeal raised issues that are similar in principle to those raised in the Company's appeal. As the other taxpayer's appeal was unsuccessful with the Federal Court of Appeal, in 2011, the Company expensed the income tax of \$4.9 million and interest charges of \$2.2 million assessed and paid in 2008. Subsequently, the Alberta Government reassessed the same time period resulting in income taxes payable of \$1.8 million and interest charges of \$1.4 million paid in 2013.

### 13. Financial instruments

#### Financial instrument classification and measurement

Financial instruments of the Company carried on the consolidated balance sheet are carried at amortized cost with the exception of cash and financial derivative instruments, specifically fixed price contracts, 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 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 and financial derivative instruments have been assessed on the fair value hierarchy described above and classified as Level 1.

#### Fair values of financial assets and liabilities

The Company's financial instruments include cash, accounts receivable, financial derivative instruments, due from private placement, current liabilities, provision for future performance based compensation and long term debt. At December 31, 2012 and 2011, cash and financial derivative instruments are carried at fair value. Accounts receivable, due from private placement, current liabilities and provision for future performance based compensation approximate their fair value due to their short term nature. The carrying value of the long term debt approximates its fair value due to the floating rate of interest charged under the credit facility.

#### Market risk

Market risk is the risk that changes in market prices will affect the Company's earnings or the value of its financial instruments. Market risk is comprised of commodity price risk and interest rate risk. The objective of market risk

management is to manage and control exposures within acceptable limits, while maximizing returns. The Company's objectives, processes and policies for managing market risks have not changed from the previous year.

### Commodity price risk management

The Company is a party to certain derivative financial instruments, including fixed price contracts. The Company enters into these contracts with well established counterparties for the purpose of protecting a portion of its future earnings and cash flows from operations from the volatility of petroleum and natural gas prices. The Company believes the derivative financial instruments are effective as hedges, both at inception and over the term of the instrument, as the term and notional amount do not exceed the Company's firm commitment or forecasted transactions and the underlying basis of the instruments correlate highly with the Company's exposure.

Following is a summary of all risk management contracts in place as at December 31, 2012:

| <b>Propane</b>                      |             |                       |  | <b>Price</b> |
|-------------------------------------|-------------|-----------------------|--|--------------|
| <b>Period Hedged</b>                | <b>Type</b> | <b>Monthly Volume</b> |  | <b>(USD)</b> |
| September 1, 2012 to March 31, 2013 | Fixed Price | 2,000 bbl             |  | \$49.56/bbl  |
| September 1, 2012 to March 31, 2013 | Fixed Price | 2,000 bbl             |  | \$44.10/ bbl |
| September 1, 2012 to March 31, 2013 | Fixed Price | 2,000 bbl             |  | \$32.34/ bbl |
| September 1, 2012 to March 31, 2013 | Fixed Price | 2,000 bbl             |  | \$33.60/ bbl |
| September 1, 2012 to March 31, 2013 | Fixed Price | 2,000 bbl             |  | \$32.97/ bbl |
| October 1, 2012 to March 31, 2013   | Fixed Price | 2,000 bbl             |  | \$34.01/ bbl |
| October 1, 2012 to March 31, 2013   | Fixed Price | 2,000 bbl             |  | \$34.65/ bbl |
| October 1, 2012 to March 31, 2013   | Fixed Price | 2,000 bbl             |  | \$36.96/ bbl |
| January 1, 2013 to March 31, 2013   | Fixed Price | 4,000 bbl             |  | \$36.12/bbl  |
| April 1, 2013 to June 30, 2013      | Fixed Price | 4,000 bbl             |  | \$34.86/bbl  |
| April 1, 2013 to December 31, 2013  | Fixed Price | 4,000 bbl             |  | \$30.66/bbl  |
| April 1, 2013 to December 31, 2013  | Fixed Price | 4,000 bbl             |  | \$32.34/bbl  |
| April 1, 2013 to December 31, 2013  | Fixed Price | 4,000 bbl             |  | \$34.86/bbl  |
| April 1, 2013 to December 31, 2013  | Fixed Price | 4,000 bbl             |  | \$35.39/bbl  |

  

| <b>Butane</b>                       |             |                       |  | <b>Price</b> |
|-------------------------------------|-------------|-----------------------|--|--------------|
| <b>Period Hedged</b>                | <b>Type</b> | <b>Monthly Volume</b> |  | <b>(USD)</b> |
| September 1, 2012 to March 31, 2013 | Fixed Price | 2,000 bbl             |  | \$80.64/bbl  |
| September 1, 2012 to March 31, 2013 | Fixed Price | 2,000 bbl             |  | \$58.38/bbl  |
| September 1, 2012 to March 31, 2013 | Fixed Price | 2,000 bbl             |  | \$60.06/bbl  |
| September 1, 2012 to March 31, 2013 | Fixed Price | 2,000 bbl             |  | \$60.06/bbl  |
| October 1, 2012 to March 31, 2013   | Fixed Price | 2,000 bbl             |  | \$66.36/bbl  |

  

| <b>Iso-Butane</b>                   |             |                       |  | <b>Price</b> |
|-------------------------------------|-------------|-----------------------|--|--------------|
| <b>Period Hedged</b>                | <b>Type</b> | <b>Monthly Volume</b> |  | <b>(USD)</b> |
| September 1, 2012 to March 31, 2013 | Fixed Price | 1,000 bbl             |  | \$82.32/bbl  |
| September 1, 2012 to March 31, 2013 | Fixed Price | 1,000 bbl             |  | \$60.48/bbl  |
| September 1, 2012 to March 31, 2013 | Fixed Price | 1,000 bbl             |  | \$62.58/bbl  |
| September 1, 2012 to March 31, 2013 | Fixed Price | 1,000 bbl             |  | \$62.58/bbl  |
| October 1, 2012 to March 31, 2013   | Fixed Price | 1,000 bbl             |  | \$69.30/bbl  |

  

| <b>Natural Gas</b>                 |             |                     |  | <b>Price</b> |
|------------------------------------|-------------|---------------------|--|--------------|
| <b>Period Hedged</b>               | <b>Type</b> | <b>Daily Volume</b> |  | <b>(CAD)</b> |
| April 1, 2011 to March 31, 2013    | Fixed Price | 5,000 GJ            |  | \$4.055/GJ   |
| April 1, 2011 to March 31, 2013    | Fixed Price | 5,000 GJ            |  | \$3.80/GJ    |
| June 1, 2011 to March 31, 2013     | Fixed Price | 5,000 GJ            |  | \$4.17/GJ    |
| June 1, 2011 to March 31, 2013     | Fixed Price | 5,000 GJ            |  | \$4.10/GJ    |
| June 1, 2011 to March 31, 2013     | Fixed Price | 5,000 GJ            |  | \$4.10/GJ    |
| November 1, 2011 to March 31, 2013 | Fixed Price | 5,000 GJ            |  | \$4.00/GJ    |
| April 1, 2012 to October 31, 2013  | Fixed Price | 5,000 GJ            |  | \$4.00/GJ    |
| April 1, 2012 to October 31, 2013  | Fixed Price | 5,000 GJ            |  | \$4.00/GJ    |
| April 1, 2012 to October 31, 2013  | Fixed Price | 5,000 GJ            |  | \$4.00/GJ    |
| April 1, 2012 to October 31, 2013  | Fixed Price | 5,000 GJ            |  | \$4.00/GJ    |
| April 1, 2012 to March 31, 2013    | Fixed Price | 5,000 GJ            |  | \$2.20/GJ    |

|                                      |             |          |             |
|--------------------------------------|-------------|----------|-------------|
| April 1, 2012 to March 31, 2013      | Fixed Price | 5,000 GJ | \$2.31/GJ   |
| April 1, 2012 to October 31, 2013    | Fixed Price | 5,000 GJ | \$2.52/GJ   |
| April 1, 2012 to March 31, 2014      | Fixed Price | 5,000 GJ | \$3.00/GJ   |
| May 1, 2012 to October 31, 2013      | Fixed Price | 5,000 GJ | \$2.30/GJ   |
| August 1, 2012 to March 31, 2014     | Fixed Price | 5,000 GJ | \$3.00/GJ   |
| August 1, 2012 to October 31, 2014   | Fixed Price | 5,000 GJ | \$3.10/GJ   |
| November 1, 2012 to October 31, 2013 | Fixed Price | 5,000 GJ | \$2.60/GJ   |
| November 1, 2012 to October 31, 2013 | Fixed Price | 5,000 GJ | \$3.005/GJ  |
| November 1, 2012 to October 31, 2013 | Fixed Price | 5,000 GJ | \$3.00/GJ   |
| November 1, 2012 to March 31, 2014   | Fixed Price | 5,000 GJ | \$2.81/GJ   |
| November 1, 2012 to March 31, 2014   | Fixed Price | 5,000 GJ | \$3.00/GJ   |
| November 1, 2012 to March 31, 2014   | Fixed Price | 5,000 GJ | \$3.05/GJ   |
| November 1, 2012 to March 31, 2014   | Fixed Price | 5,000 GJ | \$3.02/GJ   |
| November 1, 2012 to October 31, 2014 | Fixed Price | 5,000 GJ | \$3.0575/GJ |
| January 1, 2013 to October 31, 2013  | Fixed Price | 5,000 GJ | \$3.42/GJ   |
| January 1, 2013 to December 31, 2013 | Fixed Price | 5,000 GJ | \$3.105/GJ  |
| January 1, 2013 to March 31, 2013    | Fixed Price | 5,000 GJ | \$3.32/GJ   |
| January 1, 2013 to March 31, 2014    | Fixed Price | 5,000 GJ | \$3.00/GJ   |
| January 1, 2013 to March 31, 2014    | Fixed Price | 5,000 GJ | \$3.02/GJ   |
| April 1, 2013 to October 31, 2013    | Fixed Price | 5,000 GJ | \$3.205/GJ  |
| April 1, 2013 to March 31, 2014      | Fixed Price | 5,000 GJ | \$3.105/GJ  |
| April 1, 2013 to March 31, 2014      | Fixed Price | 5,000 GJ | \$3.53/GJ   |
| April 1, 2013 to March 31, 2014      | Fixed Price | 5,000 GJ | \$3.45/GJ   |
| April 1, 2013 to March 31, 2014      | Fixed Price | 5,000 GJ | \$3.50/GJ   |
| April 1, 2013 to March 31, 2014      | Fixed Price | 5,000 GJ | \$3.08/GJ   |
| April 1, 2013 to March 31, 2014      | Fixed Price | 5,000 GJ | \$3.17GJ    |
| November 1, 2013 to October 31, 2014 | Fixed Price | 5,000 GJ | \$3.50/GJ   |

As at December 31, 2012, Peyto had committed to the future sale of 261,000 barrels of natural gas liquids at an average price of \$39.86 USD per barrel and 59,810,000 gigajoules (GJ) of natural gas at an average price of \$3.19 per GJ or \$3.74 per mcf. Had these contracts been closed on December 31, 2012, Peyto would have realized a gain in the amount of \$7.7 million. If the AECO gas price on December 31, 2012 were to increase by \$1/GJ, the unrealized gain would decrease by approximately \$59.8 million. An opposite change in commodity prices rates would result in an opposite impact on other comprehensive income.

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

| <b>Propane</b>                     |             |                       | <b>Price</b> |
|------------------------------------|-------------|-----------------------|--------------|
| <b>Period Hedged</b>               | <b>Type</b> | <b>Monthly Volume</b> | <b>(USD)</b> |
| April 1, 2013 to December 31, 2013 | Fixed Price | 4,000 bbl             | \$34.44/bbl  |

| <b>Natural Gas</b>                 |             |                     | <b>Price</b> |
|------------------------------------|-------------|---------------------|--------------|
| <b>Period Hedged</b>               | <b>Type</b> | <b>Daily Volume</b> | <b>(CAD)</b> |
| April 1, 2013 to March 31, 2014    | Fixed Price | 5,000 GJ            | \$3.10/GJ    |
| April 1, 2013 to October 31, 2014  | Fixed Price | 5,000 GJ            | \$3.25/GJ    |
| April 1, 2013 to October 31, 2014  | Fixed Price | 5,000 GJ            | \$3.30/GJ    |
| April 1, 2013 to October 31, 2014  | Fixed Price | 5,000 GJ            | \$3.33/GJ    |
| April 1, 2013 to October 31, 2014  | Fixed Price | 7,500 GJ            | \$3.20/GJ    |
| April 1, 2013 to October 31, 2014  | Fixed Price | 5,000 GJ            | \$3.22/GJ    |
| April 1, 2013 to October 31, 2014  | Fixed Price | 5,000 GJ            | \$3.20/GJ    |
| April 1, 2013 to October 31, 2014  | Fixed Price | 5,000 GJ            | \$3.1925/GJ  |
| April 1, 2013 to October 31, 2014  | Fixed Price | 5,000 GJ            | \$3.25/GJ    |
| April 1, 2013 to October 31, 2014  | Fixed Price | 5,000 GJ            | \$3.30/GJ    |
| November 1, 2013 to March 31, 2015 | Fixed Price | 5,000 GJ            | \$3.6025/GJ  |

### Interest rate risk

The Company is exposed to interest rate risk in relation to interest expense on its revolving credit facility. Currently, the Company has not entered into any agreements to manage this risk. If interest rates applicable to floating rate debt were to have increased by 100 bps (1%) it is estimated that the Company's earnings before income tax for the year ended December 31, 2012 would decrease by \$4.2 million. An opposite change in interest rates will result in an opposite impact on earnings before income tax.

### Credit risk

A substantial portion of the Company's accounts receivable is with petroleum and natural gas marketing entities. Industry standard dictates that commodity sales are settled on the 25th day of the month following the month of production. The Company generally extends unsecured credit to purchasers, and therefore, the collection of accounts receivable may be affected by changes in economic or other conditions and may accordingly impact the Company's overall credit risk. Management believes the risk is mitigated by the size, reputation and diversified nature of the companies to which they extend credit. The Company has not previously experienced any material credit losses on the collection of accounts receivable. Of the Company's revenue for the year ended December 31, 2012, approximately 13% was received from one company (December 31, 2011 – 54%, four companies (18%, 13%, 12% and 11%)). Of the Company's accounts receivable at December 31, 2012, approximately 14% was receivable from a single company (December 31, 2011 – 15%, one company). The maximum exposure to credit risk is represented by the carrying amount on the balance sheet. There are no material financial assets that the Company considers past due and no accounts have been written off.

The Company may be exposed to certain losses in the event of non-performance by counterparties to commodity price contracts. The Company mitigates this risk by entering into transactions with counterparties that have investment grade credit ratings.

Counterparties to financial instruments expose the Company to credit losses in the event of non-performance. Counterparties for derivative instrument transactions are limited to high credit-quality financial institutions, which are all members of our syndicated credit facility.

The Company assesses quarterly if there should be any impairment of financial assets. At December 31, 2012, there was no impairment of any of the financial assets of the Company.

### Liquidity risk

Liquidity risk includes the risk that, as a result of operational liquidity requirements:

- The Company will not have sufficient funds to settle a transaction on the due date;
- The Company will be forced to sell financial assets at a value which is less than what they are worth; or
- The Company may be unable to settle or recover a financial asset at all.

The Company's operating cash requirements, including amounts projected to complete our existing capital expenditure program, are continuously monitored and adjusted as input variables change. These variables include, but are not limited to, available bank lines, oil and natural gas production from existing wells, results from new wells drilled, commodity prices, cost overruns on capital projects and changes to government regulations relating to prices, taxes, royalties, land tenure, allowable production and availability of markets. As these variables change, liquidity risks may necessitate the need for the Company to conduct equity issues or obtain debt financing. The Company also mitigates liquidity risk by maintaining an insurance program to minimize exposure to certain losses.

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

|  | < 1<br>Year | 1-2<br>Years | 2-5 Years | Thereafter |
|--|-------------|--------------|-----------|------------|
| Accounts payable and accrued liabilities             | 164,946     |              |           |            |
| Dividends payable                                    | 8,911       |              |           |            |
| Provision for future market and reserves based bonus | 2,677       | 59           |           |            |
| Current taxes payable                                | 1,890       |              |           |            |
| Long-term debt <sup>(1)</sup>                        |             | 430,000      |           |            |
| Senior secured notes                                 |             |              |           | 150,000    |

(1) Revolving credit facility renewed annually (see Note 5)

#### 14. Capital disclosures

The Company's objectives when managing capital are: (i) to maintain a flexible capital structure, which optimizes the cost of capital at acceptable risk; and (ii) to maintain investor, creditor and market confidence to sustain the future development of the business.

The Company manages its capital structure and makes adjustments to it in light of changes in economic conditions and the risk characteristics of its underlying assets. The Company considers its capital structure to include Shareholders' equity, debt and working capital. To maintain or adjust the capital structure, the Company may from time to time, issue common shares, raise debt, adjust its capital spending or change dividends paid to manage its current and projected debt levels. The Company monitors capital based on the following measures: current and projected debt to earnings before interest, taxes, depreciation, depletion and amortization ("EBITDA") ratios, payout ratios and net debt levels. To facilitate the management of these ratios, the Company prepares annual budgets, which are updated depending on varying factors such as general market conditions and successful capital deployment. Currently, all ratios are within acceptable parameters. The annual budget is approved by the Board of Directors.

There were no changes in the Company's approach to capital management from the previous year.

|                                   | <b>December 31<br/>2012</b> | <b>December 31<br/>2011</b> |
|-----------------------------------|-----------------------------|-----------------------------|
| Shareholders' equity              | 1,210,067                   | 1,015,708                   |
| Long-term debt                    | 580,000                     | 470,000                     |
| Working capital (surplus) deficit | 74,884                      | (40,232)                    |
|                                   | <b>1,864,951</b>            | <b>1,445,476</b>            |

#### 15. Related party transactions

An officer and director of the Company is a partner of a law firm that provides legal services to the Company. For the year ended December 31, 2012, legal fees totaled \$1.2 million (2011 - \$0.8 million). As at December 31, 2012, an amount due to this firm of \$1.2 million was included in accounts payable (2011 - \$0.7 million).

The Company has determined that the key management personnel consists of its key employees, officers and directors. In addition to the salaries and directors fees paid to these individuals, the Company also provides compensation in the form of market and reserve based bonus to some of these individuals. Compensation expense of \$1.3 million is included in general and administrative expenses and \$5.0 million in market and reserves based bonus relating to key management personnel for the year 2012 (2011 - \$1.7 million in general and administrative and \$10.1 million in market and reserves based bonus).

#### 16. Commitments

**Peyto has contractual obligations and commitments as follows:**

|                                  | <b>2013</b> | <b>2014</b> | <b>2015</b> | <b>2016</b> | <b>2017</b> | <b>Thereafter</b> |
|----------------------------------|-------------|-------------|-------------|-------------|-------------|-------------------|
| Note repayment <sup>(1)</sup>    | -           | -           | -           | -           | -           | 150,000           |
| Interest payments <sup>(2)</sup> | 4,635       | 6,830       | 6,830       | 6,830       | 6,830       | 18,785            |
| Transportation commitments       | 14,033      | 13,077      | 9,749       | 4,575       | 1,221       | 924               |
| Operating leases                 | 1,678       | 1,694       | 522         | -           | -           | -                 |
| Total                            | 20,346      | 21,601      | 17,101      | 11,405      | 8,051       | 169,709           |

<sup>(1)</sup> Long-term debt repayment on senior secured notes

<sup>(2)</sup> Fixed interest payments on senior secured notes

**Officers**

Darren Gee  
President and Chief Executive Officer

Scott Robinson  
Executive Vice President and Chief Operating Officer

Kathy Turgeon  
Vice President, Finance and Chief Financial Officer

Stephen Chetner  
Corporate Secretary

Tim Louie  
Vice President, Land

David Thomas  
Vice President, Exploration

Jean-Paul Lachance  
Vice President, Exploitation

**Directors**

Don Gray, Chairman  
Rick Braund  
Stephen Chetner  
Brian Davis  
Michael MacBean, Lead Independent Director  
Darren Gee  
Gregory Fletcher  
Scott Robinson

**Auditors**

Deloitte LLP

**Solicitors**

Burnet, Duckworth & Palmer LLP

**Bankers**

Bank of Montreal  
Union Bank, Canada Branch  
Royal Bank of Canada  
Canadian Imperial Bank of Commerce  
HSBC Bank Canada  
The Toronto-Dominion Bank  
Alberta Treasury Branches  
Canadian Western Bank

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Stock Listing Symbol: PEY.TO

Toronto Stock Exchange