# Peyto Celebrates 15 Years With Year End 2013 Report to Shareholders

05.03.2014 | Marketwired

CALGARY, ALBERTA--(Marketwired - Mar 5, 2014) - Peyto Exploration & Development Corp. (TSX:PEY) ("Peyto" or the "Company") is pleased to report operating and financial results for the fourth quarter and the 2013 fiscal year which culminate 15 years of success in the Canadian Energy Industry. Peyto set new production and reserves per share records in 2013 while delivering a 76% operating margin[1] and a 25% profit margin[2]. A 10% return on capital and a 12% return on equity were achieved in 2013 along with the following Q4 and annual highlights:

- **Production per share up 26%.** *Fourth quarter production was up 35%, also 35% per share, from 299 MMcfe/d (49,754 boe/d) in Q4 2012 to 404 MMcfe/d (67,296 boe/d) in Q4 2013. Annual production increased 33%, or 26% per share, from 267 MMcfe/d in 2012 to 356 MMcfe/d in 2013.*

- **Reserves per share up 19%.** *Proved Producing ("PP"), Total Proved ("TP") and Proved plus Probable Additional ("P+P") reserves increased 12%, 10%, and 19% (the same per share) to 1.1, 1.8, and 2.8 TCFe, respectively.*

- **Maintained industry leading total cash costs.** *Royalties, operating costs, transportation, G&A and interest expense totaled $1.06/MCFe ($6.36/boe) in both Q4 and on average in 2013, consistent with $1.05/MCFe on average in 2012.*

- **Funds from operations per share up 34%.** *Generated $438 million in Funds from Operations ("FFO") in 2013, or $2.94/share, up 34% from $2.19/share in 2012. Q4 FFO per share was up 35% from $0.62 to $0.84.*

- **Organic capital investment up 28%.** *Invested a record $578 million to build 38,400 boe/d at a cost of $15,100/boe/d in 2013, up 28% from the $452 million of organic capital spent in 2012.*

- **P+P FD&A was half the field netback.** *All in FD&A cost for PP, TP and P+P reserves was $2.35/MCFe, $2.23/MCFe and $1.86/MCFe ($11.16/boe), respectively, including changes in Future Development Capital ("FDC"), while the average field netback was $3.65/MCFe ($21.89/boe).*

- **NAV per share of $38.** *Net Asset Value ("NAV") or the Net Present Value per share, debt adjusted (discounted at 5%) of the P+P reserves was $23/share of developed reserves and $15/share of undeveloped reserves.*

- **Earnings per share up 43% and dividends per share up 22%.** *A total of $143 million in earnings were generated in 2013 ($0.96/share), and $131 million in dividends were paid to shareholders ($0.88/share). Cumulative dividend/distribution payments made by Peyto to date total $1.47 Billion ($13.19/share).*

**2013 in Review**

The year 2013 marked Peyto's 15th year in the business of profitably finding, developing, and producing natural gas in Alberta's Deep Basin. Peyto invested a record $578 million into drilling and completing 99 new gas wells, building two new gas plants at Oldman North and Brazeau River, expanding a third plant at Swanson, acquiring 49 sections of new multi-zone mineral rights and purchasing over 170 square miles of 3D seismic. For every well drilled, two new drilling locations were recognized in Peyto's reserve report further expanding the Company's NAV. A 42% increase in annual funds from operations was primarily the result of the 33% growth in production, as realized commodity prices were only up 5%. A 52% increase in earnings was commensurate with the increase in FFO, which allowed for a 33% increase in the monthly dividend mid-way through the year. The solid returns generated with the annual capital program drove a 10% return on capital and 12% return on equity. Including dividends, investors realized a 45% return[3] from year end 2012 to year end 2013.

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).*
3. *Total return is calculated using the December 31, 2012 share price of $22.99 and December 31, 2013 share price of $32.51, along with $0.88/share of dividend.*

*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 (mcfe) 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 | | % | 12 Months Ended December 31 | | % |
|---|---|---|---|---|---|---|
| | 2013 | 2012 | Change | 2013 | 2012 | Change |
| Operations | | | | | | |
| Production | | | | | | |
| Natural gas (mcf/d) | 361,870 | 266,808 | *36 %* | 317,622 | 238,490 | *33 %* |
| Oil & NGLs (bbl/d) | 6,984 | 5,286 | *32 %* | 6,376 | 4,778 | *33 %* |
| Thousand cubic feet equivalent (mcfe/d @ 1:6) | 403,774 | 298,522 | *35 %* | 355,880 | 267,160 | *33 %* |
| Barrels of oil equivalent (boe/d @ 6:1) | 67,296 | 49,754 | *35 %* | 59,313 | 44,527 | *33 %* |
| Product prices | | | | | | |
| Natural gas ($/mcf) | 3.59 | 3.45 | *4 %* | 3.54 | 3.23 | *10 %* |
| Oil & NGLs ($/bbl) | 69.84 | 73.01 | *(4 )%* | 70.97 | 73.92 | *(4 )%* |
| Operating expenses ($/mcfe) | 0.35 | 0.31 | *13 %* | 0.35 | 0.32 | *9 %* |
| Transportation ($/mcfe) | 0.13 | 0.11 | *18 %* | 0.12 | 0.12 | - |
| Field netback ($/mcfe) | 3.67 | 3.62 | *1 %* | 3.65 | 3.46 | *5 %* |
| General & administrative expenses ($/mcfe) | 0.06 | 0.02 | *200 %* | 0.04 | 0.04 | - |
| Interest expense ($/mcfe) | 0.24 | 0.32 | *(25 )%* | 0.24 | 0.26 | *(8 %)* |
| Financial ($000, except per share) | | | | | | |
| Revenue | 164,455 | 120,310 | *37 %* | 575,845 | 411,400 | *40 %* |
| Royalties | 10,288 | 9,205 | *12 %* | 40,450 | 30,754 | *32 %* |
| Funds from operations | 125,164 | 90,078 | *39 %* | 437,742 | 308,865 | *42 %* |
| Funds from operations per share | 0.84 | 0.62 | *35 %* | 2.94 | 2.19 | *34 %* |
| Total dividends | 35,702 | 26,178 | *36 %* | 130,898 | 101,593 | *29 %* |
| Total dividends per share | 0.24 | 0.18 | *33 %* | 0.88 | 0.72 | *22 %* |
| Payout ratio (%) | 29 | 28 | *4 %* | 30 | 33 | *(9 )%* |
| Earnings | 37,989 | 25,823 | *47 %* | 142,627 | 93,951 | *52 %* |
| Earnings per share | 0.26 | 0.18 | *44 %* | 0.96 | 0.67 | *43 %* |
| Capital expenditures | 154,295 | 156,847 | *(2 )%* | 578,003 | 617,985 | *(6 )%* |
| Weighted average shares outstanding | 148,758,923 | 145,449,651 | *2 %* | 148,737,654 | 141,093,829 | *5 %* |
| As at December 31 | | | | | | |
| End of period shares outstanding (includes shares to be issued) | | | | 148,949,448 | 148,673,263 | - |
| Net debt (before future compensation expense and unrealized hedging gains) | | | | 946,541 | 662,461 | *43 %* |
| Shareholders' equity | | | | 1,200,638 | 1,210,067 | *(1 )%* |
| Total assets | | | | 2,555,156 | 2,203,524 | 16 % |

| | 3 Months Ended December 31 | | 12 Months Ended December 31 | |
|---|---|---|---|---|
| ($000) | 2013 | 2012 | 2013 | 2012 |
| Cash flows from operating activities | 120,473 | 78,878 | 407,357 | 284,309 |
| Change in non-cash working capital | (5,380 ) | 4,457 | 11,667 | 12,920 |
| Change in provision for performance based compensation | (6,226 ) | (7,712 ) | 2,421 | (2,819 ) |
| Income tax paid on account of 2003 reassessment | - | 1,868 | - | 1,868 |
| Performance based compensation | 16,297 | 12,587 | 16,297 | 12,587 |
| Funds from operations | 125,164 | 90,078 | 437,742 | 308,865 |
| Funds from operations per share | 0.84 | 0.62 | 2.94 | 2.19 |

*(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 distributions may vary.*

**Historical Milestones**

Peyto Exploration & Development Corp. was founded in October 1998 with the sole purpose of investing shareholder capital into oil and gas development for maximum possible return. Now, 15 years later, that goal remains exactly the same. Only now, there are 15 years of results against which that objective can be measured. In aggregate, approximately $3.5 billion has been invested, mostly in the drilling of nearly 1,000 natural gas wells in Alberta's Deep Basin, and in the construction of over 1,100 km of pipelines and 7 gas processing facilities. These investments have generated $4.4 billion in revenue, paid $675 million in royalties to Albertans, delivered $3.1 billion in funds from operations and funded $1.5 billion in distributions and dividend payments to shareholders. On top of that, shareholders today own assets independently valued at $6.6 billion[1], 60% of which are already developed. The value of a share of Peyto, including dividends and distributions, has compounded at 53% annually over its history. It is fair to say that the Peyto strategy has been successful in achieving its objective.

In simple terms, Peyto is a profitable business - finding, developing and producing for less than what it receives in sales. The profitability of the business model is illustrated in the following table:

| ($/Mcfe) | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | Average |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Sales Price | $ 7.21 | $ 7.32 | $ 8.87 | $ 8.76 | $ 8.93 | $ 9.54 | $ 6.75 | $ 6.15 | $ 5.47 | $ 4.21 | $ 4.43 | $ 7.06 |
| Cost to develop[2] | $ (1.33 ) | $ (1.60 ) | $ (2.39 ) | $ (2.95 ) | $ (2.11 ) | $ (2.88 ) | $ (2.26 ) | $ (2.10 ) | $ (2.12 ) | $ (2.22 ) | $ (2.35 ) | $ (2.21 ) |
| Cost to produce[3] | $ (2.16 ) | $ (2.21 ) | $ (2.76 ) | $ (2.66 ) | $ (2.75 ) | $ (3.01 ) | $ (1.75 ) | $ (1.63 ) | $ (1.35 ) | $ (1.05 ) | $ (1.06 ) | $ (2.04 ) |
| "Profit" | $ 3.72 | $ 3.51 | $ 3.72 | $ 3.15 | $ 4.07 | $ 3.65 | $ 2.74 | $ 2.42 | $ 2.00 | $ 0.94 | $ 1.02 | $ 2.81 |
| Payout[4] | $ 1.36 | $ 2.28 | $ 2.81 | $ 3.47 | $ 3.92 | $ 4.25 | $ 4.03 | $ 3.37 | $ 1.24 | $ 1.04 | $ 1.01 | $ 2.62 |

1. *Based on Insite's 2013 reserves report for P+P NPV, 5% discount*
2. *Cost to develop is the PDP FD&A*
3. *Cost to produce is the total cash costs including Royalties, Operating costs, Transportation, G&A and Interest.*
4. *Payout is the annual distribution or dividend in $/mcfe of production.*

The predictability and repeatability of annual performance is a testament to the success of the Peyto's strategy and the execution of its business plan. After 15 years, there appears to be no reason to change.

**Capital Expenditures**

Peyto executed its largest ever drilling program in 2013, investing $254 million to drill 99 gross (93.4 net) horizontal gas wells, $152 million on their multi-stage fracture completions, and $48.3 million in wellsite equipment and pipelines to connect them to Company owned gathering systems. Drilling and completion costs per meter of wellbore have been decreasing, despite a 3% per year annual inflation in service costs, as execution has continued to improve. The table below outlines the past four years of horizontal drilling and completion costs.

| | 2010 | 2011 | 2012 | 2013 |
|---|---|---|---|---|
| Gross Spuds | 52 | 70 | 86 | 99 |
| Length (m) | 3,762 | 3,903 | 4,017 | 4,179 |
| Drilling ($MM) | $ 2.763 | $ 2.823 | $ 2.789 | $ 2.720 |
| $ per meter | $ 734 | $ 723 | $ 694 | $ 651 |
| Completion ($MM) | $ 1.358 | $ 1.676 | $ 1.672 | $ 1.625 |
| $ per meter | $ 361 | $ 429 | $ 416 | $ 389 |

The Company invested $112 million in 2013 to build new gas plants at Oldman North (30 MMcf/d) and Brazeau River (20 MMcf/d), as well as expand the existing Swanson gas plant (+30 MMcf/d), to accommodate increased production volumes. A total of $6.4 million was invested in 49.25 sections of new crown lands ($202/acre) and $2.5 million on tuck-in acquisitions. In addition, 173 km of 2D and 448 $km^2$ of 3D seismic was acquired for $3 million, for total capital expenditures of $578 million.

The following table summarizes the capital investments for the fourth quarter and 2013 year.

| | Three Months ended Dec. 31 | | Twelve Months ended Dec. 31 | |
|---|---|---|---|---|
| ($000) | 2013 | 2012 | 2013 | 2012 |
| Land | 1,144 | 5,206 | 6,427 | 10,770 |
| Seismic | 683 | 612 | 2,984 | 1,741 |
| Drilling | 59,825 | 77,295 | 254,000 | 210,946 |
| Completions | 46,836 | 46,484 | 151,752 | 127,042 |
| Equipping and tie-ins | 12,389 | 22,168 | 48,303 | 46,246 |
| Facilities and pipelines | 33,418 | 25,846 | 112,054 | 38,236 |
| Acquisition of Open Range | - | - | - | 187,187 |
| Acquisitions | - | 75 | 2,483 | 17,841 |
| Dispositions | - | (16,969) | - | (17,646) |
| (Gains) Losses on Dispositions | - | (3,870) | - | (4,378) |
| Total Capital Expenditures | 154,295 | 156,847 | 578,003 | 617,985 |

## Reserves

Peyto was successful growing reserves and values in all categories in 2013, despite the year over year reduction in commodity price forecasts. 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 | | | |
|---|---|---|---|---|
| | 2013 | 2012 | % Change | % Change, debt adjusted per share† |
| Reserves (BCFe) | | | | |
| Proved Producing | 1,061 | 945 | 12 % | 13 % |
| Total Proved | 1,827 | 1,659 | 10 % | 11 % |
| Proved + Probable Additional | 2,807 | 2,353 | 19 % | 20 % |
| Net Present Value ($millions) Discounted at 5% | | | | |
| Proved Producing | $ 3,156 | $ 2,806 | 12 % | 3 % |
| Total Proved | $ 4,544 | $ 4,166 | 9 % | 2 % |
| Proved + Probable Additional | $ 6,587 | $ 5,732 | 15 % | 11 % |

*†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 $32.51 for 2013. 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, 2013.The InSite price forecast is available at www.insitepc.com. For more information on Peyto's reserves, refer to the Press Releases dated February 12, 2014 and February 14, 2013 announcing the Year End Reserve Report which is available on the website at 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 2014.*

## Value Creation/Reconciliation

In order to measure the success of all of the capital invested in 2013, it is necessary to quantify the total amount of value added during the year and compare that to the total amount of capital invested. The independent engineers have 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 (ie. commodity prices). Since the capital investments in 2013 were funded from a combination of cash flow, debt and equity, it is necessary to know the change in debt and the change in shares outstanding to see if the change in value is truly accretive to shareholders.

At year end 2013, Peyto's estimated net debt had increased by $284.1 million to $946.5 million while the number of shares outstanding had increased by 0.276 million shares to 148.949 million shares. The change in debt includes all of the capital expenditures, as well as any acquisitions, and the total fixed and performance based compensation paid out for the year.

Based on this reconciliation of changes in BT NPV, the Peyto team was able to create $867 million of Proved

Producing, $1.129 billion of Total Proven, and $2.307 billion of Proved plus Probable Additional undiscounted reserve value, with $578 million of capital investment. The ratio of capital expenditures to value creation 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 2013, the Proved Producing NPV recycle ratio is 1.5. This means for each dollar invested, the Peyto team was able to create 1.5 new dollars of Proved Producing reserve value. The average Proved Producing NPV Recycle Ratio over the last 5 years is 2.9 times for undiscounted future values or 2.0 times for future values discounted at 10%.

The historic NPV recycle ratios are presented in the following table.

| Value Creation | 31-Dec-06 | 31-Dec-07 | 31-Dec-08 | 31-Dec-09 | 31-Dec-10 | 31-Dec-11 | 31-Dec-12 | 31-Dec-13 |
|---|---|---|---|---|---|---|---|---|
| $NPV_0$ Recycle Ratio | | | | | | | | |
| Proved Producing | 2.9 | 4.7 | 2.1 | 5.4 | 3.5 | 2.4 | 1.6 | 1.5 |
| Total Proved | 2.9 | 5.5 | 2.5 | 18.9 | 6.1 | 4.7 | 2.2 | 2.0 |
| Proved + Probable Additional | 3.8 | 3.8 | 2.2 | 27.1 | 10.3 | 6.6 | 3.2 | 4.0 |

**$NPV_0$ (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 ($867/$578) = 1.5).*

**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.

The following table highlights additional annual performance ratios both before and after the implementation of horizontal wells in late 2009. These can be used for comparative purposes, but it is cautioned that on their own they do not measure investment success.

| | 2013 | 2012 | 2011 | 2010 | 2009 | 2008 | 2007 |
|---|---|---|---|---|---|---|---|
| Proved Producing | | | | | | | |
| FD&A ($/mcfe) | $ 2.35 | $ 2.22 | $ 2.12 | $ 2.10 | $ 2.26 | $ 2.88 | $ 2.11 |
| RLI (yrs) | 7 | 9 | 9 | 11 | 14 | 14 | 13 |
| Recycle Ratio | 1.5 | 1.3 | 1.9 | 2.0 | 1.8 | 2.6 | 2.8 |
| Reserve Replacement | 190 % | 284 % | 230 % | 239 % | 79 % | 110 % | 127 % |
| Total Proved | | | | | | | |
| FD&A ($/mcfe) | $ 2.23 | $ 2.04 | $ 2.13 | $ 2.35 | $ 1.73 | $ 3.17 | $ 1.57 |
| RLI (yrs) | 12 | 15 | 16 | 17 | 21 | 17 | 16 |
| Recycle Ratio | 1.6 | 1.4 | 1.9 | 1.8 | 2.3 | 2.3 | 3.7 |
| Reserve Replacement | 230 % | 414 % | 452 % | 456 % | 422 % | 139 % | 175 % |
| Future Development Capital ($ millions) | $ 1,406 | $ 1,318 | $ 1,111 | $ 741 | $ 446 | $ 222 | $ 169 |
| Proved plus Probable Additional | | | | | | | |
| FD&A ($/mcfe) | $ 1.86 | $ 1.68 | $ 1.90 | $ 2.19 | $ 1.47 | $ 3.88 | $ 1.56 |
| RLI (yrs) | 19 | 22 | 22 | 25 | 29 | 23 | 21 |
| Recycle Ratio | 1.9 | 1.7 | 2.1 | 1.9 | 2.8 | 1.7 | 3.7 |
| Reserve Replacement | 450 % | 527 % | 585 % | 790 % | 597 % | 122 % | 117 % |
| Future Development Capital ($millions) | $ 2,550 | $ 2,041 | $ 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 ($578.0+$87.9)/(304.494-276.419+21.649) = $2.23/mcfe or $13.39/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 176,882/(67.296x365) = 7.2). 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 (($21.23)/$14.08=1.5). 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 ((176.882-157.491+21.649)/21.649) = 190%).

**Quarterly Review**

Peyto was very active in the fourth quarter of 2013, drilling and connecting new natural gas wells and commissioning new processing facilities, just as natural gas prices improved. A total of 21 gross (20.1 net) wells were drilled, 31 gross (28.3 net) wells completed and 32 gross (29.5 net) wells equipped and brought on production. In total, $154.2 million of capital was invested in the quarter, or 27% of the annual capital program, with $59.8 million spent on drilling, $46.8 million on completions, $12.4 million on pipelines, $33.4 million on facilities and $1.8 million on lands and seismic.

Production grew over 25%, from 59,000 boe/d at the start of the fourth quarter, to 75,000 boe/d by the end of the quarter, averaging 67,296 boe/d, up 35% over Q4 2012. Alberta daily natural gas prices climbed 45% from $2.31/GJ in the previous quarter to $3.35/GJ in Q4 2013, just as production rose. Fourth quarter 2013 prices were 4% higher than the same period in 2012. Peyto's realized price for natural gas in Q4 2013 was $3.43/mcf, prior to a $0.16/mcf hedging gain, while it's realized liquids price was $71.98/bbl, prior to a $2.14/bbl hedging loss, yielding a combined revenue stream of $4.43/mcfe. This net sales price was 1% higher than same period a year ago.

Total cash costs for Q4 2013 of $1.06/mcfe included royalties of $0.28/mcfe, operating costs of $0.35/mcfe, transportation of $0.13/mcfe, G&A of $0.06/mcfe and interest of $0.24/mcfe. Quarterly cash costs were down slightly from $1.10/mcfe in Q4 2012 but in line with the previous year's average of $1.05/mcfe.

Peyto generated total funds from operations of $125 million in the quarter, or $3.37/mcfe, equating to a 76% operating margin. DD&A charges of $1.77/mcfe, as well as a provision for current and future performance based compensation and tax, reduced FFO to earnings of $1.02/mcfe, or a 23% profit margin, which funded the $0.96/mcfe dividend to shareholders.

**Marketing**

The current natural gas price outlook is for much improved prices over the next 12 months as cold winter weather has reduced storage volumes to below seasonal levels. The AECO Monthly strip for the next 12 months is currently trading at close to $4.70/GJ, almost 50% higher than the previous 12 months. Beyond that, prices are expected to return to previous levels as low cost supplies, reversal of coal-to-gas switching and more seasonal weather patterns return storage to normal levels. The AECO Monthly strip for the second year out is currently priced at approximately $3.80/GJ.

Peyto uses a hedging strategy that is designed to smooth out the short term fluctuations in the price of natural gas and NGLs through future sales in order to provide security of price for capital planning purposes. This is done by selling approximately 35% of the total natural gas production (inclusive of Crown Royalty volumes) on the daily and monthly spot markets while the balance (approximately 65%) is pre-sold or hedged. These hedges are meant to be methodical and consistent and to avoid speculation. In general, this approach will show hedging losses when short term prices climb and hedging gains when short term prices fall. Peyto generally sells its contracts in either the 7 month summer or the 5 month winter season. In order to minimize counterparty risk, these marketing contracts are all with financial institutions that are also members of Peyto's banking syndicate. Peyto has deployed this strategy for over a decade now, which has resulted in $260 million in cumulative gains. Over the long run, however, Peyto expects to break even on forward sales, having achieved price security for little to no cost.

For 2013, Peyto realized a natural gas price of $3.10/GJ or $3.54/Mcf, for its natural gas sales. This was a combination of 47% being sold in the daily or monthly spot market, which averaged $2.98/GJ, and 53% having been pre-sold at an average hedged price of $3.20/GJ. The following table summarizes the remaining hedged volumes for the upcoming years effective March 5, 2014:

| | Future Sales | | Average Price (CAD) | |
|---|---|---|---|---|
| | GJ | Mcf | $/GJ | $/Mcf |
| 2014 | 79,117,500 | 68,839,982 | $ 3.52 | $ 4.05 |
| 2015 | 24,140,000 | 21,004,167 | $ 3.57 | $ 4.11 |
| Total | 103,257,500 | 89,844,148 | $ 3.54 | $ 4.06 |

As illustrated in the following table, Peyto's unhedged annual realized NGL prices(1) were approximately 3% lower on a year over year basis, and represented 77% of the $93.13/bbl average Edmonton par oil price in 2013, down from 86% the previous year. Lower relative Pentane and Butane prices and increased transportation charges contributed to the increased offset to light oil prices.

| | Three Months ended Dec. 31 | | Twelve Months ended Dec. 31 | |
|---|---|---|---|---|
| | 2013 | 2012 | 2013 | 2012 |
| Condensate ($/bbl) | 84.92 | 87.02 | 89.85 | 90.41 |
| Propane ($/bbl) | 28.55 | 24.40 | 25.38 | 23.01 |
| Butane ($/bbl) | 57.26 | 60.46 | 52.73 | 61.09 |
| Pentane ($/bbl) | 90.59 | 89.99 | 97.14 | 94.36 |
| Total oil and natural gas liquids ($/bbl) | 71.98 | 73.12 | 71.81 | 73.96 |
| Edmonton par crude postings ($/bbl) | 86.19 | 84.43 | 93.13 | 85.91 |

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

Peyto's hedging practice with respect to propane is similar to that for natural gas. Effective March 5, 2014, Peyto had a total of 212,000 bbls of Propane forward sold for the remainder of 2014 at $USD 40.74/bbl.

**Activity Update**

Drilling activity for the first quarter of 2014 continues to be robust. Peyto is currently running a 9 rig drilling program extending across the Greater Sundance area, through Ansell and down to Brazeau River. The program is targeting ongoing development of the Bluesky, Wilrich, Falher, Notikewin, and Cardium formations. In addition to the drilling, a 27 km pipeline was recently completed connecting a new growth area to Peyto's existing Wildhay Gas Plant. The new pipeline corridor will provide the necessary infrastructure for approximately 7 to 10 wells that will be drilled in that area over the balance of 2014.

Production is currently between 73,000 and 75,000 boe/d with the exception of a four day period in mid-January during which a powerful windstorm unexpectedly knocked out power in the Greater Sundance area for 40 hours and caused the shut in of approximately 60,000 boe/d (655 boe/d on average for the quarter).

Thus far in the quarter, 19 gross (18.1 net) new wells have been spud with 13 gross (13 net) wells having been completed and brought onstream. The Company is planning for a continuation of drilling and completion activity over the traditional April to mid-June breakup period this year. The level and progress of this planned activity will be weather and access dependent.

Facility preparations are well underway for continued expansion at key gas plants. The new Oldman North Gas Plant was expanded in late February from 30 to 50 MMcf/d with the addition of a third compressor. This facility will be further expanded to 80 MMcf/d by the fall. The installation of a refrigeration module and third compressor at the Brazeau Plant is in the final stages which will take that facility to 30 MMcf/d of capacity. One additional compressor is expected after breakup for total Brazeau capacity of 40 MMcf/d. Beyond that, additional compressors and refrigeration modules are in the fabrication stage for a late summer to early fall installation at the Oldman North, Wildhay and Swanson facilities which will bring total capacity additions for the year to above 100 MMcf/d.

**2014 Outlook**

The year 2014 looks to be another record breaking year for Peyto with continued profitable growth. As always, the primary focus is on maximizing returns, with profitable growth being the by-product of that success. Peyto's counter-cyclical investment strategy over the past four years, that has resulted in more than a tripling of production, should pay off in 2014 as natural gas prices are forecast to be 50% higher than 2013. These higher prices, however, will require even greater vigilance with respect to cost control as it is in these environments when inflation of service costs can begin to erode future returns. This focus on costs has been at the heart of Peyto's strategy over the past 15 years and will continue to be a foundation of the Company's success in the future.

With a firm belief in the future of natural gas and strengthened with a decade and a half of experience, Peyto remains well positioned to lead the industry as one of the lowest cost, most efficient and most profitable energy companies.

**Conference Call and Webcast**

A conference call will be held with the senior management of Peyto to answer questions with respect to the 2013 fourth quarter and full year financial results on Thursday, March 6th, 2014, at 9:00 a.m. Mountain Standard Time (MST), or 11:00 a.m. Eastern Standard Time (EST). To participate, please call 1-416-340-9432 (Toronto area) or 1-800-769-8320 for all other participants. The conference call will also be available on replay by calling 1-905-694-9451 (Toronto area) or 1-800-408-3053 for all other parties, using passcode 4296819. The replay will be available at 11:00 a.m. MST, 1:00 p.m. EST Thursday, March 6th, 2014 until midnight EDT on Thursday, March 13th, 2014. The conference call can also be accessed through the internet at http://www.gowebcasting.com/5190. After this time the conference call will be archived on the Peyto Exploration & Development website at www.peyto.com.

**Management's Discussion and Analysis**

A copy of the fourth quarter report to shareholders, including the MD&A, audited financial statements and related notes, is available at http://www.peyto.com/news/Q42013MDandA.pdf and will be filed at SEDAR, www.sedar.com at a later date.

**Annual General Meeting**

Peyto's Annual General Meeting of Shareholders is scheduled for 3:00 p.m. on Tuesday, May 27, 2014 at Livingston Place Conference Centre, +15 level, 222-3rd Avenue SW, Calgary, Alberta. Shareholders are encouraged to visit the Peyto website at 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 5, 2014

***Certain information set forth in this document and Management's Discussion and Analysis, including management's assessment of Peyto's future plans and operations, contains forward-looking statements. In particular, but without limiting the foregoing, this news release contains***

***forward-looking information and statements pertaining to the following: the timing of its enhanced liquids extraction project and guidance as to the capital expenditure plans of Peyto under the heading "2014 Outlook". 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 Peyto will derive therefrom.***

Peyto Exploration & Development Corp.
Balance Sheet
(Amounts in $ thousands)

| | December 31 2013 | December 31 2012 |
|---|---|---|
| Assets | | |
| Current assets | | |
| Cash | - | - |
| Accounts receivable | 83,714 | 85,677 |
| Due from private placement *(Note 7)* | 6,245 | 3,459 |
| Derivative financial instruments *(Note 13)* | - | 10,254 |
| Prepaid expenses | 5,666 | 4,150 |
| | 95,625 | 103,540 |
| Property, plant and equipment, net *(Note 4)* | 2,459,531 | 2,099,984 |
| | 2,459,531 | 2,099,984 |
| | 2,555,156 | 2,203,524 |
| Liabilities | | |
| Current liabilities | | |
| Accounts payable and accrued liabilities | 155,265 | 164,968 |
| Current income tax | - | 1,868 |
| Dividends payable *(Note 7)* | 11,901 | 8,911 |
| Derivative financial instruments *(Note 13)* | 26,606 | - |
| Provision for future performance based compensation *(Note 11)* | 5,100 | 2,677 |
| | 198,872 | 178,424 |
| Long-term debt *(Note 5)* | 875,000 | 580,000 |
| Long-term derivative financial instruments *(Note 13)* | 5,180 | 2,532 |
| Provision for future performance based compensation *(Note 11)* | 3,200 | 59 |
| Decommissioning provision *(Note 6)* | 61,184 | 58,201 |
| Deferred income taxes *(Note 12)* | 211,082 | 174,241 |
| | 1,155,646 | 815,033 |
| Equity | | |
| Shareholders' capital *(Note 7)* | 1,130,069 | 1,124,382 |
| Shares to be issued *(Note 7)* | 6,245 | 3,459 |
| Retained earnings | 86,975 | 75,247 |
| Accumulated other comprehensive income *(Note 7)* | (22,651) | 6,979 |
| | 1,200,638 | 1,210,067 |
| | 2,555,156 | 2,203,524 |

Approved by the Board of Directors

*Michael MacBean* Director
*Darren Gee* Director

Peyto Exploration & Development Corp.
Income Statement
(Amounts in $ thousands)

| | Year ended December 31 2013 | 2012 |
|---|---|---|

| | | |
|---|---|---|
| Revenue | | |
| Oil and gas sales | 561,645 | 357,734 |
| Realized gain on hedges *(Note 13)* | 14,200 | 53,667 |
| Royalties | (40,450 ) | (30,754 ) |
| Petroleum and natural gas sales, net | 535,395 | 380,647 |
| Expenses | | |
| Operating *(Note 8)* | 45,235 | 31,260 |
| Transportation | 16,221 | 11,275 |
| General and administrative *(Note 9)* | 5,204 | 3,846 |
| Market and reserves based bonus *(Note 11)* | 16,297 | 12,587 |
| Future performance based compensation *(Note 11)* | 5,564 | (2,819 ) |
| Interest *(Note 10)* | 30,991 | 25,401 |
| Accretion of decommissioning provision *(Note 10)* | 1,544 | 1,044 |
| Depletion and depreciation *(Note 4)* | 224,976 | 172,338 |
| Gain on disposition of assets *(Note 4)* | - | (4,378 ) |
| | 346,032 | 250,554 |
| Earnings before taxes | 189,363 | 130,093 |
| Income tax | | |
| Deferred income tax expense *(Note 12)* | 46,736 | 34,274 |
| Current Income tax expense *(Note 12)* | - | 1,868 |
| Earnings for the year | 142,627 | 93,951 |
| Earnings per share *(Note 7)* | | |
| Basic and diluted | $ 0.96 | $ 0.67 |
| Weighted average number of common shares outstanding *(Note 7)* | | |
| Basic and diluted | 148,737,654 | 141,093,829 |

Peyto Exploration & Development Corp.
Statement of Comprehensive Income
(Amounts in $ thousands)

| | Year ended December 31 | |
|---|---|---|
| | 2013 | 2012 |
| Earnings for the year | 142,627 | 93,951 |
| Other comprehensive income | | |
| Change in unrealized gain (loss) on cash flow hedges | (25,307 ) | 17,687 |
| Deferred tax recovery | 9,877 | 8,995 |
| Realized (gain) loss on cash flow hedges | (14,200 ) | (53,667 ) |
| Comprehensive Income | 112,997 | 66,966 |

Peyto Exploration & Development Corp.
Statement of Changes in Equity
(Amounts in $ thousands)

| | Year ended December 31 | |
|---|---|---|
| | 2013 | 2012 |
| Shareholders' capital, Beginning of Year | 1,124,382 | 889,115 |
| Common shares issued | - | 115,024 |
| Common shares issued pursuant to acquisition of Open Range Energy Corp. | - | 112,187 |
| Common shares issued by private placement | 5,742 | 11,952 |
| Common shares issuance costs (net of tax) | (55 ) | (3,896 ) |
| Shareholders' capital, End of Year | 1,130,069 | 1,124,382 |
| Common shares to be issued, Beginning of Year | 3,459 | 9,740 |
| Common shares issued | (3,459 ) | (9,740 ) |
| Common shares to be issued | 6,245 | 3,459 |
| Common shares to be issued, End of Year | 6,245 | 3,459 |
| Retained earnings, Beginning of Year | 75,247 | 82,889 |
| Earnings for the year | 142,627 | 93,951 |
| Dividends *(Note 7)* | (130,899 ) | (101,593 ) |
| Retained earnings, End of Year | 86,975 | 75,247 |
| Accumulated other comprehensive income, Beginning of Year | 6,979 | 33,964 |
| Other comprehensive income (loss) | (29,630 ) | (26,985 ) |

| | | |
|---|---|---|
| Accumulated other comprehensive income, End of Year | (22,651 ) | 6,979 |
| Total Equity | 1,200,638 | 1,210,067 |

Peyto Exploration & Development Corp.
Statement of Cash Flows
(Amounts in $ thousands)

| | Year ended December 31 | |
|---|---|---|
| | 2013 | 2012 |
| Cash provided by (used in) | | |
| Operating activities | | |
| Earnings | 142,627 | 93,951 |
| Items not requiring cash: | | |
| Deferred income tax | 46,736 | 34,274 |
| Gain on disposition of assets | - | (4,378 ) |
| Depletion and depreciation | 224,976 | 172,338 |
| Accretion of decommissioning provision | 1,544 | 1,044 |
| Long term portion of future performance based compensation | 3,141 | - |
| Change in non-cash working capital related to operating activities | (11,667 ) | (12,920 ) |
| | 407,357 | 284,309 |
| Financing activities | | |
| Issuance of common shares | 5,742 | 126,976 |
| Issuance costs | (73 ) | (5,195 ) |
| Cash dividends paid | (127,908 ) | (100,960 ) |
| Increase (decrease) in bank debt | 175,000 | (40,000 ) |
| Issuance of long term notes | 120,000 | 150,000 |
| Repayment of Open Range bank debt | - | (72,000 ) |
| | 172,761 | 58,821 |
| Investing activities | | |
| Additions to property, plant and equipment | (578,003 ) | (429,737 ) |
| Change in prepaid capital | (5,081 ) | (2,300 ) |
| Change in non-cash working capital relating to investing activities | 2,966 | 31,683 |
| | (580,118 ) | (400,354 ) |
| | (580,118 ) | (400,354 ) |
| Net increase in cash | - | (57,224 ) |
| Cash, beginning of year | - | 57,224 |
| Cash, end of year | - | - |
| The following amounts are included in Cash flows from operating activities: | | |
| Cash interest paid | 23,920 | 23,460 |
| Cash taxes paid | 1,800 | - |

Peyto Exploration & Development Corp.
Notes to Financial Statements
As at December 31, 2013 and 2012
(Amounts in $thousands, except as otherwise noted)

## 1. Nature of operations

Peyto Exploration & Development Corp. ("Peyto" or the "Company") is a Calgary based oil and natural gas company. 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.

Effective December 31, 2012, Peyto completed an amalgamation with its wholly-owned subsidiary Open Range Energy Corp. ("Open Range") pursuant to section 184(1) of the *Business Corporations Act* (Alberta). Following the amalgamation, Peyto does not have any subsidiaries.

These financial statements were approved and authorized for issuance by the Board of Directors of Peyto on March 4, 2014.

**2. Basis of presentation**

These financial statements ("financial statements") as at and for the years ended December 31, 2013 and December 31, 2012 represent the Company's results and financial position in accordance with International Financial Reporting Standards ("IFRS").

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

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 amount to be paid out.

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. Recent Accounting Pronouncement**

Certain new standards, interpretations, amendments and improvements to existing standards were issued by the International Accounting Standards Board (IASB) or International Financial Reporting Interpretations Committee (IFRIC) that are mandatory for fiscal year beginning January 1, 2013 or later periods. The affected standards are consistent with those disclosed in Peyto's financial statements as at and for the years ended December 31, 2012 and 2011.

Peyto adopted the following standards on January 1, 2013:

IFRS 10 - Consolidated Financial Statements; supersedes 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. This standard became applicable on January 1, 2013. Peyto adopted the standard on January 1, 2013, with no impact on Peyto's financial position or results of operations.

IFRS 11 - Joint Arrangements; requires a venturer to classify its interest in a joint arrangement as a joint venture or joint operation. Joint ventures will be accounted for using the equity method of accounting, whereas joint operations will require the venturer to recognize its share of the assets, liabilities, revenue and expenses. This standard became applicable on January 1, 2013. Peyto adopted the standard on January 1, 2013, with no impact on Peyto's financial position or results of operations.

IFRS 12 - Disclosure of Interests in Other Entities; establishes disclosure requirements for interests in other entities, such as joint arrangements, associates, special purpose vehicles and off-balance-sheet vehicles. The standard carries forward existing disclosure and also introduces significant additional disclosure requirements that address the nature of, and risks associated with, an entity's interests in other entities. This standard became effective for Peyto on January 1, 2013. Peyto adopted the standard on January 1, 2013, with no impact on Peyto's financial position or results of operations.

IFRS 13 - Fair Value Measurement; defines fair value, sets out a single IFRS framework for measuring fair value and requires disclosure about fair value measurements. IFRS 13 applies to accounting standards that require or permit fair value measurements or disclosure about fair value measurements (and measurements, such as fair value less costs to sell, based on fair value or disclosure about those measurements), except in specified circumstances. IFRS 13 became applicable on January 1, 2013. Peyto adopted the standard on January 1, 2013, with no impact on Peyto's financial position or results of operations.

**d. Standards issued but not yet effective**

As of January 1, 2018, Peyto will be required to adopt IFRS 9 "Financial Instruments", which is the result of the first phase of the 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 Financial Statements will not be known until the project is complete.

In May 2013, the IASB issued amendments to IAS 36 "Impairment of Assets" which reduce the circumstances in which the recoverable amount of CGUs is required to be disclosed and clarify the disclosures required when an impairment loss has been recognized or reversed in the period. The amendments are required to be adopted retrospectively for fiscal years beginning January 1, 2014, with earlier adoption permitted. These amendments will be applied by Peyto on January 1, 2014 and the adoption will only impact disclosures in the notes to the financial statements in periods when an impairment loss or impairment reversal is recognized.

In May 2013, the IASB issued IFRIC 21 "Levies," which was developed by the IFRS Interpretations Committee ("IFRIC"). IFRIC 21 clarifies that an entity recognizes a liability for a levy when the activity that triggers payment, as identified by the relevant legislation, occurs. The interpretation also clarifies that no liability should be recognized before the specified minimum threshold to trigger that levy is reached. IFRIC 21 is required to be adopted retrospectively for fiscal years beginning January 1, 2014, with earlier adoption permitted. IFRIC 21 will be applied by Peyto on January 1, 2014 and the adoption may have an impact on Peyto's accounting for production and similar taxes, which do not meet the definition of an income tax in IAS 12 "Income Taxes". Peyto is currently assessing and quantifying the effect on its financial statements.

**e. Presentation currency**

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

**f. Cash Equivalents**

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

**g. 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.

**h. 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.

**i. 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.

**j. 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.

**k. 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.

**l. 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.

**m. 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 method. The Company has made the following classifications:

| Financial Assets & Liabilities | Category |
| --- | --- |
| 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.

**n. 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 propane and 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 derivative financial 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.

**o. 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.

**p. 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

**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.

**q. 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 equity.

**r. 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.

**s. 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.

**t. Share-based payments**

Cash-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 cash-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.

**u. 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.

**v. Share capital**

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

**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 were included in general and administrative expenses in the Income Statement.

| Fair value of net assets acquired | |
|---|---|
| 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 |
| Total net assets acquired | 112,187 |
| Consideration | |
| Shares issued (5,404,007 shares) | 112,187 |
| Total purchase price | 112,187 |

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;

| | As Stated December 31, 2012 | Open Range January 1, 2012 to August 14, 2012 | Pro Forma December 31, 2012 |
|---|---|---|---|
| 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

| | |
|---|---|
| Cost | |
| At December 31, 2011 | 1,845,180 |
| Acquisitions through business combinations | 190,385 |
| Additions | 447,386 |
| Decommissioning provision additions | 19,120 |
| Dispositions | (17,649 ) |
| Prepaid capital | 2,300 |
| At December 31, 2012 | 2,486,722 |
| Additions | 578,003 |
| Decommissioning provision additions | 1,439 |
| Dispositions | - |
| Prepaid capital | 5,081 |
| At December 31, 2013 | 3,071,245 |
| Accumulated depletion and depreciation | |
| At December 31, 2011 | (214,546 ) |
| Depletion and depreciation | (172,338 ) |
| Dispositions | 146 |
| At December 31, 2012 | (386,738 ) |
| Depletion and depreciation | (224,976 ) |
| Dispositions | - |
| At December 31, 2013 | (611,714 ) |
| Carrying amount at December 31, 2012 | 2,099,984 |
| Carrying amount at December 31, 2013 | 2,459,531 |

Proceeds received for assets disposed of during 2013 were $nil (2012 - $21.9 million).

In September 2012, Peyto acquired producing properties for $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, 2013 Peyto capitalized $7.8 million (2012 - $7.8 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

| | December 31, 2013 | December 31, 2012 |
|---|---|---|
| Bank credit facility | 605,000 | 430,000 |

| | | |
|---|---|---|
| Senior unsecured notes | 270,000 | 150,000 |
| Balance, end of the year | 875,000 | 580,000 |

The Company has a syndicated $1.0 billion extendible unsecured revolving credit facility with a stated term date of April 26, 2015. The bank facility is made up of a $30 million working capital sub-tranche and a $970 million production line. The facilities are available on a revolving basis for a two year period. Borrowings under the facility bear interest at Canadian bank prime (3% at both December 31, 2013 and 2012) or US base rate, or, at Peyto's option, Canadian dollar bankers' acceptances or US dollar LIBOR loan rates, plus applicable margin and stamping fees. The total stamping fees range between 80 basis points and 225 basis points on Canadian bank prime and US base rate borrowings and between 180 basis points and 325 basis points on Canadian dollar bankers' acceptance and US dollar LIBOR borrowings. The undrawn portion of the facility is subject to a standby fee in the range of 40.5 to 73.13 basis points.

On January 3, 2012, Peyto issued $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 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 $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 have a coupon rate of 4.88% and mature on September 6, 2022. Interest will be paid semi-annually in arrears.

On April 26, 2013, the security on the notes issued on January 3, 2012 and September 6, 2012 was released pursuant to the amended and restated note purchase and private shelf agreement.

On December 4, 2013, Peyto issued $120 million of senior unsecured notes pursuant to a Note Purchase agreement. 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 4.50% and mature on December 4, 2020. Interest will be paid semi-annually in arrears.

Upon the issuance of the senior unsecured notes on April 26, 2013 and December 4, 2013, Peyto is subject to the following financial covenants as defined in the credit facility and note purchase agreements:

- Long-term debt plus the average working capital deficiency (surplus) at the end of the two most recently completed fiscal quarters adjusted for non-cash items not to exceed 3.0 times trailing twelve month net income before non-cash items, interest and income taxes;
- Long-term debt and subordinated debt plus the average working capital deficiency (surplus) at the end of the two most recently completed fiscal quarters adjusted for non-cash items not to exceed 4.0 times trailing twelve month net income before non-cash items, interest and income taxes;
- Trailing twelve months net income before non-cash items, interest and income taxes to exceed 3.0 times trailing twelve months interest expense;
- Long-term debt and subordinated debt plus the average working capital deficiency (surplus) at the end of the two most recently completed fiscal quarters adjusted for non-cash items not to exceed 55 per cent of the book value of shareholders' equity and long-term debt and subordinated debt.

Peyto is in compliance with all financial covenants and has no subordinated debt as at December 31, 2013.

Peyto's total borrowing capacity is $1.27 billion and Peyto's credit facility is $1.0 billion.

The fair value of all senior notes as at December 31, 2013, is $269.2 million compared to a carrying value of $270.0 million.

Total interest expense for 2013 was $30.9 million (2012 - $25.4 million) and the average borrowing rate for 2013 was 4.2% (2012 - 4.7%).

**6. Decommissioning provision**

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

| | |
|---|---|
| Balance, December 31, 2011 | 38,037 |
| New or increased provisions | 13,908 |
| Accretion of discount | 1,044 |
| Change in discount rate and estimates | 5,212 |
| Balance, December 31, 2012 | 58,201 |
| New or increased provisions | 10,216 |
| Accretion of discount | 1,544 |
| Change in discount rate and estimates | (8,777) |
| Balance, December 31, 2013 | 61,184 |
| Current | - |
| Non-current | 61,184 |

The Company has estimated the net present value of its total decommissioning provision to be $61.2 million as at December 31, 2013 ($58.2 million at December 31, 2012) based on a total future undiscounted liability of $177.8 million ($127.9 million at December 31, 2012). At December 31, 2013 management estimates that these payments are expected to be made over the next 50 years with the majority of payments being made in years 2040 to 2064. The Bank of Canada's long term bond rate of 3.24 per cent (2.36 per cent at December 31, 2012) and an inflation rate of 2.0 per cent (2.0 per cent at December 31, 2012) were used to calculate the present value of the decommissioning provision.

### 7. Equity

Share capital

Authorized: Unlimited number of voting common shares

Issued and Outstanding

| Common Shares (no par value) | Number of Common Shares | Amount $ |
|---|---|---|
| Balance, December 31, 2011 | 137,960,301 | 889,115 |
| 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 |
| Balance, December 31, 2012 | 148,518,713 | 1,124,382 |
| Common shares issued by private placement | 240,210 | 5,742 |
| Common share issuance costs (net of tax) | - | (55) |
| Balance, December 31, 2013 | 148,758,923 | 1,130,069 |

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).

On December 31, 2012, Peyto 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 January 7, 2013.

On March 19, 2013, Peyto completed a private placement of 85,660 common shares to employees and consultants for net proceeds of $2.2 million ($26.65 per share).

Subsequent to December 31, 2013, Peyto closed an offering for 4,720,000 common shares at a price of $34.00 per common share, receiving net proceeds of $153.6 million. The offering closed on February 5, 2014.

**Shares to be issued**

On December 31, 2013, Peyto completed a private placement of 190,525 common shares to employees and consultants for net proceeds of $6.2 million ($32.78 per share). These common shares were issued January 8, 2014.

**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, 2013 of 148,737,654 (2012 - 141,093,829). There are no dilutive instruments outstanding.

**Dividends**

During the year ended December 31, 2013, Peyto declared and paid dividends of $0.88 per common share or $0.06 per common share for the months of January to April 2013 and $0.08 per common share for the months of May to December 2013, totaling $130.9 million (2012 - $0.72 or $0.06 per share per month, $101.6 million).

On January 15, 2014 Peyto declared dividends of $0.08 per common share paid on February 14, 2014. On February 14, 2014, Peyto declared dividends of $0.08 per common share to be paid to shareholders of record on February 28, 2014. These dividends will be paid on March 14, 2014.

**Accumulated other 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 | |
|---|---|---|
| | 2013 | 2012 |
| Field expenses | 58,963 | 46,591 |
| Processing and gathering recoveries | (13,728 ) | (15,331 ) |
| Total operating expenses | 45,235 | 31,260 |

### 9. General and administrative expenses

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

| | Years ended December 31 | |
|---|---|---|
| | 2013 | 2012 |
| General and administrative expenses | 14,306 | 12,822 |
| Overhead recoveries | (9,102 ) | (8,976 ) |
| Net general and administrative expenses | 5,204 | 3,846 |

### 10. Finance costs

| | Years ended December 31 | |
|---|---|---|
| | 2013 | 2012 |
| Interest expense | 30,991 | 25,401 |
| Accretion of decommissioning provisions | 1,544 | 1,044 |
| Total finance costs | 32,535 | 26,445 |

### 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 2013 market based component was based on i) 0.6 million vested rights at an average grant price of $19.12, average cumulative distributions of $0.72 and a ten day weighted average price of $24.75; ii) 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 and iii) 1.0 million vested rights at an average grant price of $22.83, average cumulative distributions of $0.88 and a ten day weighted average price of $32.27. 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) | 2013 | 2012 |
|---|---|---|
| Market based compensation | 14,061 | 7,762 |
| Reserve based compensation | 2,236 | 4,825 |
| Total market and reserves based compensation | 16,297 | 12,587 |

For the future market based component, compensation costs as at December 31, 2013 were $5.56 million (2012 - $2.82 million recovery) related to 0.1 million non-vested rights with an average grant price of $20.63, average cumulative dividends of $0.48 and 2.0 million non-vested rights with an average grant price of $22.83 and average cumulative dividends of $0.88. (2012 - 0.6 million non-vested rights with an average grant price of $19.13 and 0.1 million non-vested rights with an average grant price of $20.63 were a recovery of $2.8 million). The cumulative provision for future performance based compensation as at December 31, 2013 was $8.3 million (2012 - $2.7 million).

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

| | December 31 2013 | December 31 2012 |
|---|---|---|
| Share price | $ 32.27 | $ 22.58 |
| Exercise price | $ 19.91 - $21.70 | $ 18.41 - $19.91 |
| Expected volatility | 0 % | 0 % |
| Option life | 1 - 2 years | 1 - 2 years |
| Dividend yield | 0 % | 0 % |
| Risk-free interest rate | 1.13 % | 1.08 % |

Subsequent to December 31, 2013, 3.2 million rights were granted at a price of $32.78 to be valued at the ten day weighted average market price at December 31, 2013 and vesting one third on each of December 31, 2014, December 31, 2015 and December 31, 2016.

## 12. Income taxes

| ($000) | 2013 | 2012 |
|---|---|---|
| Earnings before income taxes | 189,363 | 130,093 |
| Statutory income tax rate | 25.00 % | 25.00 % |
| Expected income taxes | 47,341 | 32,523 |
| Increase (decrease) in income taxes from: | | |
| True-up tax pools | (443 ) | 1,634 |
| Resolution of reassessment and other | (162 ) | 1,985 |
| Total income tax expense | 46,736 | 36,142 |
| Deferred income tax expense | 46,736 | 34,274 |
| Current income tax expense | - | 1,868 |
| Total income tax expense | 46,736 | 36,142 |
| Differences between tax base and reported amounts for depreciable assets | (249,382 ) | (207,805 ) |
| Derivative financial instruments | 7,947 | 1,930 |
| Share issuance costs | 1,826 | (3,095 ) |
| Future performance based bonuses | 2,075 | (684 ) |
| Provision for decommission provision | 15,296 | (14,550 ) |
| Cumulative eligible capital | 6,139 | (6,599 ) |
| Attributable crown royalty income carryforward | - | - |
| Tax loss carry-forwards recognized | 5,017 | (10,566 ) |
| Deferred income taxes | (211,082 ) | (174,241 ) |

At December 31, 2013 the Company has tax pools of approximately $1,467.1 million (2012 - $1,288.0 million) available for deduction against future income. The Company has approximately $19.7 million in loss carry-forwards (2012 - $42.1 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 balance sheet are carried at amortized cost with the exception of cash derivative financial 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, 2013.

The fair value of the Company's cash and derivative financial 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 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, derivative financial instruments, due from private placement, current liabilities, provision for future performance based compensation and long term debt. At December 31, 2013 and 2012, cash and derivative financial 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, 2013:

| Propane<br>Period Hedged | Type | Monthly Volume | Price (USD) |
|---|---|---|---|
| January 1, 2014 to March 31, 2014 | Fixed Price | 4,000 bbl | $37.80/bbl |
| January 1, 2014 to March 31, 2014 | Fixed Price | 4,000 bbl | $36.54/bbl |
| January 1, 2014 to March 31, 2014 | Fixed Price | 4,000 bbl | $39.354/bbl |
| January 1, 2014 to March 31, 2014 | Fixed Price | 4,000 bbl | $41.37/bbl |
| January 1, 2014 to March 31, 2014 | Fixed Price | 4,000 bbl | $44.94/bbl |
| January 1, 2014 to March 31, 2014 | Fixed Price | 4,000 bbl | $49.455/bbl |
| January 1, 2014 to December 31, 2014 | Fixed Price | 4,000 bbl | $35.70/bbl |
| January 1, 2014 to December 31, 2014 | Fixed Price | 4,000 bbl | $37.485/bbl |
| April 1, 2014 to September 30, 2014 | Fixed Price | 4,000 bbl | $41.79/bbl |
| April 1, 2014 to September 30, 2014 | Fixed Price | 4,000 bbl | $42.63/bbl |
| April 1, 2014 to September 30, 2014 | Fixed Price | 4,000 bbl | $44.31/bbl |
| October 1, 2014 to December 31, 2014 | Fixed Price | 4,000 bbl | $42.84/bbl |

| Natural Gas<br>Period Hedged | Type | Daily Volume | Price (CAD) |
|---|---|---|---|
| April 1, 2012 to March 31, 2014 | Fixed Price | 5,000 GJ | $3.00/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 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 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 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 |
| 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 |
| August 1, 2013 to March 31, 2014 | Fixed Price | 5,000 GJ | $3.55/GJ |
| November 1, 2013 to March 31, 2014 | Fixed Price | 5,000 GJ | $3.71/GJ |
| November 1, 2013 to March 31, 2014 | Fixed Price | 5,000 GJ | $3.76/GJ |
| November 1, 2013 to March 31, 2014 | Fixed Price | 5,000 GJ | $3.86/GJ |
| November 1, 2013 to March 31, 2014 | Fixed Price | 5,000 GJ | $4.00/GJ |
| November 1, 2013 to March 31, 2014 | Fixed Price | 5,000 GJ | $3.90/GJ |
| November 1, 2013 to March 31, 2014 | Fixed Price | 5,000 GJ | $3.52/GJ |
| November 1, 2013 to March 31, 2014 | Fixed Price | 5,000 GJ | $3.1025/GJ |
| November 1, 2013 to March 31, 2014 | Fixed Price | 5,000 GJ | $3.245/GJ |
| November 1, 2013 to March 31, 2014 | Fixed Price | 5,000 GJ | $3.45/GJ |
| November 1, 2013 to March 31, 2014 | Fixed Price | 5,000 GJ | $3.3075/GJ |
| November 1, 2013 to March 31, 2014 | Fixed Price | 5,000 GJ | $3.25/GJ |
| November 1, 2013 to October 31, 2014 | Fixed Price | 5,000 GJ | $3.50/GJ |
| November 1, 2013 to October 31, 2014 | Fixed Price | 5,000 GJ | $3.53/GJ |
| November 1, 2013 to March 31, 2015 | Fixed Price | 5,000 GJ | $3.6025/GJ |
| December 1, 2013 to March 31,2014 | Fixed Price | 5,000 GJ | $3.50/GJ |
| January 1, 2014 to March 31, 2014 | Fixed Price | 5,000 GJ | $3.295/GJ |

| | | | |
|---|---|---|---|
| January 1, 2014 to March 31, 2014 | Fixed Price | 5,000 GJ | $3.35/GJ |
| January 1, 2014 to March 31, 2014 | Fixed Price | 5,000 GJ | $3.51/GJ |
| January 1, 2014 to March 31, 2014 | Fixed Price | 5,000 GJ | $3.60/GJ |
| January 1, 2014 to March 31, 2014 | Fixed Price | 5,000 GJ | $3.65/GJ |
| February 1, 2014 to March 31, 2014 | Fixed Price | 5,000 GJ | $3.70/GJ |
| February 1, 2014 to March 31, 2014 | Fixed Price | 5,000 GJ | $3.80/GJ |
| April 1, 2014 to October 31, 2014 | Fixed Price | 5,000 GJ | $3.505/GJ |
| April 1, 2014 to October 31, 2014 | Fixed Price | 5,000 GJ | $3.555/GJ |
| April 1, 2014 to October 31, 2014 | Fixed Price | 5,000 GJ | $3.48/GJ |
| April 1, 2014 to October 31, 2014 | Fixed Price | 5,000 GJ | $3.335/GJ |
| April 1, 2014 to October 31, 2014 | Fixed Price | 5,000 GJ | $3.10/GJ |
| April 1, 2014 to March 31, 2015 | Fixed Price | 5,000 GJ | $3.82/GJ |
| April 1, 2014 to March 31, 2015 | Fixed Price | 5,000 GJ | $3.44/GJ |
| April 1, 2014 to March 31, 2015 | Fixed Price | 5,000 GJ | $3.52/GJ |
| April 1, 2014 to March 31, 2015 | Fixed Price | 5,000 GJ | $3.4725/GJ |
| April 1, 2014 to March 31, 2015 | Fixed Price | 5,000 GJ | $3.525/GJ |
| April 1, 2014 to March 31, 2015 | Fixed Price | 5,000 GJ | $3.60/GJ |
| April 1, 2014 to March 31, 2015 | Fixed Price | 5,000 GJ | $3.27/GJ |
| April 1, 2014 to March 31, 2015 | Fixed Price | 5,000 GJ | $3.41/GJ |
| April 1, 2014 to March 31, 2015 | Fixed Price | 5,000 GJ | $3.5575/GJ |
| April 1, 2014 to March 31, 2015 | Fixed Price | 5,000 GJ | $3.465/GJ |
| April 1, 2014 to March 31, 2015 | Fixed Price | 5,000 GJ | $3.43/GJ |
| April 1, 2014 to March 31, 2015 | Fixed Price | 5,000 GJ | $3.54/GJ |
| April 1, 2014 to March 31, 2015 | Fixed Price | 5,000 GJ | $3.50/GJ |
| April 1, 2014 to March 31, 2015 | Fixed Price | 5,000 GJ | $3.25/GJ |
| April 1, 2014 to March 31, 2015 | Fixed Price | 5,000 GJ | $3.25/GJ |
| April 1, 2014 to March 31, 2015 | Fixed Price | 5,000 GJ | $3.23/GJ |
| April 1, 2014 to March 31, 2015 | Fixed Price | 5,000 GJ | $3.23/GJ |
| April 1, 2014 to March 31, 2015 | Fixed Price | 5,000 GJ | $3.23/GJ |
| April 1, 2014 to March 31, 2015 | Fixed Price | 5,000 GJ | $3.31/GJ |
| April 1, 2014 to March 31, 2015 | Fixed Price | 5,000 GJ | $3.3525/GJ |
| April 1, 2014 to March 31, 2015 | Fixed Price | 5,000 GJ | $3.40/GJ |
| April 1, 2014 to March 31, 2015 | Fixed Price | 5,000 GJ | $3.49/GJ |
| April 1, 2014 to March 31, 2015 | Fixed Price | 5,000 GJ | $3.54/GJ |
| April 1, 2014 to March 31, 2015 | Fixed Price | 5,000 GJ | $3.61/GJ |
| April 1, 2014 to March 31, 2015 | Fixed Price | 5,000 GJ | $3.70/GJ |
| April 1, 2014 to March 31, 2015 | Fixed Price | 5,000 GJ | $3.75/GJ |
| November 1, 2014 to March 31, 2015 | Fixed Price | 5,000 GJ | $3.81/GJ |
| April 1, 2015 to October 31, 2015 | Fixed Price | 5,000 GJ | $3.285/GJ |
| April 1, 2015 to October 31, 2015 | Fixed Price | 5,000 GJ | $3.30/GJ |
| April 1, 2015 to October 31, 2015 | Fixed Price | 5,000 GJ | $3.35/GJ |
| April 1, 2015 to October 31, 2015 | Fixed Price | 5,000 GJ | $3.40/GJ |

As at December 31, 2013, Peyto had committed to the future sale of 252,000 barrels of natural gas liquids at an average price of $42.67 CAD ($40.12 USD) per barrel and 96,070,000 gigajoules (GJ) of natural gas at an average price of $3.40 per GJ or $3.91 per mcf. Had these contracts been closed on December 31, 2013, Peyto would have realized a loss in the amount of $31.7 million. If the AECO gas price on December 31, 2013 were to increase by $1/GJ, the unrealized loss would increase by approximately $96.1 million. An opposite change in commodity prices rates would result in an opposite impact on other comprehensive income.

Subsequent to December 31, 2013 Peyto entered into the following contracts:

| Propane<br>Period Hedged | Type | Monthly Volume | Price<br>(USD) |
|---|---|---|---|
| April 1, 2014 to September 30, 2014 | Fixed Price | 4,000 bbl | $46.20/bbl |

| Natural Gas<br>Period Hedged | Type | Daily Volume | Price<br>(CAD) |
|---|---|---|---|
| February 1, 2014 to March 31, 2014 | Fixed Price | 5,000 GJ | $3.90/GJ |
| February 1, 2014 to March 31, 2014 | Fixed Price | 5,000 GJ | $3.85/GJ |
| March 1, 2014 to March 31, 2014 | Fixed Price | 5,000 GJ | $4.15/GJ |
| March 1, 2014 to March 31, 2014 | Fixed Price | 5,000 GJ | $4.24/GJ |
| March 1, 2014 to March 31, 2014 | Fixed Price | 5,000 GJ | $5.10/GJ |
| April 1, 2014 to October 31, 2014 | Fixed Price | 5,000 GJ | $3.80/GJ |

| | | | |
|---|---|---|---|
| April 1, 2014 to October 31, 2014 | Fixed Price | 5,000 GJ | $3.825/GJ |
| April 1, 2014 to October 31, 2014 | Fixed Price | 5,000 GJ | $3.95/GJ |
| April 1, 2014 to October 31, 2014 | Fixed Price | 5,000 GJ | $3.98/GJ |
| April 1, 2014 to October 31, 2014 | Fixed Price | 5,000 GJ | $4.07/GJ |
| April 1, 2014 to October 31, 2014 | Fixed Price | 5,000 GJ | $4.32/GJ |
| April 1, 2014 to October 31, 2014 | Fixed Price | 5,000 GJ | $4.35/GJ |
| April 1, 2014 to October 31, 2014 | Fixed Price | 5,000 GJ | $4.55/GJ |
| April 1, 2014 to March 31, 2015 | Fixed Price | 5,000 GJ | $3.81/GJ |
| April 1, 2014 to March 31, 2015 | Fixed Price | 5,000 GJ | $3.83/GJ |
| November 1, 2014 to October 31, 2015 | Fixed Price | 5,000 GJ | $3.95/GJ |
| November 1, 2014 to October 31, 2015 | Fixed Price | 5,000 GJ | $4.05/GJ |
| November 1, 2014 to October 31, 2015 | Fixed Price | 5,000 GJ | $4.12/GJ |
| November 1, 2014 to October 31, 2015 | Fixed Price | 5,000 GJ | $4.20/GJ |
| November 1, 2014 to October 31, 2015 | Fixed Price | 5,000 GJ | $4.44/GJ |
| November 1, 2014 to October 31, 2015 | Fixed Price | 5,000 GJ | $4.585/GJ |
| November 1, 2014 to October 31, 2015 | Fixed Price | 5,000 GJ | $4.78/GJ |
| April 1, 2015 to October 31, 2015 | Fixed Price | 5,000 GJ | $3.47/GJ |
| April 1, 2015 to October 31, 2015 | Fixed Price | 5,000 GJ | $3.48/GJ |
| April 1, 2015 to October 31, 2015 | Fixed Price | 5,000 GJ | $3.52/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, 2013 would decrease by $5.8 million. An opposite change in interest rates would 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. Credit limits exceeding $2,000,000 per month are not granted to non-investment grade counterparties unless the Company receives either i) a parental guarantee from an investment grade parent; or ii) an irrevocable letter of credit for two months revenue. 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, 2013, approximately 62% was received from five companies (15%, 13%, 13%, 11%, and 10%) (December 31, 2012 - 14%, one company). Of the Company's accounts receivable at December 31, 2013, approximately 61% was receivable from five companies (14%, 14%, 11%, 11%, and 11%) (December 31, 2012 - 14%, 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, 2013, 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, 2013:

| | < 1 Year | 1-2 Years | 3-5 Years | Thereafter |
|---|---|---|---|---|
| Accounts payable and accrued liabilities | 155,265 | - | - | - |
| Dividends payable | 11,901 | - | - | - |
| Provision for future market and reserves based bonus | 5,100 | 3,200 | - | - |
| Current taxes payable | - | - | - | - |
| Long-term debt[1] | - | 605,000 | - | - |
| Unsecured senior notes | - | - | - | 270,000 |

[1] Revolving credit facility renewed annually (*see Note 5*)

**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 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.

| | December 31 2013 | December 31 2012 |
|---|---|---|
| Equity | 1,200,638 | 1,210,067 |
| Long-term debt | 875,000 | 580,000 |
| Working capital (surplus) deficit | 103,247 | 74,884 |
| | 2,178,885 | 1,864,951 |

**14. 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, 2013, legal fees totaled $0.7 million (2012 - $1.2 million). As at December 31, 2013, an amount due to this firm of $0.7 million was included in accounts payable (2012 - $1.2 million).

The Company has determined that the key management personnel consists of 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 $1.4 million is included in general and administrative expenses and $6.5 million in market and reserves based bonus relating to key management personnel for the year 2013 (2012 - $1.3 million in general and administrative and $5.0 million in market and reserves based bonus).

### 15. Commitments

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

| | 2014 | 2015 | 2016 | 2017 | 2018 | Thereafter |
|---|---|---|---|---|---|---|
| Note repayment[1] | - | - | - | - | - | 270,000 |
| Interest payments[2] | 12,230 | 12,230 | 12,230 | 12,230 | 12,230 | 22,755 |
| Transportation commitments | 18,350 | 16,354 | 12,276 | 8,414 | 6,175 | 4,873 |
| Operating leases | 2,412 | 2,380 | 1,863 | 1,654 | 1,295 | 10,356 |
| Total | 32,992 | 30,964 | 26,369 | 22,298 | 19,700 | 307,984 |

[1] Long-term debt repayment on senior unsecured notes

[2] Fixed interest payments on senior unsecured notes

### 16. Contingencies

On October 31, 2013, Peyto was named as a party to a statement of claim received with respect to transactions between Poseidon Concepts Corp. and Open Range Energy Corp. The allegations contained in the claim are based on factual matters that pre-existed Peyto's involvement with New Open Range which makes them difficult to assess at this time. However, Peyto intends to aggressively protect its interests and the interests of its shareholders and will seek all available legal remedies in defending the action. Management continues to assess the nature of this claim, in conjunction with their legal advisors.

### 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
- 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
- The Toronto-Dominion Bank
- Bank of Nova Scotia
- HSBC Bank Canada
- Alberta Treasury Branches
- Canadian Western Bank

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## Contact

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