PAINTED PONY PETROLEUM LTD.

2012

ANNUAL REPORT TO SHAREHOLDERS

SIX YEARS OF SUCCESS: A CROSSING POINT

CORPORATE PROFILE

Painted Pony Petroleum Ltd. ("Painted Pony" or the "Company") is a public oil and gas exploration company based in Calgary, Alberta, Canada. Painted Pony's philosophy is to grow through exploration and development drilling, complemented by strategic corporate and asset acquisitions. The Company is primarily focused on natural gas from the Montney formation in northeast British Columbia and light oil in southeast Saskatchewan and central Alberta. Common Shares of the Company trade on the TSX venture under the symbol "PPY".

ANNUAL GENERAL AND SPECIAL MEETING

Painted Pony Petroleum Ltd. invites shareholders and interested parties to attend its Annual General and Special Meeting to be held in the Bennett Salon at the Ranchmen's Club, 710 - 13th Avenue SW, Calgary, Alberta on Wednesday, June 5th, 2013 at 3:00 pm (Calgary time). Shareholders not attending are encouraged to complete the form of proxy and deliver it in accordance with the instructions therein at their earliest convenience.

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Cover painting "A Crossing Point" by Paul Van Ginkel (www.paulvanginkel.com)

FINANCIAL AND OPERATING HIGHLIGHTS

	Year ended December 31,	
	2012	**2011**
Financial		
($ millions, except per share and shares outstanding)		
Petroleum and natural gas revenue[1]	**74.3**	73.9
Funds flow from operations[2]	**39.3**	44.2
Per share - basic[3]	**0.56**	0.74
Per share - diluted[4]	**0.55**	0.73
Cash flows from operating activities	**39.7**	44.9
Comprehensive income (loss)	**(48.1)**	6.5
Per share - basic and diluted[3] [4]	**(0.68)**	0.11
Capital expenditures[5]	**241.3**	162.9
Working capital	**45.2**	68.3
Total assets	**612.2**	478.7
Shares outstanding[6]	**88,051,760**	69,693,027
Diluted weighted-average shares	**70,824,894**	60,829,382
Operational		
Daily sales volumes		
Gas *(mcf per day)*	**30,248**	15,589
Oil *(bbls per day)*	**1,342**	1,460
Condensate *(bbls per day)*	**64**	54
NGL's *(bbls per day)*	**142**	108
Total *(boe per day)*	**6,589**	4,221
Realized prices		
Gas *($ per mcf)*	**2.54**	3.60
Oil *($ per bbl)*	**85.67**	93.07
Field operating netbacks *($ per boe)*		
British Columbia	**9.08**	14.12
Saskatchewan	**48.69**	58.34
Company combined	**18.46**	31.34

1. *Before royalties.*
2. *This table contains the term "funds flow from operations", which should not be considered an alternative to, or more meaningful than "cash flows from operating activities" as determined in accordance with International Financial Reporting Standards ("IFRS") as an indicator of the Company's performance. Funds flow from operations and funds flow from operations per share (basic and diluted) does not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measures for other entities. Management uses funds flow from operations to analyze operating performance and leverage and considers funds flow from operations to be a key measure as it demonstrates the Company's ability to generate the cash necessary to fund future capital investment. The reconciliation between funds flow from operations and cash flows from operating activities can be found in "Management's Discussion and Analysis". Funds flow from operations per share is calculated using the basic and diluted weighted average number of shares for the period, consistent with the calculations of earnings per share.*
3. *Basic per share information is calculated on the basis of the weighted average number of shares outstanding in the period.*
4. *Diluted per share information reflects the potential dilution effect of options, which may be anti-dilutive. Comprehensive income in 2011 was adjusted for the amount of finance expense applicable to the Class B shares for the period.*
5. *Including acquisitions, decommissioning obligations, and share-based payments.*
6. *Class A shares at December 31, 2011 were re-designated as Common shares effective June 7, 2012.*

TO OUR SHAREHOLDERS

Opportunities are like sunrises...

Volatility has continued to be a day-to-day reality in the Canadian oil and gas industry. During 2012, the economics for oil and gas plays varied, echoing changes in commodity pricing, demand and transportation. Crude oil producers faced issues with the ability to transport product to market, while natural gas producers endured dropping prices, particularly in the second quarter. The Company's British Columbia gas projects netted back an average of $13.32 per boe in the fourth quarter of 2012, an improvement of 161% from the $5.11 per boe netback in the second quarter of the year. Fortunately, natural gas prices have rebounded from the lows in the second quarter of 2012 and have continued to strengthen in 2013.

LNG

The Company's Montney assets are strategically located to potentially become a future integral component of Canada's developing liquefied natural gas (“LNG”) industry. Painted Pony plans an aggressive gas-weighted drilling program in 2013 as we continue the development and expansion of our Montney gas assets. The Company is watching closely the escalation of industry momentum for the construction of LNG facilities on Canada's west coast, as we believe that Painted Pony's Montney gas project is well-positioned to become a potential supplier to these proposed export terminals. The Company's capital budget for 2013 is forecast at $145 million, of which approximately 81% ($117 million) will be directed towards gas development.

2012 BUSINESS PLAN

In 2012, Painted Pony's conservative fiscal strategy and responsiveness to play economics allowed us to be opportunistic in carrying out a prudent capital and acquisition program with the flexibility to direct spending towards rewarding projects. The Company's natural gas strategy focused on continued delineation of its Montney play in northeast British Columbia, while the Company's light oil program pursued continued development of the Saskatchewan Bakken and Mississippian assets, complemented by a new exploratory play in Alberta. Our emphasis on adding proved and probable gas reserves plus contingent resources proved highly successful. At December 31, 2012, the Company's proved plus probable reserves increased to 1.15 Tcfe, equating to 191 mmboe, up 40% from 137 mmboe at December 31, 2011. A best estimate of contingent resources for the Company's Montney asset as at December 31, 2012 was 3.15 Tcfe, which equates to 525 mmboe.

PRODUCTION

During 2012, Painted Pony posted impressive gains in production, both on a net volume basis (56% growth over 2011) and on a per weighted average share basis (34% growth compared to 2011). The Company's 2012 sales averaged 6,589 boe/d, driven principally by an increase of 94% in gas sales to 30.2 mmcf/d. During 2012, gas sales accounted for 77% of total volumes, as compared to 62% in 2011.

During the fourth quarter of 2012, the Company's average daily production rate was 7,289 boe/d (76% gas), up 15% over the third quarter rate of 2012. Average fourth quarter gas sales of 33.4 mmcf/d, represents a new gas production record for the Company. Field production for the first two months of 2013 is estimated at 8,200 boe/d (weighted 78% to gas).

LAND

Also in 2012, Painted Pony actively pursued the acquisition of additional Montney land holdings through Crown sales and asset purchases. The Company closed several asset acquisitions on this play, including the purchase of approximately 25 net contiguous sections in the Kobes-Townsend area, plus a consolidation of existing holdings in the Cypress area via a purchase of approximately 13 net sections. These transactions, combined with ongoing crown sale activity, increased the Company's total net acreage to 286,874 net acres at the end of 2012. Painted Pony's Montney land holdings now total approximately 190 net sections, an increase of approximately 30% over the past fifteen months.

if you wait too long, you miss them.
~William Arthur Ward

CAPITAL EXPENDITURES

The Company spent a total of $241 million on capital programs in 2012, including $115 million on property acquisitions. Expenditures on exploration and development in 2012 totaled $118 million.

During 2012, the Company drilled a total of 34 (26.4 net) wells, including 10 (6.6 net) in British Columbia and 21 (16.8 net) wells in Saskatchewan. The British Columbia program targeted Montney gas development at Blair, West Blair and Cameron. In Saskatchewan, the Company focused on development drilling on Bakken and Mississippian light oil projects, principally in Flat Lake. During 2012, Painted Pony initiated a light oil exploration program in Alberta. The Company drilled 3 (3.0 net) wells, targeting the Viking light oil formation at Wimborne and Corbett. An exploratory discovery has been made at Corbett and the Company plans additional drilling on this project in 2013.

FISCAL PRUDENCE

The Company adhered to a conservative fiscal policy in 2012 - a response to continued volatility in commodity prices. A bought-deal equity financing raised $172.5 million before costs, allowing Painted Pony to close its acquisition of the Kobes-Townsend Montney assets, to exit 2012 with no debt, a positive working capital position of $45.2 million and an undrawn demand credit facility of $100 million. Since inception, Painted Pony has rarely carried corporate debt and has exited every quarter end with an undrawn bank line.

OUR FUTURE

Following six years of intense exploration, development, and land acquisition, the Company now enjoys an enviable combination of significant reserves, more than 2,000 potential net drilling locations, plus a clean balance sheet. Based on this success, Painted Pony is in the process of developing a five-year model for accelerated production growth on its Montney project.

The Company has reached a major crossing point, as it enters its seventh year. We continue to strive for excellence in execution and we applaud our staff for their on-going dedication and efforts throughout 2012 as we continued to seek enhancements to our business plan and day-to-day operations. On behalf of our entire team of employees, consultants and Directors, I'd like to thank our shareholders and other stakeholders for their continued support.

At Painted Pony, we truly have “Six Years of Success: A Crossing Point”.

On Behalf of the Board of Directors

Patrick R. Ward,
President and Chief Executive Officer
March 19, 2013

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following Management's Discussion and Analysis ("MD&A") of the consolidated financial results as provided by the management of Painted Pony Petroleum Ltd. ("Painted Pony" or the "Company") should be read in conjunction with the annual consolidated financial statements and related notes thereto for the years ended December 31, 2012 and December 31, 2011. This commentary is dated March 19, 2013.

The annual consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS"). The Company adopted IFRS on January 1, 2011. Previously, Painted Pony prepared its annual consolidated financial statements in accordance with Canadian Generally Accepted Accounting Principles ("Canadian GAAP"). The financial data presented is in accordance with IFRS in Canadian dollars, except where indicated otherwise. These documents and additional information about Painted Pony, including the Annual Information Form, are available on SEDAR at www.sedar.com.

DESCRIPTION OF COMPANY

Painted Pony is a Calgary-based exploration and development company primarily focused on natural gas in northeast British Columbia and light oil in southeast Saskatchewan and central Alberta.

Painted Pony commenced commercial operations on April 3, 2007 upon completion of a financial reorganization as part of an overall restructuring of the Company. On May 23, 2007, subsequent to completion of an initial public offering on May 17, 2007, the Class A shares and Class B shares of Painted Pony began trading on the TSX Venture Exchange. Painted Pony then commenced an active exploration program.

Effective June 7, 2012, the Class A shares of Painted Pony were re-designated as Common shares. The Common shares of Painted Pony trade on the TSX Venture Exchange under the symbol "PPY". Prior to June 11, 2012, these shares traded on the TSX Venture exchange under the symbol "PPY.A". Effective December 1, 2011, the Class B shares of Painted Pony were converted to Class A shares, and, as such, the Class B shares were de-listed on the TSX Venture Exchange.

NON-GAAP MEASURES

This MD&A contains the term "funds flow from operations", which should not be considered an alternative to, or more meaningful than cash flows from operating activities as determined in accordance with IFRS as an indicator of the Company's performance. Funds flow from operations and funds flow from operations per share (basic and diluted) do not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measures for other entities. Management uses funds flow from operations to analyze operating performance and considers funds flow from operations to be a key measure as it demonstrates the Company's ability to generate the cash necessary to fund future capital investment and to repay debt. Funds flow from operations per share is calculated using the basic and diluted weighted average number of shares for the year, consistent with the calculations of earnings per share. The Company reconciles funds flow from operations to cash flows from operating activities, which is the most directly comparable measure calculated in accordance with IFRS, as follows:

Funds Flow From Operations

Years ended December 31, *($000s)*	**2012**	**2011**
Cash flows from operating activities	**39,732**	44,884
Changes in non-cash working capital	**(807)**	(922)
Decommissioning expenditures	**412**	188
Funds flow from operations	**39,337**	44,150

This MD&A also contains other industry benchmarks and terms, such as net working capital position (calculated as current assets less current liabilities) and operating netbacks (calculated on a per unit basis as oil, gas and natural gas liquids revenues less royalties and transportation and operating costs), which are not recognized measures under IFRS. Management believes these measures are useful supplemental measures of, firstly, the total net position of current assets and current liabilities the Company has and, secondly, the profitability relative to commodity prices. Readers are cautioned, however, that these measures should not be construed as alternatives to other terms such as current and long-term debt or comprehensive income determined in accordance with IFRS as measures of performance. Painted Pony's method of calculating these measures may differ from other companies, and accordingly, may not be comparable to similar measures used by other companies.

FORWARD-LOOKING STATEMENTS

Certain statements in this MD&A constitute forward-looking statements and forward-looking information (collectively, "forward-looking statements") within the meaning of applicable Canadian securities laws. Such forward-looking statements relate to future events or the Company's future performance. All statements other than statements of historical fact contained in this MD&A may be forward-looking statements. Such statements and information may be identified by words such as "anticipate", "will", "intend", "could", "should", "may", "might", "expect", "forecast", "plan", "potential", "project", "assume", "contemplate", "believe", "budget", "shall" "continue", "milestone", "target", "vision", "forward looking to", and similar terms or the negative thereof or other comparable terminology. The forward-looking statements contained in this MD&A involve known and unknown risks, uncertainties and other factors that are beyond the Company's control, which may cause actual results or events to differ materially from those anticipated in such forward-looking statements.

The forward-looking statements contained in this MD&A represent management's reasonable projections, expectations and estimates as of the date of this document, but undue reliance should not be placed upon them as they are derived from numerous assumptions. In addition, forward-looking statements may include statements or information attributable to third party industry sources. These assumptions are subject to known and unknown risks and uncertainties, including the business risks discussed in this MD&A, which may cause actual performance and financial results to differ materially from any projections of future performance or results expressed or implied by such forward-looking statements. Additionally, there can be no assurance that the plans, intentions or expectations upon which such forward-looking statements are based will occur.

The forward-looking statements in this document are subject to significant risks and uncertainties and are based on a number of material factors and assumptions which may prove to be incorrect; including, but not limited to, the following:

- *volumes in 2013 will be increasingly weighted more toward gas than in 2012 as success from operations targeting the Montney formation in British Columbia could add incremental volumes;*
- *the Company will receive a natural gas price equivalent to the AECO daily spot price;*
- *generally in 2013, the Company will receive an oil price approximately 2% less than the Edmonton par reference price, except for periods when differentials widen due to market conditions. If successful, sales of oil from the Company's new Alberta exploration play could also vary the price received compared to the reference price;*
- *overall royalties in 2013 will approximate 10% of total revenues, assuming similar commodity prices to the year ended December 31, 2012 and implementation of the proposed minimum royalty rate in British Columbia;*
- *average per unit operating and transportation costs in 2013 are expected to be approximately $10 per barrel of oil equivalent ("boe") due to incremental gas sales volumes and reduced repairs and maintenance in Saskatchewan, assuming normal seasonal weather conditions;*
- *net general and administrative costs will be reflective of operated capital expenditure levels throughout 2013;*

- *as gross Saskatchewan sales revenues fluctuate in 2013, the Saskatchewan resource surcharge is expected to vary accordingly;*
- *the capital program will be adjusted if necessary to support the objective of maintaining a net debt to funds flow from operations ratio of one times or less;*
- *the Company has sufficient financial resources with which to conduct its capital program; further, this is subject to the additional assumption that the drilling rigs, field service providers, completion and tie-in equipment will be available as required and that the costs of securing such services and equipment will not materially exceed expectations;*
- *available credit facilities may be utilized on a periodic basis in 2013;*
- *there can be no assurance that the amount of the available demand credit facility will not be decreased at the next review;*
- *the total minimum tolls for transportation of oil through a major carrier system is estimated to be $1.4 million;*
- *a ten-year take-or-pay agreement for minimum gas gathering and processing fees that began in mid-August 2012 is estimated to total a remainder of $22.5 million over the ten year period, to a total maximum volume of 52.925 billion cubic feet ("Bcf") of gas;*
- *office space rentals and a proportionate share of operating costs through 2019 is estimated to total $7.2 million; and*
- *the risk of accounts receivable becoming uncollectible is mitigated by the financial position of the applicable entities.*

Certain or all of the foregoing assumptions may prove to be incorrect and, while it is anticipated that subsequent events and developments may cause the Company's views to change, there is no intention to update the forward-looking statements, except as required by applicable securities laws. These forward-looking statements represent the Company's views as of the date of this MD&A and such information should not be relied upon as representing the Company's views as of any date subsequent to the date of this MD&A. The Company has attempted to identify important factors that could cause actual results, performance or achievements to vary from those current expectations or estimates expressed or implied by the forward-looking statements contained here-in. However, there may be other factors that cause results, performance or achievements not to be as expected or estimated and that could cause actual results, performance or achievements to differ materially from current expectations. Other risks and uncertainties include, but are not limited to, the following:

- *normal risks common to the oil and natural gas industry, including various operational risks in the carrying out of exploration, development and production operations;*
- *volatility of commodity prices;*
- *risks and uncertainty of oil and gas geological deposits;*
- *environmental risks;*
- *revisions, amendments or changes to capital expenditure plans including exploration, development and exploitation projects;*
- *risks as to the availability and pricing of appropriate financing alternatives on acceptable terms;*
- *potential changes in income tax regulations, governmental policies, rules, practices or approval process changes, or delays, or enhancements;*
- *delays resulting from an inability to obtain required regulatory approvals and ability to access sufficient debt or equity capital from internal and external sources; and*
- *the Company's ability to attract and retain qualified professional employees.*

Statements relating to "reserves" or "resources" are by their nature deemed to be forward-looking statements, as they involve the implied assessment based on certain estimates and assumptions that the resources and reserves described can be profitably produced in the future.

The reader is further cautioned that the preparation of consolidated financial statements in accordance with IFRS requires management to make certain judgments and estimates that affect the reported amounts of assets, liabilities, revenues and expenses. Estimating reserves is also critical to several accounting estimates and requires judgments and decisions based upon available geological, geophysical, engineering and economic data. These estimates may change, having either a negative or positive effect on net earnings as further information becomes available, and as the economic environment changes.

There can be no assurance that forward-looking statements will prove to be accurate, as results and future events could differ materially from those expected or estimated in such statements. Accordingly, readers should not place undue reliance on forward-looking statements. From time to time, Painted Pony's management makes estimates and forms opinions on which the forward-looking statements are based. The Company assumes no obligation to update forward-looking statements if circumstances, management's estimates, or opinions change, unless prescribed by securities laws. Furthermore, readers should be aware that historical results are not necessarily indicative of future performance.

BOE PRESENTATION

Barrels of oil equivalent ("boe") may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet of gas ("mcf") to one barrel of oil ("bbl") (6 mcf:1 bbl) is used as an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. All boe conversions in this report are derived by converting natural gas to oil in the ratio of six mcf of gas to one barrel of oil. **Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6:1, utilizing a conversion ratio of 6:1 may be misleading as an indication of value.**

COMPREHENSIVE INCOME AND FUNDS FLOW FROM OPERATIONS

Painted Pony generated funds flow from operations of $39.3 million for the year ended December 31, 2012, compared to $44.2 million for the year ended December 31, 2011. On a basic per share basis, funds flow from operations for the years ended December 31, 2012 and 2011 were $0.56 and $0.74, respectively, and on a diluted basis, funds flow from operations were $0.55 and $0.73 per share, respectively, for the two years.

Cash flow from operating activities was $39.7 million for the year ended December 31, 2012, compared to $44.9 million for the year ended December 31, 2011.

Painted Pony produced a comprehensive loss of $48.1 million in the year ended December 31, 2012, compared to $6.5 million earned during the year ended December 31, 2011. Basic and diluted loss per share are $0.68 for the year ended December 31, 2012, compared to basic and diluted income per share of $0.11 for the year ended December 31, 2011. The comprehensive loss in the year ended December 31, 2012 was primarily attributed to an impairment loss of $42.1 million on the company's Saskatchewan oil cash generating unit ("CGU") and exploration and evaluation expenses of $9.3 million resulting from non-economic drilling and completion activities and impending lease expiries.

SALES VOLUMES

During the year ended December 31, 2012, Painted Pony's sales volumes increased 56%, to average 6,589 boe per day compared to 4,221 boe per day for the year ended December 31, 2011. The increase is primarily from incremental gas sales in British Columbia. In the year ended December 31, 2012, 24% of total volumes were from Saskatchewan, compared to 39% in the year ended December 31, 2011.

Sales volumes in 2012 were weighted 77% towards gas compared to 62% in 2011, reflecting the focus of the capital program toward British Columbia gas producing assets. All of Painted Pony's light oil sales originate from Saskatchewan operations while 96% of the sales of gas, condensate and natural gas liquids ("NGL's") are from British Columbia.

Average Daily Sales Volumes

Years ended December 31,	2012	2011
Gas *(mcf/d)*	**30,248**	15,589
Oil *(bbls/d)*	**1,342**	1,460
Condensate *(bbls/d)*	**64**	54
NGL's *(bbls/d)*	**142**	108
Total *(boe/d)*	**6,589**	4,221

Daily gas sales increased by 94% and oil sales volumes decreased by 8% in 2012 compared to the year ended December 31, 2011, reflecting the focus on and the success of the Montney drilling program.

The increase of gas weighting reflects the net result of the gas-focused capital program combined with the impact of 2011 wet weather conditions in Saskatchewan. All of Painted Pony's light oil sales originate from Saskatchewan operations while most gas sales in the two years are from British Columbia.

The Company anticipates sales volumes in 2013 to be increasingly weighted towards gas sales, as success from operations targeting the Montney formation in British Columbia add incremental volumes.*

* *This paragraph contains forward-looking statements. Please refer to "Forward-looking Statements" and "Business Risks, Uncertainties and Forward-looking Statements" for a discussion of the risks and uncertainties related to such information.*

REVENUES

Petroleum and natural gas sales were relatively flat year over year, totaling $74.3 million in the year ending December 31, 2012, compared to $73.9 million for the year ended December 31, 2011. During 2012, oil sales revenues were 57% of total sales dollars compared to 67% in the year ended December 31, 2011, while oil volumes were 20% and 35% in the years ended December 31, 2012 and 2011, respectively. In both years, oil sales contributed disproportionately more to total sales dollars compared to volumes, reflecting the relative strength of crude oil prices compared to gas prices.

Sales by Product

Years ended December 31, *($000s)*	**2012**	**2011**
Gas	**28,071**	20,464
Oil	**42,093**	49,615
Condensate	**2,037**	1,813
NGL's	**2,088**	2,044
Total	**74,289**	73,936

Revenue from gas sales totaled $28.1 million during the year ended December 31, 2012, compared to $20.5 million received during the year ended December 31, 2011. The Company received an average gas price of $2.54 per mcf in the year ended December 31, 2012, 6% greater than the AECO daily spot average gas reference price of $2.39 per mcf. In the year ended December 31, 2011, the Company received an average gas price of $3.60 per mcf, 1% less than the reference price for that period. The change in gas revenues year over year was the net result of increased gas volumes of 94% partially offset by a decrease in the average gas price of 29%. Gas prices have continued to be weak in North America throughout the year 2012.

Crude oil revenue in the year ended December 31, 2012 was $42.1 million compared to $49.6 million during the year ended December 31, 2011. Oil revenues decreased 15% from the year ended December 31, 2011 to the year ended December 31, 2012. Oil prices averaged $85.67 per bbl during 2012 compared to $93.07 per bbl during 2011. Painted Pony received an average crude oil price 1% less than the Edmonton light reference price in 2012 and 3% less in 2011. Painted Pony's light oil is a premium light crude with low sulfur content. The change in oil revenues year over year was the combined result of an 8% weaker commodity price, plus a reduction in volumes of 8%.

Revenues from condensate and NGL sales totaled $4.1 million during the year ended December 31, 2012, compared to $3.9 million received during the year ended December 31, 2011, primarily from increased sales volumes of 27%, as increased gas sales have been accompanied by incremental liquids volumes. Approximately 31% of the Company's 2012 liquids volumes are condensate, which received an average price of $86.91 per barrel ("bbl"), approximating the Edmonton light reference price. For the balance of the liquids sales, NGL's, the average price received was 46% of Edmonton light.

In 2013, the Company generally expects to receive an average oil price approximately 2% less than the Edmonton par reference price, reflecting the prices currently paid for crude oil in Saskatchewan, where the Company tends to deliver the bulk of its oil production. However, this differential may widen periodically due to market conditions. If successful, sales of oil from the Company's new Alberta exploration play may also vary the price received compared to the reference price. The Company expects to receive a natural gas price equivalent to the AECO daily spot price. The average prices reported for Painted Pony's sales are the weighted net price, which is reflective of month to month price and sales volume changes.*

** This paragraph contains forward-looking statements. Please refer to "Forward-looking Statements" and "Business Risks, Uncertainties and Forward-looking Statements" for a discussion of the risks and uncertainties related to such information.*

To date, Painted Pony has not undertaken any risk management contracts or commodity price contracts.

Average Benchmark Prices

Years ended December 31,	**2012**	**2011**
Exchange rate *(US$/Cdn$)*	**1.0000**	1.0116
Gas - AECO, daily spot *($/mcf)*	**2.39**	3.63
Oil - WTI *(US$/bbl)*	**94.14**	95.11
- Edmonton par - light oil *($/bbl)*	**86.58**	95.58

Painted Pony's Realized Prices

Years ended December 31,	**2012**	**2011**
Gas *($/mcf)*	**2.54**	3.60
Condensate *($/bbl)*	**86.91**	91.70
Oil *($/bbl)*	**85.67**	93.07
NGL *($/bbl)*	**40.22**	51.80
Combined *($/boe)*	**30.80**	47.99

ROYALTIES

Royalties for the year ended December 31, 2012 are lower on a percentage of sales and on a per boe basis in comparison to the year ended December 31, 2011, primarily reflecting royalty incentives in British Columbia and lower commodity prices for both natural gas and oil. In the year ended December 31, 2012, total royalties were $6.0 million, or approximately 8.1% of total revenue. For the year ended December 31, 2011, total royalties were $9.1 million, or approximately 12.4% of revenue. In the year ended December 31, 2012, oil royalties averaged 12.8% (2011: 16.1%) of sales, while gas and associated product royalties averaged 1.9% (2011: 4.3%).

In British Columbia, the Company benefits from several royalty incentive programs, including royalty holidays for deep well drilling, royalty credits for summer drilling and capital expenditures on infrastructure. In 2012, the Company utilized deep well drilling royalty holidays, granted and drawn down on a well by well basis, of approximately $2.9 million, with remaining holiday balances totaling $25.4 million at the end of the year. The Company recorded an overall royalty expense of $0.2 million, against which infrastructure credits of $0.2 million were applied, resulting in $nil cash crown royalty payments. The British Columbia provincial government has recently proposed, effective April 1, 2013, a minimum 3% royalty on production from wells eligible for the deep well drilling royalty holidays and elimination of any future grants of summer drilling credits.

On Saskatchewan crown lands, the Company enjoys royalty holidays, granted and drawn on a well by well basis and subject to a minimum 2.5% royalty on approximately the first 100,000 barrels of oil production from eligible deep wells and up to 50,000 barrels of oil production from eligible non-deep wells, subject to certain criteria.

Throughout 2013, assuming similar commodity prices and the possible implementation of the proposed 3% minimum royalty in British Columbia for the last three quarters of the year, the Company anticipates overall royalty rates to average approximately 10% of total revenues, reflecting the combined impact of incremental sales volumes from newly drilled wells and royalty holidays, partially offset by minimum royalties and incremental royalties on wells which have maximized provincial royalty incentives.*

* *This paragraph contains forward-looking statements. Please refer to "Forward-looking Statements" and "Business Risks, Uncertainties and Forward-looking Statements" for a discussion of the risks and uncertainties related to such information.*

Painted Pony's producing properties in British Columbia are all on crown lands and in Saskatchewan are on a combination of freehold and crown lands. Approximately 77% of the crown royalty costs during the year ended December 31, 2012 were from sales on Saskatchewan oil properties, while sales of gas from recently drilled wells in British Columbia enjoyed provincial royalty incentives. Freehold royalties are from the sale of oil, gas and liquids within Saskatchewan. Gross overriding royalties are mainly from oil sales on lands earned through farm-ins and are mostly attributable to wells in Saskatchewan.

Royalties as a % of Revenue

Years ended December 31,	**2012**	**2011**
Crown	**1.3**	1.8
Freehold	**5.2**	7.8
GOR	**1.6**	2.8
	8.1	12.4

Royalties by Type

Years ended December 31, *($000s)*	**2012**	**2011**
Crown	**935**	1,314
Freehold	**3,855**	5,720
GOR	**1,212**	2,100
	6,002	9,134
$ per boe *(6 mcf:1 bbl)*	**2.49**	5.93

OPERATING AND TRANSPORTATION

Operating and transportation costs for the year ended December 31, 2012 were $23.8 million or $9.85 per boe. This compares to $16.5 million or $10.72 per boe for the year ended December 31, 2011.

Operating and Transportation Cost by Province

Years ended December 31, *($000s)*	**2012**	**2011**
British Columbia	**12,628**	7,197
Saskatchewan	**11,136**	9,313
Total	**23,764**	16,510

Per Unit Operating and Transportation Cost by Province

Years ended December 31,	**2012**	**2011**
British Columbia *($/boe)*	**6.86**	7.65
Saskatchewan *($/boe)*	**19.49**	15.52
Company operating and transportation cost *($/boe)*	**9.85**	10.72

Overall per unit operating and transportation costs decreased 8% in the year 2012 compared to the year 2011, reflecting incremental gas sales volumes and cost-saving measures implemented by the Company, as well as adjustments to processing fees, primarily offset by higher workover, repairs and maintenance expenditures in southeast Saskatchewan during the third and fourth quarters of 2012.

Operating and transportation costs for the Company's gas producing properties in British Columbia are mainly processing and compression fees, contract operating fees, equipment rentals, gas transportation and salt water disposal fees. In 2012, per unit operating and transportation costs declined by 10% to $6.86 per boe, compared to the year ended December 31, 2011, primarily due to increased 2012 volumes from the Daiber and Kobes areas where operating and transportation costs are lower.

For the Company's oil producing properties in Saskatchewan, operating and transportation costs are primarily oil transportation, emulsion and hauling, road and lease maintenance, fuel and power expenditures, minor workovers, equipment rentals and contract operator fees. During 2012, these properties required a number of minor workovers and significantly more repairs and maintenance than normal that combined contributed approximately $4.80 per boe to the average annual cost.

During 2013, the Company anticipates that per unit operating and transportation costs in British Columbia will continue to benefit from expected incremental sales volumes from lower cost areas. In Saskatchewan, the quantum of repairs and maintenance are anticipated to be less than during 2012, tempered by weather-related impacts. The result of these factors is expected to produce overall average operating and transportation costs in 2013 of approximately $10 per boe, assuming normal seasonal weather conditions.*

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The Company has committed additional Montney gas volumes toward a third party midstream gas plant expansion in the Blair/Town area. The start-up of this plant occurred mid-August 2012, bringing Painted Pony's firm processing capacity to 32 mmcf per day, with additional processing available on an interruptible basis. In conjunction with this, the Company is committed to a ten-year firm-service contract for the processing costs associated with the physical delivery of a minimum volume of 16 mmcf per day of natural gas during the first five years and 13 mmcf per day during the next five years, up to a total maximum of 52.925 Bcf of gas over the ten-year period. Since the start-up of this plant, the Company has consistently exceeded the minimum delivery volume and therefore, as at December 31, 2012, the Company has fulfilled approximately 2.9 Bcf of the overall commitment. Any shortfall of the minimum volume would be expected to result in incremental charges for unused capacity under the terms of the contract.*

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EXPLORATION AND EVALUATION

During the year ended December 31, 2012, the Company incurred $9.3 million of exploration and evaluation expense primarily related to non-economic drilling activity and imminent lease expiries, compared to $0.1 million of expired leases for the year ended December 31, 2011.

OTHER INCOME

Third party processing, salt water disposal fees and compression fees constitute other income. Other income decreased slightly to $0.6 million for the year ended December 31, 2012. This compared to $0.7 million for the year ended December 31, 2011, reflecting relatively minimal changes for third party throughput.

OPERATING NETBACKS

For the year ended December 31, 2012, field operating netbacks averaged $18.46 per boe, compared to field operating netbacks of $31.34 per boe during the year ended December 31, 2011. The decrease in the Company's overall netbacks in the year ended December 31, 2012 compared to the year 2011 is primarily due to the increased gas weighting, with its lower per unit netback and overall lower commodity prices.

Combined Field Operating Netback

Years ended December 31, *($/boe)*	**2012**	**2011**
Sales	**30.80**	47.99
Royalties	**(2.49)**	(5.93)
Operating and transportation costs	**(9.85)**	(10.72)
Field operating netback	**18.46**	31.34

Netbacks by Province

Years ended December 31, *($/boe)*	**2012**	**2011**
British Columbia	**9.08**	14.12
Saskatchewan	**48.69**	58.34

Netbacks from crude oil and associated gas and liquids production in Saskatchewan were $48.69 per boe for the year ended December 31, 2012, compared to $58.34 per boe in the year ended December 31, 2011. In Saskatchewan, the primary product was oil, which accounted for 86% of total 2012 sales volumes. The decreased per boe netback for Saskatchewan during the year 2012 compared to 2011 reflects the 8% lower oil price and higher operating and transportation costs, partially offset by lower royalties. During the year 2012, Painted Pony's per unit netback for Saskatchewan properties was 62% of the gross sales price.

During 2012, netbacks from British Columbia properties, which produce gas and associated products, averaged $9.08 per boe, compared to $14.12 per boe in the year ended December 31, 2011. In 2012, British Columbia's primary product was gas, which contributed 98% of total sales volumes. Netbacks decreased in British Columbia due to lower gas prices and despite lower per unit royalty, processing, compression and transportation costs. During the year 2012, the Company's per unit netback for British Columbia properties was 57% of the gross sales price.

GENERAL AND ADMINISTRATIVE

Net general and administrative ("G&A") expenses were $5.0 million and $4.0 million during the years ended December 31, 2012 and 2011 respectively. On a per boe basis, net general and administrative costs were $2.09 per boe in 2012, compared to $2.58 per boe in 2011.

General and Administrative Costs

Years ended December 31, *($000s, except per boe)*	**2012**	**2011**
Gross costs	**10,244**	8,891
Capitalized	**(3,312)**	(2,792)
Recoveries	**(1,899)**	(2,126)
Net costs	**5,033**	3,973
Per unit net general and administrative costs *($ per boe)*	**2.09**	2.58

Gross general and administrative costs during the year ended December 31, 2012 were 15% greater than in the year ended December 31, 2011, primarily due to salaries, consulting costs and associated administrative costs for additional staff. At December 31, 2012, the Company had thirty-five full time personnel compared to thirty-one people at the end of 2011, plus full and part time consultants in both years. Total bonuses of $1.3 million were paid in the fourth quarter of 2012, compared to total bonuses of $1.5 million paid in the second and fourth quarters of 2011. In both years, general and administrative costs included primarily office rent and parking, fees to professional service providers, costs associated with reporting and computer related charges.

Effective September 2012, the Company implemented an employee stock savings plan enabling employees to contribute up to a maximum of 8% of their base salaries, with the Company matching 150% of this amount to acquire common shares of the Company on the market. This new plan resulted in additional general and administrative expense of $169,000 during the year ended December 31, 2012.

The Company's policy of allocating and capitalizing costs associated with new capital projects was unchanged in 2012 compared to 2011. During the year ended December 31, 2012, the Company allocated $3.3 million of administrative costs to capital projects, compared to $2.8 million during the year ended December 31, 2011, directly reflecting increased exploration staff and activity. General and administrative cost recoveries in the year ended December 31, 2012, were $1.9 million, compared to $2.1 million during the year ended December 31, 2011. The portion recovered from capital projects was in accordance with common industry practice whereby an operator calculates and allocates overhead to each working interest partner in proportion to their ownership interest, based on 100% of the capital expenditures. Decreased cost recoveries during the year 2012 reflect the decreased operated capital expenditure levels compared to the year 2011.

In 2012, net general and administrative costs per boe decreased 19% compared to the year ended December 31, 2011 reflecting the increase of average sales volumes by 56% year over year. During 2013, variations in the operated capital expenditure levels will be reflected in the capitalization and recovery of general and administrative costs throughout the year.*

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CAPITAL TAXES

Capital taxes, specifically the Saskatchewan resource surcharge, were $0.7 million for the year ended December 31, 2012 compared to $0.9 million in the year ended December 31, 2011. As gross Saskatchewan sales revenues fluctuate, capital taxes are expected to vary correspondingly in 2013.*

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SHARE-BASED PAYMENTS

Share-based payment costs were $12.8 million in the year ended December 31, 2012 compared to $15.0 million in the year ended December 31, 2011. The aggregate grants of 3,015,100 options at $11.33 during 2011 compared to the 2012 option grants of 1,687,800 options at $9.38 triggered most of the incremental expense for the year ended December 31, 2011. Share-based payment expense is a non-cash estimate of the value of options granted to purchase shares, calculated using a Black-Scholes model.

Capitalized share-based payments for the year ended December 31, 2012 were $3.6 million. During the year ended December 31, 2011, the Company capitalized $3.4 million. The remainder of $9.2 million for the year ended December 31, 2012 ($11.7 million for the year ended December 31, 2011) was expensed. This expense does not represent actual cash compensation realized by the recipients of the options upon the eventual exercise and disposition of these options.

Share-Based Payments

Years ended December 31, *($000s)*	**2012**	**2011**
Gross cost	**12,824**	15,038
Capitalized	**(3,560)**	(3,376)
Net expense	**9,264**	11,662

DEPLETION AND DEPRECIATION

Depletion and depreciation expenses in the year ended December 31, 2012 totaled $39.8 million and $29.5 million in the year ended December 31, 2011. On a per boe basis, the expenses decreased in the year 2012 compared to the year 2011, reflecting the addition of reserves at lower costs than historical levels. The 2012 depletion rates reflect the addition of significant gas reserves. The depletion rate utilizes proven plus probable reserves in the calculation. In the year ended December 31, 2012, Painted Pony excluded the exploration and evaluation assets of $68.7 million from the depletion calculation, compared to $61.2 million for the year ended December 31, 2011.

Depletion and Depreciation Costs

Years ended December 31,	**2012**	**2011**
Depletion and depreciation *($000s)*	**39,848**	29,538
Per boe *($ per boe)*	**16.52**	19.17

Depreciation expense was recognized for office equipment, computer hardware and software and office furniture being depreciated on a 20% per annum declining balance basis.

IMPAIRMENT ON PROPERTY, PLANT AND EQUIPMENT

At December 31, 2012, due to declining forward prices, reserve revisions on oil properties, and higher forward oil operating costs, the Company identified indicators of impairment on the Saskatchewan oil CGU. The Company also conducted a separate impairment test whereby the exploration and evaluation ("E&E") assets were combined with all of the Company's CGUs at December 31, 2012. The recoverable amount of the Saskatchewan oil CGU was estimated on the higher of the value in use and the fair value less costs to sell. The estimate of the fair value less costs to sell was determined using forecasted cash flows discounted at 10%, with escalating prices and future development costs, as obtained from the independent reserve report, the independent undeveloped land report, and internally estimated fair values of facilities.

At December 31, 2012, it was determined that the net book value of the Saskatchewan oil CGU exceeded the recoverable amount and the Company recognized a $42.1 million (2011: $nil) impairment charge. As the recoverable amounts of the CGUs are sensitive to a decrease in commodity prices, further impairment charges could be recorded in future periods. Alternatively, an improvement of commodity prices could reverse any impairment charges recorded to date, less applicable depletion and depreciation charges. In addition, $9.3 million of E&E costs were charged to earnings, primarily as a result of non-economic drilling and completion activity and imminent lease expiries.

In determining the appropriate discount rate for the Saskatchewan oil CGU, the Company considered the acquisition metrics of recent transactions completed on similar assets. A two percent increase in the assumed discount rate (a 12% discount rate compared to the 10% discount rate used) would have resulted in an additional impairment of $9.7 million. A two percent decrease to the weighted-average forward commodity price estimate would result in an additional estimated impairment of $5.7 million. These sensitivities are based on the assumption of no variations of volumes due to economic cutoff parameters.

The following table outlines the forecasted commodity prices and exchange rates used in the Company's CGU impairment test at December 31, 2012. These future prices were based on the forecast commodity prices used by the external reserve evaluators, adjusted for commodity price differentials and transportation specific to the Company's production.*

Year	**Exchange Rate** *(US$ / CAN$)*	**Light Oil** *(C$/bbl)*	**Gas** *(C$/mcf)*	**Condensate** *(C$/bbl)*	**NGL's** *(C$/bbl)*
2013	1.00	83.32	3.38	85.73	35.40
2014	1.00	89.41	3.82	87.23	45.07
2015	1.00	91.80	4.23	87.63	53.07
2016	1.00	94.28	4.73	89.88	54.50
2017	1.00	94.24	5.00	89.06	53.33
2018	1.00	94.24	5.30	88.68	52.67
2019	1.00	95.27	5.41	89.69	53.28
2020	1.00	97.22	5.52	91.80	54.72
2021	1.00	99.20	5.63	93.94	56.22
2022	1.00	101.27	5.74	96.11	57.59
2023	1.00	103.32	5.86	98.23	59.10
2024	1.00	105.43	5.97	100.39	60.45
Rem.	1.00	117.38	7.37	124.62	76.74

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GAIN ON ASSETS - FARM-OUTS AND PROPERTY SWAPS

In the third and fourth quarters of 2011, two farm-outs and two property swap earnings events occurred with a "gain in assets" of $10.7 million. During 2012, no similar events have transpired, nor are any currently anticipated in the future.*

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Gain on Assets - Farm-outs and Property Swaps

Years ended December 31, *($000s)*	**2012**	**2011**
Gain on assets	-	10,745

NET FINANCE EXPENSE

Net finance expense for the year ending December 31, 2012 was $0.1 million, down $0.6 million from $0.7 million for the year ended December 31, 2011, primarily due to nil accretion costs on the convertible Class B shares in 2012 as the Class B shares had been converted in December 2011.

Painted Pony invests available cash in interest-bearing deposit accounts and short-term deposits, generating interest income. Interest income in the years ended December 31, 2012 and 2011 were $0.5 million and $0.6 million, respectively, reflective of both interest rates and cash investment levels.

Finance charges are the result of fees, including standby charges, on the Company's available credit facility. Finance charges in the years ended December 31, 2012 and December 31, 2011 totaled $0.4 million and $0.3 million, respectively. Finance charges have increased slightly as the Company has an available credit facility of $100 million as at December 31, 2012 compared to $80 million as at December 31, 2011.

Accretion costs on decommissioning obligations were $0.3 million for both of the years ended December 31, 2012 and 2011. Accretion has increased somewhat in 2012 as a result of additional wells drilled and acquired, along with ownership in additional facilities and properties. At the end of 2012, the Company reduced the risk-free rate related to the decommissioning obligations to 2.4% from 2.7%, resulting in increased estimated obligations of $1.0 million. This revision was partially offset by revised estimates of when the decommissioning obligations would be incurred.

Accretion costs from the convertible Class B shares were $nil in the year ended December 31, 2012 and $0.7 million in the year ended December 31, 2011. Effective December 1, 2011, the Class B shares were converted to Class A shares at a rate of 0.825, resulting in 968,221 newly issued Class A shares. Subsequently, accretion costs related to those convertible Class B shares were $nil.

Net Finance Expense

Years ended December 31, *($000s)*	**2012**	**2011**
Interest income	**(546)**	(593)
Finance charges	**357**	304
Accretion of decommissioning obligations	**313**	301
Accretion of Class B share liability	-	674
Total	**124**	686

CAPITAL EXPENDITURES

In the year ended December 31, 2012, Painted Pony conducted an active drilling program with the drilling of 34 (26.4 net) wells, of which 21 (16.8 net) wells targeted oil in Saskatchewan, 10 (6.6 net) wells targeted Montney gas in British Columbia and 3 (3.0 net) wells targeted Viking oil in Alberta. Exploration and development capital expenditures, including facilities and land costs totaled $118.6 million in the year ended December 31, 2012 compared to $146.9 million incurred in the year ended December 31, 2011.

In the year ended December 31, 2012, in Saskatchewan, the Company drilled 20 (15.8 net) horizontal wells targeting light oil in the Bakken and Mississippian formation primarily in the Flat Lake and Midale areas and 1 (1.0 net) exploratory well in the Flat Lake area. At December 31, 2012, 19 (14.8 net) of the Saskatchewan development wells had been placed on production.

In British Columbia, Painted Pony drilled 10 (6.6 net) horizontal wells during the year ended December 31, 2012, all of which were targeting the Montney gas formation (5 (1.6 net) wells in the Cameron/Kobes area, 4 (4.0 net) wells in the Blair area and 1 (1.0 net) exploratory well in the West Blair area). Of these, 6 (3.4 net) wells were completed and placed on production by December 31, 2012.

In Alberta, the Company drilled 3 (3.0 net) horizontal wells targeting light oil in the Viking formation. One well was completed and tested in the second and third quarters of 2012, and completion and testing operations began on another well during the last quarter of 2012. The third well was completed during the first quarter of 2013. Evaluation of the three wells is ongoing.

Capital Expenditures

Years ended December 31, *($000s)*	**2012**	**2011**
Lease acquisitions and retention	**585**	700
Drilling and completions	**66,687**	95,574
Facilities and equipment	**17,681**	21,656
Exploration and evaluation	**33,135**	28,996
Exploration and development	**118,088**	146,926
Head office expenditures	**489**	259
	118,577	147,185
Property acquisitions[1]	**115,058**	8,705
Share-based payments	**3,560**	3,376
Decommissioning costs	**4,060**	3,602
Total expenditures	**241,255**	162,868

1. Including acquisition of seismic license for $2,295 (2011: nil).

Capital Additions

Years ended December 31, *($000s)*	**2012**	**2011**
Total capital expenditures	**241,255**	162,868
Gain on disposition - farmout	**-**	10,159
Gain on disposition - swaps	**-**	586
Exploration and evaluation dispositions	**-**	(1,572)
Exploration and evaluation expense	**(9,313)**	(91)
Total capital additions	**231,942**	171,950
Change in gross assets:		
Property, plant, and equipment	**224,461**	154,259
Exploration and evaluation	**7,481**	17,691
Total change in gross assets	**231,942**	171,950

Painted Pony's land position continues to grow. At December 31, 2012, the Company owned 183,688 net acres of land in British Columbia, 77,643 net acres of land in Saskatchewan, and 25,543 net acres of land in Alberta. Throughout 2012, the Company added lands in British Columbia and Alberta through participation at provincial lands sales and acquisitions. Painted Pony's total land position at December 31, 2012 is 286,874 net acres. At December 31, 2011, Painted Pony had 243,651 net acres in British Columbia, Saskatchewan and Alberta.

LIQUIDITY AND CAPITAL RESOURCES

As at December 31, 2012, Painted Pony had current assets of $92.4 million and current liabilities of $47.2 million, resulting in a net working capital position of $45.2 million. Available cash has been, and is currently, on deposit in a major Canadian financial institution or invested in term deposits. Management has received confirmation from the financial institution that these funds are available on demand.*

Management anticipates that the Company will continue to have adequate liquidity to fund future working capital requirements and capital expenditures through a combination of cash flows, the availability of credit facilities and investment capital. As a result of the global economic slowdown, there exists uncertainty in the commodity, credit and capital markets, which the Company continues to monitor in conjunction with its financing alternatives. The capital program will be reviewed, and adjusted if believed necessary based on commodity prices, perceived credit and investment capital availability and share price levels to support the Company's objectives of maintaining a net debt to funds flow from operations ratio of one times or less.*

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The Company has a $100 million demand revolving credit facility with a Canadian chartered bank. Interest for the demand revolving credit facility is payable at a floating rate determined as the lender's prime rate plus 0.5% to 2.5%, depending on the Company's debt to cash flow ratio, as defined by the lender. A standby fee is charged at 0.20% to 0.45% of the undrawn portion of the credit facility, depending on the Company's cash flow ratio, as defined by the lender. Security is provided by a first fixed and floating charge demand debenture of $150 million on all of the Company's assets. Painted Pony has provided a negative pledge and undertaking to provide fixed charges over major petroleum and natural gas reserves in certain circumstances.

The availability under the demand revolving credit facility is subject to a review on or before June 1, 2013. Throughout 2012, the Company did not draw on its credit facility. The available credit facilities may be utilized on a periodic basis in 2013. There can be no assurance that the amount of the available demand credit facility will not be decreased at the next review.*

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COMMITMENTS

At December 31, 2012, the Company is committed to minimum tolls for transportation of oil through a major carrier system that began June 1, 2010 and ends in 2015. At December 31, 2012, the Company is further committed to minimum tolls for transportation of oil through a major carrier system that began September 1, 2011 and ends in 2016. The total minimum cost of the two commitments is estimated to be $1.4 million.*

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At December 31, 2012, the Company is further committed to a ten-year take-or-pay commitment for minimum gas gathering and processing fees that will apply to a total maximum volume of 52.925 Bcf of gas. Fulfillment of the commitment began in mid-August 2012, and as of December 31, 2012, the Company has delivered approximately 2.9 Bcf of gas toward the commitment. At December 31, 2012, the outstanding commitment is estimated to total $22.5 million over the remainder of the ten year period.*

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At December 31, 2012, the Company was committed to future payments totaling $7.2 million for office space rental and a proportionate share of operating costs through 2019.*

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As at December 31, 2012, under the terms of a pooling and farm-in agreement, the Company committed to drill one well at an 80% interest and an estimated net cost of $1.5 million or a cash payment of $0.1 million prior to March 31, 2013. The commitment was met during the first quarter of 2013 when the well was drilled and tested.*

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Subsequent to December 31, 2012, in conjunction with an NGL marketing agreement, the Company committed to pay minimum fractionation fees for up to approximately 7,500 barrels per month and estimated to total approximately $272,500 (based on the December 31, 2012 U.S. dollar closing exchange rate) beginning April 1, 2013 and ending March 31, 2014.*

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The Company is contingently obligated to pay $0.7 million should a specified Alberta gas index price exceed CDN $5.00 per gigajoule for an uninterrupted four month period prior to January 11, 2015. The Company is also contingently obligated to pay an additional $0.2 million should the same index price exceed CDN $6.50 per gigajoule for an uninterrupted four month period prior to January 11, 2015. The Company estimated the fair value of the contingent consideration to be negligible as at January 11, 2012 and will recognize any change in fair value in earnings until January 11, 2015.*

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SHARE CAPITAL

On February 17, 2011, the Company completed a bought deal financing of 7,620,000 Class A shares at a price of $10.50 per share for total gross proceeds of $80.0 million. On November 8, 2011, the Company completed a bought deal financing of 8,800,000 Class A shares at a price of $11.80 per share for total gross proceeds of $103.8 million. Effective December 1, 2011, the Company elected to convert the 1,173,600 Class B shares to Class A shares at a rate of 0.825, resulting in the issuance of 968,221 additional Class A shares. Effective June 7, 2012, the Class A shares of the Company were re-designated as Common shares. On December 21, 2012, the Company completed a bought deal financing of 16,997,000 Common shares at a price of $10.15 per share for total gross proceeds of $172.5 million.

As at December 31, 2012, there were 88,051,760 Common shares issued and outstanding.

The Company has a Stock Option Plan (the "Plan") whereby options to purchase Common shares may be granted by the Board of Directors to directors, officers and employees of, and consultants to, the Company. The Plan has reserved for issuance a number of Common shares equal to ten percent of the aggregate number of Common shares issued and outstanding from time to time.

In the year ended December 31, 2012, a total of 1,361,733 options were exercised at an average price of $4.55 per Common share and 132,534 options were forfeited and cancelled. During 2012, a total of 1,687,800 options were granted at an average exercise price of $9.38. As at December 31, 2012, 6,361,467 options to purchase Common shares were issued and outstanding at a weighted-average price of $9.05 per option for each Common share. The options are exercisable over a five year period, with generally one-third vesting immediately, one-third vesting one year from the date of grant, and one-third vesting two years from the date of grant.

The Company is authorized to issue an unlimited number of Preferred Shares, issuable in series. As at December 31, 2012 and March 19, 2013, no Preferred Shares were issued or outstanding.

As at March 19, 2013, there were 88,400,660 Common shares and 6,152,567 options issued and outstanding.

INCOME TAXES

At December 31, 2012, the Company had a $10.1 million (December 31, 2011: $5.0 million estimated liability) estimated deferred income tax asset. In 2012, the Company recognized deferred income tax benefits of $1.9 million for share issue costs (2011: $2.5 million) and $nil million for conversion of Class B shares (2011: $0.1 million) plus a deferred tax reduction of $13.2 million (2011: deferred tax expense of $6.4 million).

DIVIDENDS

The Company has not declared or paid any dividends. Any decision to pay dividends on any of its shares will be made by the Board of Directors on the basis of earnings, financial requirements and other conditions existing at such future time.

FOURTH QUARTER PERFORMANCE

COMPREHENSIVE INCOME AND FUNDS FLOW FROM OPERATIONS

Funds flow from operations during the fourth quarter of 2012 was $12.4 million, a decrease of 1% over the comparable quarter in 2011 when funds flow from operations was $12.5 million. On a basic and diluted per share basis, funds flow from operations in the fourth quarter of 2012 was $0.17 compared to $0.19 per share, basic and diluted, in the comparable quarter in 2011.

In the fourth quarter of 2012, cash flows from operating activities were $12.3 million compared to 2011 fourth quarter cash flow of $12.9 million. The Company reconciles funds flow from operations to cash flows from operating activities, which is the most directly comparable measure calculated in accordance with IFRS, as follows:

Funds Flow From Operations

Three months ended December 31, *($000s)*	**2012**	**2011**
Cash flows from operating activities	**12,318**	12,889
Changes in non-cash working capital	**17**	(373)
Decommissioning expenditures	**24**	1
Funds flow from operations	**12,359**	12,517

In the last quarter of 2012, the Company recorded a comprehensive loss of $40.7 million compared to fourth quarter 2011 comprehensive income of $1.5 million. The fourth quarter 2011 comprehensive income included a gain on assets from farmouts and swaps of $3.5 million. The fourth quarter of 2012 includes an impairment loss of $42.1 million, an exploration and evaluation expense of $9.3 million, and does not include any gain.

Sales Volumes

Sales volumes for the fourth quarter of 2012 averaged 7,289 boe per day compared to 5,189 boe per day in the same 2011 period, an increase of 40%. In the last quarter of 2012, the commodity mix was weighted 24% oil, condensate and natural gas liquids and 76% gas. In comparison, in the fourth quarter of 2011, Painted Pony's sales averaged 32% oil, condensate and natural gas liquids and 68% gas.

Average Daily Sales Volumes

Three months ended December 31,	**2012**	**2011**
Gas *(mcf/d)*	**33,430**	21,151
Oil *(bbls/d)*	**1,473**	1,449
Condensate *(bbls/d)*	**90**	63
NGL's *(bbls/d)*	**154**	151
Total *(boe/d)*	**7,289**	5,189

Gas sales in the three months ending December 31, 2012 averaged 33,430 mcf per day, an increase of 58% over the same 2011 quarter, and 14% greater than the 2012 third quarter rate, reflecting continued successful drilling operations on the Company's Montney gas assets in northeastern British Columbia.

Oil sales in the fourth quarter of 2012 averaged 1,473 bbls per day, an increase of 2% compared to the fourth quarter 2011 average oil sales of 1,449 bbls per day and an increase of 21% over third quarter 2012 oil sales. Fourth quarter 2012 oil sales showed some improvement over third quarter 2012 sales as incremental sales from new wells drilled in southeast Saskatchewan occurred. Natural gas liquids sales increased in the fourth quarter of 2012 reflecting the additional liquids-rich gas sales from northeast British Columbia.

REVENUES

During the fourth quarter of 2012, total revenues were $22.8 million, 11% higher than the last quarter of 2011 revenues of $20.5 million. Gas revenues in the last quarter of 2012 grew by 59% compared to the same quarter in 2011, reflecting the 58% increase in gas sales volumes and the 1% increase in the average per unit gas sales price. Oil sales declined 11% in the fourth quarter of 2012 in comparison to 2011, reflecting the 13% lower per unit oil sales price.

Sales by Product

Three months ended December 31, *($000s)*	**2012**	**2011**
Gas	**10,179**	6,390
Oil	**11,314**	12,775
Condensate	**708**	572
NGL's	**550**	791
Total	**22,751**	20,528

REALIZED PRICES

For the three months ending December 31, 2012, Painted Pony received an average crude oil price of $83.49 per bbl, 13% lower than the average price of $95.80 per bbl received during the comparable 2011 period. The Edmonton par reference price for light oil during the fourth quarter of 2012 and 2011 respectively was $84.51 per bbl and $97.89 per bbl.

In the fourth quarter of 2012, the Company received an average gas price of $3.31 per mcf compared to $3.28 per mcf received in the fourth quarter of 2011. The AECO daily spot price for the fourth quarter of 2012 was $3.20 per mcf compared to $3.19 per mcf for the fourth quarter of 2011.

Average Benchmark Prices

Three months ended December 31,	**2012**	**2011**
Gas - AECO, daily spot *($/mcf)*	**3.20**	3.19
Oil - Edmonton par- light oil *($/bbl)*	**84.51**	97.89

Painted Pony's Realized Prices

Three months ended December 31,	**2012**	**2011**
Gas *($/mcf)*	**3.31**	3.28
Oil *($/bbl)*	**83.49**	95.80

For both oil and gas, the average realized sales price per unit approximated, respectively, the Edmonton par price and AECO reference price. In the last quarter of 2012, Painted Pony received an average oil price of $83.49 per bbl, or 1% less than the Edmonton reference price of $84.51 per bbl. Similarly, the average natural gas price the Company received in the fourth quarter of 2012 was $3.31 per mcf, 3.4% above the $3.20 per mcf AECO daily spot price.

ROYALTIES

In the fourth quarter of 2012, the Company paid $1.5 million in royalties, 38% less than the $2.4 million of royalties in the comparable quarter of 2011. Royalties were 6.5% of sales during the fourth quarter of 2012, compared to 11.6% in the last quarter of 2011, reflecting the combined impact of lower oil prices and royalty holidays and incentives in both British Columbia and Saskatchewan on recent drilling activity.

Royalties as a % of Revenue

Three months ended December 31,	2012	2011
Crown	**1.5**	1.2
Freehold	**3.8**	7.4
GOR	**1.2**	3.0
	6.5	11.6

Royalties by Type

Three months ended December 31, *($000s, except per unit)*	2012	2011
Crown	**327**	253
Freehold	**867**	1,526
GOR	**275**	608
	1,469	2,387
Royalties *($ per boe)*	**2.19**	5.00

OPERATING AND TRANSPORTATION

In the fourth quarter of 2012, operating and transportation costs totaled $7.1 million ($10.53 per boe), compared to $4.6 million ($9.57 per boe) in the last quarter of 2011.

Per unit costs for gas properties in British Columbia have decreased slightly in the fourth quarter of 2012 compared to the prior year, reflecting an increased production base. In Saskatchewan, oil properties per unit costs in the fourth quarter of 2012 averaged $21.15 per boe, compared to $13.99 per boe in the comparable 2011 period, primarily due to higher fuel and power, workover, and battery turnaround costs. In comparison, third quarter 2012 costs in Saskatchewan averaged $25.80 per boe from property taxes and unusual workover and repairs and maintenance activities.

Operating and Transportation Costs

Three months ended December 31, *($000s, except per unit)*	**2012**	**2011**
British Columbia	**3,790**	2,360
Saskatchewan	**3,270**	2,208
Total	**7,060**	4,568
British Columbia *($/boe)*	**7.35**	7.39
Saskatchewan *($/boe)*	**21.15**	13.99
Company operating and transportation cost *($/boe)*	**10.53**	9.57

OPERATING NETBACKS

During the fourth quarter of 2012, Painted Pony generated field operating netbacks of $21.21 per boe, compared to $28.43 per boe in the same quarter of 2011.

Combined Field Operating Netback

Three months ended December 31, *($/boe)*	**2012**	**2011**
Sales	**33.93**	43.00
Royalties	**(2.19)**	(5.00)
Operating and transportation costs	**(10.53)**	(9.57)
Field operating netback	**21.21**	28.43

Netbacks by Province

Three months ended December 31,	**2012**	**2011**
British Columbia *($/boe)*	**13.32**	13.05
Saskatchewan *($/boe)*	**47.54**	59.59

The field operating netback in the fourth quarter of 2012 declined by 25% in comparison to the fourth quarter of 2011, despite increased netbacks for gas and associated product sales in British Columbia, due to the change in production mix, as the higher netback commodity (oil) made up 28% of the product mix in the 2011 period compared to 20% in the fourth quarter of 2012.

GENERAL AND ADMINISTRATIVE

In the fourth quarter of 2012, the net G&A costs were $1.8 million ($2.72 per boe) compared to $1.0 million ($2.12 per boe) in the fourth quarter of 2011. Net G&A costs were approximately $0.8 million higher in the fourth quarter of 2012 than in the third quarter, due to a $1.2 million bonus paid in the fourth quarter of 2012, as well as higher employee and consulting costs. On a per production unit basis, net G&A costs were higher in the fourth quarter of 2012 reflective of the additional staff and associated charges required to manage the production volume growth. Fourth quarter volumes were 40% higher in 2012 compared to the same 2011 period, while net per unit G&A increased by 28%.

General and Administrative Costs

Three months ended December 31, *($000s, except per boe)*	**2012**	**2011**
Gross costs	**3,691**	2,680
Capitalized	**(1,259)**	(979)
Recoveries	**(609)**	(689)
Net costs	**1,823**	1,012
Net G&A *($ per boe)*	**2.72**	2.12

OTHER ITEMS

Other income was $0.2 million for both the three months ended December 31, 2012 and for the quarter ended December 31, 2011.

Depletion and depreciation expense in the fourth quarter of 2012 was $12.0 million ($17.94 per boe) compared to $8.5 million ($17.86 per boe) in the fourth quarter of 2011, and $16.05 per boe in the third quarter of 2012, reflecting the fourth quarter property acquisition in Northeast British Columbia for $109.3 million. Impairment of property, plant and equipment was $42.1 million in the fourth quarter of 2012, as opposed to $nil in the last quarter of 2011 (see earlier discussion for more detail).

Fourth quarter 2012 expense for share-based compensation was $2.6 million compared to $3.9 million in the fourth quarter of 2011, reflecting options granted in November 2011 at a higher exercise price and resulting fair value.

In the fourth quarters of 2012 and 2011, capital taxes, consisting of the Saskatchewan resource surcharge were $0.2 million, primarily reflecting gross sales revenues in Saskatchewan.

Painted Pony exited both 2012 and 2011 with no bank debt.

RELATED PARTY TRANSACTIONS

The Company utilizes the services of a law firm in which the Corporate Secretary is a Partner. During the year ended December 31, 2012, the Company incurred $0.4 million (2011: $0.3 million) on legal services. All related party transactions have been measured at the agreed to terms and exchange values, being the consideration established and agreed to by the parties.

NET FINANCE EXPENSE

During the fourth quarters of 2012 and 2011, the Company earned $0.1 million and $0.2 million, respectively, of interest income reflecting available cash balances for investment. Fourth quarter 2012 finance costs were $0.1 million compared to $0.2 million in the fourth quarter of 2011, primarily due to accretion on Class B shares in the final quarter of 2011 up to December 1, 2011, when the Class B shares were converted to Class A shares.

Net Finance Expense

Three months ended December 31, *($000s)*	**2012**	**2011**
Interest income	**(81)**	(210)
Finance charges	**51**	41
Accretion of decommissioning obligations	**85**	67
Accretion of Class B share liability	**-**	125
Total	**55**	23

GAIN ON DISPOSITION OF PROPERTY - FARM-OUTS AND PROPERTY SWAPS

In the fourth quarter of 2011, the Company recognized a $3.5 million gain on assets, triggered by the earning of lands under a farm-out agreement and two property swaps in northeast British Columbia. In the comparable period in 2012, no similar gain was recognized.

CAPITAL EXPENDITURES

During the fourth quarter of 2012, Painted Pony invested $156.8 million on capital projects. In the comparable 2011 quarter, the Company invested $54.5 million. Painted Pony expended $45.5 million in the fourth quarter of 2012 compared to $51.1 million in the same 2011 period on exploration and development capital expenditures.

In the fourth quarter of 2012, exploration and development expenditures in British Columbia were $31.6 million to drill 4 (3.2 net) wells and install well facilities and gathering lines, $10.4 million in Saskatchewan to drill 4 (3.2 net) wells and $3.5 million in Alberta to drill 2 (2.0 net) wells. In the fourth quarter of 2012, the Company spent $109.3 million on property acquisitions in British Columbia, compared to $1.2 million spent in the fourth quarter of 2011 on property acquisitions in British Columbia.

Capital Expenditures

Three months ended December 31, *($000s)*	**2012**	**2011**
Lease acquisitions and retention	**107**	154
Drilling and completions	**25,073**	32,362
Facilities and equipment	**3,205**	8,472
Exploration and evaluation	**17,123**	10,102
Exploration and development	**45,508**	51,090
Head office expenditures	**37**	53
	45,545	51,143
Property acquisitions	**109,322**	1,160
Share-based payments	**827**	982
Decommissioning costs	**1,079**	1,167
Total expenditures	**156,773**	54,452

Capital Additions

Three months ended December 31, *($000s)*	**2012**	**2011**
Total capital expenditures:	**156,773**	54,452
Gain on disposition of property - farmout	**-**	2,879
Gain on disposition of property - swaps	**-**	586
Exploration and evaluation dispositions	**-**	(1,572)
Exploration and evaluation expense	**(9,313)**	-
Total capital additions	**147,460**	56,345
Change in gross assets:		
Property, plant, and equipment	**153,965**	56,818
Exploration and evaluation	**(6,505)**	(473)
Total change in gross assets	**147,460**	56,345

OFF BALANCE SHEET ARRANGEMENTS

No off balance sheet arrangements existed as at December 31, 2012 or 2011.

FINANCIAL INSTRUMENTS AND OTHER INSTRUMENTS

The fair values of the Company's cash and cash equivalents, trade and other receivables and trade and other payables approximate their carrying amounts due to the short-term nature of these financial instruments.

The Company's trade and other receivables are primarily with industry partners and are subject to normal industry credit risks. The Company extends unsecured credit to these entities, and therefore, the collection of any receivables may be affected by changes in the economic environment or other conditions. Management believes the risk is mitigated by the financial position of the entities.*

** This paragraph contains forward-looking statements. Please refer to "Forward-looking Statements" and "Business Risks, Uncertainties and Forward-looking Statements" for a discussion of the risks and uncertainties related to such information.*

The Class B shares of the Company were converted to Class A shares effective December 1, 2011 at a rate of 0.825, resulting in the issuance of 968,221 Class A shares. Prior thereto, the Class B shares were accorded compound financial instrument treatment, whereby they were separated into their liability and equity components. The liability component accreted, using the effective interest method, up to the date of conversion. The liability and equity components were reclassified to share capital upon conversion.

To date, the Company has not participated in any risk management contracts or commodity price contracts.

PERFORMANCE COMPARED TO GUIDANCE

Readers are reminded that forward-looking statements in this document are subject to significant risks and uncertainties and are based on a number of material factors and assumptions which may prove to be incorrect.

A comparison of actual performance compared to Company announced guidance is as follows:

- *Volumes in 2012 were expected to be gas-weighted. Gas constituted 77% of total sales volumes in both the year and quarter ended December 31, 2012.*

- *In 2012, the Company expected to receive an average oil price approximately 2% less than the Edmonton par reference price. During the fourth quarter and for the 2012 year, Painted Pony received a weighted average oil price 1% less than this reference price.*

- *The Company expected to receive in the fourth quarter of 2012 a gas price premium compared to AECO C similar to the 5% received in the first nine months of 2012. The actual weighted average price received in the fourth quarter was a 3% premium to this reference price. Painted Pony's British Columbia gas receives a gas price determined with reference to the British Columbia Westcoast Station 2 reference price, which varies to the AECO C reference price.*

- *While Company royalties in the fourth quarter of 2012 were expected to average 8% of total revenues, actual royalties were 6.5%, reflecting incremental new sales from wells enjoying royalty holidays.* "

- *During the last quarter of 2012, per unit operating and transportation costs in British Columbia were expected to benefit from incremental sales volumes in comparison to 2011 combined with anticipated per unit cost reductions with the start up in mid-August of an expanded third party gas plant in the Company's Blair/Town area. Fourth quarter operating and transportation costs in British Columbia averaged $7.35 per boe, compared to $6.67 per boe for the nine months ended September 30, 2012. The increased per unit cost was due to incremental costs associated with winter months and higher fixed per unit processing fees, specifically the capital component, associated with the expanded third party gas plant.*

- *As gross Saskatchewan sales revenues fluctuated in 2012, the Saskatchewan resource surcharge was expected to and did vary accordingly.*

CRITICAL ACCOUNTING ESTIMATES

The significant accounting policies used by the Company are disclosed in note 3 of the annual audited consolidated financial statements for the years ended December 31, 2012 and 2011.

The reader is cautioned that the preparation of financial statements in accordance with IFRS requires management to make certain judgments and estimates that affect the reported amounts of assets, liabilities, revenues and expenses. Estimating reserves is also critical to several accounting estimates and requires judgments and decisions based upon available geological, geophysical, engineering and economic data. Estimated reserves are also utilized by Painted Pony's bank in determining credit facilities. Reserves affect net income through depletion, decommissioning obligation estimates and the impairment test calculation. Estimating reserves is very complex, requiring many judgments based on available geological, geophysical, engineering and economic data. Changes in these judgments could have a material impact on the estimated reserves. These estimates may change, having either a negative or positive effect on net earnings as further information becomes available, and as the economic environment changes. Changes in these judgments and estimates could have a material impact on the financial results and financial condition of the Company. The MD&A outlines the accounting policies and practices that are critical to determining Painted Pony's financial results. Certain accounting policies require that management make appropriate decisions with respect to the formulation of estimates and assumptions that affect the reported amounts of assets, liabilities and expenses. The Company's management reviews its estimates regularly.

In following the liability method of accounting for income taxes, related assets and liabilities are recognized for the estimated tax consequences between amounts included in the financial statements and their tax base, using substantively enacted future income tax rates. Timing of future revenue streams and future capital spending changes can affect the timing of any temporary differences, and accordingly affect the amount of the future income tax liability calculated at a point in time. These differences could materially impact earnings.

The Black-Scholes option valuation model was developed for use in estimating the fair value of options, which were fully tradable with no vesting restrictions. This option valuation model requires the input of assumptions including the expected stock price volatility. Because the Company's stock options have characteristics significantly different from those of traded options and because changes in the input assumptions can materially affect the calculated fair value, such value is subject to measurement uncertainty. With the above risks and uncertainties, the reader is cautioned that future events and results may vary substantially from that which the Company currently foresees.*

* *This paragraph contains forward-looking statements. Please refer to "Forward-looking Statements" and "Business Risks, Uncertainties and Forward-looking Statements" for a discussion of the risks and uncertainties related to such information.*

NEW STANDARDS AND INTERPRETATIONS NOT YET ADOPTED

In November 2009, the IASB published IFRS 9 - *"Financial Instruments"*, which covers the classification and measurement of financial assets as part of its project to replace IAS 39 - *"Financial Instruments: Recognition and Measurement"* and is effective for annual periods beginning on or after January 1, 2015. Earlier application is permitted. In October 2010, the requirements for classifying and measuring financial liabilities were added to IFRS 9. Under this guidance, entities have the option to recognize financial liabilities at fair value through earnings. If this option is elected, entities would be required to reverse the portion of the fair value change due to credit risk out of earnings and recognize the change in other comprehensive income. The effective date for IFRS 9 has been deferred indefinitely. There will be no significant impact to the Company upon implementation of the issued standard.

In May 2011, IFRS 10 *"Consolidated Financial Statements"* and IAS 27 *"Separate Financial Statements"* were issued and set out the principles for the presentation and preparation of consolidated financial statements when an entity controls one or more other entities. IFRS 10 replaces SIC-12 *"Consolidation - Special Purpose Entities"* and IAS 27 supersedes IAS 27 (2008) *"Consolidated and Separate Financial Statements"*. Both are effective for annual periods beginning on or after January 1, 2013. Earlier application was permitted. The Company does not expect the implementation of this standards to have any effect on the Company's consolidated financial statements as the Company does not control any other entities.

In May 2011, IFRS 11 *"Joint Arrangements"* requires a single method to account for interests in jointly controlled entities, focusing on the rights and obligations of a joint arrangement, rather than its legal form (as is currently the case). IFRS 11 supersedes IAS 31 *"Interests in Joint Ventures"* and SIC-13 *"Jointly Controlled Entities - Non-Monetary Contributions by Venturers"*, and is effective for annual periods beginning on or after January 1, 2013. Earlier application was permitted. The Company does not expect the implementation of this standard to have any effect on the consolidated financial statements as the Company does not have any interests in jointly controlled entities.

In May 2011, IFRS 12 *"Disclosure of Interests in Other Entities"* was issued. This comprehensive standard applies to entities that have an interest in a subsidiary, a joint arrangement, an associate or an unconsolidated structured entity. IFRS 12 is effective for annual periods beginning on or after January 1, 2013. Earlier application is permitted. The Company does not expect the implementation of this standard to have any effect on the consolidated financial statements as the Company does not have interests in other entities as defined by IFRS 12.

In May 2011, IFRS 13 *"Fair Value Measurements"* was issued. This standard defines fair value, setting out a single IFRS framework for measuring fair value and required disclosures about fair value measurements. IFRS 13 is to be applied for annual periods beginning on or after January 1, 2013. Earlier application was permitted. The Company expects the implementation of this standard will result in additional disclosure, but not have an impact on its consolidated financial statements.

In June 2011, Revised IAS 19 *"Employee Benefits"* was issued. This standard outlines the accounting requirements for employee benefits and specifically establishes the principle that the cost of providing employee benefits should be recognized in the period in which the benefit is earned. IAS 19 is to be applied for annual periods beginning on or after January 1, 2013. Earlier application was permitted. The Company expects the implementation of this standard will result in additional disclosure, but not have an impact on its consolidated financial statements.

In May 2011, Revised IAS 28 *"Investments in Associates and Joint Ventures"* was issued. This standard prescribes the accounting for investments and sets out the requirements for the application of the equity method when accounting for investments in associates and joint ventures. IAS 28 is to be applied for annual periods beginning on or after January 1, 2013. Earlier application was permitted. The Company does not expect the implementation of this standard to have any effect on the consolidated financial statements as the Company does not have any investments with significant influence.

BUSINESS RISKS, UNCERTAINTIES AND FORWARD-LOOKING STATEMENTS*

Statements in this document may constitute forward-looking statements including expectations of future production, components of cash flow and earnings, expected future events and/or financial results that are forward-looking in nature and subject to substantial risks and uncertainties. The reader is cautioned that assumptions used in the preparation of such information may prove to be incorrect. The Company cautions the readers that actual performance will be affected by a number of factors, many of which may respond to changes in economic and political circumstances throughout the world. Events or circumstances may cause actual results to differ materially from those predicted, a result of numerous known and unknown risks, uncertainties, and other factors, many of which are beyond the control of the Company. These risks include, but are not limited to, the risks associated with the oil and gas industry, and changes to commodity prices and interest and foreign exchange rates. Industry related risks could include, but are not limited to, operational risks in exploration, development and production, delays or changes in plans, risks associated with the uncertainty of reserve estimates, health and safety risks and the uncertainty of estimates and projections of production, costs and expenses. The following external factors beyond the Company's control may affect the marketability of oil and natural gas produced: industry conditions including changes in laws and regulations, changes in income tax regulations, increased competition, fluctuations in commodity prices, interest rates, and variations in the Canadian/United States dollar exchange rate. The reader is cautioned not to place undue reliance on these forward-looking statements. Painted Pony's production and exploration activities are concentrated in the Western Canadian Sedimentary Basin, where activity is highly competitive and includes a variety of different sized companies ranging from smaller junior producers to the much larger integrated petroleum companies. Painted Pony is subject to the various types of business risks and uncertainties including but not limited to:

- *The availability of qualified personnel and drilling equipment;*
- *Finding and developing oil and natural gas reserves at economic costs;*
- *Production of oil and natural gas in commercial quantities; and*
- *Marketability of oil and natural gas produced.*

In order to reduce exploration risk, the Company strives to employ highly qualified and motivated professional employees with a demonstrated ability to generate quality proprietary geological and geophysical prospects. To help maximize drilling success, Painted Pony combines exploration in areas that afford multi-zone prospect potential, targeting a range of low to moderate risk prospects with some exposure to select high-risk plays with high-reward opportunities. Painted Pony also explores in areas where the Company's officers and employees have significant experience.

The Company mitigates its risk related to producing hydrocarbons through the utilization of the most appropriate technology and information systems. In addition, Painted Pony seeks operational control of its projects, where feasible.

Oil and gas exploration and production can involve environmental risks such as pollution of the environment and destruction of natural habitat, as well as safety risks such as personal injury. In order to mitigate such risks, Painted Pony conducts its operations at high standards and follows safety procedures intended to reduce the potential for personal injury to employees, contractors and the public at large. The Company maintains current insurance coverage for general and comprehensive liability as well as limited pollution liability. The amount and terms of this insurance are reviewed on an ongoing basis and adjusted as necessary to reflect changing corporate requirements, as well as industry standards and government regulations. Painted Pony may periodically use financial or physical delivery hedges to reduce its exposure against the potential adverse impact of commodity price volatility, as governed by formal policies approved by senior management, subject to controls established by the Board of Directors.

** This paragraph contains forward-looking statements. Please refer to "Forward-looking Statements" and "Business Risks, Uncertainties and Forward-looking Statements" for a discussion of the risks and uncertainties related to such information.*

LEGAL, ENVIRONMENTAL, REMEDIATION AND OTHER CONTINGENT MATTERS

The Company reviews legal, environmental, remediation and other contingent matters to both determine whether a loss is probable based on judgment and interpretation of laws and regulations, and determine that the loss can reasonably be estimated. When the loss is determined, it is charged to earnings. The Company's management monitors known and potential contingent matters and makes appropriate provisions by charges to earnings when warranted by circumstances.

The Company is currently defending an action brought by an industry participant claiming an interest in non-material assets in Saskatchewan purchased by the Company and disputing subsequent revenues and expenses. The Company has filed a counterclaim against the vendor of the assets. The amount of potential damages and legal costs have not been determined if the defense against the action were to be unsuccessful; however, based on legal advice, management does not expect the outcome of the action to have a material effect on the Company's financial position.

SELECTED CONSOLIDATED QUARTERLY INFORMATION

The following tables set forth selected consolidated financial information of the Company for the most recently completed quarters ending at the last quarter of 2012.

Quarter ended *($000s, except volumes and per share)*	**Mar. 31, 2012**	**June 30, 2012**	**Sept. 30, 2012**	**Dec. 31, 2012**
Petroleum and natural gas revenue[(1)]	**19,514**	**15,111**	**16,913**	**22,751**
Funds flow from operations	**10,791**	**7,695**	**8,492**	**12,359**
Basic and diluted, per share	**0.15**	**0.11**	**0.12**	**0.17**
Cash flow from operating activities	**11,847**	**7,986**	**7,581**	**12,318**
Comprehensive loss	**(1,325)**	**(3,523)**	**(2,594)**	**(40,669)**
Basic and diluted, per share	**(0.02)**	**(0.05)**	**(0.04)**	**(0.56)**
Capital expenditures, net	**32,310**	**10,282**	**30,440**	**45,545**
Capital acquisitions, net	**4,283**	**520**	**933**	**109,322**
Working capital	**42,667**	**42,343**	**20,309**	**45,216**
Total assets	**468,693**	**450,606**	**476,260**	**612,181**
Decommissioning obligations	**11,067**	**12,800**	**13,680**	**14,821**
Average daily sales volumes *(boe/d)*	**6,993**	**5,745**	**6,327**	**7,289**

(1) Before royalties.

Quarter ended *($000s, except volumes and per share)*	**Mar. 31, 2011**	**June 30, 2011**	**Sept. 30, 2011**	**Dec. 31, 2011**
Petroleum and natural gas revenue[(1)]	19,315	17,446	16,647	20,528
Funds flow from operations	12,098	10,376	9,159	12,517
Basic, per share	0.22	0.17	0.15	0.19
Diluted, per share	0.21	0.17	0.15	0.19
Cash flow from operating activities	11,555	11,854	8,586	12,889
Comprehensive income (loss)	2,144	(1,824)	4,765	1,457
Basic and diluted, per share	0.04	(0.03)	0.08	0.02
Capital expenditures, net	24,558	28,594	42,890	51,143
Capital acquisitions, net	27	7,357	161	1,160
Net working capital	64,100	40,327	6,709	68,291
Total assets	330,156	326,471	360,227	478,656
Decommissioning obligations	7,574	7,702	9,627	10,860
Convertible Class B shares liability	10,716	10,899	11,085	-
Average daily sales volumes *(boe/d)*	4,027	3,593	4,064	5,189

(1) Before royalties.

SELECTED CONSOLIDATED ANNUAL INFORMATION

The following table sets forth selected consolidated annual financial information of the Company for the three most recently completed years ending at December 31, 2012.

Years ended *($000s, except volumes and per share)*	**2012**	**2011**	**2010**
Petroleum and natural gas revenue[1]	**74,289**	73,936	58,283
Funds flow from operations	**39,337**	44,150	36,393
Basic, per share	**0.56**	0.74	0.78
Diluted, per share	**0.55**	0.73	0.77
Cash flow from operating activities	**39,732**	44,884	35,474
Comprehensive income (loss)	**(48,111)**	6,542	9,222
Basic, per share	**(0.68)**	0.11	0.20
Diluted, per share	**(0.68)**	0.11	0.19
Capital expenditures, net	**118,577**	147,185	109,089
Capital acquisitions, net	**115,058**	8,705	11,046
Net working capital (deficiency)	**45,216**	68,291	(1,205)
Total assets	**612,181**	478,656	244,579
Decommissioning obligations	**14,821**	10,860	7,145
Convertible Class B shares liability[2]	**-**	-	10,536
Average daily sales volumes *(boe per day)*	**6,589**	4,221	2,848

(1) Before royalties
(2) Class B shares were all converted during 2011.

Significant factors and trends that have affected the Company's results during the above quarterly and annual periods are as follows:

- *Gross revenues are impacted by both fluctuating commodity prices and production volumes. The Company's successful capital program has generated incremental production volumes in all but the second quarters of 2011 and 2012, which has, in turn, directionally lead to higher cash flows over time. Sales volumes during the second quarter of 2011 were restricted due to an unusually extended and extreme spring break-up in Saskatchewan. The sales prices realized by the Company have approximated the Edmonton par light oil prices and AECO daily spot gas prices throughout the above periods. The reference price fluctuations reflect changes in supply and demand by commodity, both internationally and domestically.*

- *Funds flow from operations have both increased and decreased over time, reflecting primarily the impact of fluctuating commodity prices on a growing production base. Per production unit operating and transportation cost variations track seasonal weather-related issues combined with fixed commitments. Throughout 2011, commodity prices were stronger than during 2012, producing higher funds flow from operations. Throughout 2012, gas prices were substantially weak and oil prices declined throughout the last half of the year. Royalty changes vary due to commodity prices, production levels and the status of the different provincial royalty holiday incentive programs. As the production base matures, incremental royalties occur on wells as the maximum volumes provided for under the provincial incentive programs are attained.*

- *Cash flows from operating activities has increased or decreased in concert with funds flow from operations and is further impacted by the timing of related trade and other payable and receivable settlements.*

- *Net capital expenditures fluctuations have reflected both available capital resources and intentional capital spending restraint during weaker economic periods.*

- *The 2012 comprehensive loss was primarily attributable to a $42.1 million impairment of property, plant and equipment and a $9.3 million charge for exploration and evaluation expense. Fourth quarter 2011 comprehensive income reflects higher sales revenues from an increasing production base. Comprehensive income in the third and fourth quarter of 2011 resulted primarily from gains on assets arising from earning of lands under a farm-out agreement and two asset swaps. Significant non-cash share-based payment costs were recognized in the second and fourth quarters of 2011 reflecting the impact of a number of options granted in those periods. Comprehensive income in 2010 was primarily impacted by growth in production and increased strength in oil prices.*

- *Net capital acquisitions occurred in all quarters of 2012, the second and fourth quarters of 2011, and the fourth quarter of 2010 when strategic opportunities were identified and completed.*

- *Total assets and non-current liabilities (provisions) have generally increased quarter over quarter and year over year, reflecting the execution of the Company's capital program, somewhat offset by depletion.*

ADDITIONAL INFORMATION

Additional information regarding the Company and its business and operations is available on the Company's profile at www.sedar.com. Copies of the information can also be obtained by contacting the Company at Painted Pony Petroleum Ltd., 300, 602 - 12 Avenue SW., Calgary, Alberta T2R 1J3 (Phone 403 475-0440), by email at info@paintedpony.ca or on the Company's website at www.paintedpony.ca.

MANAGEMENT'S RESPONSIBILITY FOR CONSOLIDATED FINANCIAL STATEMENTS

The management of Painted Pony Petroleum Ltd. (the "Company") is responsible for the preparation and integrity of the accompanying consolidated financial statements and all other information contained in this report. The consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") and include amounts that are based on management's informed judgments and estimates where necessary.

The Company has established internal accounting control systems which are designed to provide reasonable assurance regarding the reliability of the Company's financial reporting and the preparation of the consolidated financial statements together with the other financial information for external purposes in accordance with IFRS.

The Board of Directors, through its Audit Committee, monitors management's financial and accounting policies and practices and the preparation of these consolidated financial statements. The Audit Committee meets periodically with the external auditors and management to review the work of each and the propriety of the discharge of their responsibilities.

The Audit Committee reviews the consolidated financial statements of the Company with management and the external auditors prior to submission to the Board of Directors for final approval. The Board of Directors also reviews the consolidated financial statements before they are finalized. The external auditors have full and free access to the Audit Committee to discuss auditing and financial reporting matters. The Audit Committee reviews the independence of the external auditors and pre-approves audit and permitted non-audit services and fees. The Shareholders have appointed KPMG LLP as the external auditors of the Company, and in that capacity, they have audited the consolidated financial statements for the years ended December 31, 2012 and 2011.

Patrick R. Ward
President and CEO

Joan E. Dunne
Vice President, Finance and CFO

March 19, 2013

INDEPENDENT AUDITORS' REPORT

To the Shareholders of Painted Pony Petroleum Ltd.

We have audited the accompanying consolidated financial statements of Painted Pony Petroleum Ltd., which comprise the consolidated statements of financial position as at December 31, 2012 and December 31, 2011, the consolidated statements of comprehensive income (loss), changes in equity and cash flows for the years then ended, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

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

Auditors' Responsibility

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

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

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

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of Painted Pony Petroleum Ltd. as at December 31, 2012 and December 31, 2011, and its consolidated financial performance and its consolidated cash flows for the years then ended in accordance with International Financial Reporting Standards.

KPMG LLP

Chartered Accountants

Calgary, Canada
March 19, 2013

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

(000s) As at	December 31, 2012	December 31, 2011
ASSETS		
Current assets		
Cash and cash equivalents *(note 4)*	**$ 77,522**	$ 96,970
Trade and other receivables	**14,427**	21,468
Prepaid expenses and deposits	**438**	495
	92,387	118,933
Non-current assets		
Exploration and evaluation *(note 5)*	**68,707**	61,226
Property, plant and equipment *(note 6)*	**441,010**	298,497
Deferred tax asset *(note 16)*	**10,077**	-
	$ 612,181	$ 478,656
LIABILITIES		
Current liabilities		
Trade and other payables	**$ 47,171**	$ 50,642
Non-current liabilities		
Decommissioning obligations *(note 8)*	**14,821**	10,860
Deferred tax liability *(note 16)*	**-**	4,975
	61,992	66,477
EQUITY		
Share capital *(note 10)*	**550,116**	372,792
Contributed surplus	**36,226**	27,429
Retained earnings (deficit)	**(36,153)**	11,958
	550,189	412,179
	$ 612,181	$ 478,656

Commitments *(note 18)*
Contingencies *(note 22)*
Subsequent events *(notes 7 and 18)*

The notes are an integral part of these consolidated financial statements.

Approved on behalf of the Board:

Arthur J. G. Madden
Director

Patrick R. Ward
Director

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(000s, except per share amounts)

Years ended December 31,	**2012**	**2011**
Revenue		
Petroleum and natural gas	**$ 74,289**	$ 73,936
Royalties	**(6,002)**	(9,134)
Other *(note 12)*	**560**	726
	68,847	65,528
Expenses		
Operating and transportation	**23,764**	16,510
General and administrative	**5,033**	3,973
Capital taxes	**713**	895
Share-based payments *(note 10)*	**9,264**	11,662
Depletion and depreciation *(note 6)*	**39,848**	29,538
Exploration and evaluation *(note 5)*	**9,313**	91
Impairment of property, plant and equipment *(note 17)*	**42,100**	-
Gain on disposition of property *(note 6)*	**-**	(10,745)
	130,035	51,924
Results from operating activities	**(61,188)**	13,604
Finance income	**(546)**	(593)
Finance expense	**670**	1,279
Net finance expense *(note 14)*	**124**	686
Income (loss) before income tax	**(61,312)**	12,918
Deferred income tax (expense) reduction *(note 16)*	**13,201**	(6,376)
Comprehensive income (loss) for the year	**$ (48,111)**	$ 6,542
Earnings (loss) per share *(note 11)*:		
Basic and diluted	**$ (0.68)**	$ 0.11

The notes are an integral part of these consolidated financial statements.

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(000s, except shares)

Years ended December 31, 2012 and 2011

	Number of shares Common/Class A	Share capital Common/Class A	Equity component Class B	Contributed surplus	Retained earnings/ (deficit)	Total equity
Balance at December 31, 2010	51,016,700	$ 178,772	$ (2,923)	$ 15,928	$ 5,416	$ 197,193
Issue of shares	16,420,000	183,850	-	-	-	183,850
Share issue costs, net of tax of $2,507	-	(7,220)	-	-	-	(7,220)
Conversion of Class B shares, net of tax of $126	968,221	8,413	2,923	-	-	11,336
Share-based payments	-	-	-	15,038	-	15,038
Options exercised *(note 10)*	1,288,106	8,977	-	(3,537)	-	5,440
Comprehensive income for the year	-	-	-	-	6,542	6,542
Balance at December 31, 2011	69,693,027	$ 372,792	$ -	$ 27,429	$ 11,958	$ 412,179
Issue of shares	16,997,000	172,520	-	-	-	172,520
Share issue costs, net of tax of $1,851	-	(5,380)	-	-	-	(5,380)
Share-based payments	-	-	-	12,824	-	12,824
Options exercised *(note 10)*	1,361,733	10,184	-	(4,027)	-	6,157
Comprehensive loss for the year	-	-	-	-	(48,111)	(48,111)
Balance at December 31, 2012	88,051,760	$ 550,116	$ -	$ 36,226	$ (36,153)	$ 550,189

The notes are an integral part of these consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(000s)

Years ended December 31,	**2012**	**2011**
Cash flows from operating activities:		
Income (loss) for the year	**$ (48,111)**	$ 6,542
Items not affecting cash:		
Exploration and evaluation	**9,313**	91
Share-based payments	**9,264**	11,662
Depletion and depreciation	**39,848**	29,538
Impairment of property, plant and equipment	**42,100**	-
Net finance expense	**124**	686
Deferred income tax expense (reduction)	**(13,201)**	6,376
Gain on disposition of property	**-**	(10,745)
Decommissioning expenditures	**(412)**	(188)
Changes in non-cash working capital *(note 15)*	**807**	922
	39,732	44,884
Cash flows from investing activities:		
Exploration and evaluation additions	**(33,135)**	(28,996)
Exploration and evaluation dispositions	**-**	1,572
Property, plant and equipment additions	**(85,442)**	(118,189)
Acquisition of property, plant and equipment *(note 6)*	**(115,058)**	(8,705)
Changes in non-cash working capital *(note 15)*	**2,628**	16,724
	(231,007)	(137,594)
Cash flows from financing activities:		
Issue of share capital	**172,520**	183,850
Exercise of share options	**6,157**	5,440
Share issuance costs	**(7,231)**	(9,727)
Cash interest received *(note 14)*	**189**	289
Changes in non-cash working capital *(note 15)*	**192**	80
	171,827	179,932
Change in cash and cash equivalents	**(19,448)**	87,222
Cash and cash equivalents, beginning of year	**96,970**	9,748
Cash and cash equivalents, end of year *(note 4)*	**$ 77,522**	$ 96,970

The notes are an integral part of these consolidated financial statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Years ended December 31, 2012 and 2011

1. REPORTING ENTITY

Painted Pony Petroleum Ltd.'s (the "Company") principal business activity is the exploration, development and production of petroleum and natural gas resources in the Western Canada Sedimentary Basin. The consolidated financial statements of the Company as at and for the year ended December 31, 2012 include the accounts of the Company and its wholly owned subsidiary, Painted Rock Resources Ltd. and as at and for the year ended December 31, 2011 include the accounts of the Company and its wholly owned subsidiaries, Painted Pony Petroleum Corp. and Painted Rock Resources Ltd. The Company's head office is located at Suite 300, 602 - 12 Ave. S.W., Calgary, AB.

2. BASIS OF PRESENTATION

Statement of Compliance

The consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB") and effective March 19, 2013. The consolidated financial statements were authorized for issue by the Board of Directors on March 19, 2013.

Basis of Measurement

The consolidated financial statements have been prepared on the historical cost basis.

Functional and Presentation Currency

These consolidated financial statements are presented in Canadian dollars, which is the Company's and its subsidiaries' functional currency.

Use of Estimates and Judgements

The preparation of consolidated financial statements in conformity with IFRS requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses. Actual results may differ materially from these estimates.

Estimates and underlying assumptions are reviewed on an ongoing basis, with revisions to accounting recognized in the period in which the estimates are changed and in any applicable future periods.

Critical Accounting Judgments

The following are critical judgments that management has made in the process of applying accounting policies and that have the most significant effect on the amounts recognized in the consolidated financial statements.

(i) Cash Generating Units ("CGU" or "CGUs")
The Company's assets are aggregated into cash-generating units for the purpose of calculating impairment. CGUs are based on an assessment of the unit's ability to generate independent cash inflows. The determination of these CGUs was based on management's judgment in regard to shared infrastructure, geographical proximity, petroleum type and exposure to market risk and materiality.

(ii) Impairment
Judgments are required to assess when impairment indicators exist and impairment testing is required. In determining the recoverable amount of assets, in the absence of quoted market prices, impairment tests are based on estimates of reserves, production rates, future oil and natural gas prices, future costs, discount rates, market value of land and other relevant assumptions.

The application of the Company's accounting policy for exploration and evaluation assets requires management to make certain judgments as to future events and circumstances as to whether economic quantities of reserves have been found.

(iii) Taxes
In determining its deferred tax provisions, the Company must apply judgment when interpreting and applying tax laws and regulations. The determination of the appropriate rules may be uncertain for many periods. The final outcome could result in amounts different from those initially recorded and could impact tax expense in the periods where a determination is made.

Judgments are also made by management to determine the likelihood of whether deferred income tax assets at the end of the reporting period will be realized from future taxable earnings.

Critical Accounting Estimates

The following are key estimates and their assumptions made by management affecting the measurement of balances and transactions in these consolidated financial statements.

(i) Impact of Reserves
Estimation of recoverable quantities of proven and probable reserves include estimates and assumptions regarding future commodity prices, exchange rates, discount rates and production and transportation cost for future cash flows as well as the interpretation of complex geological and geophysical models and data. Changes in expected future cash flows in reported reserves can affect the impairment of assets, the decommissioning obligations, the economic feasibility of exploration and evaluation assets and the amounts reported for depletion, depreciation and amortization of property, plant and equipment, and the recognition of deferred tax assets. These reserve estimates are prepared in accordance with the Canadian Oil and Gas Evaluation Handbook and are verified by independent qualified reserve evaluators, who work with information provided by the Company to establish reserve determinations in accordance with National Instrument 51-101 - *Standards of Disclosure for Oil and Gas Activities. ("NI- 51-101")*

The Company estimates the decommissioning obligations for oil and natural gas wells and their associated production facilities and pipelines. In most instances, removal of assets and remediation occurs many years into the future. Amounts recorded for the decommissioning obligations and related accretion expense require assumptions regarding removal date, future environmental legislation, the extent of reclamation activities required, the engineering methodology for estimating cost, inflation estimates, future removal technologies in determining the removal cost, and the estimate of the liability specific discount rates to determine the present value of these cash flows.

In a business combination, management makes estimates of the fair value of assets acquired and liabilities assumed which includes assessing the value of oil and gas properties based upon the estimation of recoverable quantities of proven and probable reserves being acquired.

(ii) Share-Based Compensation
The Company's estimate of share-based compensation is dependent upon estimates of historic volatility, risk-free interest rates, and forfeiture rates.

(iii) Derivative Financial Instruments
The Company's estimate of the fair value of any derivative financial instruments would be dependent on estimated forward prices and volatility in those prices. Currently, no derivative financial instruments exist.

(iv) Taxes
The deferred tax asset is based on estimates as to the timing of the reversal of temporary differences, substantively enacted tax rates and the likelihood of assets being realized.

3. SIGNIFICANT ACCOUNTING POLICIES

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

Determination of Fair Values

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

Basis of Consolidation

(i) Subsidiaries
Subsidiaries are entities controlled by the Company. Control exists when the Company has the power to govern the financial and operating policies of an entity so as to obtain benefits from its activities. In assessing control, potential voting rights that currently are exercisable are taken into account. The financial statements of subsidiaries are included in the consolidated financial statements from the date that control commences until the date that control ceases.

The purchase method of accounting is used to account for acquisitions of subsidiaries and assets that meet the definition of a business under IFRS. The cost of an acquisition is measured as the fair value of the assets given, equity instruments issued and liabilities incurred or assumed at the date of exchange. Identifiable assets acquired and liabilities and contingent liabilities assumed in a business combination are measured initially at their fair values at the acquisition date. The excess of the cost of acquisition over the fair value of the identifiable assets, liabilities and contingent liabilities acquired is recorded as goodwill. If the cost of acquisition is less than the fair value of the net assets of the subsidiary acquired, the difference is recognized immediately in the statement of comprehensive income.

(ii) Jointly Controlled Operations and Jointly Controlled Assets
Most of the Company's oil and natural gas activities involve jointly controlled assets. The consolidated financial statements include the Company's share of these jointly controlled assets and a proportionate share of the relevant revenue and related costs.

(iii) Transactions Eliminated on Consolidation
Intercompany balances and transactions, and any unrealized income and expenses arising from intercompany transactions, are eliminated in preparing the consolidated financial statements.

Financial Instruments

(i) Non-derivative Financial Instruments

Non-derivative financial instruments comprise cash and cash equivalents, trade and other receivables, and trade and other payables. Non-derivative financial instruments are recognized initially at fair value plus, for instruments not at fair value through comprehensive income or loss, any directly attributable transaction costs. Subsequent to initial recognition, non-derivative financial instruments are measured as described below.

(ii) Cash and Cash Equivalents

Cash and cash equivalents comprise cash on hand, term deposits held with banks, other short-term highly liquid investments with original maturities of three months or less. Bank overdrafts that are repayable on demand form part of the Company's cash management whereby management has the ability and intent to net bank overdrafts against cash, and are included as a component of cash and cash equivalents, for the purpose of the statement of cash flows.

(iii) Financial Assets and Liabilities at Fair Value Through Profit or Loss

An instrument is classified at fair value through profit or loss if it is held for trading or is designated as such upon initial recognition. Financial instruments are designated at fair value through profit or loss if the Company manages such investments and makes purchase and sale decisions based on their fair value in accordance with the Company's risk management or investment strategy. Upon initial recognition, attributable transaction costs are recognized in profit or loss when incurred. Financial instruments at fair value through profit or loss are measured at fair value, and changes therein are recognized in profit or loss. The Company currently has no assets or liabilities classified as fair value through profit or loss.

(iv) Other Financial Liabilities

Other financial liabilities include trade and other payables and amounts drawn on the demand credit facility. Trade and other payables are initially recognized at the amount required to be paid less any required discount to reduce the payables to fair value. Bank debt is recognized initially at fair value, net of any transaction costs incurred, and subsequently at amortized cost using the effective interest method. Financial liabilities are classified as current liabilities if payment is due within twelve months. Otherwise, they are presented as non-current liabilities.

(v) Compound Financial Instruments

Compound financial instruments are separated into their liability and equity components using the effective interest method. The liability component accretes up to the principal balance at maturity. The equity component is reclassified to share capital upon conversion.

(vi) Other

Other non-derivative financial instruments, such as cash and cash equivalents and trade and other receivables, are measured at amortized cost using the effective interest method, less any impairment losses.

Share Capital

Common shares are classified as equity. Incremental costs directly attributable to the issue of shares and share options are recognized as a deduction from equity, net of any tax effects.

Exploration and Evaluation Assets and Property, Plant and Equipment

(i) Recognition and Measurement

Exploration and evaluation expenditures:

Pre-licence costs are expensed as incurred. Exploration and evaluation ("E&E") costs, including the costs of acquiring licenses, seismic, exploration drilling and directly attributable general and administrative costs initially are capitalized as E&E assets according to the nature of the assets acquired. The costs are accumulated in cost centers pending determination of technical feasibility and commercial viability.

The technical feasibility and commercial viability of extracting a mineral resource is considered to be determinable when proven or probable reserves are determined to exist. A review is carried out, on a quarterly basis, to ascertain whether proven or probable reserves have been discovered. Upon determination of proven or probable reserves, E&E assets attributable to those reserves are first tested for impairment and then reclassified from E&E assets to property, plant and equipment assets.

Property, plant and equipment costs:

Items of property, plant and equipment, which include oil and gas development and production assets, are measured at cost less accumulated depletion, depreciation and accumulated impairment losses. Development and production assets are grouped into CGUs for impairment testing. When significant parts of an item of property, plant and equipment, including oil and natural gas interests, have different useful lives, they are accounted for as separate items (major components).

Gains and losses on disposal of an item of property, plant and equipment, are determined by comparing the proceeds from disposal, or fair value or properties received, with the carrying amount of the asset(s) and are recognized in earnings.

(ii) Subsequent Costs

Costs incurred subsequent to the determination of technical feasibility and commercial viability and the costs of replacing parts of property, plant and equipment are recognized as oil and natural gas interests only when they increase the future economic benefits embodied in the specific assets to which they relate. All other expenditures are recognized in comprehensive income or loss as incurred. Such capitalized oil and natural gas interests generally represent costs incurred in developing proven and/or probable reserves and bringing on or enhancing production from such reserves. The carrying amount of any replaced or sold component is derecognized. The costs of periodic servicing of property, plant and equipment are recognized in earnings.

(iii) Depletion and Depreciation

The net carrying value of development or production assets is depleted using the unit of production method by reference to the ratio of production in the period to the related proven and probable reserves, taking into account estimated future development costs necessary to bring those reserves into production. Future development costs are estimated taking into account the level of development required to produce the reserves. These estimates are reviewed by independent reserve engineers on an annual basis, at minimum.

Proven and probable reserves are estimated using independent reserve engineer reports in accordance with NI 51-101 and represent the estimated quantities of oil, natural gas and natural gas liquids which geological, geophysical and engineering data demonstrate with a specified degree of certainty to be recoverable in future years from known reservoirs and which are considered commercially producible. There should be a 50 percent statistical probability that the actual quantity of recoverable reserves will be more than the amount estimated as proven and probable and a 50 percent statistical probability that it will be less. The equivalent statistical probabilities for the proven component of proven and probable reserves are 90 percent and 10 percent, respectively.

Such reserves may be considered commercially producible if management has the intention of developing and producing them and such intention is based upon:

- *a reasonable assessment of the future economics of such production;*
- *a reasonable expectation that there is a market for all or substantially all the expected oil and natural gas production; and*
- *evidence that the necessary production, transmission and transportation facilities are available or can be made available.*

In determining reserves for use in the depletion and impairment calculations, a barrel of oil equivalent ("boe") conversion ratio of six thousand cubic feet of gas ("mcf") to one barrel of oil ("bbl") (6 mcf:1 bbl) is used as an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. All boe conversions in the reserve reports are derived by converting natural gas to oil in the ratio of six mcf of gas to one barrel of oil.

Reserves may only be considered proven and probable if producibility is supported by either actual production or a conclusive formation test. The area of reservoir considered proven includes (a) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any, or both, and (b) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geophysical, geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of oil and natural gas controls the lower proved limit of the reservoir.

Reserves which can be produced economically through application of improved recovery techniques (such as fluid injection) are only included in the proven and probable classification when successful testing by a pilot project, the operation of an installed program in the reservoir or other reasonable evidence (such as, experience of the same techniques on similar reservoirs or reservoir simulation studies) provides support for the engineering analysis on which the project or program was based.

For other assets, depreciation is recognized in comprehensive income or loss on a declining-balance rate of 20% based on their estimated useful lives. Exploration and evaluation assets are not depreciated.

Leased Assets

Payments made under operating leases are recognized in comprehensive income or loss on a straight-line basis (or as otherwise contractually defined) over the term of the lease. Lease incentives received are recognized as part of the total lease expense over the term of the lease.

Impairment

(i) Financial Assets

A financial asset is assessed at each reporting date to determine whether there is any objective evidence that it is impaired. A financial asset is considered to be impaired if objective evidence indicates that one or more events have had a negative effect on the estimated future cash flows of that asset.

An impairment loss in respect of a financial asset measured at amortized cost is calculated as the difference between its carrying amount and the present value of the estimated future cash flows discounted at the original effective interest rate.

Individually significant financial assets are tested for impairment on an individual basis. The remaining financial assets are assessed collectively in groups that share similar credit risk characteristics.

All impairment losses are recognized in earnings.

An impairment loss is reversed if the reversal can be related objectively to an event occurring after the impairment loss was recognized. For financial assets measured at amortized cost the reversal is recognized in earnings.

(ii) Non-financial Assets
The carrying amounts of the Company's non-financial assets, other than exploration and evaluation assets and deferred tax assets, are reviewed whenever there is an indication of impairment. If any such indication exists, the asset's recoverable amount is estimated.

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

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. Value in use is generally computed by reference to the present value of the future cash flows expected to be derived from production of proven and probable reserves.

E&E assets are assessed for impairment if: (i) sufficient data exists to determine technical feasibility and commercial viability, (ii) facts and circumstances suggest that the carrying amount exceeds the recoverable amount and (iii) when they are reclassified to property, plant and equipment.

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses are recognized in earnings. For purposes of impairment testing, E&E assets are combined with its cash-generating units.

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

Share-Based Payments

The Company has issued options to acquire shares to directors, officers and employees. The fair value of options on the date they are granted is recognized as compensation expense with a corresponding increase in contributed surplus over the vesting period. A forfeiture rate is estimated on the grant date and is adjusted to reflect the actual number of options that vest. The Company uses the Black-Scholes model to estimate fair value.

Provisions

A provision is recognized if, as a result of a past event, the Company has a present legal or constructive obligation that can be estimated reliably and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are determined by discounting the expected future cash flows at a pre-tax risk free rate.

Decommissioning Obligations
The Company's activities give rise to dismantling, decommissioning and site disturbance re-mediation activities. Provision is made for the estimated cost of site restoration and capitalized in the relevant asset category.

Decommissioning obligations are measured at the present value of management's best estimate of the expenditure required to settle the present obligation at the reporting date. Subsequent to the initial measurement, the obligation is adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation. The increase in the provision due to the passage of time is recognized as a finance cost whereas increases/decreases due to changes in the estimated future cash flows are capitalized. Actual costs incurred upon settlement of the decommissioning obligations are charged against the provision to the extent the provision had been established.

Revenue Recognition

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

Tariffs and tolls charged to other entities for use of pipelines and facilities owned by the Company are recognized as other revenue as they accrue in accordance with the terms of the service or tariff and tolling agreements.

Royalty income is recognized in petroleum and natural gas revenues as it accrues in accordance with the terms of the overriding royalty agreements.

Finance Income and Expenses

Finance expense consists of interest expense and miscellaneous fees on credit facility borrowings, accretion of the discount on provisions, accretion of the convertible Class B share liability and impairment losses recognized on financial assets.

Finance income comprises interest income and is recognized as it accrues using the effective interest rate.

Income Tax

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

Deferred tax is recognized using the balance sheet method, providing for temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Deferred tax is not recognized on the initial recognition of assets or liabilities in a transaction that is not a business combination. Deferred tax is measured at the tax rates that are expected to be applied to temporary differences when they reverse, based on the laws that have been enacted or substantively enacted by the reporting date. Deferred tax assets and liabilities are offset if there is a legally enforceable right to offset, and they relate to income taxes levied by the same tax authority on the same taxable entity, or on different tax entities, but they intend to settle current tax liabilities and assets on a net basis or their tax assets and liabilities will be realized simultaneously.

A deferred tax asset is recognized to the extent that it is probable that future taxable profits will be available against which the temporary difference can be utilized. Deferred tax assets are reviewed at each reporting date and are reduced to the extent that it is no longer probable that the related tax benefit will be realized.

Foreign Currency Translation

The principal currency of the economic environment in which the Company and its wholly owned subsidiaries operate is the Canadian dollar. Monetary assets and liabilities denominated in foreign currencies are translated into Canadian dollars at exchange rates in effect at the end of the period, with the resulting gain or loss recognized in earnings. Revenues and expenses are translated into Canadian dollars at average exchange rates. All translation gains and losses are recorded to earnings.

Earnings per Share

Basic per share information is calculated on the basis of the weighted average number of Class A shares outstanding during the period. Diluted per share information reflects the potential dilution effect of options.

Anti-dilutive instruments are not included in the determination of diluted per share amounts.

Future Accounting Pronouncements

The following pronouncements from the IASB will become effective for financial reporting periods beginning on or after January 1, 2013, except for IFRS 9 which is effective January 1, 2015, and have not yet been adopted by the Company. All of these new or revised standards permitted early adoption with transitional arrangements depending upon the date of initial application. The Company does not anticipate that these new standards will result in significant accounting or disclosure changes.

IFRS 9 - Financial Instruments addresses the classification and measurement of financial assets.

IFRS 10 - Consolidated Financial Statements builds on existing principles and standards and identifies the concept of control as the determining factor in whether an entity should be included within the consolidated financial statements of the parent company.

IFRS 11 - Joint Arrangements establishes the principles for financial reporting by entities when they have an interest in arrangements that are jointly controlled.

IFRS 12 - Disclosure of Interest in Other Entities provides the disclosure requirements for interests held in other entities including joint arrangements, associates, special purpose entities and other off balance sheet entities.

IFRS 13 - Fair Value Measurement defines fair value, requires disclosure about fair value measurements and provides a framework for measuring fair value when it is required or permitted within the IFRS standards.

IAS 19 - Employee Benefits revises the existing standard to eliminate options to defer the recognition of gains and losses in defined benefit plans, requires re-measurements of a defined benefit plan's assets and liabilities to be presented in other comprehensive income and increases disclosure.

IAS 27 - Separate Financial Statements revised the existing standard which addresses the presentation of parent company financial statements that are not consolidated financial statements.

IAS 28 - Investments in Associate and Joint Ventures revised the existing standard and prescribes the accounting for investments and sets out the requirements for the application of the equity method when accounting for investments in associates and joint ventures.

The IASB also issued Presentation of Items of Other Comprehensive Income, an amendment to IAS 1 Financial Statement Presentation. The amendment addresses the presentation of other comprehensive income and requires the grouping of items within other comprehensive income that might eventually be reclassified to the profit and loss section of the income statement. The change became effective for financial years commencing after July 1, 2012 with earlier adoption permitted.

4. CASH AND CASH EQUIVALENTS

Years ended December 31, *(000s)*	**2012**	**2011**
Bank balances	**$ 77,522**	$ 96,970

5. EXPLORATION AND EVALUATION ASSETS

(000s)	
Cost:	
Balance, December 31, 2010	$ 43,535
Additions	28,996
Acquisitions	2,345
Dispositions - swaps	(3,331)
Transfers to property, plant and equipment	(10,228)
Lease expiries	(91)
Balance, December 31, 2011	61,226
Additions	33,135
Transfers to property, plant and equipment	(16,341)
Expensed	(9,313)
Balance, December 31, 2012	$ 68,707

E&E assets consist of the Company's exploration projects which are pending the determination of proven or probable reserves. Acquisitions represent E&E assets purchased during the period. Additions represent the Company's share of costs incurred on E&E assets during the period. As at December 31, 2012, an amount of $68.7 million (December 31, 2011: $61.2 million) remains in E&E assets in respect of undeveloped lands and unevaluated seismic data in British Columbia, Saskatchewan and Alberta and unevaluated drilling and completion costs in southeast Saskatchewan and northeast British Columbia. During 2012, $16.3 million (2011: $10.2 million) was transferred to property, plant and equipment and $9.3 million (2011: $0.1 million) was expensed due to non-economic drilling and completion activity and impending lease expiries.

The Company assesses the recoverability of E&E assets, before and at the moment of transfer to property, plant and equipment.

6. PROPERTY, PLANT AND EQUIPMENT ("PP&E")

(000s)	Oil and natural gas properties	Office furniture & equipment	Total
Cost:			
Balance, December 31, 2010	$ 197,378	$ 472	$ 197,850
Acquisitions	8,705	-	8,705
Cash additions	117,930	259	118,189
Non-cash additions	17,137	-	17,137
Transfers from exploration and evaluation	10,228	-	10,228
Balance, December 31, 2011	351,378	731	352,109
Acquisitions	115,058	-	115,058
Cash additions	84,953	489	85,442
Non-cash additions	7,620	-	7,620
Transfers from exploration and evaluation	16,341	-	16,341
Balance, December 31, 2012	$ 575,350	$ 1,220	$ 576,570
Accumulated depletion and depreciation:			
Balance, December 31, 2010	$ 23,939	$ 135	$ 24,074
Depletion and depreciation	29,442	96	29,538
Balance, December 31, 2011	53,381	231	53,612
Depletion and depreciation	39,690	158	39,848
Impairment *(note 17)*	42,100	-	42,100
Balance, December 31, 2012	$ 135,171	$ 389	$ 135,560
Carrying amounts:			
At December 31, 2011	$ 297,997	$ 500	$ 298,497
At December 31, 2012	$ 440,179	$ 831	$ 441,010

(a) Capitalized General and Administrative Expense and Share-based Payments

For the years ended December 31, 2012 and 2011, the Company capitalized general and administrative expenses and share-based payments as follows:

Years ended December 31, *(000s)*	**2012**	2011
General and administrative	**$ 3,312**	$ 2,792
Share-based payments	**3,560**	3,376
Total	**$ 6,872**	$ 6,168

(b) Property Acquisitions

During the year ended December 31, 2012, the Company acquired $115.1 million of assets, including effective December 1, 2012 the purchase of certain northeast British Columbia gas properties ("Kobes/Townsend") for total cash consideration of $112.8 million, with interim adjustments. The purchase was made to expand the Company's exposure to certain gas plays.

If the Kobes/Townsend asset had been acquired on January 1, 2012, the incremental consolidated revenue and loss recognized for the year would have been immaterial.

During the year ended December 31, 2011, the Company acquired certain southeast Saskatchewan light oil properties ($7.5 million) and northeast British Columbia gas properties ($1.2 million) for total cash consideration of $8.7 million, including final adjustments.

(c) Gain on Disposition of Property - Farmouts

During the year ended December 31, 2012, the Company recognized a gain of $nil (2011:$10.7 million) based on the estimated fair value received, determined by reference to proved and probable reserves established on assets farmed out and fair values of undeveloped land exchanged.

7. BANK DEBT

At December 31, 2012, the Company had a $100 million demand revolving credit facility available for use. Undrawn as of December 31, 2012, this facility was subject to a review on or before June 1, 2013. There can be no assurance that the amount of the available demand credit facility will not be decreased at the next scheduled review.

Interest for the demand revolving credit facility is payable at a floating rate determined as the lender's prime rate plus 0.5% to 2.5%, depending on the Company's debt to cash flow ratio, as defined by the lender. A standby fee of 0.20% to 0.45% is charged on the undrawn portion of the credit facility, depending on the Company's cash flow ratio, as defined by the lender. Security is provided by a first fixed and floating charge debenture of $150 million on all of the Company's assets. The Company has provided a negative pledge and undertaking to provide fixed charges over major petroleum and natural gas reserves in certain circumstances.

8. DECOMMISSIONING OBLIGATIONS

Years ended December 31, *(000s)*	**2012**	**2011**
Balance, beginning of year	**$ 10,860**	$ 7,145
Provisions	**3,073**	2,612
Revisions	**987**	990
Decommissioning expenditures	**(412)**	(188)
Accretion	**313**	301
Balance, end of year	**$ 14,821**	$ 10,860

The Company's decommissioning obligations result from its ownership interest in oil and natural gas assets including well sites and facilities. The total decommissioning obligation is estimated based on the Company's net ownership interest in all wells and facilities, estimated costs to reclaim and abandon these wells and facilities and the estimated timing of the costs to be incurred in future years. The Company has estimated the net present value of the decommissioning obligations to be $14.8 million as at December 31, 2012 (2011: $10.9 million) based on an undiscounted total future liability of $26.3 million (2011: $22.4 million). These payments are expected to be made over the next 10 to 36 years with the majority of costs to be incurred between 2034 and 2046. The discount factor, being the risk-free rate related to the liability, is 2.4% (2011: 2.7%) and the inflation rate is 2% (2011: 2%).

9. CONVERTIBLE CLASS B SHARES

On reorganization in 2007, the Company had 6,615 convertible Class B shares outstanding. On May 17, 2007, the Company issued 1,080,000 Class B shares on a flow-through basis and 86,985 Class B shares in satisfaction of debt, which were not on a flow-through basis, bringing the total number of Class B shares to 1,173,600. An unlimited number of Class B shares were authorized for issuance. The Class B shares were convertible at the option of the Company until the close of business on June 30, 2012, into Class A shares. The number of Class A shares obtained upon conversion of each Class B share was equal to $10.00 divided by the greater of $1.00 and the then current market price (as defined) of the Class A shares (the "conversion formula"). The Company elected to convert all outstanding Class B shares to Class A shares effective December 1, 2011 at a rate of 0.825, resulting in the issuance of 968,221 additional Class A shares.

The Class B shares were determined to be compound instruments. As the Class B shares were convertible into Class A shares, based on the conversion formula above, the number of Class A shares was unknown until the effective date of conversion, and therefore were presented as a liability. The Class B share liability was accreted using the effective interest rate method (7%) over the term of the Class B shares.

The following table indicates the convertible Class B shares activities:

Years ended December 31, *(000s)*		**2012**		**2011**
Balance, beginning of year	$	-	$	10,536
Accretion on convertible Class B share liability		-		674
Conversion to Class A shares, transfer to equity		-		(11,210)
Balance, end of year	$	-	$	-

10. SHARE CAPITAL

(a) Authorized

Unlimited: Common shares
Unlimited: Preferred shares, none outstanding as at December 31, 2012 and December 31, 2011

The Common shares are voting on the basis of one vote per share. There are no fixed dividends payable on the Common shares. In the event of the liquidation or dissolution of the Company, the Common shares are entitled to receive, on a pro rata basis, all assets of the Company as are distributable to the holders of shares.

(b) Stock Options

The Company has an option program that entitles employees, consultants, officers and directors to purchase Common shares in the Company. Options are granted at the market price of the shares at the date of grant, have a five year term and generally vest one-third immediately with the balance over two years.

The number and weighted average exercise prices of share options are as follows:

	Weighted average exercise price	Number
Balance, December 31, 2010	$ 4.68	4,548,920
Granted	11.33	3,015,100
Exercised	4.22	(1,288,106)
Forfeited	6.67	(107,980)
Balance, December 31, 2011	$ 8.00	6,167,934
Granted	9.38	1,687,800
Exercised	4.55	(1,361,733)
Forfeited	10.55	(132,534)
Balance, December 31, 2012	$ 9.05	6,361,467
Exercisable at December 31, 2012	$ 8.46	4,297,531

The following table summarizes information about stock options outstanding at December 31, 2012:

Number of options outstanding	Exercise price *($)*	Remaining life *(yrs)*	Exercisable options	Exercise price *($)*
384,000	2.85	1.6	384,000	2.85
188,300	3.15	1.6	188,300	3.15
118,000	5.88	1.9	118,000	5.88
396,167	5.88	2.0	396,167	5.88
20,000	5.60	2.4	20,000	5.60
758,000	6.51	2.7	758,000	6.51
1,345,400	10.60	3.3	896,933	10.60
354,000	12.10	3.4	236,000	12.10
105,000	11.19	3.5	70,000	11.19
152,500	14.15	3.6	101,666	14.15
867,700	11.80	3.9	578,466	11.80
602,400	7.56	4.3	193,333	7.56
80,000	7.10	4.4	26,666	7.10
423,000	10.86	4.7	141,000	10.86
567,000	10.59	4.9	189,000	10.59
6,361,467	9.05	3.4	4,297,531	8.46

The weighted average share price at the date of exercise for share options exercised during the year ended December 31, 2012 was $9.11 (2011: $11.11).

The Company accounts for its stock options granted to employees, officers and directors using the fair value method. In accordance with the Company's incentive stock plan, these options have an exercise price equal to the fair value of the Company's Common shares at the date of grant.

The following weighted-average fair value of the options granted and the assumptions used in the Black-Scholes option pricing model was as follows:

Years ended December 31,		**2012**		**2011**
Fair value per option	**$**	**6.04**	$	7.25
Volatility *(%)*		**80**		80
Option life *(years)*		**5**		5
Dividends		**-**		-
Risk-free interest rate *(%)*		**1.65**		1.95

A forfeiture rate of 3% (2011: 2%) is used when measuring share-based payments. Share-based payments of $9.3 million for the year ended December 31, 2012 (2011: $11.7 million) were expensed and $3.6 million (2011: $3.4 million) was capitalized.

11. EARNINGS (LOSS) PER SHARE

Years ended December 31, *(000s, except shares)*		**2012**		**2011**
Income (loss) for the year	**$**	**(48,111)**	$	6,542
Weighted average number of shares:				
Common shares - basic		**70,824,894**		59,860,305
Common shares - diluted		**70,824,894**		60,829,382
Comprehensive income (loss) per share - basic and diluted	**$**	**(0.68)**	$	0.11

The average market value of the Company's shares for purposes of determining the dilutive effect of outstanding share options was based on quoted market prices for the period. During the year ended December 31, 2012, 6,361,467 (2011: 1,509,200) options were excluded from the weighted-average diluted share calculation of Common shares.

12. OTHER INCOME

Other income of $0.6 million (2011: $0.7 million) is the aggregate of third party processing and compression income.

13. PERSONNEL EXPENSES

In addition to their salaries, the Company also provides non-cash benefits to executive officers. Executive officers also participate in the Company's option program. For key management personnel, being the executive officers and directors, compensation is comprised of the following:

Years ended December 31, *(000s)*		**2012**		**2011**
Short-term benefits	**$**	**2,423**	$	2,558
Share based payments[(1)]		**6,308**		6,840
Total key management personnel compensation	**$**	**8,731**	$	9,398

(1) Represents the amortization of share-based payments associated with options granted to executive officers and directors as recorded in the financial statements.

Officers and directors purchased a total of 67,000 shares in the bought-deal financing in 2012 (2011: 41,200) on the same terms as the market. In the Company's financial statements, items are primarily disclosed by nature except for employee compensation costs which are included in general and administrative expenses and operating costs. Employee compensation costs of $11.8 million were included in general and administrative expenses in 2012 (2011: $13.8 million) and $0.2 million were included in operating costs in 2012 (2011: less than $0.1 million).

14. FINANCE INCOME AND EXPENSE

Years ended December 31, *(000s)*	**2012**	**2011**
Finance income:		
Interest income	**$ (546)**	$ (593)
Finance expense:		
Interest and financing costs	**357**	304
Accretion of decommissioning obligations	**313**	301
Accretion of convertible Class B share liability	**-**	674
	670	1,279
Net finance expense	**$ 124**	$ 686

15. SUPPLEMENTAL CASH FLOW INFORMATION

Changes in non-cash working capital is comprised of:

Years ended December 31, *(000s)*	**2012**	**2011**
Source/(use) of cash:		
Trade and other receivables	**$ 7,041**	$ (4,268)
Prepaid expenses and deposits	**57**	(175)
Trade and other payables	**(3,471)**	22,169
	$ 3,627	$ 17,726
Related to operating activities	**$ 807**	$ 922
Related to investing activities	**2,628**	16,724
Related to financing activities	**192**	80
	$ 3,627	$ 17,726

16. DEFERRED INCOME TAX

The statutory tax rate was 25.6% in 2012 (2011: 27.21%). The decrease from 2011 to 2012 was due to a reduction in the 2012 Canadian corporate tax rates as part of a series of corporate tax rate reductions previously enacted by the Canadian Federal government in 2007.

Upon conversion of the Class B shares to Class A shares on December 1, 2011 (see note 9), the Company directly recognized $0.1 million in equity for the deferred income tax effect.

Reconciliation of effective tax rate:

Years ended December 31, *(000s)*	**2012**	2011
Income (loss) before income tax	**$ (61,312)**	$ 12,918
Combined corporate tax rate	**25.6%**	27.21%
Expected income tax expense (reduction)	**$ (15,696)**	$ 3,515
Non-deductible expenses	**16**	20
Share-based compensation	**2,452**	3,181
Change in statutory tax rates	**27**	(340)
Total income tax expense (reduction)	**$ (13,201)**	$ 6,376

Deferred tax assets and liabilities are attributable to the following:

Years ended December 31, *(000s)*	**2012**	2011
Deferred tax liabilities:		
PP&E and E&E assets	**$ (5,613)**	$ (12,913)
	(5,613)	(12,913)
Less deferred tax assets:		
Provisions	**3,794**	2,792
Share issue costs	**3,436**	2,927
Non-capital losses	**8,460**	2,219
Net deferred tax asset (liability)	**$ 10,077**	$ (4,975)

The non-capital losses expire as follows; $24.3 million in 19 years, $8.1 million in 18 years, $0.4 million in 17 years, $0.1 million in 16 years and the balance of $0.1 million in years 15, 14 and 13.

Based on a reserve report prepared by an independent third party, the Company has determined that it is probable that future taxable profits will be available against which the temporary differences can be utilized.

Movement in deferred tax balances during the year (000s):

	PP&E and E&E	**Provisions**	**Convertible Class B share liability**	**Share issue costs**	**Non-capital losses**
Balance, January 1, 2011	$ (4,286)	$ 1,845	$ (313)	$ 1,522	$ -
Recognized in comprehensive income	(8,627)	947	187	(1,102)	2,219
Recognized directly in equity	-	-	126	2,507	-
Balance, December 31, 2011	(12,913)	2,792	-	2,927	2,219
Recognized in comprehensive income	7,300	1,002	-	(1,342)	6,241
Recognized directly in equity	-	-	-	1,851	-
Balance, December 31, 2012	$ (5,613)	$ 3,794	$ -	$ 3,436	$ 8,460

17. IMPAIRMENT

At December 31, 2012, an impairment test on the Saskatchewan oil CGU was triggered due to declining forward oil prices, reserve revisions on oil properties, and higher oil operating costs. It was determined that the net book value of the Saskatchewan oil CGU exceeded the recoverable amounts and the Company recognized a $42.1 million (2011: $nil) impairment charge. For the purposes of impairment testing, the recoverable amount of the CGU was estimated on the higher of the value in use and the fair value less costs to sell. The estimate of the fair value less costs to sell was determined using forecasted cash flows (10%) based on discounted proved plus probable reserves as obtained from the related independent reserve report, with escalating prices and future development costs, the independent undeveloped land report, and internally estimated fair values of facilities. In determining the appropriate discount rate, the Company considered the metrics of recent transactions completed on assets similar to those in the specific CGU. A 10% discount rate was used for the Saskatchewan oil CGU.

The following table outlines the forecasted commodity prices and exchange rates used in the Company's CGU impairment test at December 31, 2012. These future prices were based on the forecast commodity prices used by the external reserve evaluators, adjusted for commodity price differentials and transportation specific to the Company's production.

Year	Exchange Rate *(US$ / CAN$)*	Light Oil *(C$/bbl)*	Gas *(C$/mcf)*	Condensate *(C$/bbl)*	NGL's *(C$/bbl)*
2013	1.00	83.32	3.38	85.73	35.40
2014	1.00	89.41	3.82	87.23	45.07
2015	1.00	91.80	4.23	87.63	53.07
2016	1.00	94.28	4.73	89.88	54.50
2017	1.00	94.24	5.00	89.06	53.33
2018	1.00	94.24	5.30	88.68	52.67
2019	1.00	95.27	5.41	89.69	53.28
2020	1.00	97.22	5.52	91.80	54.72
2021	1.00	99.20	5.63	93.94	56.22
2022	1.00	101.27	5.74	96.11	57.59
2023	1.00	103.32	5.86	98.23	59.10
2024	1.00	105.43	5.97	100.39	60.45
Rem.	1.00	117.38	7.37	124.62	76.74

For the Saskatchewan oil CGU, a two per cent increase in the assumed discount rate (a 12% discount rate compared to the 10% discount rate used) would have resulted in an additional impairment of $9.7 million. A two percent decrease to the weighted-average forward commodity price estimate would result in an additional estimated impairment of $5.7 million. These sensitivities are based on the assumption of no variations of volumes due to economic cutoff parameters.

18. COMMITMENTS

(a) At December 31, 2012, the Company is committed to two contracts, that expire in 2016, that require an estimated $1.4 million of minimum tolls for transportation of oil through a major carrier system, and are payable as follows:

(000s)		**Amount**
2013	$	619
2014		466
2015		253
2016		90
	$	1,428

(b) The Company is committed to future payments for office space rental through to 2019 as follows:

(000s)		**Amount**
2013	$	621
2014		1,271
2015		1,259
2016		1,029
2017		1,040
2018		1,051
2019		884
	$	7,155

(c) At December 31, 2012, the Company is committed to a maximum ten-year take-or-pay contract for gas gathering and processing fees that began mid-August 2012 and applies to a maximum total volume of 52.925 bcf over the ten years, as follows:

(000s)		**Amount**
2013	$	2,628
2014		2,628
2015		2,628
2016		2,628
2017		2,440
Thereafter to 2022		9,509
	$	22,461

(d) As at December 31, 2012, under the terms of a pooling and farm-in agreement, the Company committed to drill one well at an 80% interest and an estimated net cost of $1.5 million or a cash payment of $0.1 million prior to March 31, 2013. The commitment was met during the first quarter of 2013 when the well was drilled and tested.

(e) Subsequent to December 31, 2012, in conjunction with an NGL marketing agreement, the Company committed to pay minimum fractionation fees for up to approximately 7,500 barrels per month and estimated to total approximately $272,500 (based on the December 31, 2012 U.S. dollar closing exchange rate) beginning April 1, 2013 and ending March 31, 2014.

19. RELATED PARTY TRANSACTIONS

The Company utilizes the services of a law firm in which the Corporate Secretary is a Partner. During the year ended December 31, 2012, the Company incurred $431,000 (2011: $251,000) on services obtained from the firm, excluding disbursements. As at December 31, 2012, the Company owed this related party $180,304 (December 31, 2011: $85,010).

20. DETERMINATION OF FAIR VALUES

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

(a) Exploration and Evaluation and Property, Plant and Equipment Assets

The fair value of property, plant and equipment and exploration and evaluation assets recognized in an acquisition, is based on market values. The fair value of property, plant and equipment and E&E is the estimated amount for which it could be exchanged on the acquisition date between a willing buyer and a willing seller in an arm's length transaction after proper marketing wherein the parties had each acted knowledgeably, prudently and without compulsion. The fair value of oil and natural gas interests (included in property, plant and equipment) and exploration and evaluation assets is estimated with reference to the discounted cash flows expected to be derived from oil and natural gas production, based on externally prepared reserve reports. The risk-adjusted discount rate is specific to the asset with reference to general market conditions.

(b) Cash and Cash Equivalents, Trade and Other Receivables and Trade and Other Payables

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

(c) Stock Options

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

21. FINANCIAL RISK MANAGEMENT

(a) Overview:

The Company's activities expose it to a variety of financial risks that arise as a result of its exploration, development, production and financing activities such as:

- *credit risk;*
- *liquidity risk; and*
- *market risk.*

This note presents information about the Company's exposure to each of the above financial risks, the Company's objectives, policies and processes for measuring and managing risk and the Company's management of capital. Further quantitative disclosures are included throughout these consolidated financial statements.

The Board of Directors oversees management's establishment and execution of the Company's risk management framework. Management has implemented and monitors compliance with risk management policies. The Company's risk management policies are established to identify and analyze the risks faced by the Company, to set appropriate risk limits and controls and to monitor risks and adherence to market conditions and the Company's activities.

(b) Credit risk:

Credit risk is the risk of financial loss to the Company if a customer or counterparty to a financial instrument fails to meet its contractual obligations and arises principally from the Company's receivables from joint venture partners and oil and natural gas purchasers. The Company's maximum exposure to credit risk at December 31, 2012 and 2011 is as follows:

Carrying amount, December 31, *(000s)*		**2012**		**2011**
Cash and cash equivalents	**$**	**77,522**	$	96,970
Trade and other receivables		**14,427**		21,468
Total current financial instruments	**$**	**91,949**	$	118,438

Trade and other receivables:
All of the Company's operations are conducted in Canada. The Company's exposure to credit risk is influenced mainly by the individual characteristics of each customer.

Receivables from oil and natural gas purchasers are normally collected on the 25th day of the month following production. The Company's policy to mitigate credit risk associated with these balances is to establish marketing relationships with large purchasers. The Company historically has not experienced any collection issues with its oil and natural gas purchasers. Receivables from joint venture partners are typically collected within one to three months of the joint venture bill being issued. The Company attempts to mitigate the risk from joint venture receivables by obtaining partner pre-approval. However, the receivables are from participants in the oil and natural gas sector and collection of the outstanding balances is dependent on industry factors such as commodity price fluctuations, escalating costs and the risk of unsuccessful drilling. In addition, further risk exists with joint venture partners if a disagreement were to arise, which may increase the potential for non-collection. The Company does not typically obtain collateral from oil and natural gas purchasers or joint venture partners; however, the Company does have the ability to withhold joint venture partners' share of production from operated wells in the event of non-payment.

The Company does not anticipate any default as it transacts with creditworthy customers and management does not expect any losses from non-performance by these customers. As such, a provision for doubtful accounts has not been recorded at either December 31, 2012 or 2011.

The breakdown of trade and other receivables at the reporting date by type of customer was:

Carrying amount, December 31, *(000s)*		**2012**		**2011**
Sales revenue	**$**	**7,720**	$	7,830
Joint interest		**1,943**		8,975
Other		**4,764**		4,663
Total trade and other receivables	**$**	**14,427**	$	21,468

The Company has two significant independent commodity purchasers. One entity purchases the majority of natural gas produced in British Columbia, which accounted for $3.4 million of trade and other receivables at December 31, 2012 (December 31, 2011: $3.0 million). A second entity purchases the majority of oil produced in Saskatchewan, which accounted for $3.8 million of trade and other receivables at December 31, 2012 (December 31, 2011: $4.6 million).

As at December 31, 2012 and 2011, the Company's trade and other receivables are aged as follows:

Carrying amount, December 31, *(000s)*	**2012**	2011
Not past due (less than 30 days)	**$ 13,488**	$ 18,407
Past due (31 - 90 days)	**731**	2,965
Past due (more than 90 days)	**208**	96
Total receivables	**$ 14,427**	$ 21,468

Cash and cash equivalents:

The Company limits its exposure to credit risk by only investing in liquid securities that are guaranteed by the Province of Alberta. Given these credit ratings, management does not expect any counterparty to fail to meet its obligations.

(c) Liquidity Risk:

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they fall due. The Company's approach to managing liquidity is to ensure, to the extent possible, that it will always have sufficient liquidity to meet its liabilities when due, under both normal and stressed conditions, without incurring unacceptable losses or risking damage to the Company's reputation.

Typically the Company ensures that it has sufficient cash on demand to meet expected operational expenses currently and in the foreseeable future, including the servicing of financial obligations; this excludes the potential impact of extreme circumstances that cannot reasonably be predicted, such as natural disasters. To achieve this objective, the Company prepares annual capital expenditure budgets, which are regularly monitored and updated as considered necessary. Further, the Company utilizes authority for expenditures on both operated and non-operated projects to further manage capital expenditures. The Company also typically collects its oil and natural gas revenues from most properties on the 25th of each month. In addition, the Company maintains a $100 million credit facility to provide capital when needed, of which $100 million was available at the end of the period.

(d) Market Risk:

Market risk is the risk that changes in market prices, such as commodity prices, foreign exchange rates and interest rates, will affect the Company's income or the value of the financial instruments. The objective of market risk management is to manage and control market risk exposures within acceptable parameters, while optimizing the return.

The Company may use both financial derivatives and physical delivery sales contracts to manage market risks. All such transactions are conducted within risk management tolerances that are reviewed by the Board of Directors. As at December 31, 2012, the Company had not entered into any derivatives to manage market risk.

Prices for oil are determined in global markets and generally denominated in United States dollars. Natural gas prices obtained by the Company are influenced by both US and Canadian demand and the corresponding North American supply, and recently, by perceived demand for liquefied natural gas. The exchange rate effect cannot be quantified but generally an increase in the value of the Canadian dollar as compared to the U.S. dollar will reduce the prices received by the Company for its petroleum and natural gas sales. Commodity price risk is the risk that the fair value or future cash flows will fluctuate as a result of changes in commodity prices. Commodity prices for oil and natural gas are impacted by not only the relationship between the Canadian and United States dollars, but also world economic events that dictate the levels of supply and demand.

The Company's production is usually sold using “spot” or near term contracts, with prices fixed at the time of transfer of custody or on the basis of a monthly average market price. The Company, however, may give consideration in certain circumstances to the appropriateness of entering into long term, fixed price marketing contracts. To date, the Company has not undertaken any risk management contracts or commodity price contracts. The Company has contracted the majority of its oil to one purchaser on a month-to-month rolling contract. The majority of the Company's natural gas is sold monthly on a best-efforts basis to one purchaser under a one-year term contract, which runs from November 1 to October 31 of each year.

For the year ended December 31, 2012, if oil prices had been US$1 per barrel lower, with all other variables held constant, after tax net loss for the year would have been $418,000 higher. An equal and opposite impact would have occurred to net loss had oil prices been US$1 per barrel higher. For the year ended December 31, 2012, if gas prices had been US$0.50 per mcf lower, with all other variables held constant, after tax net loss for the year would have been $5.4 million higher. An equal and opposite impact would have occurred to net loss had gas prices been US$0.50 per mcf higher.

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. For the year ended December 31, 2012, if interest rates had been 0.5% lower than the 2012 weighted-average rate of 1.25%, with all other variables held constant, comprehensive loss for the year would have been $219,000 higher due to lower interest income. An equal and opposite impact would have occurred to comprehensive loss had interest rates been 0.5% higher.

(e) Capital Management:

The Company's policy is to maintain a strong capital base so as to maintain investor, creditor and market confidence and to sustain future development of the business. The Company manages its capital structure and makes adjustments to it in the light of changes in economic conditions and the risk characteristics of the underlying oil and natural gas assets. The Company considers its capital structure to include shareholders' equity, loans and borrowings and working capital. In order to maintain or adjust the capital structure, the Company may issue shares and adjust its capital spending to manage current and projected debt levels.

The Company monitors capital based on the ratio of net debt to annualized cash flow. This ratio is calculated as net debt, defined as outstanding loans and borrowings plus or minus working capital, divided by cash flow from operations before changes in non-cash working capital for the most recent calendar quarter and then annualized. The Company's objective is to maintain a net debt to funds flow from operations ratio of 1:1 or less. This ratio may increase at certain times as a result of acquisitions. In order to facilitate the management of this ratio, the Company prepares annual capital expenditure budgets, which are updated as necessary depending on varying factors including current and forecast prices, successful capital deployment and general industry conditions. The annual and updated budgets are approved by the Board of Directors. As at December 31, 2012, the Company had no drawings under its debt facility.

There were no changes in the Company's approach to capital management during the year. Neither the Company nor any of its subsidiaries are subject to externally imposed capital requirements. The credit facilities are subject to a periodic review of the borrowing base which is directly impacted by the value of the oil and natural gas reserves.

22. CONTINGENCIES

Although the Company believes it has title to its oil and natural gas properties, it cannot control or completely protect itself against the risk of title disputes or challenges. There can be no assurance that claims or challenges by third parties against the Company's properties will not be asserted at a future date.

(a) The Company is defending an action brought by an industry participant claiming interests in assets purchased by the Company and disputing subsequent revenues and expenses. The Company has filed a counterclaim against the vendor of the assets. The amount of potential damages and legal costs have not been determined if the defense against the action were to be unsuccessful; however, based on legal advice, management does not expect the outcome of the action to have a material effect on the Company's financial position.

(b) The Company is contingently obligated to pay $0.7 million should a specified Alberta gas index price exceed CDN $5.00 per gigajoule for an uninterrupted four month period prior to January 11, 2015. The Company is also contingently obligated to pay an additional $0.2 million should the same index price exceed CDN $6.50 per gigajoule for an uninterrupted four month period prior to January 11, 2015. The Company estimated the fair value of the contingent consideration to be negligible as at January 11, 2012 and will recognize any change in fair value in earnings until January 11, 2015.

ADVISORY

This Annual Report contains industry benchmarks and terms, such as operating netbacks (calculated on a per unit basis as oil, gas and natural gas liquids revenues less royalties and transportation and operating costs), which are not recognized measures under IFRS. These measures are commonly utilized in the oil and gas industry and are considered informative for management and stakeholders. Painted Pony's method of calculating operating netbacks may not be comparable to that used by other companies. Operating netbacks should not be viewed as an alternative to cash flow from operations or other measures of financial performance calculated in accordance with IFRS.

This Annual Report contains certain forward-looking statements, which are based on numerous assumptions including but not limited to: (i) drilling success; (ii) production; (iii) future capital expenditures; and (iv) cash flows from operating activities. In addition, and without limiting the generality of the foregoing, the key assumptions underlying the forward-looking statements contained herein include the following: (i) commodity prices will be volatile, and natural gas prices will remain low, throughout 2013; (ii) capital, undeveloped lands and skilled personnel will continue to be available at the level Painted Pony has enjoyed to date; (iii) Painted Pony will be able to obtain equipment in a timely manner to carry out exploration, development and exploitation activities; (iv) production rates in 2013 are expected to show growth from 2012; (v) Painted Pony will have sufficient financial resources with which to conduct the capital program; and (vi) the current tax and regulatory regime will remain substantially unchanged. The reader is cautioned that certain or all of the forgoing assumptions may prove to be incorrect.

Certain information regarding Painted Pony set forth in this document, including its future plans and operations, anticipated well results, and the planning and development of certain prospects, may constitute forward-looking statements and forward-looking information (collectively "forward-looking statements") under applicable securities laws and necessarily involve substantial known and unknown risks and uncertainties. These forward-looking statements are subject to numerous risks and uncertainties, certain of which are beyond Painted Pony's control, including without limitation, risks associated with oil and gas exploration, development, exploitation, production, marketing and transportation, loss of markets, volatility of commodity prices, environmental risks, inability to obtain drilling rigs or other services, capital expenditure costs, including drilling, completion and facility costs, unexpected decline rates in wells, wells not performing as expected, delays resulting from or inability to obtain required regulatory approvals and ability to access sufficient capital from internal and external sources, the impact of general economic conditions in Canada, the United States and overseas, industry conditions, changes in laws and regulations (including the adoption of new environmental laws and regulations) and changes in how they are interpreted and enforced, increased competition, the lack of availability of qualified personnel or management, fluctuations in foreign exchange or interest rates, and stock market volatility and market valuations of companies with respect to announced transactions and the final valuations thereof. Readers are cautioned that the foregoing list of factors is not exhaustive. Painted Pony's actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking statements and, accordingly, no assurance can be given that any of the events anticipated by the forward-looking statements will transpire or occur, or if any of them do so, what benefits that the Company will derive therefrom. All subsequent forward-looking statements, whether written or oral, attributable to the Company or persons acting on its behalf are expressly qualified in their entirety by these cautionary statements.

The forward-looking statements contained in this document are made as at the date of this Annual Report and Painted Pony does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise, except as may be required by applicable securities laws.

The reserves data of the Company set forth in this Annual Report are based upon independent evaluations by GLJ Petroleum Consultants Ltd. ("GLJ") and Sproule Associates Limited ("Sproule") each with an effective date of December 31, 2012 as contained in the consolidated report of GLJ dated February 26, 2013 (the "Painted Pony Reserves Report"). The information contained in this Annual Report in respect of Painted Pony's crude oil, natural gas liquids ("NGLs") and natural gas reserves and the net present values of future net revenue attributable to such reserves, are as evaluated in the Painted Pony Reserves Report, based on GLJ's January 1, 2013 forecast prices and costs assumptions. GLJ evaluated the Company's reserves on its British Columbia properties and Sproule evaluated the Company's reserves on its Saskatchewan properties. Sproule incorporated the GLJ forecast prices and costs assumptions in their evaluation. GLJ prepared the Painted Pony Reserves Report by consolidating the GLJ evaluation results with the Sproule evaluation results, all run on the GLJ forecast prices and costs assumptions.

Barrels of oil equivalent ("boe") may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet of gas ("mcf") to one barrel of oil ("bbl") (6 mcf:1 bbl) is used as an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. All boe conversions in this Annual Report are derived by converting natural gas to oil in the ratio of six mcf of gas to one barrel of oil. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6:1, utilizing a conversion ratio of 6:1 may be misleading as an indication of value. Mcfes may be misleading, particularly if used in isolation. A mcfe conversion ratio of 1 bbl: 6 mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

In addition to evaluating the Company's reserves, GLJ was engaged to prepare an independent contingent resources evaluation of the Company's BC Montney properties, using forecast prices and costs, dated effective December 31, 2012. The most significant positive and negative factors with respect to the contingent resources estimates relate to the fact that the field is currently at an evaluation/delineation stage. The Montney formation is aerially extensive in this region, however well control is limited. Both resources-in-place and productivity may be higher or lower than current estimates. Additional drilling and testing are required to confirm volumetric estimates and reservoir productivity for the contingent resources to be reclassified as reserves.

Contingent resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies ("contingent resources"). Contingencies which must be overcome to enable the reclassification of contingent resources as reserves can be categorized as economic, non-technical and technical. The Canadian Oil and Gas Evaluation Handbook identifies non-technical contingencies as legal, economic, environmental, political and regulatory matters or a lack of markets. There are several non-technical contingencies that prevent the classification of the contingent resources estimated above as being classified as reserves. The primary contingency which prevents the classification of the Company's contingent resources as reserves is the current early stage of development. Additional drilling, completion, and testing data is generally required before Painted Pony can commit to their development. It is also appropriate to classify as contingent resources the estimated discovered recoverable quantities associated with a project in the early evaluation stage. Contingent resources are further classified in accordance with the level of certainty associated with the estimates and may be subclassified based on project maturity and/or characterized by their economic status. As additional drilling takes place, it is expected that the contingent resources will be booked into the reserves category. Estimates of contingent resources described herein, including the corresponding estimates of before tax present value estimates, are estimates only; the actual resources may be higher or lower than those calculated in the GLJ British Columbia Montney Contingent Resources Evaluation. There is no certainty that it will be commercially viable or technically feasible to produce any portion of the resources described in the evaluation.

The most significant positive and negative factors with respect to the contingent resource estimates relate to the fact that the field is currently at an evaluation/delineation stage. Resource-in-place, productivity and capital costs may be higher or lower than current estimates. Additional drilling and testing are required to confirm volumetric estimates and reservoir productivity for the contingent resources to be reclassified as reserves.

CORPORATE INFORMATION

BOARD OF DIRECTORS

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Calgary, Alberta

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President
KD Angus & Associates Ltd.
Calgary, Alberta

Allan K. Ashton
Chairman of the Board
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Priddis, Alberta

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Chief Financial Officer
Advantage Oil & Gas Ltd.
Calgary, Alberta

Arthur J. G. Madden
Chief Financial Officer
Crown Point Energy Inc.
Calgary, Alberta

Patrick R. Ward
President & Chief Executive Officer
Painted Pony Petroleum Ltd.
Calgary, Alberta

OFFICERS

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President & Chief Executive Officer

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Development

James D. Reimer
Vice President, Exploration

Mary Kay Axford
Controller

Douglas T. McCartney
Partner, Burstall Winger LLP
Corporate Secretary

EXCHANGE LISTING

The TSX Venture Exchange
Trading symbol for Common Shares: PPY

LEGAL COUNSEL

Burstall Winger LLP

AUDITORS

KPMG LLP

BANKERS

National Bank of Canada

EVALUATION ENGINEERS

GLJ Petroleum Consultants Ltd.
Sproule Associates Limited

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GLOSSARY

/d	per day
boe	barrels of oil equivalent (6 mcf of natural gas = 1 barrel of oil equivalent)
bbls	barrels
bcf	billion cubic feet
GOR	gross overriding royalties
mboe	thousand barrels of oil equivalent
mbbl	thousand barrels
mcf	thousand cubic feet
mmcf	million cubic feet
NGL	natural gas liquids
NI 51-101	National Instrument 51-101
WTI	West Texas Intermediate, a benchmark crude oil used for pricing comparison

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