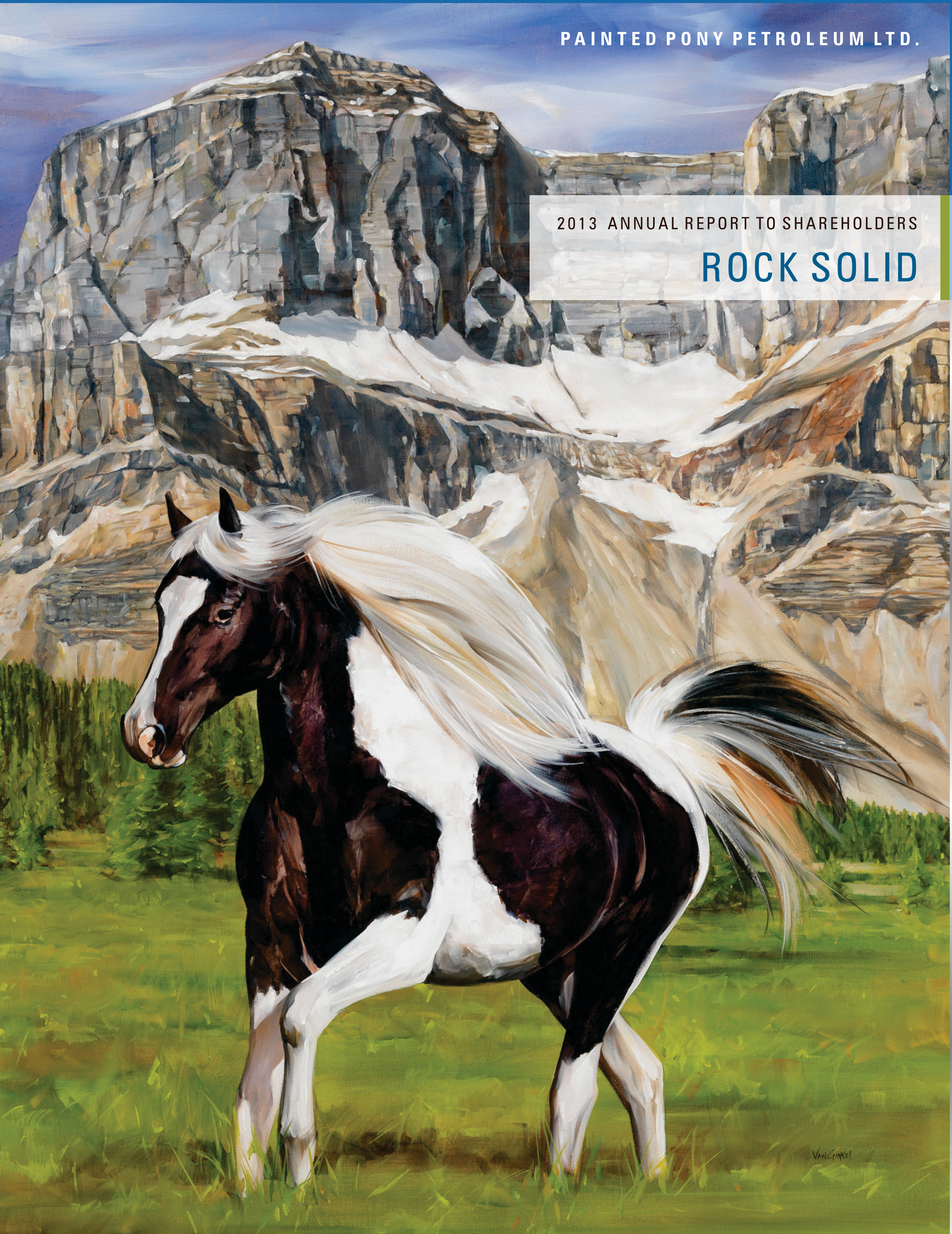
PAINTED PONY PETROLEUM LTD.

2013 ANNUAL REPORT TO SHAREHOLDERS

ROCK SOLID



CORPORATE PROFILE

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

ANNUAL GENERAL MEETING

Painted Pony Petroleum Ltd. invites shareholders and interested parties to attend its Annual General Meeting to be held in the Harford Room at the Ranchmen's Club, 710 – 13th Avenue SW, Calgary, Alberta on Thursday May 15th, 2014 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 "Rock Solid", 50"X40", oil on canvas by Paul Van Ginkel (www.paulvanginkel.com).

HIGHLIGHTS

	Year ended December 31, 2013	2012	Change
Financial			
($ millions, except per share and shares outstanding)			
Petroleum and natural gas revenue[1]	**103.1**	74.8	38%
Funds flow from operations[2]	**51.2**	39.3	30%
Per share - basic[3]	**0.58**	0.56	4%
Per share - diluted[4]	**0.58**	0.55	5%
Net loss	**(5.7)**	(48.1)	88%
Per share - basic[3] and diluted[4]	**(0.06)**	(0.68)	91%
Capital expenditures[5]	**146.6**	241.3	(39%)
Working capital (deficiency)[6]	**(16.3)**	45.2	(136%)
Bank debt	**28.6**	-	-
Total assets	**635.1**	612.2	4%
Shares outstanding *(000s)*	**88,457**	88,052	-
Basic weighted-average shares *(000s)*	**88,420**	70,825	25%
Fully diluted weighted-average shares *(000s)*	**88,488**	70,995	25%
Operational			
Daily production volumes			
Natural gas *(mcf per day)*	**42,853**	30,248	42%
Crude oil *(bbls per day)*	**1,102**	1,342	(18%)
Natural gas liquids *(bbls per day)*	**449**	206	118%
Total *(boe per day)*	**8,693**	6,589	32%
Realized prices			
Natural gas *($ per mcf)*	**3.45**	2.54	36%
Crude oil *($ per bbl)*	**93.02**	85.67	9%
Natural gas liquids *($ per bbl)*	**62.54**	54.75	14%
Field operating netbacks[7] *($ per boe)*			
British Columbia	**13.96**	9.21	52%
Saskatchewan	**48.72**	48.00	2%
Company combined	**18.88**	18.40	3%

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 dilutive effect of options.*
5. *Including acquisitions, decommissioning obligations, and capitalized share-based payments.*
6. *This table contains the term "working capital (deficiency)". Working capital (deficiency) does not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measures for other entities. Management calculates working capital (deficiency) as current assets less current liabilities and uses this ratio to analyze operating performance and leverage.*
7. *This table contains the term "field operating netbacks". Field operating netback does not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measures for other entities. Management calculates field operating netback on a per unit basis as crude oil, natural gas, natural gas liquids revenues and other income less royalties, operating and transportation costs.*

CORPORATE HISTORY

May 17, 2007

Closed the Company's initial public offering for gross proceeds of $12 million. Raised an additional $1.5 million to satisfy outstanding debt obligations.

July 11, 2007

Drilled the Company's first Bakken well, targeting light oil at Kisbey.

March 31, 2008

Acquired producing natural gas properties and undeveloped land in northeast BC for $21.2 million, setting the stage for Painted Pony's growth in the Montney.

March 16, 2009

Drilled first vertical Montney well on Cameron property at a-10-J/94-B-09.

February 22, 2010

Drilled the Company's first operated horizontal Montney well at the Blair property.

August 31, 2010

Drilled the first middle Montney well in the region and consequently announce a major Montney discovery. Drilled the Company's first Bakken well at Flat Lake announcing a major Bakken discovery.

CORPORATE HISTORY

May 25, 2011

Drilled and completed the Company's first 3 well pad at Blair, targeting the upper, middle and lower Montney zones.

September 28, 2011

Drilled and completed d-44-C/94-B-16 lower Montney well that tested at 24.5 MMcf/d.

December 21, 2012

Acquired the Townsend property for $108 million, setting the stage for liquids rich Montney growth.

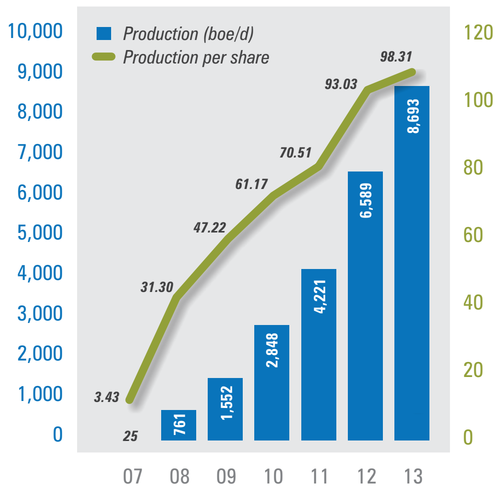
October 17, 2013

Painted Pony graduated to and commenced trading on the Toronto Stock Exchange under the symbol PPY.

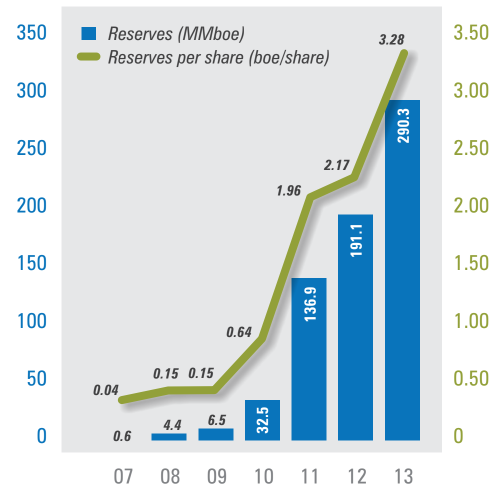
December 31, 2013

Grew proved plus probable reserves to over 1.7 Tcfe.

PRODUCTION



RESERVES



TO OUR SHAREHOLDERS

It is with great pleasure and pride that we provide the attached financial and operating results of Painted Pony for 2013. Our corporate focus over the past year has been to build and strengthen our organization, as we continue to develop one of the finest natural gas assets in the Western Canada Basin.

The key to our success lies in adhering to four fundamental operating principles:

Maintain status as a low cost producer

In any business, a low cost structure drives profitability. Painted Pony's top tier cost structure is underpinned by the predictable and repeatable nature of our operations and excellent per well economics. We continuously monitor all of our costs as we keep a watchful eye on emerging technologies that have the potential to provide step-change improvements in our development program. Over the past year, we have identified and implemented the open-hole ball-drop completion technique for Montney horizontal well completions - a new 'first' for the northern Montney fairway in British Columbia. This technology has provided us with consistent cost savings in excess of $750,000 per well and production increases of over 35% compared to previously used completion methods. Painted Pony plans to use this completion technique on all of its Montney drilling activity in 2014. We will continue to refine the ball-drop method and test and develop enhanced completion technology. Production advancements and cost effective operations remain a cornerstone in Painted Pony's philosophy of growth through the drill bit.

Position the Company to participate in future worldwide natural gas demand growth

Painted Pony is already well positioned for organic and rapid growth within the North American natural gas market. Our Montney lands are ideally located on important transportation routes, as current and proposed pipeline infrastructure intersects the Company's properties and provides takeaway capacity to both West Coast and Eastern markets. Readily accessible natural gas markets in Canada and the United States provide market opportunities for the Company to sell its products, where we have established a low cost supply. At the same time, we will be well positioned to become a leading supplier to a possible future global liquefied natural gas (LNG) market. We believe the global LNG market provides a promising future for the Canadian gas industry and the Company, and we see the future of Canadian natural gas as a premier source of supply to the global marketplace. We continue to monitor developments in North American supply and demand, and Canadian West coast LNG export plans directed towards Asian markets. In 2013, we dedicated a significant portion of our $146 million capital budget to expanding our asset base. We successfully grew our Montney land position during the year from 187 net sections to 203 net sections, all of which are well positioned within the established British Columbia Montney fairway. Through our drilling and completions program we grew our year end proved and probable reserves position by 52% to 1.7 trillion cubic feet of gas equivalent (Tcfe), with additional best estimates of contingent and prospective resources of 7.0 Tcfe and 7.3 Tcfe, respectively. This large asset base positions Painted Pony to be a leading supplier of natural gas as future North American and worldwide natural gas demand continues to increase.

Maintain balance sheet flexibility

Painted Pony remains committed to maintaining a conservative and strong balance sheet. The Company has significantly de-risked the large resource base that exists in our British Columbia Montney fairway, which has allowed the Company to initiate the use of low cost bank debt in our capital structure as part of the Company's accelerated growth plans. In conjunction with the conservative utilization of bank debt, we have also initiated a risk management strategy that will assist in providing stable and predictable cash flow from our natural gas operations. Our hedging position for 2014 currently includes 19.0 MMcf/d of natural gas per quarter through the first quarter of 2015, at average fixed AECO prices ranging from $3.99/Mcf to $4.18/Mcf, all of which are above our budget price of $3.71/Mcf. These hedges were implemented at a time when natural gas prices, in the first quarter of 2014, have been the strongest we have seen in many years.

We can throw stones, complain about them...

Target production and cash flow growth

During 2013, Painted Pony grew production by 32%, averaging 8,693 boe/d, while natural gas production increased by 42%, averaging 42.8 MMcf/d, and natural gas liquids production increased by 118% to average 449 bbls/d. We also generated record funds flow from operations of $51.2 million in a market that has been challenged by low natural gas prices. Painted Pony's 2013 field operating netbacks in British Columbia were $2.33/Mcfe, while the AECO natural gas reference price averaged $3.18/Mcf, proving that even in the current domestic gas price environment, the Company's operations offer attractive returns. The Company's corporate strategy has evolved to a focus on the development of its large resource base which will translate into rapid production and cash flow growth.

In Saskatchewan we continue to explore and develop our light oil assets, as they provide valuable cash flows that can be redeployed towards further development of the Company's Northeast British Columbia Montney project. Moving forward into 2014, Painted Pony plans to drill 17 net Montney horizontal wells and grow average production by more than 30% to 11,500 boe/d. Our forecast production growth in 2014 and into 2015 will require additional facilities infrastructure. In the first quarter of 2014, Painted Pony has built a 25 MMcf/d gas dehydration and condensate stabilization facility at Townsend, an area that has realized significantly higher liquids yields on natural gas production. A further infrastructure expansion is planned at Daiber, increasing compression and dehydration capacity to 50 MMcf/d from 25 MMcf/d to accommodate the strong production results from the area. As the Company capitalizes on economies of scale from anticipated future production growth, we are proactively addressing future infrastructure capacity requirements. Painted Pony is evaluating the feasibility of a 190 MMcf/d refrigeration plant at Townsend that will leverage off of the successful initiatives already undertaken. This planned facility, which is expected to be operational in the second half of 2015, will enhance processing capacity in line with expected production growth. This proactive approach to facility infrastructure allows Painted Pony to position itself to execute its five year plan that targets production levels to increase to approximately 100,000 boe/d by the end of 2018.

The past success of Painted Pony and the key to our future growth plans revolve around the commitment that our Directors, Officers and staff have provided the Company. I truly thank them for their efforts over the past year and I look forward to their continued contributions going into 2014. I would also like to thank our suppliers and Government agencies for their continued support of our operations. It was with great sadness that the success of 2013 was marked with the sudden passing of Mr. Kelly Drader, a valued Director of Painted Pony. Kelly's contributions to the Company were significant as he was instrumental in helping to establish the strategic growth initiatives of the Company. We extend our deepest condolences to Kelly's family as we recognize that he will be missed by all the employees and Directors of Painted Pony.

Painted Pony's focus over the past year has been on positioning the Company to become a leading British Columbia Montney natural gas producer, while enhancing the value inherent in the Company's assets for you, our shareholders. As I look back on our performance in 2013, it is evident that we have executed on and surpassed our goals. Painted Pony delivered exceptional results in all aspects of its operations including cash flow, production and reserves growth. Our goal for 2014 is to continue to provide impressive growth to our shareholders through our well established fundamental operating principles.

It is for these reasons that we truly believe 2014 to be '*the year of the Pony with a Rock Solid Future'*.

Patrick R. Ward
President and Chief Executive Officer
March 18, 2014

...stumble on them, climb over them, or build with them. William Ward

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following Management's Discussion and Analysis ("MD&A") of the consolidated financial results of Painted Pony Petroleum Ltd. ("Painted Pony" or the "Company") should be read in conjunction with the consolidated financial statements and related notes thereto for the years ended December 31, 2013 and December 31, 2012. This commentary is dated March 18, 2014.

The annual consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS"). 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 ("AIF") for the year ended December 31, 2013, 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 crude oil in southeast Saskatchewan. The Common Shares of Painted Pony trade on the Toronto Stock Exchange under the symbol "PPY". On October 11, 2013, the Company relocated to a new head office location at 736 - 6th Avenue S.W., Suite 1800, Calgary, AB.

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 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 from the TSX Venture Exchange. Effective June 7, 2012, the Class A shares of Painted Pony were re-designated as Common Shares. Effective October 17, 2013, the Common Shares of Painted Pony began trading on the Toronto Stock Exchange under the symbol "PPY" and were de-listed from 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. 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,		Year ended December 31,	
($000s)	**2013**	**2012**	**2013**	**2012**
Cash flows from operating activities	**10,229**	12,318	**49,113**	39,732
Changes in non-cash working capital	**1,865**	17	**1,731**	(807)
Decommissioning expenditures	**228**	24	**383**	412
Funds flow from operations	**12,322**	12,359	**51,227**	39,337

This MD&A also contains other industry benchmarks and terms, such as working capital (deficiency), calculated as current assets less current liabilities, and field operating netbacks, calculated on a per unit basis as crude oil, natural gas and natural gas liquids ("NGLs") revenues and other income, less royalties and operating and transportation costs. These are not recognized measures under IFRS. Management believes these measures are useful supplemental measures of the net position of current assets and current liabilities of the Company and 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.

BOE PRESENTATION

A barrel of oil equivalent ("boe") conversion ratio of six thousand cubic feet of natural 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 crude oil in the ratio of six mcf of natural gas to one bbl of crude 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.

RESULTS OF OPERATIONS – OVERVIEW

Results of operations for 2013 marked a continued shift in focus for Painted Pony as the Company continues to expand on its natural gas development plans. Capital expenditures in 2013 were directed towards the delineation and development of the Company's core Montney natural gas assets in British Columbia, particularly in the Blair and Townsend areas. In 2013, the Company drilled 13 (9.6 net) wells targeting Montney natural gas. In 2014, the Company plans to drill 18 (17.0 net) Montney horizontal wells. The advancement of new open-hole ball-drop style completion technology has resulted in production gains and significantly reduced capital costs on a per-well basis, and has allowed the Company to expand its capital program accordingly. Peak and final test production rates on wells drilled in the Townsend area during the year exceeded expectations and required that production volumes be shut in as the Company expands its facility capacity in 2014. At December 31, 2013, the Company estimates that it had approximately 2,500 boe per day ("boe/d") of shut-in production, the majority of which is expected to come on production in the second quarter of 2014.

Capital spending in 2013 included a $9.0 million strategic land acquisition in British Columbia which brings Painted Pony's total land holdings to approximately 450 net sections, 203 of which are located in the Montney natural gas resource play in British Columbia.

In 2013, annual daily production volumes increased by 32% to 8,693 boe/d, weighted 82% towards natural gas. These production gains are attributable to the success of Painted Pony's drilling program, resulting in incremental natural gas and natural gas liquids production primarily from new Montney horizontal natural gas wells. Key to the Company's continued success will be necessary facility capacity. To this end, the Company is currently in the process of constructing a 25 million cubic feet per day ("MMcf/d") compression and dehydration facility with condensate stabilization at the Company's Townsend properties, strategically located on the Montney Natural Gas Resource Play. This facility is expected to be completed in the first quarter of 2014. Further, the Company is directing additional facility capital in 2014 towards the expansion of its Daiber gas processing facility and the commissioning of an engineering study for a refrigeration and gas plant facility to be built in 2015 to take advantage of extensive pipeline infrastructure in the area. The Company expects that these improvements will address its near term facility constraints, with the capability to expand as the production base increases.

Natural gas prices in 2013 have rebounded after the significant downward pressure experienced over the previous three years. The AECO natural gas spot price averaged $3.18 per mcf in 2013, up 33% from 2012. Painted Pony realized a natural gas price in 2013 of $3.45 per mcf, which represents an 8% premium over the AECO price. This premium is a function of the higher heat content of the Company's natural gas, combined with the differential between AECO pricing and Westcoast Station 2 pricing. Significant production gains and improved natural gas prices have contributed significantly to higher funds flow from operations.

Capital activity in 2013 resulted in a reserve evaluation by external reserve evaluators at December 31, 2013 that highlighted a 52% increase in proved plus probable reserves to 290.3 million barrels of oil equivalent ("MMboe") or 1.74 trillion cubic feet equivalent, with an associated net present value discounted at 10% of $1.5 billion.

As part of the Company's development focus, it has begun incorporating lower cost bank debt as part of its capital management strategy. The principal amount utilized under the $125 million available credit facilities at December 31, 2013 was $28.6 million. Further, in 2013 Painted Pony initiated a natural gas hedging program on up to 19.0 MMcf/d of natural gas production volumes in order to manage some of the exposure to commodity price risk, and provide a level of stability to operating cash flows which enables the company to fund its capital development program.

FUNDS FLOW FROM OPERATIONS AND NET LOSS

Painted Pony generated funds flow from operations of $12.3 million during the fourth quarter of 2013, which is consistent with the comparable quarter in 2012. When comparing the years ended December 31, 2013 and 2012, funds flow from operations increased 30% to $51.2 million. The increase in funds flow from operations was driven by significant incremental natural gas production volumes and higher commodity prices, combined with lower royalty expenses. These were partially offset by higher operating and transportation costs, general and administrative expenses and interest expenses, as well as lower crude oil production volumes.

The fourth quarter net loss decreased by $36.3 million from $40.7 million in the same period last year primarily due to an impairment loss of $42.1 in the fourth quarter of 2012.

Painted Pony had a net loss of $5.7 million for the year ended December 31, 2013, compared to $48.1 million during the year ended December 31, 2012. The net loss in the year ended December 31, 2012 was primarily attributed to an impairment loss of $42.1 million.

Average Daily Production

	Three months ended December 31,				Year ended December 31,			
	2013	**% of total**	**2012**	**% of total**	**2013**	**% of total**	**2012**	**% of total**
Natural gas *(mcf/d)*	**46,841**	**84**	33,430	77	**42,853**	**82**	30,248	77
Crude oil *(bbls/d)*	**968**	**10**	1,473	20	**1,102**	**13**	1,342	20
NGLs *(bbls/d)*	**537**	**6**	244	3	**449**	**5**	206	3
Total *(boe/d)*	**9,312**	**100**	7,289	100	**8,693**	**100**	6,589	100

Fourth quarter production volumes increased 28% compared to the fourth quarter of 2012 to average 9,312 boe/d. These volumes were weighted 84% towards natural gas. Year over year volumes increased by 32% to average 8,693 boe/d, with a natural gas weighting of 82% in 2013.

The increase in overall production volumes is the result of a 40% increase in natural gas volumes quarter over quarter and 42% year over year, reflecting the focus on and success of the natural gas-focused Montney drilling program.

Crude oil volumes for the three months and year ended December 31, 2013 decreased by 34% and 18% compared to the prior year, reflecting unscheduled facility repairs and maintenance, a third party pipeline failure in Saskatchewan, as well as natural decline on wells where less capital is being deployed.

Production from NGLs increased in the three months and year ended December 31, 2013 by 120% and 118% compared to the same period in 2012 due to new production volumes from liquids-rich wells drilled in British Columbia during the year.

The Company anticipates production volumes in 2014 to be increasingly weighted towards natural gas and associated NGLs targeting the Montney formation in British Columbia. Production is expected to remain flat in the first quarter of 2014, and increase to approximately 11,500 boe/d for the second quarter of 2014. Overall production in 2014 is expected to average approximately 11,500 boe/d. The production increase is a direct result of Painted Pony's continued success in its ongoing development program, as well as the planned commissioning of facilities in the Townsend and Daiber areas which will allow shut-in production and incremental volumes from 2014 drilling to come on stream.

Petroleum and Natural Gas Revenue

	Three months ended December 31,		**Year ended December 31,**	
($000s)	**2013**	**2012**	**2013**	**2012**
Natural gas	**16,190**	10,179	**54,029**	28,071
Crude oil	**7,733**	11,314	**37,409**	42,093
NGLs	**3,138**	1,258	**10,243**	4,125
Other income	**392**	164	**1,405**	560
Total	**27,453**	22,915	**103,086**	74,849

Petroleum and natural gas revenue was $27.5 million in the three months ended December 31, 2013, 20% higher than the fourth quarter 2012 reported revenue of $22.9 million as increases in natural gas and NGL revenues more than offset lower crude oil revenues. Total revenue during the year ended December 31, 2013 was $103.1 million, which represents an increase of 38% above total revenue in 2012. For the three months ended December 31, 2013, natural gas and NGL revenues increased 59% and 149%. For the year ended December 31, 2013, natural gas and NGL revenues increased 92% and 148%, respectively.

For the three months and year ended December 31, 2013, natural gas revenue comprised 59% and 52% of total revenue, compared to 44% and 38% in 2012. Revenue growth is consistent with the increase in production over the same periods, and was even further positively impacted by higher realized commodity prices.

Other income is comprised primarily of third party processing, transportation, salt water disposal and compression fees.

Commodity Prices

	Three months ended December 31,		Year ended December 31,	
Average benchmark prices:	**2013**	**2012**	**2013**	**2012**
Natural gas - Nymex *(US$/mmbtu)*[1]	**3.85**	3.54	**3.73**	2.83
- AECO, daily spot *($/mcf)*	**3.53**	3.20	**3.18**	2.39
Crude oil - WTI *(US$/bbl)*	**97.61**	88.23	**98.05**	94.14
- Edmonton par - light oil *($/bbl)*	**85.70**	84.51	**91.84**	86.58
Exchange rate *(US$/Cdn$)*	**0.9530**	1.0090	**0.9710**	1.0000
Realized commodity prices:				
Natural gas *($/mcf)*	**3.76**	3.31	**3.45**	2.54
Crude oil *($/bbl)*	**86.88**	83.49	**93.02**	85.67
NGLs *($/bbl)*	**63.47**	56.02	**62.54**	54.75
Combined *($/boe)*	**32.05**	34.17	**32.49**	31.03

(1) Million British thermal units ("mmbtu")

For the three months and year ended December 31, 2013, the Company received average natural gas prices that represented premiums of 7% and 8% to the AECO daily spot prices, respectively. This compares to premiums of 3% and 6% in the comparative periods. Painted Pony receives a price for its British Columbia natural gas which reflects a higher heat content than the benchmark, and which varies from the AECO spot price with reference to the British Columbia Westcoast Station 2 reference price. This differential improved throughout 2013 and particularly in the fourth quarter, resulting in premium realized prices received in these periods.

Realized average crude oil prices for the three months and year ended December 31, 2013 were $86.88 per bbl and $93.02 per bbl, both of which represent a 1% premium to the Edmonton light reference price. This compares to a 1% discount to the reference price received in both periods of 2012. Painted Pony's crude oil is a premium light crude oil with low sulfur content.

For the year ended December 31, 2013, approximately 47% of the Company's 2013 NGL volumes are condensate, which received an average price of $91.73 per bbl, which closely approximates the Edmonton light reference price.

In 2014, the Company expects to receive a natural gas price which will slightly exceed the AECO daily spot price in concert with Westcoast Station 2 pricing. The Company generally expects to receive an average crude oil price that closely approximates the Edmonton par reference price, reflecting the prices currently paid for crude oil in Saskatchewan, where the Company delivers the bulk of its crude oil production. The average prices reported by Painted Pony are reflective of month to month price and production volume changes.

COMMODITY RISK MANAGEMENT

In 2013 Painted Pony initiated a natural gas hedging program on up to 20,000 gigajoules ("GJ") per day of natural gas production volumes. The financial risk management program currently uses forward price swaps to manage some of the exposure to commodity price risk, and provide a level of stability to operating cash flows which enables the company to fund its capital development program. For the year ended December 31, 2013, Painted Pony had an unrealized gain of $0.1 million on its commodity risk management contracts.

At December 31, 2013, Painted Pony had entered into the following commodity price contracts:

Natural Gas Financial Swaps

Reference	Volume *(GJ/d)*	Term	Price *($/GJ)*	Option Traded
CDN$ AECO	10,000	January - December 2014	3.72	Swap
CDN$ AECO	10,000	January - March 2015	3.90	Swap

Subsequent to December 31, 2013, Painted Pony entered into additional commodity risk management contracts as outlined in the table below.

Natural Gas Financial Swaps

Reference	Volume *(GJ/d)*	Term	Price *($/GJ)*	Option Traded
CDN$ AECO	10,000	February - March 2014	3.90	Swap
CDN$ AECO	5,000	April - December 2014	3.83	Swap
CDN$ AECO	5,000	April 2014 - March 2015	3.85	Swap
CDN$ AECO	5,000	January - March 2015	4.21	Swap

ROYALTIES

	Three months ended December 31,		Year ended December 31,	
($000s, except per boe and %)	**2013**	**2012**	**2013**	**2012**
Royalty expense	**1,663**	1,674	**6,785**	6,715
Per unit *($ per boe)*	**1.94**	2.50	**2.14**	2.78
Royalties as a % of revenue *(%)*	**6.1**	7.3	**6.6**	9.0

For the three months and year ended December 31, 2013, royalties were $1.7 million and $6.8 million, respectively, or approximately 6.1% and 6.6% of total revenue. For the three months and year ended December 31, 2012, royalties were $1.7 million and $6.7 million, respectively, or 7.3% and 9.0% of revenue. The reduced royalty rate in 2013 was due to higher revenues in British Columbia which has an average royalty rate for the three months and year ended December 31, 2013 of 2.9% and 2.7%, respectively. Painted Pony's producing properties in British Columbia are on Crown lands and in Saskatchewan are on a combination of freehold and Crown lands. Royalties include the Saskatchewan resource charge, which totaled $0.2 million and $0.7 million for both the three months and year ended December 31, 2013 and 2012.

Royalties in both the three months and year ended December 31, 2013 are lower as a percentage of revenue and on a per boe basis in comparison to the 2012 periods, primarily reflecting the benefit of new liquids-rich wells drilled in British Columbia which are eligible for royalty holidays, subject to royalty relief of a maximum of $2.2 million per well. Effective April 1, 2013, the British Columbia provincial government adopted a minimum 3% royalty on production from these wells, and discontinued the summer drilling grant program.

In 2014, assuming similar commodity prices and reflecting the 3% minimum royalty rate in British Columbia, the Company anticipates overall royalty rates to be approximately 6% to 7% of total revenues, reflecting the combined impact of incremental sales volumes from newly drilled wells which will qualify for royalty holidays, net of royalties paid on wells which have obtained the full benefit of provincial royalty incentives.

OPERATING EXPENSES

	Three months ended December 31,		Year ended December 31,	
	2013	2012	2013	2012
Operating expenses *($000s)*	**7,893**	6,021	**29,114**	20,121
Per unit *($ per boe)*	**9.21**	8.98	**9.17**	8.34

Operating expenses increased by $1.9 million or $0.23 per boe in the fourth quarter of 2013 and by $9.0 million or $0.83 per boe for the year ended December 31, 2013 compared to 2012. In British Columbia, these costs increased due to 13th month adjustments and higher processing facility costs associated with directing liquids-rich production through refrigeration facilities to increase liquids recoveries. In Saskatchewan, operating costs increased in 2013 due to increased workover and repair costs as well as fixed costs on a lower production base as the majority of capital is expended in British Columbia. In addition, an increased percentage of crude oil is being trucked and processed at third party facilities.

During 2014, the Company anticipates that per unit operating costs in British Columbia will benefit from incremental production volumes. In Saskatchewan, lower repair and maintenance costs are anticipated in 2014, subject to weather-related impacts.

TRANSPORTATION COSTS

	Three months ended December 31,		Year ended December 31,	
	2013	2012	2013	2012
Transportation costs *($000s)*	**2,241**	1,039	**7,296**	3,643
Per unit *($ per boe)*	**2.62**	1.55	**2.30**	1.51

Transportation costs for the three months and year ended December 31, 2013 were $2.2 million or $2.62 per boe and $7.3 million or $2.30 per boe, respectively. This compares to $1.0 million or $1.55 per boe for the three months ended December 31, 2012 and $3.6 million or $1.51 per boe for the year ended December 31, 2012.

The increased transportation costs are primarily due to increased NGL volumes in British Columbia that came on production in 2013 that have higher transportation costs, as well as fees associated with NGL marketing that will end in the first quarter of 2014, once a Company operated facility is built and operated. In 2014, transportation costs are also expected to decrease with the commissioning of a new battery in Saskatchewan in the second quarter.

FIELD OPERATING NETBACKS

	Three months ended December 31,		Year ended December 31,	
($/boe)	2013	2012	2013	2012
Revenue	**32.05**	34.17	**32.49**	31.03
Royalties	**(1.94)**	(2.50)	**(2.14)**	(2.78)
Operating expenses	**(9.21)**	(8.98)	**(9.17)**	(8.34)
Transportation costs	**(2.62)**	(1.55)	**(2.30)**	(1.51)
Field operating netback	**18.28**	21.14	**18.88**	18.40

In the three months ended December 31, 2013, field operating netbacks decreased as a result of higher operating and transportation costs. The increase in field operating netbacks for the year ended December 31, 2013 compared to 2012 is due to increased revenues, which were offset by higher operating and transportation costs.

BRITISH COLUMBIA FIELD OPERATING NETBACK

	Three months ended December 31,		Year ended December 31,	
($/boe)	**2013**	**2012**	**2013**	**2012**
Revenue	**25.38**	21.01	**23.52**	16.18
Royalties	**(0.72)**	(0.21)	**(0.63)**	(0.11)
Operating expenses	**(6.75)**	(5.87)	**(6.58)**	(5.46)
Transportation costs	**(2.69)**	(1.47)	**(2.35)**	(1.40)
Field operating netback	**15.22**	13.46	**13.96**	9.21

Painted Pony's production volumes from British Columbia in the three months and year ended December 31, 2013 were 8,234 and 7,464 boe/d, respectively, compared with 5,608 boe/d and 5,029 boe/d in 2012, respectively. The increase from comparable periods was due to incremental production adds from new Montney horizontal gas wells. Natural gas volumes contributed 95% and 98% of total British Columbia production volumes during 2013 and 2012.

Field operating netbacks improved in British Columbia due to higher natural gas prices, which increased 14% quarter over quarter and 36% year over year. This increase is partially offset by higher per unit royalty, operating and transportation costs. During 2013, the Company's field operating netback per unit for British Columbia properties was 59% of revenue per unit, compared to 57% in 2012.

SASKATCHEWAN FIELD OPERATING NETBACK

	Three months ended December 31,		Year ended December 31,	
($/boe)	**2013**	**2012**	**2013**	**2012**
Revenue	**82.95**	78.09	**87.01**	78.90
Royalties	**(11.25)**	(10.12)	**(11.34)**	(11.40)
Operating expenses	**(27.98)**	(19.35)	**(24.97)**	(17.64)
Transportation costs	**(2.06)**	(1.80)	**(1.98)**	(1.86)
Field operating netback	**41.66**	46.82	**48.72**	48.00

Production volumes from Saskatchewan for the three months and year ended were 1,076 and 1,227 boe/d, respectively, compared with 1,681 boe/d and 1,561 boe/d for the comparable periods in 2012. In Saskatchewan, the primary product is crude oil, which accounted for 90% of Saskatchewan production volumes in 2013, compared to 86% in 2012. The increased crude oil weighting in Saskatchewan was due to reduced solution gas production as well as an increased percentage of volumes being produced from producing properties where natural gas and NGLs are not recovered.

The lower field operating netback in the fourth quarter in Saskatchewan is primarily due to higher operating costs on mature producing properties. On a year over year basis, the higher field operating netback in Saskatchewan is reflective of a 9% increase in crude oil prices, partially offset by higher per unit royalties and operating costs. During 2013, Painted Pony's field operating netback per unit for Saskatchewan properties was 56% of revenue per unit, compared to 61% in 2012.

GENERAL AND ADMINISTRATIVE EXPENSES

	Three months ended December 31,		Year ended December 31,	
($000s, except per boe)	**2013**	**2012**	**2013**	**2012**
Gross expense	**5,448**	3,691	**14,188**	10,244
Capitalized	**(1,596)**	(1,259)	**(3,737)**	(3,312)
Recoveries	**(518)**	(609)	**(1,787)**	(1,899)
Net expense	**3,334**	1,823	**8,664**	5,033
Per unit *($ per boe)*	**3.89**	2.72	**2.73**	2.09

Net general and administrative ("G&A") expenses increased by $1.5 million or $1.17 per boe during the three months ended, and by $3.6 million or $0.64 per boe during the year ended December 31, 2013, compared to the same periods of 2012. G&A expenses during both periods increased primarily due to salaries, bonuses, consulting costs, an office relocation and associated administrative costs related to an increase of 23% in the number of employees during the year. Net G&A expenses for the three months ended December 31, 2013 included bonuses of $1.6 million, net of capitalized bonuses of $1.0 million. Net G&A expenses for the three months ended December 31, 2012 included bonuses of $0.7 million, net of capitalized bonuses of $0.5 million.

The Company's policy of allocating and capitalizing costs associated with new capital projects was unchanged in 2013 compared to 2012. During the year ended December 31, 2013, the Company capitalized $3.7 million of administrative costs to capital projects, compared to $3.3 million during the year ended December 31, 2012. G&A capital and operating recoveries were in accordance with industry practice and were $1.8 million in the year ended December 31, 2013 compared to $1.9 million in the year ended December 31, 2012.

In 2013, net G&A expenses per boe increased 31% compared to the year ended December 31, 2012, reflecting incremental staffing and associated costs, while the Company grew average production volumes by 32%. In 2014, with increased production net G&A expenses are expected to be less than $2.50 per boe.

SHARE-BASED PAYMENTS

	Three months ended December 31,		Year ended December 31,	
($000s)	**2013**	**2012**	**2013**	**2012**
Gross expense	**2,566**	3,426	**9,447**	12,824
Capitalized	**(325)**	(826)	**(2,119)**	(3,560)
Net expense	**2,241**	2,600	**7,328**	9,264

Gross share-based payments expenses were $2.6 million and $9.4 million for the three months and year ended December 31, 2013 compared to $3.4 million and $12.8 million for the year ended December 31, 2012. The lower expense in both periods is reflective of reduced costs related to forfeited options, combined with the net effect of the number of options granted at different exercise prices in each year. The weighted average fair value of stock options granted during 2013 was $3.83 per option compared to $6.04 per option in 2012.

Share-based payment expense is a non-cash estimate of the cost of granting options to purchase shares, calculated using a Black-Scholes model. The expense does not represent actual cash compensation realized by the recipients of the options upon the eventual exercise of these options.

DEPLETION AND DEPRECIATION EXPENSES

	Three months ended December 31,		Year ended December 31,	
	2013	**2012**	**2013**	**2012**
Depletion and depreciation *($000s)*	**11,278**	12,030	**42,422**	39,848
Per unit *($ per boe)*	**13.16**	17.94	**13.37**	16.52

Depletion and depreciation expense in the three months and year ended December 31, 2013 decreased by $4.78 per boe and $3.15 per boe, respectively, as compared to the same periods in 2012. The depletion rate was positively impacted by a 52% increase in total proved and probable reserves at December 31, 2013. At December 31, 2013, future development costs associated with the development of the Company's proved plus probable reserves were $2.4 billion, compared to $1.5 billion at December 31, 2012. The increase is associated with probable reserves of 230.4 mboe at December 31, 2013 compared to 148.2 mboe at December 31, 2012.

For the year ended December 31, 2013, Painted Pony excluded exploration and evaluation assets of $72.5 million from the depletion calculation, compared to $68.7 million for the year ended December 31, 2012.

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

EXPLORATION AND EVALUATION

During the three months and year ended December 31, 2013, the Company reported $3.6 million and $5.5 million, respectively, of exploration and evaluation expense related to non-economic drilling activity and lease expiries primarily in Saskatchewan, compared to $9.3 million for both the three months and year ended December 31, 2012.

IMPAIRMENT ON PROPERTY, PLANT AND EQUIPMENT

IFRS requires an impairment test to be completed to assess the recoverable value of the property, plant and equipment ("PP&E") within each cash generating unit ("CGU") whenever there is an indication of impairment. The Company currently has two CGU's, one for British Columbia and one for Saskatchewan. At December 31, 2013 an impairment test was not required for the British Columbia CGU. At December 31, 2013 as a result of a decreased reserve position compared to December 31, 2012 an impairment test was performed on the Saskatchewan CGU. The recoverable amount of the CGU was based on the higher of value in use and 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% based on proved plus probable reserves as obtained from the related independent reserve report, with forecasted 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.

The following table outlines the forecasted commodity prices and exchange rates used in the Company's CGU impairment test as at December 31, 2013. These future prices were based on the forecast commodity prices used by the external reserve evaluators.

Year	Exchange Rate *(US$ / CAN$)*	Edmonton Light Oil *(C$/bbl)*	AECO Gas *(C$/MMBtu)*
2014	0.95	92.76	4.03
2015	0.95	97.37	4.26
2016	0.95	100.00	4.50
2017	0.95	100.00	4.74
2018	0.95	100.00	4.97
2019	0.95	100.00	5.21
2020	0.95	100.77	5.33
2021	0.95	102.78	5.44
2022	0.95	104.83	5.55
2023	0.95	106.93	5.66
Rem.	0.95	109.07	5.77

Based on the impairment test completed for Saskatchewan in 2012, it was determined that the net book value of the Saskatchewan CGU exceeded the recoverable amount and the Company recognized a $42.1 million impairment charge for the year ended December 31, 2012. At December 31, 2013 the assets in the Saskatchewan CGU were not impaired.

NET FINANCE EXPENSE

	Three months ended December 31,		Year ended December 31,	
($000s)	**2013**	**2012**	**2013**	**2012**
Finance charges	**327**	51	**960**	357
Accretion of decommissioning obligations	**128**	85	**415**	313
Interest income	**(8)**	(81)	**(267)**	(546)
Total	**447**	55	**1,108**	124

Finance charges include interest expense on bank debt and standby charges on the Company's syndicated credit facilities. For the three months and year ended December 31, 2013, finance charges were higher than in the comparable period of 2012 as a result of interest expense on bank debt and from costs related to the 2013 implementation of the syndicated credit facilities.

Accretion costs on decommissioning obligations have increased for the three months and year ended December 31, 2013 as a result of additional drilled wells, combined with the impact of a higher discount rate used in calculating the present value of the decommissioning obligation. At December 31, 2013, the risk-free interest rate related to the decommissioning obligations was increased to 3.1% from 2.4% in 2012.

Interest income for the three months and year ended December 31, 2013 decreased compared to the same periods in 2012, reflective of reduced levels of cash.

CAPITAL EXPENDITURES

	Three months ended December 31,		Year ended December 31,	
($000s)	**2013**	202	**2013**	2012
Lease acquisitions and retention	**274**	107	**809**	585
Seismic	**-**	-	**824**	-
Drilling and completions	**19,445**	25,073	**77,403**	66,687
Facilities and equipment	**7,533**	3,205	**28,291**	17,681
Exploration and evaluation	**9,135**	17,123	**33,061**	33,135
Exploration and development	**36,387**	45,508	**140,388**	118,088
Head office expenditures	**(273)**	37	**2,189**	489
Capital expenditures	**36,114**	45,545	**142,577**	118,577
Property acquisitions	**20**	109,322	**258**	115,058
Share-based payments	**325**	827	**2,119**	3,560
Decommissioning costs	**3,247**	1,079	**1,629**	4,060
Total expenditures	**39,706**	156,773	**146,583**	241,255

During the three months and year ended December 31, 2013, the Company invested $36.4 million and $140.4 million in exploration and development capital expenditures, compared to $45.5 million and $118.1 million in comparable periods of 2012.

Capital expenditures for the three months ended December 31, 2013 included $19.4 million spent on drilling and completions activity. The Company drilled 6 (5.5 net) wells in the three month reporting period, including 4 (3.5 net) Montney natural gas wells in British Columbia and 2 (2.0 net) Bakken crude oil wells in Saskatchewan. Facilities and equipment spending of $7.5 million in the quarter reflects costs related to the design and construction of a 25 MMcf/d gas processing facility. Included in exploration and evaluation during the quarter was a $9.0 million land acquisition in British Columbia which brought Painted Pony's total land holdings at December 31, 2013 to 289,770 net acres, compared to 286,874 at December 31, 2012.

Capital expenditures for 2013 were $142.6 million including $77.4 million on drilling and completions. During 2013, the Company drilled 18 (13.0 net) wells, of which 13 (9.6 net) wells targeted Montney natural gas in British Columbia and 5 (3.4 net) wells targeted crude oil in Saskatchewan. Expenditures on facilities and equipment totaled $28.3 million and included design and construction costs related to a new gas processing facility, the purchase and installation of a compressor, the reactivation of a gas gathering system and facility, the installation of pipeline facilities and equipping and tie-in costs. Exploration and evaluation expenditures included undeveloped land acquisitions at Crown sales totaling $13.8 million, primarily in British Columbia, as well as drilling and completion costs on projects pending determination of proven and probable reserves. Drilling and completion costs related to an exploratory well in Saskatchewan were expensed in the first quarter of 2013.

Head office expenditures in the year included $1.8 million of leasehold improvements for new head office space in Calgary as well as new field offices in British Columbia.

The Company's Board of Directors has approved a $138 million capital exploration and development budget for 2014. The Company intends to drill a total of 18 (17.0 net) Montney horizontal wells and 3 (1.6 net) Saskatchewan crude oil wells during the year. Major 2014 facility projects include completion of a 25 MMcf/d gas processing facility, a 25 MMcf/d expansion of a Company operated facility, and an engineering study for a refrigeration and gas plant facility expected to be constructed in 2015.

RESERVES

		As at December 31,	
	2013	**2012**	**Change**
Total proved reserves *(mboe)*	**59,878**	42,978	39%
Total proved + probable reserves *(mboe)*	**290,271**	191,143	52%
Per common share outstanding *(boe/share)*	**3.28**	2.17	51%
Net present value discounted at 10% *($ millions)*	**1,502**	1,066	41%

At December 31, 2013, Painted Pony reported year end proved plus probable reserves of 290.3 MMboe representing an increase of 52% from December 31, 2012. Associated with proved plus probable reserve additions was a net present value discounted at 10% of $1.5 billion, which represents a 41% increase over prior year.

Further details of the Company's 2013 year end reserves are provided in the AIF, which is filed under the Company's profile on SEDAR at www.sedar.com.

LIQUIDITY AND CAPITAL RESOURCES

As at December 31, 2013, the Company had a working capital deficiency of $16.3 million and bank debt of $28.6 million. 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.

On August 8, 2013, the Company's $100 million demand facility was increased to $125 million syndicated credit facilities from three Canadian chartered banks with a borrowing base of $125 million, including a $115 million extendible revolving facility and a $10 million operating facility. The syndicated facilities revolve for a 364 day period plus a one year term-out, which is extendible annually, subject to syndicate approval. The facilities are subject to a semi-annual borrowing base review, the next of which is expected to occur on or before May 31, 2014.

The credit facilities bear interest on a matrix system which ranges from bank prime plus 1.0% to bank prime plus 3.5% depending on the Company's total debt to cash flow ratio as defined by the lender, ranging from less than 1:1 to greater than 3:1. The credit facilities provide that advances may be made by way of prime rate loans, U.S. Base Rate loans, London InterBank Offered Rate ("LIBOR") loans, bankers' acceptances, letters of credit or letters of guarantee. A standby fee of 0.5% to 0.875% is charged on the undrawn portion of the credit facilities, also calculated depending on the Company's total debt to cash flow ratio, as defined by the lender. Security is provided by a floating charge demand debenture in the principal amount of $300 million on all of the Company's assets. The Company has provided a negative pledge and undertaking to provide fixed charges over major producing petroleum and natural gas reserves in certain circumstances.

COMMITMENTS

($000s)	**2014**	**2015**	**2016**	**2017**	**2018**	**Thereafter**	**Total**
Gas processing	4,087	3,773	3,666	2,820	2,467	6,314	23,127
Gas gathering	1,631	700	598	-	-	-	2,929
Oil transportation	466	253	90	-	-	-	809
Equipment leases	726	618	618	144	-	-	2,106
Office leases	1,331	1,321	1,093	1,106	1,119	942	6,912

Gas processing includes numerous contracts to process natural gas through third party owned gas processing facilities in British Columbia. Gas gathering includes contracts to transport natural gas through third party owned pipeline systems in British Columbia. Oil transportation includes contracts requiring minimum tolls for transportation of crude oil through a major carrier system in Saskatchewan. Equipment leases include agreements to lease compressors related to the construction of facility infrastructure, expiring in 2016 and 2017. Office leases include the Company's contractual obligations for office space.

SHARE CAPITAL

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, 2013, there were 88,456,760 Common Shares issued and outstanding.

The Company has an incentive 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.

During the year ended December 31, 2013, a total of 2,416,500 options were granted at an average exercise price of $7.58. There were 405,000 options exercised during the year at an average price of $6.06, and 546,000 options forfeited at an average price of $10.86. During the year ended December 31, 2012, a total of 1,687,800 options were granted at an average exercise price of $9.38. During 2012 there were also 1,361,733 options exercised at an average price of $4.55 and 132,534 options forfeited at an average price of $10.55. As at December 31, 2013, 7,826,967 options to purchase Common Shares were issued and outstanding at a weighted-average price of $8.63 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, 2013 and March 18, 2014, no Preferred Shares were issued or outstanding.

As at March 18, 2014, there were 88,526,260 Common Shares and 7,492,467 options issued and outstanding.

INCOME TAXES

At December 31, 2013, the Company had a $9.4 million deferred income tax asset, compared to $10.1 million as at December 31, 2012. The Company recognized deferred income tax expense of $0.7 million in 2013. For the comparable year, the Company recognized a deferred income tax recovery of $13.2 million.

As at December 31, 2013, the Company has estimated tax pools of $619.3 million, compared to $526.7 million as at December 31, 2012. The Company expects that future taxable income will be available to utilize accumulated tax pools. Painted Pony's estimated tax pools at December 31, 2013 are comprised of the following:

Estimated Tax Pools

($000s)	**As at December 31, 2013**
Canadian exploration expense	**80,517**
Canadian development expense	**201,404**
Canadian oil and gas property expense	**160,886**
Undepreciated cost of capital	**79,799**
Non-capital losses	**87,626**
Other	**9,048**
Estimated income tax pools	**619,280**

DIVIDENDS

The Company has not declared or paid any dividends and does not intend to do so in the near future.

OFF BALANCE SHEET ARRANGEMENTS

No off balance sheet arrangements existed as at December 31, 2013 or 2012.

PERFORMANCE COMPARED TO EXPECTATIONS

Readers are reminded that forward-looking statements in this MD&A are subject to significant risks and uncertainties, many of which are beyond Painted Pony's control, and are based on a number of material factors and assumptions, certain or all of which may prove to be incorrect. A comparison of actual performance compared to Company announced expectations is as follows:

- *Volumes in 2013 were expected to be natural gas weighted. Natural gas constituted 84% and 82% of total production volumes in the three months and year ended December 31, 2013, respectively.*

- *In 2013, the Company expected to receive a natural gas price equivalent to the AECO daily spot price. The actual weighted average price received in the fourth quarter and in the year was a 7% and 8% premium, respectively, to this reference price. Painted Pony's British Columbia natural gas receives a price determined with reference to the British Columbia Westcoast Station 2 reference price, which received a premium compared to the AECO reference price.*

- *In 2013, the Company expected to receive an average crude oil price approximately 2% less than the Edmonton par reference price. In the fourth quarter and for the 2013 year, Painted Pony received a weighted average crude oil price 1% higher than this reference price.*

- *Overall royalties in 2013 were expected to average 6% to 7% of total revenues. Actual royalty rates for the three months and year ended December 31, 2013 were 6.1% and 6.6%, respectively.*

- *In 2013, per unit operating and transportation costs were expected to be approximately $10.00 per boe. Fourth quarter 2013 operating and transportation expenses were $11.83 per boe, and were $11.47 per boe for the year ended December 31, 2013. The increased cost per unit was primarily due to higher processing fees associated with directing liquids-rich production through refrigeration facilities to increase liquids recoveries, as well as 13th month adjustments.*

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, 2013 and 2012.

The reader is cautioned that the preparation of financial statements in accordance with IFRS requires management of the Company 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 banks 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.

NEW STANDARDS AND INTERPRETATIONS NOT YET ADOPTED

The IASB issued amendments to IAS 36, "Impairment of Assets" that require retrospective application and will be effective for the Company on January 1, 2014. Under the amendments, the recoverable amount is required to be disclosed when an impairment loss has been recognized or reversed. The adoption of these amendments is not expected to have a material impact on the Company's consolidated financial statements.

CHANGE IN ACCOUNTING POLICIES

Effective January 1, 2013, the Company adopted new standards with respect to IFRS 10 – *"Consolidated Financial Statements",* IFRS 11 – *"Joint Arrangements",* IFRS 12 – *"Disclosures of Interests in Other Entities",* as well as the consequential amendments to IAS 28 – *"Investments in Associates and Joint Ventures" (2011),* IFRS 13 – *"Fair Value Measurement"* and IFRS 7 – *"Amendments to Financial Instrument Disclosures".* The adoption of these standards had no impact on the amounts recorded in the financial statements as at December 31, 2013.

Business Risks, Uncertainties and Forward-looking Statements

Certain statements in this MD&A constitute forward-looking statements and forward-looking information (collectively, the "forward-looking statements") within the meaning of applicable Canadian securities laws. Such forward-looking statements relate to future events 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. 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, many of which are beyond Painted Pony's control and 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 MD&A are subject to significant risks and uncertainties, many of which are beyond Painted Pony's control and are based on a number of material factors and assumptions, certain or all of which may prove to be incorrect including, but not limited to, the following:

- *production volumes in 2014 will continue to be increasingly weighted toward natural gas and NGLs targeting the Montney formation in British Columbia;*
- *the Company will receive a natural gas price which varies in concert with Westcoast Station 2 pricing;*
- *the Company will receive an crude oil price that will vary from the Edmonton par reference price;*
  overall royalties in 2014 will approximate 6% to 7% of total revenues, assuming similar commodity prices to those realized in 2013;
- *average per unit operating and transportation expenses in 2014 are expected to decrease as a result of incremental gas volumes, as well as lower repair and maintenance costs and reduced treatment and transportation costs in Saskatchewan, assuming normal seasonal weather conditions;*
- *net G&A expenses are expected to average below $2.50 per boe in 2014;*
- *the 25 MMcf/d gas processing facility being constructed by the Company will be completed in the first quarter of 2014;*
- *the Company has sufficient financial resources with which to conduct its capital program assuming 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 will continue to be utilized in 2014;*
- *commitments to process and transport natural gas through third party owned facilities and pipeline systems in British Columbia, and commitments to transport crude oil through a major carrier system in Saskatchewan are expected to be fulfilled;*
- *agreements to lease compressors associated with the construction of facility infrastructure and agreements to lease office space are expected to be adhered to; 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 herein. 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 gas industry, including exploration, development and production operations risks;*
- *volatility of commodity prices;*
- *changes in interest and foreign exchange rates;*
- *risks and uncertainty of crude oil and natural gas geological deposits and reserves estimates;*
- *health, safety and environmental risks;*
- *revisions, amendments or changes to capital expenditure plans including exploration, development and exploitation projects;*
- *uncertainty of estimates and projections of production and costs;*
- *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 adverse weather conditions;*
- *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 and consultants.*

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.

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.

In addition to the foregoing risks and assumptions, Painted Pony's production and exploration activities are concentrated in Western Canada, where activity is highly competitive and includes a variety of companies ranging from smaller junior producers to the much larger integrated producers. Painted Pony is subject to various types of business risks and uncertainties including but not limited to:

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

In order to reduce exploration risk, the Company strives to employ highly qualified and motivated professional employees and consultants 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 with 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.

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 the circumstances.

DISCLOSURE CONTROLS AND PROCEDURES AND INTERNAL CONTROLS OVER FINANCIAL REPORTING

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

The Company's CEO and CFO have designed, or caused to be designed under their supervision, internal controls over financial reporting to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. Such officers have evaluated, or caused to be evaluated under their supervision, the effectiveness of the Company's internal controls over financial reporting at the financial year end of the Company and concluded that the Company's internal controls over financial reporting are effective, at the financial year end of the Company, for the foregoing purpose. The Company is required to disclose herein any change in the Company's internal controls over financial reporting that occurred during the period beginning on October 1, 2013 and ended on December 31, 2013 that has materially affected, or is reasonably likely to materially affect, the Company's internal controls over financial reporting. No material changes in the Company's internal controls over financial reporting were identified during such period that have materially affected, or are reasonably likely to materially affect, the Company's internal controls over financial reporting.

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

SELECTED CONSOLIDATED QUARTERLY INFORMATION

The following tables set forth selected consolidated financial information of the Company for the eight most recently completed quarters ending at the fourth quarter of 2013.

Quarter ended *($000s, except volumes and per share)*	**Mar. 31, 2013**	**June 30, 2013**	**Sept. 30, 2013**	**Dec. 31, 2013**
Petroleum and natural gas revenue[(1)]	25,522	24,644	25,467	**27,453**
Funds flow from operations	14,118	12,610	12,177	**12,322**
Basic and diluted, per share	0.16	0.14	0.14	**0.14**
Net income (loss)	(1,794)	698	(209)	**(4,417)**
Basic and diluted, per share	(0.02)	0.01	(0.00)	**(0.05)**
Cash capital expenditures, net	52,103	14,871	39,489	**36,114**
Capital acquisitions, net	-	-	238	**20**
Working capital (deficiency)	9,267	7,324	(20,657)	**(16,348)**
Bank debt	-	-	-	**28,626**
Total assets	614,714	595,417	615,935	**635,055**
Decommissioning obligations	14,582	14,351	13,335	**16,482**
Average daily production volumes *(boe/d)*	8,596	7,928	8,925	**9,312**

(1) Before royalties and including other income.

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)]	19,665	15,237	17,031	22,915
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
Net loss	(1,325)	(3,523)	(2,594)	(40,669)
Basic and diluted, per share	(0.02)	(0.05)	(0.04)	(0.56)
Cash 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 production volumes *(boe/d)*	6,993	5,745	6,327	7,289

(1) Before royalties and including other income.

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 December 31, 2013.

Years ended *($millions, except volumes and per share)*	**Dec. 31, 2013**	**Dec. 31, 2012**	**Dec. 31, 2011**
Petroleum and natural gas revenue[(1)]	**103.1**	74.8	74.7
Funds flow from operations	**51.2**	39.3	44.2
Basic, per share	**0.58**	0.56	0.74
Diluted, per share	**0.58**	0.55	0.73
Net income (loss)	**(5.7)**	(48.1)	6.5
Basic and diluted, per share	**(0.06)**	(0.68)	0.11
Cash capital expenditures, net	**142.6**	118.6	147.2
Capital acquisitions, net	**0.3**	115.1	8.7
Net working capital (deficiency)	**(16.3)**	45.2	68.3
Bank debt	**28.6**	-	-
Total assets	**635.1**	612.2	478.7
Decommissioning obligations	**16.5**	14.8	10.9
Average daily production volumes *(boe/day)*	**8,693**	6,589	4,221

(1) Before royalties and including other income.

Significant factors and trends that have affected the Company's results during the above 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 and higher cash flows. The commodity prices realized by the Company have approximated the Edmonton par light oil prices and AECO daily spot gas prices with periodic widening of differentials throughout the above periods. The reference price fluctuations reflect changes in supply and demand by commodity, both internationally and domestically.*

- *Funds flow from operations reflects the impact of fluctuating commodity prices on a growing production base. Operating and transportation cost variations track seasonal weather-related issues combined with fixed commitments. Throughout 2011, commodity prices were stronger than in 2012, producing higher funds flow from operations. Throughout 2012, natural gas and crude oil prices weakened throughout the year, while commodity prices increased in 2013. Royalty changes vary due to commodity prices, production levels and the status of the different provincial royalty 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.*

- *The net loss in 2013 is primarily attributable to exploration and evaluation, partially offset by higher funds flow from operations. The 2012 net loss was primarily attributable to a $42.1 million impairment of property, plant as well as exploration and evaluation expense.*

- *Fluctuations in capital expenditures have reflected both available capital resources and intentional capital spending restraint during weaker commodity price cycles.*

- *Total assets and non-current liabilities have increased as the Company's capital program is executed.*

ADDITIONAL INFORMATION

Additional information regarding the Company and its business and operations is available on the Company's SEDAR profile at www.sedar.com. Copies of the Company's disclosure can also be obtained by contacting the Company at Painted Pony Petroleum Ltd., 1800, 736 – 6 Avenue SW., Calgary, Alberta T2P 3T7 (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, 2013 and 2012.

Patrick R. Ward
President and CEO

John H. Van de Pol
Vice President, Finance and CFO

March 18, 2014

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, 2013 and December 31, 2012, the consolidated statements of operations, 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, 2013 and December 31, 2012, 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

March 18, 2014
Calgary, Canada

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

(000s) **As at**		**December 31, 2013**		**December 31, 2012**
ASSETS				
Current assets				
Cash and cash equivalents	**$**	**-**	$	77,522
Trade and other receivables		**16,647**		14,427
Prepaid expenses and deposits		**544**		438
Fair value of risk management contracts *(note 14)*		**42**		-
		17,233		92,387
Non-current assets				
Fair value of risk management contracts *(note 14)*		**36**		-
Exploration and evaluation *(note 4)*		**72,482**		68,707
Property, plant and equipment *(note 5)*		**535,862**		441,010
Deferred tax asset *(note 12)*		**9,442**		10,077
	$	**635,055**	$	612,181
LIABILITIES				
Current liabilities				
Trade and other payables	**$**	**33,581**	$	47,171
Non-current liabilities				
Bank debt *(note 6)*		**28,626**		-
Decommissioning obligations *(note 7)*		**16,482**		14,821
		78,689		61,992
EQUITY				
Share capital *(note 9)*		**554,149**		550,116
Contributed surplus		**44,092**		36,226
Deficit		**(41,875)**		(36,153)
		556,366		550,189
	$	**635,055**	$	612,181

Commitments *(note 17)*
Contingency *(note 18)*
Subsequent events *(note 14)*

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 OPERATIONS

(000s, except per share amounts)

Years ended December 31,		2013		2012
Revenue				
Petroleum and natural gas	$	103,086	$	74,849
Royalties		(6,785)		(6,715)
		96,301		68,134
Unrealized gain on commodity risk management *(note 14)*		78		-
		96,379		68,134
Expenses				
Operating		29,114		20,121
Transportation costs		7,296		3,643
General and administrative		8,664		5,033
Share-based payments *(note 9)*		7,328		9,264
Depletion and depreciation *(note 5)*		42,422		39,848
Exploration and evaluation *(note 4)*		5,534		9,313
Impairment of property, plant & equipment *(note 13)*		-		42,100
		100,358		129,322
Results from operating activities		(3,979)		(61,188)
Finance expense		1,375		670
Finance income		(267)		(546)
Net finance expense *(note 10)*		1,108		124
Loss before income tax		(5,087)		(61,312)
Deferred income tax (expense) reduction *(note 12)*		(635)		13,201
Net loss and comprehensive loss	$	(5,722)	$	(48,111)
Loss per share *(note 8)*:				
Basic and diluted	$	(0.06)	$	(0.68)

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

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(000s, except shares)

Years ended December 31, 2013 and 2012

	Number of shares	Share capital	Contributed surplus	Retained earnings/ (Deficit)	Total equity
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 9)*	1,361,733	10,184	(4,027)	-	6,157
Net loss for the year	-	-	-	(48,111)	(48,111)
Balance at December 31, 2012	88,051,760	$ 550,116	$ 36,226	$ (36,153)	$ 550,189
Share-based payments	-	-	9,447	-	9,447
Options exercised *(note 9)*	405,000	4,033	(1,581)	-	2,452
Net loss for the year	-	-	-	(5,722)	(5,722)
Balance at December 31, 2013	88,456,760	$ 554,149	$ 44,092	$ (41,875)	$ 556,366

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

CONSOLIDATED STATEMENTS OF CASH FLOWS

(000s)

Years ended December 31,		**2013**		**2012**
Cash flows from operating activities:				
Net loss and comprehensive loss	**$**	**(5,722)**	$	(48,111)
Adjustments for:				
Exploration and evaluation		**5,534**		9,313
Share-based payments		**7,328**		9,264
Depletion and depreciation		**42,422**		39,848
Impairment of property, plant & equipment		**-**		42,100
Net finance expense		**1,108**		124
Deferred income tax expense (reduction)		**635**		(13,201)
Unrealized gain on commodity risk management		**(78)**		-
Decommissioning expenditures		**(383)**		(412)
Changes in non-cash working capital		**(1,731)**		807
		49,113		39,732
Cash flows from investing activities:				
Exploration and evaluation additions		**(33,061)**		(33,135)
Property, plant and equipment additions		**(109,516)**		(85,442)
Acquisition of property, plant and equipment *(note 5)*		**(258)**		(115,058)
Changes in non-cash working capital		**(13,935)**		2,628
		(156,770)		(231,007)
Cash flows from financing activities:				
Issue of share capital		**-**		172,520
Share issuance costs		**-**		(7,231)
Increase in bank debt		**28,626**		-
Exercise of share options		**2,452**		6,157
Net cash finance income (expense)		**(693)**		189
Changes in non-cash working capital		**(250)**		192
		30,135		171,827
Change in cash and cash equivalents		**(77,522)**		(19,448)
Cash and cash equivalents, beginning of year		**77,522**		96,970
Cash and cash equivalents, end of year	**$**	**-**	$	77,522

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

As at and for the years ended December 31, 2013 and 2012

1. REPORTING ENTITY

Painted Pony Petroleum Ltd.'s ("Painted Pony" or the "Company") principal business activity is the exploration, development and production of petroleum and natural gas resources in Western Canada. The consolidated financial statements of the Company as at and for the years ended December 31, 2013 and 2012 include the accounts of the Company and its wholly owned subsidiary, Painted Rock Resources Ltd. The Company's head office is located at 736 – 6th Avenue S.W., Suite 1800, Calgary, Alberta.

2. BASIS OF PRESENTATION

(a) 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").

The consolidated financial statements were authorized for issuance by the Board of Directors of the Company on March 18, 2014.

(b) Basis of Measurement
The consolidated financial statements have been prepared on the historical cost basis except for derivative financial instruments which are measured at fair value. The methods used to measure fair value are discussed in note 15.

(c) Functional and Presentation Currency
These consolidated financial statements are presented in Canadian dollars, which is the Company's and its subsidiary's functional currency.

(d) Prior Period Comparatives
Prior periods have been restated to conform to presentation in the current period.

(e) Use of Judgments and Estimates
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 estimates 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 assessing 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 crude 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 includes 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 ("PP&E"), 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 crude 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 crude oil and natural 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 is dependent on estimated forward prices and volatility in those prices.

(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, by both the Company and its subsidiary.

(a) Basis of Consolidation

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 operations.

Jointly Controlled Operations and Jointly Controlled Assets

Most of the Company's crude 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.

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.

(b) Financial Instruments

Non-derivative Financial Instruments

Non-derivative financial instruments comprise cash and cash equivalents, trade and other receivables, trade and other payables and bank debt. 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.

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.

Other non-derivative financial instruments include trade and other receivables, trade and other payables and bank debt. Trade and other receivables are measured using the effective interest rate method, less any impairment losses. 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.

Derivative Financial Instruments

The Company has entered into certain financial derivative contracts in order to manage the exposure to market risks from fluctuations in commodity prices. These instruments are not used for trading or speculative purposes. The Company has not designated its financial derivative contracts as effective accounting hedges and, therefore, has not applied hedge accounting, even though the Company considers all commodity contracts to be economic hedges. As a result, all financial derivative contracts are classified as fair value through profit or loss and are recorded on the statements of financial position at fair value. Transaction costs are recognized in net income when incurred.

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

Recognition and Measurement

(i) Exploration and Evaluation

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 PP&E assets.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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(ii) Property, Plant and Equipment

Items of PP&E, which include crude oil and natural 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 crude oil and natural gas interests, have different useful lives, they are accounted for as separate items.

Gains and losses on disposal of an item of PP&E, 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.

Costs incurred subsequent to the determination of technical feasibility and commercial viability and the costs of replacing parts of PP&E are recognized as crude 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 crude 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 PP&E are recognized in earnings.

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 crude 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 crude 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 crude oil in the ratio of six mcf of gas to one barrel of crude 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 crude 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.

(d) Impairment

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.

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 CGUs, being the smallest group of assets that generate cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets. The recoverable amount of an asset or a CGU is the greater of its value in use and its fair value less costs to sell.

In assessing fair value less costs to sell, 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. Fair value less costs to sell 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, or (ii) facts and circumstances suggest that the carrying amount exceeds the recoverable amount.

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 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.

(e) 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.

(f) 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.

(g) Share-Based Payments

The Company has issued options to acquire Common 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.

(h) 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 remediation activities. Provision is made for the estimated cost of site restoration and is 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.

(i) Revenue Recognition

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

(j) Finance Income and Expenses

Finance expense consists of interest expense and standby fees on credit facilities, costs related to the implementation of the credit facilities and accretion on the decommissioning obligation.

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

(k) 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.

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.

(l) Foreign Currency Translation

The principal currency of the economic environment in which the Company and its wholly owned subsidiary 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.

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(m) Earnings (loss) per Share

Basic per share information is calculated on the basis of the weighted average number of Common Shares outstanding during the period. Diluted per share information reflects the potential dilutive effect of options.

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

(n) Future Accounting Pronouncements

The IASB issued amendments to IAS 36, "Impairment of Assets" that require retrospective application and will be effective for the Company on January 1, 2014. Under the amendments, the recoverable amount is required to be disclosed when an impairment loss has been recognized or reversed. The adoption of these amendments is not expected to have a material impact on the Company's consolidated financial statements.

(o) Change in Accounting Policies

Effective January 1, 2013, the Company adopted new standards with respect to IFRS 10 - "*Consolidated Financial Statements*", IFRS 11 - "*Joint Arrangements*", IFRS 12 - "*Disclosures of Interests in Other Entities*", as well as the consequential amendments to IAS 28 - "*Investments in Associates and Joint Ventures*" *(2011),* IFRS 13 - "*Fair Value Measurement*" and IFRS 7 - "*Amendments to Financial Instrument Disclosures*". The adoption of these standards had no impact on the amounts recorded in the financial statements as at December 31, 2013.

4. EXPLORATION AND EVALUATION

(000s)		
Cost:		
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
Additions		33,061
Transfers to property, plant and equipment		(23,752)
Expensed		(5,534)
Balance, December 31, 2013	$	72,482

E&E assets consist of undeveloped lands, unevaluated seismic data and unevaluated drilling and completion costs on the Company's exploration projects which are pending the determination of proven or probable reserves. Additions represent the Company's share of costs incurred on E&E assets during the year. Transfers are made to PP&E as proven or probable reserves are determined. E&E assets are expensed due to non-economic drilling and completion activities and lease expiries.

The Company assesses the recoverability of E&E assets as the transfer to PP&E is considered.

5. PROPERTY, PLANT AND EQUIPMENT

(000s)		Total
Cost:		
Balance, December 31, 2011	$	352,109
Acquisitions		115,058
Cash additions		85,442
Non-cash additions		7,620
Transfers from exploration and evaluation		16,341
Balance, December 31, 2012		576,570
Acquisitions		258
Cash additions		109,516
Non-cash additions		3,748
Transfers from exploration and evaluation		23,752
Balance, December 31, 2013	$	713,844
Accumulated depletion and depreciation:		
Balance, December 31, 2011	$	53,612
Depletion and depreciation		39,848
Impairment		42,100
Balance, December 31, 2012		135,560
Depletion and depreciation		42,422
Balance, December 31, 2013	$	177,982
Carrying amounts:		
At December 31, 2012	$	441,010
At December 31, 2013	$	535,862

The calculation of depletion and depreciation for the three months ended December 31, 2013 included estimated future development costs of $2.4 billion (December 31, 2012 - $1.5 billion) associated with the development of the Company's proved plus probable reserves.

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

For the years ended December 31, 2013 and 2012, the Company capitalized general and administrative expenses and share-based payments as follows:

Years ended December 31, *(000s)*		2013		2012
General and administrative	**$**	**3,737**	$	3,312
Share-based payments		**2,119**		3,560
Total	**$**	**5,856**	$	6,872

(b) Property Acquisitions

During the year ended December 31, 2013, the Company completed one minor strategic property acquisition for $0.2 million. In the year ended December 31, 2012, the Company acquired $115.1 million of assets, including the purchase of certain northeast British Columbia gas properties for total cash consideration of $112.8 million.

(c) Other Assets

The total cost associated with office furniture and fixtures at December 31, 2013 was $3.4 million, with accumulated amortization of $0.8 million. This compares to a cost of $1.2 million as at December 31, 2012, with accumulated amortization of $0.4 million.

6. BANK DEBT

The Company has syndicated credit facilities from three Canadian chartered banks with a borrowing base of $125 million, including a $115 million extendible revolving facility and a $10 million operating facility. The facilities revolve for a 364 day period plus a one year term-out, which is extendible annually, subject to syndicate approval. The facilities are subject to a semi-annual borrowing base review, the next of which is expected to occur on or before May 31, 2014.

The credit facilities bear interest on a matrix system which ranges from bank prime plus 1.0% to bank prime plus 3.5% depending on the Company's total debt to cash flow ratio as defined by the lender, ranging from less than 1:1 to greater than 3:1. The credit facilities provide that advances may be made by way of prime rate loans, U.S. Base Rate loans, London InterBank Offered Rate ("LIBOR") loans, bankers' acceptances, letters of credit or letters of guarantee. A standby fee of 0.5% to 0.875% is charged on the undrawn portion of the credit facilities, also calculated depending on the Company's total debt to cash flow ratio, as defined by the lender.

Security is provided by a floating charge demand debenture in the principal amount of $300 million on all of the Company's assets. The Company has provided a negative pledge and undertaking to provide fixed charges over major producing petroleum and natural gas reserves in certain circumstances.

7. DECOMMISSIONING OBLIGATIONS

Years ended December 31, *(000s)*		**2013**		**2012**
Balance, beginning of year	**$**	**14,821**	$	10,860
Provisions		**1,104**		3,073
Revisions		**525**		987
Decommissioning expenditures		**(383)**		(412)
Accretion		**415**		313
Balance, end of year	**$**	**16,482**	$	14,821

The Company's decommissioning obligations result from its ownership interest in crude 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 based on an undiscounted total future liability of $36.0 million (2012: $26.3 million) with payments expected to be made over the next 10 to 38 years. The discount factor, being the risk-free rate related to the liability, is 3.1% (2012: 2.4%) and the inflation rate is 2% (2012: 2%).

8. NET LOSS PER SHARE

Years ended December 31,		**2013**		**2012**
Net loss for the year *(000s)*	**$**	**(5,722)**	$	(48,111)
Weighted average common shares - basic and diluted		**88,420,058**		70,824,894
Net loss per share - basic and diluted	**$**	**(0.06)**	$	(0.68)

The average market value of the Company's Common Shares for purposes of determining the dilutive effect of outstanding stock options was based on quoted market prices for the period. During the years ended December 31, 2013 and 2012, all options were excluded from the weighted-average diluted share calculation of Common Shares.

9. SHARE CAPITAL

(a) Authorized

The Company has an unlimited number of Common and Preferred Shares authorized for issuance. At December 31, 2013 there were 88,456,760 Common Shares outstanding, compared to 88,051,760 Common Shares outstanding at December 31, 2012. At December 31, 2013 at 2012 there were no Preferred Shares outstanding.

The Common Shares entitle the holder thereof to one vote for every share held. 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. Stock 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 stock options are as follows:

		Weighted Average Exercise Price	**Number**
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
Granted		7.58	2,416,500
Exercised		6.06	(405,000)
Forfeited		10.86	(546,000)
Balance, December 31, 2013	$	8.63	7,826,967

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The following table summarizes information about stock options outstanding at December 31, 2013:

Number of options outstanding	Exercise price *($)*	Remaining life *(yrs)*	Exercisable options	Exercise price *($)*
358,500	2.85	0.6	358,500	2.85
188,300	3.15	0.6	188,300	3.15
332,167	5.88	1.0	332,167	5.88
17,000	5.60	1.4	17,000	5.60
589,400	6.51	1.7	589,400	6.51
1,130,400	10.60	2.3	1,130,400	10.60
354,000	12.10	2.4	354,000	12.10
30,000	11.19	2.5	30,000	11.19
152,500	14.15	2.6	152,500	14.15
684,700	11.80	2.9	684,700	11.80
535,900	7.56	3.3	350,866	7.56
80,000	7.10	3.4	53,332	7.10
423,000	10.86	3.7	282,000	10.86
534,600	10.59	3.9	356,400	10.59
360,000	10.33	4.0	120,000	10.33
364,000	10.13	4.3	121,333	10.13
1,692,500	6.44	5.0	564,166	6.44
7,826,967	8.63	3.1	5,685,064	8.85

The weighted average share price at the date of exercise for share options exercised during the year ended December 31, 2013 was $10.10 (2012: $9.11).

The Company accounts for its stock options granted to employees, consultants, 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 weighted-average fair values of the options granted and the assumptions used in the Black-Scholes option pricing model were as follows:

Years ended December 31,		2013		2012
Fair value per option	**$**	**3.83**	$	6.04
Volatility *(%)*		**56**		80
Option life *(years)*		**5**		5
Dividends		**-**		-
Risk-free interest rate *(%)*		**1.63**		1.65

During the year ended December 31, 2013, 2,416,500 stock options were granted at an average price of $7.58. During the year ended December 31, 2012, 1,687,800 stock options were granted at an average price of $9.38.

A forfeiture rate of 7% (2012: 3%) was used when measuring share-based payments.

10. NET FINANCE EXPENSE

Years ended December 31, *(000s)*		**2013**		**2012**
Finance expense:				
Interest and financing costs	**$**	**960**	$	357
Accretion of decommissioning obligations		**415**		313
		1,375		670
Finance income:				
Interest income		**(267)**		(546)
Net finance expense	**$**	**1,108**	$	124

11. SUPPLEMENTAL CASH FLOW INFORMATION

Changes in non-cash working capital is comprised of:

Years ended December 31, *(000s)*		**2013**		**2012**
Source/(use) of cash:				
Trade and other receivables	**$**	**(2,220)**	$	7,041
Prepaid expenses and deposits		**(106)**		57
Trade and other payables		**(13,590)**		(3,471)
	$	**(15,916)**	$	3,627

12. DEFERRED INCOME TAX

Reconciliation of effective tax rate:

Years ended December 31, *(000s)*		**2013**		**2012**
Loss before income tax	**$**	**(5,087)**	$	(61,312)
Combined corporate tax rate		**25.6%**		25.6%
Expected income tax expense (reduction)	**$**	**(1,302)**	$	(15,696)
Non-deductible expenses		**22**		16
Share-based compensation		**1,961**		2,452
Change in statutory tax rates		**(46)**		27
Total income tax expense (reduction)	**$**	**635**	$	(13,201)

Deferred tax assets and liabilities are attributable to the following:

Years ended December 31, *(000s)*		**2013**		**2012**
Deferred tax liabilities:				
PP&E and E&E assets	**$**	**(19,500)**	$	(5,613)
Fair value of financial instruments		**(20)**		-
		(19,520)		(5,613)
Less deferred tax assets:				
Provisions		**4,234**		3,794
Share issue costs		**2,240**		3,436
Non-capital losses		**22,488**		8,460
Net deferred tax asset	**$**	**9,442**	$	10,077

The Company has non-capital losses of $87.6 million. Of these losses, 99% expire beginning in the year 2030. Based on a reserve report prepared by external reservoir evaluators, the Company has determined that it is probable that these losses will be utilized against future taxable income.

Movement in deferred tax balances during the year:

	PP&E and E&E	Fair value of financial instruments	Provisions	Share issue costs	Non-capital losses
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
Recognized in comprehensive income	(13,887)	(20)	440	(1,196)	14,028
Balance, December 31, 2013	$ (19,500)	$ (20)	$ 4,234	$ 2,240	$ 22,488

13. IMPAIRMENT

IFRS requires an impairment test to be completed to assess the recoverable value of the PP&E within each CGU whenever there is an indication of impairment. The Company currently has two CGU's, one for British Columbia and one for Saskatchewan. At December 31, 2013 an impairment test was not required for the British Columbia CGU. At December 31, 2013 as a result of a decreased reserve position compared to December 31, 2012 an impairment test was performed on the Saskatchewan CGU. The recoverable amount of the CGU was based on the higher of value in use and 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% based on proved plus probable reserves as obtained from the related independent reserve report, with forecasted 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.

The following table outlines the forecasted commodity prices and exchange rates used in the Company's CGU impairment test as at December 31, 2013. These future prices were based on the forecast commodity prices used by the external reserve evaluators.

Year	Exchange Rate *(US$ / CAN$)*	Edmonton Light Oil *(C$/bbl)*	AECO Gas *(C$/MMBtu)*
2014	0.95	92.76	4.03
2015	0.95	97.37	4.26
2016	0.95	100.00	4.50
2017	0.95	100.00	4.74
2018	0.95	100.00	4.97
2019	0.95	100.00	5.21
2020	0.95	100.77	5.33
2021	0.95	102.78	5.44
2022	0.95	104.83	5.55
2023	0.95	106.93	5.66
Rem.	0.95	109.07	5.77

Based on the impairment test completed for Saskatchewan in 2012, it was determined that the net book value of the Saskatchewan CGU exceeded the recoverable amount and the Company recognized a $42.1 million impairment charge for the year ended December 31, 2012. At December 31, 2013 the assets in the Saskatchewan CGU were not impaired.

14. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

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. These include market risk, credit risk and liquidity risk.

The Board of Directors of the Company 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.

(a) 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.

Natural gas prices obtained by the Company are influenced by both US and Canadian supply and demand and an anticipated increased demand for liquefied natural gas. Prices for crude oil are determined in global markets and generally denominated in United States dollars. 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 crude oil and natural gas are impacted by not only the relationship between the Canadian and United States dollars, but also upon world economic events that dictate the levels of supply and demand.

The Company's production is usually sold through near term sales 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. The Company has contracted the majority of its crude oil to one purchaser on a month-to-month rolling contract. The majority of the Company's natural gas is sold to one purchaser monthly on a best-efforts basis.

The Company uses financial derivatives and physical delivery sales contracts to mitigate some of the exposure to commodity price risk, and provide a level of stability to operating cash flows which enables the Company to fund its capital development program. The use of these transactions is governed by and is subject to risk management policies established by the Board of Directors of the Company.

Commodity Price Contracts

At December 31, 2013, the Company has entered into the following commodity price contracts:

Natural Gas Financial Swaps

Reference	**Volume** *(GJ/d)*	**Term**	**Price** *($/GJ)*	**Option traded**		**Fair value** *(000s)*
CDN$ AECO	10,000	January - December 2014	3.72	Swap	$	42
CDN$ AECO	10,000	January - March 2015	3.90	Swap		36
Total fair value					$	78

Subsequent to December 31, 2013, the Company entered into additional commodity risk management contracts as outlined below:

Natural Gas Financial Swaps

Reference	**Volume** *(GJ/d)*	**Term**	**Price** *($/GJ)*	**Option traded**
CDN$ AECO	10,000	February - March 2014	3.90	Swap
CDN$ AECO	5,000	April - December 2014	3.83	Swap
CDN$ AECO	5,000	April 2014 - March 2015	3.85	Swap
CDN$ AECO	5,000	January - March 2015	4.21	Swap

For the year ended December 31, 2013, if natural gas prices had been US$0.10 per mcf higher, with all other variables held constant, the net loss for the year would have been $1.6 million lower. An equal and opposite impact would have occurred to net loss had natural gas prices been US$0.10 per mcf lower. For the year ended December 31, 2013, if crude oil prices had been US$1 per barrel higher, with all other variables held constant, net loss for the year would have been $0.4 million lower. An equal and opposite impact would have occurred to net loss had crude oil prices been US$1 per barrel lower.

Foreign currency exchange risk is the risk that the fair value of future cash flows will fluctuate as a result of changes in foreign exchange rates. Substantially all of the Company's petroleum and natural gas sales are conducted in Canada and are denominated in Canadian dollars, however, Canadian commodity prices are influenced by fluctuations in the Canadian to U.S. dollar exchange rate.

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. The Company is exposed to interest rate fluctuations on its bank debt which bears a floating rate of interest. In the year ended December 31, 2013, if interest rates had been 0.5% lower with all other variables held constant, net loss for the year would have been $0.1 million lower. An equal and opposite impact would have occurred to net loss had interest rates been 0.5% higher.

(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 crude oil and natural gas purchasers. The Company's maximum exposure to credit risk at December 31, 2013 and 2012 is as follows:

Carrying amounts, December 31, *(000s)*		**2013**		**2012**
Cash and cash equivalents		**-**	$	77,522
Trade and other receivables		**16,647**		14,427
Fair value of financial instruments		**78**		-
Total	**$**	**16,725**	$	91,949

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.

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 crude 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 crude 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 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 crude 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, 2013 or 2012.

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

Carrying amount, December 31, *(000s)*		**2013**		**2012**
Petroleum and natural gas revenue	**$**	**10,012**	$	7,720
Joint interest		**3,467**		1,943
Other		**3,168**		4,764
Total	**$**	**16,647**	$	14,427

The Company has two significant independent crude oil and natural gas purchasers. One entity purchases the majority of natural gas produced in British Columbia, and the second entity purchases the majority of crude oil produced in Saskatchewan. These purchases accounted for $8.8 million of trade and other receivables at December 31, 2013 (December 31, 2012: $7.2 million).

As at December 31, 2013 and 2012, the Company's trade and other receivables are aged as follows:

Carrying amount, December 31, *(000s)*		**2013**		**2012**
Less than 30 days	**$**	**16,067**	$	13,488
From 31 - 90 days		**308**		731
More than 90 days		**272**		208
Total	**$**	**16,647**	$	14,427

Derivatives:

The use of financial swap agreements involves a degree of credit risk that Painted Pony manages through its risk management policies which are designed to limit eligible counterparties to those with investment grade credit ratings or better.

(c) Liquidity Risk:

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they become 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.

Management closely monitors cash flow requirements to ensure that is has sufficient cash on demand or borrowing capacity to meet operational and financial obligations currently and in the foreseeable future; 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 crude oil and natural gas revenues from most properties on the 25th of each month.

To facilitate the capital expenditure program, the Company has an aggregate of $125 million in syndicated credit facilities at December 31, 2013 (2012: $100 million demand facility), which are reviewed semi-annually by its lenders. The principal amount utilized under the syndicated credit facilities at December 31, 2013 was $28.6 million (2012: $nil).

(d) 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 crude 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 and decommissioning expenditures for the most recent calendar quarter and then annualized. The Company's objective is to maintain a net debt to annualized cash flow ratio of less than 2:1, with a targeted ratio of 1.5:1. 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 of the Company.

As a result of shifting from an exploration-focused program to a development-focused program, the Company has adapted its approach to capital management to include low cost bank debt as part of the capital structure going forward. Neither the Company nor its subsidiary is subject to externally imposed capital requirements. The syndicated credit facilities are subject to a periodic review of the borrowing base which is directly impacted by the value of the crude oil and natural gas reserves.

15. 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 values of PP&E and E&E assets recognized in an acquisition, are based on market values. The fair values of PP&E and E&E are the estimated amounts for which they 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 crude 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 crude 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, Trade and Other Payables and Bank Debt

The fair value of cash and cash equivalents, trade and other receivables, trade and other payables and bank debt are estimated as the present value of future cash flows, discounted at the market rate of interest at the reporting date. At December 31, 2013 and December 31, 2012, the fair value of these balances approximated their carrying value. Bank debt has a floating rate of interest and therefore the carrying value approximates the fair value.

(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.

(d) Derivatives

The fair value of commodity price risk management contracts is determined by discounting the difference between the contracted prices and published forward price curves as at the date of the statement of financial position, using the remaining contracted crude oil and natural gas volumes and risk-free interest rate (based on published government rates).

Measurement

The Company classifies the fair value of these transactions according to the following hierarchy based on the amount of observable inputs used to value the instrument.

(i) Level 1: Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

(ii) Level 2: Pricing inputs are other than quoted prices in active markets included in Level 1. Prices are either directly or indirectly observable as of the reporting date. Level 2 valuations are based on inputs, including quoted forward prices for commodities, time value and volatility factors, which can be substantially observed or corroborated in the marketplace.

(iii) Level 3: Valuations in this level are those with inputs for the asset or liability that are not based on observable market data.

The Company's commodity price contracts are valued using Level 2 of the hierarchy.

16. SUPPLEMENTARY DISCLOSURES

(a) Key Management Personnel Compensation

Key management personnel are persons who have the authority and responsibility for planning, directing and controlling the activities of the Company, directly or indirectly. This includes all directors and executives of the Company. Short-term compensation includes salaries, bonuses and short-term benefits paid to executives and fees paid to directors. Share-based payments represents the amortization of share-based payment expense associated with options granted to executives and directors.

Years ended December 31, *(000s)*		**2013**		**2012**
Short-term compensation	**$**	**4,327**	$	2,423
Share based payments		**5,631**		6,308
Total	**$**	**9,958**	$	8,731

(b) Income Statement Presentation

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 expenses. In the year ended December 31, 2013, employee compensation costs of $11.7 million were included in general and administrative expenses (2012: $11.8 million) and $1.0 million were included in operating expenses (2012: $0.2 million).

17. COMMITMENTS

($000s)	2014	2015	2016	2017	2018	Thereafter	Total
Gas processing	4,087	3,773	3,666	2,820	2,467	6,314	23,127
Gas gathering	1,631	700	598	-	-	-	2,929
Oil transportation	466	253	90	-	-	-	809
Equipment leases	726	618	618	144	-	-	2,106
Office leases	1,331	1,321	1,093	1,106	1,119	942	6,912

Gas processing includes numerous contracts to process natural gas through third party owned gas processing facilities in British Columbia. Gas gathering includes contracts to transport natural gas through third party owned pipeline systems in British Columbia. Oil transportation includes contracts requiring minimum tolls for transportation of crude oil through a major carrier system in Saskatchewan. Equipment leases include agreements to lease compressors related to the construction of facility infrastructure, expiring in 2016 and 2017. Office leases include the Company's contractual obligations for office space.

18. CONTINGENCY

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

Certain information regarding Painted Pony set forth in this Annual Report, 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.

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 International Financial Reporting Standards ("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; (iv) cash flows from operating activities (v) future development costs, and finding development and acquisition cost estimates and (vi) accuracy of reserves and resource estimates. 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 2014; (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 2014 are expected to show growth from 2013; (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.

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, 2013 as contained in the consolidated report of GLJ dated February 14, 2014 (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, 2014 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.

ADVISORY

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 nontechnical 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.

Estimates of reserves for individual properties may not reflect the same confidence level as estimates of reserves for all properties due to the effects of aggregation.

The well test results disclosed in this news release represent short-term results, which may not necessarily be indicative of long-term well performance or ultimate hydrocarbon recovery therefrom.

CORPORATE INFORMATION

BOARD OF DIRECTORS

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KD Angus Corp.
Calgary, Alberta

Allan K. Ashton
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Former Country President
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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

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James D. Reimer
Vice President, Exploration

Mary Kay Axford
Controller

Douglas T. McCartney
Partner, Burstall Winger LLP
Corporate Secretary

EXCHANGE LISTING

The Toronto Stock Exchange
Trading symbol for Common Shares: PPY

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Burstall Winger LLP

AUDITORS

KPMG LLP

BANKERS

National Bank of Canada
Alberta Treasury Branches
Canadian Imperial Bank of Commerce

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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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