PAINTED PONY PETROLEUM LTD.

2011 ANNUAL REPORT TO SHAREHOLDERS

ROOM TO GROW

Painted Pony Petroleum Ltd. was recognized as a TSX Venture 50® Company in 2012. TSX Venture 50 is a trade-mark of TSX Inc. and is used under license.

CORPORATE PROFILE

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

ANNUAL GENERAL AND SPECIAL MEETING

Painted Pony Petroleum Ltd. invites shareholders and interested parties to attend its Annual General and Special Meeting to be held in the Bennett Room at the Ranchmen's Club, 710 - 13th Avenue SW, Calgary, Alberta on Wednesday, June 6th, 2012 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.

TSX VENTURE 50®

The TSX Venture Exchange named Painted Pony as one of the 2012 TSX Venture 50, a ranking of strong performers listed on the TSX Venture Exchange. The TSX Venture 50 is comprised of 10 emerging companies in five industry sectors that have been identified as leaders in Canada's public venture market.

The TSX Venture 50® are the top 10 companies listed on the TSX Venture Exchange, in each of five major industry sectors - mining, oil & gas, technology & life sciences, diversified industries and clean technology - based on a ranking formula with equal weighting given to return on investment, market cap growth, trading volume and analyst coverage. All data was as of December 31, 2011.

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Cover painting "Deep in the Meadow" by Paul Van Ginkel (www.paulvanginkel.com)

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FINANCIAL AND OPERATING HIGHLIGHTS

	Year ended December 31, 2011	2010
Financial *($000s, except per share and shares outstanding)*		
Petroleum and natural gas revenue [1]	**73,936**	58,283
Funds flow from operations [2]	**44,150**	36,393
Per share - basic [3]	**0.74**	0.78
Per share - diluted [4]	**0.73**	0.77
Cash flows from operating activities	**44,884**	35,474
Comprehensive income	**6,542**	9,222
Per share - basic [3]	**0.11**	0.20
Per share - diluted [4]	**0.11**	0.19
Capital expenditures [5]	**162,868**	124,104
Working capital (deficiency)	**68,291**	(1,205)
Total assets	**478,656**	244,579
Shares outstanding		
Class A	**69,693,027**	51,016,700
Class B	**-**	1,173,600
Diluted weighted-average shares	**60,829,382**	49,503,521
Operational		
Daily sales volumes		
Oil *(bbls per day)*	**1,460**	1,667
Condensate *(bbls per day)*	**54**	28
NGL's *(bbls per day)*	**108**	34
Gas *(mcf per day)*	**15,589**	6,718
Total *(boe per day)*	**4,221**	2,848
Realized prices		
Oil *(per bbl)*	**$ 93.07**	$ 77.84
Gas *(per mcf)*	**$ 3.60**	$ 3.94
Field operating netbacks		
British Columbia *(per boe)*	**$ 14.12**	$ 12.35
Saskatchewan *(per boe)*	**$ 58.34**	$ 54.81
Company combined *(per boe)*	**$ 31.34**	$ 37.88
Wells drilled [6]		
Gross	**42**	51
Net	**29.3**	34.9
Net success rate	**90%**	92%

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, and after the deemed conversion of the Class B shares to Class A shares, consistent with the calculations of earnings per share.*
3. *Basic per share information is calculated on the basis of the weighted average number of Class A shares outstanding in the period.*
4. *Diluted per share information reflects the potential dilution effect of options and the convertible Class B shares, each of which may be anti-dilutive. Comprehensive income is adjusted for the amount of finance expense applicable to the Class B shares for the period. The conversion of Class B shares into Class A shares, if dilutive, is computed by dividing $10 by the greater of $1.00 and the Current Trading Price, defined as the weighted average trading price of the Class A shares for the last 30 consecutive trading days.*
5. *Including decommissioning obligations and share-based payments.*
6. *Includes 3 (0.6 net) joint venture wells in 2011 and 6 (1.2 net) joint venture wells in 2010 where Painted Pony was carried for drill and complete costs.*

2011 ANNUAL REPORT TO SHAREHOLDERS

TO OUR SHAREHOLDERS

The year 2011 was marked by pivotal change and large swings in the commodity pricing structure of the North American oil and gas industry. Commodities started the year strongly, with oil rising to over $110 per barrel in the spring. This rally was followed by a decline to almost $70 per barrel in October, returning to $100 per barrel at year-end. North American natural gas prices have weakened due to continued shale gas drilling in the United States, which, in conjunction with the warmest winter in over a decade, has led to a large oversupply. Gas that sold for more than $4.00 per mcf in the spring closed the year at $3.00 per mcf, and has since plummeted to less than $2.00 per mcf in early 2012. Against this backdrop, Painted Pony has continued its adherence to a conservative fiscal strategy, providing us with the stability and flexibility to react to these fluctuations.

The recent weakness in gas markets has created an unprecedented interest in value-added ventures among many of Canada's explorers and producers. The opportunities to participate directly in innovative energy projects such as liquefied natural gas export facilities, gas-to-liquids conversion and power co-generation are increasingly attractive, as these businesses offer the potential to add significant value beyond basic gas production and processing.

Painted Pony is working hard to become an industry leader in the value-added gas business. One of our primary goals is to leverage upon our massive and ideally-located Montney gas asset in northeastern British Columbia. In this regard, we have become a founding member of the Douglas Channel BC LNG Co-operative. The BC LNG project, located in Kitimat, British Columbia, has received its necessary export permits and is slated to commence LNG exports in the first half of 2014. Painted Pony continues to evaluate a formal commitment to be a gas supplier to this project.

The Company will continue to adapt to changing market conditions. We have redirected our capital to expand our light oil exploration and development program in the face of an oversupply of natural gas. We enjoyed further successes on our Saskatchewan Bakken oil projects, particularly at Flat Lake. We are pleased to report that several recent Flat Lake discoveries have proven up a major new Bakken trend, which is expected to provide several years of development drilling inventory. In addition, Painted Pony has expanded its oil exploration program into Alberta. During the year, we gained access to approximately 22 sections of mineral rights targeting a regional Viking light oil play. We drilled our first well on this play in the first quarter of 2012, with completion results expected immediately after breakup. Our focus on investing in high return projects will provide balance to our reserves and production mix.

Our successes in 2011 were achieved through the efficient use of capital funds, which were employed to maximize value creation, and which resulted in significant increases in incremental value to shareholders. With the drilling of 42 (29.3 net) wells, with a 90% net success rate, we increased total proved plus probable reserves by 321% from 32,539 mboe to 136,877 mboe, with an associated increase in net present value, discounted at 10 percent, of 200% to $1.06 billion. Results from the Company's Montney gas project continue to be very encouraging, including the drilling of one of the best wells on the Montney gas trend at our Diaber d-44-C pad. This 50% working interest well was flow tested at 24.5 mmcf/d in September 2011, and was subsequently brought on production at 17.7 mmcf/d in February 2012. In addition to reserves increases, daily average production grew by 48% to average 4,221 boe/d in 2011. With further production gains, our first quarter of 2012 production is estimated to increase to an average of 7,000 boe/d.

Because of the Company's disciplined financial management, we continue to be in the unique and fortunate position of maintaining a high degree of financial flexibility. Over the course of 2011, we raised a total of $183.9 million in two separate bought-deal equity financings. The Company exited the year with positive working capital of $68.3 million and an undrawn demand credit facility of $80 million. Our strong balance sheet allows the Company to control the pace of development of its resource opportunities, and to focus on maximizing value from future capital expenditures.

TO OUR SHAREHOLDERS

As Painted Pony looks ahead to 2012, the Company has expanded its Viking light oil exploration program through the execution of a second farm-in agreement on the Wimborne project, providing access to an additional 11 net sections of land. Painted Pony has committed to drill and complete one additional 100% Viking well on these lands. Throughout the balance of 2012, our capital plans call for the drilling of a total of 26 (18.1 net) wells, including 23 (14.2 net) targeting light oil projects. We will adjust our capital expenditures on the Montney play as commodity pricing indicates in order to maximize the value of the asset for shareholders, with the goal of supplying BC LNG export volumes two years hence. We look forward with excitement and anticipation to the first results from our Viking light oil play as we continue to develop additional new exploration concepts.

We have consistently delivered on our growth targets, posting a five year record of steady growth. We strive to maintain a balance of "resource-style" projects in both oil and natural gas. Our strategy is proven and our results speak to excellence in execution. For this, we thank our staff for their dedication and efforts throughout 2011. We also thank our shareholders for their continued support.

At Painted Pony, we truly have "Room to Grow".

On Behalf of the Board of Directors

Patrick R. Ward
President and Chief Executive Officer

April 24, 2012

The pessimist complains about the wind;
The optimist expects it to change;
The realist adjusts the sails.

~William Arthur Ward

2011 ANNUAL REPORT TO SHAREHOLDERS

REVIEW OF OPERATIONS

Painted Pony's operations are located in southeast Saskatchewan, central Alberta and northeast British Columbia. In Saskatchewan, the Company targets light oil from the Bakken and Mississippian formations and in British Columbia the Company targets natural gas from the unconventional Montney/Doig formation. In Alberta, the Company targets light oil from the Viking formation. Production volumes averaged 4,221 boe/d in 2011, up 48% over 2010. During the fourth quarter of 2011, production averaged 5,189 boe/d (weighted 32% oil and liquids and 68% gas).

Painted Pony's capital expenditures in 2011 were $162.9 million compared to $124.1 million in 2010. Exploration and development capital expenditures, including facilities and land costs totaled $146.9 million in the year 2011 compared to $108.9 million in 2010. The Company carried out an active capital program during 2011 with the drilling of 42 (29.3 net) wells at an overall net success rate of 90%. Property acquisitions in 2011 totaled $8.7 million compared to $11.0 million in 2010.

Painted Pony's land position continues to grow. Throughout 2011, the Company added lands in Saskatchewan, Alberta and British Columbia through participation at provincial lands sales, land swaps and acquisitions. Painted Pony's total land position at December 31, 2011 is 243,650 net acres, compared to 202,307 net acres at December 2010. At the end of 2011, the Company owned 81,213 net acres in Saskatchewan, 12,640 net acres in Alberta and 149,797 net acres in British Columbia, of which 92,263 net acres contain Montney rights.

Painted Pony's 2012 capital program is budgeted at $120 million for 2012, of which approximately 55% is directed towards oil projects. Under this revised budget, the Company plans to drill 29 (21.6 net) wells targeting light oil and 7 (4.1 net) wells targeting natural gas in 2012. The capital expenditures targeting natural gas are expected to result in significant reserve additions.

2011 ANNUAL REPORT TO SHAREHOLDERS

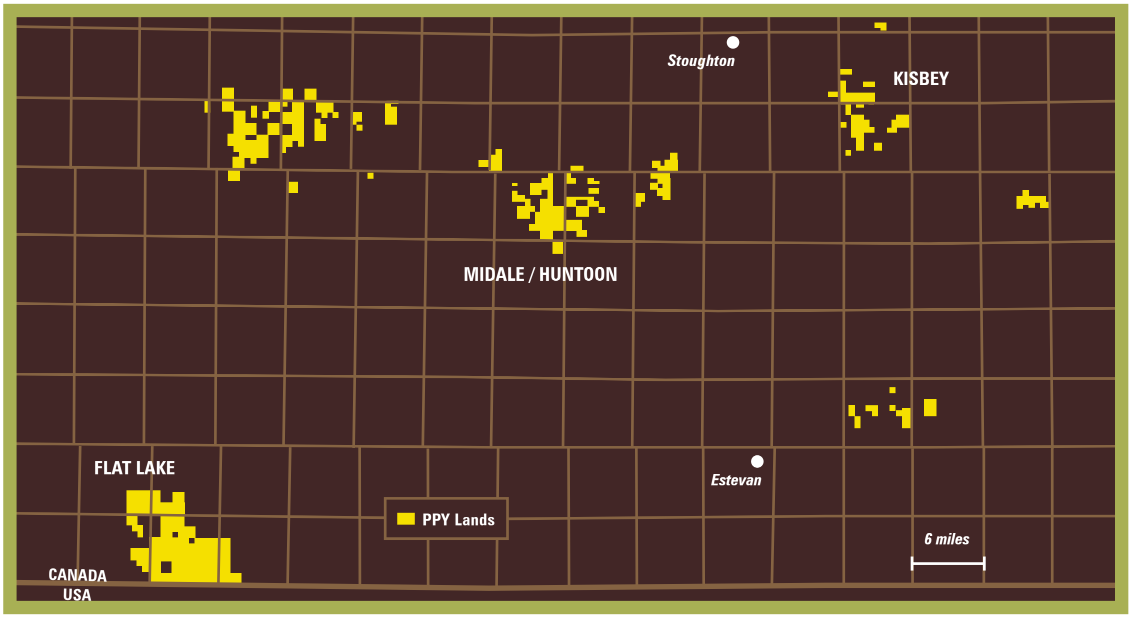
REVIEW OF OPERATIONS

SASKATCHEWAN

Painted Pony's operations in Saskatchewan are located in the general area of the town of Stoughton. The Company targets high netback, light sweet oil primarily from the Bakken formation, plus the Midale, Frobisher, Mississippian and Alida zones. The combination of technological advances, such as horizontal drilling and multi-stage fracture stimulation techniques, and provincial royalty incentive programs for horizontal drilling has encouraged the pursuit of this resource play. Extremely wet weather and resulting road bans and flooding during the second and third quarter of 2011 limited access to leases and hampered the ability to complete operations. Despite this, the Company continued to develop its Saskatchewan light oil program throughout 2011, enjoying success on the Flat Lake Bakken oil project. Several recent Flat Lake discoveries appear to have proved up a new Bakken trend, and are expected to provide several years of development drilling inventory.

During 2011, Painted Pony carried out an active drilling program in Saskatchewan participating in 29 (20.7 net) wells. Of these, 27 (19.2 net) were horizontal and 2 (1.5 net) were vertical wells targeting light oil in the Bakken and Mississippian formations. Operations are grouped into three main areas, based primarily on geographic proximity; Midale/Huntoon/Kisbey, Flat Lake, and Other. Within these geographic operational areas, 18 (13.7 net) wells were drilled in the Midale/Huntoon/Kisbey area, 4 (1.6 net) wells in the Flat Lake area and 7 (5.4 net) wells in Other areas. Production volumes in Saskatchewan averaged 1,644 boe/d (weighted 95% oil and liquids) for the 2011 year and 1,715 boe/d in the fourth quarter.

SOUTHEAST SASKATCHEWAN



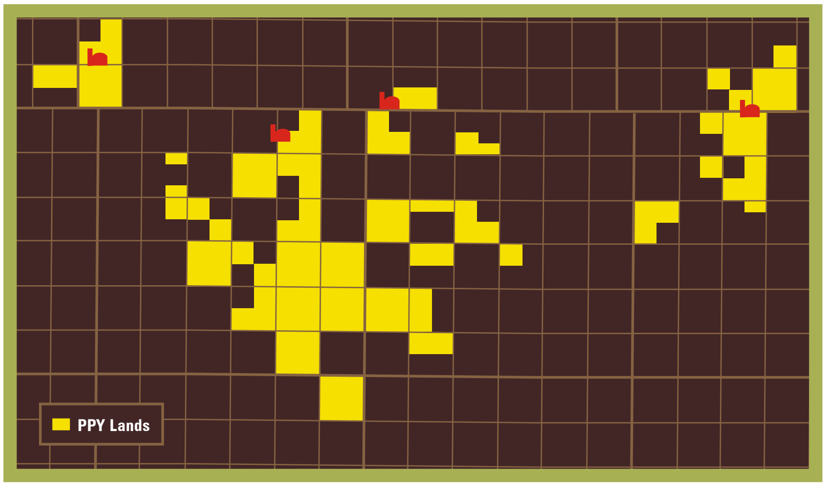
2011 ANNUAL REPORT TO SHAREHOLDERS

REVIEW OF OPERATIONS

Midale/Huntoon/Kisbey Area

The Midale/Huntoon/Kisbey area is located east of the town of Weyburn and produces 43 degree API light oil from the Bakken formation. Painted Pony operates in both the Midale and Huntoon areas, which are in close proximity to each other and together comprise the Corporation's main producing area in Saskatchewan. The Kisbey area, which is located approximately 15 miles to the east of Midale and Huntoon, is non-operated and has an average working interest of 25%.

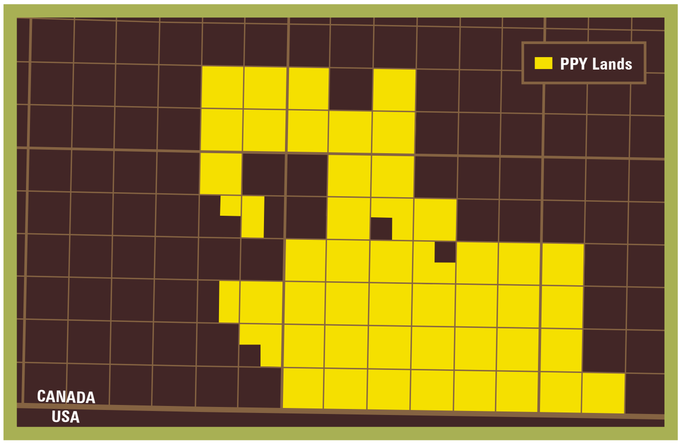
MIDALE/HUNTOON



As at December 31, 2011, Painted Pony held 15,480 net acres (24 net sections) of land in the Midale/Huntoon/Kisbey areas. In 2011, total sales from this area averaged 1,414 boe/d, weighted 95% oil and liquids. During 2011, Painted Pony drilled 13 (12.3 net) wells in the Midale/Huntoon area and participated in the drilling of 5 (1.4 net) wells in the Kisbey area. In 2012, the Company anticipates drilling 11 (9.3 net) wells on these lands.

Flat Lake Area

The Flat Lake area is located approximately 30 miles southwest of Weyburn, close to the U.S. border. Painted Pony entered the Flat Lake area through a farm-in agreement in 2010, followed by an acquisition in the first quarter of 2011 of 6,018 net acres and successful bids at a provincial land sale. As at December 31, 2011, the Company had accumulated a total of 13,668 net acres of land, or 21.4 net sections, at an average working interest of 46%. During 2011 Painted Pony drilled 4 (1.6 net) horizontal oil wells in the Flat Lake area. The Company plans to drill 10 (6.4 net) wells in the Flat Lake area during 2012.



FLAT LAKE

Other Areas

At December 31, 2011, Painted Pony had 52,065 net acres of land in Other Areas, primarily at Wapella and Weyburn. In 2011, the Company drilled 7 (5.4 net) wells on these lands, targeting Bakken, Frobisher and Mississippian zones.

2011 ANNUAL REPORT TO SHAREHOLDERS

REVIEW OF OPERATIONS

ALBERTA

In 2011, Painted Pony initiated exploration activity on new light oil plays in Alberta, targeting light Viking oil. By the end of the 2011 year, the Company owned 12,640 net acres of 100% working interest lands, or 19.8 net sections.

Wimborne

In the Central Alberta Wimborne area, through participating in provincial land sales, the Company has acquired 8,160 net acres (12.8 net sections) of primarily Crown lands. In the first quarter of 2012, Painted Pony executed a farm-in agreement on 10 additional net sections of Crown and freehold lands, also considered prospective in the Viking formation. Under the terms of the farm-in agreement, Painted Pony has committed to drill at least 1 (1.0 net) horizontal Viking well, subject to a non-convertible gross overriding royalty. In the first quarter of 2012, the first 100% working interest exploratory earning well was drilled on this play, with completion results expected after breakup.

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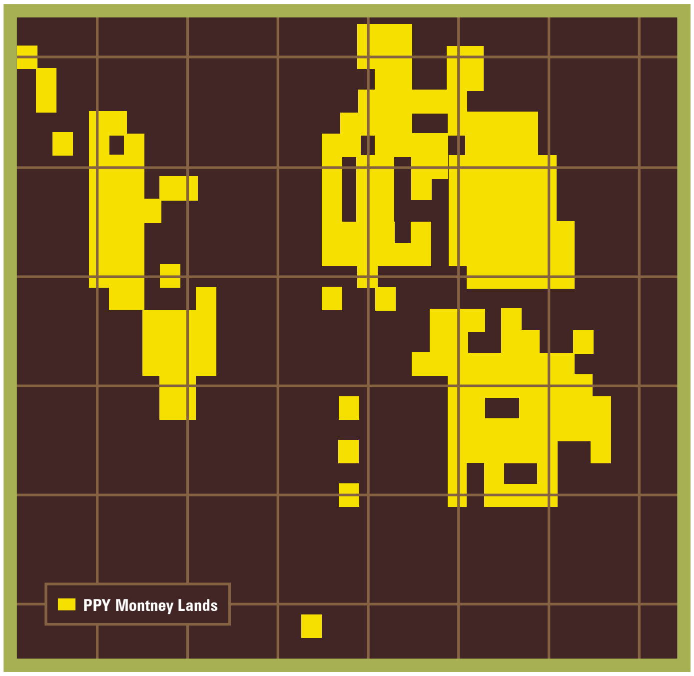
REVIEW OF OPERATIONS

BLAIR/CAMERON/CYPRESS

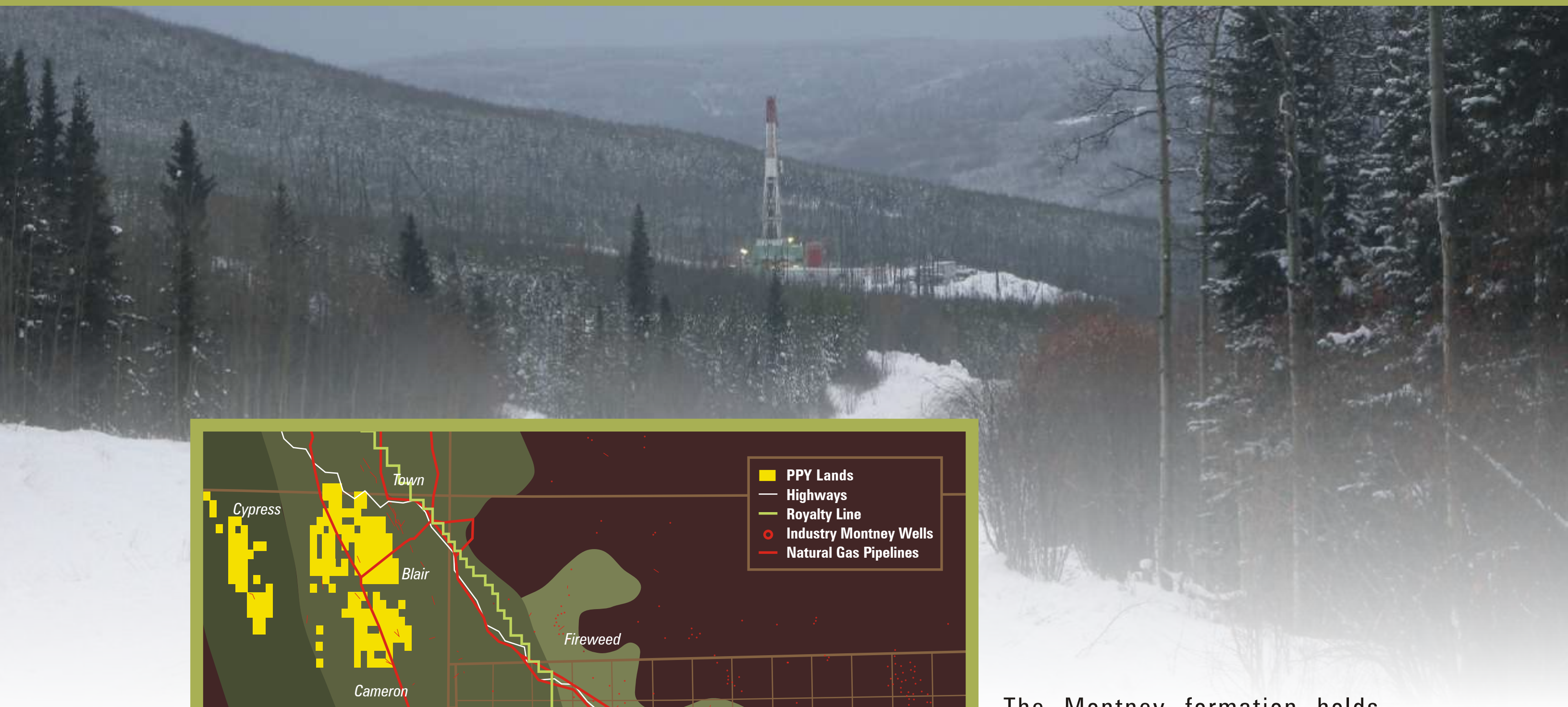


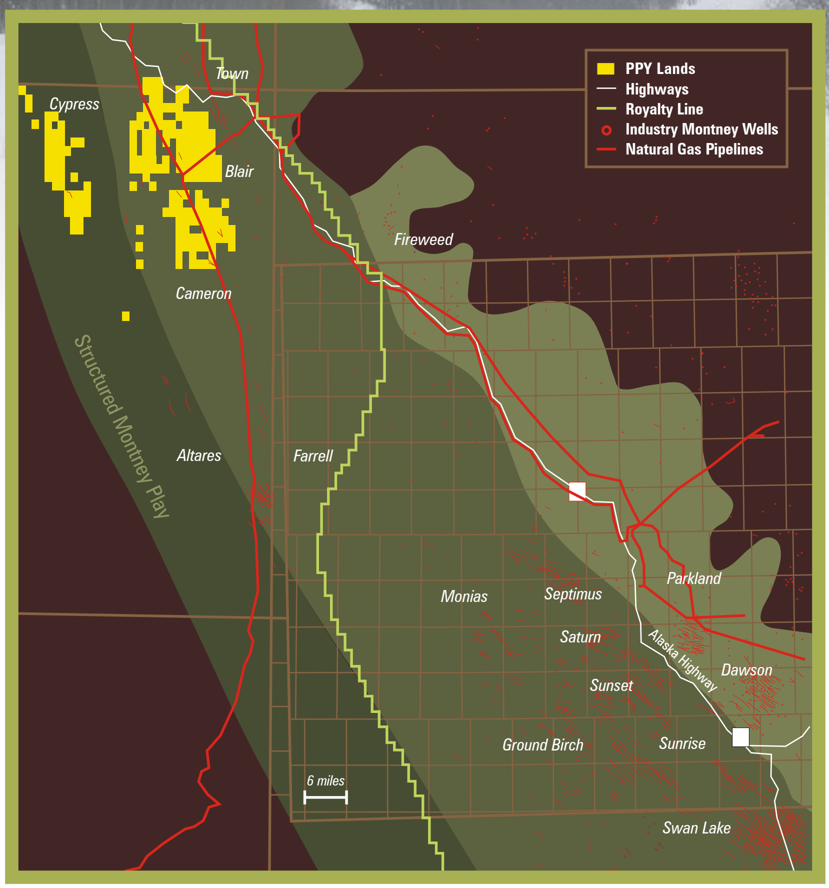
BRITISH COLUMBIA

Since 2009, industry activity on the Montney play has accelerated, with numerous successful wells drilled by various operators. The Montney reservoirs on and adjacent to the Company's acreage are thick (more than 300 meters) gas-charged and over-pressured. Gas in the area is produced through gathering systems that are owned in part by the Company, and processed and transported through facilities owned by third-party midstream companies. Play economics have been enhanced by improvements to the British Columbia provincial royalty incentive programs.

2011 ANNUAL REPORT TO SHAREHOLDERS

REVIEW OF OPERATIONS





The Montney formation holds significant reserves which can be recovered by applying advanced horizontal multi-stage fracture stimulations. The Montney formation is informally subdivided into the upper, middle and lower zones, with each zone being prospective for gas drilling development.

The Company's operations in northeast British Columbia are located north of Fort St. John near mile post 132 on the Alaska Highway. The area is prospective for natural gas from multiple zones, including the Montney, Halfway, Gething, Bluesky, Cadomin and Buckinghorse formations.

During 2011, the Company participated in the drilling of 13 (8.6 net) wells, all of which targeted the Montney formation. Operations are grouped into three main areas, based primarily on geographic proximity: Blair / Town, Cameron / Kobes, and Other (which is primarily the Cypress area). Within these geographic operational areas, 12 (7.6 net) wells were horizontally drilled in 2011 by the Company on the Cameron / Kobes and Blair / Town land blocks and one vertical well (1.0 net) was located in the Other (Beg) area.

At December 31, 2011, Painted Pony had 149,797 net acres of land in British Columbia, of which 92,263 net acres contain Montney rights. Sales volumes in British Columbia averaged 2,577 boe/d, weighted 98% gas, for the 2011 year, with production rates averaging 3,473 boe/d in the fourth quarter.

2011 ANNUAL REPORT TO SHAREHOLDERS

REVIEW OF OPERATIONS

CAMERON/KOBES

Cameron/Kobes

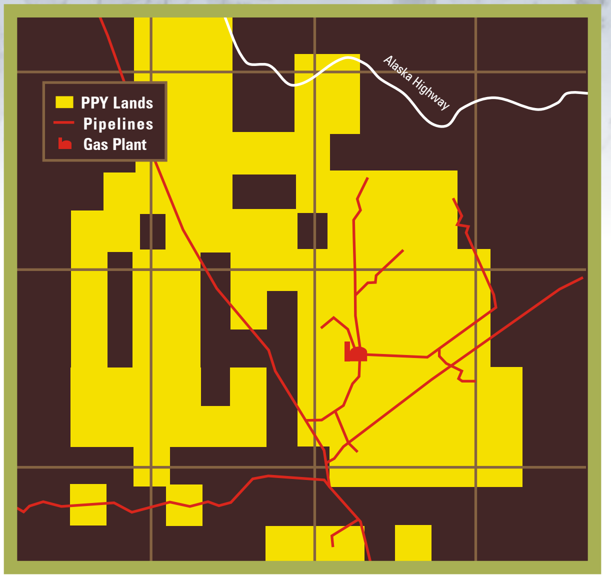
The Cameron/Kobes block is comprised of the Kobes, Gundy and Diaber strike areas. In 2011, Painted Pony participated in the drilling of a total of 4 (1.1 net) Montney wells.

On the Cameron/Kobes block, under the terms of a farm-out agreement struck in 2008 with a senior oil and gas producer, Painted Pony was carried for the drilling and completion costs for 3 (0.6 net) horizontal wells drilled in 2011, which completed the earning obligations. At the end of 2011, Painted Pony had 25,214 net acres of land in the Cameron/Kobes area, of which 11,145 net acres contain Montney rights at an average working interest of 27%. All earning wells were tied in and placed on production by year-end.

At Diaber, Painted Pony drilled 1 (0.5 net) well targeting the lower Montney formation. This well was subsequently completed and flow tested at rates up to 24.5 MMcf/d, making it the Company's most successful Montney well to-date and one of the most prolific wells on the entire Montney gas trend. In February 2012, this well was tied into the sales line through a newly constructed processing facility with a current throughput capacity of 25 MMcf/d, constructed and operated by Painted Pony. A further 2 (1.0 net) wells were subsequently drilled from this pad over year-end and into the first quarter of 2012, and await completion.

Sales from this area in 2011 averaged 1,058 boe/d (99% gas), with fourth quarter sales averaging 1,213 boe/d.

BLAIR/TOWN



Blair/Town

On the Blair/Town block, Painted Pony commenced drilling operations targeting the Montney gas formation in the first quarter of 2010. During 2011, 8 (6.5 net) horizontal wells were drilled at Blair/Town; with 3 (2.5 net) targeting the upper Montney, 4 (3.5 net) targeting the lower Montney and 1 (0.5 net) targeting the middle Montney. All wells were successful and tied in to existing infrastructure. The Company continues to develop all three intervals within the Montney in order to quantify the resource in-place and contribute towards de-risking the total land block.

At the end of 2011, Painted Pony had 91,648 net acres of land in the Blair/Town area, of which 63,759 net acres contain Montney rights at an average working interest of 92%. Sales averaged 1,484 boe/d (97% gas) from the area during 2011, and 2,257 boe/d during the fourth quarter. During 2012, Painted Pony plans to drill 2 (2.0 net) additional Montney wells at Blair/Town.

REVIEW OF OPERATIONS

Cypress

At Cypress, the Montney zone is structurally complex due to tectonic thrusting in this region. As a result, development of this block will proceed at a more cautious pace to limit capital risk. Due to the natural fracturing of the rock, this area may be tested and developed vertically. Late in 2011, Painted Pony acquired additional lands from a working interest partner, bringing total Montney land holdings in the Cypress area to 16,436 net acres, at an average working interest of 47%. Sales from this area ceased in late June 2011 after a third party pipeline was shut-in for repairs.

LNG EXPORT CO-OPERATIVE

The recent weakness in gas markets, in tandem with a general bearish medium-term view, has created an unprecedented interest in value-added ventures among many of Canada's explorers and producers. The opportunity to directly participate in innovative energy projects such as LNG (Liquefied Natural Gas) export facilities, GTL (Gas-to-Liquids) conversion or power co-generation is increasingly attractive, as these businesses offer the potential to add significant value beyond basic gas production and processing.

Painted Pony is working hard to become an industry leader in the value-added gas business. One of Painted Pony's goals is to leverage upon the Company's ideally-located Montney gas asset in northeast British Columbia. In this regard, the Company is a founding member of the Douglas Channel BC LNG project. The BC LNG CO-OP project, to be located in Kitimat, British Columbia, has received its necessary export permits and is slated to commence LNG exports in the first half of 2014. Painted Pony continues to evaluate a formal commitment to be a gas supplier to this project.

REVIEW OF OPERATIONS

LAND HOLDINGS

Painted Pony focuses on identifying potentially prospective new areas where the Company can aggregate an acreage position on a cost effective basis. When Painted Pony commenced operations in May of 2007, the Company had no land, but had access to two large blocks of land in Saskatchewan through farm-in agreements. In 2008, the Company acquired producing properties and undeveloped lands in British Columbia. Since that time, Painted Pony has grown its net land position in both provinces by a combination of earning lands through farm-in agreements, freehold leasing, participating in Crown land sales and land sales and swaps with industry participants. Competition for land in both Saskatchewan and British Columbia from other larger industry competitors intensified and, in many areas, prices escalated. By December 31, 2010, the Company's net land acres totaled 125,192 in British Columbia, and 77,115 in Saskatchewan.

In Saskatchewan in 2011, Painted Pony completed an acquisition of 6,018 net acres of land at its core area at Flat Lake, and continued to aggregate acreage on its other core Saskatchewan properties. In British Columbia, the Company executed its strategy of further consolidating the Blair/Town block with the completion of a strategic swap with an industry competitor, gaining 5,882 net acres of undeveloped land. Painted Pony also acquired 8,427 net acres of additional Montney mineral interests at Cypress, adding to the Company's holdings on the block. Additional Saskatchewan and British Columbia lands were added by way of strategic purchases, acquisitions at Crown land sales, freehold leasing and executing on farm-in agreements.

At December 31, 2011, Painted Pony's land position totaled 243,650 net acres in Saskatchewan, Alberta and British Columbia.

As at December 31, 2011, Painted Pony's detailed land position is as follows:

Summary of Land *(acres)*

	Undeveloped		Developed		Total	
	Gross	Net	Gross	Net	Gross	Net
Saskatchewan						
Midale/Huntoon/Kisbey	18,858	12,641	4,285	2,839	23,143	15,480
Flat Lake	28,905	13,448	680	220	29,585	13,668
Other	51,048	49,427	4,220	2,638	55,268	52,065
	98,811	75,516	9,185	5,697	107,996	81,213
British Columbia						
Blair/Town	88,688	75,214	30,057	16,434	118,745	91,648
Cameron/Kobes	58,927	21,279	9,933	3,935	68,860	25,214
Other	44,589	23,662	16,944	9,273	61,533	32,935
	192,204	120,155	56,934	29,642	249,138	149,797
Alberta						
Wimborne	8,160	8,160	-	-	8,160	8,160
Other	4,480	4,480	-	-	4,480	4,480
	12,640	12,640	-	-	12,640	12,640
Total	303,655	208,311	66,119	35,339	369,774	243,650

The Company continues to proactively address expiries on its core operating areas. The majority of expiries in Saskatchewan are related to non-core holdings. In northeast British Columbia all expiries are expected to be continued.

As at December 31, 2011, in a report prepared by Seaton-Jordan and Associates Ltd. ("Seaton-Jordan"), the Company's undeveloped land in Saskatchewan, British Columbia and Alberta was valued at $179.8 million. Seaton-Jordan's assessment of the Company’s lands was prepared in accordance with National Instrument 51-101 - Standards of Disclosure for Oil and Gas Activities ("NI 51-101").

2011 ANNUAL REPORT TO SHAREHOLDERS

RESERVES

The Reserves Sub Committee is comprised of independent board members appointed by the Board of Directors of Painted Pony. In accordance with its mandate, this committee has reviewed the Company reserves, which is based on independent evaluations by GLJ Petroleum Consultants Ltd. ("GLJ") and Sproule Associates Limited ("Sproule") each with an effective date of December 31, 2011 as contained in a consolidated report of GLJ dated March 6, 2012 (the "Painted Pony Reserve Report").

The tables below summarize Painted Pony's crude oil, natural gas liquids ("NGL") and natural gas reserves and the net present values of future net revenue attributable to such reserves as evaluated in the Painted Pony Reserve Report, based on GLJ's January 1, 2012 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 Reserve Report by consolidating the GLJ evaluation with the Sproule evaluation, all run on the GLJ pricing and cost assumptions.

The Painted Pony Reserve Report was prepared utilizing definitions as set out under NI 51-101. This instrument adopted by the Canadian Securities Administrators, sets out standards of disclosure for oil and gas activities and mandates the application of evaluation standards defined in the Canadian Oil and Gas Evaluation Handbook (COGEH). The information that follows has been derived from the Painted Pony Reserve Report. The estimates of reserves are subject to revisions as additional reservoir and performance information becomes available, and contains judgements of future events for which the actual results may vary materially. The reader is referred to the Company's Statement of Reserves Data and Other Oil and Gas Information, which will be filed before the end of April 2012 on the Company's website and on www.sedar.com. The Annual Report contains extracts of Painted Pony's reserves only.

At December 31, 2011 the Company's proved plus probable working interest reserves were 136,877 mboe compared to 32,539 mboe at December 31, 2010, an increase of 321%. At December 31, 2011, Painted Pony's total proved working interest reserves were 31,383 mboe, compared to 11,336 mboe at December 31, 2010.

Summary of Company Reserves[(1),(3),(5)]
Forecast Prices and Costs

	As at December 31, 2011				As at December 31, 2010
	Natural gas [(4)] (mmcf)	Light and medium oil (mbbl)	Natural gas liquids (mbbl)	Total (mboe [(2)])	Total (mboe [(2)])
Proved					
Developed producing	**38,620**	**2,024**	**808**	**9,269**	4,477
Developed non-producing	**10,673**	**50**	**188**	**2,017**	48
Undeveloped	**102,892**	**837**	**2,113**	**20,098**	6,811
Total proved	**152,186**	**2,911**	**3,108**	**31,383**	11,336
Probable	**549,875**	**2,188**	**11,660**	**105,494**	21,203
Total proved plus probable	**702,060**	**5,099**	**14,768**	**136,877**	32,539

Notes:
(1) Painted Pony's total working interest reserves are before royalties owned by others.
(2) Oil equivalent amounts (boe) have been calculated using a conversion rate of six thousand cubic feet of natural gas per barrel of oil (6 mcf: 1 bbl).
(3) One thousand barrels is equal to 1 mbbl, and one thousand boe is equal to 1 mboe. One million cubic feet of natural gas is equal to 1 mmcf.
(4) Includes non-associated gas, associated gas and solution gas
(5) Numbers in this table are subject to rounding error

"Gross" reserves (being working interest reserves, excluding royalty interest reserves, before deduction of royalty burdens payable) are disclosed. The Painted Pony Reserve Report was prepared utilizing definitions as set out under NI 51-101.

RESERVES

NET PRESENT VALUE OF FUTURE NET REVENUE

In the Painted Pony Reserve Report, the net total future development costs ("FDC") associated with the proved plus probable reserves is $1,027.3 million, an increase of $780.3 million from 2010, over the life of the reserves. Of the FDC expenditures included in the Painted Pony Reserve Report for proved plus probable reserves, approximately 20% or $204.6 million is expected to be incurred in 2012 and 2013, with the remainder expected to be invested through 2018. An incremental $105.8 million of future development costs are associated with the proved reserves.

Summary of Net Present Values of Future Net Revenue (1),(2),(3),(4)
Forecast Prices and Costs *($ millions)*
Before Income Taxes

	As at December 31, 2011					As at December 31, 2010	
	0%	5%	8%	10%	15%	0%	10%
Proved							
Developed producing	**239**	**191**	**171**	**160**	**139**	145	108
Developed non-producing	**50**	**34**	**28**	**26**	**21**	-	-
Undeveloped	**408**	**243**	**185**	**157**	**107**	123	49
Total proved	**697**	**468**	**385**	**343**	**267**	268	157
Probable	**2,660**	**1,279**	**892**	**719**	**444**	485	197
Total proved plus probable	**3,358**	**1,747**	**1,277**	**1,062**	**711**	753	354

Notes:

(1) Painted Pony's total working interest reserves are before royalties owned by others. The estimated future net revenues are stated before deducting income taxes and future estimated site restoration costs and are reduced for estimated future abandonment costs, the Saskatchewan Capital Tax and estimated capital for future development associated with the reserves.

(2) It should not be assumed that the undiscounted and discounted net present values represent the fair market value of the reserves.

(3) The price deck used for the evaluation as at December 31, 2011 was the GLJ price deck dated January 1, 2012.

(4) Numbers in this table are subject to rounding error.

Summary of Pricing and Inflation Rate Assumptions
Forecast Prices and Costs
As at December 31, 2011

	WTI Cushing Oklahoma *($US/bbl)*	Edmonton Par price 40° API light crude oil *($Cdn/bbl)*	AECO-C Spot *($Cdn/mmbtu)*	Edmonton Pentanes Plus *($Cdn/bbl)*	Inflation rate *(%/year)*	Exchange rate *($US/$Cdn)*
2012	97.00	97.96	3.49	107.76	2.0	0.98
2013	100.00	101.02	4.13	108.09	2.0	0.98
2014	100.00	101.02	4.59	105.06	2.0	0.98
2015	100.00	101.02	5.05	105.06	2.0	0.98
2016	100.00	101.02	5.51	105.06	2.0	0.98
2017	100.00	101.02	5.97	105.06	2.0	0.98
2018	101.35	102.40	6.21	106.49	2.0	0.98
2019	103.38	104.47	6.33	108.65	2.0	0.98
2020	105.45	106.58	6.46	110.84	2.0	0.98
2021	107.56	108.73	6.58	113.08	2.0	0.98
Thereafter	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	2.0	0.98

RESERVE LIFE INDEX

The reserve life index is calculated by dividing reserves as at the effective date of the Painted Pony Reserve Report (December 31, 2011) by the production during the applicable period, and represents a measure of the amount of time production could be sustained at the production rates based on the reserves at the applicable point in time. Based upon the year-end reserve volumes and the fourth quarter 2011 annualized production rate for Painted Pony, sufficient reserves exist to continue production at that rate for approximately 71.7 years based on proved plus probable reserves, and approximately 16.4 years based on proved reserves.

Reserve Life

Years	Proved	Proved and probable
Natural gas	19.6	90.2
Crude oil and NGLs	9.8	32.5
Total boe	16.4	71.7

PRODUCTION REPLACEMENT RATIO

The production replacement ratio measures the number of times the fourth quarter's annualized production has been replaced by net reserve additions. The 2011 production replacement ratio reflects the significant increase in reserve volumes from the Company's British Columbia Montney gas program.

	2011	2010
Proved basis	**11.3x**	6.7x
Proved plus probable basis	**55.5x**	21.4x

Net present value of future net revenue does not represent fair market value of the reserves. There is no assurance that the forecast prices and cost assumptions will be attained and variances could be material.

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following Management's Discussion and Analysis ("MD&A") of the consolidated financial results as provided by the management of Painted Pony Petroleum Ltd. ("Painted Pony" or the "Company") should be read in conjunction with the annual consolidated financial statements and related notes for the years ended December 31, 2011 and December 31, 2010. This commentary is dated March 28, 2012.

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

DESCRIPTION OF COMPANY

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

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.

The Class A shares of Painted Pony trade on the TSX Venture Exchange under the symbol "PPY.A". Effective December 1, 2011, the Class B shares of Painted Pony were converted to Class A shares, and, as such, the Class B shares were de-listed on the TSX Venture Exchange.

NON-GAAP MEASURES

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

(000s)

Years ended December 31,	2011	2010
Cash flows from operating activities	**$ 44,884**	$ 35,474
Changes in non-cash working capital	**(922)**	819
Decommissioning expenditures	**188**	100
Funds flow from operations	**$ 44,150**	$ 36,393

2011 ANNUAL REPORT TO SHAREHOLDERS

MANAGEMENT'S DISCUSSION AND ANALYSIS

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

FORWARD-LOOKING STATEMENTS

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

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

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

- *volumes in 2012 will be increasingly weighted towards gas than in 2011 as success from operations targeting the Montney formation in British Columbia could add incremental volumes;*
- *generally in 2012, the Company will receive an oil price approximately 2% less than the Edmonton par reference price, except for the February to June 2012 period when the differential to the Edmonton light price is expected to temporarily widen to range between $7 and $20 per bbl due to market conditions. If successful, sales of oil from the Company's new Alberta exploration play could also vary the price received compared to the reference price;*
- *the Company will receive a natural gas price equivalent to the AECO daily spot price;*
- *overall royalties in 2012 will approximate 12% of total revenues, assuming similar commodity prices to the year ended December 31, 2011;*
- *average per unit operating and transportation costs in 2012 are expected to be less than 2011 due to incremental gas sales volumes and reduced repairs and maintenance in Saskatchewan although tempered by weather-related impacts;*
- *net general and administrative costs will be reflective of capital expenditure levels throughout 2012;*
- *as gross Saskatchewan sales revenues fluctuate in 2012, the Saskatchewan resource surcharge is expected to vary accordingly;*

- *certain leases that are approaching expiry in British Columbia will be continued through execution of work programs;*
- *the capital program will be adjusted if necessary to support the objective of maintaining a net debt to funds flow from operations ratio of one times or less;*
- *the Company has sufficient financial resources with which to conduct its capital program; further, this is subject to the additional assumption that the drilling rigs, field service providers, completion and tie-in equipment will be available as required and that the costs of securing such services and equipment will not materially exceed expectations;*
- *available credit facilities may be utilized on a periodic basis in 2012;*
- *there can be no assurance that the amount of the available demand credit facility will not be decreased at the next review;*
- *the total minimum tolls for transportation of oil through a major carrier system is estimated to be $2.3 million;*
- *a ten-year take-or-pay agreement for minimum gas gathering and processing fees is estimated to begin in July 2012 and is estimated to total $23.8 million over the ten year period, to a total maximum volume of 52.925 Bcf of gas;*
- *office space rentals and a proportionate share of operating costs through 2015 is estimated to total $1.6 million; and*
- *the risk of accounts receivables 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 document and such information should not be relied upon as representing the Company's views as of any date subsequent to the date of this document. The Company has attempted to identify important factors that could cause actual results, performance or achievements to vary from those current expectations or estimates expressed or implied by the forward-looking statements contained here-in. However, there may be other factors that cause results, performance or achievements not to be as expected or estimated and that could cause actual results, performance or achievements to differ materially from current expectations. Other risks and uncertainties include, but are not limited to, the following:

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

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

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

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

BOE PRESENTATION

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

COMPREHENSIVE INCOME AND FUNDS FLOW FROM OPERATIONS

Painted Pony generated funds flow from operations of $44.2 million for the year ended December 31, 2011, compared to $36.4 million for the year ended December 31, 2010. On a basic per share basis, funds flow from operations for the years ended December 31, 2011 and 2010 were $0.74 and $0.78, respectively, and on a diluted basis, funds flow from operations was $0.73 and $0.77 per share, respectively, for the two years.

Cash flow from operating activities was $44.9 million for the year ended December 31, 2011, compared to $35.5 million for the year ended December 31, 2010.

Painted Pony produced comprehensive income of $6.5 million in the year ended December 31, 2011, compared to $9.2 million earned during the year ended December 31, 2010. Basic and diluted income per share are $0.11 for the year ended December 31, 2011, compared to basic income per share of $0.20 and diluted income per share of $0.19 for the year ended December 31, 2010.

SALES VOLUMES

During the year ended December 31, 2011, Painted Pony's sales volumes increased 48%, to average 4,221 boe per day compared to 2,848 boe per day for the year ended December 31, 2010. The increase is primarily from incremental gas sales in British Columbia. In the year ended December 31, 2011, 39% of total volumes were from Saskatchewan, compared to 60% in the year ended December 31, 2010.

Sales volumes in 2011 were weighted 62% towards gas compared to 39% in 2010, reflecting the focus of the capital program towards British Columbia gas producing assets. All of Painted Pony's light oil sales originate from Saskatchewan operations while 93% of the sales of gas, condensate and NGL's are from British Columbia.

Average Daily Sales Volumes

Years ended December 31,	2011	2010
Oil *(bbls/d)*	**1,460**	1,667
Condensate *(bbls/d)*	**54**	28
NGL's *(bbls/d)*	**108**	34
Gas *(mcf/d)*	**15,589**	6,718
Total *(boe/d)*	**4,221**	2,848

Daily oil sales volumes in 2011 decreased by 12% compared to the year ended December 31, 2010 and gas sales increased by 132% year over year, reflecting the significant success of the Montney drilling program.

Saskatchewan operations and production volumes were negatively impacted during the second and third quarters of 2011 due to an unusually wet and extended spring break-up. Company oil production was temporarily shut-in due to road bans and flooding, field operations were delayed and sales of gas and liquids from the Huntoon area ceased for several months due to non-operated plant scheduled and unscheduled repairs and maintenance. Normal activity resumed late in the third quarter of the year.

In British Columbia, gas sales from the Cameron/Gundy area were shut-in for 21 days during the second quarter of 2011 for the scheduled McMahon gas processing plant turn-around. The Company anticipates sales volumes in 2012 to be increasingly weighted towards gas sales, as success from operations targeting the Montney formation in British Columbia add incremental volumes.*

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

REVENUES

Petroleum and natural gas sales increased 27% to $73.9 million in the year ending December 31, 2011, compared to $58.3 million for the year ended December 31, 2010. During 2011, oil sales revenues were 67% of total sales dollars compared to 81% in the year ended December 31, 2010, while oil volumes were 35% and 59% in the years ended December 31, 2011 and 2010, respectively. In both years, oil sales contributed disproportionately more to total sales dollars compared to volumes, reflecting the relative strength of crude oil prices compared to gas prices.

Sales by Product (000s)

Years ended December 31,	2011	2010
Oil	**$ 49,615**	$ 47,361
Gas	**20,464**	9,662
Condensate	**1,813**	757
NGL's	**2,044**	503
Total	**$ 73,936**	$ 58,283

Crude oil revenue in the year ended December 31, 2011 was $49.6 million compared to $47.4 million during the year ended December 31, 2010. Oil revenues increased 5% from the year ended December 31, 2010 to the year ended December 31, 2011. Oil prices averaged $93.07 per bbl during 2011 compared to $77.84 per bbl during 2010. Painted Pony received an average crude oil price 2% less than the Edmonton light reference price in both 2011 and 2010. Painted Pony's light oil is a premium light crude with low sulfur content. The change in oil revenues year over year was the net result of a 20% stronger commodity price partially offset by a reduction in volumes of 12%.

Revenue from gas sales totaled $20.5 million during the year ended December 31, 2011, compared to $9.7 million received during the year ended December 31, 2010. The Company received an average gas price of $3.60 per mcf in the year ended December 31, 2011, 1% less than the AECO daily spot average gas reference price of $3.63 per mcf. In the year ended December 31, 2010, the Company received an average gas price of $3.94 per mcf, again 1% less than the reference price. The change in gas revenues year over year was the net result of increased gas volumes of 132% partially offset by a decrease in the average gas price of 9%. Gas prices have continued to be very weak in North America throughout the year 2011.

Revenues from condensate and NGL sales totaled $3.9 million during the year ended December 31, 2011, compared to $1.3 million received during the year ended December 31, 2010, primarily from increased sales volumes of 161%, as increased gas sales have been accompanied by incremental liquids volumes. Approximately one-third of the Company's 2011 liquids sales are condensate, which received an average price 4% less than the Edmonton light reference price. For the balance of the liquids sales, NGL's, the average price received was 54% of Edmonton light.

In 2012, the Company generally expects to receive an average oil price approximately 2% less than the Edmonton par reference price, reflecting the prices currently paid for crude oil in Saskatchewan, where the Company tends to deliver the bulk of its oil production. However, this differential is expected to temporarily widen to range between $7 and $20 per bbl during the February to June 2012 period due to market conditions. If successful, sales of oil from the Company's new Alberta exploration play may also vary the price received compared to the reference price. The Company expects to receive a natural gas price equivalent to the AECO daily spot price. The average prices reported for Painted Pony's sales are the weighted net price, which is reflective of month to month price and sales volume changes.*

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

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

Average Benchmark Prices

Years ended December 31,	2011	2010
Exchange rate *(US$/Cdn$)*	**1.0116**	0.971
Gas - AECO, daily spot *($/mcf)*	**3.63**	4.00
Oil - WTI *(US$/bbl)*	**95.11**	79.61
- Edmonton par - light oil *($/bbl)*	**95.58**	77.88

Painted Pony's Realized Prices

Years ended December 31,	2011	2010
Gas *($/mcf)*	**3.60**	3.94
Condensate *($/bbl)*	**91.70**	74.09
Oil *($/bbl)*	**93.07**	77.84
NGL *($/bbl)*	**51.80**	41.05
Combined *($/boe)*	**47.99**	56.07

ROYALTIES

Royalties for the year ended December 31, 2011 are lower on a percentage of sales and on a per boe basis in comparison to the year ended December 31, 2010, primarily reflecting royalty incentives in British Columbia and lower commodity prices for natural gas. In the year ended December 31, 2011, total royalties were $9.1 million, or approximately 12.4% of total revenue. For the year ended December 31, 2010, total royalties were $7.5 million, or approximately 12.9% of revenue. In the year ended December 31, 2011, oil royalties averaged 16.1% (2010: 14.7%) of sales, while gas and associated product royalties averaged 4.3% (2010: 5.1%).

Throughout 2012, assuming similar commodity prices, the Company anticipates overall royalty rates to average approximately 12% of total revenues, reflecting the combined impact of incremental sales volumes from newly drilled wells and royalty holidays, partially offset by incremental royalties on wells which have maximized provincial royalty incentives.*

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

Painted Pony's producing properties in British Columbia are all on crown lands and in Saskatchewan are on a combination of freehold and crown lands. Approximately 42% of the crown royalty costs during the year ended December 31, 2011 were from sales on Saskatchewan oil properties, while sales of gas from recently drilled wells in British Columbia enjoyed provincial royalty incentives. Freehold royalties are from the sale of oil, gas and liquids within Saskatchewan. Gross overriding royalties are mainly from oil sales on lands earned through farm-ins and are mostly attributable to wells in Saskatchewan.

Royalties as a % of Revenue

Years ended December 31,	2011	2010
Crown	**1.8**	1.4
Freehold	**7.8**	8.3
GOR	**2.8**	3.2
	12.4	12.9

Royalties by Type *(000s)*

Years ended December 31,	2011	2010
Crown	**$ 1,314**	$ 806
Freehold	**5,720**	4,841
GOR	**2,100**	1,882
	$ 9,134	$ 7,529
Per boe *(6 mcf:1 bbl)*	**$ 5.93**	$ 7.25

OPERATING AND TRANSPORTATION *(000s, except per unit)*

Operating and transportation costs for the year ended December 31, 2011 were $16.5 million or $10.72 per boe. This compares to $11.4 million or $10.94 per boe for the year ended December 31, 2010.

Years ended December 31,	2011	2010
British Columbia	**$ 7,197**	$ 4,717
Saskatchewan	**9,313**	6,662
Total	**$ 16,510**	$ 11,379
British Columbia *($/boe)*	**$ 7.65**	$ 11.38
Saskatchewan *($/boe)*	**15.52**	10.66
Operating and transportation cost *($/boe)*	**$ 10.72**	$ 10.94

Overall per unit operating and transportation costs decreased 2% in the year 2011 compared to the year 2010, reflecting incremental gas sales volumes and cost-saving measures implemented by the Company, primarily offset by significant weather-related issues in southeast Saskatchewan during the second and third quarters of 2011.

Operating and transportation costs for the Company's gas producing properties in British Columbia are mainly processing and treating, compression fees, contract operating fees, fuel and power, gas transportation and maintenance expenditures on the more mature properties. In 2011, per unit operating and transportation costs declined by 33% to $7.65 per boe, compared to the year ended December 31, 2010, primarily due to increased 2011 volumes.

For the Company's oil producing properties in Saskatchewan, operating and transportation costs are primarily oil transportation, emulsion and hauling, road and lease maintenance, fuel and power expenditures, minor workovers, equipment rentals and contract operator fees. During 2011, these properties required a number of minor workovers and significantly more repairs and maintenance than normal as a consequence of the extended spring breakup and extensive surface water issues which contributed approximately $1.05 per boe to the average annual cost.

During 2012, the Company anticipates that per unit operating and transportation costs in British Columbia will continue to benefit from expected incremental sales volumes. In Saskatchewan, the quantum of repairs and maintenance are anticipated to be less than during 2011, tempered by weather-related impacts. These factors, combined with facility upgrades, are expected to reduce average operating and transportation costs during 2012 in comparison to 2011.*

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

The Company has committed additional Montney gas volumes towards a third party midstream gas plant expansion in the Blair/Town area. Through an interim expansion late in 2011, total gas processing capacity increased from 24 mmcf per day up to 32 mmcf per day. Expansion of this plant to a licensed gross capacity of 80 mmcf per day is expected by the end of the second quarter of 2012, when Painted Pony's firm share of this capacity will increase to 32 mmcf per day. In conjunction with this, the Company is committed to a ten-year firm-service contract for the processing costs associated with the physical delivery of a minimum volume of 16 mmcf per day of natural gas during the first five years and 13 mmcf per day during the next five years, up to a total maximum of 52.925 Bcf of gas, thus ensuring deliverability of product. Any shortfall of the minimum volume would be expected to result in incremental charges for excess capacity under the terms of the contract.*

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

OTHER INCOME

Third party processing, salt water disposal fees and compression fees constitute other income. Other income increased to $0.7 million for the year ended December 31, 2011 with completion of construction in two facilities and acquisition of the third facility generating processing income. Throughout most of the year 2010, these facilities had yet to be constructed or acquired hence other income was less significant.

Other Income *(000s)*

Years ended December 31,	2011	2010
Other income	**$ 726**	$ 115

OPERATING NETBACKS

For the year ended December 31, 2011, field operating netbacks averaged $31.34 per boe, compared to field operating netbacks of $37.88 per boe during the year ended December 31, 2010. The decrease in the Company's overall netbacks in the year ended December 31, 2011 compared to the year 2010 is primarily due to the increased gas weighting, with its lower per unit netback.

Combined Field Operating Netback *($/boe)*

Years ended December 31,	2011	2010
Sales	**$ 47.99**	$ 56.07
Royalties	**(5.93)**	(7.25)
Operating and transportation costs	**(10.72)**	(10.94)
Field operating netback	**$ 31.34**	$ 37.88

Netbacks by Province

Years ended December 31,	2011	2010
British Columbia *($/boe)*	**$ 14.12**	$ 12.35
Saskatchewan *($/boe)*	**$ 58.34**	$ 54.81

Netbacks from crude oil and associated gas and liquids production in Saskatchewan were $58.34 per bbl for the year ended December 31, 2011, compared to $54.81 per bbl in the year ended December 31, 2010. In Saskatchewan, the primary product was oil, which accounted for 89% of total 2011 sales volumes. The increased per boe netback for Saskatchewan during the year 2011 compared to 2010 reflects the higher oil price partially offset by higher operating and transportation costs. During the year 2011, Painted Pony's per unit netback for Saskatchewan properties was 67% of the gross sales price.

During 2011, netbacks from British Columbia properties, which produce gas and associated products, averaged $14.12 per boe, compared to $12.35 per boe in the year ended December 31, 2010. In 2011, British Columbia's primary product was gas, which contributed 98% of total sales volumes. Netbacks increased in British Columbia as increased volumes resulted in lower per unit royalty, processing, compression and transportation costs despite lower gas prices. During the year 2011, the Company's per unit netback for British Columbia properties was 62% of the gross sales price.

EXPLORATION AND EVALUATION

During the year ended December 31, 2011, the Company incurred $0.1 million of exploration and evaluation expense due to lease expiries, compared to $nil for the year ended December 31, 2010.

GENERAL AND ADMINISTRATIVE

Net general and administrative expenses were $4.0 million and $2.3 million during the years ended December 31, 2011 and 2010. On a per boe basis, net general and administrative costs were $2.58 per boe in 2011, compared to $2.19 per boe in 2010.

General and Administrative Costs *(000s, except per boe)*

Years ended December 31,		2011		2010
Gross costs	**$**	**8,891**	$	5,069
Capitalized		**(2,792)**		(1,474)
Recoveries		**(2,126)**		(1,320)
Net costs	**$**	**3,973**	$	2,275
Net general and administrative costs, per boe	**$**	**2.58**	$	2.19

Gross general and administrative costs during the year ended December 31, 2011 were 75% greater than in the year ended December 31, 2010, primarily due to salaries, consulting costs and associated administrative costs for additional staff. At December 31, 2011, the Company had thirty-one full time personnel compared to eighteen people at the end of 2010, plus full and part time consultants in both years. Total bonuses of $1.5 million were paid in the second and fourth quarters of 2011, compared to total bonuses of $0.4 million paid in the first and last quarters of 2010. In both years, general and administrative costs included primarily office rent and parking, fees to professional service providers, costs associated with reporting and computer related charges.

The Company's policy of allocating and capitalizing costs associated with new capital projects was unchanged in 2011 compared to 2010. During the year ended December 31, 2011, the Company allocated $2.8 million of administrative costs to capital projects, compared to $1.5 million during the year ended December 31, 2010, directly reflecting increased exploration staff and activity. General and administrative cost recoveries in the year ended December 31, 2011, were $2.1 million, compared to $1.3 million during the year ended December 31, 2010. The portion recovered from capital projects was in accordance with common industry practice whereby an operator calculates and allocates overhead to each working interest partner in proportion to their ownership interest, based on 100% of the capital expenditures. Increased cost recoveries during the year 2011 reflect the increased operated capital expenditure levels compared to the year 2010.

In 2011, net general and administrative costs per boe increased 18% compared to the year ended December 31, 2010 reflecting incremental staffing while average sales volumes increased 48% year over year. During 2012, variations in the capital expenditure levels will be reflected in the capitalization and recovery of general and administrative costs throughout the year.*

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CAPITAL TAXES

Capital taxes, specifically the Saskatchewan resource surcharge, were $0.9 million for the year ended December 31, 2011 compared to $0.8 million in the year ended December 31, 2010. As gross Saskatchewan sales revenues fluctuate, capital taxes are expected to vary correspondingly in 2012.*

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SHARE-BASED PAYMENTS

Share-based payment costs were $15.0 million in the year ended December 31, 2011 compared to $5.9 million in the year ended December 31, 2010. The aggregate grants of 3,015,100 options during 2011, with one-third vesting immediately, triggered most of the incremental expense for the year ended December 31, 2011. Share-based payment expense is a non-cash estimate of the cost of granting options to purchase shares, calculated using a Black-Scholes model.

Capitalized share-based payments for the year ended December 31, 2011 were $3.4 million. During the year ended December 31, 2010, the Company capitalized $1.2 million. The remainder of $11.7 million for the year ended December 31, 2011 ($4.7 million for the year ended December 31, 2010) was expensed. This expense does not represent actual cash compensation realized by the recipients of the options upon the eventual exercise and disposition of these options.

Share-Based Payments *(000s)*

Years ended December 31,	2011	2010
Gross cost	**$ 15,038**	$ 5,902
Capitalized	**(3,376)**	(1,237)
Net expense	**$ 11,662**	$ 4,665

DEPLETION AND DEPRECIATION

Depletion and depreciation expenses in the year ended December 31, 2011 totaled $29.5 million and $24.0 million in the year ended December 31, 2010. On a per boe basis, the expenses decreased in the 2011 year compared to the 2010 year, reflecting the addition of reserves at lower costs than historical levels. The 2011 depletion rates reflect the addition of significant gas reserves. The depletion rate utilizes proven plus probable reserves in the calculation. In the year ended December 31, 2011, Painted Pony excluded the exploration and evaluation assets of $61.2 million from the depletion calculation, compared to $43.5 million for the year ended December 31, 2010.

Depletion and Depreciation Costs *(000s, except per boe)*

Years ended December 31,	2011	2010
Depletion and depreciation	**$ 29,538**	$ 24,000
Per boe	**$ 19.17**	$ 23.09

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

NET FINANCE EXPENSE

Net finance expense for the year ending December 31, 2011 was $0.7 million, down $0.4 million from $1.1 million for the year ended December 31, 2010, primarily due to incremental interest income earned on surplus funds.

Painted Pony invests available cash in interest-bearing deposit accounts and short-term deposits, generating interest income. Interest income in the years ended December 31, 2011 and 2010 were $0.6 million and $0.1 million, respectively, reflective of both interest rates and cash investment levels.

Finance charges are the result of fees, including standby charges, on the Company's available credit facility. Finance charges in the years ended December 31, 2011 and December 31, 2010 totaled $0.3 million. Finance charges have increased slightly as the Company has an available credit facility of $80 million as at December 31, 2011 compared to $65 million as at December 31, 2010.

Accretion costs on decommissioning obligations increased from $0.2 million for the year ended December 31, 2010 compared to $0.3 million in 2011. Accretion has increased somewhat in 2011 as a result of additional wells drilled and acquired, along with ownership in additional facilities and properties. At the end of 2011, the Company reduced the risk-free rate related to the decommissioning obligations to 2.7% from 4%, resulting in increased estimated obligations of $1.0 million. This revision was partially offset by revised estimates of when the decommissioning obligations would be incurred.

Accretion costs from the convertible Class B shares were $0.7 million in both years ended December 31, 2011 and 2010. Effective December 1, 2011, the Class B shares were converted to Class A shares at a rate of 0.825, resulting in 968,221 newly issued Class A shares. Consequently, accretion costs related to those convertible Class B shares will be $nil for 2012 and subsequent years.

Net Finance Expense *(000s)*

Years ended December 31,	2011	2010
Interest income	**$ (593)**	$ (134)
Finance charges	**304**	274
Accretion of decommissioning obligations	**301**	224
Accretion of Class B share liability	**674**	689
Total	**$ 686**	$ 1,053

GAIN ON DISPOSITION OF PROPERTY - FARMOUTS AND PROPERTY SWAPS

After adjusting the financial statements in 2010 to reflect IFRS standards, seven earnings events occurred in 2010 resulting in a "gain on assets" of $7.5 million. These earnings events were triggered by the earning of lands under a farm-out agreement in northeast British Columbia, plus one undeveloped land property swap in northeast British Columbia. In 2011, two similar farm-out earnings events and two property swaps in northeast British Columbia occurred with a "gain in assets" of $10.7 million. This accounting treatment reflects the IFRS standard as outlined in the "Significant Accounting Policies" in note 3 of the consolidated financial statements for the year ended December 31, 2011 and in this MD&A under the heading "Property, Plant and Equipment and Impairment of Assets".

Gain on Disposition of Property - Farmouts and Property Swaps *(000s)*

Years ended December 31,	2011	2010
Gain on disposition of property	**$ 10,745**	$ 7,482

CAPITAL EXPENDITURES

In the year ended December 31, 2011, Painted Pony conducted an active drilling program with the drilling of 42 (29.3 net) wells, of which 29 (20.7 net) wells were targeting oil in Saskatchewan and 13 (8.6 net) wells were targeting Montney gas in British Columbia. Exploration and development capital expenditures, including facilities and land costs totaled $146.9 million in the year 2011 compared to $108.9 million incurred in the year 2010.

Capital Expenditures *(000s)*

Years ended December 31,	2011	2010
Lease acquisitions and retention	**$ 700**	$ 763
Drilling and completions	**95,574**	41,886
Facilities and equipment	**21,656**	18,550
Exploration and evaluation	**28,996**	47,690
Exploration and development	**146,926**	108,889
Head office expenditures	**259**	200
	147,185	109,089
Property acquisitions	**8,705**	11,046
Share-based payments	**3,376**	1,238
Decommissioning costs	**3,602**	2,731
Total expenditures	**$ 162,868**	$ 124,104

Capital Additions (000s)

Years ended December 31,	2011	2010
Total capital expenditures	**$ 162,868**	$ 124,104
Gain on disposition - farmout	**10,159**	7,482
Gain on disposition - swaps	**586**	-
Exploration and evaluation dispositions	**(1,572)**	-
Exploration and evaluation expense	**(91)**	-
Total capital additions	**$ 171,950**	$ 131,586
Change in gross assets:		
Property, plant, and equipment	**$ 154,259**	$ 101,475
Exploration and evaluation	**17,691**	30,111
Total change in gross assets	**$ 171,950**	$ 131,586

In 2011, in Saskatchewan, the Company drilled 27 (19.2 net) horizontal and 2 (1.5 net) vertical wells targeting light oil in the Bakken and Mississippian formations primarily in the Midale, Huntoon, Kisbey and Flat Lake areas. Of these wells, 3 (1.3 net) wells were placed on production in the first quarter of 2012. Extremely wet weather and resulting road bans and flooding in Saskatchewan during the second and third quarters of 2011 limited access to leases and hampered the ability to complete operations.

In British Columbia, Painted Pony drilled 12 (7.6 net) horizontal wells during 2011, targeting the upper, middle and lower Montney formations on the Cameron Kobes and Blair Town land blocks and one vertical well (1.0 net) in the Beg area. In the fourth quarter of 2011, the vertical well was disposed of as part of a land swap. At the end of 2011, 3 (2.5 net) wells rig released during 2011 awaited being placed onto production.

Painted Pony's land position continues to grow. At December 31, 2011, the Company owned 81,213 net acres of land (93% undeveloped) in Saskatchewan, 149,797 net acres of land (80% undeveloped) in British Columbia, and 12,640 net acres of land (100% undeveloped) in Alberta. Throughout 2011, the Company added lands in British Columbia and Alberta through participation at provincial lands sales, land swaps and acquisitions. Painted Pony's total land position at December 31, 2011 is 243,651 net acres, of which 85% are undeveloped. At December 31, 2010, Painted Pony had 202,307 net acres in Saskatchewan and British Columbia.

The Company continues to expect certain leases that are approaching expiry in British Columbia to be continued through execution of work programs comprised of seismic and/or drilling operations.*

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IMPAIRMENT TEST

The Company calculated an impairment test at December 31, 2011 whereby the carrying amount of petroleum and natural gas properties, grouped by cash generating unit ("CGU"), is compared to the present value of estimated future cash flows from the production of proved and probable reserves. For purposes of impairment testing, exploration and evaluation assets are combined with CGU's. The impairment test resulted in the recoverable amount (value in use) of each CGU in isolation and the recoverable amount of its CGU's, in combination with the exploration and evaluation assets, exceeding the carrying amount of the oil and gas assets. Consequently, no impairment in oil and gas assets was identified.

At December 31, 2011, the Company calculated the impairment test using weighted Canadian-dollar average prices of $102.39 per bbl for light gravity crude oil, $6.81 per mcf for natural gas, $112.30 per bbl for condensate, and $74.48 per bbl for NGL's. The future prices used in the impairment test are based on a benchmark commodity price forecast used by the Company's independent reserve evaluators as at December 31, 2011 and adjusted for transportation and quality differentials specific to the Company's reserves.

LIQUIDITY AND CAPITAL RESOURCES

As at December 31, 2011, Painted Pony had current assets of $118.9 million and current liabilities of $50.6 million, resulting in a net working capital position of $68.3 million. Available cash has been, and is currently, on deposit in a major Canadian financial institution or invested in term deposits. Management has received confirmation from the financial institution that these funds are available on demand.

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

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The Company has an $80 million demand revolving credit facility with a Canadian chartered bank. Interest for the demand revolving credit facility is payable at a floating rate determined as the lender's prime rate plus 0.5% to 2.5%, depending on the Company's debt to cash flow ratio, as defined by the lender. A standby fee is charged at 0.20% to 0.45% of the undrawn portion of the credit facility, depending on the Company's cash flow ratio, as defined by the lender. Security is provided by a first fixed and floating charge demand debenture of $100 million on all of the Company's assets. Painted Pony has provided a negative pledge and undertaking to provide fixed charges over major petroleum and natural gas reserves in certain circumstances.

The availability under the demand revolving credit facility is subject to a review on or before June 1, 2012. Throughout 2011, the Company did not draw on its credit facility. The available credit facilities may be utilized on a periodic basis in 2012. There can be no assurance that the amount of the available demand credit facility will not be decreased at the next review.*

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COMMITMENTS

At December 31, 2011, the Company is committed to minimum tolls for transportation of oil through a major carrier system that began June 1, 2010 and ends in 2015. At December 31, 2011, the Company is further committed to minimum tolls for transportation of oil through a major carrier system that began September 1, 2011 and ends in 2016. The total minimum cost of the two commitments is estimated to be $2.3 million.*

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At December 31, 2011, the Company is further committed to a ten-year take-or-pay commitment for minimum gas gathering and processing fees, estimated to begin in July 2012. The commitment is estimated to total $23.8 million over the ten year period, and will apply to a total maximum volume of 52.925 Bcf of gas.*

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At December 31, 2011, the Company was committed to future payments totaling $1.6 million for office space rental and a proportionate share of operating costs through 2015.*

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

SHARE CAPITAL

On February 17, 2011, the Company completed a bought deal financing of 7,620,000 Class A shares at a price of $10.50 per share for total gross proceeds of $80.0 million.

On November 8, 2011, the Company completed a bought deal financing of 8,800,000 Class A shares at a price of $11.80 per share for total gross proceeds of $103.8 million.

Effective December 1, 2011, the Company elected to convert the 1,173,600 Class B shares to Class A shares at a rate of 0.825, resulting in the issuance of 968,221 additional Class A shares. As at December 31, 2011, there were 69,693,027 Class A shares and no Class B shares issued and outstanding.

The Company has a Stock Option Plan (the "Plan") whereby options to purchase Class A 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 Class A shares equal to ten percent of the aggregate number of Class A and Class B shares issued and outstanding from time to time.

In the year ended December 31, 2011, a total of 1,288,106 options were exercised at an average price of $4.22 per Class A share and 107,980 options were forfeited and cancelled. During 2011, a total of 3,015,100 options were granted at an average exercise price of $11.33. As at December 31, 2011, 6,167,934 options to purchase Class A shares were issued and outstanding at a weighted-average price of $8.00 per option for each Class A 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, 2011 and March 28, 2012, no Preferred Shares were issued or outstanding.

As at March 28, 2012, there were 69,743,027 Class A shares, no Class B shares and 6,117,934 options issued and outstanding.

INCOME TAXES

At December 31, 2011, the Company had a $5.0 million (December 31, 2010: $1.2 million) estimated deferred income tax liability. In 2011, the Company recognized deferred income tax benefits of $2.5 million for share issue costs (2010: $0.7 million) and $0.1 million for conversion of Class B shares (2010: nil) which was partially offset by a deferred tax expense of $6.4 million (2010: $4.9 million).

DIVIDENDS

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

FOURTH QUARTER PERFORMANCE

COMPREHENSIVE INCOME AND FUNDS FLOW FROM OPERATIONS

Funds flow from operations during the fourth quarter of 2011 was $12.5 million, an increase of 20% over the comparable quarter in 2010 when funds flow from operations was $10.4 million. On a basic and diluted per share basis, funds flow from operations in the fourth quarter of 2011 was $0.19 compared to $0.20 per share, basic and diluted, in the comparable quarter in 2010.

In the fourth quarter of 2011, cash flows from operating activities was $12.9 million compared to 2010 fourth quarter cash flow of $10.2 million. The Company reconciles funds flow from operations to cash flows from operating activities, which is the most directly comparable measure calculated in accordance with IFRS, as follows:

(000s)

Three months ended December 31,	2011	2010
Cash flows from operating activities	**$ 12,889**	$ 10,200
Changes in non-cash working capital	**(373)**	204
Decommissioning expenditures	**1**	7
Funds flow from operations	**$ 12,517**	$ 10,411

In the last quarter of 2011, the Company recorded comprehensive income of $1.5 million compared to fourth quarter 2010 income of $4.5 million. The fourth quarter 2011 income included stock-based compensation expense of $3.9 million compared to fourth quarter 2010 share-based compensation expense of $1.0 million. Gains on assets from farmouts and swaps in the last quarters of 2011 and 2010 were $3.5 million and $4.1 million, respectively.

SALES VOLUMES

Sales volumes for the fourth quarter of 2011 averaged 5,189 boe per day compared to 3,443 boe per day in the same 2010 period, an increase of 51%. In the last quarter of 2011, the commodity mix was weighted 32% oil, condensate and natural gas liquids and 68% gas. In comparison, in the fourth quarter of 2010, Painted Pony's sales averaged 53% oil, condensate and natural gas liquids and 47% gas.

Average Daily Sales Volumes

Three months ended December 31,	2011	2010
Oil *(bbls/d)*	**1,449**	1,739
Condensate *(bbls/d)*	**63**	34
NGL's *(bbls/d)*	**151**	57
Gas *(mcf/d)*	**21,151**	9,678
Total *(boe/d)*	**5,189**	3,443

Gas sales in the three months ending December 31, 2011 averaged 21,151 mcf per day, an increase of 119% over the same 2010 quarter, and 32% greater than the 2011 third quarter rate, reflecting continued successful drilling operations on the Company's Montney gas assets in northeastern British Columbia.

Oil sales in the fourth quarter of 2011 averaged 1,449 bbls per day, a decrease of 17% compared to the fourth quarter 2010 average oil sales of 1,739 bbls per day and an increase of 10% over third quarter 2011 oil sales. Fourth quarter 2011 oil sales showed some improvement over third quarter 2011 sales as southeast Saskatchewan flooding conditions subsided. Natural gas liquids sales increased in the fourth quarter of 2011 reflecting the return of normal operations at a non-operated processing facility in southeast Saskatchewan combined with additional liquids-rich gas sales from northeast British Columbia.

REVENUES

During the fourth quarter of 2011, total revenues were $20.5 million, 24% higher than the last quarter of 2010 revenues of $16.6 million. Gas revenues in the last quarter of 2011 grew by 95% compared to the same quarter in 2010, reflecting the 119% increase in gas sales volumes, partially offset by the 11% decrease in the average per unit gas sales price. Oil sales were flat in the fourth quarter of 2011 in comparison to 2010, reflecting 17% lower volumes almost entirely offset by a 19% increase in the per unit oil sales price.

Sales by Product *($000s)*

Three months ended December 31,	2011	2010
Oil	**12,775**	12,868
Gas	**6,390**	3,272
Condensate	**572**	236
NGL's	**791**	245
Total	**20,528**	16,621

REALIZED PRICES

For the three months ending December 31, 2011, Painted Pony received an average crude oil price of $95.80 per bbl, 19% higher than the average price of $80.43 per bbl received during the comparable 2010 period. The Edmonton par reference price for light oil during the fourth quarter of 2011 and 2010 respectively was $97.89 per bbl and $80.86 per bbl.

In the fourth quarter of 2011, the Company received an average gas price of $3.28 per mcf compared to $3.67 per mcf received in the fourth quarter of 2010. The AECO daily spot price for the fourth quarter of 2011 was $3.19 per mcf compared to $3.65 per mcf for the fourth quarter of 2010.

Average Benchmark Prices

Three months ended December 31,	2011	2010
Gas - AECO, daily spot *($/mcf)*	**3.19**	3.65
Oil - Edmonton par- light oil *($/bbl)*	**97.89**	80.86

Painted Pony's Realized Prices

Three months ended December 31,	2011	2010
Gas *($/mcf)*	**3.28**	3.67
Oil *($/bbl)*	**95.80**	80.43

For both oil and gas, the average realized sales price per unit approximated, respectively, the Edmonton par price and AECO reference price. In the last quarter of 2011, Painted Pony received an average oil price of $95.80 per bbl, or 2% less than the Edmonton reference price of $97.89 per bbl. Similarly, the average natural gas price the Company received in the fourth quarter of 2011 was $3.28 per mcf, approximating the $3.19 per mcf AECO daily spot price.

ROYALTIES

In the fourth quarter of 2011, the Company paid $2.4 million in royalties, up 11% from the $2.1 million of royalties in the comparable quarter of 2010. Royalties were 11.6% of sales during the fourth quarter of 2011, compared to 12.9% in the last quarter of 2010, reflecting the impact of royalty holidays and incentives in both British Columbia and Saskatchewan on recent drilling activity.

Royalties as a % of Revenue

Three months ended December 31,	2011	2010
Crown	**1.2**	1.2
Freehold	**7.4**	8.3
GOR	**3.0**	3.4
	11.6	12.9

Royalties by Type *($000s, except per unit)*

Three months ended December 31,	2011	2010
Crown	**253**	200
Freehold	**1,526**	1,384
GOR	**608**	556
	2,387	2,140
Royalties *($ per boe)*	**5.00**	6.76

OPERATING AND TRANSPORTATION

In the fourth quarter of 2011, operating and transportation costs totaled $4.6 million ($9.57 per boe), compared to $3.2 million ($10.17 per boe) in the last quarter of 2010.

Per unit costs for gas properties in British Columbia have decreased in the fourth quarter of 2011 compared to the prior year, reflecting a significantly increased production base. In Saskatchewan, oil properties per unit costs in the fourth quarter of 2011 averaged $13.99 per boe, compared to $11.68 per boe in the comparable 2010 period, primarily due to higher transportation, fuel and power, and chemical and treating costs, partially offset by lower workover costs. Costs have returned to more normalized per unit levels. As in comparison, third quarter 2011 costs in Saskatchewan averaged $22.26 per boe from property taxes and additional repairs and maintenance activities triggered by the abnormally wet and prolonged spring breakup.

Operating and Transportation Costs *($000s, except per unit)*

Three months ended December 31,	2011	2010
British Columbia	**2,360**	1,247
Saskatchewan	**2,208**	1,974
Total	**4,568**	3,221
British Columbia *($/boe)*	**7.39**	8.43
Saskatchewan *($/boe)*	**13.99**	11.68
Operating and transportation cost *($/boe)*	**9.57**	10.17

OPERATING NETBACKS

During the fourth quarter of 2011, Painted Pony generated field operating netbacks of $28.43 per boe, compared to $35.54 per boe in the same quarter of 2010.

Combined Field Operating Netback *($/boe)*

Three months ended December 31,	2011	2010
Sales	**43.00**	52.47
Royalties	**(5.00)**	(6.76)
Operating and transportation costs	**(9.57)**	(10.17)
Field operating netback	**28.43**	35.54

Netbacks by Province

Three months ended December 31,	2011	2010
British Columbia *($/boe)*	**13.05**	13.66
Saskatchewan *($/boe)*	**59.59**	54.69

The field operating netback in the fourth quarter of 2011 declined by 20% in comparison to the fourth quarter of 2010, despite increased netbacks for oil and associated gas and product sales in Saskatchewan, due to the change in production mix, as the higher netback commodity (oil) made up 51% of the product mix in the 2010 period compared to 28% in the fourth quarter of 2011.

GENERAL AND ADMINISTRATIVE

In the fourth quarter of 2011, the net general and administrative costs were $1.0 million ($2.12 per boe) compared to $0.7 million ($2.09 per boe) in the fourth quarter of 2010. Net general and administrative costs were approximately $0.2 million higher in the fourth quarter of 2011 than in the third quarter, due to a $0.8 million bonus paid in the fourth quarter of 2011 compared to $0.2 million in the fourth quarter of 2010. On a per production unit basis, net general and administrative costs were higher in the fourth quarter of 2011 reflective of the additional staff and associated charges required to manage the production volume growth. Fourth quarter volumes were 51% higher in 2011 compared to the same 2010 period, while net per unit G&A increased by 1%.

General and Administrative Costs *($000s, except per boe)*

Three months ended December 31,	2011	2010
Gross costs	**2,680**	1,527
Capitalized	**(979)**	(467)
Recoveries	**(689)**	(397)
Net costs	**1,012**	663
Net G&A *($ per boe)*	**2.12**	2.09

OTHER ITEMS

Other income for the three months ended December 31, 2011 was $0.2 million, compared to $48,000 for the quarter ended December 31, 2010 primarily due to higher processing income.

Depletion and depreciation expense in the fourth quarter of 2011 was $8.5 million ($17.86 per boe) compared to $6.8 million ($21.46 per boe) in the fourth quarter of 2010, and $18.48 per boe in the third quarter of 2011, reflecting the generation of additional proven and probable reserves throughout 2011.

Fourth quarter 2011 expense for share-based compensation was $3.9 million compared to $1.0 million in the fourth quarter of 2010, reflecting options granted in November 2011 at a higher exercise price and resulting fair value.

In the fourth quarters of 2011 and 2010, capital taxes, consisting of the Saskatchewan resource surcharge were $0.2 million, primarily reflecting gross sales revenues in Saskatchewan.

Painted Pony exited both 2011 and 2010 with no bank debt.

RELATED PARTY TRANSACTIONS

The Company utilizes the services of a law firm in which the Corporate Secretary is a Partner. During the year ended December 31, 2011, the Company incurred $0.3 million (2010: $0.2 million) on legal services. All related party transactions have been measured at the agreed to terms and exchange values, being the consideration established and agreed to by the parties.

NET FINANCE EXPENSE

During the fourth quarters of 2011 and 2010, the Company earned $0.2 million and $48,000 of interest income reflecting available cash balances for investment. Fourth quarter 2011 finance costs were $0.2 million compared to $0.3 million in the fourth quarter of 2010, primarily due to accretion on Class B shares throughout the entire final quarter of 2010. In the fourth quarter of 2011, accretion was recorded up to December 1, 2011 when the Class B shares were converted to Class A shares.

Net Finance Expense *(000s)*

Three months ended December 31,		2011		2010
Interest income	**$**	**(210)**	$	(48)
Finance charges		**41**		65
Accretion of decommissioning obligations		**67**		68
Accretion of Class B share liability		**125**		177
Total	**$**	**23**	$	262

GAIN ON DISPOSITION OF PROPERTY - FARMOUTS AND PROPERTY SWAPS

In the fourth quarter of 2011, the Company recognized a $3.5 million gain on assets, triggered by the earning of lands under a farm-out agreement and two property swaps in northeast British Columbia. In the comparable period in 2010, a gain on assets of $4.1 million was recognized.

CAPITAL EXPENDITURES

During the fourth quarter of 2011, Painted Pony invested $54.5 million on capital projects. In the comparable 2010 quarter, the Company invested $35.9 million. Painted Pony expended $51.1 million in the fourth quarter of 2011 compared to $23.1 million in the same 2010 period on exploration and development capital expenditures.

In the fourth quarter of 2011, exploration and development expenditures in British Columbia were $37.2 million to drill 3 (3.0 net) wells and install pad production facilities, $11.8 million in Saskatchewan to drill 7 (3.8 net) wells and $2.1 million in Alberta for land acquisitions and pre-drilling costs. In the fourth quarter of 2011, the Company spent $1.2 million on property acquisitions in British Columbia, compared to $11.0 million spent in the fourth quarter of 2010 on property acquisitions in Saskatchewan.

Capital Expenditures (000s)

Three months ended December 31,	2011	2010
Lease acquisitions and retention	**$ 154**	$ 238
Drilling and completions	**32,362**	8,546
Facilities and equipment	**8,472**	6,916
Exploration and evaluation	**10,102**	7,442
Exploration and development	**51,090**	23,142
Head office expenditures	**53**	15
	51,143	23,157
Property acquisitions	**1,160**	11,046
Share-based payments	**982**	269
Decommissioning costs	**1,167**	1,457
Total expenditures	**$ 54,452**	$ 35,929

For comparative purposes, 2010 data has been summarized to correspond to 2011 data.

Capital Additions (000s)

Three months ended December 31,	2011	2010
Total capital expenditures:	**$ 54,452**	$ 35,929
Gain on disposition of property - farmout	**2,879**	4,089
Gain on disposition of property - swaps	**586**	-
Exploration and evaluation dispositions	**(1,572)**	-
Total capital additions	**$ 56,345**	$ 40,018
Change in gross assets:		
Property, plant, and equipment	**$ 56,818**	$ 35,403
Exploration and evaluation	**(473)**	4,615
Total change in gross assets	**$ 56,345**	$ 40,018

OFF BALANCE SHEET ARRANGEMENTS

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

SUBSEQUENT EVENTS

Subsequent to December 31, 2011, under the terms of a farm-in agreement on Alberta lands, the Company committed to drill and complete or abandon one horizontal well at an estimated cost of $3.1 million prior to May 31, 2012. At March 28, 2012, the well has been drilled and awaits completion.

On January 11, 2012, the Company closed an acquisition of a gross overriding royalty interest and seismic data in northeast British Columbia for cash consideration of $4.3 million, before closing adjustments and related costs. In conjunction with the acquisition, the Company committed to spend a minimum of $0.2 million by December 31, 2012 on seismic processing. The Company further committed to pay an additional $0.7 million should a specified Alberta gas index price exceed CDN $5.00 per gigajoule for an uninterrupted four month period within three years of the closing date of the transaction.

FINANCIAL INSTRUMENTS AND OTHER INSTRUMENTS

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

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

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

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

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

PERFORMANCE COMPARED TO GUIDANCE

Readers are reminded that forward-looking statements in this document are subject to significant risks and uncertainties and is based on a number of material factors and assumptions which may prove to be incorrect. A comparison of performance in 2011 to previously announced specific guidance by the Company is as follows:

- *The Company indicated it expected fourth quarter 2011 sales volumes to have a higher gas weighing than the third quarter's 65% weighting; fourth quarter sales volumes were weighted 68% gas.*
- *The Company indicated it expected the average oil price in the fourth quarter of 2011 to be approximately 3% less than the Edmonton light reference price; the average actual oil price received was 2% less.*
- *The Company indicated it expected fourth quarter royalty rates in 2011 to approximate 12% of total revenues; the actual royalty rate was 11.6%.*
- *The Company indicated it expected per unit operating and transportation costs in the fourth quarter of 2011 to be lower in Saskatchewan than the third quarter of 2011 average cost ($22.26 per boe) and are expected to continue to benefit from increased sales volumes in British Columbia ($7.65 per boe). Fourth quarter 2011 operating and transportation costs per boe for Saskatchewan and British Columbia were $13.99 and $7.39 respectively.*
- *The Company indicated the share-based payment expense for the fourth quarter of 2011 was expected to be approximately $1.6 million, based on options granted as at November 23, 2011. The fourth quarter cost was $3.9 million due to options granted subsequent to November 23, 2011.*

CHANGE IN ACCOUNTING POLICIES

IFRS

The consolidated financial statements have been prepared in accordance with IFRS. The Company mandatorily adopted IFRS on January 1, 2011. Previously, Painted Pony prepared its consolidated financial statements in accordance with Canadian GAAP. The Company has provided IFRS accounting policies and prepared reconciliations between Canadian GAAP and IFRS in Notes 2, 3 and 24 of its December 31, 2011 consolidated financial statements and the 2010 comparative information. The adoption of IFRS did not have an impact on the Company's operations. The following table provides summary reconciliations of Painted Pony's 2010 comprehensive income under Canadian GAAP and IFRS to illustrate the impact on adoption.

Summary of Comprehensive Income

(000s)	Total 2010	Q4 2010	Q3 2010	Q2 2010	Q1 2010
Net income (loss) - Canadian GAAP	$ 1,894	$ 1,373	$ (510)	$ 350	$ 681
Additions/ (deductions):					
Other income	(134)	(48)	(34)	(17)	(35)
General and administrative	248	64	85	74	25
Share-based payments	108	29	21	25	33
Depletion and depreciation	3,194	345	643	908	1,298
Net finance charges	(1,053)	(262)	(282)	(303)	(206)
Deferred income taxes	(2,517)	(1,077)	(954)	(132)	(354)
Gain on sale of property	7,482	4,089	3,289	-	104
Total increase to income	7,328	3,140	2,768	555	865
Comprehensive income - IFRS	$ 9,222	$ 4,513	$ 2,258	$ 905	$ 1,546

ACCOUNTING POLICY CHANGES

The following discussion illustrates the significant differences between Canadian GAAP and the accounting policies applied by the Company under IFRS. IFRS 1 "First-time Adoption of International Financial Reporting Standards" allows first-time adopters certain exemptions from retrospective application of certain IFRS policies. IFRS policies have been retrospectively applied except where specific IFRS 1 optional and mandatory exemptions permitted an alternative treatment upon transition to IFRS.

IFRS 1 EXEMPTIONS

IFRS 1 contains exemptions whereby a company may choose to apply IFRS to property, plant and equipment prospectively to its full cost pool, provided an impairment test under IFRS standards is conducted at the transition date. More specifically a company may choose to allocate the historical full cost pool to CGUs by utilizing either volumes or values from current reserves at the transition date. Painted Pony elected to apply this optional exemption under IFRS 1 and has allocated the historical cost pool (net book value) to CGUs based on proven plus probable reserve values.

As part of the aforementioned exemption, Painted Pony re-measured its decommissioning liabilities, previously referred to as asset retirement obligations, as at the date of transition in accordance with IFRS standards and recognized the difference from the amount recorded under Canadian GAAP directly into retained earnings. Refer to "Decommissioning Obligations" below for further details.

The Company applied the optional exemption in respect of business combinations and share-based payment transactions, both of which grant a first-time adopter relief from restatement in accordance with IFRS prior to the date of transition to IFRS.

Painted Pony determined that the total impact of the conversion to IFRS was a reduction in retained earnings on January 1, 2010 in the amount of $4.8 million. The Company has performed impairment calculations at the transition date and did not have any transitional write-downs associated with its petroleum and natural gas properties.

EXPLORATION AND EVALUATION

Exploration and evaluation ("E&E") costs are expenditures incurred for which technical feasibility and commercial viability have not yet been determined. Such expenditures include costs of acquiring licenses, seismic and exploratory drilling and completion costs and directly attributable general and administration costs. When technical feasibility and commercial viability are determined, the costs are transferred to property, plant and equipment. At the date of transition, Painted Pony determined its E&E balance was $13.4 million, almost entirely related to undeveloped land.

E&E will be expensed if the costs do not relate to an established CGU or its technically feasibility and commercial viability cannot be established. Exploration and evaluation assets are assessed for impairment if (i) sufficient data exists to determine technical feasibility and commercial viability, (ii) facts and circumstances suggest that the carrying amount exceeds the recoverable amount and (iii) amounts are transferred to CGUs. For purposes of impairment testing, exploration and evaluation assets are combined with cash-generating units. For the year ended December 31, 2011, the Company expensed $0.1 million of E&E expenditures due to lease expiries. For the year ended December 31, 2010, no impairment of E&E costs was recognized.

PROPERTY, PLANT AND EQUIPMENT AND IMPAIRMENT OF ASSETS

Property, plant and equipment ("PP&E") costs include expenditures where technical feasibility and viability have been determined. Under IFRS, Painted Pony capitalizes these costs in PP&E, within CGUs, and measures them at cost less accumulated depletion, depreciation and impairment losses. The cost of property, plant and equipment at the date of transition to IFRS, was determined by adopting the IFRS 1 exemption whereby the carrying value of property, plant and equipment assets assumes the carrying value under GAAP at the transition date. Under IFRS, Painted Pony is required to recognize and measure an impairment loss if the carrying value of PP&E exceeds the recoverable amount for any individual CGU. This recoverable amount is the higher of fair value less costs to sell and value in use. The Company's CGUs will be used for the impairment testing, while under Canadian GAAP, impairment tests were measured at the country level. There were no impairments recorded upon transition, comparative period or at December 31, 2011.

With respect to dispositions, under Canadian GAAP there is no recognition of a gain or loss unless the sale would result in a change to the depletion rate of 20 percent or greater. Under IFRS, property, plant and equipment dispositions will generally result in recognition of a gain or loss to income regardless of the amount of the transaction, as there is no threshold for measurement.

Under Canadian GAAP full cost principles, farm-out arrangements with third parties did not result in a recognizable event for financial reporting purposes. Under IFRS standards, farm-out arrangements result in a recognizable event. On a concurrent basis, a working interest in lease rights is exchanged or "sold" (derecognized) after an earnings event within a farm-out arrangement occurs for the value of reserves "received" (purchased). This transaction will result in a "gain or loss on assets", being the difference between the purchase amount and the sale amount.

DEPLETION AND DEPRECIATION

Under IFRS, the net carrying value of property, plant and equipment assets are depleted using the unit of production method with reference to the related proven and probable reserves at a component level, taking into account estimated future development costs necessary to bring those reserves into production. Under Canadian GAAP, proven reserves and associated future development costs were applied at a country level and used for depletion purposes. The reserve information is determined by independent reserve engineers on an annual basis. On a quarterly basis, this information may be updated internally or by independent reserve engineers. This change has resulted in a lower depletion and depreciation charge to comprehensive income during 2010. The impact of this change is illustrated in the reconciliation of comprehensive income above.

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 capitalized in the relevant asset category.

Under Canadian GAAP, decommissioning liabilities were measured as the estimated fair value of the retirement and decommissioning expenditures expected to be incurred. In measuring the fair value, Painted Pony used a credit-adjusted risk-free rate. Under IFRS, decommissioning obligations are measured as the best estimate of the expenditures to be incurred using a lower risk-free discount rate. As a result, Painted Pony's decommissioning obligations increased at the date of transition by $1.9 million. During the year ended December 31, 2010, the Company's decommissioning liabilities increased by $3.2 million, including accretion adjustments. Due to the higher present values and the reduced discount rate, the accretion recognized in comprehensive income throughout 2010 decreased. Under IFRS, this accretion is now classified and disclosed as a finance cost in the statement of comprehensive income. The impact of this change is illustrated in the reconciliation of comprehensive income above.

SHARE-BASED PAYMENTS

Under Canadian GAAP, the Company accounted for options granted to directors, officers, employees and certain consultants by measuring the fair value of the instruments issued and amortized this value over the instruments vesting periods. Fair value was measured using the Black-Scholes option pricing model using inputs that included share price on measurement date, exercise price of the instrument, expected volatility, weighted average expected life of the instruments, expected dividends and a risk-free interest rate. Under IFRS the Company must also estimate and apply a forfeiture rate on the grant date and subsequently adjust it to reflect the actual number of options that vest. Under Canadian GAAP, forfeitures were recorded at the time of expiry or cancellation. The impact of the forfeiture rate changes was nominal for the Company. A required change in treatment for options granted to consultants under IFRS compared to GAAP was the primary reason for differences recognized. Under IFRS, no options were considered to have been granted to consultants.

FLOW-THROUGH SHARES

Flow-through shares are resource expenditure deductions for income tax purposes related to development and exploratory activities funded by flow-through share arrangements which are renounced to investors in accordance with income tax legislation. Under Canadian GAAP, the accounting treatment for flow-through shares was to record the full amount of the proceeds in share capital. When expenditures are renounced, the related tax effect is recorded to share capital and the deferred income tax liability. Under IFRS, the amount initially recorded in share capital was limited to the amount of proceeds that would have been received on that date if they were not issued as flow-through shares. The difference between the actual proceeds and the amount recorded in share capital is set up as a deferred premium on the statement of financial position. When the expenditures are incurred, the deferred premium on the flow-through shares is reversed and the related tax effect is recorded to the deferred income tax liability. The impact of this change in accounting policy is incorporated in the table in note 24(f) of the "Notes to Consolidated Financial Statements".

INCOME TAX

Income tax expense is comprised of deferred income tax expense and has been adjusted to reflect the tax effect arising from the differences between Canadian GAAP and IFRS. The impact of this change is illustrated in the reconciliation of comprehensive income above and in note 24(h) of the "Notes to Consolidated Financial Statements".

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, 2011 and 2010. The significant accounting policies followed by the Company under Canadian GAAP prior to conversion to IFRS are disclosed in the Company's annual audited consolidated financial statements for the year ended December 31, 2010. For a discussion on critical accounting policies and estimates under GAAP prior to conversion to IFRS, the reader is directed to the 2010 annual MD&A on SEDAR.

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

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

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

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

NEW STANDARDS AND INTERPRETATIONS NOT YET ADOPTED

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

In May 2011, IFRS 10 *"Consolidated Financial Statements"* was issued which sets out the principles for the presentation and preparation of consolidated financial statements when an entity controls one or more other entities. IFRS 10 replaces SIC-12 *"Consolidation - Special Purpose Entities"* and parts of IAS 27 *"Consolidated and Separate Financial Statement"* and is effective for annual periods beginning on or after January 1, 2013. Earlier application is permitted. The Company is currently evaluating the impact of this standard on its consolidated financial statements.

In May 2011, IFRS 11 *"Joint Arrangements"* was issued to address reporting inconsistencies. This standard requires a single method to account for interests in jointly controlled entities, focusing on the rights and obligations of a joint arrangement, rather than its legal form (as is currently the case). IFRS 11 supersedes IAS 31 *"Interests in Joint Ventures"* and SIC-13*"Jointly Controlled Entities - Non-Monetary Contributions by Venturers"*, and is effective for annual periods beginning on or after January 1, 2013. Earlier application is permitted. The Company is currently evaluating the impact of this standard on its consolidated financial statements.

In May 2011, IFRS 12 *"Disclosure of Interests in Other Entities"* was issued. This comprehensive standard applies to entities that have an interest in a subsidiary, a joint arrangement, an associate or an unconsolidated structured entity. IFRS 12 is effective for annual periods beginning on or after January 1, 2013. Earlier application is permitted. The Company is currently evaluating the impact of this standard on its consolidated financial statements.

In May 2011, IFRS 13 *"Fair Value Measurements"* was issued. This standard defines fair value, setting out a single IFRS framework for measuring fair value and required disclosures about fair value measurements. IFRS 13 is to be applied for annual periods beginning on or after January 1, 2013. Earlier application is permitted. The Company is currently evaluating the impact of this standard on its consolidated financial statements.

BUSINESS RISKS, UNCERTAINTIES AND FORWARD-LOOKING STATEMENTS*

Statements in this document may constitute forward-looking statements including expectations of future production, components of cash flow and earnings, expected future events and/or financial results that are forward-looking in nature and subject to substantial risks and uncertainties. The reader is cautioned that assumptions used in the preparation of such information may prove to be incorrect. The Company cautions the readers that actual performance will be affected by a number of factors, many of which may respond to changes in economic and political circumstances throughout the world. Events or circumstances may cause actual results to differ materially from those predicted, a result of numerous known and unknown risks, uncertainties, and other factors, many of which are beyond the control of the Company. These risks include, but are not limited to, the risks associated with the oil and gas industry, and changes to commodity prices and interest and foreign exchange rates. Industry related risks could include, but are not limited to, operational risks in exploration, development and production, delays or changes in plans, risks associated with the uncertainty of reserve estimates, health and safety risks and the uncertainty of estimates and projections of production, costs and expenses.

The following external factors beyond the Company's control may affect the marketability of oil and natural gas produced: industry conditions including changes in laws and regulations, changes in income tax regulations, increased competition, fluctuations in commodity prices, interest rates, and variations in the Canadian/United States dollar exchange rate. The reader is cautioned not to place undue reliance on this forward-looking statements.

Painted Pony's production and exploration activities are concentrated in the Western Canadian Sedimentary Basin, where activity is highly competitive and includes a variety of different sized companies ranging from smaller junior producers to the much larger integrated petroleum companies. Painted Pony is subject to the various types of business risks and uncertainties including:

- *Finding and developing oil and natural gas reserves at economic costs;*
- *Production of oil and natural gas in commercial quantities; and*
- *Marketability of oil and natural gas produced.*

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

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

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

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

LEGAL, ENVIRONMENTAL, REMEDIATION AND OTHER CONTINGENT MATTERS

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

SELECTED CONSOLIDATED QUARTERLY INFORMATION

The following tables set forth selected consolidated financial information of the Company for the most recently completed quarters ending at the last quarter of 2011.

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

(1) Before royalties.

Quarter ended *(unaudited)* *($000s, except volumes and per share)*	**Mar. 31, 2010**	**June 30, 2010**	**Sept. 30, 2010**	**Dec. 31, 2010**
Petroleum and natural gas revenue[(1)]	14,146	12,752	14,764	16,621
Funds flow from operations	9,156	7,704	9,123	10,411
Basic, per share	0.21	0.17	0.19	0.20
Diluted, per share	0.20	0.17	0.19	0.20
Cash flow from operating activities	9,221	8,355	7,699	10,200
Comprehensive income	1,546	905	2,258	4,513
Basic, per share	0.04	0.02	0.05	0.09
Diluted, per share	0.03	0.02	0.05	0.09
Capital expenditures, net	34,424	31,853	19,655	23,157
Capital acquisitions, net	-	-	-	11,046
Net working capital (deficiency)	15,639	(8,592)	22,454	(1,205)
Total assets	186,881	175,983	223,347	244,579
Decommissioning obligations	4,961	5,137	5,626	7,145
Convertible Class B shares liability	10,015	10,186	10,359	10,536
Average daily sales volumes *(boe/d)*	2,322	2,532	3,080	3,443

(1) Before royalties.

SELECTED CONSOLIDATED ANNUAL INFORMATION

The following table sets forth selected consolidated annual financial information of the Company for the three most recently completed years ending at December 31, 2011.

Years ended *($000s, except volumes and per share)*	**2011**	**2010**	**2009**[2]
Petroleum and natural gas revenue[1]	**73,936**	58,283	28,895
Funds flow from operations	**44,150**	36,393	15,210
Basic, per share	**0.74**	0.78	0.44
Diluted, per share	**0.73**	0.77	0.44
Cash flow from operating activities	**44,884**	35,474	12,460
Comprehensive income (loss)	**6,542**	9,222	(3,656)
Basic, per share	**0.11**	0.20	(0.10)
Diluted, per share	**0.11**	0.19	(0.10)
Capital expenditures, net	**147,185**	109,089	40,563
Capital acquisitions, net	**8,705**	11,046	13,588
Net working capital (deficiency)	**68,291**	(1,205)	40,679
Total assets	**478,656**	244,579	164,907
Decommissioning obligations[3]	**10,860**	7,145	2,439
Convertible Class B shares liability[4]	**-**	10,536	-
Average daily sales volumes *(boe per day)*	**4,221**	2,848	1,552

(1) Before royalties.
(2) The Company's IFRS transition date was January 1, 2010, and, therefore, 2009 comparative data has not been restated from Canadian GAAP.
(3) Formerly asset retirement obligations under Canadian GAAP.
(4) Under Canadian GAAP the convertible Class B shares were equity settled vs. liability settled under IFRS. The Class B shares were all converted during 2011.

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

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

- *Funds flow from operations have both increased and decreased over time, reflecting primarily the impact of fluctuating commodity prices on a growing production base. Per production unit operating and transportation cost variations track seasonal weather-related issues combined with fixed commitments. Throughout 2010, commodity prices were substantially stronger than during 2009, increasing funds flow from operations. Oil prices continued to improve in 2011, while natural gas prices modestly declined. The net effect of strong oil prices will contribute towards increasing funds flow from operations. Royalty changes vary due to commodity prices, production levels and the status of the different provincial royalty holiday incentive programs. As the production base matures, incremental royalties occur on wells as the maximum volumes provided for under the provincial incentive programs are attained. Royalty incentive programs have continued in Saskatchewan and British Columbia and the Company should continue to enjoy lower royalty rates on newer wells.*

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

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

- *Fourth quarter 2011 comprehensive income reflects higher sales revenues from an increasing production base. Comprehensive income in the third and fourth quarter of 2011 resulted primarily from gains on assets arising from earning of lands under a farm-out agreement and two asset swaps. Significant non-cash share-based payment costs were recognized in the second and fourth quarters of 2011 reflecting the impact of a number of options granted in those periods. Comprehensive income in three of the four quarters of 2010 were primarily impacted by growth in production and increased strength in oil prices. In the third quarter of 2010, the Company recorded $2.0 million of non-cash share-based payments for share options surrendered for cancellation.*

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

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

ADDITIONAL INFORMATION

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

2011 ANNUAL REPORT TO SHAREHOLDERS

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, 2011 and 2010.

Patrick R. Ward
President and CEO

Joan E. Dunne
Vice President, Finance and CFO

March 28, 2012

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, 2011, December 31, 2010 and January 1, 2010, the consolidated statements of comprehensive income, changes in equity and cash flows for the years ended December 31, 2011 and 2010, 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, 2011, December 31, 2010 and January 1, 2010, and the consolidated results of its operations and its consolidated cash flows for the years ended December 31, 2011 and 2010 in accordance with International Financial Reporting Standards.

KPMG LLP

KPMG LLP
Chartered Accountants

Calgary, Canada
March 28, 2012

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

(000s) **As at**	**December 31, 2011**	**December 31, 2010** *(note 24)*	**January 1, 2010** *(note 24)*
ASSETS			
Current assets			
Cash and cash equivalents *(note 4)*	**$ 96,970**	$ 9,748	$ 46,575
Trade and other receivables	**21,468**	17,200	5,198
Prepaid expenses and deposits	**495**	320	324
	118,933	27,268	52,097
Non-current assets			
Exploration and evaluation *(note 5)*	**61,226**	43,535	13,424
Property, plant and equipment *(note 6)*	**298,497**	173,776	96,301
Deferred tax asset	**-**	-	3,052
	$ 478,656	$ 244,579	$ 164,874
LIABILITIES			
Current liabilities			
Trade and other payables	**$ 50,642**	$ 28,473	$ 11,418
Non-current liabilities			
Decommissioning obligations *(note 8)*	**10,860**	7,145	4,290
Convertible Class B shares liability *(note 9)*	**-**	10,536	9,847
Deferred tax liability *(note 16)*	**4,975**	1,232	-
	66,477	47,386	25,555
EQUITY			
Share capital *(note 10)*	**372,792**	178,772	135,731
Equity component of convertible Class B shares *(note 9)*	**-**	(2,923)	(2,923)
Contributed surplus	**27,429**	15,928	10,317
Retained earnings (deficit)	**11,958**	5,416	(3,806)
	412,179	197,193	139,319
	$ 478,656	$ 244,579	$ 164,874

Commitments *(note 18)*
Contingencies *(note 22)*
Subsequent events *(notes 18 and 23)*

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

2011 ANNUAL REPORT TO SHAREHOLDERS

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(000s, except per share amounts)

Years ended December 31,	2011	2010 (note 24)
Revenue		
Petroleum and natural gas	**$ 73,936**	$ 58,283
Royalties	**(9,134)**	(7,529)
Other *(note 12)*	**726**	115
	65,528	50,869
Expenses		
Operating and transportation	**16,510**	11,379
Exploration and evaluation *(note 5)*	**91**	-
General and administrative	**3,973**	2,275
Capital taxes	**895**	822
Share-based payments *(note 10)*	**11,662**	4,665
Depletion and depreciation *(note 6)*	**29,538**	24,000
Gain on disposition of property *(note 6)*	**(10,745)**	(7,482)
	51,924	35,659
Results from operating activities	**13,604**	15,210
Finance income	**(593)**	(134)
Finance expense	**1,279**	1,187
Net finance expense *(note 14)*	**686**	1,053
Income before income tax	**12,918**	14,157
Deferred income tax expense *(note 16)*	**(6,376)**	(4,935)
Comprehensive income for the year	**$ 6,542**	$ 9,222
Earnings per share *(note 11)*:		
Basic	**$ 0.11**	$ 0.20
Diluted	**$ 0.11**	$ 0.19

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

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(000s, except shares)

Years ended December 31, 2011 and 2010

	Number of shares Class A	Share capital Class A	Equity component Class B	Contributed surplus	Retained earnings (deficit)	Total equity
Balance at January 1, 2010 *(note 24)*	44,081,700	$ 135,731	$ (2,923)	$ 10,317	$ (3,806)	$ 139,319
Issue of shares	6,800,000	44,064	-	-	-	44,064
Share issue costs, net of tax of $653	-	(1,800)	-	-	-	(1,800)
Share-based payments	-	-	-	5,902	-	5,902
Options exercised *(note 10)*	135,000	777	-	(291)	-	486
Comprehensive income for the year	-	-	-	-	9,222	9,222
Balance at December 31, 2010	51,016,700	$ 178,772	$ (2,923)	$ 15,928	$ 5,416	$ 197,193
Issue of shares	16,420,000	183,850	-	-	-	183,850
Share issue costs, net of tax of $2,507	-	(7,220)	-	-	-	(7,220)
Conversion of Class B shares, net of tax of $126	968,221	8,413	2,923	-	-	11,336
Share-based payments	-	-	-	15,038	-	15,038
Options exercised *(note 10)*	1,288,106	8,977	-	(3,537)	-	5,440
Comprehensive income for the year	-	-	-	-	6,542	6,542
Balance at December 31, 2011	69,693,027	$ 372,792	$ -	$ 27,429	$ 11,958	$ 412,179

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

2011 ANNUAL REPORT TO SHAREHOLDERS

CONSOLIDATED STATEMENTS OF CASH FLOWS

(000s)

Years ended December 31,	2011	2010 *(note 24)*
Cash flows from operating activities:		
Income for the year	**$ 6,542**	$ 9,222
Items not affecting cash:		
Exploration and evaluation	**91**	-
Share-based payments	**11,662**	4,665
Depletion and depreciation	**29,538**	24,000
Net finance expense	**686**	1,053
Deferred income tax expense	**6,376**	4,935
Gain on disposition of property	**(10,745)**	(7,482)
Decommissioning expenditures	**(188)**	(100)
Changes in non-cash working capital *(note 15)*	**922**	(819)
	44,884	35,474
Cash flows from investing activities:		
Exploration and evaluation additions	**(28,996)**	(47,690)
Exploration and evaluation dispositions	**1,572**	-
Property, plant and equipment additions	**(118,189)**	(61,399)
Acquisition of property, plant and equipment	**(8,705)**	(11,046)
Changes in non-cash working capital *(note 15)*	**16,724**	5,940
	(137,594)	(114,195)
Cash flows from financing activities:		
Issue of share capital	**183,850**	44,064
Exercise of share options	**5,440**	486
Share issuance costs	**(9,727)**	(2,453)
Cash interest received (paid) *(note 14)*	**289**	(139)
Changes in non-cash working capital *(note 15)*	**80**	(64)
	179,932	41,894
Change in cash and cash equivalents	**87,222**	(36,827)
Cash and cash equivalents, beginning of year	**9,748**	46,575
Cash and cash equivalents, end of year *(note 4)*	**$ 96,970**	$ 9,748

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Years ended December 31, 2011 and 2010

1. REPORTING ENTITY

Painted Pony Petroleum Ltd.'s (the "Company") principal business activity is the exploration, development and production of petroleum and natural gas resources in western Canada. The consolidated financial statements of the Company as at and for the years ended December 31, 2011 and 2010 include the accounts of the Company and its wholly owned subsidiaries, Painted Pony Petroleum Corp. and Painted Rock Resources Ltd. The Company's head office is located at Suite 300, 602 - 12 Ave. S.W., Calgary, AB.

2. BASIS OF PRESENTATION

Statement of Compliance

The consolidated financial statements have been prepared in accordance with International Financial Reporting Standards (IFRS). These are the Company's first IFRS annual consolidated financial statements, and IFRS 1 *"First-time Adoption of International Financial Reporting Standards"* has been applied (see note 24). The consolidated financial statements were authorized for issue by the Board of Directors on March 28, 2012.

Basis of Measurement

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

Functional and Presentation Currency

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

Use of Estimates and Judgements

The preparation of 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 from these estimates.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the year in which the estimates are revised and in any future years affected.

Information about significant areas of estimation uncertainty and critical judgments in applying accounting policies that have the most significant effect on the amounts recognized in the consolidated financial statements is included in the following notes:

- *Note 5 - valuation of exploration and evaluation assets*
- *Note 6 - valuation of property, plant and equipment*
- *Note 8 - provisions*
- *Notes 9 and 10 - measurement of share-based payments*

Reserve estimates impact a number of the areas referred to above; in particular, the valuation of property, plant and equipment and the calculation of depletion and depreciation.

3. SIGNIFICANT ACCOUNTING POLICIES

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

Basis of Consolidation

(i) Subsidiaries

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

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

(ii) Jointly controlled operations and jointly controlled assets

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

(iii) Transactions eliminated on consolidation

Intercompany balances and transactions, and any unrealized income and expenses arising from intercompany transactions, are eliminated in preparing the consolidated financial statements.

Financial Instruments

(i) Non-derivative financial instruments

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

(ii) Cash and cash equivalents

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

(iii) Financial assets and liabilities at fair value through profit or loss

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

(iv) Other financial liabilities
Other financial liabilities include trade and other payables, amounts drawn on the demand credit facility and the convertible Class B share liability. 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. Long-term debt is recognized initially at fair value, net of any transaction costs incurred, and subsequently at amortized cost using the effective interest method.

Financial liabilities are classified as current liabilities if payment is due within twelve months. Otherwise, they are presented as non-current liabilities.

(v) Compound financial instruments
Compound financial instruments, being the convertible Class B shares, are separated into their liability and equity components using the effective interest method. The liability component accretes up to the principal balance at maturity. The equity component is reclassified to share capital upon conversion.

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

Share Capital

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

Exploration and Evaluation Assets and Property, Plant and Equipment

(i) Recognition and measurement
Exploration and evaluation expenditures:
Pre-licence costs are expensed as incurred. Exploration and evaluation costs, including the costs of acquiring licenses, seismic, exploration drilling and directly attributable general and administrative costs initially are capitalized as exploration and evaluation 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, exploration and evaluation assets attributable to those reserves are first tested for impairment and then reclassified from exploration and evaluation assets to property, plant and equipment assets.

Property, plant and equipment costs:
Items of property, plant and equipment, which include oil and gas development and production assets, are measured at cost less accumulated depletion, depreciation and accumulated impairment losses. Development and production assets are grouped into cash-generating units ("CGU"s) for impairment testing. The cost of property, plant and equipment at January 1, 2010, the date of transition to IFRS, was determined by adopting the IFRS 1 exemption whereby the carrying value of property, plant and equipment assets under IFRS assumes the carrying value under Canadian GAAP at transition date. When significant parts of an item of property, plant and equipment, including oil and natural gas interests, have different useful lives, they are accounted for as separate items (major components).

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Years ended December 31, 2011 and 2010

(ii) Subsequent costs

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

(iii) Depletion and depreciation

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

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

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

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

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

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

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

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

Leased Assets

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

Impairment

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

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

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

All impairment losses are recognized in earnings.

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

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

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

In assessing value in use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. Value in use is generally computed by reference to the present value of the future cash flows expected to be derived from production of proven and probable reserves.

Exploration and evaluation assets are assessed for impairment if: (i) sufficient data exists to determine technical feasibility and commercial viability, (ii) facts and circumstances suggest that the carrying amount exceeds the recoverable amount and (iii) when they are reclassified to property, plant and equipment. For purposes of impairment testing, exploration and evaluation assets are combined with its cash-generating units.

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.

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

Share-Based Payments

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

Provisions

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

(i) Decommissioning obligations

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

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

Revenue Recognition

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

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

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

Finance Income and Expenses

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

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

Income Tax

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

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

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

Earnings per Share

Basic per share information is calculated on the basis of the weighted average number of Class A shares outstanding during the period. Diluted per share information reflects the potential dilution effect of options and convertible Class B shares. The Company calculated the dilutive impact of the convertible Class B shares assuming the outstanding Class B shares are converted at the later of the beginning of the period or the date of issue. Comprehensive income is adjusted for the amount of finance expense applicable to the Class B shares for the period. The number of Class A shares issued upon the conversion of each Class B share for purposes of calculating per share amounts was determined to be equal to $10.00 divided by the greater of $1.00 and the weighted average trading price per share of the Class A shares for the last 30 consecutive trading days as of the statement of financial position date.

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

Future Accounting Pronouncements

The following pronouncements from the International Accounting Standards Board ("IASB") will become effective for financial reporting periods beginning on or after January 1, 2013, except for IFRS 9 which is effective January 1, 2015, and have not yet been adopted by the Company. All of these new or revised standards permit early adoption with transitional arrangements depending upon the date of initial application.

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

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

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

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

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

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

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

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

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

The Company has not completed its evaluation of the effect of adopting these standards on its financial statements.

4. CASH AND CASH EQUIVALENTS

(000s)

Years ended December 31,	2011	2010
Bank balances	**$ 96,970**	$ 9,748

5. EXPLORATION AND EVALUATION ASSETS ("E&E")

(000s)	
Cost:	
Balance, January 1, 2010	$ 13,424
Additions	45,890
Acquisitions	1,800
Transfers to property, plant and equipment	(17,579)
Balance, December 31, 2010	43,535
Additions	28,996
Acquisitions	2,345
Dispositions - swaps	(3,331)
Transfers to property, plant and equipment	(10,228)
Lease expiries	(91)
Balance, December 31, 2011	$ 61,226

E&E assets consist of the Company's exploration projects which are pending the determination of proven or probable reserves. Acquisitions represent E&E assets purchased during the period. Additions represent the Company's share of costs incurred on E&E assets during the period. As at December 31, 2011 an amount of $61.2 million (December 31, 2010: $43.5 million) remains in E&E assets in respect of undeveloped lands and unevaluated seismic data in British Columbia, Saskatchewan and Alberta and unevaluated drilling and completion costs in southeast Saskatchewan. During 2011, $10.2 million (2010: $17.6 million) was transferred to property, plant and equipment following the successful conclusion of the appraisal program in certain areas of northeast British Columbia.

(a) Impairment charge

The impairment of E&E assets, and any eventual reversal thereof, is recognized as additional depletion and depreciation expense.

(b) Recoverability of exploration and evaluation assets

The Company assesses the recoverability of E&E assets, before and at the moment of transfer to property, plant and equipment, using CGU's. The CGU includes both the E&E CGU and CGU's related to oil and natural gas interests for that area.

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

(000s)	Oil and natural gas properties	Office furniture & equipment	Total
Cost or deemed cost:			
Balance, January 1, 2010	$ 96,103	$ 272	$ 96,375
Acquisitions	11,046	-	11,046
Cash additions	61,199	200	61,399
Non-cash additions	11,451	-	11,451
Transfers from exploration and evaluation	17,579	-	17,579
Balance, December 31, 2010	197,378	472	197,850
Acquisitions	8,705	-	8,705
Cash additions	117,930	259	118,189
Non-cash additions	17,137	-	17,137
Transfers from exploration and evaluation	10,228	-	10,228
Balance, December 31, 2011	$ 351,378	$ 731	$ 352,109
Depletion and depreciation:			
Balance, January 1, 2010	$ -	$ 74	$ 74
Depletion and depreciation	23,939	61	24,000
Balance, December 31, 2010	23,939	135	24,074
Depletion and depreciation	29,442	96	29,538
Balance, December 31, 2011	$ 53,381	$ 231	$ 53,612
Carrying amounts:			
At January 1, 2010	$ 96,103	$ 198	$ 96,301
At December 31, 2010	$ 173,439	$ 337	$ 173,776
At December 31, 2011	$ 297,997	$ 500	$ 298,497

(a) Depreciation and impairment charge

The depletion, depreciation and impairment of property, plant and equipment, and any eventual reversal thereof, are recognized in depletion and depreciation.

(b) Capitalized general and administrative expense and share-based payments

For the years ended December 31, 2011 and 2010, the Company capitalized general and administrative expenses and share-based payments as follows:

(000s)

Years ended December 31,	2011	2010
General and administrative	**$ 2,792**	$ 1,474
Share-based payments	**3,376**	1,238
Total	**$ 6,168**	$ 2,712

(c) Property acquisitions

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

During the year ended December 31, 2010, the Company acquired certain southeast Saskatchewan light oil properties for total cash consideration of $11.0 million, including final adjustments.

(d) Gain on disposition of property - farmouts

During the year ended December 31, 2011, the Company recognized a gain of $10.7 million (2010: $7.5 million) based on the estimated fair value received, determined by reference to proved and probable reserves established on assets farmed out and fair values of undeveloped land exchanged.

7. BANK DEBT

At December 31, 2011 the Company had an $80 million demand revolving credit facility available for use. Undrawn as of December 31, 2011, this facility is subject to a review on or before June 1, 2012. There can be no assurance that the amount of the available demand credit facility will not be decreased at the next scheduled review.

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

8. DECOMMISSIONING OBLIGATIONS

(000s)

Years ended December 31,	2011	2010
Balance, beginning of year	**$ 7,145**	$ 4,290
Provisions	**2,612**	2,731
Revisions	**990**	-
Decommissioning expenditures	**(188)**	(100)
Accretion	**301**	224
Balance, end of year	**$ 10,860**	$ 7,145

The Company's decommissioning obligations result from its ownership interest in oil and natural gas assets including well sites and facilities. The total decommissioning obligation is estimated based on the Company's net ownership interest in all wells and facilities, estimated costs to reclaim and abandon these wells and facilities and the estimated timing of the costs to be incurred in future years. The Company has estimated the net present value of the decommissioning obligations to be $10.9 million as at December 31, 2011 (2010: $7.1 million) based on an undiscounted total future liability of $22.4 million (2010 - $14.2 million). These payments are expected to be made over the next 10 to 35 years with the majority of costs to be incurred between 2034 and 2046. The discount factor, being the risk-free rate related to the liability, is 2.7% (2010: 4.0%) and the inflation rate is 2% (2010: 2%).

9. CONVERTIBLE CLASS B SHARES

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

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

The following table indicates the convertible Class B shares activities:

(000s)

Years ended December 31,	2011	2010
Balance, beginning of year	**$ 10,536**	$ 9,847
Accretion on convertible Class B share liability	**674**	689
Conversion to Class A shares, transfer to equity	**(11,210)**	-
Balance, end of year	**$ -**	$ 10,536

At the date of transition to IFRS, the Company recognized the equity component for the convertible Class B shares as a conversion option of $2.0 million and recorded $0.9 million related to the deferred income tax effect of the Class B shares.

10. SHARE CAPITAL

(a) Authorized

Unlimited: Class A shares
Unlimited: Preferred shares, none outstanding as at December 31, 2011 and 2010 and January 1, 2010

The Class A shares are voting on the basis of one vote per share. There are no fixed dividends payable on the Class A shares. In the event of the liquidation or dissolution of the Company, the Class A 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 shares in the Company. Options are granted at the market price of the shares at the date of grant, have a five year term and generally vest one-third immediately with the balance over two years.

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

		Weighted average exercise price	Number
Balance, January 1, 2010	$	3.53	2,755,000
Granted		6.25	1,938,920
Exercised		3.60	(135,000)
Forfeited and cancelled		5.88	(10,000)
Balance, December 31, 2010	$	4.68	4,548,920
Granted		11.33	3,015,100
Exercised		4.22	(1,288,106)
Forfeited and cancelled		6.67	(107,980)
Balance, December 31, 2011	$	8.00	6,167,934
Exercisable at December 31, 2011	$	6.48	3,702,999

The following table summarizes information about stock options outstanding at December 31, 2011:

Number of options outstanding	Exercise price *($)*	Remaining life *(yrs)*	Exercisable options	Exercise price *($)*
622,000	3.97	1.1	622,000	3.97
562,000	2.85	2.6	562,000	2.85
318,300	3.15	2.6	318,300	3.15
134,500	5.88	2.9	134,500	5.88
550,667	5.88	3.0	377,000	5.88
28,000	5.60	3.4	4,000	5.60
991,200	6.51	3.7	660,000	6.51
1,452,067	10.60	4.3	522,133	10.60
354,000	12.10	4.4	118,000	12.10
105,000	11.19	4.5	35,000	11.19
152,500	14.15	4.6	50,833	14.15
897,700	11.80	4.9	299,233	11.80
6,167,934	8.00	3.6	3,702,999	6.48

The weighted average share price at the date of exercise for share options exercised during the year ended December 31, 2011 was $11.11 (2010: $9.41).

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

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

Years ended December 31,	2011	2010
Fair value per option	**$ 7.25**	$ 3.95
Volatility *(%)*	**80**	80
Option life *(years)*	**5**	5
Dividends	**-**	-
Risk-free interest rate *(%)*	**1.95**	1.93

A forfeiture rate of 2% (2010: 0%) is used when measuring share-based payments. Share-based payments of $11.7 million for the year ended December 31, 2011 (2010: $4.7 million) were expensed and $3.4 million (2010: $1.2 million) was capitalized.

11. EARNINGS PER SHARE

Basic earnings per share was calculated as follows:

(000s, except shares)

Years ended December 31,	2011	2010
Income for the year	**$ 6,542**	$ 9,222
Weighted average number of shares		
Class A shares - basic	**59,860,305**	46,558,897
Class A shares - diluted	**60,829,382**	49,503,521
Comprehensive income per share - basic	**$ 0.11**	$ 0.20
Comprehensive income per share - diluted	**$ 0.11**	$ 0.19

The average market value of the Company's shares for purposes of determining the dilutive effect of converting the Class B shares to Class A shares and of outstanding share options was based on quoted market prices for the period. All of the Class B shares were excluded from the diluted earnings per share calculation as they were determined to be anti-dilutive for the year ended December 31, 2010. There were no dilutive outstanding Class B shares during the year ended December 31, 2011. During the year ended December 31, 2011, 1,509,200 (2010: nil) options were excluded from the weighted-average diluted share calculation of Class A shares.

12. OTHER INCOME

Other income of $0.7 million (2010: $0.1 million) is the aggregate of third party processing, salt water disposal fees and compression income.

13. PERSONNEL EXPENSES

In addition to their salaries, the Company also provides non-cash benefits to executive officers. Executive officers also participate in the Company's option program.

For key management personnel, being the executive officers and directors, compensation is comprised of the following:

(000s)

Years ended December 31,	2011	2010
Short-term benefits	$ 2,558	$ 1,763
Share based payments[(1)]	6,840	3,607
Total key management personnel compensation	$ 9,398	$ 5,370

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

Officers and directors purchased a total of 41,200 shares in the bought-deal financings in 2011 (2010: 15,500) on the same terms as the market.

In the Company's financial statements, items are primarily disclosed by nature except for employee compensation costs which are included in general and administrative expenses and operating costs. Employee compensation costs of $13.8 million were included in general and administrative expenses in 2011 (2010: $5.5 million) and less than $0.1 million in operating costs in both 2011 and 2010.

14. FINANCE INCOME AND EXPENSE

(000s)

Years ended December 31,	2011	2010
Finance income:		
Interest income	$ (593)	$ (134)
Finance expense:		
Interest and financing costs	304	274
Accretion of decommissioning obligations	301	224
Accretion of convertible Class B share liability	674	689
	1,279	1,187
Net finance expense	$ 686	$ 1,053

15. SUPPLEMENTAL CASH FLOW INFORMATION

Changes in non-cash working capital is comprised of:

(000s)

Years ended December 31,	2011	2010
Source/(use) of cash:		
Trade and other receivables	$ (4,268)	$ (12,002)
Prepaid expenses and deposits	(175)	4
Trade and other payables	22,169	17,055
	$ 17,726	$ 5,057
Related to operating activities	$ 922	$ (819)
Related to investing activities	16,724	5,940
Related to financing activities	80	(64)
	$ 17,726	$ 5,057

16. DEFERRED INCOME TAX EXPENSE

The statutory tax rate was 27.21% in 2011 (2010: 28.91%). The decrease from 2010 to 2011 was due to a reduction in the 2011 Canadian corporate tax rates as part of a series of corporate tax rate reductions previously enacted by the Canadian Federal government in 2007.

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

Reconciliation of effective tax rate:

(000s)

Years ended December 31,	2011	2010
Income before income tax	**$ 12,918**	$ 14,157
Combined corporate tax rate	**27.21%**	28.91%
Expected income tax expense	**$ 3,515**	$ 4,093
Non-deductible expenses	**20**	12
Share-based compensation	**3,181**	1,357
Change in statutory tax rates	**(340)**	(527)
Total income tax expense	**$ 6,376**	$ 4,935

Deferred tax assets and liabilities are attributable to the following:

(000s)

Years ended December 31,	2011	2010
Deferred tax liabilities:		
PP&E and E&E assets	**$ (12,913)**	$ (4,286)
Class B share liability	**-**	(313)
	(12,913)	(4,599)
Less deferred tax assets:		
Provisions	**2,792**	1,845
Share issue costs	**2,927**	1,522
Non-capital losses	**2,219**	-
Net deferred tax liability	**$ (4,975)**	$ (1,232)

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

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

	PP&E and E&E	Provisions	Convertible Class B share liability	Share issue costs	Non-capital losses
Balance, January 1, 2010	$ 967	$ 1,106	$ (512)	$ 1,489	$ -
Recognized in comprehensive income	(5,253)	739	199	(620)	-
Recognized directly in equity	-	-	-	653	-
Balance, December 31, 2010	(4,286)	1,845	(313)	1,522	-
Recognized in comprehensive income	(8,627)	947	187	(1,102)	2,219
Recognized directly in equity	-	-	126	2,507	-
Balance, December 31, 2011	$ (12,913)	$ 2,792	$ -	$ 2,927	$ 2,219

17. IMPAIRMENT TEST

The Company conducted an impairment test of each CGU, and then conducted a separate test whereby the E&E assets were combined with each CGU at December 31, 2011. The impairment test concluded that no impairment had occurred for any CGU, or for E&E.

The recoverable amount of each CGU was estimated on the higher of the value in use and the fair value less costs to sell. The estimates of the fair value less costs to sell were determined using discounted forecasted cash flows, with escalating prices and future development costs, as obtained from the related reserve reports.

The Company's future prices, as adjusted for commodity price differentials and transportation specific to the Company's production, used in the 2011 impairment test calculation are as follows:

	Exchange Rate *(US$ / CAN$)*	Light Oil *(C$/bbl)*	Gas *(C$/mcf)*	Condensate *(C$/bbl)*	NGL's *(C$/bbl)*
2012	0.98	94.63	3.37	95.31	49.78
2013	0.98	97.52	3.96	96.87	61.80
2014	0.98	97.24	4.45	94.16	63.18
2015	0.98	97.18	4.93	94.28	63.70
2016	0.98	97.15	5.41	94.34	63.91
2017	0.98	97.13	5.90	94.40	64.07
2018	0.98	98.46	6.14	95.87	65.08
2019	0.98	100.47	6.27	98.00	66.38
2020	0.98	102.52	6.40	100.19	67.73
2021	0.98	104.61	6.53	102.42	69.14
2022	0.98	106.72	6.66	104.63	70.56
2023	0.98	108.87	6.79	106.89	72.05
Rem.	0.98	122.90	8.41	134.14	89.99

18. COMMITMENTS

(a) At December 31, 2011, the Company is committed to two contracts, that expire in 2016, that require an estimated $2.3 million of minimum tolls for transportation of oil through a major carrier system, and are payable as follows:

(000s)	Amount
2012	$ 837
2013	619
2014	466
2015	253
2016	90
	$ 2,265

(b) The Company is committed to future payments for office space rental through to 2015 as follows:

(000s)	Amount
2012	$ 649
2013	454
2014	263
2015	241
	$ 1,607

(c) At December 31, 2011, the Company is committed to a ten-year take-or-pay contract, estimated to begin in July 2012, that requires an estimated $23.8 million of minimum gas gathering and processing fees, applied to a maximum total volume of 52.925 bcf over the ten years and with minimum payments as follows:

(000s)		Amount
2012	$	1,325
2013		2,628
2014		2,628
2015		2,628
2016		2,628
Thereafter to 2022		11,979
	$	23,816

(d) Subsequent to December 31, 2011, in conjunction with an acquisition of seismic data and royalty interests, the Company committed to spend a minimum of $0.2 million by December 31, 2012 on seismic processing. The Company further committed to pay an additional $0.7 million should a specified Alberta gas index price exceed CDN $5.00 per gigajoule for an uninterrupted four month period within three years of the closing date of the transaction.

19. RELATED PARTY TRANSACTIONS

The Company utilizes the services of a law firm in which the Corporate Secretary is a Partner. During the year ended December 31, 2011, the Company incurred $251,000 (2010: $188,000) on services obtained from the firm, excluding disbursements. As at December 31, 2011, the Company owed this related party $85,010 (December 31, 2010: $15,329).

20. DETERMINATION OF FAIR VALUES

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

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

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

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

The fair value of cash and cash equivalents, trade and other receivables and trade and other payables are estimated as the present value of future cash flows, discounted at the market rate of interest at the reporting date. At December 31, 2011 and December 31, 2010, the fair value of these balances approximated their carrying value due to their short term to maturity.

(c) Stock Options

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

(d) Class B Shares

The fair value of the convertible Class B liability at December 31, 2011 was $nil (2010: $10.9 million based on the December 24, 2010 closing price of $9.25 per Class B share, being the last trade of 2010) as the Class B shares were converted to Class A shares on December 1, 2011 at a rate of 0.825, resulting in the issuance of 968,221 Class A shares.

21. FINANCIAL RISK MANAGEMENT

(a) Overview:

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

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

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

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

(b) Credit Risk:

Credit risk is the risk of financial loss to the Company if a customer or counterparty to a financial instrument fails to meet its contractual obligations and arises principally from the Company's receivables from joint venture partners and oil and natural gas purchasers. The Company's maximum exposure to credit risk at December 31, 2011 and 2010 is as follows:

(000s)

Carrying amount, December 31,	2011	2010
Cash and cash equivalents	**$ 96,970**	$ 9,748
Trade and other receivables	**21,468**	17,200
Total current financial instruments	**$ 118,438**	$ 26,948

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

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

The Company does not anticipate any default as it transacts with creditworthy customers and management does not expect any losses from non-performance by these customers. As such, a provision for doubtful accounts has not been recorded at either December 31, 2011 or 2010.

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

(000s)

Carrying amount, December 31,	2011	2010
Sales revenue	**$ 7,830**	$ 7,109
Joint interest	**8,975**	9,045
Other	**4,663**	1,046
Total trade and other receivables	**$ 21,468**	$ 17,200

The Company has two significant independent commodity purchasers. One entity purchases the majority of natural gas produced in British Columbia, which accounted for $3.0 million of trade and other receivables at December 31, 2011 (December 31, 2010: $1.5 million). A second entity purchases the majority of oil produced in Saskatchewan, which accounted for $4.6 million of trade and other receivables at December 31, 2011 (December 31, 2010: $5.0 million).

As at December 31, 2011 and 2010, the Company's trade and other receivables are aged as follows:

(000s)

Carrying amount, December 31,	2011	2010
Not past due (less than 30 days)	**$ 18,407**	$ 15,339
Past due (31 - 90 days)	**2,965**	1,691
Past due (more than 90 days)	**96**	170
Total receivables	**$ 21,468**	$ 17,200

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

(c) Liquidity Risk:

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Years ended December 31, 2011 and 2010

Typically the Company ensures that it has sufficient cash on demand to meet expected operational expenses currently and in the foreseeable future, including the servicing of financial obligations; this excludes the potential impact of extreme circumstances that cannot reasonably be predicted, such as natural disasters. To achieve this objective, the Company prepares annual capital expenditure budgets, which are regularly monitored and updated as considered necessary. Further, the Company utilizes authority for expenditures on both operated and non-operated projects to further manage capital expenditures. The Company also typically collects its oil and natural gas revenues from most properties on the 25th of each month. In addition, the Company maintains an $80 million credit facility to provide capital when needed, of which $80 million was available at the end of the period.

(d) Market Risk:

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

The Company may use both financial derivatives and physical delivery sales contracts to manage market risks. All such transactions are conducted within risk management tolerances that are reviewed by the Board of Directors. As at December 31, 2011, the Company had not entered into any derivatives to manage market risk.

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

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

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. For the year ended December 31, 2011, if interest rates had been 0.5% lower than the 2011 weighted-average rate of 1.25%, with all other variables held constant, comprehensive income for the year would have been $237,000 lower due to lower interest income. An equal and opposite impact would have occurred to comprehensive income had interest rates been 0.5% higher.

(e) Capital Management:

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

The Company monitors capital based on the ratio of net debt to annualized cash flow. This ratio is calculated as net debt, defined as outstanding loans and borrowings plus or minus working capital, divided by cash flow from operations before changes in non-cash working capital for the most recent calendar quarter and then annualized. The Company's objective is to maintain a net debt to funds flow from operations ratio of 1:1 or less. This ratio may increase at certain times as a result of acquisitions. In order to facilitate the management of this ratio, the Company prepares annual capital expenditure budgets, which are updated as necessary depending on varying factors including current and forecast prices, successful capital deployment and general industry conditions. The annual and updated budgets are approved by the Board of Directors. As at December 31, 2011, the Company did not have a debt balance on its statement of financial position.

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

22. CONTINGENCIES

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

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

23. SUBSEQUENT EVENTS

On January 11, 2012, the Company closed an acquisition of a gross overriding royalty interest and seismic data in northeastern British Columbia for cash consideration of $4.3 million, before closing adjustments and related costs.

On February 7, 2012, under the terms of a farm-in agreement, the Company committed to drill and complete or abandon one horizontal well at an estimated cost of $3.1 million prior to May 31, 2012. The well has been drilled and is expected to be completed after spring break-up.

24. FIRST TIME ADOPTION OF INTERNATIONAL FINANCIAL REPORTING STANDARDS

As disclosed in note 2, these are the Company's first annual consolidated financial statements to be prepared in accordance with IFRS. The significant accounting policies set out in note 3 have been applied in preparing the annual consolidated financial statements for the year ended December 31, 2011, the comparative financial statements for the year ended December 31, 2010 and the January 1, 2010 transitional consolidated statement of financial position. IFRS 1 “First-time Adoption of IFRS” has been applied to these annual consolidated financial statements.

As a result of applying IFRS 1, the Company is required to present comparative information with the application of IFRS accounting policies as at the January 1, 2010 transition date and comparative information for the year ended December 31, 2010. IFRS 1 provides for certain mandatory and optional exemptions for first-time adopters to alleviate the retrospective application of all the accounting standards under IFRS.

An explanation of how the transition from Canadian GAAP to IFRS has affected the Company's financial position, financial performance and cash flows is set out in the following tables.

Key First Time Adoption Exemptions Applied

IFRS 1 "First-Time Adoption of International Financial Reporting" allows first-time adopters certain exemptions from retrospective application of certain IFRS.

The following include the significant IFRS 1 exemptions taken by the Company at January 1, 2010:

- ***Historical cost as deemed cost:***
  The Company elected an IFRS 1 exemption whereby the Canadian GAAP full cost pool was measured upon transition to IFRS at the amount determined under Canadian GAAP as at January 1, 2010. Costs included in the full cost pool on January 1, 2010 were allocated on a pro-rata basis to the underlying assets on the basis of proven and probable reserves values as at January 1, 2010. The exploration and evaluation assets were reclassified from the full cost pool to exploration and evaluation assets at the amount that was recorded under Canadian GAAP.

- ***Business combinations:***
  IFRS 3 "Business Combinations" has not been applied to acquisitions of subsidiaries or interests in joint ventures that occurred before January 1, 2010.

- ***Decommissioning obligations:***
  The Company elected the exemption under IFRS 1 which allows for the re-measurement of decommissioning obligations on the IFRS transition date to be recorded through the deficit.

- ***Share-based payment transactions:***
  The Company elected the exemption under IFRS 1 and prospectively applied IFRS 2 to its awards that vest after the transition date.

RECONCILIATION OF CONSOLIDATED STATEMENT OF FINANCIAL POSITION FROM CANADIAN GAAP TO IFRS AT THE DATE OF IFRS TRANSITION - JANUARY 1, 2010

(000s)	Canadian GAAP	Effect of transition to IFRS	IFRS
ASSETS			
Current assets			
Cash and cash equivalents	$ 46,575	$ -	$ 46,575
Trade and other receivables	5,198	-	5,198
Prepaid expenses and deposits	324	-	324
	52,097	-	52,097
Non-current assets			
Exploration and evaluation *(note a)*	-	13,424	13,424
Property, plant and equipment *(note a)*	109,725	(13,424)	96,301
Deferred tax asset *(note h)*	3,085	(33)	3,052
	$ 164,907	$ (33)	$ 164,874
LIABILITIES			
Current liabilities			
Trade and other payables	$ 11,418	$ -	$ 11,418
Non-current liabilities			
Decommissioning obligations *(note b)*	2,439	1,851	4,290
Convertible Class B shares liability *(note c)*	-	9,847	9,847
	13,857	11,698	25,555
EQUITY			
Share capital *(note f)*	139,739	(4,008)	135,731
Equity component of convertible Class B shares	-	(2,923)	(2,923)
Contributed surplus *(note d)*	10,360	(43)	10,317
Retained earnings (deficit) *(notes b, c, d, f, h)*	951	(4,757)	(3,806)
	151,050	(11,731)	139,319
	$ 164,907	$ (33)	$ 164,874

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Years ended December 31, 2011 and 2010

RECONCILIATION OF CONSOLIDATED STATEMENT OF FINANCIAL POSITION FROM CANADIAN GAAP TO IFRS AT THE END OF THE LAST REPORTING YEAR UNDER CANADIAN GAAP - DECEMBER 31, 2010

(000s)	Canadian GAAP	Effect of transition to IFRS	IFRS
ASSETS			
Current assets			
Cash and cash equivalents	$ 9,748	$ -	$ 9,748
Trade and other receivables	17,200	-	17,200
Prepaid expenses and deposits	320	-	320
	27,268	-	27,268
Non-current assets			
Exploration and evaluation *(note a)*	-	43,535	43,535
Property, plant and equipment *(note a, e)*	206,078	(32,302)	173,776
Deferred tax asset *(note h)*	851	(851)	-
	$ 234,197	$ 10,382	$ 244,579
LIABILITIES			
Current liabilities			
Trade and other payables	$ 28,473	$ -	$ 28,473
Non-current liabilities			
Decommissioning obligations *(note b)*	3,970	3,175	7,145
Convertible Class B shares liability *(note c)*	-	10,536	10,536
Deferred tax liability *(note h)*	-	1,232	1,232
	32,443	14,943	47,386
EQUITY			
Share capital *(note f)*	182,795	(4,023)	178,772
Equity component of convertible Class B shares	-	(2,923)	(2,923)
Contributed surplus *(note d)*	16,114	(186)	15,928
Retained earnings *(note b, c, d, e, f, h)*	2,845	2,571	5,416
	201,754	(4,561)	197,193
	$ 234,197	$ 10,382	$ 244,579

RECONCILIATION OF CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME FOR THE YEAR ENDED DECEMBER 31, 2010 FROM CANADIAN GAAP TO IFRS

(000s, except per share amounts)	Canadian GAAP	Effect of transition to IFRS	IFRS
Revenue			
Petroleum and natural gas	$ 58,283	$ -	$ 58,283
Royalties	(7,529)		(7,529)
Other	249	(134)	115
	51,003	(134)	50,869
Expenses			
Operating and transportation	11,379	-	11,379
General and administrative	2,523	(248)	2,275
Capital taxes	822	-	822
Share-based payments *(note d)*	4,773	(108)	4,665
Depletion and depreciation *(note e)*	27,194	(3,194)	24,000
Gain on disposition of property *(note g)*	-	(7,482)	(7,482)
	46,691	(11,032)	35,659
Results from operating activities	4,312	10,898	15,210
Finance income	-	(134)	(134)
Finance expense *(note b)*	-	1,187	1,187
Net finance expense	-	1,053	1,053
Income before income tax	4,312	9,845	14,157
Deferred income tax expense *(note h)*	2,418	2,517	4,935
Comprehensive income for the year	$ 1,894	$ 7,328	$ 9,222
Earnings per share:			
Basic	$ 0.04		$ 0.20
Diluted	$ 0.04		$ 0.19

RECONCILIATION OF CONSOLIDATED STATEMENT OF CASH FLOWS FOR THE YEAR ENDED DECEMBER 31, 2010 FROM CANADIAN GAAP TO IFRS

(000s)	Canadian GAAP	Effect of transition to IFRS	IFRS
Cash flows from operating activities:			
Income for the year	$ 1,894	$ 7,328	$ 9,222
Items not affecting cash:			
Share-based payments	4,773	(108)	4,665
Depletion and depreciation	27,194	(3,194)	24,000
Net finance expense	-	1,053	1,053
Deferred income tax expense	2,418	2,517	4,935
Gain on disposition of property	-	(7,482)	(7,482)
Decommissioning expenditures	(100)	-	(100)
Changes in non-cash working capital	(819)	-	(819)
	35,360	114	35,474
Cash flows from investing activities:			
Exploration and evaluation additions	-	(47,690)	(47,690)
Property, plant and equipment additions	(107,314)	45,915	(61,399)
Acquisition of property, plant & equipment	(12,846)	1,800	(11,046)
Changes in non-cash working capital	5,940	-	5,940
	(114,220)	25	(114,195)
Cash flows from financing activities:			
Issue of share capital	44,550	(486)	44,064
Exercise of share options	-	486	486
Share issuance costs	(2,453)	-	(2,453)
Finance and interest costs	-	(139)	(139)
Changes in non-cash working capital	(64)	-	(64)
	42,033	(139)	41,894
Change in cash and cash equivalents	(36,827)	-	(36,827)
Cash and cash equivalents, beginning of year	46,575	-	46,575
Cash and cash equivalents, end of year *(note i)*	$ 9,748	$ -	$ 9,748

Under IFRS 1 "First time adoption of International Financial Reporting Standards", IFRS is applied retrospectively at the transition date with the offsetting adjustments to assets and liabilities included in retained earnings.

IFRS employs a conceptual framework that is similar to Canadian GAAP. While the adoption of IFRS has not changed the actual cash flows of the Company, the adoption has resulted in significant changes to the reported financial position and results of operation of the Company and in immaterial changes to the makeup of operating, investing and financing cash flows.

(a) IFRS 1 election for full cost oil and gas entities:

The Company elected an IFRS 1 exemption whereby the Canadian GAAP full cost pool was measured upon transition to IFRS as follows:

(i) exploration and evaluation assets were reclassified from the full cost pool to exploration and evaluation assets at the amount that was recorded under Canadian GAAP; and

(ii) the remaining full cost pool was allocated to the producing/development assets pro-rata using proven plus probable pre-tax reserve values based on a discount rate of 10%.

The impact on the reclassification from the full cost pool to exploration and evaluation assets on the consolidated statements of financial position for the periods ended January 1, 2010 and December 31, 2010 are as follows:

Consolidated Statements of Financial Position:

(000s) Increase (decrease) as at	January 1, 2010	December 31, 2010
Exploration and evaluation	$ 13,424	$ 43,535
Property, plant and equipment	(13,424)	(43,535)
Impact on total assets	$ -	$ -

(b) Decommissioning obligations:

Under Canadian GAAP asset retirement obligations were discounted at a credit adjusted risk free rate of 8%. Under IFRS the estimated cash flow to abandon and remediate the wells and facilities has been risk adjusted; therefore, the provision is discounted at a risk free rate in effect at the end of each reporting period (4% for January 1, 2010 and December 31, 2010). Upon transition to IFRS, this resulted in a $1.9 million increase in the decommissioning obligations with a corresponding increase in the deficit. As a result of the lower discount rate, the Company recorded additional decommissioning costs to PP&E and lower related accretion expense during the 2010 period. In addition, under Canadian GAAP accretion of the discount was included in depletion and depreciation. Under IFRS it is included in finance expense.

As a result of the change in the decommissioning obligation, the impact on the consolidated statements of financial position and consolidated statement of comprehensive income for the periods ended January 1, 2010 and December 31, 2010 are as follows:

Consolidated Statements of Financial Position:

(000s) Increase (decrease) as at	January 1, 2010	December 31, 2010
Property, plant and equipment	$ -	$ 1,352
Decommissioning obligations	1,851	3,175
Impact on retained earnings (deficit)	$ (1,851)	$ (1,823)

Consolidated Statement of Comprehensive Income:

(000s) Increase (decrease) for the year ended		December 31, 2010
Finance expense	$	(28)
Impact on comprehensive income	$	28

(c) Convertible Class B shares:

Under Canadian GAAP, the Company's convertible Class B shares were presented as share capital. Under IFRS, the Class B shares do not qualify for equity presentation and must be presented as a liability due to the number of Class A shares issued on conversion, based on the conversion formula (note 9), being variable until the Company or shareholders exercise conversion rights. The value of the Class A shares on issuance was determined to be $5.2 million ($1.00 per Class A share). It was also determined that the face value of convertible Class B shares is $11.7 million ($9.97 per Class B share). Using a 7 percent discount rate and a term of 5.21 years, the Company calculated a present value of approximately $8.2 million on issuance, which would accrete to the $11.7 million face value on August 1, 2012, the expiration date of the shareholder's conversion option. A deferred tax liability of $0.9 million was recognized on issuance relating to the difference between the face value and present value of the Class B shares. The deferred tax liability is reversed proportionately to the accretion expense on the convertible Class B share liability.

The flow-through share premium of $1.6 million was recognized for the Class A and Class B shares issued on the initial public offering. The flow-through share premium reduced share capital, and as expenditures were incurred, the premium was recorded through income. The amount recorded for the Class B equity component relates to the conversion feature of $2.0 million, recognizing the value of the Company's lower limit of $1.00 per Class A share in the Class B to Class A conversion formula, along with the deferred income tax effect of the Class B shares of $0.9 million.

The following table provides the effect of transition to IFRS for the Company's share capital transactions involving convertible Class B shares from previous GAAP to IFRS:

(000s) Increase (decrease)		Effect of Transition to IFRS
Class A share capital	$	3,916
Convertible Class B share capital		(11,704)
Convertible Class B share liability		8,247
Deferred income tax liability		899
Equity component of Class B shares		(2,923)
Retained earnings		1,565
	$	-

In addition to the above adjustment, the Company recorded the effect of accretion expense from May 2007 through to December 1, 2011, when the Class B shares were converted to Class A shares. As a result of adopting this policy, the effect of the change to accretion expense and the Class B liability was as follows:

Consolidated Statements of Financial Position:

(000s) Increase (decrease) as at		January 1, 2010		December 31, 2010
Impact on Convertible Class B liability	$	1,600	$	689

Consolidated Statement of Comprehensive Income:

(000s) Increase (decrease) for the year ended	December 31, 2010
Impact on finance expense	$ 689
Impact on comprehensive income	$ (689)

(d) Share-based payments:

Under Canadian GAAP, the Company recognized an expense related to share-based payments on a graded basis over individual vesting periods, but did not incorporate a forfeiture rate. Under IFRS, the Company is required to estimate a forfeiture rate and apply this to the Black-Scholes model. Furthermore, the Company has determined that option recipients classified as consultants under Canadian GAAP would not be classified as such under IFRS. The impact of the changes to share-based payments for the periods ended January 1, 2010 and December 31, 2010 are as follows:

Consolidated Statements of Financial Position:

(000s) Increase (decrease) as at	January 1, 2010	December 31, 2010
Property, plant and equipment	$ -	$ (50)
Share capital	-	15
Contributed surplus	43	186
Impact on retained earnings (deficit)	$ 43	$ 151

Consolidated Statement of Comprehensive Income:

(000s) Increase (decrease) for the year ended	December 31, 2010
Share-based payments	$ (108)
Impact on comprehensive income	$ 108

(e) Depletion policy:

Upon transition to IFRS, the Company adopted a policy of depleting oil and natural gas interests on a unit of production basis over proven plus probable reserves. The depletion policy under Canadian GAAP was based on units of production over proven reserves. In addition, depletion was done on the Canadian cost centre under Canadian GAAP. IFRS requires depletion and depreciation to be calculated based on a component basis, as determined by the Company. In addition, accretion expense is reported as finance expense under IFRS.

There was no impact on property, plant and equipment of the depletion policy change on adoption of IFRS at January 1, 2010, due to the IFRS 1 election discussed above. As a result of the change in policy of depleting oil and natural gas interests on a proven plus probable basis and the reclassification of accretion expense to finance expense, the impact on the consolidated statement of financial position and consolidated statement of comprehensive income for the year ended December 31, 2010 are as follows:

Consolidated Statements of Financial Position:

(000s) Increase (decrease) as at	December 31, 2010
Property, plant and equipment	$ 3,194
Impact on total assets	$ 3,194

Consolidated Statement of Comprehensive Income:

(000s) Increase (decrease) for the year ended		December 31, 2010
Depletion and depreciation expense	$	(3,194)
Impact on comprehensive income	$	3,194

(f) Flow-through shares:

In 2007, the Company issued flow-through shares where the amount of the issue represented the "flow-through" of tax pool deductions to investors. Under Canadian GAAP, the accounting treatment for the flow-through shares is to record the full amount of the proceeds in share capital. When expenditures are renounced, the related tax effect is recorded to share capital and the future tax liability. Under IFRS, the amount initially recorded in share capital is limited to the value that would have been received for shares issued on a non-flow-through basis, and the difference between the actual proceeds and the amount recorded in share capital is set up as a deferred premium on flow-through shares. When the expenditures are incurred, the related deferred premium on flow-through shares is reversed and the related tax effect is recorded to the deferred income tax liability (see note 24 (c)).

(g) Gains and losses on disposition of assets:

Under Canadian GAAP, proceeds from asset sales were deducted from the full cost pool without recognition of a gain or loss unless the deduction resulted in a change in the depletion rate of 20 percent or greater, in which case a gain or loss was recorded. Under IFRS, gains and losses are recorded on asset sales and are calculated as the difference between the proceeds and the net book value of the asset disposed. For the year ended December 31, 2010, the Company recognized gains of $7.5 million on farmout's of certain lands held by the Company.

(h) Income taxes:

Deferred income taxes have been adjusted to reflect the tax effect arising from the differences between IFRS and Canadian GAAP. The application of the IFRS adjustments for note 24 (a) through to (g) resulted in the following impact for the periods ended January 1, 2010 and December 31, 2010 as follows:

Consolidated Statements of Financial Position:

(000s) Increase (decrease) as at		January 1, 2010		December 31, 2010
Property, plant and equipment	$	-	$	(468)
Deferred income tax asset (liability)				
Related to property, plant and equipment		-		(2,590)
Related to decommissioning obligations		478		820
Related to convertible Class B shares		(512)		(313)
Impact on retained earnings (deficit)	$	(34)	$	(2,551)

Consolidated Statement of Comprehensive Income:

(000s) Increase (decrease) for the year ended		December 31, 2010
Deferred income tax expense	$	2,517
Impact on comprehensive income	$	(2,517)

(i) Statement of Cash Flows:

The transition from Canadian GAAP to IFRS had no material effect upon the reported cash flows of the Company.

CORPORATE INFORMATION

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Calgary, Alberta

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Surge Energy Inc.
Calgary, Alberta

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President & Chief Executive Officer
Painted Pony Petroleum Ltd.
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Controller

Douglas T. McCartney
Partner, Burstall Winger LLP
Corporate Secretary

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TSX Venture Exchange
Trading symbol: PPY.A

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AUDITORS

KPMG LLP

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National Bank of Canada

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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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