PAINTED PONY PETROLEUM LTD.

2016 | ANNUAL REPORT | TSX: PPY

Table of Contents

Corporate Profile

Painted Pony is a publicly-traded natural gas corporation based in Western Canada. The Corporation is primarily focused on the development of natural gas and natural gas liquids from the Montney formation in Northeast British Columbia. Painted Pony's common shares trade on the Toronto Stock Exchange under the symbol "PPY".

Annual General Meeting

Painted Pony Petroleum Ltd. invites shareholders and interested parties to attend its Annual General Meeting to be held in the Bennett Room at the Ranchmen's Club, 710 - 13th Avenue SW, Calgary, Alberta, at 3:00 pm (Calgary time), on May 11, 2017. Shareholders not attending are encouraged to complete the form of proxy and deliver it in accordance with the instructions therein at their earliest convenience.

Cover painting "Bringing them home", oil on canvas by Paul Van Ginkel (www.paulvanginkel.com).

Financial and Operating Highlights

Year Ended December 31
$ millions, except per share and shares outstanding

Financial	2016	2015	Change
Petroleum and natural gas revenue [1]	121.6	81.6	49%
Funds flow from operations [2]	55.6	28.5	95%
Per share – basic [3] and diluted [4]	0.56	0.29	93%
Net loss	(51.9)	(5.2)	898%
Per share – basic [3] and diluted [4]	(0.52)	(0.05)	940%
Capital expenditures	204.4	106.7	92%
Working capital (deficiency) [5]	(73.6)	(4.6)	1,500%
Bank debt	200.8	63.6	216%
Net debt [6]	228.5	77.4	195%
Total assets	1,337.0	781.6	71%
Shares outstanding (millions)	100.2	100.0	–
Basic and fully diluted weighted-average shares (millions)	100.1	99.8	–
Operating			
Daily production volumes			
Natural gas (MMcf/d)	129.9	88.7	46%
Natural gas liquids (bbls/d)	1,557	826	88%
Total (MMcfe/d)	139.2	93.6	49%
Total (boe/d)	23,204	15,604	49%
Realized commodity prices			
Natural gas ($/Mcf)	2.04	2.10	(3%)
Natural gas liquids ($/bbl)	43.49	44.30	(2%)
Total ($/Mcfe)	2.39	2.39	–
Operating netbacks ($/Mcfe) [7]	1.73	1.23	41%

1. Before royalties.
2. Funds flow from operations and funds flow from operations per share (basic and diluted) are non-GAAP measures used to represent cash flow from operating activities before the effects of changes in non-cash working capital, DSU expense and decommissioning expenditures. Funds flow from operations per share is calculated by dividing funds flow from operations by the weighted average number of basic or diluted shares outstanding in the period. See "Non-GAAP Measures".
3. Basic per share information is calculated on the basis of the weighted average number of shares outstanding in the period.
4. Diluted per share information reflects the potential dilutive effect of stock options.
5. Working capital deficiency is a non-GAAP measure calculated as current assets less current liabilities. See "Non-GAAP Measures".
6. Net debt is a non-GAAP measure calculated as bank debt and working capital deficiency, adjusted for the current portion of fair value of risk management contracts. See "Non-GAAP Measures".
7. Operating netbacks is a non-GAAP measure calculated on a per unit basis as natural gas and natural gas liquids revenues, adjusted for realized gains or losses on commodity risk management, less royalties, operating expenses and transportation costs. See "Non-GAAP Measures" and "Operating Netbacks".

Message to Shareholders

Ten years ago in May 2007, Painted Pony raised $12 million in the equity market and became a public company. We didn't have any production but we had 2 farm-in deals in Saskatchewan and access to 3-D seismic in northeast BC. Today, we will have, upon closing of the UGR acquisition, the third-largest natural gas reserves in Canada of any publicly traded company on both a Proven ("1P") and a Proved plus Probable ("2P") basis.

When we first introduced the concept of growing to 40,000 boe/d in the third year of our initial five-year plan, we believed it to be a very ambitious but achievable goal. However, when you carefully plan the development of a world class asset, and have a great group of dedicated people, you can accomplish exceptional things. We did this despite a challenging commodity price environment. Exiting 2016 with production volumes at these levels in conjunction with the commissioning of the AltaGas Townsend Facility, marked a significant milestone for Painted Pony. As proud as we are of the accomplishments in 2016, we strongly believe the best is yet to come. Our vision is continued production growth to between one and two Bcfe per day and hold our production flat for the following 20 years.

Painted Pony had a dramatic year of growth in 2016 and we haven't slowed down in 2017.

The production growth we achieved in 2016 was generated through drilling on our Montney sweet spot in northeast BC. We have the best royalty structure in North America and a highly supportive provincial government. Between the fourth quarter of 2013 with production of 9,312 boe/d and our December 2016 production volumes of more than 40,000 boe/d, we have organically **grown our production by 330%. We are indeed just getting started.**

"Opportunities don't happen. You create them."

-- Chris Grosser

Acquisition of UGR Blair Creek

Before discussing key highlights from 2016, I want to outline a significant development for Painted Pony. On March 15, 2017 we announced the acquisition of UGR Blair Creek Ltd. ("UGR") in an all-stock transaction of 41 million shares and assumed net debt of $47 million for total consideration of $277 million. We will be adding two large, supportive and technically strong shareholders who each took 100% shares in this transaction as they believe in the Painted Pony story for growth and increasing shareholder value. This acquisition is a highly strategic expansion of our world-class Montney project and one which we strongly believe is in the best long-term interests of shareholders. We have long-believed that the UGR assets are exceptionally synergistic with the Painted Pony assets. In the UGR acquisition, we are buying:

108 net sections of land in one of the most prolific parts of the Montney

51 MMcfe/d or **8,500** boe/d of production

99 MMcf/d of owned processing capacity

56 MMcf/d of third-party firm processing capacity

2P reserves of **2.0** Tcfe with a net present value (discounted 10%) of **$1.3** billion

1P reserves of **0.8** Tcfe with a net present value (discounted 10%) of **$568** million

We both have some of the best wells in the North Montney and we have partnered and been neighbours for 8 years. In fact, a recent analysis of 1,046 horizontal wells drilled in the North Montney as of January 1, 2017 showed that 11 of the top 12 most productive wells based on cumulative natural gas production during their initial 6 month production period are either Painted Pony or UGR. Of the 35 gross Montney wells drilled on UGR lands to-date, 20 have been drilled in partnership with us. Of the 218 gross undeveloped 2P locations on UGR lands as at December 31, 2016 per McDaniel & Associates Consultants, UGR's third-party independent reserves evaluator, 57 gross drilling locations are located on lands jointly held with us. The acquisition of UGR includes 197 net 2P drilling locations which will complement our inventory and are expected to drive our near-term growth in Proved Developed Producing ("PDP") reserves. In addition to those locations booked, our team estimates over 1,000 additional unbooked drilling locations on UGR lands.

Total consideration to be paid to UGR shareholders is $277 million or 41 million Painted Pony shares at a price of $5.60 per share and the assumption of $47 million of net debt. The price on this acquisition produced some of the best acquisition metrics for Montney assets in the last five years. This makes it extremely attractive value for Painted Pony shareholders. At closing, we will have the third-largest 2P and the third-largest 1P natural gas reserves of any Canadian publicly listed company at 6.4 Tcf and 3.2 Tcf, respectively. That makes both our 2P and our 1P natural gas reserves greater than EnCana, Birchcliff, Seven Generations, Peyto, ARC Resources, and Advantage. We are expanding our inventory of drilling locations and increasing our Montney land position by 52% to 314 net sections (201,009 net acres) at an average 94% working interest. We are acquiring 108 net sections

Daily Trading Volume (30 day average)

1.5 million shares per day

of land in an area where recent transactions indicate a market price of approximately $2.5 – $3.0 million per section. In addition to land, we are acquiring 1P reserves at just $0.36 per Mcfe and 2P reserves at $0.14 per Mcfe, all within some of the best Montney acreage with the most compelling economics in the Western Canadian Sedimentary Basin, and for that matter, North America.

As partners and neighbours, UGR's assets fit like a glove with our existing asset base. The acquired unused owned and third-party processing capacity of approximately 105 MMcf/d and transportation service will facilitate prudent growth in the near term. Our significantly lower drilling and completion costs relative to UGR will generate markedly improved economics as we execute our business plan on an expanded land base. When we apply our capital costs to the UGR resource base, future development capital is expected to be reduced by approximately $200 million which dramatically increases the net present value of UGR's assets upon closing of the acquisition. We strongly believe the acquisition of UGR provides us with a significantly expanded and de-risked platform from which we can accelerate production, cash flow, and further position Painted Pony as a dominant, full-cycle and low-cost producer in the Montney. The acquisition of UGR is consistent with our long-term strategy of cost-effective, counter-cyclical growth. A shareholder vote on this acquisition is set for May 11, 2017 at our Annual and Special Meeting of Shareholders.

Impressive and Continued Reserves Growth

Reserves represent the deep, underlying value of companies in the oil and gas business. During 2016, we were very pleased with the increase of our reserves and reserve value. Our PDP reserves went up by 102% to 0.5 Tcfe (80.7 MMboe) while total 1P reserves increased by 31% to 2.7 Tcfe and 2P reserves increased to more than 4.9 Tcfe. We were able to generate one of the best finding, development and acquisition PDP recycle ratios in the industry of 2.0 times and a Proved recycle ratio of 2.6 times in 2016, inclusive of changes in future development capital. We believe this key measure is necessary to determine the health of our business and such a strong result in 2016 verifies our value-creation strategies. In addition to reducing the cost of adding new reserves, due to lower well capital costs in 2016, we reduced 2P future development capital by approximately $300 million to $2.9 billion. The reduction in future development capital is more than the capital that was spent on our entire 2016 capital program. This resulted in a negative 2P finding and development cost and drove our 3-year weighted average 2P finding, development and acquisition recycle ratio to 5.7x which is top decile performance compared to industry peers.

Production Volumes

Daily production for 2016 averaged 139.2 MMcfe/d (23,204 boe/d) which was a 49% increase over 2015 annual average daily production of 93.6 MMcfe/d (15,604 boe/d). Of note, natural gas liquids production volumes increased 416% to 3,177 bbls/d during the fourth quarter of 2016 compared to 616 bbls/d during the fourth quarter of 2015. This increased production was made possible through the drilling program in our liquids-rich Townsend and Blair acreage and the early commissioning of the Townsend Facility. As a result of the increase in production volumes, we saw dramatically increased funds flow from operations during the fourth quarter of 2016 by a factor of 10 times to $26.5 million ($0.26/share) compared to $2.6 million ($0.03/ share) during the fourth quarter of 2015. It is rare that a company of our size can show this magnitude of cash flow per share growth year-over-year on growth from organic drilling.

Daily Production for 2016 averaged

139.2 MMcfe/day
(23,204 boe/d)

Capital Expenditures Below Budget

We were able to accomplish these operating results with capital expenditures of $203.5 million which was $11.5 million below budget. We had a busy year drilling 36 (36.0 net) wells targeting Montney natural gas. Facilities and equipment spending totaled $43.8 million and included wellsite facilities costs, pipeline construction costs and spending on compression and dehydration facilities. Solid execution of our 2016 capital budget, including significant growth of PDP reserves to 0.5 Tcfe, hitting production target milestones, all while spending less capital than forecasted, is something of which everyone at Painted Pony is very proud. I would like to thank an extraordinary team at Painted Pony for exceeding all expectations of cost reductions while maintaining an excellent health, safety and environmental record.

Key Transportation Strategies

We believe that a diversified transportation and sales hub network is vital to an effective risk mitigation strategy. We currently have access to total firm transportation of 357 MMcf/d by year-end 2017 and 577 MMcf/d by year-end 2018. In addition, Painted Pony has committed to an additional 130 MMcf/d of firm transportation to AECO at Groundbirch via the TCPL Towerbirch Expansion Project, further diversifying our market exposure. Our long-term firm natural gas transportation agreements provide for our growing production base and delivers AECO pricing on a significant portion of our natural gas production. During 2016 our natural gas sold at an average of 6% less than AECO pricing. In addition, we have executed physical delivery contracts with a number of counter-parties, which further diversify our pricing exposure. We will continue to pursue strategies such as these to position us for the best possible margins on our production volumes.

Summary

During 2016, we executed a capital plan that delivered results for shareholders entirely consistent with our 5 year growth plan, most notably organic production growth per share of more than 150% exit 2016 over exit 2015. The significant production milestones achieved in 2016 combined with decreasing cash expenses, continued capital cost reductions, and robust full-cycle economics highlighted by an exceptional PDP recycle ratio of 2.0 times, positions Painted Pony as an industry leader in low-cost, full-cycle Montney development. All of this was achieved in a continually challenging commodity price environment.

I want to thank everyone at Painted Pony for their hard work and commitment during 2016 which produced the results of which we are so proud. I look forward to many more successful milestones as we continue to build shareholder value through the development of our world-class Montney asset. I would also like to thank our Board of Directors, shareholders, service suppliers, government agencies, First Nations groups, staff and all other stakeholders for their continued support of Painted Pony. It truly has been a remarkable 10 years.

"signed"
Patrick R. Ward
President and Chief Executive Officer
March 30, 2017

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following Management's Discussion and Analysis ("MD&A") of the consolidated financial results of Painted Pony Petroleum Ltd. ("Painted Pony" or the "Corporation") should be read in conjunction with the consolidated financial statements and related notes thereto for the years ended December 31, 2016 and December 31, 2015. This commentary is dated February 27, 2017.

The annual consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS"). The financial data presented is in accordance with IFRS in Canadian dollars, except where indicated otherwise. These documents and additional information about Painted Pony, including the Annual Information Form ("AIF") for the year ended December 31, 2015, are available under the Corporation's profile on SEDAR at www.sedar.com and on the Corporation's website at www.paintedpony.ca.

BUSINESS OF THE CORPORATION

Painted Pony is a publicly traded corporation focused on the production of natural gas and natural gas liquids ("NGLs") from the Montney formation in northeast British Columbia. The common shares of Painted Pony ("Common Shares") trade on the Toronto Stock Exchange ("TSX") under the symbol "PPY". The Corporation's head office is located at Suite 1800, 736 – 6th Avenue SW, Calgary, Alberta.

NON-GAAP MEASURES

This MD&A contains the terms "funds flow from operations", "funds flow from operations per share", "funds flow from operations per Mcfe", "working capital deficiency", "net debt" and "operating netbacks", which do not have standardized meanings prescribed by IFRS and therefore may not be comparable with the calculation of similar measures presented by other issuers.

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 Corporation's ability to generate the cash necessary to fund future capital investment and to repay debt. Funds flow from operations denotes cash flow from operating activities before the effects of changes in non-cash working capital, deferred share unit ("DSU" or "DSUs") expense and decommissioning expenditures. "Funds flow from operations per share" is calculated using the basic and diluted weighted average number of shares for the period. "Funds flow from operations per Mcfe" is calculated using the average production volumes for the period. These terms 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 Corporation's performance. The Corporation 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:

Cash Flows from Operating Activities and Funds Flow from Operations

	Three months ended December 31,		**Years ended December 31,**	
($000s, except per share)	**2016**	2015	**2016**	2015
Cash flows from operating activities	**21,859**	3,024	**44,658**	31,705
Changes in non-cash working capital	**3,355**	(420)	**7,931**	(3,730)
Deferred share unit expense	**1,284**	(36)	**2,914**	487
Decommissioning expenditures	**3**	4	**102**	4
Funds flow from operations	**26,501**	2,572	**55,605**	28,466
Funds flow from operations per share *($/share)*	**0.26**	0.03	**0.56**	0.29

Management uses "working capital deficiency" and "net debt" as useful supplemental measures of the liquidity of the Corporation. Working capital deficiency is calculated as current assets less current liabilities. Net debt is calculated as bank debt and working capital deficiency, adjusted for the current portion of fair value of risk management contracts. These terms should not be considered alternatives to, or more meaningful than, current and long-term debt as determined in accordance with IFRS. The following table summarizes Painted Pony's calculations of working capital deficiency and net debt:

Working Capital Deficiency and Net Debt

($000s)	**December 31, 2016**	December 31, 2015
Current assets	**30,677**	18,856
Current liabilities	**(104,324)**	(23,485)
Working capital deficiency	**(73,647)**	(4,629)
Current portion of fair value of risk management contracts	**46,020**	(9,106)
Bank debt	**(200,836)**	(63,626)
Net debt	**(228,463)**	(77,361)

The increase in working capital deficiency is impacted by a $55.1 million change in the current portion of the fair value of risk management contracts.

“Operating netbacks” is used as a supplemental measure of the Corporation’s profitability relative to commodity prices. Operating netbacks are calculated on a per unit basis as natural gas and NGL revenues, adjusted for realized gains or losses on commodity risk management, less royalties, operating expenses and transportation costs. This term should not be considered an alternative to, or more meaningful than net income (loss) and comprehensive income (loss) as determined in accordance with IFRS. Please refer to “Operating Netbacks” for the calculation of this measure.

RESULTS OF OPERATIONS - OVERVIEW

Results of operations for 2016 were highlighted by the commencement of commercial operations at the 198 MMcf/d AltaGas Townsend Facility (“Townsend Facility”) in July 2016, approximately one month earlier than anticipated. Painted Pony exited 2016 having achieved a significant milestone with average daily production volumes for December of over 240.0 MMcfe/d or 40,000 boe/d. With production at the Townsend Facility ramping up throughout the third and fourth quarters, average volumes for the year ended December 31, 2016 of 139.2 MMcfe/d or 23,204 boe/d represented a 49% increase over 2015 average production.

With higher volumes and a combined 24% reduction in per unit royalties, operating expenses and transportation costs during the year, the Corporation nearly doubled its funds flow from operations for 2016 of $55.6 million ($0.56/share), compared to 2015 funds flow from operations of $28.5 million ($0.29/share).

Although commodity prices have recovered in the fourth quarter of 2016, the first nine months of the year were dominated by continued price depression. Painted Pony’s exposure to low commodity prices in 2016 was mitigated by risk management contracts that resulted in a $19.9 million realized gain on commodity risk management contracts for the year. After the impact of realized gains on commodity risk management contracts of $0.38 per Mcfe, Painted Pony’s operating netback was $1.73 per Mcfe, a 41% improvement over the previous year operating netback of $1.23 per Mcfe. As pricing improved through the fourth quarter, Painted Pony’s operating netback for the three months ended December 31, 2016 was $2.09/Mcfe, representing a 118% improvement over the fourth quarter of 2015 operating netback of $0.96 per Mcfe. For 2017, the Corporation has executed financial risk management contracts on 192.0 MMcf/d of natural gas and 500 bbl/d of NGL production. As part of the Corporation’s long term sales point diversification strategy, during the fourth quarter Painted Pony also began selling 45 MMcf/d of its production volumes directly into the AECO market and 18 MMcf/d of its production volumes into the SUMAS/Huntingdon market. In addition, during 2016, the Corporation entered into fixed price contracts for physical delivery of 71.0 MMcf/d priced at AECO less fixed differentials.

The capital program for 2016 was primarily focused on pre-drilling the wells required to supply the Townsend Facility upon startup, and included 36 (36.0 net) Montney natural gas wells drilled and 38 (38.0 net) Montney natural gas wells completed, as well as associated facilities infrastructure. The planned 2017 capital program is $319 million, and includes 61 (61.0 net) Montney wells drilled and completed.

At December 31, 2016, the Corporation’s syndicated credit facilities were $325 million, with the semi-annual borrowing base review to be completed by April 30, 2017. With an anticipated increase in credit facilities, and available transportation and processing capacity, Painted Pony is well positioned for continued growth.

CASH FLOWS FROM OPERATING ACTIVITIES, FUNDS FLOW FROM OPERATIONS AND NET LOSS

Increases in both cash flows from operating activities and funds flow from operations for the fourth quarter of 2016 compared to the fourth quarter of 2015, are a result of increased production and decreased operating expenses. Increases in both cash flows from operating activities and funds flow from operations for year ended December 31, 2016 compared to the year ended December 31, 2015, are a result of increased production, decreased operating expenses and transportation costs, and a $19.9 million gain on commodity risk management. For the three months and year ended December 31, 2016, Painted Pony generated funds flow from operations of $26.5 million and $55.6 million, respectively. The compares to $2.6 million and $28.5 million for the three months and year ended December 31, 2015, respectively.

For the quarter ended December 31, 2016, the Corporation generated a net loss of $27.8 million, resulting from an unrealized loss on commodity risk management contracts of $45.5 million. This compares to net income of $2.6 million for the quarter ended December 31, 2015, resulting from an unrealized gain on commodity risk management contracts of $10.0 million. Excluding the unrealized loss on commodity risk management contracts, income before taxes would be $8.0 million for the quarter ended December 31, 2016, compared to a $6.3 million loss before taxes for the quarter ended December 31, 2015. For the year ended December 31, 2016, the Corporation generated a net loss of $51.9 million, primarily due to an unrealized loss on commodity risk management of $75.7 million. For the year ended December 31, 2015, the Corporation had a net loss of $5.2 million.

AVERAGE DAILY PRODUCTION

	Three months ended December 31,				**Years ended December 31,**			
	2016	**% of total**	2015	% of total	**2016**	**% of total**	2015	% of total
Natural Gas *(Mcf/d)*	**201,111**	**91**	86,561	96	**129,881**	**93**	88,673	95
NGLs *(bbls/d)*	**3,177**	**9**	616	4	**1,557**	**7**	826	5
Total *(Mcfe/d)*	**220,170**	**100**	90,258	100	**139,222**	**100**	93,627	100
Total *(boe/d)*	**36,695**	**100**	15,043	100	**23,204**	**100**	15,604	100

Fourth quarter production volumes increased 144% compared to the fourth quarter of 2015 to average 220.2 MMcfe/d or 36,695 boe/d. Annual average production volumes increased 49% compared to the year ended December 31, 2015 to average 139.2 MMcfe/d or 23,204 boe/d. The production volume increase during both the quarter and year, was driven by the commissioning of the Townsend Facility in July 2016, and the subsequent increase in production volumes throughout the remainder of the year.

Production volumes for 2017 are expected to average 288.0 MMcfe/d or 48,000 boe/d. This represents a 107% increase over production volumes for the year ended December 31, 2016. Exit volumes for 2017 are expected to be approximately 408.0 MMcfe/d or 68,000 boe/d.

PETROLEUM AND NATURAL GAS REVENUE

	Three months ended December 31,		**Years ended December 31,**	
($000s)	**2016**	2015	**2016**	2015
Natural Gas	**51,529**	12,752	**96,803**	68,231
NGLs	**13,626**	2,296	**24,777**	13,352
Total	**65,155**	15,048	**121,580**	81,583

Petroleum and natural gas revenue totaled $65.2 million for the three months ended December 31, 2016, representing a 333% increase from the fourth quarter 2015 revenue of $15.0 million. The increase in quarterly revenue is driven by a 144% increase in production volumes, a 74% increase in realized natural gas prices and a 15% increase in realized NGLs prices.

During the year ended December 31, 2016, petroleum and natural gas revenue increased by 49% to $121.6 million compared to the year ended December 31, 2015, as a result of a 49% increase in average production volumes for the period, partially offset by a 3% decline in realized natural gas prices and a 2% decline in realized NGLs prices.

Commodity Prices

Average Benchmark Prices:		Three months ended December 31, 2016	2015	Years ended December 31, 2016	2015
Natural Gas	- Nymex *(US$/mmbtu)*	**3.18**	2.23	**2.55**	2.63
	- AECO, daily spot *($/Mcf)*	**3.12**	2.48	**2.17**	2.70
Crude Oil	- WTI *(US$/bbl)*	**49.29**	42.16	**43.48**	48.76
	- Edmonton par – light oil *($/bbl)*	**60.99**	52.68	**54.13**	58.43
Exchange rate *(US$/Cdn$)*		**0.75**	0.75	**0.76**	0.78
Realized Commodity Prices Before Commodity Risk Management:					
Natural Gas *($/Mcf)*		**2.78**	1.60	**2.04**	2.10
NGLs *($/bbl)*		**46.62**	40.51	**43.49**	44.30
Total *($/Mcfe)*		**3.22**	1.81	**2.39**	2.39

Despite the higher heat content of Painted Pony's natural gas as compared to the benchmark, realized pricing for both periods are reflective of a discount to AECO daily spot pricing. During the three months and year ended December 31, 2016, the Corporation realized natural gas prices that represented discounts of 11% and 6%, respectively, to the AECO daily spot price. This compares to discounts of 35% and 22% to the AECO daily spot price realized in the three months and year ended December 31, 2015.

As part of the Corporation's long term sales point diversification strategy, effective October 1, 2016, Painted Pony began selling 45 MMcf/d of its production volumes directly into the AECO market, and effective November 1, 2016, Painted Pony began selling 18 MMcf/d of its production volumes into the SUMAS/Huntingdon market. In addition, during 2016, the Corporation entered into fixed price contracts for physical delivery of 71.0 MMcf/d priced at AECO less fixed differentials.

For the three months ended December 31, 2016, approximately 49% of the Corporation's NGL volumes were condensate. For the year ended December 31, 2016, approximately 56% of the Corporation's NGL volumes were condensate.

In 2017, the Corporation expects to receive a realized natural gas price that represents a discount to the AECO daily spot price of 10% to 15%. A large component of the Corporation's exposure to volatility in commodity pricing in 2017 has been mitigated by the commodity risk management contracts described below, as well as physical contracts using AECO-based pricing or SUMAS-based pricing, less a fixed differential, as was done in 2016. The average prices reported are reflective of month to month price and production volume changes.

Financial Risk Management

The Audit Committee, on behalf of the Board of Directors of the Corporation (the "Board"), has overall responsibility for the establishment and oversight of the Corporation's risk management framework. The Audit Committee has implemented and monitors compliance with risk management policies. The Corporation's risk management policies are established to identify and analyze the risks faced by the Corporation, to set appropriate risk limits and controls, and to monitor risks and adherence to market conditions and the Corporation's activities. Painted Pony may be exposed to certain losses in the event that counterparties to derivative financial instruments are unable to fulfill their obligations under these contracts. The Corporation minimizes these risks by entering into agreements with investment grade counterparties. Painted Pony's exposure is limited to those counterparties holding derivative contracts with net positive fair values at a reporting date. For a further discussion of the Corporation's financial risks, see note 13 of the Corporation's audited consolidated financial statements for the year ended December 31, 2016.

Painted Pony has a commodity risk management program that currently uses financial instruments on a portion of its commodity production volumes to manage some of the exposure to commodity price risk and to provide a level of stability to operating cash flows, which further enables the Corporation to fund its capital development program. For the three months and year ended December 31, 2016, Painted Pony realized a loss of $1.6 million and a gain of $19.9 million, respectively, on its commodity risk management contracts, compared to realized gains of $2.0 million and $6.8 million for the three months and year ended December 31, 2015, respectively.

For the three months and year ended December 31, 2016, Painted Pony had unrealized losses on its commodity risk management contracts of $45.5 million and $75.7 million, respectively, compared to an unrealized gain of $10.0 million for both the three months and year ended December 31, 2015.

The Corporation's method of determining the fair values of derivative financial instruments is disclosed in note 14 of the Corporation's audited consolidated financial statements for the year ended December 31, 2016. The following is a summary of all commodity risk management contracts in place as at December 31, 2016:

Financial AECO Natural Gas Contracts

Reference	Volume (GJ/d)	Term	Weighted Average Price ($/GJ)	Options Traded
CDN$ AECO	90,000	Q1 2017	2.87	Swaps
CDN$ AECO	75,000	Q2 2017	2.85	Swaps
CDN$ AECO	90,000	Q3 2017	2.86	Swaps
CDN$ AECO	145,000	Q4 2017	2.89	Swaps
CDN$ AECO	71,000	Q1 2018	2.93	Swaps
CDN$ AECO	71,000	Q2 2018	2.85	Swaps
CDN$ AECO	50,000	Q3 2018	2.81	Swaps
CDN$ AECO	24,000	Q4 2018	2.72	Swaps
CDN$ AECO	18,000	Q1 2019	2.64	Swaps
CDN$ AECO	18,000	Q2 2019	2.64	Swaps
CDN$ AECO	25,000	Q4 2017 – Q4 2019	2.88	Call Options

Financial Station 2 Natural Gas Contracts

Reference	Volume (GJ/d)	Term	Weighted Average Price ($/GJ)	Options Traded
CDN$ Station 2	75,000	Q1 2017	1.82	Swaps
CDN$ Station 2	90,000	Q2 2017	1.90	Swaps
CDN$ Station 2	100,000	Q3 2017	1.93	Swaps
CDN$ Station 2	120,000	Q4 2017	2.07	Swaps
CDN$ Station 2	105,000	Q1 2018	2.04	Swaps
CDN$ Station 2	42,000	Q2 2018	2.38	Swaps
CDN$ Station 2	37,000	Q3 2018	2.36	Swaps
CDN$ Station 2	37,000	Q4 2018	2.36	Swaps
CDN$ Station 2	37,000	Q1 2019	2.36	Swaps
CDN$ Station 2	37,000	Q2 2019	2.36	Swaps
CDN$ Station 2	25,000	Q3 2019	2.37	Swaps
CDN$ Station 2	10,000	Q4 2019	2.45	Swaps

Financial WTI Crude Oil Contracts

Reference	Volume (bbl/d)	Term	Weighted Average Price ($/bbl)	Options Traded
CDN$ WTI	500	Q1 2017 – Q4 2017	70.05	Swaps
CDN$ WTI	500	Q1 2018 – Q4 2019	70.20	Swaps

Subsequent to December 31, 2016, Painted Pony entered into an additional commodity risk management contract as follows:

Reference	Volume (GJ/d)	Term	Weighted Average Price ($/GJ)	Options Traded
CDN$ AECO	10,000	Q1 2018	3.16	Swaps

ROYALTIES

	Three months ended December 31, 2016	2015	Years ended December 31, 2016	2015
Royalty expense *($000s)*	**1,382**	320	**2,672**	2,008
Per unit *($/Mcfe)*	**0.07**	0.04	**0.05**	0.06
Royalties as a % of Revenue *(%)*	**2.1**	2.1	**2.2**	2.5

For the three months ended December 31, 2016, and December 31, 2015, royalties were $1.4 million and $0.3 million, respectively, which represents 2.1% of total revenue for both periods. For the year ended December 31, 2016, and December 31, 2015, royalties were $2.7 million and $2.0 million, respectively, which represents 2.2% and 2.5% of total revenue, respectively, due to a decrease in commodity prices. The Corporation's properties are on the west side of the British Columbia reduced royalty line, and therefore receive significant average royalty credits of approximately $2.2 million per well.

For 2017, the Corporation anticipates overall royalty rates to be approximately 3.0% of total revenues as a result of royalty credits. This estimate considers the combined impact of incremental sales volumes from newly drilled wells that will qualify for royalty holidays, net of royalties paid on wells that have obtained the full benefit of provincial royalty incentives.

OPERATING EXPENSES

	Three months ended December 31, 2016	2015	Years ended December 31, 2016	2015
Operating expenses *($000s)*	**12,035**	6,161	**34,535**	31,978
Per unit *($/Mcfe)*	**0.59**	0.74	**0.68**	0.94

Operating expenses were reduced by $0.15 per Mcfe or 20% in the fourth quarter of 2016 compared to the fourth quarter of 2015. On an annual basis, operating expenses decreased by $0.26 per Mcfe or 28%. Per unit operating expenses for the quarter and year have improved as a result of incremental production volumes positively impacting fixed cost components. In addition, with the start-up of the Townsend Facility in the third quarter of 2016, the capital fee associated with the facility is classified separately from operating expenses, with the interest portion of the capital fee included in finance expense.

For 2017, the Corporation anticipates that average per unit operating expenses will be in the range of $0.45 to $0.55 per Mcfe, assuming normal seasonal weather conditions.

TRANSPORTATION COSTS

	Three months ended December 31, 2016	2015	Years ended December 31, 2016	2015
Transportation costs *($000s)*	**7,653**	2,549	**15,894**	12,149
Per unit *($/Mcfe)*	**0.38**	0.31	**0.31**	0.36

Transportation costs for the three months ended December 31, 2016 increased by $0.07 per Mcfe or 23%, compared to the three months ended December 31, 2015. For the year ended December 31, 2016, transportation costs decreased by $0.05 per Mcfe or 14% compared to the year ended December 31, 2015.

Transportation costs have increased for the three months ended December 31, 2016 compared to the three months ended December 31, 2015 due to an increase in NGL volumes, which have higher transportation costs, and have decreased for the year ended December 31, 2016, as the Corporation successfully negotiated access to alternate delivery points with improved economics for trucking of NGLs.

For 2017, the Corporation expects average per unit transportation costs to be approximately $0.35 to $0.40 per Mcfe.

OPERATING NETBACKS

($/Mcfe)	Three months ended December 31, **2016**	2015	Years ended December 31, **2016**	2015
Realized commodity price	**3.22**	1.81	**2.39**	2.39
Realized gain (loss) on commodity risk management contracts	**(0.09)**	0.24	**0.38**	0.20
Royalties	**(0.07)**	(0.04)	**(0.05)**	(0.06)
Operating expenses	**(0.59)**	(0.74)	**(0.68)**	(0.94)
Transportation costs	**(0.38)**	(0.31)	**(0.31)**	(0.36)
Operating netbacks	**2.09**	0.96	**1.73**	1.23

For the three months ended December 31, 2016, operating netbacks increased by $1.13 per Mcfe or 118% due to a reduction of 5% in combined per unit royalties, operating expenses and transportation costs, due to a 78% increase in commodity prices, and due to higher relative liquid volumes compared to the three months ended December 31, 2015.

For the year ended December 31, 2016, operating netbacks increased by $0.50 per Mcfe or 41% due to a reduction of 24% in combined per unit royalties, operating expenses and transportation costs, and due to higher relative liquid volumes compared to the year ended December 31, 2015.

GENERAL AND ADMINISTRATIVE EXPENSES

($000s, except per Mcfe)	Three months ended December 31, **2016**	2015	Years ended December 31, **2016**	2015
Gross expenses	**6,963**	7,061	**19,310**	17,251
Capitalized	**(2,646)**	(2,128)	**(5,937)**	(4,720)
Capital recoveries	**(668)**	(239)	**(2,343)**	(1,291)
Operating recoveries	**(118)**	(103)	**(464)**	(296)
Net expenses	**3,531**	4,591	**10,566**	10,944
Per unit *($/Mcfe)*	**0.17**	0.55	**0.21**	0.32

Net general and administrative ("G&A") expenses per unit decreased by $0.38 per Mcfe or 69% and $0.11 per Mcfe or 34% for the three months and year ended December 31, 2016, respectively, compared to the three months and year ended December 31, 2015. The lower per unit expense in both periods was primarily due to higher volumes, as well as the Corporation's continued focus on cost control.

The Corporation's policy of allocating and capitalizing costs associated with new capital projects remained unchanged for the period ended December 31, 2016. G&A capitalized and operating recoveries are in accordance with industry practice.

For 2017, the Corporation anticipates that per unit G&A expenses will average approximately $0.10 per Mcfe to $0.12 per Mcfe.

FINANCE EXPENSE

($000s)	Three months ended December 31, 2016	2015	Years ended December 31, 2016	2015
Finance lease expense	**9,730**	-	**14,165**	-
Bank finance expense	**2,691**	849	**8,055**	2,868
Accretion of decommissioning obligations	**158**	120	**550**	392
Total	**12,579**	969	**22,770**	3,260
Per unit *($/Mcfe)*	**0.68**	0.12	**0.48**	0.10

Finance lease expense is incurred in connection with the capital fee paid on the Townsend Facility, and is expected to vary with production volumes processed at the facility. The capital fee associated with the Townsend Facility includes finance lease expense and any amortization of the outstanding finance lease obligation.

Bank finance expense includes interest expense on bank debt and standby charges on the Corporation's syndicated credit facilities.

Per unit finance expense for the three months ended December 31, 2016 was $0.68 per Mcfe compared to $0.12 per Mcfe for the three months ended December 31, 2015. For the years ended December 31, 2016 and December 31, 2015, per unit finance expense was $0.48 Mcfe and $0.10 per Mcfe, respectively. For the quarter and year ended December 31, 2016, bank finance expense was higher than the quarter and year ended December 31, 2015 due to additional bank debt throughout the periods, as well as larger available syndicated credit facilities on which standby fees are calculated.

Accretion expense on decommissioning obligations increased for the three months ended December 31, 2016, compared to the three months ended December 31, 2015, as a result of a higher decommissioning obligation balance on which accretion expense is calculated. At December 31, 2016, the risk-free interest rate related to the decommissioning obligations was 2.1% compared to 2.2% at December 31, 2015. The Corporation has estimated the net present value of the decommissioning obligations based on an undiscounted total future liability of $64.2 million at December 31, 2016, compared to $47.5 million at December 31, 2015.

FUNDS FLOW FROM OPERATIONS

($000s)	Three months ended December 31, 2016	2015	Years ended December 31, 2016	2015
Petroleum and natural gas revenue	**65,155**	15,048	**121,580**	81,583
Realized gain (loss) on commodity risk management	**(1,632)**	1,994	**19,912**	6,830
Royalties	**(1,382)**	(320)	**(2,672)**	(2,008)
Operating expenses	**(12,035)**	(6,161)	**(34,535)**	(31,978)
Transportation costs	**(7,653)**	(2,549)	**(15,894)**	(12,149)
General and administrative expenses	**(3,531)**	(4,591)	**(10,566)**	(10,944)
Finance lease expense	**(9,730)**	-	**(14,165)**	-
Bank finance expense	**(2,691)**	(849)	**(8,055)**	(2,868)
Funds flow from operations	**26,501**	2,572	**55,605**	28,466
Per unit *($/Mcfe)*	**1.31**	0.31	**1.09**	0.83

SHARE-BASED COMPENSATION EXPENSE

	Three months ended December 31,		Years ended December 31,	
($000s)	**2016**	2015	**2016**	2015
Gross expense	**711**	2,114	**3,484**	5,653
Capitalized	**(121)**	(391)	**(620)**	(1,073)
Deferred share unit expense	**1,284**	(36)	**2,914**	487
Net expense	**1,874**	1,687	**5,778**	5,067

Gross share-based compensation expense was $0.7 million and $2.1 million for the three months ended December 31, 2016 and 2015, respectively. The lower expense was driven primarily by stock options having been granted in the fourth quarter of 2015, and not in the fourth quarter of 2016. Gross share-based compensation expense for the year ended December 31, 2016 of $3.5 million was 38% lower than gross share-based compensation expense for the year ended December 31, 2015 of $5.7 million due to fewer stock options granted throughout the year.

The weighted average fair value of stock options granted during the year using the Black-Scholes model was $1.86 per stock option during the year ended December 31, 2016, compared to $1.81 per stock option during the year ended December 31, 2015.

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

Deferred Share Unit Expense

The Corporation has a DSU plan, whereby DSUs are issued to members of the Board, who are not employees of the Corporation, and to eligible executive officers, in the Board's discretion. Each DSU is a notional unit equal in value to one Common Share, which entitles the holder to a cash payment upon redemption. DSUs vest upon grant but can only be converted to cash upon the holder ceasing to be a director or executive officer of the Corporation. As at December 31, 2016 there were 282,342 DSUs outstanding, and 70,347 DSUs accrued but not granted. At February 27, 2017, there were 299,982 DSUs outstanding, and 52,707 DSUs accrued but not granted.

The expense associated with the DSU plan is determined based on the 20-day volume weighted average price of Common Shares at the grant date. The expense is recognized in the statement of operations immediately upon grant, with a corresponding DSU liability recorded as a current liability in the statement of financial position. At period end dates, the DSU liability is adjusted based on the 20-day volume weighted average price of Common Shares.

For the three months ended December 31, 2016, the Corporation recognized DSU expense of $1.3 million compared to a reduction in the liability of less than $0.1 million for the three months ended December 31, 2015. For the year ended December 31, 2016, the Corporation recognized DSU expense of $2.9 million compared to $0.5 million for the year ended December 31, 2015. The increased expense was due to additional DSUs granted in the period as well as share appreciation, causing the 20-day volume weighted average price of Common Shares used in DSU calculations to increase.

DEPLETION AND DEPRECIATION EXPENSE

	Three months ended December 31,		Years ended December 31,	
	2016	2015	**2016**	2015
Depletion and depreciation *($000s)*	**16,491**	7,109	**43,329**	39,829
Per unit *($/Mcfe)*	**0.81**	0.86	**0.85**	1.17

Depletion and depreciation expense per unit for the three months ended December 31, 2016 decreased by 6% or $0.05 per Mcfe, as compared to the same period in 2015. The depletion rate was positively impacted by a 7% increase in total proved and probable reserves since December 31, 2015. The depletion calculation for the three months ended December 31, 2016 included future development costs associated with the development of the Corporation's proved plus probable reserves of $2.9 billion, compared to $3.2 billion for the three months ended December 31, 2015.

The Corporation's exploration and evaluation ("E&E") assets totaling $114.3 million as at December 31, 2016, compared to $116.1 million as at December 31, 2015, were not subject to depletion.

CAPITAL EXPENDITURES

	Three months ended December 31,		**Years ended December 31,**	
($000s)	**2016**	2015	**2016**	2015
Drilling and completions	**37,081**	8,936	**152,894**	78,699
Facilities and equipment	**11,234**	3,119	**43,767**	22,056
Lease acquisitions and retention	**138**	197	**614**	646
Seismic	**166**	79	**716**	153
Property dispositions	**9**	-	**(386)**	-
Capitalized G&A	**2,646**	2,128	**5,937**	4,720
Exploration and development	**51,274**	14,459	**203,542**	106,274
Head office expenditures	**232**	108	**849**	380
Capital expenditures	**51,506**	14,567	**204,391**	106,654
Finance lease assets	**(4,140)**	-	**360,860**	-
Share-based compensation	**121**	391	**620**	1,073
Decommissioning costs	**(2,214)**	4,013	**7,929**	6,834
Total	**45,273**	18,971	**573,800**	114,561

During the three months and year ended December 31, 2016 the Corporation invested $51.3 million and $203.5 million in exploration and development capital expenditures, respectively, compared to $14.5 million and $106.3 million, respectively, during the three months and year ended December 31, 2015.

Capital expenditures for 2016 included $152.9 million on drilling and completions activity. During 2016, the Corporation drilled 36 (36.0 net) wells and completed 38 (38.0 net) wells targeting Montney natural gas. Expenditures on facilities and equipment during the year totaled $43.8 million and included equipment costs and pipeline construction costs.

On July 27, 2016, Painted Pony announced that it had entered into a non-cash asset exchange agreement, in respect of acreage, wells and non-operated facility interests, with a large industry partner on jointly held acreage in the Daiber, Cameron and Blair Creek areas of British Columbia. The asset exchange closed on September 26, 2016, with an effective date of January 1, 2016. Adjustments between the effective and closing dates are included in property, plant and equipment as property dispositions. Management has performed an assessment of the exchange and has concluded that the transaction does not meet the criteria of commercial substance as defined in IAS 16.

The Corporation's 2017 capital program is currently anticipated to be $319 million. In 2017, the Corporation intends to drill and complete 61 (61.0 net) Montney horizontal natural gas wells on its 100% working interest lands in the Townsend and Blair Creek areas.

LIQUIDITY AND CAPITAL RESOURCES

As at December 31, 2016, the Corporation had a working capital deficiency of $73.6 million. Management anticipates that the Corporation will continue to have adequate liquidity to fund working capital requirements and capital expenditures through a combination of cash flows and available credit facilities. As a result of the current commodity pricing environment, uncertainty exists in the commodity, credit and capital markets, which the Corporation continues to monitor in conjunction with its financing alternatives.

As at December 31, 2016, the Corporation's syndicated credit facilities were $325 million, with the semi-annual borrowing base review to be completed by April 30, 2017.

The facilities are provided by a syndicate of financial institutions, and include a $275 million extendible revolving facility and a $50 million operating facility. The facilities revolve for a 2-year period, which is extendible annually, subject to syndicate approval. The facilities are subject to semi-annual review and re-determination of borrowing base by April 30 and October 31 of each year, or in the circumstance of a material adverse event. Any re-determination of the borrowing base is effective immediately, and if the borrowing base is reduced, the Corporation has 60 days to repay any shortfall. The next review is expected to occur on or before April 30, 2017.

As at December 31, 2016 Painted Pony had $200.0 million in bankers' acceptances with an effective interest rate of 4.68% per annum. In addition, as at December 31, 2016 the Corporation had an outstanding letter of credit of $14.9 million, which reduces the credit available on the operating facility.

The credit facilities bear interest on a matrix system that ranges from the bank's prime rate plus 1.0% to the bank's prime rate plus 3.5% per annum depending on the Corporation's total debt to EBITDA ratio as defined by the lenders, ranging from less than 1:1 to greater than 4:1. The credit facilities provide that advances may be made by way of prime rate loans, U.S. Base Rate loans, London InterBank Offered Rate loans, bankers' acceptances, letters of credit or letters of guarantee. A standby fee of 0.5% to 1.125% per annum is charged on the undrawn portion of the credit facilities, also calculated depending on the Corporation's total debt to EBITDA ratio, as defined by the lenders.

Security is provided by a floating charge demand debenture in the aggregate amount of $500 million on all of the Corporation's assets. The Corporation has provided a negative pledge and an undertaking to provide fixed charges over major producing petroleum and natural gas reserves in certain circumstances. The syndicated credit facilities are not subject to financial covenants.

The Corporation's objective is to maintain a total debt to annualized EBITDA ratio of less than 2.5:1, with a targeted ratio of 2.0:1. At December 31, 2016 the Corporation's total debt to EBITDA ratio was 1.96:1. Painted Pony anticipates that its total debt to EBITDA ratio will be reduced significantly in conjunction with a full year of operations at the Townsend Facility, as current debt levels are primarily associated with the capital expenditures that were required in advance of commissioning of the Townsend Facility to ensure that sufficient production volumes would be available upon start-up.

ALTAGAS STRATEGIC ALLIANCE

On August 18, 2014 the Corporation entered into a series of agreements (collectively the "Strategic Alliance") with AltaGas Ltd. ("AltaGas") relating to the development of processing infrastructure and marketing services for natural gas and NGLs. The chairman of the board of directors of AltaGas is a director of Painted Pony.

Under the Strategic Alliance, AltaGas committed to building the Townsend Facility and related pipeline infrastructure, which commenced commercial operations in July 2016. Painted Pony does not acquire any legal right, title, or interest in the Townsend Facility or pipeline. All construction costs are borne by AltaGas. The Corporation has the right to a minimum of 150 MMcf/d of firm capacity at this facility effective October 1, 2016, increasing to 198 MMcf/d of firm capacity by August 1, 2017, in respect of each of which there is a take or pay obligation on production volumes delivered to the facility of 135 MMcf/d commencing October 1, 2016 and 180 MMcf/d commencing August 1, 2017.

The Townsend Facility and related pipeline infrastructure have been recorded as a finance lease. Painted Pony has recorded the asset, representing the total estimated construction cost of the Townsend Facility, with a corresponding obligation on the statement of financial position. Over the course of the 20-year lease, there will be a capital fee paid to AltaGas, which will include finance costs and the amortization of the obligation. The associated processing fee will be recorded in operating expenses.

The cost of the Townsend Facility and related pipeline infrastructure is $360.9 million. Total expected payments based on annual take or pay volumes, including both the principal and financing components, are reflected in the table below.

($000s)	**Within 1 year**	**After 1 year but no more than five years**	**More than five years**	**Total**
Processing	34,437	218,669	487,113	740,219
Transportation	3,570	20,653	83,372	107,595
Total	38,007	239,322	570,485	847,814
Principal	-	44,515	316,345	360,860

COMMITMENTS

The following is a summary of the estimated costs required to fulfill Painted Pony's remaining contractual commitments as at December 31, 2016.

($000s)	**2017**	**2018**	**2019**	**2020**	**2021**	**Thereafter**	**Total**
Transportation	18,733	40,229	46,228	44,618	41,518	663,935	855,261
Processing	3,129	-	-	-	-	-	3,129
Office leases	1,447	1,466	1,175	-	-	-	4,088
Total commitments	23,309	41,695	47,403	44,618	41,518	663,935	862,478

Transportation commitments include contracts to transport natural gas and NGLs through third-party owned pipeline systems in British Columbia. Processing commitments include contracts to process natural gas through third-party owned gas processing facilities in British Columbia. Office leases include the Corporation's contractual obligations for office space.

The Corporation has certain lease arrangements that are reflected in the commitments table above, which were entered into in the normal course of operations. All leases, other than the Townsend Facility finance lease, have been treated as operating leases whereby the lease payments are included in operating expenses or general and administrative expenses depending on the nature of the lease.

Subsequent to December 31, 2016, Painted Pony committed to enter into an agreement with AltaGas in respect of the next phase of the Townsend Facility ("Townsend Phase 2"). AltaGas will be constructing Townsend Phase 2 in two separate gas processing trains, the first of which will be a 99 MMcf/d gas processing facility to be located on the existing Townsend site. Including the addition of incremental field compression equipment, the estimated total cost of the first train will be approximately $120 to $140 million. Painted Pony expects to enter into the agreement to be the sole supplier of natural gas to this first train and associated field compression equipment during 2017.

OFF BALANCE SHEET ARRANGEMENTS

No off balance sheet arrangements existed as at December 31, 2016 or December 31, 2015.

SHARE CAPITAL

The Corporation has an unlimited number of Common Shares and an unlimited number of Preferred Shares ("Preferred Shares") authorized for issuance. As at December 31, 2016 and February 27, 2017, there were 100,158,192 Common Shares issued and outstanding, and nil Preferred Shares issued and outstanding at either date.

The Corporation has an incentive stock option plan whereby stock options to purchase Common Shares may be granted to directors, executive officers and employees of the Corporation and are exercisable over a five-year period. Effective January 1, 2016, new stock options granted vest as to one-third on each of the first, second, and third anniversaries of the grant date. Stock options granted prior to January 1, 2016 vested as to one-third immediately, with the balance over two years. As at December 31, 2016, an aggregate of 8,622,517 stock options were issued and outstanding at a weighted-average price of $7.45 per stock option. As at February 27, 2017, an aggregate of 8,577,517 stock options were issued and outstanding at a weighted-average price of $7.43 per stock option.

INCOME TAXES

As at December 31, 2016, the Corporation had a $32.6 million deferred tax asset, which was recognized as cash flows are expected to be sufficient to realize the deferred tax asset. This compares to $14.7 million as at December 31, 2015. The Corporation recognized a deferred tax recovery of $17.9 million during the year ended December 31, 2016, compared to $1.6 million for the year ended December 31, 2015. The deferred tax recovery resulted primarily from an unrealized loss on commodity risk management of $75.7 million during the year.

The Corporation expects that future taxable income will be available to utilize accumulated tax pools. Painted Pony's estimated tax pools at December 31, 2016 were $926.8 million.

DIVIDENDS

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

PERFORMANCE COMPARED TO EXPECTATIONS

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

- For 2016, the Corporation expected to receive a natural gas price that represented a discount to the AECO daily spot price. The actual weighted average price received during the year of 2016 represented a 6% discount pricing to the AECO reference price. The realized price for the year does not include a $19.9 million realized gain on commodity risk management contracts, which partially mitigated lower realized prices.
- The actual royalty rate for the fourth quarter of 2016 was 2.1% of total revenues, compared to Painted Pony's third quarter 2016 announced guidance of less than 3.0 % of total revenues. The actual royalty rate for the year ended 2016 was 2.2% of total revenues, compared to the previous year's announced estimate of approximately 3.0% of total revenues. Lower royalty expense in both periods is due to lower than expected commodity prices.
- Operating expenses for the fourth quarter of 2016 were $0.59 per Mcfe, compared to Painted Pony's third quarter 2016 announced guidance of $0.55 to $0.60 per Mcfe. Operating expenses for the year ended December 31, 2016 were $0.68 per Mcfe, compared to the previous year's announced estimate of approximately $0.85 per Mcfe. Lower than anticipated operating expenses for the year are primarily due to lower than expected processing fees and the early start-up of the Townsend Facility.
- Transportation costs for the fourth quarter of 2016 were $0.38 per Mcfe, compared to Painted Pony's third quarter 2016 announced guidance of $0.30 per Mcfe, due to higher transportation tolls commencing in November 2016. Transportation costs for the year ended December 31, 2016 were $0.31 per Mcfe, compared to the previous year's announced estimate of approximately $0.40 per Mcfe, due to lower than estimated NGL production volumes, which have higher associated trucking costs.
- G&A expenses for the fourth quarter of 2016 were $0.17 per Mcfe, compared to Painted Pony's third quarter 2016 announced guidance of $0.20 per Mcfe. G&A expenses for the year ended December 31, 2016 were $0.21 per Mcfe, compared to the previous years announced estimate of approximately $0.25 per Mcfe. Lower G&A expenses in both periods is related to the Corporation's continued focus on cost control.

CRITICAL ACCOUNTING JUDGMENTS AND ESTIMATES

The preparation of financial statements requires management to make judgments, estimates and assumptions that affect the application of IFRS accounting policies, reported amounts of assets and liabilities, and income and expenses. Accordingly, 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 period in which the estimates are revised and in any future periods affected.

Critical Accounting Judgments

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

Cash-Generating Units

The Corporation's assets are aggregated into cash-generating units ("CGU" or "CGUs") for the purpose of assessing impairment. CGUs are based on an assessment of the unit's ability to generate independent cash inflows. The determination of these CGUs was based on management's judgment in regard to shared infrastructure, geographical proximity, petroleum type and exposure to market risk and materiality. By their nature, these assumptions are subject to management's judgment and may impact the carrying value of the Corporation's net assets in future periods.

Impairment Indicators

Judgments are required to assess when impairment indicators exist and impairment testing is required. The Corporation is required to consider information from both external sources (such as negative downturn in commodity prices, significant adverse changes in the technological, market, economic or legal environment in which the entity operates) and internal sources (such as downward revisions in reserves, significant adverse effect on the financial and operational performance of a CGU, evidence of obsolescence or physical damage to the asset). In determining the recoverable amount of assets, in the absence of quoted market prices, impairment tests are based on estimates of reserves, production rates, future petroleum and natural gas prices, future costs, discount rates, market value of land and other relevant assumptions.

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

Deferred Taxes

In determining its deferred tax provisions, the Corporation must apply judgment when interpreting and applying tax laws and regulations. The determination of the appropriate rules may be uncertain for many periods. The final outcome could result in amounts different from those initially recorded and could impact tax expense in the periods where a determination is made. Judgments are also made by management to determine the likelihood of whether deferred income tax assets at the end of the reporting period will be realized from future taxable income.

Critical Accounting Estimates

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

Impact of Reserves

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

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

Share-Based Compensation

All equity-settled, share-based awards issued by the Corporation are fair valued using the Black-Scholes option-pricing model. In assessing the fair value of equity-based compensation, estimates have to be made regarding the expected volatility in share price, option life, dividend yield, risk-free rate and estimated forfeitures at the initial grant date.

Derivative Financial Instruments

Painted Pony records commodity price contracts at fair value with changes in fair value recognized in the statements of operations. The Corporation's estimate of the fair value is determined using observable market data and external counterparty information, including estimated forward prices and volatility in those prices.

Decommissioning Obligations

The Corporation estimates future remediation costs of production facilities, wells and pipelines at different stages of development and construction of assets or facilities. In most instances, removal of assets occurs many years into the future. This requires judgment regarding abandonment date, future environmental and regulatory legislation, the extent of reclamation activities, the engineering methodology for estimating cost, future removal technologies in determining the removal cost and liability-specific discount rates to determine the present value of these cash flows.

Deferred Taxes

Tax provisions are based on enacted or substantively enacted laws. Changes in those laws could affect amounts recognized in net income or loss both in the period of change, which would include any impact on cumulative provisions, and in future periods.

Deferred tax assets are recognized only to the extent it is considered probable that those assets will be recoverable. This involves an assessment of when those deferred tax assets are likely to reverse and a judgment as to whether or not there will be sufficient taxable profits available to offset the tax assets when they do reverse. This requires assumptions regarding future profitability and is therefore inherently uncertain. Estimates of future taxable income are based on forecasted cash flows from operations.

FUTURE ACCOUNTING PRONOUNCEMENTS

A number of new accounting standards, amendments to accounting standards and interpretations are effective for annual periods beginning on or after January 1, 2017 and have not been applied in preparing the consolidated financial statements for the year ended December 31, 2016. The standards applicable to the Corporation are as follows and will be adopted on their respective effective dates:

Liabilities Arising from Financing Activities

As of January 1, 2017, the Corporation will be required to adopt IAS 7 "Statement of Cash Flows", which requires disclosures that enable financial statement users to evaluate changes in liabilities arising from financing activities, including both changes arising from cash flows and non-cash changes. The Corporation does not anticipate a material impact on its consolidated financial statements as a result of adopting IAS 7.

Financial Instruments

In July 2014, the IASB issued the final version of IFRS 9 "Financial Instruments", which replaces IAS 39 "Financial Instruments: Recognition and Measurement". The standard will come into effect for annual periods beginning on or after January 1, 2018 with earlier adoption permitted.

IFRS 9 introduces a single approach to determine whether a financial asset is measured at amortized cost or fair value and replaces the multiple rules in IAS 39. The approach is based on how an entity manages its financial instruments in the context of its business model and the contractual cash flow characteristics of the financial assets. For financial liabilities, IFRS 9 retains most of the requirements of IAS 39; however, where the fair value option is applied to financial liabilities, any change in fair value resulting from an entity's own credit risk is recorded in OCI rather than the statement of operations, unless this creates an accounting mismatch. Based on its preliminary assessment, the Corporation does not anticipate these changes to have a material impact on its consolidated financial statements.

In addition, IFRS 9 introduces a new expected credit loss model for calculating impairment of financial assets, replacing the incurred loss impairment model required by IAS 39. The new model will result in more timely recognition of expected credit losses. Painted Pony does not anticipate the new impairment model to have a material impact on the consolidated financial statements.

IFRS 9 also contains a new model to be applied for hedge accounting, aligning hedge accounting more closely with risk management. The Corporation does not currently apply hedge accounting to its risk management contracts and does not currently intend to apply hedge accounting to any of its existing risk management contracts on adoption of IFRS 9.

Revenue Recognition

As of January 1, 2018, the Corporation will be required to adopt IFRS 15 “Revenue from Contracts with Customers”, which replaces IAS 18 “Revenue”. The standard provides a single, principles based five-step model to be applied to all contracts with customers. The standard requires an entity to recognize revenue to reflect the transfer of goods and services for the amount it expects to receive, when control is transferred to the purchaser. Disclosure requirements have also been expanded.

The standard is required to be adopted either retrospectively or using a modified retrospective approach for annual periods beginning on or after January 1, 2018, with earlier adoption permitted. The Corporation is in the process of reviewing its revenue streams and underlying contracts with customers to determine the impact, if any, that the adoption of IFRS 15 will have on its financial statements and related disclosure.

Leases

In January 2016, the IAS issued IFRS 16 “Leases”, which replaces IAS 17 “Leases”, and provides that a single recognition and measurement model for leases would apply, with required recognition of assets and liabilities for most leases. For lessees, IFRS 16 removes the classification of leases as either operating or finance leases, effectively treating all leases as finance leases. Certain short-term leases (less than 12 months) and leases of low-value assets are exempt from the requirements, and may continue to be treated as operating leases.

IFRS 16 is effective for years beginning on or after January 1, 2019, with early adoption permitted if IFRS 15 “Revenue from Contracts with Customers” has been adopted. The standard may be applied retrospectively or using a modified retrospective approach. It is anticipated that the adoption of IFRS 16 will have a material impact on the Corporation’s consolidated statement of financial position due to material operating lease commitments as disclosed in note 16.

BUSINESS RISKS

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

- volatility of natural gas and crude oil prices;
- availability of qualified personnel and drilling equipment;
- finding and developing petroleum and natural gas reserves at economic costs;
- production of petroleum and natural gas in commercial quantities; and
- marketability of petroleum and natural gas production.

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

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

Oil and gas exploration and production can involve environmental risks such as pollution of the environment and destruction of natural habitat, as well as safety risks such as personal injury. In order to mitigate such risks, Painted Pony conducts its operations with high standards and follows safety procedures intended to reduce the potential for personal injury to employees, contractors and the public at large. The Corporation maintains insurance coverage to address significant business risks, at market rates and within defined limits and deductibles. 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.

Additional information about the Corporation's business risks is outlined in the advisories section of this MD&A and is available in Painted Pony's AIF for the year ended December 31, 2015 that is filed on SEDAR at www.sedar.com.

LEGAL, ENVIRONMENTAL, REMEDIATION AND OTHER CONTINGENT MATTERS

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

Aboriginal peoples have claimed aboriginal title and rights to portions of western Canada, including northeast British Columbia. On August 8, 2016, the Blueberry River First Nation (BRFN) applied for an interlocutory injunction in the Supreme Court of British Columbia. This injunction seeks to restrain the Province of British Columbia from, among other things, permitting new oil and gas activities within a portion of northeast British Columbia, where a substantial portion of the Corporation's land is situated. In the highly unlikely event that this application is successful, it would likely have an adverse impact on the Corporation, its operations and its production. The interlocutory injunction was heard in early November 2016 and a decision is expected to be handed down in the first quarter of 2017. The interlocutory injunction is part of an underlying claim against the Province of British Columbia, filed on March 3, 2015, which seeks relief for alleged breaches of treaty rights in northeast British Columbia. The Corporation is not a party to either the interlocutory injunction or to the underlying claim.

DISCLOSURE CONTROLS & PROCEDURES AND INTERNAL CONTROL OVER FINANCIAL REPORTING

The Corporation's Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO") have designed, or caused to be designed under their supervision, disclosure controls and procedures ("DC&P"), as defined in National Instrument 52-109 – *Certification of Disclosure in Issuer's Annual and Interim Filings* ("NI 52-109") to provide reasonable assurance that: (i) material information relating to the Corporation is made known to the Corporation's CEO and CFO by others, particularly during the period in which the annual and interim filings are being prepared; and (ii) information required to be disclosed by the Corporation in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time period specified in securities legislation. As at December 31, 2016, the CEO and CFO evaluated the design and operation of the Corporation's DC&P. Based on that evaluation, the CEO and CFO concluded that the Corporation's DC&P was effective as at December 31, 2016.

The Corporation has established and maintains internal control over financial reporting using the criteria that were set forth by the Committee of Sponsoring Organizations of the Treadway Commission in Internal Control – Integrated Framework (2013). The Corporation's CEO and CFO have designed, or caused to be designed under their supervision, internal controls over financial reporting ("ICFR"), as defined in NI 52-109, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. As at December 31, 2016, the CEO and CFO evaluated the design and operating effectiveness of the Corporation's ICFR. Based on that evaluation, the CEO and CFO concluded that the Corporation's ICFR was effective as at December 31, 2016.

No material changes in the Corporation's ICFR were identified during the period beginning on October 1, 2016 and ended on December 31, 2016 that have materially affected, or are reasonably likely to materially affect, the Corporation's ICFR. It should be noted that a control system, including the Corporation's disclosure and internal controls and procedures, no matter how well conceived, can provide only reasonable, but not absolute assurance that the objectives of the control system will be met and it should not be expected that the disclosure and internal controls will prevent all errors or fraud.

SELECTED CONSOLIDATED QUARTERLY INFORMATION

The following tables set forth selected consolidated financial information of the Corporation for the eight most recently completed quarters ending at the fourth quarter of 2016.

Quarter ended *($000s, except where noted)*	**Dec. 31, 2016**	**Sept. 30, 2016**	**June 30, 2016**	**March 31, 2016**
Petroleum and natural gas revenue[(1)]	65,155	27,987	11,863	16,575
Funds flow from operations	26,501	12,639	8,908	7,557
Per share – basic	0.26	0.13	0.09	0.08
Per share – diluted	0.26	0.12	0.09	0.08
Net income (loss)	(27,761)	11,614	(33,559)	(2,151)
Per share – basic	(0.28)	0.12	(0.34)	(0.02)
Per share – diluted	(0.28)	0.11	(0.34)	(0.02)
Cash capital expenditures	51,506	50,471	35,338	67,076
Working capital deficiency	73,647	36,626	36,677	26,016
Bank debt	200,836	172,054	136,897	87,559
Net debt	228,463	202,494	164,493	137,239
Total assets	1,336,955	1,290,228	876,295	857,942
Decommissioning obligations	29,857	32,015	27,321	25,738
Average daily production volumes *(boe/d)*	36,695	22,741	16,634	16,601
Average daily production volumes *(MMcfe/d)*	220.2	136.4	99.8	99.6
Realized commodity prices				
Natural gas *($/Mcf)*	2.78	1.97	0.94	1.60
NGLs *($/bbl)*	46.62	41.67	41.73	36.26
Total *($/Mcfe)*	3.22	2.23	1.31	1.83
Operating netbacks *($/Mcfe)*	2.09	1.74	1.44	1.21

(1) Before royalties

Quarter ended *($000s, except where noted)*	**Dec. 31, 2015**	**Sept. 30, 2015**	**June 30, 2015**	**March 31, 2015**
Petroleum and natural gas revenue[(1)]	15,048	20,180	22,801	23,554
Funds flow from operations	2,572	6,268	9,637	9,990
Per share – basic and diluted	0.03	0.06	0.10	0.10
Net income (loss)	2,550	(391)	(3,845)	(3,524)
Per share – basic and diluted	0.02	(0.00)	(0.04)	(0.04)
Cash capital expenditures	14,567	21,761	21,917	48,409
Working capital deficiency	4,629	16,880	11,790	29,122
Bank debt	63,626	45,929	38,802	7,656
Net debt	77,361	65,397	51,562	39,516
Total assets	781,574	759,971	746,063	740,132
Decommissioning obligations	21,480	17,351	16,391	18,024
Average daily production volumes *(boe/d)*	15,043	15,523	15,622	16,243
Average daily production volumes *(MMcfe/d)*	90.3	93.1	93.7	97.5
Realized commodity prices				
Natural gas *($/Mcf)*	1.60	2.07	2.35	2.38
NGLs *($/bbl)*	40.51	46.68	48.53	41.35
Total *($/Mcfe)*	1.81	2.36	2.67	2.69
Operating netbacks *($/Mcfe)*	0.96	1.09	1.50	1.38

(1) Before royalties

SELECTED CONSOLIDATED ANNUAL INFORMATION

The following table sets forth selected consolidated annual financial information of the Corporation for the three most recently completed years ending December 31, 2016.

Years ended *($000s, except where noted)*	**Dec. 31, 2016**	**Dec. 31, 2015**	**Dec. 31, 2014**
Petroleum and natural gas revenue[1]	121,580	81,583	160,545
Funds flow from operations	55,605	28,466	87,376
Per share – basic and diluted	0.56	0.29	0.88
Net loss	(51,857)	(5,210)	(15,564)
Per share – basic and diluted	(0.52)	(0.05)	(0.17)
Cash capital expenditures	204,391	106,654	262,932
Property acquisitions	-	-	1,155
Property dispositions	386	-	101,001
Working capital (deficiency)	(73,647)	(4,629)	2,835
Bank debt	200,836	63,626	-
Net debt	228,463	77,361	2,295
Total assets	1,336,955	781,574	737,836
Decommissioning obligations	29,857	21,480	14,258
Average daily production volumes *(boe/d)*	23,204	15,604	13,192
Average daily production volumes *(MMcfe/d)*	139.2	93.6	79.2

(1) Before royalties

Significant factors and trends that have affected the Corporation's results during the above annual and quarterly periods include:

- Petroleum and natural gas revenues are impacted by both fluctuating commodity prices and production volumes. The Corporation's successful capital program and commencement of commercial operations at the Townsend Facility in Q3 2016 have generated incremental production volumes. The commodity prices realized by the Corporation have approximated the AECO daily spot gas prices and Edmonton par light oil prices with periodic widening of differentials throughout the above periods. The reference price fluctuations reflect changes in supply and demand by commodity, both internationally and domestically.
- Funds flow from operations reflects the impact of fluctuating commodity prices on a growing production base. Operating and transportation cost variations track seasonal weather-related issues combined with fixed commitments. Natural gas and crude oil prices strengthened throughout 2014, and declined throughout 2015 and through the first half of 2016. Prices started to recover in the third and fourth quarter of 2016. Royalties vary due to commodity prices, production levels and the status of provincial royalty incentive programs. As the production base matures, incremental royalties occur on wells as the maximum volumes provided for under provincial incentive programs are attained.
- Net income (loss) throughout the periods was primarily influenced by non-cash items including unrealized gains or losses on commodity risk management.
- Fluctuations in capital expenditures have reflected both available capital resources and capital spending restraints during weaker commodity price cycles.
- As the Corporation's focus has shifted from exploration to development, working capital has decreased and the Corporation has begun utilizing bank debt. As a result of the disposition of the Corporation's Saskatchewan crude oil assets, and private placement and bought deal financings completed during 2014, the Corporation had no bank debt and a positive working capital position as at December 31, 2014. As the Corporation proceeds with its growth plans, it has resumed utilizing bank debt, which amounted to $200.8 million as at December 31, 2016.
- Total assets and non-current liabilities have increased as the Corporation's capital program has been executed.

ADVISORIES

Forward-looking Statements

Certain statements in this MD&A constitute forward-looking statements and forward-looking information (collectively, the "forward-looking statements") within the meaning of applicable Canadian securities laws. Such forward-looking statements relate to future events, including expectations of future production, components of cash flow and net income, expected future events, including with respect to the Corporation's well program, contractual commitments, capital expenditures, dividend policy and credit facility, and/or financial results that are forward-looking in nature and subject to substantial risks and uncertainties. All statements other than statements of historical fact contained in this MD&A may be forward-looking statements. Such statements and information may be identified by words such as "anticipate", "will", "intend", "could", "should", "may", "might", "expect", "forecast", "plan", "potential", "project", "assume", "contemplate", "believe", "budget", "shall", "continue", "milestone", "target", "vision", "forward looking to", and similar terms or the negatives 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 Corporation'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; however, undue reliance should not be placed upon them as they are derived from numerous assumptions, certain or all of which may prove to be incorrect. These assumptions are subject to known and unknown risks and uncertainties, including the business risks discussed in this MD&A and the risks discussed in the Corporation's AIF for the year ended December 31, 2015, many of which are beyond Painted Pony's control and which may cause actual performance and financial results to differ materially from any projections of future performance or results expressed or implied by such forward-looking statements. In addition, forward-looking statements may include statements or information attributable to third-party industry sources. Additionally, there can be no assurance that the plans, intentions or expectations upon which such forward-looking statements are based will occur.

In particular, and without limitation, this MD&A contains forward-looking statements pertaining to the following:

- *production volumes in 2017 will meet forecasted levels;*
- *the Corporation receiving a natural gas price that is representative of a discount to the AECO daily spot price of 10% to 15%;*
- *the Corporation's plans with respect to its drilling program;*
- *the expectation that overall royalties for 2017 will be approximately 3.0% of total revenues;*
- *the expectation that average per unit operating expenses for the 2017 will be approximately $0.45 to $0.55 per Mcfe assuming normal seasonal weather conditions;*
- *the expectation that average per unit transportation costs for 2017 will be approximately $0.35 to $0.40 per Mcfe;*
- *the expectation that average per unit G&A expenses for 2017 will be approximately $0.10 to $0.12 per Mcfe;*
- *the expectation that finance lease expense will vary with production volumes processed at the Townsend Facility;*
- *the expectation as to the timing and availability of the Townsend Phase 2 expansion;*
- *the corporation having adequate liquidity to fund working capital requirements and capital expenditures through a combination of cash flows and available credit facilities;*
- *expectations as to timing of the next review of the Corporation's credit facilities;*
- *expectations that future cash flows will be sufficient to realize the Corporation's deferred tax asset and that future taxable income will be available to utilize accumulated tax pools;*
- *the expectation that the Corporation's total debt to EBITDA ratio will be reduced in conjunction with a full year of operations at the Townsend Facility; and*
- *the expectation that commitments to process and transport natural gas through third-party owned facilities and pipeline systems will be fulfilled.*

With respect to the forward-looking statements contained in this MD&A, assumptions have been made regarding:

- *the utilization of available credit facilities for 2017;*
- *the validity of data used by GLJ Petroleum Consultants Ltd. in their independent reserves evaluation;*
- *the continued adherence to agreements to lease office space; and*
- *the financial position of the applicable entities mitigating the risk of accounts receivable becoming uncollectible.*

Certain or all of the forward-looking statements may prove to be incorrect and, while it is anticipated that subsequent events and developments may cause the Corporation'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 Corporation's views as of the date of this MD&A and such information should not be relied upon as representing the Corporation's views as of any date subsequent to the date of this MD&A. The Corporation has attempted to identify important factors that could cause actual results, performance or achievements to vary from those current expectations or estimates expressed or implied by the forward-looking statements contained herein. However, there may be other factors that cause results, performance or achievements not to be as expected or estimated and that could cause actual results, performance or achievements to differ materially from current expectations. Other risks and uncertainties include, but are not limited to, the following:

- *normal risks common to the oil and gas industry, including exploration, development and production operations risks;*
- *volatility of commodity prices;*
- *changes in interest and foreign exchange rates;*
- *risks and uncertainty of petroleum and natural gas geological deposits and reserves estimates;*
- *health, safety and environmental risks;*
- *revisions, amendments or changes to capital expenditure plans including exploration, development and exploitation projects;*
- *uncertainty of estimates and projections of production and costs;*
- *uncertainty of the outcome of the injunction application filed by the BRFN and the risk of delays resulting from the need to change the location of planned activities and a potential reduction in future volumes of natural gas and NGLs available for production by the Corporation;*
- *risks as to the availability and pricing of appropriate financing alternatives on acceptable terms;*
- *potential changes in income tax regulations, governmental policies, rules, practices or approval process changes, or delays, or enhancements;*
- *delays resulting from adverse weather conditions;*
- *delays resulting from an inability to obtain required regulatory approvals and ability to access sufficient debt or equity capital from internal and external sources; and*
- *the Corporation's ability to attract and retain qualified professional employees and consultants.*

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

There can be no assurance that the forward-looking statements contained herein 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 Corporation 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.

Forecast Prices and Costs

Reserves estimates are calculated using the forecast price and cost assumptions by the reserves evaluator which were in effect at the time of the applicable reserves evaluation. The complete GLJ January 1, 2017 price forecast is available on its website at gljpc.com.

Gross Reserves

Unless otherwise stated, references to "reserves" are to the Corporation's gross reserves, defined as the Corporation's working interest (operating or non-operating) share before deduction of royalties and without including any royalty interests of the Corporation.

Estimated Future Net Revenues

Estimated future net revenues are stated before deducting income taxes and future estimated site restoration costs and are reduced for estimated future abandonment costs and estimated capital for future development associated with the reserves. The undiscounted and discounted net present values disclosed do not represent the fair market value of the reserves.

Potential Transactions

Within its focus area, the Corporation regularly reviews potential property acquisitions and corporate mergers and acquisitions for the purpose of determining whether any such potential transaction would benefit the Corporation, as well as the terms on which such a potential transaction would be available. As a result, the Corporation may from time to time be involved in discussions or negotiations with other parties or their agents in respect of potential property acquisitions and corporate merger and acquisition opportunities. The Corporation is not committed to any such potential transaction and cannot be reasonably confident that it can complete any such potential transaction until appropriate legal documentation has been signed by the relevant parties.

BOE Conversions

Barrel of oil equivalent amounts have been calculated by using the conversion ratio of six thousand cubic feet (6 Mcf) of natural gas to one barrel of oil (1 bbl). Boe amounts may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf to 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

MCFE Conversions

Thousands of cubic feet of gas equivalent amounts have been calculated by using the conversion ratio of one barrel of oil (1 bbl) to six thousand cubic feet (6 Mcf) of natural gas. Mcfe amounts may be misleading, particularly if used in isolation. A conversion ratio of 1 bbl to 6 Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Abbreviations

Natural Gas		***Natural Gas Liquids***	
Mcf	*thousand cubic feet*	*bbls*	*barrels*
Mcf/d	*thousand cubic feet per day*	*bbls/d*	*barrels per day*
MMcf/d	*million cubic feet per day*	*NGLs*	*natural gas liquids*
Boe	*barrels of oil equivalent*	*Mcfe*	*thousand cubic feet equivalent*
boe/d	*barrels of oil equivalent per day*	*Mcfe/d*	*thousand cubic feet equivalent per day*
Mboe	*thousand barrels of oil equivalent*	*MMcfe/d*	*million cubic feet equivalent per day*

ADDITIONAL INFORMATION

Additional information regarding the Corporation and its business and operations, including the AIF for the year ended December 31, 2015 is available on the Corporation's SEDAR profile at www.sedar.com. Copies of the Corporation's disclosure can also be obtained by contacting the Corporation at Painted Pony Petroleum Ltd., Suite 1800, 736 – 6 Avenue SW., Calgary, Alberta T2P 3T7 (Phone (403) 475-0440), by email at info@paintedpony.ca or on the Corporation's website at www.paintedpony.ca.

MANAGEMENT'S RESPONSIBILITY FOR CONSOLIDATED FINANCIAL STATEMENTS

Management of Painted Pony Petroleum Ltd. (the "Corporation") 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 Corporation has established internal accounting control systems which are designed to provide reasonable assurance regarding the reliability of the Corporation'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 Corporation 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 Board of Directors has approved the consolidated financial statements for the years ended December 31, 2016 and 2015.

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 Corporation, and in that capacity, they have audited the consolidated financial statements for the years ended December 31, 2016 and 2015.

"signed"
Patrick R. Ward
President and CEO

"signed"
Stuart W. Jaggard
Vice President and Interim CFO

February 27, 2017

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, 2016 and December 31, 2015, the consolidated statements of operations, changes in equity and cash flows for the years then ended, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

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

Auditors' Responsibility

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

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

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

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of Painted Pony Petroleum Ltd. as at December 31, 2016 and December 31, 2015, and its consolidated financial performance and its consolidated cash flows for the years then ended in accordance with International Financial Reporting Standards.

KPMG LLP

Chartered Professional Accountants

February 27, 2017
Calgary, Canada

PAINTED PONY PETROLEUM LTD.
CONSOLIDATED STATEMENTS OF FINANCIAL POSITION
(000s)

As at	December 31, 2016	December 31, 2015
ASSETS		
Current assets		
Accounts receivable	$ 29,568	$ 8,174
Prepaid expenses and deposits	1,109	1,576
Fair value of risk management contracts *(note 13)*	-	9,106
	30,677	18,856
Non-current assets		
Fair value of risk management contracts *(note 13)*	1,269	6,039
Exploration and evaluation *(note 4)*	114,251	116,145
Property, plant and equipment *(note 5)*	1,158,198	625,833
Deferred tax *(note 12)*	32,560	14,701
	$ 1,336,955	$ 781,574
LIABILITIES		
Current liabilities		
Accounts payable and accrued liabilities	$ 54,903	$ 22,998
Deferred share units liability *(note 10)*	3,401	487
Fair value of risk management contracts *(note 13)*	46,020	-
	104,324	23,485
Non-current liabilities		
Fair value of risk management contracts *(note 13)*	15,768	-
Bank debt *(note 6)*	200,836	63,626
Decommissioning obligations *(note 7)*	29,857	21,480
Finance lease obligation *(note 15)*	360,860	-
	711,645	108,591
EQUITY		
Share capital *(note 9)*	687,701	686,702
Contributed surplus	52,115	48,930
Deficit	(114,506)	(62,649)
	625,310	672,983
	$ 1,336,955	$ 781,574

Commitments *(notes 16 & 17)*

Subsequent event *(note 16)*

See accompanying notes to the Consolidated Financial Statements

Approved on behalf of the Board:

"signed" Arthur J. G. Madden
Director

"signed" Patrick R. Ward
Director

PAINTED PONY PETROLEUM LTD.
CONSOLIDATED STATEMENTS OF OPERATIONS
(000s, except per share amounts)

	Years ended December 31, 2016	2015
Revenue		
Petroleum and natural gas	$ 121,580	$ 81,583
Royalties	(2,672)	(2,008)
	118,908	79,575
Realized gain on commodity risk management *(note 13)*	19,912	6,830
Unrealized gain (loss) on commodity risk management *(note 13)*	(75,664)	10,015
	63,156	96,420
Expenses		
Operating	34,535	31,978
Transportation	15,894	12,149
General and administrative	10,566	10,944
Share-based compensation *(note 9)*	5,778	5,067
Depletion and depreciation *(note 5)*	43,329	39,829
	110,102	99,967
Loss from operations	(46,946)	(3,547)
Finance expense *(note 11)*	(22,770)	(3,260)
Loss before taxes	(69,716)	(6,807)
Deferred tax recovery *(note 12)*	17,859	1,597
Net loss and comprehensive loss	**$ (51,857)**	**$ (5,210)**
Net loss per share *(note 8)*:		
Basic and diluted	$ (0.52)	$ (0.05)

See accompanying notes to the Consolidated Financial Statements.

PAINTED PONY PETROLEUM LTD.
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
(000s, except shares)

Years ended December 31, 2016 and 2015

	Number of Common Shares	Share capital	Contributed surplus	Deficit	Total equity
Balance at December 31, 2014	99,469,775	$ 680,820	$ 45,544	$ (57,439)	$ 668,925
Share-based compensation	-	-	5,653	-	5,653
Stock options exercised *(note 9)*	561,167	5,882	(2,267)	-	3,615
Net loss	-	-	-	(5,210)	(5,210)
Balance at December 31, 2015	100,030,942	686,702	48,930	(62,649)	672,983
Share-based compensation	-	-	3,484	-	3,484
Stock options exercised *(note 9)*	127,250	999	(299)	-	700
Net loss	-	-	-	(51,857)	(51,857)
Balance at December 31, 2016	100,158,192	$ 687,701	$ 52,115	$ (114,506)	$ 625,310

See accompanying notes to the Consolidated Financial Statements.

PAINTED PONY PETROLEUM LTD.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(000s)

	Years ended December 31,	
	2016	**2015**
Cash flows from operating activities:		
Net loss and comprehensive loss	$ (51,857)	$ (5,210)
Adjustments for:		
Depletion and depreciation	43,329	39,829
Share-based compensation	2,864	4,580
Accretion expense	550	392
Deferred income tax recovery	(17,859)	(1,597)
Unrealized (gain) loss on commodity risk management	75,664	(10,015)
Decommissioning expenditures *(note 7)*	(102)	(4)
Changes in non-cash working capital *(note 17)*	(7,931)	3,730
	44,658	31,705
Cash flows from investing activities:		
Property, plant and equipment additions	(204,391)	(106,654)
Changes in non-cash working capital *(note 17)*	20,609	(22,926)
	(183,782)	(129,580)
Cash flows from financing activities:		
Exercise of stock options	700	3,613
Increase in bank debt	137,210	63,626
Changes in non-cash working capital *(note 17)*	1,214	(79)
	139,124	67,160
Change in cash and cash equivalents	-	(30,715)
Cash and cash equivalents, beginning of period	-	30,715
Cash and cash equivalents, end of period	-	-

See accompanying notes to the Consolidated Financial Statements.

1. REPORTING ENTITY

Painted Pony Petroleum Ltd.'s ("Painted Pony" or the "Corporation") principal business activity is the exploration, development and production of petroleum and natural gas resources in northeast British Columbia. The consolidated financial statements of the Corporation as at and for the years ended December 31, 2016 and 2015 include the accounts of the Corporation and its wholly owned subsidiary, Painted Rock Resources Ltd. The Corporation's head office is located at 1800, 736 – 6th Avenue S.W., Calgary, Alberta.

2. BASIS OF PRESENTATION

The consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB"). The consolidated financial statements were authorized for issuance by the Board of Directors of the Corporation (the "Board") on February 27, 2017.

The consolidated financial statements have been prepared on the historical cost basis except for derivative financial instruments, which are measured at fair value. The methods used to measure fair value are discussed in note 14.

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

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

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

(a) Critical Accounting Judgments

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

Cash-Generating Units

The Corporation's assets are aggregated into cash-generating units ("CGU" or "CGUs") for the purpose of assessing impairment. CGUs are based on an assessment of the unit's ability to generate independent cash inflows. The determination of these CGUs was based on management's judgment in regard to shared infrastructure, geographical proximity, petroleum type and exposure to market risk and materiality. By their nature, these assumptions are subject to management's judgment and may impact the carrying value of the Corporation's net assets in future periods.

Impairment Indicators

Judgments are required to assess when impairment indicators exist and impairment testing is required. The Corporation is required to consider information from both external sources (such as negative downturn in commodity prices, significant adverse changes in the technological, market, economic or legal environment in which the entity operates) and internal sources (such as downward revisions in reserves, significant adverse effect on the financial and operational performance of a CGU, evidence of obsolescence or physical damage to the asset). In determining the recoverable amount of assets, in the absence of quoted market prices, impairment tests are based on estimates of reserves, production rates, future petroleum and natural gas prices, future costs, discount rates, market value of land and other relevant assumptions.

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

Deferred Taxes

In determining its deferred tax provisions, the Corporation must apply judgment when interpreting and applying tax laws and regulations. The determination of the appropriate rules may be uncertain for many periods. The final outcome could result in amounts different from those initially recorded and could impact tax expense in the periods where a determination is made. Judgments are also made by management to determine the likelihood of whether deferred tax assets at the end of the reporting period will be realized from future taxable income.

(b) Critical Accounting Estimates

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

Impact of Reserves

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

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

Share-Based Compensation

All equity-settled, share-based awards issued by the Corporation are fair valued using the Black-Scholes option-pricing model. In assessing the fair value of equity-based compensation, estimates have to be made regarding the expected volatility in share price, option life, dividend yield, risk-free rate and estimated forfeitures at the initial grant date.

Derivative Financial Instruments

Painted Pony records commodity price contracts at fair value with changes in fair value recognized in the statements of operations. The Corporation's estimate of the fair value is determined using observable market data and external counterparty information, including estimated forward prices and volatility in those prices.

Decommissioning Obligations

The Corporation estimates future remediation costs of production facilities, wells and pipelines at different stages of development and construction of assets or facilities. In most instances, removal of assets occurs many years into the future. This requires judgment regarding abandonment date, future environmental and regulatory legislation, the extent of reclamation activities, the engineering methodology for estimating cost, future removal technologies in determining the removal cost and liability-specific discount rates to determine the present value of these cash flows.

Deferred Taxes

Tax provisions are based on enacted or substantively enacted laws. Changes in those laws could affect amounts recognized in net income or loss both in the period of change, which would include any impact on cumulative provisions, and in future periods.

Deferred tax assets are recognized only to the extent it is considered probable that those assets will be recoverable. This involves an assessment of when those deferred tax assets are likely to reverse and a judgment as to whether or not there will be sufficient taxable profits available to offset the tax assets when they do reverse. This requires assumptions regarding future profitability and is therefore inherently uncertain. Estimates of future taxable income are based on forecasted cash flows from operations.

3. SIGNIFICANT ACCOUNTING POLICIES

The accounting policies set out below have been applied consistently to all years presented in these consolidated financial statements, by both the Corporation and its subsidiary. Certain prior period amounts have been restated to conform to presentation in the current period.

(a) Basis of Consolidation

Subsidiaries

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

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

Jointly controlled operations and jointly controlled assets

A portion of the Corporation’s petroleum and natural gas activities involve jointly controlled assets. The consolidated financial statements include the Corporation’s share of these jointly controlled assets and a proportionate share of the relevant revenue and related costs.

Transactions eliminated on consolidation

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

(b) Financial instruments

Non-derivative financial instruments

Non-derivative financial instruments comprise accounts receivable, accounts payable and accrued liabilities, and bank debt. Non-derivative financial instruments are recognized initially at fair value plus, for instruments not at fair value through comprehensive income or loss, any directly attributable transaction costs. Subsequent to initial recognition, non-derivative financial instruments are measured as described below.

Accounts receivable are measured using the effective interest rate method, less any impairment losses. Accounts payable and accrued liabilities are recognized at the amount required to be paid less any required discount to reduce the payables to fair value. The carrying value of bank debt approximates its fair value.

Derivative financial instruments

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

The Corporation has issued deferred share units (“DSU” or “DSUs”) to members of the Board and eligible executive officers. Each DSU is a notional unit equal in value to common share in the capital of the Corporation (“Common Share”), which entitles the holder to a cash payment upon redemption. DSUs are measured at fair value upon grant and each period end date, using the 20-day volume weighted average price of Common Shares. DSUs are classified as fair value through profit or loss and are recorded on the statements of financial position at fair value.

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

Recognition and measurement

(i) Exploration and evaluation assets

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

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

(ii) Property, plant and equipment

Items of PP&E, which include petroleum and natural gas development and production assets, and finance lease assets, are measured at cost less accumulated depletion, depreciation and accumulated impairment losses. Development and production assets are grouped into CGUs for impairment testing. When significant parts of an item of PP&E, including petroleum and natural gas interests, have different useful lives, they are accounted for as separate items.

Gains and losses on disposal of PP&E, are determined by comparing the proceeds from disposal, or fair value or properties received, with the carrying amount of the asset and are recognized in income or loss.

Costs incurred subsequent to the determination of technical feasibility and commercial viability and the costs of replacing parts of PP&E are recognized as petroleum 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 net income or loss as incurred. Such capitalized petroleum and natural gas interests generally represent costs incurred in developing proved and/or probable reserves and bringing on or enhancing production from such reserves. The carrying amount of any replaced or sold component is derecognized. The costs of periodic servicing of PP&E are recognized in net income or loss.

Depletion and depreciation

The net carrying value of development or production assets and finance lease assets are depleted using the unit of production method by reference to the ratio of production in the period to the related proved 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 a minimum.

Proved and probable reserves are estimated using independent reserve engineer reports in accordance with NI 51-101 and represent the estimated quantities of petroleum, 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 proved and probable and a 50 percent statistical probability that it will be less. The equivalent statistical probabilities for proved reserve components 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 petroleum and natural gas production; and

- evidence that the necessary production, transmission and transportation facilities are available or can be made available.

In determining reserves for use in the depletion and impairment calculations, a barrel of oil equivalent ("boe") conversion ratio of six thousand cubic feet of gas ("Mcf") to one barrel of oil ("bbl") (6 Mcf:1 bbl) is used as an energy equivalency conversion method.

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

(d) Impairment

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

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

Individually significant financial assets are tested for impairment on an individual basis. The remaining financial assets are assessed collectively in groups that share similar credit risk characteristics. All impairment losses are recognized in net income or loss.

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 net income or loss.

Non-financial assets
The carrying amounts of the Corporation's non-financial assets, other than E&E assets and deferred tax assets, are reviewed whenever there is an indication of impairment. If any such indication exists, the asset's recoverable amount is estimated.

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

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

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

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

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

(e) Leased Assets

Payments made under operating leases are recognized in net 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.

Leases which transfer substantially all of the risks and rewards of ownership are classified as finance leases. On initial recognition, the leased asset is measured at an amount equal to the lower of its fair value and the present value of the minimum lease payments. Subsequent to initial recognition, the asset is accounted for in accordance with the accounting policy applicable to the asset. Minimum lease payments are apportioned between the finance expense and the reduction of the outstanding liability. The finance expense is allocated to each period during the lease term so as to produce a constant periodic rate of interest on the remaining balance of the liability.

(f) Share Capital

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

(g) Share-Based Compensation

The Corporation has issued stock options to acquire Common Shares to directors, executive officers and employees. The fair value of stock options on the date they are granted is recognized as share-based compensation expense with a corresponding increase in contributed surplus over the vesting period. A forfeiture rate is estimated on the grant date, and the expense is adjusted to reflect actual forfeitures throughout the vesting period. The Corporation uses the Black-Scholes model to estimate fair value.

(h) Provisions

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

Decommissioning obligations

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

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

(i) Revenue Recognition

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

(j) Finance Expense

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

(k) Income Tax

Income tax expense comprises current and deferred tax expense and is recognized in net income or loss except to the extent that it relates to items recognized directly in equity.

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

A deferred tax asset is recognized to the extent that it is likely 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 likely that the related tax benefit will be realized.

(l) Foreign Currency Translation

The principal currency of the economic environment in which the Corporation and its wholly owned subsidiary operate is the Canadian dollar. Monetary assets and liabilities denominated in foreign currencies are translated into Canadian dollars at exchange rates in effect at the end of the period, and revenues and expenses are translated into Canadian dollars at average exchange rates. All translation gains and losses are recorded to income.

(m) Per Share Information

Basic per share information is calculated on the basis of the weighted average number of Common Shares outstanding during the period. Diluted per share information reflects the potential dilutive effect of stock options. Anti-dilutive instruments are not included in the determination of diluted income (loss) per share.

(n) Future Accounting Pronouncements

A number of new accounting standards, amendments to accounting standards and interpretations are effective for annual periods beginning on or after January 1, 2017 and have not been applied in preparing the consolidated financial statements for the year ended December 31, 2016. The standards applicable to the Corporation are as follows and will be adopted on their respective effective dates:

Liabilities Arising from Financing Activities

As of January 1, 2017, the Corporation will be required to adopt IAS 7 “Statement of Cash Flows”, which requires disclosures that enable financial statement users to evaluate changes in liabilities arising from financing activities, including both changes arising from cash flows and non-cash changes. The Corporation does not anticipate a material impact on its consolidated financial statements as a result of adopting IAS 7.

Financial Instruments

In July 2014, the IASB issued the final version of IFRS 9 “Financial Instruments”, which replaces IAS 39 “Financial Instruments: Recognition and Measurement”. The standard will come into effect for annual periods beginning on or after January 1, 2018 with earlier adoption permitted.

IFRS 9 introduces a single approach to determine whether a financial asset is measured at amortized cost or fair value and replaces the multiple rules in IAS 39. The approach is based on how an entity manages its financial instruments in the context of its business model and the contractual cash flow characteristics of the financial assets. For financial liabilities, IFRS 9 retains most of the requirements of IAS 39; however, where the fair value option is applied to financial liabilities, any change in fair value resulting from an entity’s own credit risk is recorded in OCI rather than the statement of operations, unless this creates an accounting mismatch. Based on its preliminary assessment, the Corporation does not anticipate these changes to have a material impact on its consolidated financial statements.

In addition, IFRS 9 introduces a new expected credit loss model for calculating impairment of financial assets, replacing the incurred loss impairment model required by IAS 39. The new model will result in more timely recognition of expected credit losses. Painted Pony does not anticipate the new impairment model to have a material impact on the consolidated financial statements.

IFRS 9 also contains a new model to be applied for hedge accounting, aligning hedge accounting more closely with risk management. The Corporation does not currently apply hedge accounting to its risk management contracts and does not currently intend to apply hedge accounting to any of its existing risk management contracts on adoption of IFRS 9.

Revenue Recognition
As of January 1, 2018, the Corporation will be required to adopt IFRS 15 "Revenue from Contracts with Customers", which replaces IAS 18 "Revenue". The standard provides a single, principles based 5 step model to be applied to all contracts with customers. The standard requires an entity to recognize revenue to reflect the transfer of goods and services for the amount it expects to receive, when control is transferred to the purchaser. Disclosure requirements have also been expanded.

The standard is required to be adopted either retrospectively or using a modified retrospective approach for annual periods beginning on or after January 1, 2018, with earlier adoption permitted. The Corporation is in the process of reviewing its revenue streams and underlying contracts with customers to determine the impact, if any, that the adoption of IFRS 15 will have on its financial statements and related disclosure.

Leases
In January 2016, the IAS issued IFRS 16 "Leases", which replaces IAS 17 "Leases", and provides that a single recognition and measurement model for leases would apply, with required recognition of assets and liabilities for most leases. For lessees, IFRS 16 removes the classification of leases as either operating or finance leases, effectively treating all leases as finance leases. Certain short-term leases (less than 12 months) and leases of low-value assets are exempt from the requirements, and may continue to be treated as operating leases.
IFRS 16 is effective for years beginning on or after January 1, 2019, with early adoption permitted if IFRS 15 "Revenue from Contracts with Customers" has been adopted. The standard may be applied retrospectively or using a modified retrospective approach. It is anticipated that the adoption of IFRS 16 will have a material impact on the Corporation's consolidated statement of financial position due to material
operating lease commitments as disclosed in note 16.

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

(000s)		
As at December 31, 2014	$	120,078
Transfer to property, plant and equipment		(3,933)
As at December 31, 2015	$	116,145
Transfer to property, plant and equipment		(1,894)
As at December 31, 2016	$	114,251

Exploration and evaluation assets consist of undeveloped lands and unevaluated seismic data on the Corporation's exploration projects which are pending the determination of proved or probable reserves. Additions represent the Corporation's share of costs incurred on E&E assets during the period. Transfers are made to PP&E as proved or probable reserves are determined. E&E assets are expensed due to non-economic drilling and completion activities and lease expiries. The Corporation assesses the recoverability of E&E assets on the transfer to PP&E.

5. PROPERTY, PLANT & EQUIPMENT

(000s)		
Cost:		
As at December 31, 2014	$	683,898
Cash additions		106,654
Non-cash additions		7,907
Transfer from exploration and evaluation		3,933
As at December 31, 2015	$	802,392
Cash additions		204,391
Non-cash additions		8,549
Finance lease assets		360,860
Transfer from exploration and evaluation		1,894
As at December 31, 2016	$	1,378,086
Accumulated depletion and depreciation:		
As at December 31, 2014	$	136,730
Depletion and depreciation		39,829
As at December 31, 2015	$	176,559
Depletion and depreciation		43,329
As at December 31, 2016	$	219,888
Carrying amounts:		
December 31, 2015	$	625,833
December 31, 2016	$	1,158,198

Estimated future development costs associated with the development of the Corporation's proved plus probable reserves at December 31, 2016 and at December 31, 2015 were $2.9 billion and $3.2 billion, respectively.

(a) Property Swap

On July 27, 2016, Painted Pony announced that it had entered into a non-cash asset exchange agreement, in respect of acreage, wells and non-operated facility interests, with a large industry partner on jointly held acreage in the Daiber, Cameron and Blair Creek areas of British Columbia. The asset exchange closed on September 26, 2016, with an effective date of January 1, 2016. Adjustments between the effective and closing dates are included in PP&E as property dispositions. Management performed an assessment of the exchange agreement, and concluded that the transaction did not meet the criteria to record an accounting gain or loss.

(b) Capitalized General and Administrative Expense, Recoveries and Share-Based Compensation

(000s)	**Years ended December 31,**			
		2016		**2015**
General and administrative	$	5,937	$	4,720
Capital recoveries		2,343		1,291
Share-based compensation		620		1,073
Total	$	8,900	$	7,084

6. BANK DEBT

At December 31, 2016, the Corporation's syndicated credit facilities were $325 million, with the semi-annual borrowing base review to be completed by April 30, 2017.

The facilities are provided by a syndicate of financial institutions, and include a $275 million extendible revolving facility and a $50 million operating facility. The facilities revolve for a 2-year period, which is extendible annually, subject to syndicate approval. The facilities are subject to semi-annual review and re-determination of borrowing base by April 30 and October 31 of each year, or in the circumstance of a material adverse event. Any re-determination of the borrowing base is effective immediately, and if the borrowing base is reduced, the Corporation has 60 days to repay any shortfall.

As at December 31, 2016 Painted Pony had $200.0 million in bankers' acceptances with an effective interest rate of 4.68% per annum. In addition, as at December 31, 2016 the Corporation had an outstanding letter of credit of $14.9 million, which reduces the credit available on the operating facility.

The credit facilities bear interest on a matrix system that ranges from the bank's prime rate plus 1.0% to the bank's prime rate plus 3.5% per annum depending on the Corporation's total debt to EBITDA ratio as defined by the lenders, ranging from less than 1:1 to greater than 4:1. The credit facilities provide that advances may be made by way of prime rate loans, U.S. Base Rate loans, London InterBank Offered Rate loans, bankers' acceptances, letters of credit or letters of guarantee. A standby fee of 0.5% to 1.125% per annum is charged on the undrawn portion of the credit facilities, also calculated depending on the Corporation's total debt to EBITDA ratio, as defined by the lenders. At December 31, 2016, the Corporation's total debt to EBITDA ratio was 1.96:1.

Security is provided by a floating charge demand debenture in the aggregate amount of $500 million on all of the Corporation's assets. The Corporation has provided a negative pledge and an undertaking to provide fixed charges over major producing petroleum and natural gas reserves in certain circumstances. The syndicated credit facilities are not subject to financial covenants.

7. DECOMMISSIONING OBLIGATIONS

Years ended December 31, *(000s)*	**2016**	**2015**
Balance, beginning of year	$ 21,480	$ 14,258
Provisions	7,721	2,446
Revisions	208	4,388
Decommissioning expenditures	(102)	(4)
Accretion *(note 11)*	550	392
Balance, end of year	$ 29,857	$ 21,480

The Corporation's decommissioning obligations result from its ownership interest in petroleum and natural gas assets including well sites and facilities. The total decommissioning obligation is estimated based on the Corporation'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 Corporation has estimated the net present value of the decommissioning obligations based on an undiscounted total future liability of $64.2 million, compared to $47.5 million at December 31, 2015, with payments expected to be made over the next 12 to 49 years. The discount factor, being the risk-free rate related to the liability at December 31, 2016, was 2.1%, compared to 2.2% at December 31, 2015, and the inflation rate was 2% at both December 31, 2016 and 2015.

8. NET LOSS PER SHARE

Years ended December 31,	2016	2015
Net loss (000s)	$ (51,857)	$ (5,210)
Weighted average common shares – basic and diluted	100,069,546	99,800,764
Net loss per share – basic and diluted	$ (0.52)	$ (0.05)

The average market value of the Corporation's Common Shares for purposes of determining the dilutive effect of outstanding stock options was based on quoted market prices for the period. During the years ended December 31, 2016 and 2015, all stock options were excluded from the weighted-average diluted share calculation of Common Shares.

9. SHARE CAPITAL

(a) Authorized

The Corporation has an unlimited number of Common Shares and an unlimited number of preferred shares ("Preferred Shares") authorized for issuance. At December 31, 2016 there were 100,158,192 Common Shares issued and outstanding, compared to 100,030,942 Common Shares issued and outstanding at December 31, 2015 and, nil Preferred Shares issued and outstanding at either date.

The Common Shares entitle the holder thereof to one vote for every share held. There are no fixed dividends payable on the Common Shares. In the event of the liquidation or dissolution of the Corporation, the Common Shares are entitled to receive, on a pro rata basis, all assets of the Corporation as are distributable to the holders of shares.

(b) Stock options

The Corporation has a stock option program that entitles employees, officers and directors to purchase Common Shares in the Corporation. Stock options are granted at the market price of the shares at the date of grant and have a five-year term. Prior to December 31, 2015, options granted vested as to one-third immediately, with the balance over two years. Effective January 1, 2016, options granted vest as to one-third on each of the first, second and third anniversaries of the grant date.
The number and weighted average exercise prices of stock options are as follows:

	Weighted Average Exercise Price	Number
As at December 31, 2014	$ 9.17	8,155,101
Granted	4.34	1,979,300
Exercised	6.45	(561,167)
Forfeited	9.11	(697,767)
As at December 31, 2015	$ 8.26	8,875,467
Granted	4.30	1,066,650
Exercised	5.50	(127,250)
Forfeited	10.93	(1,192,350)
As at December 31, 2016	$ 7.45	8,622,517

The following table summarizes information about stock options outstanding at December 31, 2016:

Number of Stock Options Outstanding	Exercise Price ($)	Remaining Life (Years)	Exercisable Stock Options	Exercise Price ($)
411,900	11.80	0.1	411,900	11.80
408,900	7.56	0.3	408,900	7.56
330,000	10.86	0.7	330,000	10.86
353,100	10.59	0.9	353,100	10.59
360,000	10.33	1.0	360,000	10.33
359,000	10.13	1.2	359,000	10.13
1,349,167	6.44	1.9	1,349,167	6.44
290,000	8.44	2.2	290,000	8.44
66,000	10.64	2.4	66,000	10.64
154,000	12.17	2.5	154,000	12.17
210,000	14.14	2.7	210,000	14.14
1,398,100	8.78	2.9	1,398,100	8.78
33,000	6.72	3.2	22,000	6.72
4,500	6.09	3.2	3,000	6.09
1,837,350	4.26	3.9	1,205,184	4.26
987,000	4.14	4.1	-	4.14
39,000	5.58	4.4	-	5.58
16,500	7.61	4.5	-	7.61
15,000	7.90	4.7	-	7.90
8,622,517	7.45	2.5	6,920,351	8.22

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

The weighted-average fair values of the stock options granted and the assumptions used in the Black-Scholes option pricing model were as follows:

Years ended December 31,	**2016**	**2015**
Fair value per stock option	$ 1.86	$ 1.81
Volatility (%)	50	47
Life (years)	5	5
Risk-free interest rate (%)	0.68	0.96

A forfeiture rate of 11% was used when measuring share-based compensation, for both December 31, 2016 and 2015.

The components of share-based compensation expense are presented in the table below:

Years ended December 31, *(000s)*	**2016**	**2015**
Share-based compensation	$ 2,864	$ 4,580
Deferred share unit expense	2,914	487
Total	$ 5,778	$ 5,067

10. DEFERRED SHARE UNITS

	Deferred Share Units	Deferred Share Units Liability *(000s)*
As at December 31, 2014	-	$ -
Grant	143,337	939
Revaluation	-	(452)
As at December 31, 2015	143,337	487
Grant	139,005	812
Accrued but not granted	70,347	670
Revaluation	-	1,432
As at December 31, 2016	352,689	$ 3,401

The Corporation has a deferred share unit ("DSU") plan, where by DSUs are issued to members of the Board and eligible executive officers. Each DSU is a notional unit equal in value to one Common Share, which entitles the holder to a cash payment upon redemption. DSUs vest upon grant but can only be converted to cash upon the holder ceasing to be a director or executive officer of the Corporation.

The expense associated with the DSU plan is determined based on the 20-day volume weighted average price of Common Shares at the grant date. The expense is recognized in the statement of operations immediately upon grant, with a corresponding DSU liability recorded as a current liability in the statement of financial position. At period end dates, the DSU liability is adjusted based on the 20-day volume weighted average price of Common Shares.

11. FINANCE EXPENSE

Years ended December 31, *(000s)*	**2016**	**2015**
Finance lease expense *(note 15)*	$ 14,165	$ -
Bank finance expense	8,055	2,868
Accretion of decommissioning obligations *(note 7)*	550	392
Finance expense	$ 22,770	$ 3,260

12. DEFERRED TAXES

Reconciliation of effective tax rate:

Years ended December 31, *(000s)*	**2016**	**2015**
Loss before taxes	$ (69,716)	$ (6,807)
Combined corporate tax rate	26.5%	26.0%
Expected tax reduction	(18,475)	(1,770)
Non-deductible expenses	45	38
Non-deductible share-based compensation	759	1,191
Change in statutory tax rates and true-ups	(214)	(1,081)
Other	26	25
Total deferred tax recovery	$ (17,859)	$ (1,597)

Deferred tax assets and liabilities are attributable to the following:

December 31, *(000s)*	**2016**	**2015**
Deferred tax liabilities:		
PP&E and E&E assets	$ (69,174)	$ (38,487)
Fair value of financial instruments	-	(3,938)
	(69,174)	(42,425)
Less deferred tax assets:		
Non-capital losses	75,897	49,944
Fair value of financial instruments	16,038	-
Decommissioning obligations	7,912	5,692
Other	1,887	1,490
Net deferred tax asset	$ 32,560	$ 14,701

The Corporation has non-capital losses of $286.4 million. Virtually all of these losses expire beginning in the year 2030. The Corporation has determined that it is likely that these losses will be utilized against future taxable income.

13. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The Corporation's activities expose it to a variety of financial risks that arise as a result of its exploration, development, production and financing activities. These include market risk, credit risk and liquidity risk.

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

(a) Market risk

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

Natural gas prices obtained by the Corporation are influenced by both US and Canadian supply and demand. 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 Corporation 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 petroleum and natural gas are impacted by not only the relationship between the Canadian and United States dollars, but also upon world political and economic events that dictate the levels of supply and demand.

The Corporation's production is usually sold through near term sales contracts with prices fixed at the time of transfer of custody or on the basis of a monthly average market price. The Corporation, however, may give consideration in certain circumstances to the appropriateness of entering into long term fixed price marketing contracts. The majority of the Corporation's natural gas and NGLs are sold to one purchaser monthly on a best-efforts basis.

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

These instruments are not used for trading or speculative purposes. The Corporation has not designated its financial derivative contracts as effective accounting hedges, even though the Corporation considers all commodity contracts to be effective economic hedges. As a result, all such commodity contracts are recorded at fair value on the statement of financial position, with changes in the fair value being recognized as an unrealized gain or loss in the statement of operations.

Financial assets and liabilities carried at fair value are required to be classified into a hierarchy that prioritizes the inputs used to measure the fair value. The Corporation's risk management contracts are valued using Level 2 inputs. Assets and liabilities in Level 2 are based on valuation models and techniques where the significant inputs are derived from quoted indices.

The following is a summary of all commodity risk management contracts in place as at December 31, 2016.

Financial AECO Natural Gas Contracts

Reference	Volume (GJ/d)	Term	Weighted Average Price ($/GJ)	Options Traded
CDN$ AECO	90,000	Q1 2017	2.87	Swaps
CDN$ AECO	75,000	Q2 2017	2.85	Swaps
CDN$ AECO	90,000	Q3 2017	2.86	Swaps
CDN$ AECO	145,000	Q4 2017	2.89	Swaps
CDN$ AECO	71,000	Q1 2018	2.93	Swaps
CDN$ AECO	71,000	Q2 2018	2.85	Swaps
CDN$ AECO	50,000	Q3 2018	2.81	Swaps
CDN$ AECO	24,000	Q4 2018	2.72	Swaps
CDN$ AECO	18,000	Q1 2019	2.64	Swaps
CDN$ AECO	18,000	Q2 2019	2.64	Swaps
CDN$ AECO	25,000	Q4 2017 – Q4 2019	2.88	Call Options

Financial Station 2 Natural Gas Contracts

Reference	Volume (GJ/d)	Term	Weighted Average Price ($/GJ)	Options Traded
CDN$ Station 2	75,000	Q1 2017	1.82	Swaps
CDN$ Station 2	90,000	Q2 2017	1.90	Swaps
CDN$ Station 2	100,000	Q3 2017	1.93	Swaps
CDN$ Station 2	120,000	Q4 2017	2.07	Swaps
CDN$ Station 2	105,000	Q1 2018	2.04	Swaps
CDN$ Station 2	42,000	Q2 2018	2.38	Swaps
CDN$ Station 2	37,000	Q3 2018	2.36	Swaps
CDN$ Station 2	37,000	Q4 2018	2.36	Swaps
CDN$ Station 2	37,000	Q1 2019	2.36	Swaps
CDN$ Station 2	37,000	Q2 2019	2.36	Swaps
CDN$ Station 2	25,000	Q3 2019	2.37	Swaps
CDN$ Station 2	10,000	Q4 2019	2.45	Swaps

Financial WTI Crude Oil Contracts

Reference	Volume (bbl/d)	Term	Weighted Average Price ($/bbl)	Options Traded
CDN$ WTI	500	Q1 2017 – Q4 2017	70.05	Swaps
CDN$ WTI	500	Q1 2018 – Q4 2019	70.20	Swaps

Subsequent to December 31, 2016, Painted Pony entered into an additional commodity risk management contract as follows:

Reference	Volume (GJ/d)	Term	Weighted Average Price ($/GJ)	Options Traded
CDN$ AECO	10,000	Q1 2018	3.16	Swap

Changes in the price assumptions can have a significant effect on the fair value of the derivative assets and liabilities and thereby impact income. For financial instruments in place at December 31, 2016, It is estimated that a $0.10 per mcf change in the forward natural gas prices used to calculate the fair value of natural gas derivatives at December 31, 2016 would result in a $10.1 million change in net loss for the year ended December 31, 2016. It is estimated that a $1.00 per bbl change in the forward crude oil prices used to calculate the fair value of crude oil derivatives at December 31, 2016 would result in a $0.4 million change in net loss for the year ended December 31, 2016.

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

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. The Corporation is exposed to interest rate fluctuations on its bank debt which bears a floating rate of interest. In the year ended December 31, 2016, if interest rates had been 1.0% lower with all other variables held constant, net loss for the year would have been $1.3 million lower. An equal and opposite impact would have occurred to net loss had interest rates been 1.0% higher.

Financial assets and liabilities are presented on a net basis if the Corporation has a legal right to offset and intends to either settle on a net basis or to realize the asset and settle the liability simultaneously. The Corporation offsets financial assets and liabilities when the counterparty, currency and timing of settlement are the same. The following tables provide a summary of the Corporation's offsetting financial derivative positions, and how risk management contracts are classified on the statement of financial position, respectively.

As at	December 31, 2016	December 31, 2015
Gross in-the-money risk management contracts	$ 1,269	$ 15,145
Gross out-of-the-money risk management contracts	(61,788)	-
Net fair value of risk management contracts	$ (60,519)	$ 15,145

As at	December 31, 2016	December 31, 2015
Current assets	$ -	$ 9,106
Non-current assets	1,269	6,039
Current liabilities	(46,020)	-
Non-current liabilities	(15,768)	-
Net fair value of risk management contracts	$ (60,519)	$ 15,145

(b) Credit risk

Credit risk is the risk of financial loss to the Corporation if a customer or counterparty to a financial instrument fails to meet its contractual obligations and arises principally from the Corporation's receivables from joint venture partners and petroleum and natural gas purchasers. The Corporation's maximum exposure to credit risk at December 31, 2016 and 2015 is as follows:

Carrying amount, December 31, *(000s)*	2016	2015
Accounts receivable	$ 29,568	$ 8,174
Fair value of financial instruments	1,269	15,145
Total	$ 30,837	$ 23,319

Accounts receivable
All of the Corporation's operations are conducted in Canada. The Corporation's exposure to credit risk is influenced mainly by the individual characteristics of each customer.

Receivables from petroleum and natural gas purchasers are normally collected on the 25th day of the month following production. The Corporation's policy to mitigate credit risk associated with these balances is to establish marketing relationships with large purchasers. The Corporation historically has not experienced any collection issues with its petroleum 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 Corporation does not typically obtain collateral from petroleum and natural gas purchasers or joint venture partners; however, the Corporation does have the ability to withhold joint venture partners' share of production from operated wells in the event of non-payment.

The Corporation 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, 2016 or 2015.

The breakdown of accounts receivable at the reporting date by type of customer was:

Carrying amount, December 31, *(000s)*	**2016**	**2015**
Petroleum and natural gas revenue	$ 27,781	$ 6,855
Joint interest	523	143
Other	1,264	1,176
Total	$ 29,568	$ 8,174

The Corporation has one primary purchaser (see note 15) of natural gas and NGLs; these purchases accounted for $23.6 million of accounts receivable at December 31, 2016, compared to $5.5 million as at December 31, 2015. As at December 31, 2016 and 2015, the Corporation's accounts receivable are aged as follows:

Carrying amount, December 31, *(000s)*	**2016**	**2015**
Less than 30 days	$ 29,542	$ 8,124
From 31 – 90 days	24	7
More than 90 days	2	43
Total	$ 29,568	$ 8,174

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

(c) Liquidity risk
Liquidity risk is the risk that the Corporation will not be able to meet its financial obligations as they become due. The Corporation'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 Corporation's reputation.

Management closely monitors cash flow requirements to ensure that is has sufficient borrowing capacity to meet operational and financial obligations currently and in the foreseeable future; this excludes the potential impact of extreme circumstances that cannot reasonably be predicted, such as natural disasters. To achieve this objective, the Corporation prepares annual capital expenditure budgets, which are regularly monitored and updated as considered necessary. Further, the Corporation utilizes authority for expenditures on both operated and non-operated projects to further manage capital expenditures. The Corporation also typically collects its petroleum and natural gas revenues from most properties on the 25th of each month.

To facilitate the capital expenditure program, the Corporation has an aggregate of $325 million in available syndicated credit facilities at December 31, 2016 compared to $225 million at December 31, 2015, which are reviewed semi-annually by its lenders.

(d) Capital management

The Corporation'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 Corporation manages its capital structure and makes adjustments to it in the light of changes in economic conditions and the risk characteristics of the underlying petroleum and natural gas assets. The Corporation considers its capital structure to include shareholders' equity, loans and borrowings and working capital. In order to maintain or adjust the capital structure, the Corporation may issue shares and adjust its capital spending to manage current and projected debt levels.

The Corporation monitors capital based on the ratio of total debt to annualized cash flow. This ratio is calculated as total debt, defined as outstanding loans and borrowings plus or minus working capital, excluding fair value of risk management contracts, divided by cash flow from operations before changes in non-cash working capital and decommissioning expenditures for the most recent calendar quarter and then annualized. In order to facilitate the management of this ratio, the Corporation prepares annual capital expenditure budgets, which are updated as necessary depending on varying factors including current and forecast prices, successful capital deployment and general industry conditions. The annual and updated budgets are approved by the Board of Directors of the Corporation.

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

14. DETERMINATION OF FAIR VALUES

A number of the Corporation'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) Property, Plant and Equipment and Exploration and Evaluation Assets

The fair values of PP&E and E&E assets recognized in an acquisition, are based on market values. The fair values of PP&E and E&E are the estimated amounts for which they could be exchanged on the acquisition date between a willing buyer and a willing seller in an arm's length transaction after proper marketing wherein the parties had each acted knowledgeably, prudently and without compulsion. The fair value of petroleum and natural gas interests (included in PP&E) and E&E assets is estimated with reference to the discounted cash flows expected to be derived from petroleum 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) Accounts Receivable, Accounts Payable and Accrued Liabilities and Bank Debt

The fair value of accounts receivable, accounts payable and accrued liabilities, and bank debt are estimated as the present value of future cash flows, discounted at the market rate of interest at the reporting date. At December 31, 2016 and December 31, 2015, the fair value of these balances approximated their carrying value. Bank debt has a floating rate of interest and therefore the carrying value approximates the fair value.

(c) Stock Options

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

(d) Derivatives

Measurement

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

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

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

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

The fair value of commodity price risk management contracts is determined by discounting the difference between the contracted prices and published forward price curves as at the date of the statement of financial position, using the remaining contracted petroleum and natural gas volumes and risk-free interest rate (based on published government rates). The Corporation's commodity price contracts are valued using Level 2 of the hierarchy.

The fair value of DSUs is measured upon grant and at each period end date, using the 20-day volume weighted average price of Common Shares. The Corporation's deferred share units are valued using Level 1 of the hierarchy.

15. ALTAGAS STRATEGIC ALLIANCE

On August 18, 2014 the Corporation entered into a series of agreements (collectively the "Strategic Alliance") with AltaGas Ltd. ("AltaGas") relating to the development of processing infrastructure and marketing services for natural gas and NGLs. The chairman of the board of directors of AltaGas is a director of Painted Pony.

Under the Strategic Alliance, AltaGas committed to building gas processing facilities including a 198 MMcf/d shallow cut gas processing facility at the Townsend property (the "Townsend Facility") and related pipeline infrastructure, which commenced commercial operations in July 2016. Painted Pony does not acquire any legal right, title, or interest in the Townsend Facility or pipeline. All construction costs are borne by AltaGas. The Corporation has the right to a minimum of 150 MMcf/d of firm capacity at this facility effective October 1, 2016, increasing to 198 MMcf/d of firm capacity by August 1, 2017, in respect of each of which there is a take or pay obligation on production volumes delivered to the facility of 135 MMcf/d commencing October 1, 2016 and 180 MMcf/d commencing August 1, 2017.

The Townsend Facility and related pipeline infrastructure have been recorded as a finance lease. Painted Pony has recorded the asset, representing the total estimated construction cost of the Townsend Facility, with a corresponding obligation on the statement of financial position. Over the course of the 20-year lease, there will be a capital fee paid to AltaGas, which will include finance costs and the amortization of the obligation. The associated processing fee will be recorded in operating expenses.

The cost of the Townsend Facility is approximately $325.2 million and the cost of related pipeline infrastructure is approximately $35.6 million. Total expected payments based on annual take or pay volumes, including both the principal and financing components, are reflected in the table below in addition to other commitments that are reflected in Note 16.

($000s)	Within 1 year	After 1 year but no more than five years	More than five years	Total
Processing	34,437	218,669	487,113	740,219
Transportation	3,570	20,653	83,372	107,595
Total	38,007	239,322	570,485	847,814
Principal	-	44,515	316,345	360,860

Under the Strategic Alliance, AltaGas is committed to acting as the primary marketer of Painted Pony's natural gas and NGLs production volumes. As a result, effective April 1, 2015, Painted Pony began receiving and will continue to receive substantially all of its NGLs revenue from AltaGas. Effective November 1, 2015, Painted Pony also began receiving and will continue to receive substantially all of its natural gas revenue from AltaGas. At December 31, 2016, $23.6 million was outstanding from Altagas in accounts receivable.

16. COMMITMENTS

($000s)	2017	2018	2019	2020	2021	Thereafter	Total
Transportation	18,733	40,229	46,228	44,618	41,518	663,935	855,261
Processing	3,129	-	-	-	-	-	3,129
Office leases	1,447	1,466	1,175	-	-	-	4,088
Total commitments	23,309	41,695	47,403	44,618	41,518	663,935	862,478

Transportation commitments include contracts to transport natural gas and NGLs through third-party owned pipeline systems in British Columbia. Processing commitments include contracts to process natural gas through third-party owned gas processing facilities in British Columbia. Office leases include the Corporation's contractual obligations for office space.

The Corporation has certain lease arrangements that are reflected in the commitments table above, which were entered into in the normal course of operations. All leases, other than the Townsend Facility finance lease, have been treated as operating leases whereby the lease payments are included in operating expenses or general and administrative expenses depending on the nature of the lease.

Subsequent to December 31, 2016, Painted Pony committed to enter into an agreement with AltaGas in respect of the next phase of the Townsend Facility ("Townsend Phase 2"). AltaGas will be constructing Townsend Phase 2 in two separate gas processing trains, the first of which will be a 99 MMcf/d gas processing facility to be located on the existing Townsend site. Including the addition of incremental field compression equipment, the estimated total cost of the first train will be approximately $120 to $140 million. Painted Pony expects to enter into the agreement to be the sole supplier of natural gas to this first train and associated field compression equipment during 2017.

17. SUPPLEMENTAL DISCLOSURES

(a) Key Management Personnel Compensation

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

Years ended December 31, *(000s)*	2016	2015
Short-term compensation	$ 4,256	$ 5,190
Share-based compensation	4,711	3,454
Total	$ 8,967	$ 8,644

(b) Presentation in Statements of Operations

In the Corporation's financial statements, items are primarily disclosed by nature except for employee compensation costs which are included in general and administrative expenses, operating expenses and share based compensation expenses. In the year ended December 31, 2016, employee compensation costs of $9.6 million were included in general and administrative expenses and share based compensation expense, compared to $11.1 million in the year ended December 31, 2015. In the year ended December 31, 2016 employee compensation costs of $1.0 million were included in operating expenses, compared to $1.0 million in the year ended December 31, 2015.

(c) Presentation in Statements of Cash Flows

Changes in non-cash working capital are comprised of:

Years ended December 31, *(000s)*	**2016**	**2015**
Source/(use) of cash:		
Accounts receivable	$ (21,394)	$ 12,540
Prepaid expenses and deposits	467	(647)
Accounts payable and accrued liabilities	31,905	(31,655)
Deferred share units liability	2,914	487
	13,892	(19,275)
Operating activities	(7,931)	3,730
Investing activities	20,609	(22,926)
Financing activities	1,214	(79)
	$ 13,892	$ (19,275)

Notes

Corporate Information

DIRECTORS

Glenn R. Carley
Independent Director
and Chairman of the Board
Compensation Committee
Nominating Committee
Governance Committee
Audit Committee

Kevin D. Angus
Independent Director
Reserves Committee
Compensation Committee

David W. Cornhill
Director
Governance Committee

Joan E. Dunne
Independent Director

Nereus L. Joubert
Independent Director
Governance Committee (Chair)
Nominating Committee (Chair)

Lynn Kis
Independent Director
Reserves Committee (Chair)
Audit Committee

Arthur J. G. Madden
Independent Director
Audit Committee (Chair)
Reserves Committee

Patrick R. Ward
Director

Peter A. Williams
Independent Director
Compensation Committee (Chair)
Audit Committee

DESIGN: ARTHUR / HUNTER

OFFICERS

Patrick R. Ward
President and Chief Executive Officer

John H. Van de Pol
Senior Vice President & Chief Financial Officer

Edwin S. (Ted) Hanbury
Senior Vice President, Engineering

Tonya L. Fleming
Vice President, General Counsel & Corporate Secretary

Bruce G. Hall
Vice President, Land

Stuart W. Jaggard
Vice President & Controller

L. Barry McNamara
Vice President, Corporate Development & Marketing

James D. Reimer
Vice President, Geoscience & Technology

STOCK EXCHANGE LISTING

The Toronto Stock Exchange
Trading symbol for Common Shares: **PPY**

AUDITORS

KPMG LLP

BANKERS

The Toronto-Dominion Bank
The Bank of Nova Scotia
Alberta Treasury Branches
Canadian Imperial Bank of Commerce
HSBC Bank Canada
Wells Fargo Bank, N.A. Canadian Branch

EVALUATION ENGINEERS

GLJ Petroleum Consultants Ltd.

REGISTRAR AND TRANSFER AGENT

TMX Equity Transfer Services Inc.

HEAD OFFICE

1800, 736 - 6 Ave SW
Calgary, Alberta T2P 3T7
T 403.475.0440
F 403.238.1487
TOLL FREE 1.866.975.0440
E info@paintedpony.ca
W www.paintedpony.ca

PAINTED PONY PETROLEUM LTD.

10 YEARS 07-17

PAINTED PONY PETROLEUM LTD.

1800, 736 - 6 Ave SW
Calgary, Alberta T2P 3T7
T 403.475.0440
F 403.238.1487
TOLL FREE 1.866.975.0440
E info@paintedpony.ca
W www.paintedpony.ca