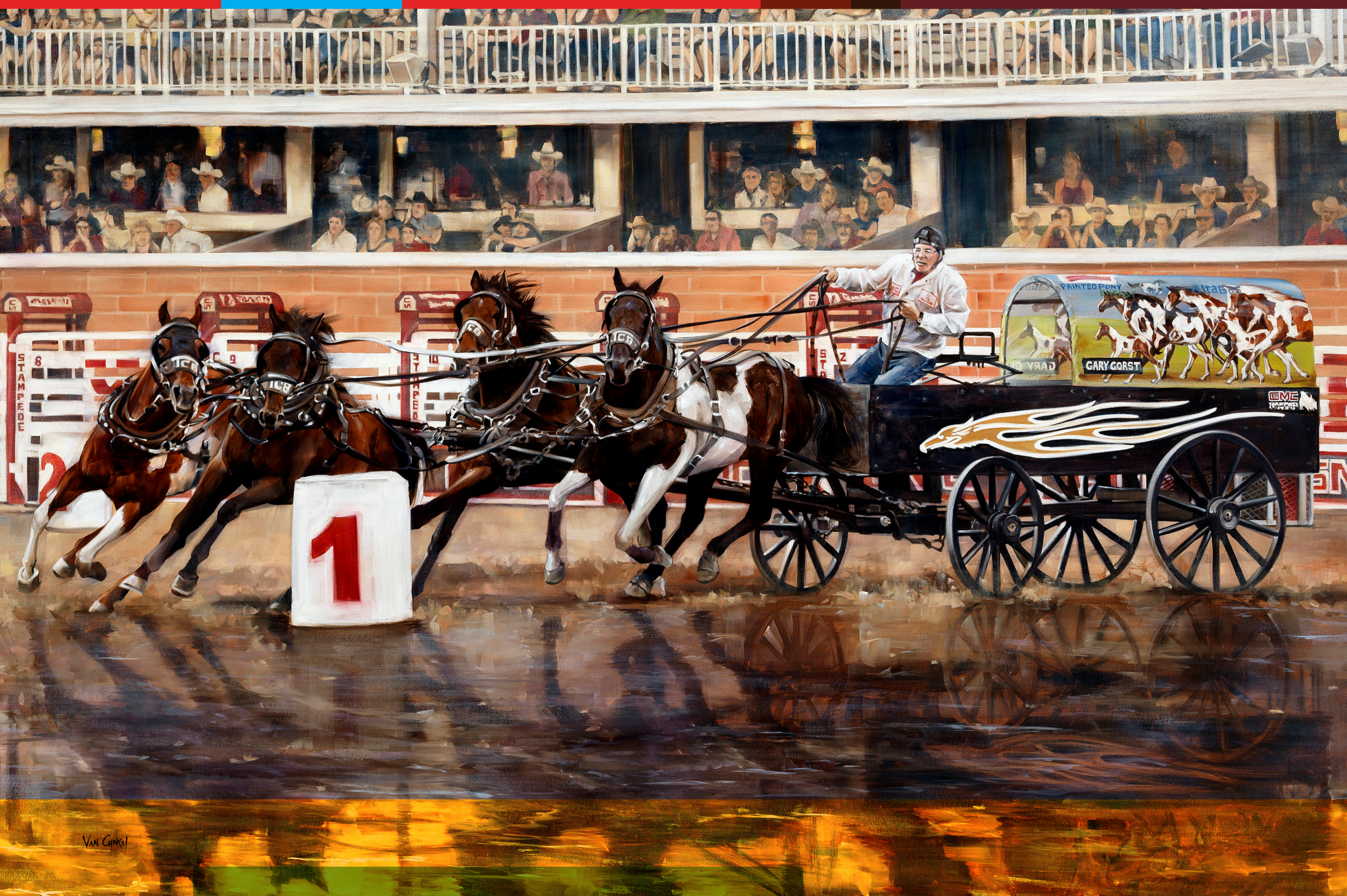
2017 ANNUAL REPORT

TSX | PONY



PAINTED PONY ENERGY LTD.

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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 "PONY".

"Come Hell or High Water"

- By Paul Van Ginkel

No matter the weather, the drivers and horses always show up to the race ready to run. This painting symbolizes both the energy industry and our western Canadian way of life. Many likely recall the Rangeland Derby Chuckwagon Races on that first night of the 2013 Calgary Stampede, the year of the massive flood that swept Calgary. Calgarians feared that the Stampede might not happen that year. To everyone's amazement, the Stampede managed to repair and reconstruct the infield racetrack in a very short period of time. No other city in the world could have pulled off such a feat, but Calgary did. It was truly inspiring to watch the drivers and the horses line up, chomping at their bits and ready to go! Nobody reflects this spirit better than Gary Gorst, the driver featured in "Come Hell or High Water" and sponsored jointly by Painted Pony and AltaGas in the 2017 and the 2018 Rangeland Derby Chuckwagon Races. This same spirit of perseverance through adversity is part of everything we do at Painted Pony. Regardless of the headwinds, we work relentlessly for the best outcomes for stakeholders.

Cover painting "Come Hell or High Water", oil on canvas by Paul Van Ginkel
www.paulvanginkel.com

Annual General Meeting

Painted Pony Energy 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 10, 2018. Shareholders not attending are encouraged to complete the form of proxy and deliver it in accordance with the instructions therein at their earliest convenience.

Financial and Operating Highlights

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

Financial	2017	2016	Change
Petroleum and natural gas revenue [1]	249.2	121.6	105%
Cash flow from operating activities	106.9	44.7	139%
Per share – basic [3]	0.76	0.45	69%
Per share – diluted [4]	0.74	0.45	64%
Adjusted funds flow from operations [2]	107.5	55.6	93%
Per share – basic [3]	0.76	0.56	36%
Per share – diluted [4]	0.75	0.56	34%
Net income (loss) and comprehensive income (loss)	122.4	(51.9)	–
Per share – basic [3]	0.87	(0.52)	–
Per share – diluted [4]	0.85	(0.52)	–
Capital expenditures	302.6	204.4	48%
Working capital (deficiency) [5]	33.0	(73.6)	–
Bank debt	149.2	200.8	(26%)
Senior notes	141.6	–	–
Convertible debentures - liability	44.9	–	–
Net debt [6]	363.9	228.5	59%
Total assets	2,031.6	1,337.0	52%
Shares outstanding (millions)	161.0	100.2	61%
Basic weighted-average shares (millions)	140.7	100.1	41%
Fully diluted weighted-average shares (millions)	144.1	100.1	44%
Operating			
Daily production volumes			
Natural gas (MMcf/d)	235.8	129.9	82%
Natural gas liquids (bbls/d)	3,587	1,557	130%
Total (MMcfe/d)	257.3	139.2	85%
Total (boe/d)	42,882	23,204	85%
Realized commodity prices			
Natural gas ($/Mcf)	2.13	2.04	4%
Natural gas liquids ($/bbl)	50.53	43.49	16%
Total ($/Mcfe)	2.65	2.39	11%
Operating netbacks ($/Mcfe) [7]	2.01	1.73	16%

1. Before royalties.
2. Adjusted funds flow from operations and adjusted 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, share unit expense and decommissioning expenditures. Adjusted funds flow from operations per share is calculated by dividing adjusted 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 and convertible debentures.
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, senior notes, liability portion of convertible debentures, and working capital deficiency, adjusted for the net current portion of fair value of risk management contracts and current portion of finance lease obligation.
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 risk management, less royalties, operating expenses and transportation costs. See "Non-GAAP Measures" and "Operating Netbacks".

Message to Shareholders

As 2017 drew to a close, the collapse of natural gas prices in the summer and fall at the main Canadian sales hub at AECO, as well as in the forward natural gas strip price at AECO, dominated the industry. In response to this, companies reduced capital investment. Production forecasts are reflective of the weakness in future strip prices. The current forward strip remains well below $2.00 at the AECO sales hub for the next several years. The forecasted reduction in capital investment by industry and the expected shrinking production volumes should begin to reverse the severe price decline and improve the future price of natural gas in western Canada, but the timeline is unclear. As such, we will continue to fortify our business through diversified market access, capital spending limited to internally generated cash flow, and reducing or maintaining debt levels.

2017 was a **notable year** as we took several major steps to **enhance the size and quality** of our asset base while **maintaining our financial flexibility.** We acquired UGR Blair Creek Ltd. ("UGR") in an all-share deal, raised $111 million in an equity financing at $5.60 per share, and diversified our debt capital through a $200 million private placement debt financing. We reached record annual average daily production of 257 MMcfe/d (42,882 boe/d) and signed a 14-year contract with Methanex Corporation for delivery of natural gas to their Methanol plant in Alberta. We achieved record adjusted funds flow from operations of $108 million ($0.76 per share). Finally, we ended the year with record Proved Plus Probable reserves of 6.9 Tcfe, which equates to over 1.1 billion boe, and have a net present value of $3.3 billion using a 10% discount rate using pricing from independent qualified reserves evaluators, GLJ Petroleum Consultants Ltd. ("GLJ").

Production Growth

I am pleased to report that annual average daily production for 2017 was 257 MMcfe/d or 42,882 boe/d, representing an increase of 85% over 2016 annual average daily production of 139 MMcfe/d or 23,204 boe/d. This production growth is particularly notable when considering that fourth quarter 2017 production volumes were impacted by approximately 48 MMcfe/d or 8,000 boe/d of voluntary pricing-related production shut-ins.

> "Tough times don't last, tough people do"
>
> -- Robert Schuller

Along with the increase in annual average daily production volumes, we also saw the growth in natural gas liquids ("NGL") which increased 130% to 3,587 bbls/d during 2017 compared to 1,557 bbls/d during 2016. The increase in both absolute production volumes and NGL production volumes reflects the impact of a full year of liquids-rich processing capacity of the Townsend Facility that came on-line during the third quarter of 2016 and the 99 MMcf/d expansion that became operational in the third quarter of 2017. Although liquids production was 8% of the total annual average daily production volumes, liquids revenue was 27% of total revenue during 2017.

Capital Expenditures

The 2017 capital program was the largest and most ambitious capital program in Painted Pony's history. We executed the 2017 capital plan efficiently and with discipline, meeting production growth targets from spending $303 million during the year compared to spending guidance of $315 million. We drilled 52 net wells and completed 51 net wells, supported by minor investments into associated facilities and infrastructure.

2017 was our most active year to date, and we maintained our high standards of workplace and environmental safety. In addition to a year without a single lost-time injury, we conducted a test of our Emergency Response Plan in conjunction with the British Columbia Oil and Gas Commission and received a score of 92%. It is a testament to the high regard we place on workplace and environmental safety while achieving our operational goals at Painted Pony.

Acquisition of UGR Blair Creek

On May 16, 2017 we closed the acquisition of UGR Blair Creek Ltd. in an all-share deal that resulted in an increase of more than 50% to our Montney acreage to more than 200,000 acres. From the beginning, we were partners with UGR in several key sections of land and shared working interest in a number of producing wells. In fact, of UGR's 36 producing wells, 20 of them were drilled by Painted Pony. We long-believed that UGR would be a logical fit into Painted Pony's acreage. Through the consolidation of our lands with UGR's 100 net sections, we now have a larger and more concentrated position in what we believe to be the best Montney acreage in the play. This also increased our working interest to 94% from 86% previously. UGR's underutilized gas processing facilities, combined with the

85% Growth in Annual Average Daily Production Volumes

AltaGas Townsend Facility, ensures we have all the necessary capacity to process our current natural gas production volumes and room for expansion. We firmly believe the acquisition of UGR will provide long-term value through our expanded asset base and will deliver value to shareholders for years to come.

Reserves Growth

The impact of our successful 2017 capital program combined with the acquisition of UGR, increased our year-end 2017 Proved Plus Probable reserves by 40% to 6.9 Tcfe or over 1.1 billion boe. We also increased our Total Proved reserves by 17% to 3.1 Tcfe as at year-end 2017. Our Proved Developed Producing reserves grew by 64% to 797 Bcfe, over 130 MMboe, and carried a value at year-end 2017 of $905 million ($5.62 per share) at a 10% discount rate using pricing from GLJ. While we believe reserve totals and value are important, the cost of finding the reserves is equally as important. I am pleased that our finding, development and acquisition ("FD&A") cost on Total Proved reserves in 2017 produced a 1.6 times recycle ratio, inclusive of changes in future development costs. This meant that were generating 1.6 times as much cash flow per Mcfe than what it was costing us to find and develop new reserves to replace those which we produce. We believe that the strength of this key measure highlights the efficiency of our capital spending and demonstrates the health of our business.

Sales Diversification

As our production volumes were increasing three years ago, we knew we needed to diversify our marketing efforts into as many sales regions and pricing hubs as possible to protect Painted Pony from regional pricing volatility and increase the price received for our natural gas. As we begin 2018, we continue to see the benefits from the execution of this strategy. We have successfully assembled a diversified marketing portfolio consisting of fixed-price contracts, direct-to-customer physical contracts, basis contracts and financial hedges, across several pricing hubs. Combined, this portfolio provides the price protection from commodity price volatility necessary in this environment.

Our firm transportation on the Enbridge system using the T-North line is now 357 MMcf/d, of which 174 MMcf/d has firm receipt into the NGTL system at Groundbirch via the TCPL

Daily Production for 2017 averaged

257 MMcfe/day

(42,882 boe/d)

Towerbirch Expansion Project. This access is complimented with 43 MMcf/d which continues moving east to be delivered into the Dawn market in southern Ontario. The volumes delivered into the Dawn market will increase to 81 MMcf/d by November 2019. In addition to volumes sold into the Dawn market we have diversified our sales exposure to cover 55% of our forecasted 2018 production volumes on fixed-price contracts (hedges) at a blended price of $3.76/Mcfe, capturing prices much higher than current spot prices in western Canada. Combined, we have natural gas pricing exposure to AECO, Station 2, Sumas, Dawn, and NYMEX. Liquids volumes are sold both on spot prices as well as fixed price contracts. We have greatly reduced the risk of commodity price volatility on our 2018 revenue.

2018 and Forward

The prospect of investment into a number of liquefied natural gas ("LNG") export facilities on the west coast and the east coast seem more likely now than in recent years. We hope to have clarity on some of these potential projects in the coming months. Due to the size and scale of our production and reserves, we are well-positioned to provide natural gas for LNG projects such as the ones being considered on Canada's west coast. If approved, these projects are several years away from completion but will provide a much-needed diversification of markets for Canadian natural gas.

2017 was a year of capital discipline, diversification of sales, and significant growth. While there is much of which to be proud, many challenges remain. I am confident we will weather this storm caused by low natural gas prices and emerge a stronger company, well-positioned for future success and profitability. Finally, a sincere thank you to the staff and Board of Directors at Painted Pony. We also would like to thank our service providers and shareholders for your continued support of Painted Pony Energy.

"signed"

Patrick R. Ward

President and Chief Executive Officer

March 30, 2018

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following Management's Discussion and Analysis ("MD&A") of the consolidated financial results of Painted Pony Energy 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, 2017 and December 31, 2016. This commentary is dated March 7, 2018.

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, 2017, 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 "PONY". The Corporation's head office is located at Suite 1800, 736 - 6th Avenue SW, Calgary, Alberta. During the second quarter of 2017, the Corporation changed its name from Painted Pony Petroleum Ltd., and its stock trading symbol from "PPY".

NON-GAAP MEASURES

This MD&A contains the terms "adjusted funds flow from operations", "adjusted funds flow from operations per share", "adjusted 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 "adjusted funds flow from operations" to analyze operating performance and considers adjusted 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. Adjusted funds flow from operations denotes cash flow from operating activities before the effects of changes in non-cash working capital, share unit expense and decommissioning expenditures. "Adjusted funds flow from operations per share" is calculated using the basic and diluted weighted average number of shares for the period. "Adjusted funds flow from operations per Mcfe" is calculated using the average production volumes for the period. For the year ended December 31, 2017, adjusted funds flow from operations, adjusted funds flow from operations per share and adjusted funds flow from operations per Mcfe are presented net of UGR acquisition costs. These terms should not be considered alternatives 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 adjusted 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 Adjusted Funds Flow from Operations

	Three months ended December 31,		**Years ended December 31,**	
($000s, except per share)	**2017**	**2016**	**2017**	**2016**
Cash flows from operating activities	**27,417**	21,859	**106,917**	44,658
Changes in non-cash working capital	**8,212**	3,355	**2,287**	7,931
Share unit expense (recovery)	**(399)**	1,284	**(1,724)**	2,914
Decommissioning expenditures	**—**	3	**—**	102
Adjusted funds flow from operations	**35,230**	26,501	**107,480**	55,605
Adjusted funds flow from operations per share *($/share)*:				
Basic	**0.22**	0.26	**0.76**	0.56
Diluted	**0.21**	0.26	**0.75**	0.56

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, senior notes, liability portion of convertible debentures, and working capital deficiency, adjusted for the net current portion of fair value of risk management contracts and current portion of finance lease obligation. 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

As at *($000s)*	**December 31, 2017**	**December 31, 2016**
Current assets	**105,795**	30,677
Current liabilities	**(72,770)**	(104,324)
Working capital (deficiency)	**33,025**	(73,647)
Current portion of fair value of risk management contracts (net)	**(64,463)**	46,020
Current portion of finance lease obligation	**3,282**	—
Bank debt	**(149,228)**	(200,836)
Senior notes	**(141,613)**	—
Convertible debentures - liability	**(44,887)**	—
Net debt	**(363,884)**	(228,463)

Management uses "operating netbacks" 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 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

The Corporation successfully closed the acquisition (the "UGR acquisition") of all of the issued and outstanding shares of UGR Blair Creek Ltd. ("UGR") during 2017, in exchange for the issuance of 41.0 million Common Shares of the Corporation to the vendor, the assumption by the Corporation of UGR's bank debt of approximately $48.2 million on closing and the payment of certain acquisition costs. The price of the Corporation's Common Shares at the close of trading on the closing date of the UGR acquisition, May 16, 2017, was $5.37 per common share, resulting in total share consideration of $220.2 million. The UGR acquisition is a strategic expansion of the Corporation's Montney project in northeast British Columbia, providing for an increase of the Corporation's land base, natural gas processing infrastructure, reserves and drilling inventory.

During the year ended December 31, 2017, the Corporation closed a transaction with Magnetar Capital to issue a total of $200 million of term debt consisting of $150 million of senior unsecured notes and $50 million of unsecured subordinated convertible debentures. The Corporation received $188.8 million of cash, net of financing fees, which was used to repay bank debt and fund the Corporation's capital program.

A public offering of 19.8 million Common Shares was completed during 2017, at a price of $5.60 per Common Share for aggregate gross proceeds of approximately $111.0 million (including the exercise in full of the over-allotment option granted to the underwriters).

As part of the Corporation's strategy to enhance realized natural gas commodity prices through innovative sales contracts, Painted Pony entered into a long-term agreement in 2017 to deliver natural gas (the "Agreement") to Methanex Corporation ("Methanex") under a fixed price US dollar denominated contract. Painted Pony will supply the majority of the natural gas required for Methanex's existing 600,000 tonne methanol plant in Medicine Hat, Alberta for a term of 14 years. Deliveries under the Agreement will commence in 2018 and contracted quantities will be approximately 10 MMcf/d (10,000 MMBtu/d) in 2018, increasing over time to approximately 50 MMcf/d (50,000 MMBtu/d) in 2023.

The Townsend Phase 2 expansion commenced commercial operation in the fourth quarter of 2017. The Corporation has the right to the full 99 MMcf/d of firm capacity of the new gas processing train at Townsend, in respect of which there is a take or pay obligation on production volumes delivered to the facility of 90 MMcf/d commencing in the first quarter of 2018. The Townsend Phase 2 expansion was recorded as a finance lease, recording the asset, representing the total estimated construction cost of the Townsend Phase 2 expansion and related pipeline infrastructure of $130 million, with a corresponding obligation on the statement of financial position. The efficiencies associated with this expansion are expected to reduce the fixed capital fee on a per mcf basis, paid by Painted Pony at the Townsend Phase 1 and 2 complex, by approximately 20% after commencement of the Townsend Phase 2 expansion take or pay.

Results of operations for the year highlight an increase in production volumes through both organic growth and the acquisition of UGR. With an increase in volumes of 85%, higher realized commodity prices and realized gains on risk management contracts, the Corporation increased its adjusted funds flow from operations for 2017 by 93% to $107.5 million ($0.76/share), compared to 2016 adjusted funds flow from operations of $55.6 million ($0.56/share).

Although commodity prices in the first and second quarter of 2017 recovered from comparable period commodity prices in 2016, the third and fourth quarters of 2017 saw price reductions. Painted Pony's exposure to low commodity prices in 2017 was mitigated by risk management contracts that resulted in a $44.0 million realized gain. After the impact of realized gains on risk management contracts of $0.47/Mcfe, Painted Pony's operating netback was $2.01/Mcfe, an increase of 16% over the previous year operating netback of $1.73/Mcfe. Painted Pony's operating netback for the three months ended December 31, 2017 was $2.05/Mcfe, comparable to the fourth quarter of 2016 operating netback of $2.09/Mcfe. For 2018, the Corporation has executed fixed price risk management contracts on 204.7 MMcf/d of natural gas and 3,400 bbl/d of NGL production. The Corporation continues to expand into new markets as part of its long term sales point diversification strategy, and is now delivering a significant portion of its natural gas volumes into the AECO, Dawn and Sumas markets. In addition, the Corporation has entered into fixed price contracts for physical delivery of natural gas priced at AECO or Sumas, less fixed differentials.

The capital program for 2017 of $302.6 million included 52 (52.0 net) Montney natural gas wells drilled and 51 (51.0 net) Montney natural gas wells completed, as well as associated facilities infrastructure. During the fourth quarter of 2017, Painted Pony drilled 7 (7.0 net) and completed 15 (15.0 net) Montney natural gas wells, and executed a capital program of $62.5 million including associated facilities infrastructure spending. The planned 2018 capital program is currently anticipated to include 29 (29.0 net) Montney horizontal natural gas wells drilled and 31 (31.0 net) completed.

At December 31, 2017, the Corporation's syndicated credit facilities consisted of available credit facilities of $450 million.

CASH FLOWS FROM OPERATING ACTIVITIES, ADJUSTED FUNDS FLOW FROM OPERATIONS AND NET INCOME

For the fourth quarter of 2017, cash flows from operating activities and adjusted funds flow from operations increased to $27.4 million and $35.2 million, respectively, compared to cash flows from operating activities of $21.9 million and adjusted funds flow from operations of $26.5 million in the fourth quarter of 2016. The increases in both cash flows from operating activities and adjusted funds flow from operations were primarily the result of an overall increase in average production of 43%.

For the year ended December 31, 2017, cash flows from operating activities and adjusted funds flow from operations increased to $106.9 million and $107.5 million respectively, compared to cash flows from operating activities of $44.7 million and adjusted funds flow from operations of $55.6 million in the year ended December 31, 2016. Increases in both cash flows from operating activities and adjusted funds flow from operations for the year ended December 31, 2017 compared to the year ended December 31, 2016, are as a result of an 85% increase in production volumes, a 24% increase in per unit realized gains on risk management contracts, and an 11% increase in realized commodity prices, offset by a 7% increase in costs per unit.

For the fourth quarter of 2017, the Corporation generated income and comprehensive income of $37.1 million, positively impacted by an unrealized gain on risk management contracts and higher revenue due to increased production. This compares to a net loss and comprehensive loss of $27.8 million for the quarter ended December 31,

2016. Excluding the unrealized gain on risk management contracts, income before taxes was $9.2 million for the quarter ended December 31, 2017, compared to income before taxes of $8.0 million for the quarter ended December 31, 2016.

For the year ended December 31, 2017, the Corporation generated income and comprehensive income of $122.4 million positively impacted by an unrealized gain on risk management contracts, partially offset by UGR acquisition costs. This compares to a net loss and comprehensive loss of $51.9 million for the year ended December 31, 2016. Excluding the unrealized gain (loss) on risk management contracts and UGR acquisition costs, income before taxes was $26.8 million for the year ended December 31, 2017, compared to $5.9 million for the year ended December 31, 2016.

AVERAGE DAILY PRODUCTION

	Three months ended December 31,				Year ended December 31,			
	2017	**% of total**	**2016**	**% of total**	**2017**	**% of total**	**2016**	**% of total**
Natural Gas *(Mcf/d)*	**287,811**	**91**	201,111	91	**235,767**	**92**	129,881	93
NGLs *(bbls/d)*	**4,575**	**9**	3,177	9	**3,587**	**8**	1,557	7
Total *(Mcfe/d)*	**315,264**	**100**	220,170	100	**257,292**	**100**	139,224	100
Total *(boe/d)*	**52,544**	**100**	36,695	100	**42,882**	**100**	23,204	100

Production volumes for the three months and year ended December 31, 2017 increased by 43% and 85%, respectively, compared to the three months and year ended December 31, 2016. The increase in NGL volumes reflects a greater focus on the liquids-rich processing capacity of the Townsend Facility. The production volume increase during the period was driven by production additions from successful new drills in the Blair Creek, Townsend and Daiber areas, the commissioning of the Townsend Facility expansion in the third quarter of 2016, and the UGR acquisition. For the fourth quarter ended December 31, 2017, the Corporation voluntarily shut-in approximately 48 MMcfe/d (8,000 boe/d) of production due to commodity pricing declines.

PETROLEUM AND NATURAL GAS REVENUE

	Three months ended December 31,		Years ended December 31,	
($000s)	**2017**	**2016**	**2017**	**2016**
Natural Gas	**43,883**	51,529	**183,030**	96,803
NGLs	**23,915**	13,626	**66,156**	24,777
Total	**67,798**	65,155	**249,186**	121,580

Petroleum and natural gas revenue totaled $67.8 million for the three months ended December 31, 2017, representing a 4% increase from the fourth quarter 2016 revenue of $65.2 million. The increase in quarterly revenue is driven by a 43% increase in average production volumes partially offset by a 27% decline in realized commodity pricing.

During the year ended December 31, 2017, petroleum and natural gas revenue increased by 105% to $249.2 million as a result of an 85% increase in average production volumes as well as an 11% increase in realized commodity pricing.

Commodity Prices

		Three months ended December 31,		Years ended December 31,	
Average Benchmark Prices:		**2017**	**2016**	**2017**	**2016**
Natural Gas	NYMEX (US$/MMBtu)	**2.92**	3.18	**3.02**	2.55
	AECO, daily (5A) ($/Mcf)	**1.69**	3.12	**2.16**	2.17
	Westcoast Station 2 ($/Mcf)	**0.56**	2.27	**1.56**	1.64
	Dawn ($/Mcf)	**3.72**	4.22	**3.95**	3.39
Crude Oil	WTI (US$/bbl)	**55.40**	49.29	**50.96**	43.48
Exchange rate *(US$/Cdn$)*		**0.79**	0.75	**0.77**	0.76
Realized Commodity Prices Before Commodity Risk Management:					
Natural Gas *($/Mcf)*		**1.66**	2.78	**2.13**	2.04
NGLs *($/bbl)*		**56.81**	46.62	**50.53**	43.49
Total *($/Mcfe)*		**2.34**	3.22	**2.65**	2.39

During the three months and year ended December 31, 2017, the Corporation realized natural gas prices of $1.66/Mcf and $2.13/Mcf, respectively, which represents a decrease of 40% and an increase of 4% over the three months and year ended December 31, 2016 realized natural gas prices of $2.78/Mcf and $2.04/Mcf, respectively. The increase during the year ended December 31, 2017 reflects stable or higher spot natural gas benchmark prices on most indexes, compared to the same period in 2016, as well as the impact of the Corporation's physical fixed price contracts. The decrease in realized natural gas prices for the three months ended December 31, 2017 compared to the three months ended December 31, 2016 resulted from a combination of market factors, including temporary disruptions to the natural gas pipeline system, as well as other major supply and demand issues in North America.

As part of the Corporation's long term market diversification strategy, Painted Pony reduced its exposure to Daily Station 2 pricing to less than 10% in the last half of 2017. In 2018, exposure to Station 2 is expected to average below 15%. Diversification away from Station 2 has been achieved by entering into financial and physical commitments, including contracting for transportation outside of the British Columbia market.

For the three months ended December 31, 2017, approximately 44% of the Corporation's NGL volumes were condensate, which received an average price of $73.27/bbl, representing a premium of 5% to the WTI reference price. For the year ended December 31, 2017, approximately 46% of the Corporation's NGL volumes were condensate, which received an average price of $67.99/bbl, representing a premium of 4% to the WTI reference price.

For 2018, the Corporation expects to receive a realized natural gas price that represents a premium to the benchmark Westcoast Station 2 price and comparable with the AECO (5A) benchmark price. The majority of the volatility experienced by the Corporation in commodity pricing in 2017 has been mitigated for 2018 by the commodity risk management contracts described below, as well as the completion of the Towerbirch pipeline expansion at Groundbirch, allocating Painted Pony an increase in direct to AECO production of 130MMcf/d.

Financial Risk Management

The Corporation uses financial derivative contracts to mitigate some of its exposure to commodity price, foreign exchange and interest rate risk. The use of these transactions is governed by and is subject to risk management policies established by the Board of Directors of the Corporation (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 financial derivative contracts to be effective economic hedges. As a result, all such contracts are recorded at fair value on the consolidated statement of financial position, with changes in the fair value being recognized as an unrealized gain or loss on the consolidated statement of operations.

Realized Gain (Loss) on Risk Management Contracts

	Three months ended December 31,		Years ended December 31,	
	2017	**2016**	**2017**	**2016**
Realized gain (loss) on risk management contracts *($000s)*	**24,156**	(1,632)	**44,002**	19,912
Per unit *($/Mcfe)*	**0.83**	(0.09)	**0.47**	0.38

The Corporation's method of determining the fair values of derivative financial instruments is disclosed in note 17 to the Annual Consolidated Financial Statements.

At December 31, 2017, the Corporation held commodity risk management contracts summarized as follows:

Financial AECO Natural Gas Contracts

Options traded	**Term**	**Volume (GJ/d)**	**Price (CDN$/GJ)**
AECO Fixed Price Swap	January 2018 - September 2018	6,000	3.07
AECO Fixed Price Swap	January 2018 - March 2018	10,000	3.18
AECO Fixed Price Swap	January 2018 - September 2018	10,000	2.84
AECO Fixed Price Swap	January 2018 - September 2018	10,000	2.85
AECO Fixed Price Swap	January 2018 - June 2018	6,000	3.03
AECO Fixed Price Swap	January 2018 - December 2018	6,000	2.95
AECO Fixed Price Swap	January 2018 - June 2019	8,000	2.66
AECO Fixed Price Swap	January 2018 - June 2018	10,000	2.88
AECO Fixed Price Swap	January 2018 - June 2018	5,000	3.01
AECO Fixed Price Swap	January 2018 - March 2018	10,000	3.16
AECO Fixed Price Swap	January 2018 - December 2018	10,000	2.57
AECO Fixed Price Swap	January 2018 - December 2018	10,000	2.56
AECO Fixed Price Swap	January 2018 - December 2018	10,000	2.32
AECO Fixed Price Swap	April 2018 - June 2019	10,000	2.62
AECO Fixed Price Swap	April 2018 - March 2019	10,000	2.32
AECO Call Option Sold	January 2018 - December 2019	10,000	2.80
AECO Call Option Sold	January 2018 - December 2019	15,000	2.93

Financial Dawn Natural Gas Contracts

Options traded	**Term**	**Volume (GJ/d)**	**Price (CDN$/GJ)**
Dawn Fixed Price Swap	April 2018 - March 2019	10,000	3.47
Dawn Fixed Price Swap	April 2018 - March 2019	10,000	3.50

Financial NYMEX Basis Differential Contracts

Options traded	**Term**	**Volume (MMBtu/d)**	**Price (NYMEX less US$/MMBtu)**
NYMEX-AECO Basis Swap	April 2018 - October 2018	10,000	1.14
NYMEX-AECO Basis Swap	April 2019 - September 2021	10,000	1.14
NYMEX-Dawn Basis Swap	January 2018 - December 2018	10,000	0.11

Financial Station 2 Natural Gas Contracts			
Options traded	**Term**	**Volume (GJ/d)**	**Price (CDN$/GJ)**
Stn. 2 Fixed Price Swap	January 2018 - March 2018	30,000	1.78
Stn. 2 Fixed Price Swap	January 2018 - March 2018	10,000	1.88
Stn. 2 Fixed Price Swap	January 2018 - March 2018	15,000	1.74
Stn. 2 Fixed Price Swap	January 2018 - March 2018	10,000	1.89
Stn. 2 Fixed Price Swap	January 2018 - March 2018	10,000	1.91
Stn. 2 Fixed Price Swap	January 2018 - March 2018	15,000	2.70
Stn. 2 Fixed Price Swap	January 2018 - June 2018	5,000	2.50
Stn. 2 Fixed Price Swap	January 2018 - December 2019	10,000	2.45
Stn. 2 Fixed Price Swap	April 2018 - June 2019	12,000	2.35
Stn. 2 Fixed Price Swap	April 2018 - September 2019	10,000	2.30
Stn. 2 Fixed Price Swap	April 2018 - September 2019	5,000	2.34

Financial AECO Basis Differential Contracts			
Options traded	**Term**	**Volume (GJ/d)**	**Price (AECO less CDN$/GJ)**
AECO-Station 2 Basis Swap	November 2018 - October 2020	10,000	0.32
AECO-Station 2 Basis Swap	November 2018 - October 2020	20,000	0.32
AECO-Station 2 Basis Swap	November 2018 - August 2021	20,000	0.29
AECO-Station 2 Basis Swap	November 2019 - October 2020	10,000	0.33

Financial WTI Crude Oil Contracts			
Options traded	**Term**	**Volume (Bbl/d)**	**Price (CDN$/Bbl)**
WTI Fixed Price Swap	January 2018 - December 2018	500	65.15
WTI Fixed Price Swap	January 2018 - December 2018	250	70.15
WTI Fixed Price Swap	January 2018 - December 2018	250	71.05
WTI Fixed Price Swap	January 2018 - December 2019	500	70.20
WTI Fixed Price Swap	January 2018 - December 2019	500	70.20

Financial Propane Contracts			
Options traded	**Term**	**Volume (GAL/d)**	**Price (CDN$/GAL)**
Conway Fixed Price Swap	January 2018 - December 2018	8,400	0.90
Conway Fixed Price Swap	January 2018 - December 2018	10,500	0.88
Conway Fixed Price Swap	January 2018 - December 2018	8,400	1.00

In addition to the commodity risk management contracts discussed above, the Corporation has entered into physical delivery sales contracts to manage commodity risk.

The Corporation has the following foreign exchange risk management contract in place as at December 31, 2017:

Reference Currency	Notional amount (USD 000s)	Term	Strike Rate
USD	$1,000/month	January 2018 - April 2018	1.3538 CAD/USD

ROYALTIES

	Three months ended December 31,		Years ended December 31,	
	2017	**2016**	**2017**	**2016**
Royalty expense *($000s)*	**906**	1,382	**4,901**	2,672
Per unit *($/Mcfe)*	**0.03**	0.07	**0.05**	0.05
Royalties as a % of Revenue *(%)*	**1.3**	2.1	**2.0**	2.2

For the year ended December 31, 2017 and December 31, 2016, royalties averaged 2.0% and 2.2% of revenue. For the three months ended December 31, 2017, the lower royalty rate of 1.3% compared to 2.1% for the three months ended December 31, 2016 can be attributed to reduced royalty rates on lower realized natural gas prices. The majority of the Corporation's properties are on the west side of the British Columbia royalty line and are eligible to receive an average royalty credit of approximately $2.2 million per well. The remainder of the Corporation's properties, on the east side of the British Columbia royalty line, are eligible to receive an average royalty credit of approximately $0.8 million per well.

During 2018, the Corporation anticipates overall royalty rates to be approximately 2.0% to 2.5% of total revenues. 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,		Years ended December 31,	
	2017	**2016**	**2017**	**2016**
Operating expenses *($000s)*	**18,095**	12,035	**59,834**	34,535
Per unit *($/Mcfe)*	**0.62**	0.59	**0.64**	0.68

Operating expenses increased by $0.03 per Mcfe or 5% in the fourth quarter of 2017 compared to the fourth quarter of 2016 and decreased by $0.04 per Mcfe or 6% for the year ended December 31, 2017 compared to the year ended December 31, 2016. Per unit operating expenses for the year ended December 31, 2017 have improved primarily as a result of incremental production volumes positively impacting fixed cost components, as well as lower rental expenses and consulting fees in 2017. Per unit operating expenses for the three months ended December 31, 2017 increased over 2016 due to voluntarily shut-ins of production, attributable to commodity pricing declines.

For 2018, the Corporation anticipates that average per unit operating expenses will be between $0.60 and $0.65 per Mcfe.

TRANSPORTATION COSTS

	Three months ended December 31,		Years ended December 31,	
	2017	**2016**	**2017**	**2016**
Transportation costs *($000s)*	**13,646**	7,653	**39,197**	15,894
Per unit *($/Mcfe)*	**0.47**	0.38	**0.42**	0.31

Transportation costs for the three months and year ended December 31, 2017 increased by $0.09 per Mcfe or 24% and $0.11 per Mcfe or 35%, respectively, compared to the three months and year ended December 31, 2016.

For both the three months and year ended December 31, 2017, the increased transportation costs per unit are the result of an increase in transport tolls on third party pipelines, as well as higher liquids trucking costs compared to the three months and year ended December 31, 2016, due to a 44% and 130% increase in liquids production respectively.

During 2017, the Corporation signed various firm transportation agreements which facilitated its diversification into the Dawn, Sumas, and AECO markets. On November 1, 2017, under a 10 year firm transportation agreement, the Corporation began delivering 38 MMcf/d of natural gas to the Dawn market via the Long Term Fixed Price service, with delivered volumes increasing to 88 MMcf/d by November 2019. On November 1, 2017, the Corporation began delivering 6.4 MMcf/d of natural gas to Sumas via firm transportation on the Enbridge T-South system. As of February 1, 2018 the Corporation was delivering 174 MMcf/d to the AECO/NIT system with firm transportation through the NGTL Towerbirch expansion.

For 2018, the Corporation expects average per unit transportation costs to be between $0.70 and $0.75 per Mcfe. 2018 per unit transportation costs are expected to be higher than 2017 as a result of increasing sales to more distant sales points as part of our natural gas market diversification strategy, increased tolls on third party pipelines and an anticipated increase in liquids production.

OPERATING NETBACKS

	Three months ended December 31,		Years ended December 31,	
($/Mcfe)	**2017**	**2016**	**2017**	**2016**
Realized commodity price	**2.34**	3.22	**2.65**	2.39
Realized gain on risk management contracts	**0.83**	(0.09)	**0.47**	0.38
Royalties	**(0.03)**	(0.07)	**(0.05)**	(0.05)
Operating expenses	**(0.62)**	(0.59)	**(0.64)**	(0.68)
Transportation costs	**(0.47)**	(0.38)	**(0.42)**	(0.31)
Operating netbacks	**2.05**	2.09	**2.01**	1.73

For the three months ended December 31, 2017, operating netbacks decreased by $0.04 per Mcfe or 2% compared to the three months ended December 31, 2016. For the three months ended December 31, 2017, the decrease in operating netbacks was the result of an 8% increase in combined per unit royalties, operating, and transportation costs compared to the three months ended December 31, 2016, and lower realized commodity prices, offset by an increase in realized gains on risk management contracts.

For the year ended December 31, 2017, operating netbacks increased by $0.28 per Mcfe or 16%, compared to the year ended December 31, 2016. For the year ended December 31, 2017, the increase in operating netbacks is the result of an 11% increase in realized commodity prices, a 24% increase in realized gains on risk management contracts, offset by a 7% increase in combined per unit royalties, operating, and transportation costs compared to the year ended December 31, 2016.

The Corporation's operating netback for the three months and year ended December 31, 2017 was 88% and 76% of revenue, respectively, compared to 65% and 72% of revenue for the three months and year ended December 31, 2016, respectively.

GENERAL AND ADMINISTRATIVE EXPENSES

	Three months ended December 31,		Years ended December 31,	
($000s, except per Mcfe)	**2017**	**2016**	**2017**	**2016**
Gross expenses	**7,749**	6,963	**26,134**	19,310
Capitalized	**(1,703)**	(2,646)	**(5,764)**	(5,937)
Capital recoveries	**(857)**	(668)	**(3,339)**	(2,343)
Operating recoveries	**(196)**	(118)	**(549)**	(464)
Net expenses	**4,993**	3,531	**16,482**	10,566
Per unit *($/Mcfe)*	**0.17**	0.17	**0.18**	0.21

Net general and administrative ("G&A") expenses for the three months ended December 31, 2017 were comparable to the three months ended December 31, 2016. Annual net G&A decreased by $0.03 per Mcfe or 14%, compared to the year ended December 31, 2016, due to higher production volumes.

The Corporation's policy of allocating and capitalizing costs associated with new capital projects remained unchanged for the year ended December 31, 2017. G&A capitalized and operating recoveries are in accordance with industry practice.

For 2018, with increased production, the Corporation anticipates that per unit G&A expenses will average in the range of $0.12 to $0.16 per Mcfe.

UGR ACQUISITION COSTS

For the year ended December 31, 2017, the Corporation expensed $5.5 million ($0.06 per Mcfe) in acquisition costs related to the UGR acquisition. For the year ended December 31, 2017, UGR acquisition costs were $0.04 per basic share.

FINANCE EXPENSE

	Three months ended December 31,		**Years ended December 31,**	
($000s)	**2017**	**2016**	**2017**	**2016**
Finance lease expense	**13,247**	9,730	**44,157**	14,165
Interest expense	**5,837**	2,691	**15,640**	8,055
Accretion	**877**	158	**1,794**	550
Total	**19,961**	12,579	**61,591**	22,770
Per unit *($/Mcfe)*	**0.69**	0.62	**0.66**	0.45

Finance lease expense is a component of the capital fee paid on facilities treated as a capital lease, and varies with production volumes processed. The capital fee includes finance lease expense and any amortization of the outstanding finance lease obligation.

Interest expense includes interest on bank debt and standby charges on the Corporation's syndicated credit facilities, as well as interest on the senior notes and convertible debentures issued during the third quarter of 2017.

Per unit finance expense for the three months and year ended December 31, 2017 was $0.69 per Mcfe and $0.66 per Mcfe, respectively, compared to $0.62 per Mcfe and $0.45 per Mcfe for the three months and year ended December 31, 2016. Interest expense increased for both the three months and year ended December 31, 2017 due to larger available syndicated credit facilities on which standby fees are calculated, as well as additional interest expense related to the senior notes and convertible debentures.

Accretion expense consists of accretion on the decommissioning obligation, senior notes and convertible debentures. Accretion expense on the decommissioning obligation increased for the three months and year ended December 31, 2017, compared to the three months and year ended December 31, 2016 as a result of a higher decommissioning liability balance and a higher risk free rate. At December 31, 2017, the risk free rate was 2.3% compared to 2.1% at December 31, 2016. The Corporation has estimated the net present value of the decommissioning obligation based on an undiscounted total future liability of $106.0 million at December 31, 2017, compared to $64.2 million at December 31, 2016.

ADJUSTED FUNDS FLOW FROM OPERATIONS

($000s, except per Mcfe)	Three months ended December 31, 2017	Three months ended December 31, 2016	Years ended December 31, 2017	Years ended December 31, 2016
Petroleum and natural gas revenue	**67,798**	65,155	**249,186**	121,580
Royalties	**(906)**	(1,382)	**(4,901)**	(2,672)
Realized gain (loss) on risk management contracts	**24,156**	(1,632)	**44,002**	19,912
Operating expenses	**(18,095)**	(12,035)	**(59,834)**	(34,535)
Transportation costs	**(13,646)**	(7,653)	**(39,197)**	(15,894)
General and administrative expenses	**(4,993)**	(3,531)	**(16,482)**	(10,566)
Costs on acquisition of UGR	**—**	—	**(5,497)**	—
Finance lease expense	**(13,247)**	(9,730)	**(44,157)**	(14,165)
Interest expense	**(5,837)**	(2,691)	**(15,640)**	(8,055)
Adjusted funds flow from operations	**35,230**	26,501	**107,480**	55,605
Per unit *($/Mcfe)*	**1.21**	1.31	**1.14**	1.09

SHARE-BASED COMPENSATION EXPENSE

($000s)	Three months ended December 31, 2017	Three months ended December 31, 2016	Years ended December 31, 2017	Years ended December 31, 2016
Gross expense	**1,205**	711	**3,118**	3,484
Capitalized	**(586)**	(121)	**(913)**	(620)
Share unit expense (recovery)	**(399)**	1,284	**(1,724)**	2,914
Total	**220**	1,874	**481**	5,778

Gross share-based compensation expense was approximately $1.2 million for the three months ended December 31, 2017 and $0.7 million for the three months ended December 31, 2016. There were 600,000 stock options granted during the three months ended December 31, 2017 at a weighted average exercise price of $3.52. For the three months ended December 31, 2017, the weighted average fair value of stock options granted was $1.62 per stock option.

Gross share-based compensation expense was approximately $3.1 million for the year ended December 31, 2017, compared to $3.5 million for the year ended December 31, 2016. There were 3,376,650 stock options granted during the year ended December 31, 2017 at a weighted average exercise price of $4.42. For the year ended December 31, 2017, the weighted average fair value of stock options granted was $2.00 per stock option.

Gross 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 exercise of these stock options.

Share Unit Plans

The Corporation has a deferred share unit ("DSU") plan, whereby 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 in the capital of the Corporation (“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 and/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. As at December 31, 2017, there were 690,104 DSUs outstanding under the plan.

The Corporation has a restricted share unit ("RSU") plan, whereby RSUs are issued to eligible employees. Each RSU is a notional unit equal in value to one Common Share, which entitles the holder to a cash payment upon redemption. RSUs vest in three equal installments on the first, second, and third anniversaries of the grant date, at which time the holder is eligible to receive a cash payment equal to the number of vested awards multiplied by the fair market value. The expense associated with the RSU 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 over the vesting period, with a corresponding RSU liability recorded as a current liability in the statement of financial position. At period end dates, the RSU liability is adjusted based on the 20-day volume weighted average price of Common Shares. As at December 31, 2017, there were 222,630 RSUs outstanding under the plan.

The Corporation has a performance share unit ("PSU") plan, whereby PSUs are issued to eligible executive officers. Each PSU is a notional unit equal in value to one Common Share, which entitles the holder to a cash payment upon redemption. PSUs vest upon the third anniversary of the grant date, at which time the holder is eligible to receive a cash payment equal to the number of vested awards multiplied by the fair market value. The unit value is adjusted for a performance multiplier which can range from 0 to 2 and is dependent on the performance of the Corporation for a predefined period. The expense associated with the PSU plan is determined based on the 20-day weighted average price of Common Shares at the grant date. The expense is recognized in the statement of operations over the vesting period, with a corresponding PSU liability recorded as a current liability in the statement of financial position. At period end dates, the PSU liability is adjusted based on the 20-day volume weighted average price of Common Shares. As at December 31, 2017, there were 303,900 PSUs outstanding under the plan.

DEPLETION AND DEPRECIATION EXPENSE

	Three months ended December 31,		Years ended December 31,	
	2017	**2016**	**2017**	**2016**
Depletion and depreciation *($000s)*	**24,921**	16,491	**83,887**	43,329
Per unit *($/Mcfe)*	**0.86**	0.81	**0.89**	0.85

Depletion and depreciation expense per unit for the three months and year ended December 31, 2017 of $0.86/Mcfe and $0.89/Mcfe, respectively, were comparable to the three months and year ended December 31, 2016 depletion and depreciation expense of $0.81/Mcfe and $0.85/Mcfe, respectively. The depletion calculation for the three months ended December 31, 2017 included future development costs associated with the development of the Corporation's proved plus probable reserves of $4.1 billion, compared to $2.9 billion for the three months ended December 31, 2016.

The Corporation's exploration and evaluation ("E&E") assets totaling $159.0 million as at December 31, 2017, compared to $114.3 million as at December 31, 2016, were not subject to depletion. The increase in E&E assets was the direct result of the undeveloped land acquired in the UGR acquisition. Substantially all of the E&E assets relate to undeveloped land.

CAPITAL EXPENDITURES

	Three months ended December 31,		Years ended December 31,	
($000s)	**2017**	**2016**	**2017**	**2016**
Drilling and completions	**45,144**	37,081	**240,640**	152,894
Facilities and equipment	**14,954**	11,234	**49,613**	43,767
Lease acquisitions and retention	**294**	138	**1,095**	614
Seismic	**267**	166	**4,143**	716
Property dispositions	**—**	9	**19**	(386)
Capitalized G&A	**1,703**	2,646	**5,764**	5,937
Exploration and development	**62,362**	51,274	**301,274**	203,542
Head office expenditures	**103**	232	**1,340**	849
Capital expenditures	**62,465**	51,506	**302,614**	204,391
Capital lease assets	**130,000**	(4,140)	**130,000**	360,860
Share-based compensation	**586**	121	**913**	620
Decommissioning costs[1]	**5,322**	(2,214)	**14,973**	7,929
UGR acquisition	**—**	—	**207,491**	—
Total	**198,373**	45,273	**655,991**	573,800

1. Subsequent to the date of acquisition, decommissioning liabilities acquired in the UGR acquisition were revalued, resulting in a $7.1 million increase to capital expenditures.

During the three months and year ended December 31, 2017, the Corporation invested $62.4 million and $301.3 million, respectively, in exploration and development capital expenditures, compared to $51.3 million and $203.5 million, respectively, during the three months and year ended December 31, 2016.

Capital expenditures for the year ended December 31, 2017 included $240.6 million on drilling and completions activity. The Corporation drilled 52 (52.0 net) and completed 51 (51.0 net) Montney natural gas wells during 2017 as part of the Corporation's capital program. Facilities capital of $49.6 million for the year ended December 31, 2017 included equipping costs, pipeline construction costs and spending on processing facilities.

In 2018, the Corporation intends to drill 29 (29.0 net) and complete 31 (31.0 net) Montney horizontal natural gas wells on its 100% working interest lands.

LIQUIDITY AND CAPITAL RESOURCES

As at December 31, 2017, the corporation had working capital of $33.0 million and net debt of $363.9 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, available credit facilities, senior notes and convertible debentures. 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.

SENIOR NOTES

On August 23, 2017, the Corporation issued $150.0 million of 8.5% senior unsecured notes (the "Notes") with a 5 year term by way of private placement. Proceeds net of discount and transaction costs of $8.9 million amounted to $141.1 million. Interest is payable in equal quarterly installments in arrears. The Notes are fully and unconditionally guaranteed as to the payment of principal and interest, on a senior unsecured basis by the Corporation. There are no maintenance financial covenants.

The Notes are non-callable by the Corporation prior to the three year anniversary. If the Corporation chooses to redeem the Notes prior to August 23, 2020, they will be subject to a make-whole premium equal to the Canada Yield Price, plus accrued and unpaid interest. At any time on or after August 23, 2020, the Corporation can redeem all or part of the Notes at the redemption prices set forth in the table below plus any accrued and unpaid interest.

Redemption Schedule	Percentage
August 23, 2020 - August 22, 2021	104.250%
August 23, 2021 - February 22, 2022	102.125%
February 23, 2022 - August 23, 2022	100.000%

If a change of control event occurs at any time before maturity, the Corporation must offer to repurchase the Notes at a price according to the redemption schedule above.

CONVERTIBLE DEBENTURES

On August 23, 2017, the Corporation issued $50.0 million of convertible unsecured subordinated debentures (the "Debentures") for net proceeds of $47.7 million. The Debentures mature on August 23, 2021 and bear interest at 6.5% per annum payable quarterly commencing November 23, 2017. At the holder's option, the Debentures may be converted into common shares of the Corporation at any time prior to the close of business on the date of maturity at a conversion price of $5.60 per share (the "conversion price").

The Debentures are non-redeemable by the Corporation between August 23, 2017 and February 22, 2020 other than pursuant to the 90% redemption right (see Change of Control below). The Debentures are redeemable by the Corporation between February 23, 2020 and August 23, 2021 at a redemption price equal to principal amount plus interest. Redemption may be satisfied in common shares if the 30-day volume weighted average price ("VWAP") on notice date and the closing price immediately prior to notice date are both greater than 140% of the conversion price.

On maturity, the Corporation may satisfy its obligation to Debenture holders by issuing common shares if the Corporation's market capitalization exceeds $750 million. The number of common shares issued is calculated based on 95% of the lesser of the 30-day VWAP and the 2-day VWAP on the date of maturity.

Upon occurrence of a change of control event, the Corporation must offer to repurchase the Debentures at a price according to the schedule below. If 90% or more of the principal amount accept the offer, the Corporation shall have the right to repurchase 100% of the Debentures outstanding.

Redemption Schedule	Percentage of Principal
August 23, 2017 - August 22, 2018	110.000%
August 23, 2018 - February 22, 2020	105.000%
February 23, 2020 - August 23, 2021	100.000%

BANK DEBT

At December 31, 2017, the Corporation’s syndicated credit facilities consisted of available credit facilities of $450 million. The available facilities are provided by a syndicate of financial institutions, and include a $400 million extendable revolving facility and a $50 million operating facility. The facilities revolve for a 2-year period, which is extendable 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 change. 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, 2017, Painted Pony had $160 million in bankers’ acceptances with an effective interest rate of 3.65% per annum. In addition, as at December 31, 2017, the Corporation had outstanding letters of credit totaling $21.5 million and US$15.0 million, which reduce the credit available on the syndicated facilities. At December 31, 2016, the Corporation had an outstanding letter of credit of $14.9 million.

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 3.25% per annum depending on the Corporation’s senior debt to quarterly annualized EBITDA ratio as defined by the lenders, ranging from less than 1.00:1 to 3.00:1. 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 0.8125% per annum is charged on the undrawn portion of the credit facilities, also calculated depending on the Corporation's senior debt to quarterly annualized EBITDA ratio, as defined by the lenders.

Security over all of the Corporation's assets is provided by a floating charge demand debenture in the aggregate amount of $1.0 billion. The Corporation has provided a negative pledge and an undertaking to provide fixed charges over its petroleum and natural gas reserves in certain circumstances. The Corporation's syndicated credit facilities include financial covenants as follows: senior debt to EBITDA ratio of not greater than 3.00:1 on a trailing four fiscal quarter basis, and total debt to EBITDA ratio of not greater than 4.25:1 on a trailing four fiscal quarter basis until Q2 2018, thereafter of not greater than 4.00:1 on a trailing four fiscal quarter basis. At December 31, 2017 the senior debt to EBITDA ratio was 1.77:1.00, and the total debt to EBITDA ratio was 3.28:1.00. The Corporation is in compliance with all covenants as at December 31, 2017.

ALTAGAS STRATEGIC ALLIANCE

The Corporation is party to 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.

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 and related pipeline infrastructure, which commenced commercial operations in 2016. Painted Pony does not acquire any legal right, title, or interest in the Townsend Facility or pipeline. All construction costs were borne by AltaGas. The Corporation has the right to a minimum of 198 MMcf/d of firm capacity, in respect of which there is a take or pay obligation on production volumes delivered to the facility of 180 MMcf/d.

During the second quarter of 2017, Painted Pony entered into an agreement with AltaGas in respect of a Townsend Phase 2 expansion. The Townsend Phase 2 expansion consists of a 99 MMcf/d gas processing train located on the existing Townsend site adjacent to, and sharing joint equipment with the original Townsend Facility. The Corporation has the right to the full 99 MMcf/d of firm capacity at Townsend Phase 2, since commencement of commercial operation in the fourth quarter of 2017, in respect of which there is a take or pay obligation on production volumes delivered to the facility of 90 MMcf/d commencing in the first quarter of 2018.

The Townsend Facility, related pipeline infrastructure and Phase 2 expansion have been recorded as a finance lease. Painted Pony has recorded the asset, representing the total estimated construction cost of the Townsend Facility of $490.9 million, 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.

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 not more than five years**	**More than five years**	**Total**
Processing	52,328	269,998	579,843	902,169
Transportation	9,880	53,114	182,355	245,349
Total	62,208	323,112	762,198	1,147,518
Principal	3,282	64,981	422,597	490,860

In conjunction with the Phase 2 expansion, AltaGas commissioned a fractionation facility and railway terminal. All NGL Mix produced at the expanded AltaGas Townsend Facility is now pipelined directly to the AltaGas Fractionation Facility, while the stabilized condensate flows directly to the AltaGas Rail Terminal.

COMMITMENTS

The following is a summary of the estimated costs required to fulfill Painted Pony's remaining contractual commitments as at December 31, 2017.

($000s)	2018	2019	2020	2021	2022	Thereafter	Total
Transportation and processing	77,704	90,093	99,775	98,020	97,438	1,030,077	1,493,107
Interest on senior notes	14,242	14,399	14,613	14,765	9,576	—	67,595
Interest on convertible debentures	3,250	3,250	3,250	2,438	—	—	12,188
Office leases and other	1,740	1,216	117	101	7	—	3,181
Total commitments	96,936	108,958	117,755	115,324	107,021	1,030,077	1,576,071

Transportation commitments include contracts to transport natural gas and NGLs through third-party owned pipeline systems in Canada. Processing commitments include contracts to process natural gas through third-party owned gas processing facilities in British Columbia. Interest on senior notes includes quarterly interest on senior notes. Interest on convertible debentures includes quarterly interest on convertible debentures. 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.

OFF BALANCE SHEET ARRANGEMENTS

No off balance sheet arrangements existed as at December 31, 2017 or December 31, 2016, except those noted within.

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, 2017 and March 7, 2018, there were 160,995,692 Common Shares issued and outstanding, respectively. At December 31, 2017 and March 7, 2018, there were no Preferred Shares issued and outstanding.

The Corporation has a stock option plan, pursuant to which options to purchase Common Shares are granted to officers and employees of the Corporation. Stock options are granted at the volume weighted average trading price of the Common Shares for the five trading days immediately preceding the date of grant, and have a five-year term. Stock options granted vest as to one-third on each of the first, second and third anniversaries of the grant date. As at December 31, 2017, an aggregate of 10,298,367 stock options were issued and outstanding at a weighted-average price of $6.01 per stock option. As at March 7, 2018, an aggregate of 11,836,192 stock options were issued and outstanding at a weighted-average price of $5.33 per stock option.

INCOME TAXES

As at December 31, 2017, the Corporation had a $7.8 million deferred tax liability. This compares to a $32.6 million deferred tax asset at December 31, 2016. The deferred tax expense was $45.4 million during the year ended December 31, 2017, compared to a deferred income tax recovery of $17.9 million during the year ended December 31, 2016.

The Corporation expects that future taxable income will be available to utilize accumulated tax pools. Painted Pony's estimated tax pools at December 31, 2017 were $1.4 billion.

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. See "Advisories - Forward-looking Statements" in the MD&A for further discussion of forward looking statements, risks and uncertainties. A comparison of actual performance to the previously announced expectations of the Corporation is as follows:

- For the fourth quarter of 2017, the Corporation expected to receive a realized natural gas price at a premium to the benchmark Westcoast Station 2 price and comparable to the AECO (5A) benchmark price. The actual weighted average price received during the fourth quarter of 2017 represented a 196% premium to the Westcoast Station 2 price and a 2% discount to the AECO 5A daily spot price.
- Painted Pony's royalty rate for the fourth quarter of 2017 was expected to be approximately 2.5% of total revenues. The actual royalty rate for the fourth quarter of 2017 was 1.3% of total revenues. Royalty rates were lower than expectation due to pricing declines during the fourth quarter of 2017.
- Operating expenses for the fourth quarter of 2017 were expected to be between $0.60 and $0.65 per Mcfe. Actual operating expenses for the fourth quarter were $0.62 per Mcfe.
- Transportation expenses for the fourth quarter of 2017 were expected to be between $0.35 and $0.40 per Mcfe. Actual transportation expenses for the quarter were $0.47 per Mcfe due to an increase in transport tolls on third party pipelines, as well as higher liquids trucking costs.
- Net G&A expenses for the fourth quarter of 2017 were expected to be $0.10 to $0.15 per Mcfe. Actual net G&A for the fourth quarter were $0.17 per Mcfe. G&A expenses were higher than expectation due to increased professional fees.

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 ("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.

Critical Accounting Estimates

The following are key estimates 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 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 obligation, 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 risk management contracts at fair value with changes in fair value recognized in the consolidated 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 Obligation

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 estimates 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 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 income 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, 2018 and have not yet been applied in preparing the consolidated financial statements for the year ended December 31, 2017. The standards applicable to the Corporation are as follows and will be adopted on their respective effective dates:

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 has adopted 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 has been adopted using a modified retrospective approach effective January 1, 2018. The Corporation has reviewed its revenue streams and underlying contracts with customers and has determined that there will not be a material impact on its earnings. Additional disclosures will be implemented.

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 an impact on the Corporation’s consolidated statement of financial position.

BUSINESS RISKS

Painted Pony's production and exploration and development 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 minimal 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, development 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.

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.

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, 2017 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.

The Corporation may from time to time be involved in legal claims or litigation arising in the normal course of business. The outcome of legal claims or litigation is uncertain and there can be no assurance that such legal claims or litigation will be resolved in the Corporation's favor. Other than disclosed herein, the Corporation does not currently believe that the outcome of adverse decisions in any pending or threatened legal claims or litigation, or any amount which it may be required to pay, would have a material adverse impact on its financial position or results of operations.

Aboriginal peoples have claimed aboriginal title and rights to portions of western Canada, including northeast British Columbia. On May 31, 2017, the British Columbia Supreme Court denied an injunction application brought by the Blueberry River First Nation ("BRFN") which sought 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. Had the injunction application been successful, it would likely have had an adverse impact on the Corporation, its operations and production. The interlocutory injunction was part of an underlying claim, by the BRFN 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 underlying claim is scheduled to be heard by the British Columbia Supreme Court in the spring 2018. The Corporation was not a party to the interlocutory injunction and it is not party 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, 2017, 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, 2017.

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. The Corporation has established and maintains ICFR using the criteria that were set forth by the Committee of Sponsoring Organizations of the Treadway Commission in Internal Control - Integrated Framework (2013). As at December 31, 2017, 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, 2017.

No material changes in the Corporation's ICFR were identified during the period beginning on October 1, 2017 and ended on December 31, 2017 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 2017.

Quarter ended *($000s, except where noted)*	**Dec 31, 2017**	**Sept 30, 2017**	**Jun 30, 2017**	**Mar 31, 2017**
Petroleum and natural gas revenue	**67,798**	50,016	66,424	64,948
Cash flow from operating activities	**27,417**	29,609	18,230	31,661
Per share - basic	**0.17**	0.18	0.13	0.32
Per share - diluted	**0.16**	0.18	0.13	0.31
Adjusted funds flow from operations	**35,230**	29,462	17,989	24,799
Per share - basic	**0.22**	0.18	0.13	0.25
Per share - diluted	**0.21**	0.18	0.13	0.25
Net income	**37,067**	14,592	13,829	56,888
Per share - basic	**0.23**	0.09	0.10	0.57
Per share - diluted	**0.22**	0.09	0.10	0.56
Capital expenditures	**62,465**	85,592	57,879	96,678
Working capital (deficiency)	**33,025**	(21,486)	(30,794)	(74,225)
Bank debt	**149,228**	93,759	235,547	232,649
Senior notes	**141,613**	141,260	—	—
Convertible debentures - liability	**44,887**	44,597	—	—
Net debt	**363,884**	336,405	283,538	299,791
Total assets	**2,031,643**	1,809,283	1,742,761	1,406,214
Decommissioning obligation	**46,811**	41,255	44,517	30,431
Average daily production volumes *(boe/d)*	**52,544**	42,353	40,574	35,878
Average daily production volumes *(MMcfe/d)*	**315.3**	254.1	243.4	215.3
Realized commodity prices				
Natural gas *($/Mcf)*	**1.66**	1.59	2.64	2.87
NGLs *($/bbl)*	**56.81**	45.70	47.04	50.30
Total *($/Mcfe)*	**2.34**	2.14	3.00	3.35
Operating netbacks *($/Mcfe)*	**2.05**	2.12	1.81	2.08

Quarter ended *($000s, except where noted)*	**Dec 31, 2016**	**Sept 30, 2016**	**Jun 30, 2016**	**Mar 31, 2016**
Petroleum and natural gas revenue	65,155	27,987	11,863	16,575
Cash flow from operating activities	21,859	10,325	5,272	7,202
Per share - basic	0.22	0.10	0.05	0.07
Per share - diluted	0.21	0.10	0.05	0.07
Adjusted funds flow from operations	26,501	12,639	8,908	7,557
Per share - basic	0.26	0.13	0.09	0.08
Per share - diluted	0.26	0.12	0.09	0.08
Net income (loss)	(27,761)	11,614	(33,559)	(2,151)
Per share - basic	(0.28)	0.12	(0.34)	(0.02)
Per share - diluted	(0.28)	0.11	(0.34)	(0.02)
Capital expenditures	51,506	50,471	35,338	67,076
Working capital (deficiency)	(73,647)	(36,626)	(36,677)	(26,016)
Bank debt	200,836	172,054	136,897	87,559
Net debt	228,463	202,494	164,493	137,239
Total assets	1,336,955	1,290,228	876,295	857,942
Decommissioning obligation	29,857	32,015	27,321	25,738
Average daily production volumes *(boe/d)*	36,695	22,741	16,634	16,601
Average daily production volumes *(MMcfe/d)*	220.2	136.4	99.8	99.6
Realized commodity prices				
Natural gas *($/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

SELECTED CONSOLIDATED ANNUAL INFORMATION

The following tables set forth selected consolidated annual financial information of the Corporation for the three most recently completed years ending December 31, 2017.

Year ended *($000s, except where noted)*	**Dec 31, 2017**	**Dec 31, 2016**	**Dec 31, 2015**
Petroleum and natural gas revenue	**249,186**	121,580	81,583
Cash flow from operating activities	**106,917**	44,658	31,705
Per share - basic	**0.76**	0.45	0.32
Per share - diluted	**0.74**	0.45	0.32
Adjusted funds flow from operations	**107,480**	55,605	28,466
Per share - basic	**0.76**	0.56	0.29
Per share - diluted	**0.75**	0.56	0.29
Net income (loss)	**122,376**	(51,857)	(5,210)
Per share - basic	**0.87**	(0.52)	(0.05)
Per share - diluted	**0.85**	(0.52)	(0.05)
Capital expenditures	**302,614**	204,391	106,654
Working capital (deficiency)	**33,025**	(73,647)	(4,629)
Bank debt	**149,228**	200,836	63,626
Senior notes	**141,613**	—	—
Convertible debentures - liability	**44,887**	—	—
Net debt	**363,884**	228,463	77,361
Total assets	**2,031,643**	1,336,955	781,574
Decommissioning obligation	**46,811**	29,857	21,480
Average daily production volumes *(boe/d)*	**42,882**	23,204	15,604
Average daily production volumes *(MMcfe/d)*	**257.3**	139.2	93.6

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 have generated incremental production volumes, offset by shut-in production volumes during low pricing environments. 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.
- Adjusted 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 declined through the first half of 2016. Prices started to recover in the second half of 2016, and into the first and second quarter of 2017, however declined through the third and fourth quarter of 2017.
- 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) and comprehensive income (loss) throughout the periods was primarily influenced by unrealized gains or losses on risk management contracts and acquisition costs.
- 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 to development and production, the Corporation has begun utilizing bank debt and has issued convertible debentures and senior notes to assist with the capital program and debt repayment. As the Corporation proceeds with its growth plans, bank debt amounted to $149.2 million

as at December 31, 2017, the carrying value of senior notes was $141.6 million and the carrying value of the liability portion of the convertible debentures was $44.9 million.
- 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, 2017, 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:

- *the expectation that efficiencies associated with the Townsend Phase 2 expansion will reduce the fixed capital fee on a per MCF basis paid by the Corporation by approximately 20% after commencement of the Townsend Phase 2 expansion take or pay;*
- *the Corporation receiving a natural gas price that represents a premium to the Westcoast Station 2 price and comparable to the AECO (5A) benchmark price;*
- *expectations with respect to average price estimates for 2018;*
- *the expectation that exposure to Station 2 pricing is expected to average below 15% in 2018;*
- *the expectation that overall royalties for 2018 will be approximately 2.0% to 2.5% of total revenues;*
- *the expectation that average per unit operating expenses for 2018 will be between $0.60 and $0.65 per Mcfe, assuming normal seasonal weather conditions;*
- *the expectation that average per unit transportation costs for 2018 will be between $0.70 and $0.75 per Mcfe;*
- *the expectation that per unit G&A expenses will average between $0.12 to $0.16 per Mcfe for 2018;*
- *the expectation that the Corporation's 2018 capital program will include drilling 29 (29.0 net) and completing 31 (31.0 net) wells;*
- *the Corporation having adequate liquidity to fund working capital requirements and capital expenditures through a combination of cash flows, available credit facilities, senior notes and convertible debentures;*
- *expectations as to timing and outcome of the next review of the Corporation's credit facilities;*
- *expectations as to the estimated costs required to fulfill the Corporation's remaining contractual commitments as at December 31, 2017;*
- *expectations with respect to the declaration or payment of dividends;*
- *expectations that future taxable income will be available to utilize accumulated tax pools;*
- *expectations regarding future accounting pronouncements and their impact on the Corporation; and*
- *expectations regarding the underlying claim filed by BRFN against the Province of British Columbia.*

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

- *the utilization of available credit facilities for 2018;*
- *the validity of data used by GLJ Petroleum Consultants Ltd.("GLJ") in their independent reserves evaluation;*
- *the continued adherence to contractual commitments;*
- *the financial position of the applicable entities mitigating the risk of accounts receivable becoming uncollectible; and*
- *the cost structure of the Corporation.*

Certain or all of the forward-looking statements may prove to be incorrect. 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 the 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;*
- *unforeseen title defects;*
- *risks arising from future acquisition activities;*
- *restrictions contained in the Corporation's credit facility;*
- *uncertainty of the outcome of the underlying claim against the Province of British Columbia 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, 2018 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 merger and acquisition opportunities 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

Mcf	*thousand cubic feet*	*bbls/d*	*barrels per day*
Mcf/d	*thousand cubic feet per day*	*NGLs*	*natural gas liquids*
MMcf/d	*million cubic feet per day*	*Mcfe*	*thousand cubic feet equivalent*
boe	*barrels of oil equivalent*	*Mcfe/d*	*thousand cubic feet equivalent per day*
boe/d	*barrels of oil equivalent per day*	*MMcfe/d*	*million cubic feet equivalent per day*
Mboe	*thousand barrels of oil equivalent*	*MMBtu*	*million British thermal units*
bbls	*barrels*	*MMBtu/d*	*million British thermal units per day*

ADDITIONAL INFORMATION

Additional information regarding the Corporation and its business and operations, including the AIF for the year ended December 31, 2017 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 Energy 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 Energy 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 & Risk Committee, monitors management's financial and accounting policies and practices and the preparation of these consolidated financial statements. The Audit & Risk 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 & Risk 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, 2017 and 2016.

The external auditors have full and free access to the Audit & Risk Committee to discuss auditing and financial reporting matters. The Audit & Risk 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, 2017 and 2016.

"signed"
Patrick R. Ward
President and CEO

"signed"
W. Derek Aylesworth
Senior Vice President and CFO

March 7, 2018

INDEPENDENT AUDITORS' REPORT

To the Shareholders of Painted Pony Energy Ltd.

We have audited the accompanying consolidated financial statements of Painted Pony Energy Ltd, which comprise the consolidated statements of financial position as at December 31, 2017 and December 31, 2016, 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 Energy Ltd. as at December 31, 2017 and December 31, 2016, 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

March 7, 2018
Calgary, Canada

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

As at	December 31, 2017	December 31, 2016
ASSETS		
Current assets		
Accounts receivable	39,115	29,568
Prepaid expenses and deposits	1,664	1,109
Fair value of risk management contracts *(note 16)*	65,016	—
	105,795	30,677
Non-current assets		
Fair value of risk management contracts *(note 16)*	22,552	1,269
Exploration and evaluation *(note 5)*	159,004	114,251
Property, plant and equipment *(note 6)*	1,744,292	1,158,198
Deferred tax (note 12)	—	32,560
	2,031,643	1,336,955
LIABILITIES		
Current liabilities		
Accounts payable and accrued liabilities	66,931	54,903
Share unit liability *(note 15)*	2,004	3,401
Fair value of risk management contracts *(note 16)*	553	46,020
Current portion of finance lease obligation *(note 18)*	3,282	—
	72,770	104,324
Non-current liabilities		
Fair value of risk management contracts *(note 16)*	294	15,768
Bank debt *(note 7)*	149,228	200,836
Senior notes *(note 8)*	141,613	—
Convertible debentures *(note 9)*	44,887	—
Decommissioning obligation *(note 13)*	46,811	29,857
Finance lease obligation *(note 18)*	487,578	360,860
Deferred tax (note 12)	7,772	—
	950,953	711,645
EQUITY		
Share capital *(note 14)*	1,015,235	687,701
Equity portion of convertible debentures *(note 9)*	2,382	—
Contributed surplus	55,203	52,115
Retained earnings (deficit)	7,870	(114,506)
	1,080,690	625,310
	2,031,643	1,336,955

Commitments *(notes 18 & 19)*
See accompanying notes to the consolidated financial statements.

Approved on behalf of the Board:

"signed" Joan E. Dunne
Director

"signed" Patrick R. Ward
Director

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

	Years ended December 31,	
	2017	**2016**
Revenue		
Petroleum and natural gas	249,186	121,580
Royalties	(4,901)	(2,672)
	244,285	118,908
Realized gain on risk management contracts *(note 16)*	44,002	19,912
Unrealized gain (loss) on risk management contracts *(note 16)*	146,465	(75,664)
	434,752	63,156
Expenses		
Operating	59,834	34,535
Transportation	39,197	15,894
General and administrative	16,482	10,566
Costs on acquisition of UGR Blair Creek Ltd. *(note 4)*	5,497	—
Share-based compensation *(note 15)*	481	5,778
Depletion and depreciation *(note 6)*	83,887	43,329
	205,378	110,102
Income (loss) from operations	229,374	(46,946)
Finance expense *(note 11)*	(61,591)	(22,770)
Income (loss) before taxes	167,783	(69,716)
Deferred tax (expense) recovery *(note 12)*	(45,407)	17,859
Net income (loss) and comprehensive income (loss)	**122,376**	**(51,857)**
Net income (loss) and comprehensive income (loss) per share: ($ per share)		
Basic *(note 10)*	0.87	(0.52)
Diluted *(note 10)*	0.85	(0.52)

See accompanying notes to the consolidated financial statements.

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

Years ended December 31, 2017 and 2016	Number of Common Shares	Share capital	Equity portion of convertible debentures	Contributed surplus	Retained earnings / (deficit)	Total equity
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 14)*	127,250	999	—	(299)	—	700
Net loss and comprehensive loss	—	—	—	—	(51,857)	(51,857)
Balance at December 31, 2016	100,158,192	687,701	—	52,115	(114,506)	625,310
Acquisition of UGR Blair Creek Ltd. *(note 4)*	41,000,000	220,170	—	—	—	220,170
Issuance of shares *(note 14)*	19,820,000	110,992	—	—	—	110,992
Share issue costs, net of tax impact	—	(3,730)	—	—	—	(3,730)
Share-based compensation	—	—	—	3,118	—	3,118
Stock options exercised *(note 14)*	17,500	102	—	(30)	—	72
Issuance of convertible debentures, net of tax impact *(note 9)*	—	—	2,382	—	—	2,382
Net income and comprehensive income	—	—	—	—	122,376	122,376
Balance at December 31, 2017	160,995,692	1,015,235	2,382	55,203	7,870	1,080,690

See accompanying notes to the consolidated financial statements.

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

	Years ended December 31, 2017	2016
Cash flows from operating activities:		
Net income (loss) and comprehensive income (loss)	122,376	(51,857)
Adjustments for:		
Depletion and depreciation	83,887	43,329
Share-based compensation	2,205	2,864
Accretion expense	1,794	550
Deferred income tax expense (recovery)	45,407	(17,859)
Unrealized (gain) loss on risk management contracts	(146,465)	75,664
Decommissioning expenditures	—	(102)
Changes in non-cash working capital	(2,287)	(7,931)
	106,917	44,658
Cash flows from investing activities:		
Property, plant and equipment additions	(302,614)	(204,391)
Cash assumed on acquisition of UGR Blair Creek Ltd.	864	—
Changes in non-cash working capital	(4,195)	20,609
	(305,945)	(183,782)
Cash flows from financing activities:		
Issuance of shares	110,992	—
Exercise of stock options	72	700
Increase (repayment) in bank debt	(99,825)	137,210
Share issue costs	(5,074)	—
Issuance of senior notes	141,115	—
Issuance of convertible debentures	47,718	—
Changes in non-cash working capital	4,030	1,214
	199,028	139,124
Change in cash and cash equivalents	—	—
Cash and cash equivalents, beginning of year	—	—
Cash and cash equivalents, end of year	—	—

See accompanying notes to the consolidated financial statements.

1. REPORTING ENTITY

Painted Pony Energy Ltd.'s ("Painted Pony" or the "Corporation") principal business activity is the exploration, development and production of petroleum and natural gas resources in western Canada. The consolidated financial statements of the Corporation as at and for the years ended December 31, 2017 and 2016 include the accounts of the Corporation and its wholly owned subsidiaries, UGR Blair Creek Ltd. (from the date of acquisition - see note 4) and Painted Rock Resources Ltd. The Corporation's head office is located at 1800, 736 - 6th Avenue S.W., Calgary, Alberta. On January 1, 2018, the wholly owned subsidiaries were amalgamated with the Corporation.

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 March 7, 2018.

The consolidated financial statements have been prepared on the historical cost basis except for risk management contracts and share and cash settled awards, which are measured at fair value. The methods used to measure fair value are discussed in note 17.

These consolidated financial statements are presented in Canadian dollars, which is the Corporation's and its subsidiaries' 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 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 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 obligation, 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 risk management contracts at fair value with changes in fair value recognized in the consolidated 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 Obligation

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 estimates 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 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 income 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 subsidiaries.

(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.

Business Combinations
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 consolidated 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, bank debt, senior notes and convertible debentures. 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, accounts payable and accrued liabilities, bank debt, senior notes and convertible debentures are measured at amortized cost using the effective interest rate method, less any impairment losses.

Compound Financial Instruments
The Corporation's compound financial instruments are comprised of its convertible debentures that can be converted into common shares in the capital of the Corporation (“Common Share” or "Common Shares") at

the option of the holder. The liability component of the convertible debentures is recognized initially at fair value of a similar liability that does not have an equity conversion option. The equity component is recognized initially as the difference between the fair value of the convertible debenture and the fair value of the liability component. Any directly attributable transaction costs are allocated to the liability and equity components in proportion to their initial carrying values. Subsequent to initial recognition the liability component of the convertible debentures is measured at amortized cost using the effective interest rate method. The equity component of the convertible debentures is not re-measured subsequent to initial recognition.

Derivative Financial Instruments

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

The Corporation has issued preferred share units ("PSU" or "PSUs") to eligible executive officers. Each PSU is a notional unit equal in value to a Common Share, which entitles the holder to a cash payment upon redemption. PSUs are measured at fair value through profit or loss and are recorded on the consolidated statement of financial position at fair value.

The Corporation has issued restricted share units ("RSU" or "RSUs") to eligible employees. Each RSU is a notional unit equal in value to a Common Share, which entitles the holder to a cash payment on redemption. RSUs are measured at fair value through profit or loss and are recorded on the consolidated statement 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-license 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 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 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 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 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 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 of disposal.

Fair value less costs of disposal is derived by estimating the discounted after-tax future net cash flows from proved plus probable oil and gas reserves, adjusted for the discounted abandonment and reclamation costs on proved plus probable undeveloped oil and gas reserves. Discounted future net cash flows are based on forecasted commodity prices and costs over the expected economic life of the reserves and discounted using market-based rates to reflect a market participant's view of the risks associated with the assets. Value in use is assessed using the expected future cash flows from proved plus probable oil and gas reserves discounted at a pre-tax rate, adjusted for the discounted abandonment and reclamation costs associated with wells without reserves and facilities that relate to the CGUs.

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 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 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.

The Corporation has issued DSUs, PSUs and RSUs. The DSUs, PSUs and RSUs are accounted for as cash-settled, share-based payment plans. The fair value of the amount payable under the DSU, PSU, and RSU plans are recognized as an expense with a corresponding increase in liabilities. The liability is calculated at each reporting date and at settlement date. Any changes in the fair value of the liability are recognized in the consolidated statement of operations.

A portion of share-based compensation directly attributable to the exploitation and development of the Corporation's assets is capitalized.

(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 Obligation

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.

The decommissioning obligation is 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 obligation 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, senior notes and convertible debentures, 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 income 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 subsidiaries operate is the Canadian dollar. Monetary assets and liabilities denominated in foreign currencies are translated into Canadian dollars at exchange rates in effect at the end of the period, and revenues and expenses are translated into Canadian dollars at average exchange rates. All translation gains and losses are recorded in income or loss.

(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 and convertible debentures. 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, 2018 and have not been applied in preparing the consolidated financial statements for the year ended December 31, 2017. The standards applicable to the Corporation are as follows and will be adopted on their respective effective dates:

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 other comprehensive income ("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 has adopted 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 has been adopted using a modified retrospective approach as of January 1, 2018. The Corporation has reviewed its revenue streams and underlying contracts with customers and has determined that there will not be a material impact on its earnings. Additional disclosure will be implemented.

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 an impact on the Corporation’s consolidated statement of financial position.

4. ACQUISITION OF UGR BLAIR CREEK LTD.

Effective May 16, 2017, the Corporation acquired all of the issued and outstanding shares of UGR Blair Creek Ltd. ("UGR") in exchange for the issuance of 41.0 million Common Shares of the Corporation with an assigned value of $220.2 million. The Common Shares were ascribed a fair value of $5.37 per Common Share issued, as determined based on the Corporation's closing share price at the date of closing, being May 16, 2017. The UGR acquisition is a strategic expansion of the Corporation's Montney project in NEBC, providing for an expansion of the Corporation's land base, natural gas processing infrastructure, reserves and drilling inventory. The operations from the UGR acquisition have been included in the results of the Corporation commencing May 16, 2017. Acquisition costs of $5.5 million were expensed through the consolidated statement of operations. The UGR acquisition was accounted for using the purchase method of accounting. The allocation of the purchase price, based on management's estimates of fair values, is as follows:

($000s)	
Fair value of the net assets acquired:	
Cash	864
Other current assets	5,884
Current liabilities	(8,865)
Risk management contracts	775
Property, plant and equipment	207,491
Exploration and evaluation	58,743
Bank debt	(48,217)
Decommissioning obligation	(1,093)
Deferred tax asset	4,588
Net assets acquired	220,170

Consideration:	
Common Shares (41.0 million shares @ $5.37/share)	220,170

On acquisition, the Corporation recorded the decommissioning obligation at a credit adjusted risk free rate resulting in a decommissioning obligation totaling $1.1 million. Subsequent to the date of acquisition, the decommissioning obligation was revalued using the risk free rate, resulting in an adjustment of $7.1 million, with a corresponding increase to property, plant and equipment.

Included in the consolidated statement of operations are the following amounts relating to the UGR acquisition from May 16, 2017 to December 31, 2017.

($000s)	
Revenue	24,542
Net income and comprehensive income	10,115

If the UGR acquisition had occurred on January 1, 2017, the Corporation's estimated pro forma results of revenue and net income and comprehensive income for the year ended December 31, 2017 would have been as follows:

($000s)	Painted Pony Energy Ltd.	UGR acquisition (January 1, 2017 to closing date)	Pro forma results
Revenue	249,186	17,868	267,054
Net income and comprehensive income	122,376	5,765	128,141

5. EXPLORATION AND EVALUATION ASSETS

($000s)	
As at December 31, 2015	116,145
Transfer to property, plant and equipment	(1,894)
As at December 31, 2016	114,251
UGR acquisition *(note 4)*	58,743
Transfer to property, plant and equipment	(13,990)
As at December 31, 2017	159,004

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.

6. PROPERTY, PLANT & EQUIPMENT

($000s)	
Cost:	
As at December 31, 2015	802,392
Capital expenditures	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
Capital expenditures	302,614
UGR acquisition *(note 4)*	207,491
Finance lease assets	130,000
Non-cash additions	15,886
Transfer from exploration and evaluation	13,990
As at December 31, 2017	2,048,067
Accumulated depletion and depreciation:	
As at December 31, 2015	176,559
Depletion and depreciation	43,329
As at December 31, 2016	219,888
Depletion and depreciation	83,887
As at December 31, 2017	303,775
Carrying amounts:	
December 31, 2016	1,158,198
December 31, 2017	1,744,292

Estimated future development costs associated with the development of the Corporation's proved plus probable reserves at December 31, 2017 and at December 31, 2016 were $4.1 billion and $2.9 billion, respectively.

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.

Capitalized General and Administrative Expense, Recoveries and Share-Based Compensation

($000s)	**Years ended December 31,**	
	2017	**2016**
General and administrative	5,764	5,937
Capital recoveries	3,339	2,343
Share-based compensation	913	620
Total	10,016	8,900

7. BANK DEBT

At December 31, 2017, the Corporation's syndicated credit facilities consisted of available credit facilities of $450 million. The available facilities are provided by a syndicate of financial institutions, and include a $400 million extendable revolving facility and a $50 million operating facility. The facilities revolve for a 2-year period, which is extendable 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 change. 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, 2017, Painted Pony had $160 million in bankers' acceptances with an effective interest rate of 3.65% per annum. In addition, as at December 31, 2017 the Corporation had outstanding letters of credit totaling $21.5 million and US$15.0 million, which reduce the credit available on the syndicated facilities. At December 31, 2016, the Corporation had an outstanding letter of credit of $14.9 million.

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 3.25% per annum depending on the Corporation's senior debt to quarterly annualized EBITDA ratio as defined by the lenders, ranging from less than 1.00:1 to 3.00:1. 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 0.8125% per annum is charged on the undrawn portion of the credit facilities, also calculated depending on the Corporation's senior debt to quarterly annualized EBITDA ratio, as defined by the lenders.

Security over all of the Corporation's assets is provided by a floating charge demand debenture in the aggregate amount of $1.0 billion. The Corporation has provided a negative pledge and an undertaking to provide fixed charges over its petroleum and natural gas reserves in certain circumstances. The Corporation's syndicated credit facilities include financial covenants as follows: senior debt to EBITDA ratio of not greater than 3.00:1 on a trailing four fiscal quarter basis, and total debt to EBITDA ratio of not greater than 4.25:1 on a trailing four fiscal quarter basis until Q2 2018, thereafter of not greater than 4.00:1 on a trailing four fiscal quarter basis. At December 31, 2017 the senior debt to EBITDA ratio was 1.77:1.00, and the total debt to EBITDA ratio was 3.28:1.00. The Corporation is in compliance with all covenants as at December 31, 2017.

8. SENIOR NOTES

On August 23, 2017, the Corporation issued $150.0 million of 8.5% senior unsecured notes (the "Notes") with a 5 year term by way of private placement. Proceeds net of discount and transaction costs of $8.9 million amounted to $141.1 million. Interest is payable in equal quarterly installments in arrears. The Notes are fully and unconditionally guaranteed as to the payment of principal and interest, on a senior unsecured basis by the Corporation. There are no maintenance financial covenants.

The Notes are non-callable by the Corporation prior to the three year anniversary. If the Corporation chooses to redeem the Notes prior to August 23, 2020, they will be subject to a make-whole premium equal to the Canada Yield Price, plus accrued and unpaid interest. At any time on or after August 23, 2020, the Corporation can redeem all or part of the Notes at the redemption prices set forth in the table below plus any accrued and unpaid interest.

Redemption Schedule	Percentage
August 23, 2020 - August 22, 2021	104.250%
August 23, 2021 - February 22, 2022	102.125%
February 23, 2022 - August 23, 2022	100.000%

If a change of control event occurs at any time before maturity, the Corporation must offer to repurchase the Notes at a price according to the redemption schedule above.

The Notes were recorded at their fair value on the date of issuance of $141.1 million. Accretion of the liability will be included in finance expense in the consolidated statement of operations. At December 31, 2017 the carrying value of the Notes was $141.6 million and accretion expense of $0.5 million was recorded in the consolidated statement of operations.

9. CONVERTIBLE DEBENTURES

($000s)	Liability component	Equity component
Balance at December 31, 2016	—	—
Issuance of convertible debentures	46,607	3,393
Issue costs	(2,128)	(154)
Deferred tax liability	—	(857)
Accretion of discount	408	—
Balance at December 31, 2017	44,887	2,382

On August 23, 2017, the Corporation issued $50.0 million of convertible unsecured subordinated debentures (the "Debentures") for net proceeds of $47.7 million. The Debentures mature on August 23, 2021 and bear interest at 6.5% per annum payable quarterly. At the holder's option, the Debentures may be converted into Common Shares of the Corporation at any time prior to the close of business on the date of maturity at a conversion price of $5.60 per share (the "conversion price").

The Debentures are non-redeemable by the Corporation between August 23, 2017 and February 22, 2020 other than pursuant to the 90% redemption right (see change of control below). The Debentures are redeemable by the Corporation between February 23, 2020 and August 23, 2021 at a redemption price equal to the principal amount plus interest. Redemption may be satisfied in Common Shares if the 30-day volume weighted average price ("VWAP") on notice date and the closing price immediately prior to notice date are both greater than 140% of the conversion price.

On maturity, the Corporation may satisfy its obligation to Debenture holders by issuing Common Shares if the Corporation's market capitalization exceeds $750 million. The number of Common Shares issued is calculated based on 95% of the lesser of the 30-day VWAP and the 2-day VWAP on the date of maturity.

Upon occurrence of a change of control event, the Corporation must offer to repurchase the Debentures at a price according to the schedule below. If 90% or more of the principal amount accept the offer, the Corporation shall have the right to repurchase 100% of the Debentures outstanding.

Redemption Schedule	Percentage of Principal
August 23, 2017 - August 22, 2018	110.000%
August 23, 2018 - February 22, 2020	105.000%
February 23, 2020 - August 23, 2021	100.000%

The liability component of the Debentures was recognized initially at the fair value of a similar liability that does not have an equity conversion option, which was calculated based on a market interest rate of 8.5%. The difference between the $50.0 million principal amount of the Debentures and the fair value of the liability component was recognized in shareholder's equity, net of deferred taxes. Total transaction costs directly attributable to the offering of $2.3 million were allocated to the liability and equity components of the Debentures proportionately.

Accretion of the liability component and accrued interest payable on the Debentures are included in accretion and financing expense respectively, in the consolidated statement of operations. At December 31, 2017 the carrying value of the Debentures was $44.9 million.

10. NET INCOME (LOSS) AND COMPREHENSIVE INCOME (LOSS) PER SHARE

($000s, except shares and per share amounts)	**Years ended December 31,**	
	2017	**2016**
Net income (loss) and comprehensive income (loss)-basic	122,376	(51,857)
Net income (loss) and comprehensive income (loss)-diluted	123,227	(51,857)
Weighted average Common Shares-basic	140,717,740	100,069,546
Weighted average Common Shares-diluted	144,149,853	100,069,546
Net income (loss) per share - basic *($/share)*	0.87	(0.52)
Net income (loss) per share - diluted *($/share)*	0.85	(0.52)

The average market value of the Common Shares for purposes of determining the dilutive effect of outstanding stock options was based on quoted market prices for the year. For the year ended December 31, 2017, there were 252,074 stock options were included in the weighted-average diluted share calculation of Common Shares. For the year ended December 31, 2016, all stock options were excluded from the weighted-average diluted share calculation of Common Shares as they were anti-dilutive.

The Common Shares potentially issuable on conversion of the Debentures were included in diluted net income and comprehensive income per share. For the year ended December 31, 2017, 3,180,039 potential Common Shares (December 31, 2016 - nil) were included in diluted net income and comprehensive income per share.

11. FINANCE EXPENSE

	Years ended December 31,	
($000s)	**2017**	**2016**
Finance lease expense *(note 18)*	44,157	14,165
Interest expense	15,640	8,055
Accretion	1,794	550
Total	61,591	22,770

Finance lease expense is a component of the capital fee paid on facilities treated as a capital lease, and varies with production volumes processed. The capital fee includes finance lease expense and any amortization of the outstanding finance lease obligation. Interest expense includes interest on bank debt and standby charges on the Corporation's syndicated credit facilities, as well as interest on the senior notes and convertible debentures. Accretion expense consists of accretion on the decommissioning obligation, senior notes and convertible debentures.

12. DEFERRED TAX

Reconciliation of effective tax rate:

($000s)	**Years ended December 31,**	
	2017	**2016**
Income (loss) before taxes	167,783	(69,716)
Combined corporate tax rate	26.5%	26.5%
Expected tax reduction	44,462	(18,475)
Non-deductible expenses	337	45
Non-deductible share-based compensation	584	759
Change in statutory rates and true-ups	14	(214)
Other	10	26
Total deferred tax expense (recovery)	45,407	(17,859)

Deferred tax assets and liabilities are attributable to the following:

($000s)	**December 31, 2017**	**December 31, 2016**
Deferred tax liabilities:		
PP&E and E&E assets	(101,559)	(69,174)
Fair value of risk management contracts	(23,415)	—
Senior notes	(1,049)	—
Convertible debentures	(465)	—
Other	(382)	—
	(126,870)	(69,174)
Less deferred tax assets:		
Non-capital losses	103,327	75,897
Fair value of risk management contracts	—	16,038
Decommissioning obligation	12,639	7,912
Finance costs	3,132	—
Other	—	1,887
Net deferred tax (liability) asset	(7,772)	32,560

The Corporation has non-capital losses of $382.7 million which expire in the years 2026 through 2035. The Corporation has determined that it is likely that these losses will be utilized against future taxable income. Total tax pools at December 31, 2017 were $1.4 billion (December 31, 2016 – $0.9 billion).

13. DECOMMISSIONING OBLIGATION

($000s)	**December 31, 2017**	**December 31, 2016**
Balance, beginning of year	29,857	21,480
UGR acquisition *(note 4)*	1,093	—
Provisions	9,032	7,721
Decommissioning expenditures	—	(102)
Revisions	5,941	208
Accretion	888	550
Balance, end of year	46,811	29,857

The Corporation's decommissioning obligation results 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 obligation based on an undiscounted total future liability of $106.0 million, compared to $64.2 million at December 31, 2016, with payments expected to be made over the next 11 to 49 years. The discount factor, being the risk-free rate related to the liability at December 31, 2017, was 2.3%, compared to 2.1% at December 31, 2016, and the inflation rate was 2% at both December 31, 2017 and 2016.

14. SHARE CAPITAL

(a) Authorized

The Corporation has an unlimited number of Common Shares and Preferred Shares authorized for issuance. At December 31, 2017, there were 160,995,692 Common Shares outstanding, compared to 100,158,192 Common Shares outstanding at December 31, 2016. At December 31, 2017 and December 31, 2016, there were no Preferred Shares outstanding.

On April 5, 2017, Painted Pony completed a public offering of 19.8 million Common Shares at a price of $5.60 per Common Share for aggregate gross proceeds of approximately $111.0 million (including the exercise in full of the over-allotment option granted to the underwriters).

On May 16, 2017, the Corporation issued 41.0 million Common Shares to acquire all of the issued and outstanding shares of UGR (see note 4). At the closing date of the UGR acquisition, the Common Shares were ascribed a fair value of $5.37 per Common Share issued, resulting in total share consideration of $220.2 million (gross of share issue costs).

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 pursuant to which options to purchase Common Shares are granted to officers and employees of the Corporation. Stock options are granted at the volume weighted average trading price of the Common Shares for the five trading days immediately preceding the date of grant, and have a five-year term. Stock 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, 2015	8.26	8,875,467
Granted	4.30	1,066,650
Exercised	5.50	(127,250)
Forfeited	7.23	(43,350)
Expired	11.07	(1,149,000)
As at December 31, 2016	7.45	8,622,517
Granted	4.42	3,376,650
Exercised	4.14	(17,500)
Forfeited	10.71	(179,400)
Expired	10.16	(1,503,900)
As at December 31, 2017	6.01	10,298,367

The following table summarizes information about stock options outstanding at December 31, 2017:

Number of Stock Options Outstanding	Exercise Price Range ($)	Weighted Average Remaining Life (Years)	Number of Stock Options Exercisable	Weighted Average Exercise Price ($)
2,037,750	3.47 - 4.20	4.0	311,498	4.14
1,837,350	4.21 - 4.28	2.9	1,837,350	4.26
2,199,500	4.29 - 5.40	4.4	—	—
1,811,667	5.41 - 8.61	1.2	1,700,167	6.79
2,412,100	8.62 - 14.14	1.4	2,412,100	9.72
10,298,367	6.01	2.8	6,261,115	7.04

The Corporation accounts for its stock options 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,	
	2017	2016
Fair value per stock option ($)	2.00	1.86
Volatility (%)	51	50
Life (years)	5	5
Risk-free interest rate (%)	1.34	0.68

A forfeiture rate of 9% was used when measuring share-based compensation during the year ended December 31, 2017, compared to 11% during the year ended December 31, 2016.

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

($000s)	**Years ended December 31,**	
	2017	**2016**
Share-based compensation	2,205	2,864
Share unit expense (recovery) *(note 15)*	(1,724)	2,914
Total	481	5,778

15. SHARE UNIT PLANS

(a) Deferred Share Units

The Corporation has a DSU plan, whereby 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 and/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 consolidated statement of operations immediately upon grant, with a corresponding DSU liability recorded as a current liability in the consolidated 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.

The following table summarizes information related to the DSUs:

Deferred share units	**December 31, 2017**	**December 31, 2016**
Balance, beginning of year	352,689	143,337
Granted	407,762	139,005
Accrued but not granted	—	70,347
Prior accrual reversal	(70,347)	—
Balance, end of year	690,104	352,689

(b) Restricted Share Units

The Corporation has a RSU plan, whereby RSUs are issued to eligible employees. Each RSU is a notional unit equal in value to one Common Share, which entitles the holder to a cash payment upon redemption. RSUs vest in three equal installments on the first, second, and third anniversaries of the grant date, at which time the holder is eligible to receive a cash payment equal to the number of vested awards multiplied by the fair market value. The expense associated with the RSU 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 consolidated statement of operations over the vesting period, with a corresponding RSU liability recorded in the consolidated statement of financial position. At period end dates, the RSU liability is adjusted based on the 20-day volume weighted average price of Common Shares. During the year ended December 31, 2017, the Company granted 222,630 RSUs. There were no RSUs granted in 2016.

(c) Preferred Share Units

The Corporation has a PSU plan, whereby PSUs are issued to eligible executive officers. Each PSU is a notional unit equal in value to one Common Share, which entitles the holder to a cash payment upon redemption. PSUs vest upon the third anniversary of the grant date, at which time the holder is eligible to receive a cash payment equal to the number of vested awards multiplied by the fair market value. The unit value is adjusted for a performance multiplier which can range from 0 to 2 and is dependent on the performance of the Corporation for a predefined period. The expense associated with the PSU plan is determined based on the 20-day weighted average price of Common Shares at the grant date. The expense is recognized in the consolidated statement of operations over the vesting period, with a corresponding PSU liability recorded in the consolidated statement of financial position. During the year ended December 31, 2017, the Company granted 303,900 PSUs. There were no PSUs granted in 2016.

During the year ended December 31, 2017, the Company recorded a recovery of $1.7 million related to the share unit plans, compared to an expense of $2.9 million for the year ended December 31, 2016. In addition, $0.3 million was capitalized (2016 - $nil).

16. 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 consolidated statement of financial position, with changes in the fair value being recognized as an unrealized gain or loss in the consolidated 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, 2017.

Financial AECO Natural Gas Contracts

Options traded	Term	Volume (GJ/d)	Price (CDN$/GJ)
AECO Fixed Price Swap	January 2018 - September 2018	6,000	3.07
AECO Fixed Price Swap	January 2018 - March 2018	10,000	3.18
AECO Fixed Price Swap	January 2018 - September 2018	10,000	2.84
AECO Fixed Price Swap	January 2018 - September 2018	10,000	2.85
AECO Fixed Price Swap	January 2018 - June 2018	6,000	3.03
AECO Fixed Price Swap	January 2018 - December 2018	6,000	2.95
AECO Fixed Price Swap	January 2018 - June 2019	8,000	2.66
AECO Fixed Price Swap	January 2018 - June 2018	10,000	2.88
AECO Fixed Price Swap	January 2018 - June 2018	5,000	3.01
AECO Fixed Price Swap	January 2018 - March 2018	10,000	3.16
AECO Fixed Price Swap	January 2018 - December 2018	10,000	2.57
AECO Fixed Price Swap	January 2018 - December 2018	10,000	2.56
AECO Fixed Price Swap	January 2018 - December 2018	10,000	2.32
AECO Fixed Price Swap	April 2018 - June 2019	10,000	2.62
AECO Fixed Price Swap	April 2018 - March 2019	10,000	2.32
AECO Call Option Sold	January 2018 - December 2019	10,000	2.80
AECO Call Option Sold	January 2018 - December 2019	15,000	2.93

Financial Dawn Natural Gas Contracts

Options traded	Term	Volume (GJ/d)	Price (CDN$/GJ)
Dawn Fixed Price Swap	April 2018 - March 2019	10,000	3.47
Dawn Fixed Price Swap	April 2018 - March 2019	10,000	3.50

Financial NYMEX Basis Differential Contracts

Options traded	Term	Volume (MMBtu/d)	Price (NYMEX less US$/MMBtu)
NYMEX-AECO Basis Swap	April 2018 - October 2018	10,000	1.14
NYMEX-AECO Basis Swap	April 2019 - September 2021	10,000	1.14
NYMEX-Dawn Basis Swap	January 2018 - December 2018	10,000	0.11

Financial Station 2 Natural Gas Contracts			
Options traded	**Term**	**Volume (GJ/d)**	**Price (CDN$/GJ)**
Stn. 2 Fixed Price Swap	January 2018 - March 2018	30,000	1.78
Stn. 2 Fixed Price Swap	January 2018 - March 2018	10,000	1.88
Stn. 2 Fixed Price Swap	January 2018 - March 2018	15,000	1.74
Stn. 2 Fixed Price Swap	January 2018 - March 2018	10,000	1.89
Stn. 2 Fixed Price Swap	January 2018 - March 2018	10,000	1.91
Stn. 2 Fixed Price Swap	January 2018 - March 2018	15,000	2.70
Stn. 2 Fixed Price Swap	January 2018 - June 2018	5,000	2.50
Stn. 2 Fixed Price Swap	January 2018 - December 2019	10,000	2.45
Stn. 2 Fixed Price Swap	April 2018 - June 2019	12,000	2.35
Stn. 2 Fixed Price Swap	April 2018 - September 2019	10,000	2.30
Stn. 2 Fixed Price Swap	April 2018 - September 2019	5,000	2.34

Financial AECO Basis Differential Contracts			
Options traded	**Term**	**Volume (GJ/d)**	**Price (AECO less CDN$/GJ)**
AECO-Station 2 Basis Swap	November 2018 - October 2020	10,000	0.32
AECO-Station 2 Basis Swap	November 2018 - October 2020	20,000	0.32
AECO-Station 2 Basis Swap	November 2018 - August 2021	20,000	0.29
AECO-Station 2 Basis Swap	November 2019 - October 2020	10,000	0.33

Financial WTI Crude Oil Contracts			
Options traded	**Term**	**Volume (Bbl/d)**	**Price (CDN$/Bbl)**
WTI Fixed Price Swap	January 2018 - December 2018	500	65.15
WTI Fixed Price Swap	January 2018 - December 2018	250	70.15
WTI Fixed Price Swap	January 2018 - December 2018	250	71.05
WTI Fixed Price Swap	January 2018 - December 2019	500	70.20
WTI Fixed Price Swap	January 2018 - December 2019	500	70.20

Financial Propane Contracts			
Options traded	**Term**	**Volume (GAL/d)**	**Price (CDN$/GAL)**
Conway Fixed Price Swap	January 2018 - December 2018	8,400	0.90
Conway Fixed Price Swap	January 2018 - December 2018	10,500	0.88
Conway Fixed Price Swap	January 2018 - December 2018	8,400	1.00

In addition to the commodity risk management contracts discussed above, the Corporation has entered into physical delivery sales contracts to manage commodity risk. These contracts are considered normal sales contracts and are not recorded at fair value in the consolidated financial statements.

The Corporation has the following foreign exchange risk management contract in place as at December 31, 2017:

Reference Currency	Notional amount (USD 000s)	Term	Strike Rate
USD	$1,000/month	January 2018 - April 2018	1.3538 CAD/USD

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, 2017, it is estimated that a $0.10 per mcf change in forward natural gas prices used to calculate the fair value of natural gas derivatives at December 31, 2017 would result in a $4.9 million change in income for the year ended December 31, 2017. 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, 2017 would result in a $0.9 million change in income for the year ended December 31, 2017.

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. A 1% change in the CAD/US dollar exchange rate would not result in a material change to income for the year ended December 31, 2017.

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. For the year ended December 31, 2017, it is estimated that a 1.0% change in interest rates would result in a change to income for the year of $1.2 million.

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 consolidated statement of financial position, respectively.

($000)	December 31, 2017	December 31, 2016
Gross in-the-money risk management contracts	92,200	1,269
Gross out-of-the-money risk management contracts	(5,479)	(61,788)
Net fair value of risk management contracts	86,721	(60,519)

($000)	December 31, 2017	December 31, 2016
Current assets	65,016	—
Non-current assets	22,552	1,269
Current liabilities	(553)	(46,020)
Non-current liabilities	(294)	(15,768)
Net fair value of risk management contracts	86,721	(60,519)

(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, 2017 and 2016 is as follows:

($000)	December 31, 2017	December 31, 2016
Accounts receivable	39,115	29,568
Fair value of risk management contracts	87,568	1,269
Total	126,683	30,837

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, 2017 or 2016.

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

($000)	December 31, 2017	December 31, 2016
Petroleum and natural gas revenue	28,946	27,781
Financial risk management contracts	7,805	—
Joint interest	282	523
Other	2,082	1,264
Total	39,115	29,568

The Corporation has one primary purchaser of natural gas and NGLs; these purchases accounted for $23.8 million of accounts receivable at December 31, 2017, compared to $23.6 million as at December 31, 2016. As at December 31, 2017 and 2016, the Corporation's accounts receivable is aged as follows:

($000)	December 31, 2017	December 31, 2016
Less than 30 days	38,227	29,542
From 31 - 90 days	771	24
More than 90 days	117	2
Total	39,115	29,568

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 $450 million in available syndicated credit facilities at December 31, 2017 compared to $325 million at December 31, 2016, 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 or debt and adjust its capital spending to manage current and projected debt levels.

The Corporation monitors capital based on the total debt to cash flow ratio, on a trailing four fiscal quarter basis. 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 four quarters. 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 and introduced fixed term debt to ensure financial liquidity, as part of the capital structure going forward. Neither the Corporation nor its subsidiaries 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.

17. 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, Bank Debt, Senior Notes and Convertible Debentures

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, 2017 and December 31, 2016, 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. The fair value of the senior notes fluctuates in response to changes in the market rates of interest payable on similar instruments. At December 31, 2017, the carrying value of the senior notes and convertible debentures approximated 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 consolidated statement of financial position, using the remaining contracted petroleum and natural gas volumes and risk-free interest rate (based on published government rates). The fair value of foreign exchange contracts is determined based on the difference between the contracted forward rate and current forward rates, using the remaining settlement amount. The Corporation's commodity price contracts and foreign exchange contracts are valued using Level 2 of the hierarchy.

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

18. FINANCE LEASE OBLIGATION

The Corporation is party to a series of agreements relating to the development of processing infrastructure for natural gas and natural gas liquids. The facilities and related pipeline infrastructure included in these agreements have been recorded as a finance lease. The Corporation has recorded the asset, with a corresponding obligation on the consolidated statement of financial position. Over the course of the 20-year lease, there is a capital fee, which will include finance expense and the amortization of the obligation.

The cost of the facilities and related pipeline infrastructure capitalized was $490.9 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 not more than five years	More than five years	Total
Processing	52,328	269,998	579,843	902,169
Transportation	9,880	53,114	182,355	245,349
Total	62,208	323,112	762,198	1,147,518
Principal	3,282	64,981	422,597	490,860

The Corporation has the right to a minimum of 198 MMcf/d of firm capacity at the Townsend Facility, of which there is a take or pay obligation on production volumes delivered to the facility of 180 MMcf/d. The Corporation also has the right to the full 99 MMcf/d of firm capacity of the new gas processing train at Townsend, in respect of which there is a take or pay obligation on production volumes delivered to the facility of 90 MMcf/d commencing in the first quarter of 2018.

19. COMMITMENTS

($000s)	2018	2019	2020	2021	2022	Thereafter	Total
Transportation and processing	77,704	90,093	99,775	98,020	97,438	1,030,077	1,493,107
Interest on senior notes	14,242	14,399	14,613	14,765	9,576	—	67,595
Interest on convertible debentures	3,250	3,250	3,250	2,438	—	—	12,188
Office leases and other	1,740	1,216	117	101	7	—	3,181
Total commitments	96,936	108,958	117,755	115,324	107,021	1,030,077	1,576,071

Transportation commitments include contracts to transport natural gas and NGLs through third-party owned pipeline systems in Canada. Processing commitments include contracts to process natural gas through third-party owned gas processing facilities in British Columbia. Interest on senior notes includes quarterly interest on senior notes. Interest on convertible debentures includes quarterly interest on convertible debentures. 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 leases, 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.

20. 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, PSUs and DSUs granted to executives and directors.

($000)	December 31, 2017	December 31, 2016
Short-term compensation	5,454	4,256
Share-based compensation	379	4,711
Total	5,833	8,967

(b) Presentation in Consolidated Statements of Operations

In the Corporation's consolidated financial statements, items are primarily disclosed by nature except for employee compensation costs which are included in general and administrative expenses and operating expenses. In the year ended December 31, 2017, employee compensation costs of $7.0 million were included in general and administrative expenses, compared to $6.7 million in the year ended December 31, 2016. In the year ended December 31, 2017 employee compensation costs of $1.1 million were included in operating expenses, compared to $1.0 million in the year ended December 31, 2016.

(c) Presentation in Consolidated Statements of Cash Flows

Changes in non-cash working capital are comprised of:

($000)	**December 31, 2017**	**December 31, 2016**
Source/(use) of cash:		
Accounts receivable	(9,547)	(21,394)
Prepaid expenses and deposits	(555)	467
Accounts payable and accrued liabilities	12,028	31,905
Non-cash working capital on business combination	(2,981)	—
Share unit liability	(1,397)	2,914
	(2,452)	13,892
Operating activities	(2,287)	(7,931)
Investing activities	(4,195)	20,609
Financing activities	4,030	1,214
	(2,452)	13,892

Corporate Information

BOARD OF DIRECTORS

Glenn R. Carley
Chairman of the Board
Compensation and HR Committee
Nominating Committee
Governance Committee
Audit and Risk Committee

Kevin D. Angus
Independent Director
Compensation and HR Committee (Chair)

Paul J. Beitel
Director

Joan E. Dunne
Independent Director
Audit and Risk Committee (Chair)
Reserves and HSE Committee

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

Lynn Kis
Independent Director
Reserves and HSE Committee (Chair)
Audit and Risk Committee

Arthur J. G. Madden
Independent Director
Audit and Risk Committee
Governance Committee
Nominating Committee

George W. Voneiff
Director
Reserves and HSE Committee

Patrick R. Ward
Director
President and Chief Executive Officer

DESIGN: ARTHUR / HUNTER

OFFICERS

Patrick R. Ward
President and Chief Executive Officer

Stuart W. Jaggard
Chief Financial Officer

Richard W. Kessy
Chief Operating Officer

Edwin S. (Ted) Hanbury
Senior Vice President, Strategic Projects

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

L. Barry McNamara
Vice President, Development and Marketing

STOCK EXCHANGE LISTING

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

AUDITORS

KPMG LLP

BANKERS

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

EVALUATION ENGINEERS

GLJ Petroleum Consultants Ltd.

REGISTRAR AND TRANSFER AGENT

TSX Trust Company

HEAD OFFICE

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