PAINTED PONY ENERGY LTD.

TSX | PONY

2018 ANNUAL REPORT

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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".

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 9, 2019. Shareholders not attending are encouraged to complete the voting instruction form and deliver it in accordance with the instructions therein at their earliest convenience.

"Plowing through the Challenges"

- By Paul Van Ginkel

Cover painting "Plowing through the Challenges", oil on canvas by Paul Van Ginkel
www.paulvanginkel.com

Financial and Operating Highlights

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

Financial	2018	2017	Change
Petroleum and natural gas revenue [1]	404.4	249.2	62 %
Cash flows from operating activities	169.0	106.9	58 %
Per share - basic [3][8]	1.05	0.76	38 %
Per share - diluted [4][8]	0.99	0.74	34 %
Adjusted funds flow from operations [2]	174.6	109.2	60 %
Per share - basic [3]	1.08	0.78	38 %
Per share - diluted [4]	1.03	0.76	36 %
Net income and comprehensive income	7.1	122.4	(94%)
Per share - basic [3]	0.04	0.87	(95%)
Net income and comprehensive income - diluted	7.1	123.2	(94%)
Per share - diluted [4]	0.04	0.85	(95%)
Capital expenditures	154.4	302.6	(49%)
Working capital [5]	32.9	33.0	— %
Bank debt	163.1	149.2	9 %
Senior notes	143.1	141.6	1 %
Convertible debentures - liability	46.1	44.9	3 %
Net debt [6]	348.5	363.9	(4%)
Total assets	2,055.4	2,031.6	1 %
Shares outstanding (millions)	161.0	161.0	— %
Basic weighted-average shares (millions)	161.0	140.7	14 %
Fully diluted weighted-average shares (millions)	169.9	144.1	18 %
Operational			
Daily production volumes			
Natural gas (MMcf/d)	316.5	235.8	34 %
Natural gas liquids (bbls/d)	5,128	3,587	43 %
Total (MMcfe/d)	347.3	257.3	35 %
Total (boe/d)	57,879	42,882	35 %
Realized commodity prices before financial risk management contracts			
Natural gas ($/Mcf)	2.54	2.13	19 %
Natural gas liquids ($/bbl)	59.43	50.53	18 %
Total ($/Mcfe)	3.19	2.65	20 %
Operating netbacks ($/Mcfe) [7]	2.16	2.01	7 %
Corporate netbacks ($/Mcfe) [7]	1.71	1.54	11 %

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 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" in Management Discussion and Analysis for the year ended December 31, 2018.
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 is a non-GAAP measure calculated as current assets less current liabilities. See "Non-GAAP Measures" in Management Discussion and Analysis for the year ended December 31, 2018.
6. Net debt is a non-GAAP measure calculated as bank debt, senior notes, liability portion of convertible debentures, and working capital, 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 contracts, less royalties, operating expenses and transportation expenses. Corporate netback is calculated as operating netback less finance lease expense per unit. See "Non-GAAP Measures" and "Operating and Corporate Netbacks" in Management Discussion and Analysis for the year ended December 31, 2018.
8. Cash flows from operating activities per share - basic and diluted are non-GAAP measures calculated by dividing cash flows from operating activities by the weighted average of basic or diluted shares outstanding in the period.

Message to Shareholders

Despite predictions coming into 2018 of a very challenging year, we delivered record adjusted funds flow per share, reduced debt, cut costs, and grew production and PDP reserves year-over-year. We realized a natural gas price of $2.54/Mcf in 2018 which significantly exceeded the average natural gas price at the main Canadian sales hub at AECO (5A) that averaged just $1.50/Mcf for the year. Our much higher realized natural gas price was made possible through the market diversification strategy we began pursuing several years ago in response to our growing concern about being tied to just two sales locations. Natural gas strip prices in western Canada remain low and that has resulted in another year of forecasted lower capital investment by industry, which we believe is likely to result in lower overall natural gas production levels from industry. We will continue to diversify our sales points while also seeking long-term sales contracts with large-scale end-users, as we did with our 14 year supply contract with Methanex Corporation.

Cold weather, slowing supply growth, and increasing US exports have forced natural gas storage levels well below the 5-year average in Canada and in the US. We believe this positions Painted Pony for better realized prices than the AECO 5A daily spot price in 2019. It is because of this economic backdrop that we plan, once again, to constrain capital spending to internally generated adjusted funds flow, while retaining our optimism for the future of clean, energy efficient Canadian natural gas. We stated clearly in late 2017 that any adjusted funds flow in excess of capital spending in 2018 would be used to reduce debt levels, which I am pleased to report we did. We believe 2019 is not the time to grow our production, rather it is a time to continue to 'Plow Through The Challenges', as illustrated in our annual painting on the cover of this report.

Sales Diversification

Our 2018 adjusted funds flow of $1.08 per share was a record for us and was delivered through a combination of increased production volumes, capital discipline, and diversification of sales points. We structured a sales diversification portfolio for 2018 that included fixed price and basis contracts, and firm transportation that took Painted Pony natural gas to the Dawn market in southern Ontario and to the Sumas sales hub on the BC / Washington state border as well as to Station 2 and AECO as well as our contract with Methanex Corporation.

In October 2018, LNG Canada announced a positive Final Investment Decision ("FID") on the construction of their West Coast LNG project. This was a great day for Canada, for the Canadian natural gas industry, and for Painted Pony. With construction well under-way in Kitimat, BC and on the Coastal GasLink Pipeline, we continue to expect that some portion of gas supply for LNG Canada will be sourced by producers in British Columbia. Long-term LNG contracts would fit into our

Success is the sum of small efforts, repeated day in and day out

-- Robert Collier

focus on delivery diversity and our strategy of increasing profitability through direct sales diversification.

Capital Expenditures

Our 2018 capital investment program totaled approximately $154 million, which was $21 million less than our 2018 adjusted funds flow of $175 million. Activities included the drilling of 22 (22.0 net) wells, the completion of 28 (28.0 net) wells and investment into associated facilities and infrastructure.

We stated in early 2018 that we would limit 2018 capital spending to match adjusted funds flow and that any cash generated above our planned capital spending would be used to reduce debt. I am proud that through prudent and disciplined capital spending we were able to reduce our net-debt from the third quarter of 2018 to the end of the fourth quarter of 2018 by $37 million, a change of 10%.

Health, Safety and Environment

I cannot stress enough the importance we place on the health and safety of our employees and contractors at Painted Pony as well as protection of the environment.

We foster a culture of safe work, making it a top priority in all that we do. We are proud that in 2018 we had no material incidents and zero lost time incidents. Our total recordable injury frequency averaged 0.70 in 2018 compared to an industry average of 0.75. Never satisfied with the status quo, work is ongoing to improve our overall performance. Recent initiatives include hazard identification and near-miss reporting, integrity management plans for regulatory compliance and we will soon implement a new preventative maintenance program. We continue to focus significant effort on water management initiatives, including recycling an average of 93% of water from completions operations over the past three years.

Reserves Growth

In 2018, we focused our capital program on converting our Total Proved Plus Probable reserves to Proved Developed Producing reserves and grew this reserves category by 19% to approximately 1.0 Tcfe. As we continuously improve the cost effectiveness and efficiency of operations, our average reserves bookings per well continues to increase.

We were able to lower the cost of bringing on future production by reducing future development capital in both the Total Proved Plus Probable and the Total Proved categories. In the Total Proved Plus Probable category alone, we were able to reduce the future development capital requirements by over $650 million, and over $300 million in Total Proved reserves. This is a significant accomplishment as larger reserve bookings per well means fewer wells needed to develop the same amount of reserves. Our recycle ratio is a great measure of our ability to invest capital efficiently. Our recycle ratio is calculated by dividing the annual corporate netback of

35%
Growth in Annual Average Daily Production Volumes

2018 Adjusted funds flow
$175 Million
($1.08 per share basic)

$1.71/Mcfe by the annual finding, development and acquisition cost of $0.55/Mcfe. Our Proved Developed Producing recycle ratio of 3.1x is industry leading and is proof of the robustness of our assets in both the near and long term.

Production Growth

We delivered 35% annual production growth over our 2017 annual average daily production volumes, averaging 347 MMcfe/d (57,879 boe/d) during 2018. Also notable was the 43% increase in our average daily liquids volumes of 5,128 bbls/d in 2018, compared to our 2017 average daily liquids volumes of 3,587 bbls/d. We continue to face low natural gas prices on the forward strip in western Canada and as a result we have decided to allow production volumes to reduce by approximately 4% in 2019 to preserve financial flexibility. While we are forecasting slightly lower production volumes this year, I think it is important to reflect back on just how far we have come over the past 3 years. In 2016 we generated adjusted funds flow of $0.53 per share on 139 MMcfe/d (23,204 boe/d) or 1.39 MMcfe/d per share. In 2018 we generated adjusted funds flow of $1.08 per share on 347 MMcfe/d (57,879 boe/d) or 2.16 MMcfe/d per share. I believe our production growth of over 149% and the corresponding adjusted funds flow per share growth of 104% during the past 3 years speaks for itself. I think our track record of rapid production growth is compelling for our future as demand for western Canadian natural gas increases.

2019 and Forward

Despite the headwinds we have faced over the past few years both in western Canadian natural gas pricing and in the capital markets, **we remain focused on creating shareholder value through strong adjusted funds flow per share growth and through the pursuit of strategies that will continue to produce profitability for Painted Pony shareholders in the coming years.**

Finally, a sincere thank you to the staff and Board of Directors at Painted Pony for another year of jobs well done. We also would like to thank our First Nations neighbours, the people of BC, service providers and shareholders for your continued support of Painted Pony Energy.

"signed"
Patrick R. Ward
President and Chief Executive Officer
March 21, 2019

Advisories

Boe Conversions: Barrel of oil equivalent ("**boe**") 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 ("**Mcfe**") 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.

Forward-Looking Information: This message to shareholders section contains certain forward-looking information and forward-looking statements within the meaning of Canadian securities laws (collectively, "forward-looking information"). Forward-looking information relates to future events or future performance and is based upon the Corporation's current internal expectations, estimates, projections, assumptions and beliefs. All information other than historical fact is forward-looking information. Information relating to "reserves" or "resources" is forward-looking as it involves the implied assessment, based on certain estimates and assumptions, that the reserves or resources exist in the quantities estimated and that they will be commercially viable to produce in the future. Words such as "plan", "expect", "intend", "believe", "anticipate", "estimate", "may", "will", "could", "potential", and other similar words that indicate events or conditions may occur are intended to identify forward-looking information. This message to shareholders section contains forward-looking information, including, without limitation, information relating to: forecasted lower capital investment by industry, assumptions regarding overall natural gas production levels and realized prices, future capital spending, forecasted production volumes, and estimates regarding the Corporation's growth.

Undue reliance should not be placed on forward-looking information, as there can be no assurance that the plans, intentions or expectations on which they are based will occur. Although the Corporation's management believes that the expectations in the forward-looking statements are reasonable, there can be no assurance that such expectations will prove to be correct.

Forward-looking information is based on estimates and opinions of management at the time the information is presented. The Corporation is not under any duty to, nor will it, update the forward-looking information after the date of this document to revise such information to actual results or to changes in the Corporation's plans or expectations, except as required by applicable securities laws.

Any "financial outlook" contained in this message to shareholders section, as such term is defined by applicable securities laws, is provided for the purpose of providing information about management's current expectations and plans relating to the future. Readers are cautioned that reliance on such information may not be appropriate for other purposes.

Non-GAAP Measures: This message makes reference to the terms "adjusted funds flow", "adjusted funds flow per share", and "corporate netback" 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 of the Corporation believes these measures are useful supplemental measures of the net position of current assets and current liabilities of the Corporation and the profitability relative to commodity prices. Readers are cautioned, however, that these measures should not be construed as alternatives to other terms such as current and long-term debt or comprehensive income determined in accordance with IFRS as measures of performance. The Corporation's method of calculating these non-GAAP measures may differ from other companies, and accordingly, may not be comparable to similar measures used by other entities.

Management uses "adjusted funds flow" to analyze operating performance and considers adjusted funds flow 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 denotes cash flow from operating activities before the effects of changes in non-cash working capital 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. 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.

"Corporate netback" is used as a supplemental measure of the Corporation's profitability relative to commodity prices. Corporate netback is calculated on a per unit basis as natural gas and natural gas liquids revenues, adjusted for realized gains or losses on risk management contracts, less royalties, operating expenses, transportation costs and finance lease expense. This term should not be considered alternatives to, or more meaningful than net income (loss) and comprehensive income (loss) as determined in accordance with IRFS.

Independent Reserves Evaluation: GLJ Petroleum Consultants ("**GLJ**"), independent qualified reserves evaluators of Calgary, Alberta, prepared a reserves estimation and economic evaluation of the Corporation's oil and natural gas properties effective December 31, 2018, which is contained in a report dated March 5, 2019 (the "**2018 Reserves Report**"). GLJ prepared reserves estimations and economic evaluations of the Corporation's reserves effective December 31, 2018. The 2018 Reserves Report and the prior reserves evaluation were prepared in accordance with the standards contained in the Canadian Oil & Gas Evaluation Handbook and National Instrument 51-101 - Standards of Disclosure for Oil and Gas Activities, which were in effect at the time of the evaluation.

Reserves Categories: Reserves means estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, based on the analysis of drilling, geological, geophysical and engineering data; the use of established technology; and specified economic conditions, which are generally accepted as being reasonable. Reserves are classified according to the degree of certainty associated with the estimates:

- **Proved Reserves** are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves; and
- **Probable Reserves** are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

Each of the reserves categories (proved, probable and possible) may be divided into developed and undeveloped categories:

- **Developed Reserves** are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (e.g. when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following Management's Discussion and Analysis ("MD&A") of the financial results of Painted Pony Energy Ltd. ("Painted Pony" or the "Corporation") should be read in conjunction with the audited financial statements and related notes thereto for the years ended December 31, 2018 and December 31, 2017 ("the Annual Financial Statements"). This commentary is dated March 6, 2019.

The annual 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 its Annual Information Form ("AIF") for the year ended December 31, 2018, 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 1200, 520 - 3 Avenue SW, Calgary, Alberta.

NON-GAAP MEASURES

This MD&A contains the terms "adjusted funds flow from operations", "adjusted funds flow from operations per share", "cash flows from operating activities per share", "working capital (deficiency)", "net debt", "income before taxes, unrealized gains (losses) on risk management contracts and acquisition costs", and "operating and corporate 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.

Cash Flows from Operating Activities Per Share, Adjusted Funds Flow from Operations and Adjusted Funds flow from Operations per Share

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 and decommissioning expenditures. "Adjusted funds flow from operations per share" and "cash flows from operating activities per share" are calculated using the basic and diluted weighted average number of shares for the period. 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 each of adjusted funds flow from operations, adjusted funds flow from operations per share and cash flows from operating activities per share to cash flows from operating activities, which is the most directly comparable measure calculated in accordance with IFRS, as follows:

	Three months ended December 31,		Years ended December 31,	
($000s, except per share)	**2018**	**2017**	**2018**	**2017**
Cash flows from operating activities	**48,475**	27,417	**169,035**	106,917
Changes in non-cash working capital	**10,228**	8,212	**5,604**	2,287
Adjusted funds flow from operations	**58,703**	35,629	**174,639**	109,204
Cash flows from operating activities per share *($/share):*				
Basic	**0.30**	0.17	**1.05**	0.76
Diluted	**0.29**	0.16	**0.99**	0.74
Adjusted funds flow from operations per share *($/share):*				
Basic	**0.36**	0.22	**1.08**	0.78
Diluted	**0.35**	0.21	**1.03**	0.76

Working Capital and Net Debt

Management uses "working capital" and "net debt" as useful supplemental measures of the liquidity of the Corporation. Working capital 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, adjusted for the net current portion of the fair value of risk management contracts and current portion of the 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 the Corporation's calculations of working capital and net debt:

As at *($000s)*	**December 31, 2018**	**December 31, 2017**
Current assets	**92,976**	105,795
Current liabilities	**(60,086)**	(72,770)
Working capital	**32,890**	33,025
Current portion of fair value of risk management contracts (net)	**(34,685)**	(64,463)
Current portion of finance lease obligation	**5,680**	3,282
Bank debt	**(163,140)**	(149,228)
Senior notes	**(143,105)**	(141,613)
Convertible debentures - liability	**(46,113)**	(44,887)
Net debt	**(348,473)**	(363,884)

Income Before Taxes, Unrealized Gains (Losses) on Risk Management Contracts and Acquisition Costs

Management uses "income before taxes, unrealized gains (losses) on risk management contracts and acquisition costs" to analyze the ongoing operational activities of the Corporation before taking into account taxes, acquisition costs and the non-cash effects of changes in the fair value of risk management contracts. This term should not be considered an alternative to, or more meaningful than income before taxes as determined in accordance with IFRS as an indicator of the Corporation's performance. The Corporation reconciles income before taxes, unrealized gains (losses) on risk management contracts and acquisition costs, to income before taxes, which is the most directly comparable measure calculated in accordance with IFRS, as follows:

	Three months ended December 31,		**Years ended December 31,**	
($000s)	**2018**	**2017**	**2018**	**2017**
Income before taxes	**85,847**	51,596	**10,196**	167,783
Unrealized (gain) loss on risk management contracts	**(53,862)**	(42,384)	**48,608**	(146,465)
Costs on acquisition of UGR Blair Creek Ltd.	—	—	—	5,497
Income before taxes, unrealized gains (losses) on risk management contracts and acquisition costs	**31,985**	9,212	**58,804**	26,815

Operating and Corporate Netbacks

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 contracts, less royalties, operating expenses and transportation expenses. Corporate netbacks is used as a supplemental measure of the Corporation's profitability after taking into consideration the costs associated with the finance lease. These terms 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 and Corporate Netbacks" for the calculation of these measures.

RESULTS OF OPERATIONS - OVERVIEW

Results of operations for the year ended December 31, 2018, compared to December 31, 2017, continue to highlight an increase in production volumes through organic growth and incremental value from market diversification practices. With an increase in volumes, the Corporation increased its adjusted funds flow from operations for the year ended December 31, 2018 by 60% to $174.6 million ($1.08/share), compared to the year ended December 31, 2017 for which adjusted funds flow from operations was $109.2 million ($0.78/share).

Painted Pony's exposure to low commodity prices was mitigated during the year ended December 31, 2018 by risk management contracts that resulted in a $38.7 million realized gain ($0.30/Mcfe). Painted Pony's operating netback was $2.16/Mcfe, an increase of 7% over the operating netback of $2.01/Mcfe for the year ended December 31, 2017. As at December 31, 2018, the Corporation has executed fixed price risk management contracts on 123 MMcf/d of natural gas and 3,060 bbl/d of NGL production for 2019. The Corporation has expanded into new markets as part of its long term sales point diversification strategy, including the AECO, Dawn, Sumas and Nymex markets, to receive a premium over the AECO (5A) benchmark price. These markets continue to provide incremental operating netbacks to the Corporation. This is evidenced by the Corporation realizing increased natural gas prices from 2017 to 2018 of 19%.

The capital program for the fourth quarter of 2018 was $19.2 million, including $17.1 million for drilling and completion costs. For the year ended December 31, 2018, the capital program was $154.4 million including $127.6 million for drilling and completion costs. During the three months and year ended December 31, 2018 the Corporation drilled 1 (1.0 net) and 22 (22.0 net) respectively, and completed 5 (5.0 net) and 28 (28.0 net) respectively, Montney natural gas wells. The planned capital program for 2019 is currently estimated between $95 and $110 million, and is anticipated to include 19 (19.0 net) Montney horizontal natural gas wells drilled and 18 (18.0 net) completed.

At December 31, 2018, the Corporation's syndicate provided a credit facility of $400 million.

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

For the fourth quarter of 2018, cash flows from operating activities and adjusted funds flow from operations increased to $48.5 million and $58.7 million, respectively, compared to cash flows from operating activities of $27.4 million and adjusted funds flow from operations of $35.6 million in the fourth quarter of 2017. These respective increases are a result of a 38% increase in realized natural gas prices (including realized gains on hedges), partially offset by an increase in transportation expenses per unit.

For the year ended December 31, 2018, cash flows from operating activities and adjusted funds flow from operations increased to $169.0 million and $174.6 million, respectively, compared to cash flows from operating activities of $106.9 million and adjusted funds flow from operations of $109.2 million for the year ended December 31, 2017. These increases are a result of a 35% increase in production volumes and higher realized natural gas and natural gas liquid prices compared to 2017, partially offset by an increase in transportation expenses per unit.

For the fourth quarter of 2018, the Corporation earned net income and comprehensive income of $62.5 million impacted by an unrealized gain on risk management contracts of $53.9 million. This compares to net income and comprehensive income of $37.1 million for the quarter ended December 31, 2017. Income before taxes, unrealized gains (losses) on risk management contracts and acquisition costs was $32.0 million for the quarter ended December 31, 2018, compared to $9.2 million for the quarter ended December 31, 2017. Stronger commodity prices due to market diversification primarily resulted in the increase.

For the year ended December 31, 2018, the Corporation generated net income and comprehensive income of $7.1 million compared to net income and comprehensive income of $122.4 million for the year ended December 31, 2017. Income before taxes, unrealized gains (losses) on risk management contracts and acquisition costs was $58.8 million for the year ended December 31, 2018, compared to $26.8 million for the year ended December 31, 2017. Market diversification strategies resulting in higher realized prices contributed to this improvement.

AVERAGE DAILY PRODUCTION

	Three months ended December 31,				Years ended December 31,			
	2018	% of total	2017	% of total	**2018**	% of total	2017	% of total
Natural Gas *(Mcf/d)*	**289,820**	**92**	287,811	91	**316,507**	**91**	235,767	92
NGLs *(bbls/d)*	**4,150**	**8**	4,575	9	**5,128**	**9**	3,587	8
Total *(Mcfe/d)*	**314,718**	**100**	315,264	100	**347,274**	**100**	257,292	100
Total *(boe/d)*	**52,453**	**100**	52,544	100	**57,879**	**100**	42,882	100

Overall production volumes for the three months ended December 31, 2018 remained fairly consistent compared to the three months ended December 31, 2017. Temporary shut-ins of approximately 5,300 boe/d were experienced in the fourth quarter of 2018, with the majority due to third party interruptions and voluntary shut-ins due to price weakness created by these third party restrictions and outages. NGL production for the fourth quarter was affected by approximately 9% compared to the fourth quarter of 2017 due to issues at the Townsend facility. The Corporation is working with the facility operator to ensure the issues are resolved.

Production volumes for the year ended December 31, 2018 increased 35%, compared to the year ended December 31, 2017. The production volume increase was driven by production additions from successful new drills in the Blair Creek, Townsend and Daiber areas, and the acquisition of UGR Blair Creek Ltd. in 2017 (the "UGR Acquisition"). Liquids production increased 43% for the year ended December 31, 2018 when compared to the year ended December 31, 2017 due to the emphasis on more liquids rich drilling locations.

PETROLEUM AND NATURAL GAS REVENUE

	Three months ended December 31,		Years ended December 31,	
($000s)	**2018**	**2017**	**2018**	**2017**
Natural Gas	**104,014**	43,883	**293,145**	183,030
Natural Gas Liquids	**21,655**	23,915	**111,227**	66,156
Total	**125,669**	67,798	**404,372**	249,186

For the three months ended December 31, 2018, petroleum and natural gas revenue increased by 85% compared to the fourth quarter of 2017. The change in quarterly revenue is driven by a 135% increase in realized natural gas prices, caused by strong Dawn and Sumas pricing. Similarly, during the year ended December 31, 2018, petroleum and natural gas revenue increased by 62% as a result of a 35% increase in average production volumes and 20% increase in realized prices.

Commodity Prices

		Three months ended December 31,		Years ended December 31,	
Average Benchmark Prices:		**2018**	**2017**	**2018**	**2017**
Natural Gas	NYMEX (US$/mmbtu)	**3.64**	2.93	**3.09**	3.11
	AECO, daily (5A) ($/Mcf)	**1.56**	1.69	**1.50**	2.16
	Sumas (US$/mmbtu)	**11.06**	2.72	**4.30**	2.76
	Dawn ($/Mcf)	**5.01**	3.72	**4.05**	3.95
Crude Oil	WTI (US$/bbl)	**58.92**	55.40	**64.79**	50.96
Exchange rate *(US$/Cdn$)*		**0.76**	0.79	**0.77**	0.77
Realized Commodity Prices Before Financial Risk Management Contracts:					
Natural Gas *($/Mcf)*		**3.90**	1.66	**2.54**	2.13
NGLs *($/bbl)*		**56.72**	56.81	**59.43**	50.53
Total *($/Mcfe)*		**4.34**	2.34	**3.19**	2.65

The Corporation addresses volatility in commodity prices through an active risk management strategy which uses fixed price and location differentials to effectively reduce the Corporation's exposure to the volatile pricing experienced at the AECO and Station 2 sales hubs. This strategy is further supported with physical transportation capacity to other sales hubs.

During the three months ended December 31, 2018, the Corporation's realized natural gas price of $3.90/Mcf represented a 150% premium to the AECO daily (5A) benchmark price. During the year ended December 31, 2018, the Corporation realized a natural gas price of $2.54/Mcf, a 69% premium to the AECO daily (5A) benchmark price.

The Corporation's long term market diversification strategy consists of entering into financial and physical commitments, including contracting for transportation outside of the British Columbia market. For 2019, Painted Pony's revenue exposure to Westcoast Station 2 pricing is expected to average below 2% of revenue, after the impact of financial commodity risk management contracts.

Financial Risk Management

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 assists the Corporation in funding its capital development program. The use of these transactions is governed by and is subject to risk management policies established by the board of directors of the 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 commodity contracts to be effective economic hedges. As a result, all such commodity contracts are recorded at fair value on the statement of financial position, with changes in the fair value being recognized as an unrealized gain or loss in the statement of operations.

Realized Gain On Risk Management Contracts

	Three Months Ended December 31, 2018	Three Months Ended December 31, 2017	Years ended December 31, 2018	Years ended December 31, 2017
Realized gain on risk management contracts *($000s)*	**474**	24,156	**38,650**	44,002
Per unit *($/Mcfe)*	**0.02**	0.83	**0.30**	0.47

The Corporation's method of determining the fair values of derivative financial instruments is disclosed in note 17 to the Annual Financial Statements. At December 31, 2018, 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 2019 - March 2019	10,000	2.32
AECO Fixed Price Swap	January 2019 - March 2019	10,000	1.98
AECO Fixed Price Swap	January 2019 - June 2019	8,000	2.66
AECO Fixed Price Swap	January 2019 - June 2019	10,000	2.62
AECO Call Option Sold	January 2019 - December 2019	10,000	2.80
AECO Call Option Sold	January 2019 - December 2019	15,000	2.93

Financial Westcoast Station 2 Natural Gas Contracts

Options traded	Term	Volume (GJ/d)	Price (CDN$/GJ)
Westcoast Station 2 Fixed Price Swap	January 2019 - June 2019	12,000	2.35
Westcoast Station 2 Fixed Price Swap	January 2019 - September 2019	10,000	2.30
Westcoast Station 2 Fixed Price Swap	January 2019 - September 2019	5,000	2.34
Westcoast Station 2 Fixed Price Swap	January 2019 - December 2019	10,000	2.45

Financial NYMEX Natural Gas Contracts

Options traded	Term	Volume (Mmbtu/d)	Price (US$/Mmbtu)
USD Nymex Fixed Price	January 2019 - March 2019	5,000	4.39
USD Nymex Fixed Price	January 2019 - December 2019	5,000	3.22
USD Nymex Fixed Price	April 2019 - October 2019	5,000	2.85

Financial Dawn Natural Gas Contracts

Options traded	Term	Volume (GJ/d)	Price (CDN$/GJ)
Dawn Fixed Price Swap	January 2019 - March 2019	10,000	3.47
Dawn Fixed Price Swap	January 2019 - March 2019	10,000	3.50
Dawn Fixed Price Swap	January 2019 - June 2019	5,000	3.14

Financial Dawn Natural Gas Contracts

Options traded	Term	Volume (MMBtu/d)	Price (US$/MMBtu)
USD Dawn Fixed Price Swap	January 2019 - March 2019	5,000	3.29
USD Dawn Fixed Price Swap	January 2019 - March 2019	5,000	4.40
USD Dawn Fixed Price Swap	January 2019 - December 2019	10,000	2.53
USD Dawn Fixed Price Swap	April 2019 - December 2019	5,000	2.52

Financial Sumas Natural Gas Contracts			
Options traded	Term	Volume (MMBtu/d)	Price (US$/MMBtu)
USD Sumas Fixed Price Swap	January 2019 - March 2019	10,000	3.17
USD Sumas Fixed Price Swap	January 2019 - March 2019	5,000	5.00

Financial AECO Station 2 Differential Contracts			
Options traded	Term	Volume (GJ/d)	Price (AECO 7A basis CDN$/GJ)
AECO-Station 2 Basis Swap	January 2019 - December 2019	10,000	(0.25)
AECO-Station 2 Basis Swap	January 2019 - October 2020	10,000	(0.32)
AECO-Station 2 Basis Swap	January 2019 - October 2020	20,000	(0.32)
AECO-Station 2 Basis Swap	January 2019 - August 2021	20,000	(0.29)
AECO-Station 2 Basis Swap	April 2019 - October 2019	10,000	(0.24)
AECO-Station 2 Basis Swap	November 2019 - October 2020	10,000	(0.33)

Financial NYMEX Basis Differential Contracts			
Options traded	Term	Volume (MMBtu/d)	Price (NYMEX basis US$/MMBtu)
NYMEX-Sumas Basis Swap	January 2019 - December 2019	5,000	(0.60)
NYMEX-AECO Basis Swap	April 2019 - October 2019	10,000	(1.45)
NYMEX-AECO Basis Swap	April 2019 - September 2021	10,000	(1.14)
NYMEX-AECO Basis Swap	April 2020 - October 2020	10,000	(1.45)
NYMEX-AECO Basis Swap	October 2021 - March 2023	5,000	(1.05)
NYMEX-AECO Basis Swap	October 2021 - March 2023	5,000	(1.05)
NYMEX-Dawn Basis Swap	January 2019 - March 2019	5,000	0.26
NYMEX-Dawn Basis Swap	April 2019 - December 2019	10,000	(0.20)
NYMEX-Dawn Basis Swap	January 2020 - December 2020	5,000	(0.06)
NYMEX-Dawn Basis Swap	January 2020 - December 2020	5,000	(0.07)

Financial WTI Crude Oil Contracts			
Options traded	Term	Volume (Bbl/d)	Price (CDN$/Bbl)
WTI Fixed Price Swap	January 2019 - June 2019	500	80.30
WTI Fixed Price Swap	January 2019 - December 2019	500	70.20
WTI Fixed Price Swap	January 2019 - December 2019	500	70.20
WTI Fixed Price Swap	January 2019 - December 2019	250	72.30
WTI Fixed Price Swap	January 2019 - December 2019	250	74.00
WTI Fixed Price Swap	January 2019 - December 2019	250	74.80
WTI Fixed Price Swap	January 2019 - December 2019	500	77.00
WTI Fixed Price Swap	July 2019 - December 2019	500	80.75
WTI Fixed Price Swap	January 2020 - December 2020	500	75.80

Financial Propane Contracts			
Options traded	Term	Volume (GAL/d)	Price (US$/GAL)
Conway Fixed Price Swap	January 2019 - March 2019	10,500	0.85
Conway Fixed Price Swap	January 2019 - December 2019	10,500	0.67

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 contracts in place as at December 31, 2018:

Financial Foreign Exchange Contracts			
Reference Currency	Term	Notional Amount (USD 000s/month)	Strike Rate
USD	January 2019 - March 2019	2,000	1.35
USD	January 2019 - December 2019	1,000	1.33

The Corporation periodically enters into USD cross currency basis swap transactions related to London InterBank Offered Rate ("LIBOR") borrowings, which results in a reduction to interest expense paid on borrowings on the credit facility. As at December 31, 2018 the following cross currency basis swap was outstanding:

Contract Quantity	Type of Contract	Term / Expiry	Contract Price
$147 Million	Cross currency basis swap	January 28, 2019	$1.335 CAD/USD

ROYALTIES

	Three Months Ended December 31,		Years ended December 31,	
	2018	**2017**	**2018**	**2017**
Royalty expense *($000s)*	**1,639**	906	**6,345**	4,901
Per unit *($/Mcfe)*	**0.06**	0.03	**0.05**	0.05
Royalties as a % of Revenue	**1.3**	1.3	**1.6**	2.0

For the year ended December 31, 2018, the lower royalty rate of 1.6% compared to 2.0% for the year ended December 31, 2017 can be attributed to lower Crown royalty gas reference 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.

For 2019, the Corporation anticipates overall royalty rates to be approximately 2.0% - 2.5% of total revenue. 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,	
	2018	**2017**	**2018**	**2017**
Operating expenses *($000s)*	**17,521**	18,095	**72,830**	59,834
Per unit *($/Mcfe)*	**0.61**	0.62	**0.57**	0.64

Per unit operating expenses were reduced by 2% in the fourth quarter of 2018 compared to the fourth quarter of 2017 and by 11% in the year ended December 31, 2018 compared to the year ended December 31, 2017. The reduction in annual per unit operating expenses is attributable to reduced processing rates, equalization payments and increased production volumes.

For 2019, the Corporation anticipates that average per unit operating expenses will be between $0.60/Mcfe and $0.65/Mcfe.

TRANSPORTATION EXPENSES

	Three Months Ended December 31,		Years ended December 31,	
	2018	**2017**	**2018**	**2017**
Transportation expenses *($000s)*	**23,468**	13,646	**89,876**	39,197
Per unit *($/Mcfe)*	**0.81**	0.47	**0.71**	0.42

Per unit transportation expenses for the three months and year ended December 31, 2018 increased by 72% and 69%, respectively, compared to the three months and year ended December 31, 2017. The increased transportation expenses per unit are the result of an increase in transport tolls on third party pipelines, as well as higher liquids pipeline costs, due to a 43% increase in liquids production for the year ended December 31, 2018 over the same period in 2017.

The Corporation signed various firm transportation agreements which facilitated its diversification into the Dawn, Sumas, and AECO markets. During the year ended December 31, 2018, the Corporation delivered an average of 65 MMcf/d of natural gas to the Dawn market via Long Term Fixed Price service contracts. The increase in transportation expenses was anticipated given the Corporation's focus on market diversification. The Corporation has realized incremental revenues, net of applicable transportation, in excess of $85 million to the end of the fourth quarter, as a result of this strategy. In November 2019, the Corporation will add an additional 15MMcf/d of sales into the Dawn market via the Long Term Fixed Price transport contracts for a total of 88MMcf/d.

For 2019, the Corporation expects average per unit transportation expenses to be between $0.70/Mcfe and $0.75/Mcfe.

OPERATING AND CORPORATE NETBACKS

	Three Months Ended December 31,		Years ended December 31,	
($/Mcfe)	**2018**	**2017**	**2018**	**2017**
Realized commodity price	**4.34**	2.34	**3.19**	2.65
Realized gain on risk management contracts	**0.02**	0.83	**0.30**	0.47
Royalties	**(0.06)**	(0.03)	**(0.05)**	(0.05)
Operating expenses	**(0.61)**	(0.62)	**(0.57)**	(0.64)
Transportation expenses	**(0.81)**	(0.47)	**(0.71)**	(0.42)
Operating netbacks	**2.88**	2.05	**2.16**	2.01
Finance lease expense	**(0.49)**	(0.46)	**(0.45)**	(0.47)
Corporate netbacks	**2.39**	1.59	**1.71**	1.54

For the three months and year ended December 31, 2018, per unit operating netbacks increased by 40% and 7%, respectively. For the three months and year ended December 31, 2018, per unit corporate netbacks increased by 50% and 11%, respectively. The increase in operating and corporate netbacks was the result of higher realized commodity prices (including financial contracts), partially offset by increased transportation expenses, both due to the Corporation's market diversification efforts.

The Corporation's operating netback for the three months and year ended December 31, 2018 was 66% and 68% of revenue, respectively, compared to 88% and 76% of revenue for the year ended December 31, 2017, respectively. The Corporation's corporate netback for the three months and year ended December 31, 2018 was 55% and 54% of revenue, respectively, compared to 68% and 58% of revenue for the year ended December 31, 2017, respectively.

GENERAL AND ADMINISTRATIVE EXPENSES

	Three Months Ended December 31,		Years ended December 31,	
($000s)	**2018**	**2017**	**2018**	**2017**
Gross expenses	**6,957**	7,749	**25,825**	26,134
Capitalized	**(644)**	(1,703)	**(6,399)**	(5,764)
Capital recoveries	**(334)**	(857)	**(1,735)**	(3,339)
Operating recoveries	**(194)**	(196)	**(733)**	(549)
Net expenses	**5,785**	4,993	**16,958**	16,482
Per unit *($/Mcfe)*	**0.20**	0.17	**0.13**	0.18

Net general and administrative ("G&A") expenses per unit for the three months ended December 31, 2018 increased by 18%, compared to the three months ended December 31, 2017 due to lower capitalized expenses and capital recoveries. Net G&A expenses per unit for the year ended December 31, 2018 decreased by 28%, compared to the year ended December 31, 2017 due to increased production volumes and staff composition.

The Corporation's policy of allocating and capitalizing costs associated with new capital projects remained unchanged for the period ended December 31, 2018. G&A capitalized and operating recoveries are in accordance with industry practice.

The Corporation anticipates that per unit G&A expenses will average in the range of $0.11/Mcfe to $0.13/Mcfe for 2019.

FINANCE EXPENSE

	Three Months Ended December 31,		Years ended December 31,	
($000s)	**2018**	**2017**	**2018**	**2017**
Finance lease expense	**14,119**	13,247	**56,927**	44,157
Interest expense	**6,241**	5,837	**25,427**	15,640
Accretion	**1,000**	877	**3,849**	1,794
Total	**21,360**	19,961	**86,203**	61,591
Per unit *($/Mcfe)*	**0.74**	0.69	**0.68**	0.66

Finance lease expense increased due to interest charges in respect of the Townsend Phase 2 expansion, which commenced commercial operation in the fourth quarter of 2017. Interest expense increased due to the issuance of senior notes and convertible debentures in August 2017.

Finance lease expense is a component of the capital fee paid on facilities treated as a finance lease, and is based on the committed share of production volumes processed through a facility. 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. Overall accretion expense increased due to the addition of the senior notes and convertible debentures in the third quarter of 2017. In addition, accretion on the decommissioning obligation increased as a result of a higher decommissioning liability balance. At December 31, 2018, the risk-free interest rate was 2.2% compared to 2.3% at December 31, 2017. The Corporation has estimated the net present value of the decommissioning obligations based on an undiscounted total future liability of $116.3 million at December 31, 2018, compared to $106.0 million at December 31, 2017.

ADJUSTED FUNDS FLOW FROM OPERATIONS

	Three Months Ended December 31,		Years ended December 31,	
($000s)	**2018**	**2017**	**2018**	**2017**
Petroleum and natural gas revenue	**125,669**	67,798	**404,372**	249,186
Royalties	**(1,639)**	(906)	**(6,345)**	(4,901)
Realized gain on risk management contracts	**474**	24,156	**38,650**	44,002
Operating expenses	**(17,521)**	(18,095)	**(72,830)**	(59,834)
Transportation expenses	**(23,468)**	(13,646)	**(89,876)**	(39,197)
General and administrative expenses	**(5,785)**	(4,993)	**(16,958)**	(16,482)
Acquisition costs	**—**	—	**—**	(5,497)
Share unit (expense) recovery	**1,333**	399	**(20)**	1,724
Finance lease expense	**(14,119)**	(13,247)	**(56,927)**	(44,157)
Interest expense	**(6,241)**	(5,837)	**(25,427)**	(15,640)
Adjusted funds flow from operations	**58,703**	35,629	**174,639**	109,204
Per unit ($/Mcfe)	**2.03**	1.23	**1.38**	1.16

SHARE-BASED COMPENSATION AND SHARE UNIT EXPENSE (RECOVERY)

	Three months ended December 31,		Years ended December 31,	
($000s)	**2018**	**2017**	**2018**	**2017**
Share-based compensation	**797**	619	**2,757**	2,205
Share unit expense (recovery)	**(1,333)**	(399)	**20**	(1,724)
Total	**(536)**	220	**2,777**	481

No stock options were granted during the three months ended December 31, 2018, pursuant to the Corporation's stock option plan (the "Stock Option Plan"). There were 2,042,200 stock options granted during the year ended December 31, 2018 pursuant to the Stock Option Plan, at a weighted average exercise price of $2.65.

Share-based Compensation

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. A portion of share-based compensation costs are capitalized on the same basis as general and administrative costs.

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, which entitles the holder to a cash payment upon redemption. DSUs vest at the end of the financial quarter in which they are granted, 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 ("VWAP") of Common Shares at the grant date. The expense is recognized in the statement of operations in the quarter in which the units are granted, 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 VWAP of Common Shares. As at December 31, 2018, there were 949,476 units outstanding under the plan.

The Corporation has a restricted share unit ("RSU") plan, whereby RSUs are issued to eligible employees and executive officers. 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 VWAP 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 VWAP of Common Shares. As at December 31, 2018, there were 486,500 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 VWAP 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 VWAP of Common Shares. As at December 31, 2018, there were 659,900 PSUs outstanding under the plan.

DEPLETION AND DEPRECIATION EXPENSE

	Three Months Ended December 31,		Years ended December 31,	
	2018	**2017**	**2018**	**2017**
Depletion and depreciation *($000s)*	**23,204**	24,921	**107,513**	83,887
Per unit *($/Mcfe)*	**0.80**	0.86	**0.85**	0.89

Depletion and depreciation expense per unit for the three months ended December 31, 2018 decreased by 7%, compared to the three months ended December 31, 2017. Depletion and depreciation expense per unit for the year ended December 31, 2018 decreased by 4%, compared to the year ended December 31, 2017. The depletion calculation for the three months ended December 31, 2018 included future development costs associated with the development of the Corporation's proved plus probable reserves of $3.5 billion, compared to $4.1 billion as at December 31, 2017.

The Corporation's exploration and evaluation ("E&E") assets totaled $130.3 million as at December 31, 2018, compared to $159.0 million as at December 31, 2017, and were not subject to depletion. Substantially all of the E&E assets relate to undeveloped land. At December 31, 2018, management expensed $1.7 million (December 31, 2017 - nil) relating to land that is expiring in 2019.

CAPITAL EXPENDITURES

	Three Months Ended December 31,		Years ended December 31,	
($000s)	**2018**	**2017**	**2018**	**2017**
Drilling and completions	**17,148**	45,144	**127,636**	240,640
Facilities and equipment	**765**	14,954	**17,935**	49,613
Lease acquisitions and retention	**144**	294	**692**	1,095
Seismic	**61**	267	**102**	4,143
Property dispositions	**—**	—	**—**	19
Capitalized G&A	**716**	1,703	**6,923**	5,764
Exploration and development	**18,834**	62,362	**153,288**	301,274
Head office expenditures	**362**	103	**1,072**	1,340
Capital expenditures - cash	**19,196**	62,465	**154,360**	302,614
Capital lease assets	**—**	130,000	**—**	130,000
Share-based compensation	**13**	586	**978**	913
Decommissioning costs	**4,780**	5,322	**5,623**	14,973
UGR acquisition	**—**	—	**—**	207,491
Total	**23,989**	198,373	**160,961**	655,991

During the three months and year ended December 31, 2018, the Corporation drilled 1 (1.0 net) and 22 (22.0 net) Montney natural gas wells, respectively, and completed 5 (5.0 net) and 28 (28.0 net) Montney natural gas wells, respectively.

Capital expenditures for the three months and year ended December 31, 2018 included $17.1 million and $127.6 million, respectively, on drilling and completions activity. Facilities and equipment capital consists of equipping costs, pipeline construction costs and spending on processing facilities. Non-cash decommissioning costs are impacted by drilling activity and changes in risk-free interest rates. In 2017, subsequent to the date of the UGR Acquisition, the decommissioning obligation was revalued resulting in a $7.1 million adjustment, with a corresponding increase to property, plant and equipment.
The planned capital program for 2019 of $95 to $110 million is currently anticipated to include 19 (19.0 net) Montney horizontal natural gas wells drilled and 18 (18.0 net) completed.

LIQUIDITY AND CAPITAL RESOURCES

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 it 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 $400 million in syndicated credit facilities at December 31, 2018 compared to $450 million at December 31, 2017, which are reviewed semi-annually by its lenders. As at December 31, 2018, the Corporation had net debt of $348.5 million, which included working capital of $32.9 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.

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, dispose of assets, 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 four calendar 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.

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. The Corporation is not 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.

SENIOR NOTES

On August 23, 2017, the Corporation issued $150.0 million of 8.5% senior unsecured notes (the "Notes") with a five year term by way of a private placement. 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"). 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 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 before February 22, 2020 other than pursuant to the 90% redemption right (see change of control event 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 VWAP on the notice date and the closing price immediately prior to the notice date are both greater than 140% of the conversion price.

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

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

Redemption Schedule	Percentage of Principal
January 1, 2019 - February 22, 2020	105.000%
February 23, 2020 - August 23, 2021	100.000%

BANK DEBT

As at December 31, 2018 the Corporation's syndicate provided credit facilities of $400 million. The facilities are provided by a syndicate of financial institutions, and include a $350 million extendable revolving facility and a $50 million operating facility. The facilities revolve for a two-year period, which is extendable annually, subject to syndicate approval. The facilities are subject to semi-annual review and re-determination of the 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.

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 2.25% 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, LIBOR 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, which was 0.80:1.00 at December 31, 2018.

As at December 31, 2018, Painted Pony had USD $108.5 million (CAD $147 million) outstanding in a LIBOR loan, as well as $20 million in bankers' acceptances outstanding with an effective interest rate of 4.2% per annum. In addition, as at December 31, 2018 and December 31, 2017, the Corporation had outstanding letters of credit totaling $21.5 million and USD $15.0 million (CAD $20.5 million), which reduce the credit available on the syndicated facilities. Unrealized foreign exchange loss on translation of the USD LIBOR loan was $1.1 million at December 31, 2018, which subsequently reversed in January 2019.

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 syndicated facilities are not subject to financial covenants.

STRATEGIC ALLIANCE

The Corporation is party to a series of agreements (collectively the "Strategic Alliance") with a Canadian midstream company (the "Midstream Company"), relating to the development of processing infrastructure and marketing services for natural gas and NGLs.

Under the Strategic Alliance, the Midstream Company 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 (the "Townsend Facility"). During 2017, Painted Pony entered into an agreement with the Midstream Company in respect of a Townsend Phase 2 expansion ("Townsend Phase 2") which consisted 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. Painted Pony did not acquire any legal right, title, or interest in the Townsend Facility, Townsend Phase 2 or related pipeline infrastructure. The Corporation is not responsible for future pipeline or facility restoration liabilities. All construction costs were borne by the Midstream Company. 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. The Corporation also has the right to the full 99 MMcf/d of firm capacity at Townsend Phase 2, in respect of which there is a take or pay obligation on production volumes delivered to the facility of 90 MMcf/d, which commenced in the first quarter of 2018.

The Townsend Facility, related pipeline infrastructure and Townsend Phase 2 have been recorded as a finance lease. Painted Pony has recorded the asset, representing the total construction cost of the Townsend Facility of approximately $490 million, with a corresponding obligation on the statement of financial position. Over the course of the 20-year lease, there is a capital fee paid to the Midstream Company, which includes finance costs and the amortization of the obligation. The associated processing fee is 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	53,785	285,500	574,624	913,909
Transportation	9,902	53,258	169,281	232,441
Total	63,687	338,758	743,905	1,146,350
Principal	5,680	66,654	417,464	489,798

COMMITMENTS

The following is a summary of the estimated costs required to fulfill Painted Pony's remaining contractual commitments as at December 31, 2018.

($000s)	2019	2020	2021	2022	2023	Thereafter	Total
Transportation and processing	92,362	118,236	136,617	135,919	114,915	1,450,013	2,048,062
Interest on senior notes	12,750	12,750	12,750	9,563	—	—	47,813
Interest on convertible debentures	3,250	3,250	2,438	—	—	—	8,938
Office leases and other	1,582	1,579	1,563	1,347	—	—	6,071
Total commitments	109,944	135,815	153,368	146,829	114,915	1,450,013	2,110,884

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 and natural gas liquids 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, 2018 or December 31, 2017, except those discussed above.

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, 2018 and March 6, 2019, there were 160,995,692 Common Shares issued and outstanding. At December 31, 2018 and March 6, 2019, there were no Preferred Shares issued and outstanding.

Pursuant to the Stock Option Plan, options to purchase Common Shares are granted to executive officers and employees of the Corporation. Non-employee directors are not eligible for grants of stock options. Stock options are granted at the VWAP 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, 2018, an aggregate of 8,925,075 stock options were issued and outstanding at a weighted-average price of $5.09 per stock option. As at

March 6, 2019, an aggregate of 9,921,975 stock options were issued and outstanding at a weighted-average price of $4.42 per stock option.

INCOME TAXES

As at December 31, 2018, the Corporation had a $10.9 million deferred tax liability, compared to a $7.8 million liability as at December 31, 2017. The deferred tax expense was $3.1 million during the year ended December 31, 2018, compared to $45.4 million during the year ended December 31, 2017. Painted Pony's estimated tax pools at December 31, 2018 were $1.4 billion.

DIVIDENDS

The Corporation has not declared or paid any dividends and does not have a current intention to do so.

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 2018, the Corporation expected to receive a realized natural gas price at a premium to the AECO (5A) benchmark price. The actual weighted average price received during 2018 represented a 69% premium to the AECO (5A) daily spot price, influenced by the Corporation's market diversification efforts, and pipeline disruptions.
- Painted Pony's royalty rate for 2018 was expected to be approximately 2.0% - 2.5% of total revenues. The actual royalty rate for 2018 was 1.6% of total revenues. Royalty rates were lower than expected due to lower Crown royalty gas reference prices.
- Operating expenses for 2018 were expected to be between $0.55/Mcfe and $0.60/Mcfe. Actual operating expenses for 2018 were $0.57/Mcfe.
- Transportation expenses for 2018 were expected to be between $0.70/Mcfe and $0.75/Mcfe. Actual transportation expenses for 2018 were $0.71/Mcfe.
- Net G&A expenses for 2018 were expected to be between $0.10/Mcfe to $0.14/Mcfe. Actual net G&A expenses for 2018 were $0.13/Mcfe.

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 financial statements.

Cash-Generating Units

The Corporation's assets are aggregated into cash-generating units ("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 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 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 expenses 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 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 the statement of operations 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.

NEW ACCOUNTING PRONOUNCEMENTS

New accounting standards, amendments to accounting standards and interpretations are effective for annual periods beginning on or after January 1, 2018 and have been applied in preparing the financial statements for the year ended December 31, 2018. The standards applicable to the Corporation are as follows:

Financial Instruments

Effective January 1, 2018, the Corporation adopted IFRS 9 "Financial Instruments" and applied the standard on a retrospective basis. IFRS 9 sets out requirements for recognizing and measuring financial assets, financial liabilities and some contracts to buy or sell non-financial items. This standard replaces IAS 39 Financial Instruments: Recognition and Measurement. The application of IFRS 9 has not resulted in any differences between the previous carrying amounts and the carrying amounts at the date of initial application of IFRS 9.

Revenue from Contracts with Customers

Effective January 1, 2018, the Corporation adopted IFRS 15 "Revenue from Contracts with Customers", and applied the standard on a modified retrospective basis. IFRS 15 provides guidance on the nature, amount, timing and uncertainty of revenue and cash flows arising from contracts with customers. The Corporation has reviewed all revenue contracts with customers, and has determined that there is no material impact on the financial statements with respect to the application of IFRS 15. IFRS 15 replaces IAS 18 and IAS 11.

The Corporation principally generates revenue from the sale of natural gas and NGLs, and revenue associated with the sale of natural gas and NGLs is recognized when control is transferred from the Corporation to the customer.

Revenue is measured based on the consideration specified in the contract with the customer. Payment terms for the Corporation's natural gas and NGL contracts are within one month following delivery. The Corporation does not have any contracts where the period between the transfer of the promised goods to the customer and payment by the customer exceed one year. As a result, the Corporation does not adjust its revenue transactions for the time value of money.

Management has applied the following expedients as part of the adoption of the standard:

- contracts that started and were completed in the comparative period were not restated - no changes were made to the revenue recognized under the previous standard for contracts for which the entity transferred all of the goods or services identified during the comparative period;
- exemption from applying variable consideration requirements - the transaction price at the end of completion of the contract has been used, rather than estimating variable consideration in each comparative reporting period; and
- disclosure exemption - for reporting periods before the date of initial application, no disclosure was included about the amount of the transaction price allocated to remaining performance obligations and when these were expected to be recognized in revenue.

FUTURE ACCOUNTING PRONOUNCEMENTS

Leases

In January 2016, the IAS issued IFRS 16 Leases ("IFRS 16"), 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.

The Corporation adopted IFRS 16 effective January 1, 2019, and is in the process of finalizing its analysis with respect to the determination of leases. The Corporation is analyzing whether the existing finance lease obligation totaling $490 million as at December 31, 2018 meets the definition of a lease. In the event that the finance lease obligation is determined not to be a lease, the balance will be removed from the statement of financial position with a reduction to property, plant and equipment and an adjustment to retained earnings. Further, the removal of the finance lease obligation would result in a reduction to finance and depletion expense and an increase in operating costs in the statement of operations. The Corporation has determined that office leases for both the corporate and field locations will be added to the Statement of Financial Position effective January 1, 2019. The Corporation has elected to apply the optional exemptions for short-term and low-value leases.

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 and completion 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 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, 2018 that is filed on SEDAR at www.sedar.com under the Corporation's profile.

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 favour. 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.

There is ongoing litigation involving the Blueberry River First Nation ("BRFN") and the British Columbia government regarding the obligations of natural resource companies and the Crown relative to adequacy of consultation and cumulative effects in respect of upstream oil and gas development in northeast British Columbia, where a substantial portion of the Corporation's land and assets are situated. The Corporation is not a party to the litigation, and the BRFN and the Crown are currently in negotiations. However, if the claim is decided in BRFN's favour, the Corporation may incur increased costs relative to operations in northeast British Columbia, particularly for those operations that may be considered to impact Aboriginal traditional lands or rights. The Corporation is therefore, actively monitoring the status of the BRFN 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, 2018, 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, 2018.

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, 2018, 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, 2018.

No material changes in the Corporation's ICFR were identified during the period beginning on October 1, 2018 and ended on December 31, 2018 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 QUARTERLY INFORMATION

The following tables set forth selected financial information of the Corporation for the eight most recently completed quarters ending at the fourth quarter of 2018.

Quarter ended *($000s, except where noted)*	**Dec 31, 2018**	**Sept 30, 2018**	**Jun 30, 2018**	**Mar 31, 2018**
Petroleum and natural gas revenue	125,669	90,238	87,656	100,809
Cash flows from operating activities	48,475	33,269	35,734	51,557
Per share - basic	0.30	0.21	0.22	0.32
Per share - diluted	0.29	0.20	0.21	0.30
Adjusted funds flow from operations	58,703	30,319	39,056	46,561
Per share - basic	0.36	0.19	0.24	0.29
Per share - diluted	0.35	0.18	0.23	0.27
Net income (loss) and comprehensive income (loss)	62,473	(13,847)	(33,169)	(8,394)
Per share - basic	0.39	(0.09)	(0.21)	(0.05)
Net income (loss) and comprehensive income (loss) - diluted	63,071	(13,847)	(33,169)	(8,394)
Per share - diluted	0.37	(0.09)	(0.21)	(0.05)
Capital expenditures	19,196	39,433	17,638	78,093
Working capital (deficiency)	32,890	(37,664)	(1,142)	(5.089)
Bank debt	163,140	172,909	184,271	163,533
Senior notes	143,105	142,715	142,335	141,968
Convertible debentures - liability	46,113	45,792	45,480	45,178
Net debt	348,473	385,119	375,313	396,062
Total assets	2,055,354	2,011,154	2,010,612	2,057,878
Decommissioning obligation	53,565	48,496	50,885	49,613
Average daily production volumes (boe/d)	52,453	58,330	60,116	60,703
Average daily production volumes (MMcfe/d)	314.7	350.0	360.7	364.2
Realized commodity prices before financial risk				
Natural gas ($/Mcf)	3.90	2.10	1.90	2.38
NGLs ($/bbl)	56.72	59.21	61.75	59.39
Total ($/Mcfe)	4.34	2.80	2.67	3.08
Operating netbacks ($/Mcfe)	2.88	1.72	1.95	2.18
Corporate netbacks ($/Mcfe)	2.39	1.27	1.51	1.76

Quarter ended *($000s, except where noted)*	**Dec 31, 2017**	**Sept 30, 2017**	**Jun 30, 2017**	**Mar 31, 2017**
Petroleum and natural gas revenue	67,798	50,016	66,424	64,948
Cash flows from operating activities	27,417	29,609	18,230	31,661
Per share - basic	0.17	0.18	0.13	0.32
Per share - diluted	0.16	0.18	0.13	0.31
Adjusted funds flow from operations	35,629	29,712	18,149	25,714
Per share - basic	0.22	0.18	0.13	0.26
Per share - diluted	0.21	0.18	0.13	0.25
Net income and comprehensive income	37,067	14,592	13,829	56,888
Per share - basic	0.23	0.09	0.10	0.57
Net income (loss) and comprehensive income (loss) - diluted	37,917	14,592	13,829	56,888
Per share - diluted	0.22	0.09	0.10	0.56
Capital expenditures	62,465	85,592	57,879	96,678
Working capital (deficiency)	33,025	(21,486)	(30,794)	(74,225)
Bank debt	149,228	93,759	235,547	232,649
Senior notes	141,613	141,260	—	—
Convertible debentures - liability	44,887	44,597	—	—
Net debt	363,884	336,405	283,538	299,791
Total assets	2,031,643	1,809,283	1,742,761	1,406,214
Decommissioning obligation	46,811	41,255	44,517	30,431
Average daily production volumes (boe/d)	52,544	42,353	40,574	35,878
Average daily production volumes (MMcfe/d)	315.3	254.1	243.4	215.3
Realized commodity prices before financial risk				
Natural gas ($/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 ($/Mcfe)	2.05	2.12	1.81	2.08
Corporate netbacks ($/Mcfe)	1.59	1.62	1.37	1.59

SELECTED ANNUAL INFORMATION

The following table sets forth selected annual financial information of the Corporation for the three most recently completed years ending December 31, 2018.

Year ended ($000s, except where noted)	Dec 31, 2018	Dec 31, 2017	Dec 31, 2016
Petroleum and natural gas revenue	404,372	249,186	121,580
Cash flows from operating activities	169,035	106,917	44,658
Per share - basic	1.05	0.76	0.45
Per share - diluted	0.99	0.74	0.45
Adjusted funds flow from operations	174,639	109,204	52,589
Per share - basic	1.08	0.78	0.53
Per share - diluted	1.03	0.76	0.53
Net income (loss) and comprehensive income (loss)	7,064	122,376	(51,857)
Per share - basic	0.04	0.87	(0.52)
Net income (loss) and comprehensive income (loss) - diluted	7,064	123,226	(51,857)
Per share - diluted	0.04	0.85	(0.52)
Capital expenditures	154,360	302,614	204,391
Working capital (deficiency)	32,890	33,025	(73,647)
Bank debt	163,140	149,228	200,836
Senior notes	143,105	141,613	—
Convertible debentures - liability	46,113	44,887	—
Net debt	348,473	363,884	228,463
Total assets	2,055,354	2,031,643	1,336,955
Decommissioning obligation	53,565	46,811	29,857
Average daily production volumes *(boe/d)*	57,879	42,882	23,204
Average daily production volumes *(MMcfe/d)*	347.3	257.3	139.2

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, the UGR Acquisition, and commencement of commercial operations at the Townsend Facilities have generated incremental production volumes, offset by shut-in production volumes during low pricing environments and pipeline disruptions. There has been significant volatility and fluctuation in commodity prices over the last two years.
- 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 significantly influenced by unrealized and realized gains or losses on risk management contracts and costs related to the UGR Acquisition.
- Fluctuations in capital expenditures have reflected both available capital resources and capital spending restraints during weaker commodity price cycles.
- The Corporation's focus is now on development and production, with the Corporation utilizing bank debt, convertible debentures, senior notes and cash flow to assist with the capital program. As the Corporation proceeds with its prudent capital program, bank debt amounted to $163.1 million as at December 31, 2018.
- Total assets and non-current liabilities have generally increased as the Corporation's capital program has been executed, as well as with the UGR Acquisition.

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", "expect", "forecast", "plan", "potential", "project", "budget", "estimate", "assume", "believe", "shall", "continue", "target", "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, 2018, 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 Corporation receiving a natural gas price that exceeds the AECO (5A) benchmark price;*
- *expectations with respect to average price estimates for 2019;*
- *the expectation that exposure to Westcoast Station 2 pricing is expected to average below 2% in 2019;*
- *the expectation that overall royalties for 2019 will be approximately 2.0% - 2.5% of total revenues;*
- *the expectation that average per unit operating expenses will be between $0.60/Mcfe and $0.65/Mcfe for 2019, assuming normal seasonal weather conditions;*
- *the expectation that average per unit transportation expenses will be between $0.70/Mcfe and $0.75/Mcfe for 2019;*
- *the expectation that per unit G&A expenses will average between $0.11/Mcfe to $0.13/Mcfe for 2019;*
- *the expectation that the Corporation's capital program for 2019 will include drilling* 19 *(19.0 net) and completing 18 (18.0 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;*
- *the Corporation's plans to monitor the commodity, credit and capital markets;*
- *expectations as to payments in relation to the Townsend Facility;*
- *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, 2018;*
- *expectations with respect to the declaration or payment of dividends;*
- *expectations that future taxable income will be available to utilize accumulated tax pools;*
- *expectations as to the impact of critical accounting judgments and estimates;*
- *expectations regarding future accounting pronouncements and their impact on the Corporation; and*
- *expectations regarding the potential settlement between the BRFN and the Province of British Columbia.*

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

- *the continued suitability of the Corporation's planned capital program;*
- *the utilization of available credit facilities for 2019;*
- *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, 2019 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 reclamation 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, dispositions 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 its AIF for the year ended December 31, 2018 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 1200, 520 – 3 Avenue SW., Calgary, Alberta T2P 0R3 (Phone (403) 475-0440), by email at info@paintedpony.ca or on the Corporation's website at www.paintedpony.ca.

MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL STATEMENTS

Management of Painted Pony Energy Ltd. (the "Corporation") is responsible for the preparation and integrity of the accompanying financial statements and all other information contained in this report. The 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 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 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 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 financial statements before they are finalized. The Board of Directors has approved the financial statements for the years ended December 31, 2018 and 2017.

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 financial statements for the years ended December 31, 2018 and 2017.

"signed"
Patrick R. Ward
President and CEO

"signed"
Stuart W. Jaggard
CFO

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INDEPENDENT AUDITORS' REPORT

To the Shareholders of Painted Pony Energy Ltd.

Opinion

We have audited the financial statements of Painted Pony Energy Ltd. ("the Entity"), which comprise:

- the statements of financial position as at December 31, 2018 and 2017
- the statements of operations for the years then ended
- the statements of changes in equity for the years then ended
- the statements of cash flows for the years then ended
- and notes to the financial statements, including a summary of significant accounting policies

(Hereinafter referred to as the "financial statements").

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Entity as at December 31, 2018 and December 31, 2017, and its financial performance and its cash flows for the years then ended in accordance with International Financial Reporting Standards ("IFRS").

Basis for Opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the "*Auditors' Responsibilities for the Audit of the Financial Statements"* section of our auditors' report.

We are independent of the Entity in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada and we have fulfilled our other ethical responsibilities in accordance with these requirements.

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

Other Information

Management is responsible for the other information. Other information comprises:

- the information included in Management's Discussion and Analysis to be filed with the relevant Canadian Securities Commissions.
- the information, other than the financial statements and the auditors' report thereon, included in a document likely to be entitled "2018 Annual Report".

Our opinion on the financial statements does not cover the other information and we do not and will not express any form of assurance conclusion thereon.

In connection with our audit of the financial statements, our responsibility is to read the other information identified above and, in doing so, consider whether the other information is materially inconsistent with the financial statements or our knowledge obtained in the audit and remain alert for indications that the other information appears to be materially misstated.

We obtained the information included in Management's Discussion and Analysis filed with the relevant Canadian Securities Commissions as at the date of this auditors' report. If, based on the work we have performed on this other information, we conclude that there is a material misstatement of this other information, we are required to report that fact in the auditors' report. We have nothing to report in this regard.

The information, other than the financial statements and the auditors' report thereon, included in a document likely to be entitled "2018 Annual Report" is expected to be made available to us after the date of this auditors' report. If, based on the work we will perform on this other information, we conclude that there is a material misstatement of this other information, we are required to report that fact to those charged with governance.

Responsibilities of Management and Those Charged with Governance for the Financial Statements

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

In preparing the financial statements, management is responsible for assessing the Entity's ability to continue as a going concern, disclosing as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Entity or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Entity's financial reporting process.

Auditors' Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditors' report that includes our opinion.

Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists.

Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of the financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism through the audit.

We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion.

  The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit 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.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Entity's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditors' report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditors' report. However, future events or conditions may cause the Entity to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.
- Communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.
- Provide those charged with governance with a statement that we have complied with relevant ethical requirements regarding independence, and communicate with them all relationships and other matters that may reasonably be thought to bear on our independence, and where applicable, related safeguards.

The engagement partner on the audit resulting in this auditors' report is Jason Stuart Brown.

KPMG LLP

Chartered Professional Accountants

Calgary, Canada
March 6, 2019

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

As at	December 31, 2018	December 31, 2017
ASSETS		
Current assets		
Accounts receivable *(note 16)*	55,532	39,115
Prepaid expenses and deposits	2,229	1,664
Fair value of risk management contracts *(note 16)*	35,215	65,016
	92,976	105,795
Non-current assets		
Fair value of risk management contracts *(note 16)*	7,350	22,552
Exploration and evaluation *(note 5)*	130,348	159,004
Property, plant and equipment *(note 6)*	1,824,680	1,744,292
	2,055,354	2,031,643
LIABILITIES		
Current liabilities		
Accounts payable and accrued liabilities	51,813	66,931
Share unit liability *(note 15)*	2,063	2,004
Fair value of risk management contracts *(note 16)*	530	553
Current portion of finance lease obligation *(note 18)*	5,680	3,282
	60,086	72,770
Non-current liabilities		
Fair value of risk management contracts *(note 16)*	2,834	294
Bank debt *(note 7)*	163,140	149,228
Senior notes *(note 8)*	143,105	141,613
Convertible debentures *(note 9)*	46,113	44,887
Deferred tax *(note 12)*	10,904	7,772
Decommissioning obligation *(note 13)*	53,565	46,811
Finance lease obligation *(note 18)*	484,118	487,578
	963,865	950,953
EQUITY		
Share capital *(note 14)*	1,015,235	1,015,235
Equity portion of convertible debentures *(note 9)*	2,382	2,382
Contributed surplus	58,938	55,203
Retained earnings	14,934	7,870
	1,091,489	1,080,690
	2,055,354	2,031,643

Commitments *(notes 18 & 19)*

See accompanying notes to the financial statements.

Approved on behalf of the Board:

"signed" Joan E. Dunne
Director

"signed" Patrick R. Ward
Director

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

	Years ended December 31,	
	2018	**2017**
Revenue		
Petroleum and natural gas *(note 20)*	404,372	249,186
Royalties	(6,345)	(4,901)
	398,027	244,285
Realized gain on risk management contracts *(note 16)*	38,650	44,002
Unrealized gain (loss) on risk management contracts *(note 16)*	(48,608)	146,465
	388,069	434,752
Expenses		
Operating	72,830	59,834
Transportation	89,876	39,197
General and administrative	16,958	16,482
Costs on acquisition of UGR Blair Creek Ltd. *(note 4)*	—	5,497
Share-based compensation *(note 14 and 15)*	2,777	481
Exploration and evaluation *(note 5)*	1,716	—
Depletion and depreciation *(note 6)*	107,513	83,887
	291,670	205,378
Income from operations	96,399	229,374
Finance expense *(note 11)*	(86,203)	(61,591)
Income before taxes	10,196	167,783
Deferred tax expense *(note 12)*	(3,132)	(45,407)
Net income and comprehensive income	**7,064**	**122,376**
Net income and comprehensive income per share:		
Basic *(note 10)*	$0.04	$0.87
Diluted *(note 10)*	$0.04	$0.85

See accompanying notes to the financial statements.

PAINTED PONY ENERGY LTD.
STATEMENTS OF CHANGES IN EQUITY

($000s, except shares)

Years ended December 31, 2018 and 2017

	Number of Common Shares	Share capital	Equity portion of convertible debentures	Contributed surplus	Retained earnings / (deficit)	Total equity
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
Share-based compensation	—	—	—	3,735	—	3,735
Net income and comprehensive income	—	—	—	—	7,064	7,064
Balance at December 31, 2018	160,995,692	1,015,235	2,382	58,938	14,934	1,091,489

See accompanying notes to the financial statements.

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

	Years ended December 31,	
	2018	**2017**
Cash flows from operating activities:		
Net income and comprehensive income	7,064	122,376
Adjustments for:		
Depletion and depreciation	107,513	83,887
Exploration and evaluation	1,716	—
Share-based compensation	2,757	2,205
Accretion expense	3,849	1,794
Deferred income tax expense	3,132	45,407
Unrealized (gain) loss on risk management contracts	48,608	(146,465)
Changes in non-cash working capital	(5,604)	(2,287)
	169,035	106,917
Cash flows from investing activities:		
Property, plant and equipment additions	(154,360)	(302,614)
Cash assumed on acquisition of UGR Blair Creek Ltd.	—	864
Changes in non-cash working capital	(22,513)	(4,195)
	(176,873)	(305,945)
Cash flows from financing activities:		
Issuance of shares	—	110,992
Exercise of stock options	—	72
Increase (repayment) in bank debt	12,824	(99,825)
Repayment of finance lease	(1,062)	—
Share issue costs	—	(5,074)
Issuance of senior notes	—	141,115
Issuance of convertible debentures	—	47,718
Changes in non-cash working capital	(3,924)	4,030
	7,838	199,028
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 financial statements.

1. REPORTING ENTITY

Painted Pony Energy Ltd.'s ("Painted Pony" or the "Corporation") principal business activity is the development and production of petroleum and natural gas resources in western Canada. The financial statements of the Corporation as at and for the years ended December 31, 2018 and 2017 include the accounts of the Corporation. On January 1, 2018, the Corporation's wholly owned subsidiaries, UGR Blair Creek Ltd. and Painted Rock Resources Ltd., were amalgamated with the Corporation. The Corporation's head office is located at 1200, 520 - 3 Avenue S.W., Calgary, Alberta.

2. BASIS OF PRESENTATION

The financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB"). The financial statements were authorized for issuance by the Board of Directors of the Corporation (the "Board") on March 6, 2019.

The 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 financial statements are presented in Canadian dollars, which is the Corporation's functional currency.

The preparation of financial statements in conformity with IFRS requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, revenue 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 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 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 expenses 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 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 the statement of operations 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 financial statements by Corporation.

(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

Classification and Measurement of Financial Instruments

Financial assets and financial liabilities are classified into three categories: Amortized Cost, Fair Value through Other Comprehensive Income ("FVTOCI") and Fair Value through Profit and Loss ("FVTPL"). The classification of financial assets is determined by their context in the Corporation's business model and by the characteristics of the financial asset's contractual cash flows.

Financial assets and financial liabilities are measured at fair value on initial recognition, which is typically the transaction price unless a financial instrument contains a significant financing component. Subsequent measurement is dependent on the financial instrument's classification.

(i) Amortized Cost

Accounts receivable, prepaid expenses and deposits, accounts payable and accrued liabilities, bank debt, senior notes and debt portion of convertible debentures are measured at amortized cost. The contractual cash flows received from the financial assets are solely payments of principal and interest and are held within a business model whose objective is to collect the contractual cash flows. The financial assets and financial liabilities are subsequently measured at amortized cost using the effective interest method.

(ii) Fair Value Through Profit and Loss

Risk management contracts, deferred share units ("DSUs"), preferred share units ("PSUs") and restricted share units ("RSUs"), all of which are derivatives, are measured initially at FVTPL and are subsequently measured at fair value with changes in fair value immediately charged to the statements of operations.

(iii) Fair Value Through Other Comprehensive Income

As at December 31, 2018, the Corporation does not have any financial instruments measured at FVTOCI.

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 FVTPL and are recorded on the statement of financial position at fair value. Transaction costs are recognized in the statement of operations when incurred.

Impairment of Financial Assets
Impairment of financial assets is determined by measuring the assets' expected credit loss ("ECL"). Accounts receivable are due within one year or less; therefore, these financial assets are not considered to have a significant financing component and a lifetime ECL is measured at the date of initial recognition of the accounts receivable. ECL allowances have not been recognized for cash and cash equivalents due to the virtual certainty associated with their collection.

The ECL pertaining to accounts receivable is assessed at initial recognition and this provision is re-assessed at each reporting date. ECLs are a probability-weighted estimate of all possible default events related to the financial asset (over the lifetime or within 12 months after the reporting period, as applicable) and are measured as the difference between the present value of the cash flows due to the Corporation and the cash flows the Corporation expects to receive, including cash flows expected from collateral and other credit enhancements that are a part of contractual terms. In making an assessment as to whether financial assets are credit-impaired, the Corporation considers historically realized bad debts, evidence of a debtor's present financial condition and whether a debtor has breached certain contracts, the probability that a debtor will enter bankruptcy or other financial reorganization, changes in economic conditions that correlate to increased levels of default, the number of days a debtor is past due in making a contractual payment, and the term to maturity of the specified receivable. The carrying amounts of financial assets are reduced by the amount of the ECL through an allowance account and losses are recognized within general and administrative ("G&A") expense in the statement of operations.

(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 of properties received, with the carrying amount of the asset and are recognized in the statement of operations.

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 the statement of operations 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 the statement of operations.

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 ("NGLs") 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 the statement of operations on a declining-balance rate of 20% based on their estimated useful lives. E&E assets are not depreciated.

Impairment

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 the statement of operations. 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.

(d) Leased Assets
Payments made under operating leases are recognized in the statement of operations 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.

(e) 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.

(f) Share-Based Compensation

The Corporation has issued stock options to acquire Common Shares to executive officers and employees. Non-employee directors are not eligible for grants of stock options. 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 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 VWAP average price of Common Shares. DSUs are classified as fair value through profit or loss and are recorded on the statement of financial position at fair value.

The Corporation has issued 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 statement of financial position at fair value.

The Corporation has issued RSUs to eligible employees and executive officers. 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 statement of financial position at fair value.

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

(g) 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.

(h) Revenue Recognition

Revenue associated with the sale of natural gas and NGLs is measured based on the consideration specified in the contract with a customer and excludes amounts collected on behalf of third parties. The Corporation recognizes revenue when it transfers control of the product or service to a customer, which is generally when the title transfers from the Corporation to the customer.

The Corporation satisfies its performance obligations in contracts with customers upon delivery of natural gas and NGLs at a point in time, when title transfers to the customer.

(i) 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.

(j) Income Tax

Income tax expense comprises current and deferred tax expense and is recognized in the statement of operations 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.

(k) Foreign Currency Translation

The principal currency of the economic environment in which the Corporation operates 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 the statement of operations.

(l) 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.

(m) Changes to Accounting Policies

Financial Instruments

Effective January 1, 2018, the Corporation adopted IFRS 9 "Financial Instruments" and applied the standard on a retrospective basis. IFRS 9 sets out requirements for recognizing and measuring financial assets, financial liabilities and some contracts to buy or sell non-financial items. This standard replaces IAS 39 Financial Instruments: Recognition and Measurement. The application of IFRS 9 has not resulted in any differences between the previous carrying amounts and the carrying amounts at the date of initial application of IFRS 9.

Revenue Recognition

Effective January 1, 2018, the Corporation adopted IFRS 15 "Revenue from Contracts with Customers", and applied the standard on a modified retrospective basis. IFRS 15 provides guidance on the nature, amount, timing and uncertainty of revenue and cash flows arising from contracts with customers. The Corporation has reviewed all revenue contracts with customers, and has determined that there is no material impact on the financial statements with respect to the application of IFRS 15. IFRS 15 replaces IAS 18 and IAS 11.

The Corporation principally generates revenue from the sale of natural gas and NGLs, and revenue associated with the sale of natural gas and NGLs is recognized when control is transferred from the Corporation to the customer.

Revenue is measured based on the consideration specified in the contract with the customer. Payment terms for the Corporation's natural gas and NGL contracts are within one month following delivery. The Corporation does not have any contracts where the period between the transfer of the promised goods to the customer and payment by the customer exceeds one year. As a result, the Corporation does not adjust revenue transactions for the time value of money.

Management has applied the following expedients as part of the adoption of the standard.

- Contracts that started and were completed in the comparative period were not restated - no changes were made to the revenue recognized under the previous standard for contracts for which the entity transferred all of the goods or services identified during the comparative period;
- Exemption from applying variable consideration requirements - the transaction price at the end of completion of the contract has been used, rather than estimating variable consideration in each comparative reporting period; and
- Disclosure exemption - for reporting periods before the date of initial application, no disclosure was included about the amount of the transaction price allocated to remaining performance obligations and when these were expected to be recognized in revenue.

Refer to note 20 for additional disclosures.

(n) Future Accounting Pronouncements

Leases

In January 2016, the IAS issued IFRS 16 Leases ("IFRS 16"), 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.

The Corporation adopted IFRS 16 effective January 1, 2019, and is in the process of finalizing its analysis with respect to the determination of leases. The Corporation is analyzing whether the existing finance lease obligation totaling $490 million as at December 31, 2018 meets the definition of a lease. In the event that the finance lease obligation is determined not to be a lease, the balance will be removed from the statement of financial position with a reduction to property, plant and equipment and an adjustment to retained earnings. Further, the removal of the finance lease obligation would result in a reduction to finance and depletion expense and an increase in operating costs in the statement of operations. The Corporation has determined that office leases for both the corporate and field locations will be added to the Statement of Financial Position effective January 1, 2019. The Corporation has elected to apply the optional exemptions for short-term and low-value leases.

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 northeast British Columbia, 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 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 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, 2016	114,251
UGR acquisition *(note 4)*	58,743
Transfer to property, plant and equipment	(13,990)
As at December 31, 2017	159,004
Transfer to property, plant and equipment	(26,940)
Expensed	(1,716)
As at December 31, 2018	130,348

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 property, plant and equipment as proved or probable reserves are determined and as ongoing wells are drilled within the Corporation's CGU. E&E assets were expensed in 2018 due to 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, 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
Capital expenditures	154,360
Non-cash additions	6,601
Write off of office assets and leasehold improvements	(2,313)
Transfer from exploration and evaluation	26,940
As at December 31, 2018	2,233,655

Accumulated depletion and depreciation:	
As at December 31, 2016	219,888
Depletion and depreciation	83,887
As at December 31, 2017	303,775
Write off of office assets and leasehold improvements	(2,313)
Depletion and depreciation	107,513
As at December 31, 2018	408,975

Carrying amounts:	
December 31, 2017	1,744,292
December 31, 2018	1,824,680

Estimated future development costs associated with the development of the Corporation's proved plus probable reserves were $3.5 billion at December 31, 2018 (December 31, 2017 - $4.1 billion).

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

($000s)	**Years ended December 31,**	
	2018	**2017**
General and administrative and unit awards	6,923	5,764
Capital recoveries	1,735	3,339
Share-based compensation	978	913
Total	9,636	10,016

7. BANK DEBT

As at December 31, 2018, the Corporation's syndicated credit facilities consisted of available credit facilities of $400 million. The available facilities are provided by a syndicate of financial institutions, and include a $350 million extendable revolving facility and a $50 million operating facility. The facilities revolve for a two-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.

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 2.25% 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. This ratio is calculated as senior debt, defined as outstanding loans and borrowings plus or minus working capital, excluding the fair value of risk management contracts, less the principal amount of the Corporation's unsecured notes and convertible debentures; divided by the quarterly annualized EBITDA, defined as net income plus finance expense excluding the costs associated with the finance lease obligation, plus income taxes and adjustments for earnings or losses attributable to extraordinary and non-recurring gains or losses, as well as adjustments for any non-cash items including depreciation, depletion, amortization, deferred income taxes and non-cash gains or losses resulting from marking-to-market the outstanding risk management contracts.

The credit facilities provide that advances may be made by way of prime rate loans, U.S. Base Rate loans, London InterBank Offered Rate ("LIBOR") loans, bankers' acceptances, letters of credit or letters of guarantee. A standby fee of 0.5% to 0.8125% 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, which was 0.80:1.00 at December 31, 2018.

As at December 31, 2018, Painted Pony had USD $108.5 million (CAD $147 million) outstanding in a LIBOR loan, as well as $20 million in bankers' acceptances outstanding with an effective interest rate of 4.2% per annum. In addition, as at December 31, 2018 and December 31, 2017, the Corporation had outstanding letters of credit totaling $21.5 million and USD $15.0 million (CAD $20.5 million), which reduce the credit available on the syndicated facilities. Unrealized foreign exchange loss on translation of the USD LIBOR loan was $1.1 million at December 31, 2018, which subsequently reversed in January 2019.

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 syndicated facilities are not subject to financial covenants.

8. SENIOR NOTES

On August 23, 2017, the Corporation issued $150.0 million of 8.5% senior unsecured notes (the "Notes") with a five 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 statement of operations. At December 31, 2018 the carrying value of the Notes was $143.1 million (December 31, 2017 - $141.6 million). Accretion expense of $1.5 million was recorded in the statement of operations for the year ended December 31, 2018 (for the year ended December 31, 2017 - $0.5 million).

9. CONVERTIBLE DEBENTURES

($000s)	Liability component	Equity component
As 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	—
As at December 31, 2017	44,887	2,382
Accretion of discount	1,226	—
As at December 31, 2018	46,113	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 January 1, 2019 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 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
January 1, 2019 - 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 statement of operations. At December 31, 2018 the carrying value of the Debentures was $46.1 million (December 31, 2017 - $44.9 million).

10. NET INCOME AND COMPREHENSIVE INCOME PER SHARE

	Years ended December 31,	
	2018	2017
Net income and comprehensive income - basic *($000's)*	7,064	122,376
Net income and comprehensive income - diluted *($000's)*	7,064	123,227
Weighted average Common Shares - basic	160,995,692	140,717,740
Weighted average Common Shares- diluted	160,995,692	144,149,853
Net income per share - basic *($/share)*	0.04	0.87
Net income per share - diluted *($/share)*	0.04	0.85

The average market value of the Common Shares of the Corporation for purposes of determining the dilutive effect of outstanding stock options was based on quoted market prices for the period. For the year ended December 31, 2018, there were 8,925,075 stock options excluded from the weighted-average diluted share calculation of Common Shares as they were anti-dilutive (December 31, 2017 - 10,046,293).

For the year ended December 31, 2018 there were 8,928,571 potential Common Shares related to the conversion of the convertible debentures that were excluded from the weighted-average diluted share calculation, as they were anti-dilutive. For the year ended December 31, 2017, 3,180,039 potential Common Shares were included in diluted net income and comprehensive income per share.

11. FINANCE EXPENSE

($000s)	Years ended December 31, 2018	2017
Finance lease expense	56,927	44,157
Interest expense	25,427	15,640
Accretion	3,849	1,794
Total	86,203	61,591

Finance lease expense is a component of the capital fee paid on facilities treated as a finance lease, and is based on the committed share of production volumes processed through a facility. 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, 2018	2017
Income before taxes	10,196	167,783
Combined corporate tax rate	27.0%	26.5%
Expected tax reduction	2,753	44,462
Non-deductible expenses	139	337
Non-deductible share-based compensation	613	584
Change in statutory rates	(354)	14
Other	(19)	10
Total deferred tax expense	3,132	45,407

Deferred tax assets and liabilities are attributable to the following:

($000s)	December 31, 2018	December 31, 2017
Deferred tax liabilities:		
PP&E and E&E assets	(119,783)	(101,559)
Fair value of risk management contracts	(10,584)	(23,415)
Senior notes	(646)	(1,049)
Convertible debentures	(134)	(465)
Other	—	(382)
	(131,147)	(126,870)
Less deferred tax assets:		
Non-capital losses	103,312	103,327
Decommissioning obligation	14,462	12,639
Finance costs	2,241	3,132
Other	228	—
Net deferred tax liability	(10,904)	(7,772)

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, 2018 were $1.4 billion (December 31, 2017 – $1.4 billion).

13. DECOMMISSIONING OBLIGATION

($000s)	December 31, 2018	December 31, 2017
Balance, beginning of year	46,811	29,857
UGR acquisition *(note 4)*	—	1,093
Provisions	4,451	9,032
Revisions	1,172	5,941
Accretion	1,131	888
Balance, end of year	53,565	46,811

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 $116.3 million, compared to $106.0 million at December 31, 2017, with payments expected to be made over the next 10 to 48 years. The discount factor, being the risk-free rate related to the liability at December 31, 2018, was 2.2%, compared to 2.3% at December 31, 2017, and the inflation rate was 2% at both December 31, 2018 and 2017.

14. SHARE CAPITAL

(a) Authorized

The Corporation has an unlimited number of Common Shares and an unlimited number of preferred shares ("Preferred Shares") authorized for issuance. At December 31, 2018 and December 31, 2017 there were 160,995,692 Common Shares outstanding. At December 31, 2018 and December 31, 2017 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 plan ("the 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 VWAP 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, 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
Granted	2.65	2,042,200
Forfeited	5.02	(1,872,992)
Expired	8.10	(1,542,500)
As at December 31, 2018	5.09	8,925,075

The following table summarizes information about stock options outstanding and exercisable at December 31, 2018:

Number of Stock Options Outstanding	Exercise Price Range ($)	Weighted Average Remaining Life (Years)	Number of Stock Options Exercisable	Weighted Average Exercise Price ($)
1,791,400	1.92 - 3.13	4.0	—	—
1,504,125	3.14 - 4.20	2.9	768,116	3.97
1,581,950	4.21 - 4.28	1.9	1,581,950	4.26
2,033,600	4.29 - 5.40	3.4	677,866	4.73
2,014,000	5.41 - 14.14	0.9	1,954,500	9.27
8,925,075	5.09	2.6	4,982,432	6.24

The Corporation accounts for its stock options using the fair value method. In accordance with the Stock Option Plan, 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	
	2018	2017
Fair value per stock option ($)	1.26	2.00
Volatility (%)	53	51
Life (years)	5	5
Risk-free interest rate (%)	1.90	1.34

A forfeiture rate of 8.7% was used when measuring share-based compensation during the year ended December 31, 2018, compared to 9.0% during the year ended December 31, 2017.

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

($000s)	Years ended December 31,	
	2018	2017
Share-based compensation	2,757	2,205
Share unit expense (recovery) *(note 15)*	20	(1,724)
Total	2,777	481

15. SHARE UNIT PLANS

(a) Deferred Share Units

The Corporation has a deferred share unit 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 at the end of the financial quarter in which they are granted, 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 VWAP of Common Shares at the grant date. The expense is recognized in the statement of operations in the quarter in which the units are granted, 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 VWAP of Common Shares.

(b) Restricted Share Units

The Corporation has a restricted share unit plan, whereby RSUs are issued to executive officers and 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 VWAP 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 VWAP of Common Shares.

(c) Preferred Share Units

The Corporation has a performance share unit 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 VWAP 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 VWAP of Common Shares.

The following table summarizes information related to the Corporation's deferred share unit plan, restricted share unit plan, and performance share unit plan:

	Deferred Share Units	Restricted Share Units	Preferred Share Units	Total
As at December 31, 2016	352,689	—	—	352,689
Granted	407,762	222,630	303,900	934,292
Prior accrual reversal	(70,347)	—	—	(70,347)
As at December 31, 2017	690,104	222,630	303,900	1,216,634
Granted	400,703	413,100	482,000	1,295,803
Exercised	(141,331)	(85,070)	—	(226,401)
Forfeited	—	(64,160)	(126,000)	(190,160)
As at December 31, 2018	949,476	486,500	659,900	2,095,876
($000s)				
Value of share unit liability as at December 31, 2018	1,448	410	205	2,063
Value of share unit liability as at December 31, 2017	1,797	159	48	2,004

During the year ended December 31, 2018, the Corporation capitalized $0.5 million (2017 - $0.3 million).

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

(a) Market risk

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

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

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

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

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

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

The following is a summary of all commodity risk management contracts in place as at December 31, 2018:

Financial AECO Natural Gas Contracts			
Options traded	**Term**	**Volume (GJ/d)**	**Price (CDN$/GJ)**
AECO Fixed Price Swap	January 2019 - March 2019	10,000	2.32
AECO Fixed Price Swap	January 2019 - March 2019	10,000	1.98
AECO Fixed Price Swap	January 2019 - June 2019	8,000	2.66
AECO Fixed Price Swap	January 2019 - June 2019	10,000	2.62
AECO Call Option Sold	January 2019 - December 2019	10,000	2.80
AECO Call Option Sold	January 2019 - December 2019	15,000	2.93

Financial Westcoast Station 2 Natural Gas Contracts			
Options traded	Term	Volume (GJ/d)	Price (CDN$/GJ)
Westcoast Station 2 Fixed Price Swap	January 2019 - June 2019	12,000	2.35
Westcoast Station 2 Fixed Price Swap	January 2019 - September 2019	10,000	2.30
Westcoast Station 2 Fixed Price Swap	January 2019 - September 2019	5,000	2.34
Westcoast Station 2 Fixed Price Swap	January 2019 - December 2019	10,000	2.45

Financial NYMEX Natural Gas Contracts			
Options traded	Term	Volume (Mmbtu/d)	Price (US$/Mmbtu)
USD Nymex Fixed Price	January 2019 - March 2019	5,000	4.39
USD Nymex Fixed Price	January 2019 - December 2019	5,000	3.22
USD Nymex Fixed Price	April 2019 - October 2019	5,000	2.85

Financial Dawn Natural Gas Contracts			
Options traded	Term	Volume (GJ/d)	Price (CDN$/GJ)
Dawn Fixed Price Swap	January 2019 - March 2019	10,000	3.47
Dawn Fixed Price Swap	January 2019 - March 2019	10,000	3.50
Dawn Fixed Price Swap	January 2019 - June 2019	5,000	3.14

Financial Dawn Natural Gas Contracts			
Options traded	Term	Volume (MMBtu/d)	Price (US$/MMBtu)
USD Dawn Fixed Price Swap	January 2019 - March 2019	5,000	3.29
USD Dawn Fixed Price Swap	January 2019 - March 2019	5,000	4.40
USD Dawn Fixed Price Swap	January 2019 - December 2019	10,000	2.53
USD Dawn Fixed Price Swap	April 2019 - December 2019	5,000	2.52

Financial Sumas Natural Gas Contracts			
Options traded	Term	Volume (MMBtu/d)	Price (US$/MMBtu)
USD Sumas Fixed Price Swap	January 2019 - March 2019	10,000	3.17
USD Sumas Fixed Price Swap	January 2019 - March 2019	5,000	5.00

Financial AECO Station 2 Differential Contracts			
Options traded	Term	Volume (GJ/d)	Price (AECO 7A basis CDN$/GJ)
AECO-Station 2 Basis Swap	January 2019 - December 2019	10,000	(0.25)
AECO-Station 2 Basis Swap	January 2019 - October 2020	10,000	(0.32)
AECO-Station 2 Basis Swap	January 2019 - October 2020	20,000	(0.32)
AECO-Station 2 Basis Swap	January 2019 - August 2021	20,000	(0.29)
AECO-Station 2 Basis Swap	April 2019 - October 2019	10,000	(0.24)
AECO-Station 2 Basis Swap	November 2019 - October 2020	10,000	(0.33)

Financial NYMEX Basis Differential Contracts			
Options traded	**Term**	**Volume (MMBtu/d)**	**Price (NYMEX basis US$/MMBtu)**
NYMEX-Sumas Basis Swap	January 2019 - December 2019	5,000	(0.60)
NYMEX-AECO Basis Swap	April 2019 - October 2019	10,000	(1.45)
NYMEX-AECO Basis Swap	April 2019 - September 2021	10,000	(1.14)
NYMEX-AECO Basis Swap	April 2020 - October 2020	10,000	(1.45)
NYMEX-AECO Basis Swap	October 2021 - March 2023	5,000	(1.05)
NYMEX-AECO Basis Swap	October 2021 - March 2023	5,000	(1.05)
NYMEX-Dawn Basis Swap	January 2019 - March 2019	5,000	0.26
NYMEX-Dawn Basis Swap	April 2019 - December 2019	10,000	(0.20)
NYMEX-Dawn Basis Swap	January 2020 - December 2020	5,000	(0.06)
NYMEX-Dawn Basis Swap	January 2020 - December 2020	5,000	(0.07)

Financial WTI Crude Oil Contracts			
Options traded	**Term**	**Volume (Bbl/d)**	**Price (CDN$/Bbl)**
WTI Fixed Price Swap	January 2019 - June 2019	500	80.30
WTI Fixed Price Swap	January 2019 - December 2019	500	70.20
WTI Fixed Price Swap	January 2019 - December 2019	500	70.20
WTI Fixed Price Swap	January 2019 - December 2019	250	72.30
WTI Fixed Price Swap	January 2019 - December 2019	250	74.00
WTI Fixed Price Swap	January 2019 - December 2019	250	74.80
WTI Fixed Price Swap	January 2019 - December 2019	500	77.00
WTI Fixed Price Swap	July 2019 - December 2019	500	80.75
WTI Fixed Price Swap	January 2020 - December 2020	500	75.80

Financial Propane Contracts			
Options traded	**Term**	**Volume (GAL/d)**	**Price (US$/GAL)**
Conway Fixed Price Swap	January 2019 - March 2019	10,500	0.85
Conway Fixed Price Swap	January 2019 - December 2019	10,500	0.67

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 financial statements.

The Corporation has the following foreign exchange risk management contracts in place as at December 31, 2018:

Financial Foreign Exchange Contracts			
Reference Currency	**Term**	**Notional Amount (USD 000s/month)**	**Strike Rate**
USD	January 2019 - March 2019	2,000	1.35
USD	January 2019 - December 2019	1,000	1.33

The Corporation periodically enters into USD cross currency swap basis transactions related to LIBOR borrowings, which results in a reduction to interest expense paid on borrowings on the credit facility. As at December 31, 2018 the following cross currency basis swap was outstanding:

Contract Quantity	Type of Contract	Term / Expiry	Contract Price
$147 Million	Cross currency basis swap	January 28, 2019	$1.335 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, 2018, 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, 2018 would result in a $1.9 million change in income and comprehensive income for the year ended December 31, 2018. 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, 2018 would result in a $0.9 million change in income and comprehensive income for the year ended December 31, 2018.

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. Approximately 27% of the Corporation's 2018 petroleum and natural gas sales were denominated in USD. A 1% change in the CAD/USD exchange rate, on the Corporation's USD denominated sales, would result in a $0.7 million change in income and comprehensive income for the year ended December 31, 2018. The remaining 73% of the Corporation's 2018 petroleum and natural gas sales were denominated in Canadian dollars; Canadian commodity prices are influenced by fluctuations in the Canadian to USD exchange rate which are not captured in the foreign currency exchange income sensitivity above.

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, 2018, it is estimated that a 1.0% change in interest rates would result in a change to income and comprehensive income of $1.3 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 statement of financial position, respectively.

($000s)	**December 31, 2018**	**December 31, 2017**
Gross in-the-money risk management contracts	48,325	92,200
Gross out-of-the-money risk management contracts	(9,124)	(5,479)
Net fair value of risk management contracts	39,201	86,721

($000s)	**December 31, 2018**	**December 31, 2017**
Current assets	35,215	65,016
Non-current assets	7,350	22,552
Current liabilities	(530)	(553)
Non-current liabilities	(2,834)	(294)
Net fair value of risk management contracts	39,201	86,721

(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, 2018 and 2017 is as follows:

($000s)	**December 31, 2018**	**December 31, 2017**
Accounts receivable	55,532	39,115
Fair value of risk management contracts	42,565	87,568
Total	98,097	126,683

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.

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. The lifetime ECL allowances related to the Corporation's accounts receivable were nominal as at and for the years ended December 31, 2018 and 2017.

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

($000s)	**December 31, 2018**	**December 31, 2017**
Petroleum and natural gas revenue	50,779	28,946
Financial risk management contracts	4,390	7,805
Joint interest	281	282
Other	82	2,082
Total	55,532	39,115

The Corporation has three primary purchasers of natural gas and NGLs; these purchasers accounted for $49.9 million of accounts receivable at December 31, 2018, compared to $23.8 million from one purchaser as at December 31, 2017. As at December 31, 2018 and 2017, the Corporation's accounts receivable is aged as follows:

($000s)	**December 31, 2018**	**December 31, 2017**
Less than 30 days	55,364	38,227
From 31 - 90 days	106	771
More than 90 days	62	117
Total	55,532	39,115

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 it 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 $400 million in syndicated credit facilities at December 31, 2018 compared to $450 million at December 31, 2017, 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. The Corporation is not 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, 2018 and December 31, 2017, 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, 2018, 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 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, foreign exchange contracts, senior notes and convertible debentures 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 VWAP 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 NGLs. 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 statement of financial position. Over the course of the 20-year lease, there is a capital fee, which includes the finance expense and amortization of the obligation.

The cost of the facilities and related pipeline infrastructure capitalized was approximately $490 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	53,785	285,500	574,624	913,909
Transportation	9,902	53,258	169,281	232,441
Total	63,687	338,758	743,905	1,146,350
Principal	5,680	66,654	417,464	489,798

19. COMMITMENTS

($000s)	2019	2020	2021	2022	2023	Thereafter	Total
Transportation and processing	92,362	118,236	136,617	135,919	114,915	1,450,013	2,048,062
Interest on senior notes	12,750	12,750	12,750	9,563	—	—	47,813
Interest on convertible debentures	3,250	3,250	2,438	—	—	—	8,938
Office leases and other	1,582	1,579	1,563	1,347	—	—	6,071
Total commitments	109,944	135,815	153,368	146,829	114,915	1,450,013	2,110,884

Transportation commitments include contracts to transport natural gas and NGLs through third-party owned pipeline systems in North America. Processing commitments include contracts to process natural gas and NGLs 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 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. REVENUE

Painted Pony produces natural gas and NGLs from its assets in the Western Canadian Sedimentary Basin, specifically in Northeastern British Columbia. The Corporation sells its production pursuant to fixed and variable price physical delivery contracts. Under the contracts, the Corporation is required to deliver a fixed or variable volume of natural gas or NGLs to the contract counterparty. The transaction price for variable priced contracts is based on a benchmark commodity price, adjusted for quality, location and other factors, whereby each component of the pricing formula can be fixed or variable depending on the contract terms.

Production revenue is recognized when the Corporation gives up control of a unit of production at the delivery point in accordance with the terms of the contract. Revenue recognized is based on the agreed transaction price and the volumes delivered. Any variability in the transaction price relates specifically to the Corporation's efforts to transfer production, and is therefore recognized in the period in which the variability relates. The Corporation does not have any factors considered to be constraining in the recognition of revenue for variable pricing factors.

Contract terms have lengths varying from one to 14 years, with delivery taking place throughout the term of the contracts. Production revenues are normally collected on the 25th day of the month following production.

The Corporation's revenue was generated entirely in British Columbia, and the production was sold in British Columbia, Alberta, Ontario, and Washington, primarily to three major purchasers. The three purchasers individually accounted for more than 10% of, and together represented 97% of sales for the year ended December 31, 2018 (2017 - 100%).

These three purchasers individually represented more than 10% of, and together represented 89% of accounts receivable at December 31, 2018 (December 31, 2017 - 74%). The following table represents the Corporation's petroleum and natural gas sales disaggregated by product:

($000s)	**Years ended December 31,**	
	2018	**2017**
Natural gas	293,145	183,030
Natural gas liquids	111,227	66,156
Total	404,372	249,186

Under certain marketing arrangements, the Corporation transfers title of its natural gas production to a third party marketing company who subsequently redelivers the natural gas production by utilizing the Corporation's transportation pipeline capacity. Under the terms of these contracts, the Corporation has assigned a portion of their pipeline capacity to the marketing company for the specified contract term. The marketing revenue stream related to these assigned transportation contracts represents 23% (2017 - 0%) of total natural gas revenue for the year ended December 31, 2018.

At times, the Corporation purchases commodity products from third parties to fulfill sales commitments and subsequently sells these products to its purchasers. During the year ended December 31, 2018, the Corporation purchased commodity products for $1.7 million (2017 - $0.5 million), and subsequently sold them for $2.5 million (2017 - $0.4 million).

21. 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.

($000s)	**December 31, 2018**	**December 31, 2017**
Short-term compensation	5,829	5,454
Share-based compensation	2,505	379
Total	8,334	5,833

(b) Presentation in Statements of Cash Flows

Changes in non-cash working capital are comprised of:

($000s)	December 31, 2018	December 31, 2017
Source/(use) of cash:		
Accounts receivable	(16,417)	(9,547)
Prepaid expenses and deposits	(565)	(555)
Accounts payable and accrued liabilities	(15,118)	12,028
Non-cash working capital on business combination	—	(2,981)
Share unit liability	59	(1,397)
	(32,041)	(2,452)
Operating activities	(5,604)	(2,287)
Investing activities	(3,924)	(4,195)
Financing activities	(22,513)	4,030
	(32,041)	(2,452)

Corporate Information

BOARD OF DIRECTORS

Glenn R. Carley
Chairman of the Board
Independent Director
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

OFFICERS

Patrick R. Ward
President and Chief Executive Officer

Stuart W. Jaggard
Chief Financial Officer

Richard W. Kessy
Chief Operating Officer

Edwin (Ted) S. 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

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