Persta Resources Inc.

(incorporated under the laws of Alberta with limited liability)

(Stock Code: 3395)

ANNOUNCEMENT OF AUDITED RESULTS FOR THE YEAR ENDED DECEMBER 31, 2018

This announcement is issued pursuant to Rule 13.09 of the Rules Governing the Listing of the Securities on The Stock Exchange of Hong Kong Limited and under Part XIVA of the Securities and Futures Ordinance (Cap. 571 of the Laws of Hong Kong).

The Board of Persta Resources Inc. is pleased to announce its audited financial results for the year ended December 31, 2018.

The board (the "**Board**") of directors (the "**Directors**") of Persta Resources Inc. (the "**Company**") is pleased to announce the audited financial results of the Company for the year ended December 31, 2018 (the "**Year End Results**") and the business updates. This announcement is issued by the Company pursuant to Rule 13.09 of the Rules Governing the Listing of the Securities on The Stock Exchange of Hong Kong Limited and under Part XIVA of the Securities and Futures Ordinance (Cap. 571 of the Laws of Hong Kong). The Board and its audit and risk committee have reviewed the Year End Results. Please see the attached announcement for further information.

By Order of the Board
Persta Resources Inc.
Le Bo
Chairman

Calgary, March 29, 2019
Hong Kong, March 29, 2019

As at the date of this announcement, the executive Director is Mr. Le Bo; the non-executive Director is Mr. Yuan Jing; and the independent non-executive Directors are Mr. Richard Dale Orman, Mr. Bryan Daniel Pinney and Mr. Peter David Robertson.

Persta Resources Inc.
Announcement of Results
for the Year ended December 31, 2018

Net loss narrowed by 37.5% to C$7.28 million
(Year ended December 31, 2017: C$11.64 million)

CALGARY/HONG KONG — Persta Resources Inc. (the "**Company**" or "**Persta**") (Stock code: 3395) today announced its annual financial results for the year ended December 31, 2018. The Company's annual financial statements, notes to the annual financial statements and management's discussion and analysis have been filed on SEDAR (www.sedar.com) and with The Stock Exchange of Hong Kong Limited (www.hkexnews.hk) and are available on the Company's website (www.persta.ca). All figures used in this release are in Canadian dollars ("**C$**") unless otherwise stated.

MESSAGE TO SHAREHOLDERS

For the year ended December 31, 2018, the Company's net loss narrowed by 37.5% to C$7.28 million compared to C$11.64 million for the year ended December 31, 2017. The smaller net loss in 2018 was attributable to reduced finance and transaction costs incurred in 2017 for the Company's initial public offering ("**IPO**").

For the year ended December 31, 2018, the Company's total production volume decreased by 236,490 barrels of oil equivalent ("**Boe**") to 806,081 Boe compared to 1,042,571 Boe for the same period in 2017.

The Company's natural gas production slightly decreased by 2% while natural gas revenues decreased by 33% in 2018. The natural gas market remained weakened in 2018, and in response the Company has strategically decreased production volumes to retain its reserves/resources for future recovery and long term growth. To fulfil its committed forward contracts for natural gas, the Company has taken advantage of the low price environment and purchased from the market, saving operating, transport and processing costs and arbitraging the price difference. Natural gas liquids ("**NGLs**") and condensate are the by-products from the production of natural gas, and their production volumes decreased commensurate with lower gas production in 2018 compared to 2017. The Company's crude oil production increased 7% while crude oil revenues increased 22% in 2018, as the Company increased production to exploit the higher oil price experienced this year.

FINANCIAL HIGHLIGHTS

(Expressed in Canadian dollars)

	Three months ended December 31, 2018 *C$*	Three months ended December 31, 2017 *C$*	Increase/ (Decrease) %	Year ended December 31, 2018 *C$*	Year ended December 31, 2017 *C$*	Increase/ (Decrease) %
Revenue from crude oil and natural gas sales	**3,286,345**	4,771,967	(31.1)	**15,364,294**	21,443,207	(28.3)
Trading revenue from natural gas sales	**256,444**	561,743	(54.3)	**1,070,898**	1,240,648	(13.7)
Operating netback *(Note 1)*	**1,613,505**	3,208,695	(49.7)	**9,508,184**	13,644,355	(30.3)
Adjusted EBITDA *(Note 2)*	**487,667**	1,504,219	(67.6)	**4,736,353**	7,543,448	(37.2)
Loss and total comprehensive loss for the period attributable to owners of the Company	**(5,335,197)**	(2,858,561)	86.6	**(7,279,461)**	(11,636,792)	(37.5)
Loss per share	**(0.02)**	(0.01)	100	**(0.03)**	(0.04)	(25)
Total production volume (Boe)	**180,018**	208,840	(13.8)	**806,081**	1,042,571	(22.7)
Daily average production volume (Boe/d)	**1,957**	2,270	(13.8)	**2,208**	2,856	(22.7)

Notes:

(1) Operating netback is defined as revenue less royalties, trading cost and operating costs. Operating netback is a non-IFRS financial measure. See "Non-IFRS Financial Measures" of this announcement for further information.

(2) Adjusted EBITDA is defined as earnings before deduction of finance expenses, income taxes, depletion and depreciation, impairment losses and write-offs, transaction costs and share-based compensation. Adjusted EBITDA is a non-IFRS financial measure. See "Non-IFRS Financial Measures" of this announcement for further information.

ASSETS AND LIABILITIES

(Expressed in Canadian dollars)

	As at December 31, 2018 *C$*	As at December 31, 2017 *C$*
Total assets	**103,581,802**	111,091,364
Total liabilities	**(35,521,138)**	(36,398,273)
Total net assets	**68,060,664**	74,693,091
Share capital	**204,366,683**	204,366,683
Warrants	**647,034**	—
Accumulated deficit	**(136,953,053)**	(129,673,592)
Total equity	**68,060,664**	74,693,091

FUTURE PROSPECTS

The Company acquired Petroleum and Natural Gas Licenses for Basing, Voyager and Kaydee in the Alberta Foothills, Dawson near Peace River and Progress-Montney in northern Alberta between 2006 and 2018. In 2018, approximately 90% of the Company's revenue was generated from the Basing area. Voyager is geologically analogous and located approximately 30 kilometers ("**km**") from Basing.

The Company is evaluating development alternatives for Voyager, where it has four gas wells drilled and completed, awaiting tie-in and connection to our Basing network through a new pipeline. Subject to capital availability, this development is currently forecast to be completed in the first quarter of 2020. Voyager production is expected to increase the Company's revenue and cashflow which is intended to be used to fund new drilling.

The Company plans to develop its natural gas assets in Basing, Voyager and Progress-Montney through new drilling as there is sufficient capital, and construct facilities to support future increases in production which would lower unit production costs in the long run.

On March 25, 2019, the Company announced it entered into a subscription agreement with a subscriber to conditionally issue 23.6 million common shares at a price of HK$1.50 per share for gross proceeds of HK$35.4 million (approximately C$6 million) (the "**Subscription**"). The subscriber is a company incorporated under the laws of the British Virgin Islands, and is principally engaged in the investment of clean energy worldwide.

The Company intends to apply the net proceeds from the Subscription for the expansion of its existing business, the development of new business, and general working capital. The Subscription is scheduled to close on or before May 14, 2019. Refer to the Company's announcement dated March 25, 2019 and the Company's clarification announcement dated March 25, 2019 for additional information regarding the Subscription.

By Order of the Board
Persta Resources Inc.
Le Bo
Chairman

ABOUT PERSTA RESOURCES INC.

The Company is a Calgary-based oil and gas exploration and development company focusing on liquids-rich gas and light crude oil in Western Canada with four core areas of operations: Alberta Foothills liquids-rich natural gas; Deep Basin Devonian natural gas; Peace River light oil and Progress-Montney liquids-rich natural gas.

For further enquiries, please contact:

Le Bo
Chairman
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FORWARD LOOKING INFORMATION

Certain statements in this announcement are forward-looking statements that are, by their nature, subject to significant risks and uncertainties and the Company hereby cautions investors about important factors that could cause the Company's actual results to differ materially from those projected in a forward-looking statement. Any statements that express, or involve discussions as to expectations, beliefs, plans, objectives, assumptions or future events or performance (often, but not always, through the use of words or phrases such as "will", "expect", "anticipate", "estimate", "believe", "going forward", "ought to", "may", "seek", "should", "intend", "plan", "projection", "could", "vision", "goals", "objective", "target", "schedules" and "outlook") are not historical facts, are forward-looking and may involve estimates and assumptions and are subject to risks (including the risk factors detailed in the MD&A), uncertainties and other factors some of which are beyond the Company's control and which are difficult to predict. Accordingly, these factors could cause actual results or outcomes to differ materially from those expressed in the forward-looking statements.

Since actual results or outcomes could differ materially from those expressed in any forward-looking statements, the Company strongly cautions investors against placing undue reliance on any such forward-looking statements. Statements relating to "reserves" or "resources" are deemed to be forward-looking statements, as they involve the implied assessment, based on estimates and assumptions that the resources and reserves described can be profitably produced in the future. Further, any forward-looking statement speaks only as of the date on which such statement is made and the Company undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances after the date on which such statement is made or to reflect the occurrence of unanticipated events.

All forward-looking statements in this announcement are expressly qualified by reference to this cautionary statement.

Persta Resources Inc.

ANNUAL FINANCIAL STATEMENTS

For the years ended December 31, 2018 and 2017

STATEMENT OF FINANCIAL POSITION

As at December 31, 2018

(Expressed in Canadian dollars)

	Note	As at December 31, 2018 C$	As at December 31, 2017 C$
ASSETS			
Current assets			
Cash and cash equivalents	7	**2,605,709**	2,363,183
Investments	8	**—**	3,333,500
Accounts receivable	9	**1,196,062**	1,813,992
Prepaid expenses and deposits		**796,744**	870,286
		4,598,515	8,380,961
Non-current assets			
Exploration and evaluation assets	10	**43,484,822**	40,065,106
Property, plant and equipment	11	**55,498,465**	62,645,297
		98,983,287	102,710,403
TOTAL ASSETS		**103,581,802**	111,091,364
LIABILITIES AND EQUITY			
Current liabilities			
Accounts payable and accrued liabilities	12	**6,038,478**	8,230,602
Current portion of long term debt	13	**—**	22,197,243
Decommissioning liabilities	14	**205,836**	205,429
		6,244,314	30,633,274
Non-current liabilities			
Other liabilities	15	**4,225,734**	3,798,280
Long term debt	13	**23,063,945**	—
Decommissioning liabilities	14	**1,987,145**	1,966,719
		29,276,824	5,764,999
TOTAL LIABILITIES		**35,521,138**	36,398,273

	Note	As at December 31, 2018 C$	As at December 31, 2017 C$
SHAREHOLDERS' EQUITY			
Share capital	*16*	**204,366,683**	204,366,683
Warrants	*16*	**647,034**	—
Accumulated deficit		**(136,953,053)**	(129,673,592)
TOTAL EQUITY		**68,060,664**	74,693,091
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY		**103,581,802**	111,091,364
SUBSEQUENT EVENTS	*30*		

The accompanying notes form part of these annual financial statements.

STATEMENT OF LOSS AND OTHER COMPREHENSIVE LOSS

For the year ended December 31, 2018

(Expressed in Canadian dollars)

		Year ended December 31,	
		2018	2017
	Note	***C$***	*C$*
Production revenue from crude oil and natural gas sales	*17*	**15,364,294**	21,443,207
Royalties		**(1,163,804)**	(2,793,481)
		14,200,490	18,649,726
Trading revenue from natural gas sales	*17*	**1,070,898**	1,240,648
Trading cost from natural gas purchases		**(409,440)**	(499,859)
		661,458	740,789
Net revenue		**14,861,948**	19,390,515
Operating costs		**(5,353,764)**	(5,746,160)
General and administrative costs ("G&A cost")		**(5,584,534)**	(6,149,973)
Depletion and depreciation		**(5,368,825)**	(6,179,377)
Direct write-off of exploration and evaluation assets	*10*	**(1,790,883)**	(900,685)
Impairment losses of property, plant and equipment	*18*	**(1,962,280)**	(2,212,697)
Loss from operations		**(5,198,338)**	(1,798,377)
Other income	*29*	**812,703**	49,066
Transaction costs		**—**	(3,003,350)
Finance expenses	*22*	**(2,893,826)**	(6,884,131)
Loss before income taxes		**(7,279,461)**	(11,636,792)
Income taxes	*23*	**—**	—
Loss and comprehensive loss for the year attributable to owners of the Company		**(7,279,461)**	(11,636,792)
Loss per share			
Basic and diluted	*24*	**(0.03)**	(0.04)

The accompanying notes form part of these annual financial statements.

STATEMENT OF CHANGES IN SHAREHOLDERS' EQUITY

For the year ended December 31, 2018

(Expressed in Canadian dollars)

	Note	**Share capital**	**Warrants**	**Accumulated deficit**	**Total equity**
		C$	*C$*	*C$*	*C$*
Balance as at January 1, 2017		169,247,367	—	(118,036,800)	51,210,567
New shares issued	*16*	38,131,133	—	—	38,131,133
Share issue costs	*16*	(3,011,817)	—	—	(3,011,817)
Loss for the year		—	—	(11,636,792)	(11,636,792)
Balance as at December 31, 2017		204,366,683	—	(129,673,592)	74,693,091
Balance as at January 1, 2018		**204,366,683**	**—**	**(129,673,592)**	**74,693,091**
Warrants	*16*	**—**	**647,034**	**—**	**647,034**
Loss for the year		**—**	**—**	**(7,279,461)**	**(7,279,461)**
Balance as at December 31, 2018		**204,366,683**	**647,034**	**(136,953,053)**	**68,060,664**

The accompanying notes form part of these annual financial statements.

STATEMENT OF CASH FLOWS

For the year ended December 31, 2018

(Expressed in Canadian dollars)

		Year ended December 31,	
		2018	2017
	Note	***C$***	*C$*
Operating activities			
Loss for the year		**(7,279,461)**	(11,636,792)
Adjustments for:			
Depletion and depreciation		**5,368,825**	6,179,377
Non-cash finance expenses		**209,660**	598,083
Unrealized foreign exchange (gain)/loss		**(12,624)**	77,709
Direct write-offs on exploration and evaluation assets		**1,790,883**	900,685
Impairment losses of property, plant and equipment		**1,962,280**	2,212,697
Funds from operations		**2,039,563**	(1,668,241)
Changes in non-cash working capital	*7*	**1,474,482**	(381,231)
Net cash generated from/(used in) operating activities		**3,514,045**	(2,049,472)
Investing activities			
Expenditures on property, plant and equipment		**(79,683)**	(2,099,064)
Expenditures on exploration and evaluation assets		**(7,882,275)**	(16,764,568)
Investments	*8*	**3,333,500**	(3,333,500)
Net cash used in investing activities		**(4,628,458)**	(22,197,132)

		Year ended December 31,	
		2018	2017
	Note	***C$***	*C$*
Financing activities			
Proceeds from share issuance, net of issue cost		**—**	36,146,427
Proceeds from debt, net	*13*	**18,730,281**	—
Proceeds from warrants, net	*16*	**647,034**	—
Proceeds from bank loan		**—**	2,791,804
Repayment of bank loan	*13*	**(18,033,000)**	(16,216,889)
Net cash generated from financing activities		**1,344,315**	22,721,342
Effect of exchange rate fluctuation on cash and cash equivalents		**12,624**	(77,709)
Increase/(decrease) in cash and cash equivalents		**242,526**	(1,602,971)
Cash and cash equivalents at the beginning of the year		**2,363,183**	3,966,154
Cash and cash equivalents at the end of the year		**2,605,709**	2,363,183
Supplementary information:			
Interest paid		**2,358,125**	5,813,111

The accompanying notes form part of these annual financial statements.

NOTES TO THE ANNUAL FINANCIAL STATEMENTS

For the year ended December 31, 2018

(Expressed in Canadian dollars unless otherwise indicated)

1 CORPORATE INFORMATION

Persta Resources Inc. (the "**Company**" or "**Persta**") was incorporated in Calgary, Alberta, Canada under the Business Corporations Act (Alberta) in 2005. Persta is an exploration and development company pursuing petroleum and natural gas production in Alberta, Canada. The Company's registered office is located at 15th Floor, Bankers Court, 850-2nd Street SW, Calgary, Alberta T2P 0R8, Canada, and its head office is located at 3600, 888-3rd Street SW, Calgary, Alberta T2P 5C5, Canada.

Pursuant to an initial public offering on March 10, 2017, the Company's shares were listed on The Stock Exchange of Hong Kong Limited (the "**Stock Exchange**") and traded under the stock code of "3395". The Company has been a reporting issuer under the Securities Act (Alberta) since October 2, 2018.

2 BASIS OF PREPARATION

(a) Statement of compliance

The Financial Statements set out in this report have been prepared in accordance with all applicable International Financial Reporting Standards ("**IFRSs**"), as issued by the International Accounting Standards Board ("**IASB**").

The IASB has issued a number of new and revised IFRSs. For the purpose of preparing these Financial Statements, the Company has adopted all applicable new and revised IFRSs to the year ended December 31, 2018, except for any new standards or interpretations that are not yet effective for the year ended December 31, 2018. The revised and new accounting standards and interpretations issued but not yet effective are set out in Note 5.

The Financial Statements also comply with the applicable disclosure provisions of the Rules Governing the Listing of Securities on the Stock Exchange.

The accounting policies set out below have been applied consistently in all years presented in the Financial Statements.

(b) Basis of measurement

The Financial Statements are prepared on the historical cost basis except for derivative financial instruments, which are measured at fair value. The methods used to measure fair value are discussed in Note 6.

(c) Functional and presentation currency

The Financial Statements are presented in Canadian dollars ("**C$**"), which is the Company's functional currency.

(d) Use of estimates and judgments

The preparation of Financial Statements in conformity with IFRSs requires management to make judgments, estimates and assumptions that affect the application of policies and reported amounts of assets, liabilities, income and expenses. The estimates and associated assumptions are based on historical experience and various other factors that are believed to be reasonable under the circumstances, the results of which form the basis of making the judgments about carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates.

The estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which the estimate is revised if the revision affects only that period, or in the period of the revision and future periods if the revision affects both current and future periods.

Judgments made by management in the application of IFRSs that have significant effect on the Financial Statements and major sources of estimation uncertainty are discussed in Note 4.

The Financial Statements have been prepared on a going concern basis. The going concern basis of presentation assumes that the Company will continue in operation for the foreseeable future and will be able to realize its assets and discharge its liabilities and commitments in the normal course of business.

Significant doubt about the Company's ability to continue as a going concern would exist when relevant conditions and events, considered in the aggregate, indicate that it is probable that the Company will not be able to meet its obligations as they become due for a period at least, but not limited to twelve months from the balance sheet date. When the Company identifies conditions or events that raise potential for significant doubt about its ability to continue as a going concern, the Company considers whether its plans that are intended to mitigate those relevant conditions or events will alleviate the potential significant doubt. The mitigating effect of management's plans are considered to the extent that; (i) it is probable that the plans will be effectively implemented and, if so, (ii) it is probable that the plans will mitigate the conditions or events that raise significant doubt about the Company's ability to continue as a going concern.

After considering its plans to mitigate the going concern risk, management has concluded that there are no material uncertainties related to events or conditions that may cast significant doubt upon the Company's ability to continue as a going concern. Furthermore, the estimates made by management in reaching this conclusion are based on information available as of the date these Financial Statements were authorized for issuance.

3 SIGNIFICANT ACCOUNTING POLICIES

The accounting policies have been applied consistently in all years presented in these Financial Statements.

(a) Joint arrangements

Joint arrangements are contractual arrangements classified as either joint operations or joint ventures. Joint operations exist when the Company has rights to the assets and obligations for the liabilities, relating to an arrangement. As such, the Financial Statements only include the Company's share of its assets, liabilities and transactions associated with its joint operations.

(b) Revenue recognition

Revenue is measured at the fair value of the consideration received or receivable. Provided it is probable that the economic benefits will flow to the Company and the revenue and costs, if applicable, can be measured reliably, revenue is recognized in profit or loss as follows:

Revenue from the sale of crude oil and natural gas is recognized when title to the products passes to the purchasers based on volumes delivered at contracted delivery points and prices and are recorded gross of transportation charges incurred by the Company. The costs associated with the delivery, including transportation and production-based royalty expenses, are recognized in the same period in which the related revenue is earned and recorded.

(c) Finance income and expenses

Finance income is comprised of interest income. Finance expenses are recognized as the interest accrues, using the effective interest method. The effective interest method uses the rate that discounts estimated future cash receipts through the expected life of the financial instrument to the net carrying amount of the financial asset.

Finance expense comprises interest expense and other fees on the bank loan and various other loans, amortization of debt issue costs, accretion of the discount on decommissioning liabilities and foreign exchange gains and losses on foreign currency transactions.

(d) Financial instruments

The Company recognizes financial assets and financial liabilities on the statements of financial position when the Company becomes a party to the contract. Financial assets are derecognized when the rights to receive cash flows from the assets have expired or when the Company has transferred substantially all risks and rewards of ownership. Financial liabilities are derecognized from the consolidated financial statements when the liability is extinguished either through settlement of or release from the obligation of the underlying liability.

Financial assets, financial liabilities and derivatives are measured at fair value on initial recognition. Measurement in subsequent periods depends on the financial instrument's classification, as described below.

- ***Amortized cost***

  A financial asset is measured at amortized cost if the objective of the business model is to hold the financial asset for the collection of the cash flows; and all contractual cash flows represent only principal and interest on that principal. All financial liabilities are measured at amortized cost using the effective interest method except for liabilities incurred for the purposes of selling or repurchasing in the short-term liabilities, if they are held-for trading and those that meet the definition of a derivative.

- ***Fair value through other comprehensive income ("FVTOCI")***

  A financial asset shall be measured at FVTOCI if the financial asset is held within a business model whose objective is achieved by both collecting contractual cash flows and selling financial assets; and the contractual terms of the financial asset give rise on specified dates to cash flows that are Solely Payment of Principal and Interest ("SPPI") on the principal amount outstanding.

- ***Fair value through profit or loss ("FVTPL")***

  All financial assets that do not meet the definition of being measured at amortized cost or FVTOCI are measured at FVTPL, this includes all derivative financial assets. A financial liability is classified as measured at FVTPL if it is held-for-trading, a derivative, or designated as FVTPL on initial recognition. For financial assets and liabilities, the Company may make an irrevocable election to designate an asset at FVTPL. If the election is made it is irrevocable, meaning that asset, liability, or group of financial instruments must be recorded at FVTPL until that asset, liability or group of financial instruments are derecognized.

  Financial assets and liabilities are offset and the net amount is reported on the balance sheet when there is a legally enforceable right to offset the recognized amounts, and there is an intention to settle on a net basis, or realize the asset and settle the liability simultaneously.

  Commodity contracts that are entered into and continue to be held for the purpose of the receipt or delivery of commodity in accordance with the Company's expected purchase, sale or usage fall within the normal purchase or sale exemption and are accounted for as executory contracts.

  Financial assets are assessed with an expected credit loss model. The new impairment model applies to financial assets measured at amortized cost, a lease receivable, a contract asset or a loan commitment and a financial guarantee contract.

(e) Exploration and evaluation assets

Exploration and evaluation ("**E&E**") assets include costs capitalized by the Company in connection with the exploration for and evaluation of mineral resources before the technical feasibility and commercial viability of extracting a mineral resource are demonstrable. E&E expenditures, including the costs of acquiring licences and directly attributable general and administrative costs ("**G&A**"), geological and geophysical costs, other direct costs of exploration (drilling, trenching, sampling and evaluating the technical feasibility and commercial viability of extraction) and appraisal are accumulated and capitalized as E&E assets. Costs incurred before the Company has obtained the legal rights to explore an area are expensed.

E&E assets are initially capitalized as intangible assets and are not amortized. E&E assets are assessed for impairment when facts and circumstances indicate that the carrying amount may exceed the recoverable amount. An impairment loss is recognized in profit or loss and separately disclosed.

Once the technical feasibility and commercial viability is determined, E&E assets attributable to that area are assessed for impairment with any impairment loss recognized in profit or loss. The remaining carrying value of the relevant E&E assets is then reclassified as development and production assets within property, plant and equipment. Technical feasibility and commercial viability is generally considered to be determined when proved plus probable reserves are determined to exist and commercial production of oil and gas has commenced on the licence or field.

For divestitures of E&E assets, a gain or loss is recognized in profit or loss for the difference between the net disposal proceeds and the carrying amount of the asset. Exchanges of properties are measured at fair value, unless the transaction lacks commercial substance or fair value cannot be reliably measured. Where the exchange is measured at fair value, a gain or loss is recognized in profit or loss.

(f) Property, plant and equipment

Property, plant and equipment ("**PP&E**") of the Company consists of development and production assets and office equipment.

Development and production assets

Development and production assets are carried at cost less accumulated depletion, depreciation, amortization and impairment losses. The cost of a development and production asset includes the initial purchase price and directly attributable expenditures to develop, construct and complete an asset. These costs include property acquisitions, development drilling, completion, gathering and infrastructure, asset retirement costs and transfers from E&E assets. Any costs directly attributable to bringing the asset to the location and condition necessary to operate as intended by management, and which result in an identifiable future benefit, are capitalized, including directly attributable G&A costs. Improvements that increase the capacity or extend the useful lives of related assets are also capitalized.

For divestitures of properties, a gain or loss is recognized in profit or loss for the difference between the net disposal proceeds and the carrying amount of the asset. Exchanges of properties are measured at fair value, unless the transaction lacks commercial substance or fair value cannot be reliably measured. Where the exchange is measured at fair value, a gain or loss is recognized in profit or loss.

(g) Impairments

Development and production assets are assessed for impairment when facts and circumstances suggest that the carrying amount may exceed the recoverable amount. For the purposes of impairment testing, assets are grouped together into the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets (the "**cash-generating unit**" or "**CGU**").

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 ("**FVLCD**").

Value in use is estimated by consideration of the following:

(i) net present value of the proved plus probable reserves using a pre-tax discount rate as determined annually by independent reservoir engineers using future prices and costs; and

(ii) management's estimate of net present value of additional asset development not included in (i) above, using a pre-tax discount rate.

FVLCD is estimated by consideration of the following:

(i) net present value of proved plus probable reserves using a pre-tax discount rate as determined annually by independent reservoir engineers using future prices and costs;

(ii) management's estimate of fair value of undeveloped land;

(iii) a review of the values indicated by the metrics of recent market transactions of similar assets within the oil and gas industry; and

(iv) management's estimate of additional fair value from asset development not included in (i) above.

An impairment loss is recognized if the carrying amount of an asset or a CGU exceeds its estimated recoverable amount. Impairment losses are recognized in profit or loss.

(h) Reversal of impairment

An impairment loss may be reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depreciation and depletion, if no impairment loss had been recognized and circumstances indicate the loss no longer exists or is decreased. An impairment loss reversal is recognized in profit or loss.

(i) Depletion and depreciation

Depletion of development and production assets is provided using the unit-of-production method based on production volumes before royalties in relation to total estimated proved plus probable reserves as determined annually by independent reservoir engineers using future prices and costs. Natural gas reserves and production are converted at the energy equivalent of six thousand cubic feet to one barrel of oil.

Calculations for depletion and depreciation are based on total capitalized costs plus estimated future development costs of proved plus probable reserves.

Depreciation of other assets is provided for on a 20%–100% declining balance basis.

(j) Decommissioning liability

The Company records a liability for the legal obligation associated with the retirement of long-lived tangible assets at the time the liability is incurred, normally when a long-lived tangible asset is purchased or developed, discounted to its present value using a risk-free interest rate. On recognition of the liability there is a corresponding increase in the carrying amount of the related asset known as the decommissioning liability cost, which is depleted on a unit-of-production basis over the life of the estimated proved plus probable reserves, before royalties. The liability amount is increased each reporting period due to the passage of time and the amount of accretion is charged to profit or loss in the period. The decommissioning liability obligation can also increase or decrease due to changes in estimates of timing of cash flow, changes in the original estimated undiscounted cost or changes in the discount rate. The decommissioning liability obligation is re-measured at each reporting date using the risk-free rate in effect at that time and the changes in fair value are capitalized as property, plant and equipment. Actual costs incurred upon settlement of the obligations are charged against the liability.

(k) Share capital

Common shares are classified as equity. Incremental costs directly attributable to the issue of common shares are recognized as a deduction from equity, net of any tax effects.

The Company may incur various costs when issuing or acquiring its own equity instruments. Those costs might include registration and other regulatory fees, amounts paid to legal, accounting and other professional advisers, printing costs and stamp duties. The transaction costs of an equity transaction are accounted for as a deduction from equity (net of any related income tax benefit) to the extent they are incremental costs directly attributable to the equity transaction that otherwise would have been avoided. Costs related to a planned equity offering not completed at the financial statement date are recorded as deferred financing costs until the offering is either completed or abandoned. The costs of an equity transaction that is abandoned are recognized as an expense.

(l) Income taxes

Income tax is recognized in profit or loss except to the extent that it relates to items recognized directly in shareholders' equity, in which case the income tax is recognized directly in shareholders' equity.

Current income taxes payable are based on taxable earnings for the year. Taxable earnings differs from profit before income taxes as reported in the statement of loss and other comprehensive loss because of items of income or expense that are taxable or deductible in different years and items that are never taxable or deductible. The Company's liability for current tax is calculated using tax rates that have been enacted or substantively enacted at the end of the reporting period. Current taxes are recognized in profit or loss.

The Company follows the statement of financial position method of accounting for income taxes. Under this method, deferred income taxes are recorded for the effect of any temporary difference between the accounting and income tax basis of an asset or liability.

Deferred income tax is calculated using the enacted or substantively enacted income tax rates expected to apply when the assets are realized or the liabilities are settled. The effect of a change in the enacted or substantively enacted tax rates is recognized in profit or loss or shareholders' equity depending on the item to which the adjustment relates.

Deferred tax assets are recognized only to the extent that it is probable that future taxable earnings will be available against which the assets can be utilized. Deferred tax assets are reduced to the extent that it is not probable that sufficient tax earnings will be available to allow all or part of the asset to be recovered. Deferred tax assets and liabilities are offset only when a legally enforceable right of offset exists and the deferred tax assets and liabilities arose in the same tax jurisdiction and relate to the same taxable entity.

(m) Related party transactions

(a) A person, or a close member of that person's family, is related to the Company if that person:

  (i) has control or joint control over the Company;

  (ii) has significant influence over the Company; or

  (iii) is a member of the key management personnel of the Company or the Company's parent.

(b) An entity is related to the Company if any of the following conditions applies:

  (i) The entity and the Company are members of the same group (which means that each parent, subsidiary and fellow subsidiary is related to the others).

  (ii) One entity is an associate or joint venture of the other entity (or an associate or joint venture of a member of a group of which the other entity is a member).

  (iii) Both entities are joint ventures of the same third party.

  (iv) One entity is a joint venture of a third entity and the other entity is an associate of the third entity.

  (v) The entity is a post-employment benefit plan for the benefit of employees of either the Company or an entity related to the Company.

(vi) The entity is controlled or jointly-controlled by a person identified in (a).

(vii) A person identified in (a)(i) has significant influence over the entity or is a member of the key management personnel of the entity (or of a parent of the entity).

(viii) The entity, or any member of a group of which it is a part, provides key management personnel services to the Company or to the Company's parent.

Close members of the family of a person are those family members who may be expected to influence, or be influenced by, that person in their dealings with the entity.

A transaction is considered to be a related party transaction when there is a transfer of resources or obligations between related parties.

(n) Cash and cash equivalents

Cash and cash equivalents can consist of cash in bank and short-term highly liquid investments with original maturities of three months or less.

(o) Loss per share

Basic loss per share is calculated by dividing the loss attributable to the shareholders of the Company by the weighted average number of shares outstanding during the period. Diluted loss per share is determined by adjusting the loss attributable to shareholders and the weighted average number of shares outstanding for the effects of all potential shares, which is comprised of any outstanding awards, options or warrants.

4 SIGNIFICANT ACCOUNTING JUDGMENTS, ESTIMATES AND ASSUMPTIONS

The preparation of the Financial Statements requires management to make judgments, estimates and assumptions that affect the application of IFRS accounting policies and 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 Judgments in Applying Accounting Policies

The following are critical judgments that management has made in the process of applying the Company's IFRS accounting policies and that have the most significant effect on the amounts recognized in the Financial Statements:

(i) *Identification of CGUs*

Persta's assets are aggregated into CGUs for the purpose of calculating impairment based on their ability to generate largely independent cash inflows. CGUs have been determined based on similar geological structure, shared infrastructure, geographical proximity, operating structure, commodity type and similar exposures to market risks. By their nature, these assumptions are subject to management's judgment and may impact the carrying value of the Company's assets in future periods.

(ii) *Identification of impairment indicators*

IFRS requires Persta to assess, at each reporting date, whether there are any indicators that its assets may be impaired. Persta is required to consider information from both external sources (such as a negative downturn in commodity prices and 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 and evidence of obsolescence or physical damage to the asset). By their nature, these assumptions are subject to management's judgment and may impact the carrying value of the Company's assets in future periods.

Key sources of estimation uncertainty

The following are the key assumptions concerning the sources of estimation uncertainty for the year ended December 31, 2018 that have a significant risk of causing adjustments to the carrying amounts of assets and liabilities.

(i) *Reserves*

Reported recoverable quantities of proved and probable reserves requires estimation regarding production profile, commodity prices, exchange rates, remediation costs, timing and amount of future development costs, and production, transportation and marketing costs for future cash flows. It also requires interpretation of geological and geophysical models in order to make an assessment of the size, shape, depth and quality of the reservoir, and the anticipated recoveries. The economical, geological and technical factors used to estimate reserves may change from period to period. Changes in reported reserves can impact the carrying values of the Company's petroleum and natural gas properties and equipment, the calculation of depletion and depreciation, the provision for decommissioning obligations, and the recognition of deferred tax assets due to changes in expected future cash flows. The recoverable quantities of reserves and estimated cash flows from Persta's petroleum and natural gas interests are evaluated by independent reserve engineers at least annually.

The Company's petroleum and natural gas reserves represent the estimated quantities of petroleum, natural gas and NGLs which geological, geophysical and engineering data demonstrate with a specified degree of certainty to be economically recoverable in future years from known reservoirs and which are considered commercially producible. Such reserves may be considered commercially producible if management has the intention of developing and producing them and such intention is based upon (i) a reasonable assessment of the future economics of such production; (ii) a reasonable expectation that there is a market for all or substantially all the expected petroleum and natural gas production; and (iii) evidence that the necessary production, transmission and transportation facilities are available or can be made available. Reserves may only be considered proved and probable if supported by either production or conclusive formation tests. Persta's oil and gas reserves are determined in accordance with the standards contained in National Instrument 51–101 Standards of Disclosure for Oil and Gas Activities and the Canadian Oil and Gas Evaluation Handbook.

(ii) *Decommissioning obligations*

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

(iii) *Impairment of non-financial assets*

For the purposes of determining the extent of any impairment or its reversal, estimates must be made regarding future cash flows taking into account key assumptions including future petroleum and natural gas prices, expected forecasted production volumes and anticipated recoverable quantities of proved and probable reserves. These assumptions are subject to change as new information becomes available. Changes in economic conditions can also affect the rate used to discount future cash flow estimates. Changes in the aforementioned assumptions could affect the carrying amount of the Company's assets, and impairment charges and reversals will affect income or loss.

(iv) *Liquidity*

The Company has a working capital deficiency as at December 31, 2018 of C$1.6 million and incurred a loss for the year ended December 31, 2018 of C$7.3 million. As at December 31, 2018 the Company had a C$4.2 million bank loan and C$20 million of subordinated debt ("**SubDebt**") outstanding (refer to Note 13).

The Company was not in compliance with the net debt to run rate EBITDA covenant of the SubDebt agreement as at September 30, 2018 and obtained a waiver for that covenant breach. Effective December 31, 2018 the Company and the SubDebt lender ("**SubLender**") amended the net debt to run rate EBITDA covenant effective for the quarter ended December 31, 2018 and thereafter. At December 31, 2018, the Company was in compliance with all covenants it is subject to under the bank loan and SubDebt.

In March 2019 the Company and the SubLender amended the SubDebt agreement such that the net debt to run rate EBITDA covenant was eliminated for calendar 2019. The SubLender further agreed to defer the monthly interest due for the SubDebt starting January 1, 2019. The interest will be deferred until the earlier of the repayment of the bank loan or January 1, 2020.

The bank loan is subject to a semi-annual borrowing base review, and the next review is scheduled to occur in the second quarter of 2019. That review may result in a reduction in the funds available to the Company.

Additional funds are required to enable the Company to further develop its oil and gas properties. Subject to approval by the SubLender, an additional C$5 million of SubDebt is available under the amended SubDebt agreement. On March 25, 2019, the Company announced it entered into a subscription agreement with a subscriber to conditionally issue 23.6 million common shares at a price of HK$1.50 per share for gross proceeds of HK$35.4 million (approximately C$6 million) (the "**Subscription**"). The Subscription is anticipated to close on or before May 14, 2019.

There can be no guarantees that the Company will be able to access any additional funds pursuant to the amended SubDebt agreement, nor can there be any guarantee that additional funds will be raised from the Subscription.

Management believes the borrowing base review with the bank will not result in a material reduction in the borrowing base below the level of bank debt currently outstanding, and that the necessary funds will be available to enable it to develop its properties and meet its obligations as they become due.

(v) *Taxes*

Persta files corporate income tax, goods and service tax and other tax returns with various provincial and federal taxation authorities in Canada. There can be differing interpretations of applicable tax laws and regulations. The resolution of any differing tax positions through negotiations or litigation with tax authorities can take several years to complete. The Company does not anticipate that there will be any material impact upon the results of its operations, financial position or liquidity.

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

Deferred tax assets are recognized only to the extent it is considered probable that those assets will be recoverable. This involves an assessment of when those deferred tax assets are likely to reverse and a judgment as to whether or not there will be sufficient taxable profits available to offset the tax assets when they do reverse. This requires assumptions regarding future profitability and is therefore inherently uncertain. Estimates of future taxable income are based on forecasted funds from operations. During the years ended December 31, 2018 and 2017, the Company has not recorded any deferred tax assets or liabilities due to the uncertainty of future taxable profits.

5 CHANGES IN ACCOUNTING POLICIES

IFRS 9 — Financial Instruments replaces the existing guidance in IAS 39 Financial Instruments: Recognition and Measurement. The new standard includes revised guidance on the classification and measurement of financial instruments, including a new expected credit loss model for calculating impairment on financial assets, and the new general hedge accounting requirements. It also carries forward the guidance on recognition and derecognition of financial instruments from IAS 39.

IFRS 9 is effective for annual reporting periods beginning on or after January 1, 2018 with early adoption permitted. As of January 1, 2018, the Company adopted all of the requirements of IFRS 9. IFRS 9 contains three principal classification categories for financial assets: measured at amortized cost, fair value through other comprehensive income ("**FVTOCI**") and fair value through profit or loss ("**FVTPL**"). The previous IAS 39 categories of held to maturity, loans and receivables and available for sale are eliminated. IFRS 9 uses a single approach to determine whether a financial asset is measured at amortized cost or fair value, replacing the multiple rules in IAS 39. The approach in IFRS 9 is based on how an entity manages its financial instruments and the contractual cash flow characteristics of the financial assets. Most of the requirements in IAS 39 for classification and measurement of financial liabilities were carried forward in IFRS 9. IFRS 9 has introduced a single expected credit loss impairment model, which is based on changes in credit quality since initial recognition. The adoption of the expected credit loss impairment model did not have any impact on the Financial Statements of the Company. Accounts receivable, accounts payable, accrued liabilities and long term debt are classified and measured at amortized cost. The Company does not have any asset contracts and debt investments measured at FVTOCI.

IFRS 9 also contains a new hedge accounting model, however the Company does not apply hedge accounting to any of its risk management contracts. The adoption of IFRS 9 has been applied retrospectively and did not result in a change in the carrying value of any of the Company's financial instruments on the transition date.

IFRS 15 — Revenue from Contracts with Customers establishes a comprehensive framework for determining whether, how much and when revenue is recognized. It replaces existing revenue recognition guidance, including IAS 18 Revenue, IAS 11 Construction Contracts and IFRIC 13 Customer Loyalty Programmes. IFRS 15 is effective for annual reporting periods beginning on or after January 1, 2018 with early adoption permitted. The Company adopted the standard on January 1, 2018 using the modified retrospective approach. There were no changes to reported net earnings or retained earnings as a result of adopting IFRS 15. IFRS 15 requires additional disclosures to disclose disaggregated revenue by product type, refer to note 17.

Revenue from the sale of natural gas, natural gas liquids, condensate and crude oil (collectively the "**products**") is recognized based on the consideration specified in contracts with customers and when the control of the products are transferred to the customers and collection is reasonably assured. The revenue is based on prices specified in the contract and the revenue is recognized when it transfers control of the product to a customer. The sales or transaction price of the Company's products to customers are made pursuant to contracts based on prevailing commodity pricing and adjusted by quality and equalization adjustments. The revenue is collected on the 25th day of the month following production.

IFRS 16 — Leases sets out the principles for the recognition, measurement, presentation and disclosure of leases for both parties to a contract, i.e. the customer (the "**lessee**") and the supplier (the "**lessor**") and replaces the previous leases standard, IAS 17 Leases. IFRS 16 is effective for annual reporting periods beginning on or after January 1, 2019. The Company is in the process of evaluating the impact of IFRS 16 on its financial statements and the extent of the impact has not yet been determined.

6 DETERMINATION OF FAIR VALUE

A number of the Company's accounting policies and disclosures require the determination of fair value, for both financial and non-financial assets and liabilities. Fair values have been determined for both 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) Cash and cash equivalents, investments, accounts receivable, deposits, accounts payable and accrued liabilities

The fair value of cash and cash equivalents, investment, accounts receivable, deposits and accounts payable and accrued liabilities is estimated as the present value of future cash flows, discounted at the market rate of interest at the reporting date. As at December 31, 2018, the fair value of these balances approximated their carrying value due to their short term to maturity.

(b) Loans

As at December 31, 2018, the fair value of the Company's bank loans approximates their carrying value, as they bear interest at floating rates, the premium charged as at December 31, 2018 was indicative of the Company's current credit spread and the loans are due on demand.

(c) Financial derivative instruments

The fair value of financial derivative contracts and swaps is derived from quoted prices received from financial institutions and is based on published forward price curves as at the measurement date, using the remaining contracted oil and natural gas volumes.

The Company classified the fair value of its financial instruments measured at fair value according to the following hierarchy based on the amount of observable inputs used to value the instrument:

— Level 1 — observable inputs such as quoted prices in active markets;

— Level 2 — inputs, other than the quoted market prices in active markets, which are observable, either directly and/or indirectly; and

— Level 3 — unobservable inputs for the asset or liability in which little or no market data exists, therefore requiring an entity to develop its own assumptions.

The fair value of any financial derivative instruments entered into by the Company have been measured using the above criteria. The fair value of the Company's loans have been measured using:

— Bank loans: Level 2

— Other liabilities: Level 3

During the year ended December 31, 2018, there were no transfers between Level 1, Level 2 and Level 3 classified assets and liabilities.

7 CASH AND CASH EQUIVALENTS

(a) Cash and cash equivalents

	As at December 31, 2018	As at December 31, 2017
	C$	*C$*
Deposits with banks and other financial institutions	**2,600,382**	2,358,542
Cash on hand	**5,327**	4,641
Cash and cash equivalents in the statement of financial position and statement of cash flows	**2,605,709**	2,363,183

(b) Supplementary cash flows information

	Year ended December 31,	
	2018	2017
	C$	*C$*
Changes in non-cash working capital and other liabilities:		
Accounts receivable	**(617,930)**	1,414,063
Prepaid expenses and deposits	**(73,542)**	514,912
Accounts payable and accrued liabilities and other liabilities	**1,764,669**	8,571,653
	1,073,197	10,500,628
Add: Movement in non-cash working capital and other liabilities directly included in investing and financing activities	**401,285**	(10,881,859)
Movement in non-cash working capital directly included in operating activities	**1,474,482**	(381,231)

8 INVESTMENTS

	As at December 31, 2018	As at December 31, 2017
	C$	*C$*
Short term investments	**—**	3,333,500

Prior to April 25, 2018, the Company held a Guaranteed Investment Certificate ("**GIC**") amounting to C$3,223,500 that was in place as a security against a C$3,223,500 irrevocable standby letter of credit for the construction of the necessary facilities related to the Company's Dismal Creek South Metering Station. This GIC was for a period of one year from the date of issuance on March 15, 2017, carried interest at 0.45% per annum, and was renewed for one year on the same terms expiring March 15, 2019. On May 7, 2018, the Company terminated this GIC receiving C$3,228,477 (interest included), as the Company obtained a performance services guarantee ("**PSG**") from Export Development Canada ("**EDC**") to guarantee qualifying letters of credit ("**L/C**"). Refer to Note 27(e).

The Company also held a GIC amounting to C$110,000 that was in place as a security against a C$110,000 irrevocable letter of credit for transportation services. This GIC was for a period of one year from the date of issuance on January 5, 2017, carried a 0.45% interest per annum and was renewed for one year on the same terms expiring January 5, 2019. On May 7, 2018, the Company terminated this GIC receiving C$110,323 (interest included), as the Company obtained a PSG from EDC to guarantee qualifying L/C, refer to Note 27(e). The irrevocable standby letter of credit was automatically extended for one year on January 5, 2018 and expired on January 5, 2019.

9 ACCOUNTS RECEIVABLE

	As at December 31, 2018 *C$*	As at December 31, 2017 *C$*
Trade receivables	**1,196,062**	1,813,992

(a) Aging analysis of trade receivables

As at December 31, 2018 and December 31, 2017, the aging analysis of trade receivables (included in accounts receivable), based on the invoice date (or date of revenue recognition, if earlier) and net of allowance for doubtful debts, is as follows:

	As at December 31, 2018 *C$*	As at December 31, 2017 *C$*
Within 1 month	**1,196,062**	1,798,983
1 to 3 months	**—**	144
Over 3 months	**—**	14,865
	1,196,062	1,813,992

Trade receivables are generally collected within 25 days from the date of billing.

(b) Impairment of accounts receivable

Impairment losses in respect of trade receivables are recorded using an allowance account unless the Company determines that recovery of the amount is remote, in which case the impairment loss is written off against trade receivables directly.

No trade receivables, which are included in accounts receivable, are considered individually nor collectively to be impaired. No material balances of trade receivables are past due, and no impairment loss has been recognized for the years ended December 31, 2018 and 2017.

10 EXPLORATION AND EVALUATION ASSETS

	As at December 31, 2018	As at December 31, 2017
	C$	*C$*
Balance, beginning of year	**40,065,106**	14,562,811
Additions	**5,210,599**	26,402,980
Write-offs	**(1,790,883)**	(900,685)
Balance, end of year	**43,484,822**	40,065,106

Exploration and evaluation ("**E&E**") assets consist of undeveloped lands, unevaluated seismic data and unevaluated drilling and completion costs on the Company's exploration projects which are pending the determination of proven or probable reserves in sufficient quantity to warrant commercial development. Transfers are made to property, plant and equipment ("**PP&E**") as proven or probable reserves are determined. E&E assets are expensed due to uneconomic drilling and completion activities and lease expiries.

During the year ended December 31, 2018, the Company completed one well and incurred E&E costs totalling C$5,210,599 (December 31, 2017: C$26,402,980). Included in E&E additions are G&A costs of C$524,625 (December 31, 2017: C$674,652) which were capitalized in accordance with the Company's accounting policies. Based on the Company's accounting policy, once the technical feasibility and commercial viability of the extraction of resources in an area of interest are determined, E&E assets attributable to that area are assessed for impairment with any impairment loss recognized in profit or loss. The remaining carrying value of the relevant E&E assets is then reclassified as development and production assets within PP&E. As at December 31, 2018, the technical feasibility and commercial viability of the four wells drilled in 2017 has not been demonstrated. In 2019, subject to availability of capital, the Company anticipates to complete extended production tests and evaluate development options for these wells.

For the year ended December 31, 2018, the Company wrote-off C$1,790,883 (December 31, 2017: C$900,685) of E&E assets attributable to land lease expiries. As at December 31, 2018, the Company concluded that there were no trigger for impairment on its E&E assets.

11 PROPERTY, PLANT AND EQUIPMENT

	Cost	Accumulated depletion and depreciation	Net book value
	C$	*C$*	*C$*
Balance, January 1, 2017	152,091,843	(83,803,018)	68,288,825
Additions	2,315,400	—	2,315,400
Change in decommissioning obligations	433,146	—	433,146
Write-offs	(2,212,697)	—	(2,212,697)
Depletion and depreciation	—	(6,179,377)	(6,179,377)
Balance, December 31, 2017	152,627,692	(89,982,395)	62,645,297
Balance, January 1, 2018	**152,627,692**	**(89,982,395)**	**62,645,297**
Additions	**203,679**	**—**	**203,679**
Change in decommissioning obligations	**(19,405)**	**—**	**(19,405)**
Impairment loss	**(1,962,280)**	**—**	**(1,962,280)**
Depletion and depreciation	**—**	**(5,368,826)**	**(5,368,826)**
Balance, December 31, 2018	**150,849,686**	**(95,351,221)**	**55,498,465**

Substantially all of PP&E consists of development and production assets. Included in PP&E additions for the year ended December 31, 2018 are G&A costs of C$13,432 (December 31, 2017: C$46,338) which were capitalized in accordance with the Company's accounting policies.

Depletion, depreciation and impairment charges

Depletion and depreciation, impairment of PP&E, and any reversal thereof, are recognized as separate line items in the statement of loss and other comprehensive loss. The depletion calculation for the year ended December 31, 2018 includes estimated future development costs of C$24,490,000 (December 31, 2017: C$24,380,000) associated with the development of the Company's proved plus probable reserves.

For the year ended December 31, 2018, there were no write-offs (December 31, 2017: C$2,212,697) of PP&E attributable to land lease expiries.

As December 31, 2018, the Company has identified indicators of impairment in its PPE assets in the Basing Alberta CGU attributable to declines in natural gas prices, and no indicator of impairment in its PPE assets in the Dawson CGU. The Company calculated the recoverable amount of the Basing Alberta CGU based on forecasted cash flows from proved plus probable reserves using a 12% pre-tax discount rate. Based on the assessment as at December 31, 2018, the carrying amount of the Company's Basing CGU was higher than its recoverable amount. As such, the Company recognized an impairment loss of C$1,962,280 (December 31, 2017: nil) for this CGU (Note 18).

12 ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

	As at December 31, 2018	As at December 31, 2017
	C$	*C$*
Trade payables	**651,209**	182,386
Accrued liabilities	**1,432,903**	2,679,869
Accrued compensation for independent non-executive directors per Phantom Unit Plan *(Note)*	**373,642**	262,833
Subtotal	**2,457,754**	3,125,088
Other payables	**3,580,724**	5,105,514
Total	**6,038,478**	8,230,602

Note: The accrued compensation for independent non-executive directors per Phantom Unit Plan is accrued quarterly and will be paid in accordance with the terms set out in the Phantom Unit Plan.

As at December 31, 2018, there were C$3,095,029 of unpaid capital expenditures included in other payables (December 31, 2017: C$4,348,191).

All trade payables and accrued liabilities are expected to be settled within one year or are payable on demand.

Aging analysis of trade payables and accrued liabilities

As at December 31, 2018 and December 31, 2017, the aging analysis of trade payables and accrued liabilities (included in accounts payable and accrued liabilities) is as follows:

	As at December 31, 2018	As at December 31, 2017
	C$	*C$*
Within 1 month	**1,534,348**	1,226,481
1 to 3 months	**402,865**	1,635,774
Over 3 months but within 6 months	**146,899**	—
	2,084,112	2,862,255

13 LONG TERM DEBT

	As at December 31, 2018 C$	As at December 31, 2017 C$
Bank loan	**4,164,243**	22,197,243
Subordinated debt	**20,000,000**	—
Less: Deferred financing costs	**(1,100,298)**	—
Balance, end of year	**23,063,945**	22,197,243
Current	**—**	22,197,243
Long term	**23,063,945**	—

(a) Bank loan

On August 24, 2017, the Company and its lender (the "**Lender**") agreed to an early termination of its existing facility and then entered into a new facility (the "**New Facility**"). A financing fee totaling C$4.3 million was paid to the Lender upon termination of the old facility and it has been recognized under finance expenses.

The maximum debt available under the New Facility is C$100 million, maturing on September 22, 2020 (36 months) from closing, and is subject to a semi-annual review of the borrowing base by the Lender. The initial New Facility draw was capped at C$24 million, and reduced to C$18.5 million during the period. With the closing of the SubDebt (as defined below), the New Facility is capped at C$10 million until the Company has repaid the SubDebt in full. Pursuant to the terms of the Second Amending Agreement to the SubDebt Agreement, if the bank loan is not paid in full on or prior to January 1, 2020, the SubDebt shall be in deficit and due upon demand.

The New Facility carries interest of 4% plus one month Canadian Dealer Offered Rate ("**CDOR**"means the arithmetic average of the yields to maturity for bankers' acceptances quoted on the Reuter's Canadian Deposit Offered Rate) calculated on a 365 day basis on drawn amounts and payable in cash on a monthly basis in arrears and a commitment fee equal to 1% per annum will be payable on all amounts committed but undrawn, payable quarterly in arrears. As at December 31, 2018, the applicable effective interest rate on the New Facility was 5.7%.

The New Facility is secured by fixed and floating first priority perfected security interests in the properties and all assets, tangible and intangible, owned by the Company and thereafter acquired by the Company, including, but not limited to, all real and personal property, goods, accounts, contract rights, assignable licenses and assignable permits. The New Facility is subject to the following financial covenants: (a) maintenance at the end of each fiscal quarter a working capital ratio not less than 1.0:1.0; and (b) as measured at the end of each fiscal quarter, total debt to adjusted EBITDA not exceeding 3.0/1.0 through the fiscal quarter ended September 30, 2018 and 2.5/1.0 thereafter (Total debt and EBITDA as defined in the loan agreement). The Company was in compliance with these covenants as at December 31, 2018.

Under the New Facility agreement, "total debt" is defined as the consolidated debt of the Company and including any liability; and "adjusted EBITDA" is defined as earnings before deduction of finance expenses, income taxes, depletion and depreciation, write-offs, transaction costs and share-based compensation. With the closing of the SubDebt (as defined below), "total debt" is defined as the consolidated debt of the Company, including any liability and excluding debt defined as other liabilities (Note 15).

The principal and all accrued and unpaid interest and fees are due on the maturity date or in accordance with the terms of the New Facility. The Company maintains no letter of credit, as at December 31, 2018 (December 31, 2017: C$558,000) for transportation services in relation to the New Facility.

(b) Subordinated debt

On May 16, 2018, the Company completed a subordinated debt (the "**SubDebt**") financing with an arm's length lender (the "**SubLender**") totaling C$25 million. The SubDebt has a term of 60 months, and bears interest at 12% per annum, compounded and payable monthly. The Company has the option to prepay as follows: (i) after 12 months, the right to prepay C$10 million subject to a prepayment fee of 1% of the amount prepaid; and (ii) after 18 and up to 36 months, the right to prepay any SubDebt amount outstanding in tranches of C$5 million, subject to a prepayment fee of 3% of the amount prepaid; and (iii) after 37 months, the right to prepay any SubDebt amount outstanding in tranches of C$5 million, subject to a prepayment fee of 1% of the amount prepaid. An exit fee of C$0.75 million is payable when the SubDebt facility is repaid or at maturity on May 16, 2023.

The SubDebt is secured by a general security agreement over all present and after-acquired property of the Company subject to the fixed and floating first priority held by the Lender. Prior to December 2018, the SubDebt was subject to the following covenants: (a) maintenance at the end of each fiscal quarter a working capital ratio not less than 1.0:1.0; and (b) as measured at the end of each fiscal quarter, net debt to run rate EBITDA not exceeding 4.0/1.0 through the fiscal quarter ending March 2019, and 3.0/1.0 through the fiscal quarter ending March 31, 2020 and 2.5/1.0 thereafter; and (c) net debt to total proved reserves not exceeding 0.75/1.0 through the fiscal quarter ending March 31, 2019, and not exceeding 0.60/1.0 thereafter; and (d) maintaining the Company's Alberta Energy liability management ratio above 2.0/1.0.

Pursuant to the SubDebt agreement, no later than September 30 in each year, the Company must enter into arrangements to protect against fluctuations in commodity prices for 80% of its forecast production volume from proved Developed Producing Reserves.

Effective December 31, 2018, the Company and SubLender amended the SubDebt agreement (the "**First Amending Agreement**") such that run rate EBITDA for the covenant calculation was changed to trailing twelve months ("**TTM**") EBITDA, and for the fiscal quarter ended December 31, 2018, net debt to TTM EBITDA would not exceed 4.75/1.0.

Under the terms of the SubDebt agreement, "net debt" is defined as the consolidated debt of the Company, less cash held, and excluding debt defined as other liabilities (Note 15). Under the terms of the First Amending Agreement, TTM EBITDA is defined as the annualized earnings before deduction of interest expenses/income, income taxes, depletion and depreciation, write-offs, unrealized hedging gains/losses and share-based compensation for the four most recent fiscal quarters.

The Company was not in compliance with the net debt to run rate EBITDA covenant of the SubDebt agreement as at September 30, 2018 and obtained a waiver for that covenant breach. After giving effect to the First Amending Agreement, the Company is in compliance with all covenants for the New Facility and SubDebt as at December 31, 2018.

In connection with the SubDebt, the Company sold 8 million share purchase warrants to the SubLender for C$750,000, refer to Note 16(c). The Company completed an initial draw of C$20.0 million from the SubDebt at closing. Pursuant to the Second Amending Agreement, subject to approval by the SubLender, the Company has an additional C$5.0 million of SubDebt available.

C$1.25 million in costs have been incurred in relation to the SubDebt and such amounts have been paid to the SubLender. These costs have been capitalised in long term debt and amortised until the maturity of the SubDebt.

In March 2019, the Company and SubLender further amended the SubDebt agreement (the "**Second Amending Agreement**"). The Second Amending Agreement eliminates the TTM EBITDA covenant for 2019, and implements a deferral of the monthly interest payable to the SubLender starting January 1, 2019 until the earlier of the repayment of the New Facility or January 1, 2020. The Company incurred a fee of C$1.0 million pursuant to the Second Amending Agreement. The fee was deemed to be incurred with the signing of the agreement, but capitalized as an increase of the SubDebt principal, such that the total amount owed under the SubDebt increased to C$21 million, and the total SubDebt available subject to SubLender approval increases to C$26 million. As such, no cash cost will be incurred in relation to the fee in 2019.

In light of the current volatility in oil and gas prices and uncertainty regarding the timing for recovery in such prices as well as pipeline and transportation capacity constraints, management's ability to prepare financial forecasts is challenging.

Due to this volatile economic environment, it is possible that the Company could breach the covenants noted within its facility and SubDebt agreements in future periods. If a covenant violation does occur, this will represent an event of default under the facility and the lenders will have the right to demand repayment of all amounts owed under the facility and SubDebt.

14 DECOMMISSIONING LIABILITIES

The total future decommissioning obligations were estimated based on the Company's net ownership interest in petroleum and natural gas assets including well sites, gathering systems and facilities, the estimated costs to abandon and reclaim the petroleum and natural gas assets and the estimated timing of the costs to be incurred in future periods. As at December 31, 2018, the Company estimated the total undiscounted amount of cash flows required to settle its decommissioning obligations to be approximately C$3.0 million which will be incurred between 2019 and 2067. The majority of these costs will be incurred by 2037. As at December 31, 2018, an average risk free rate of 2.04% (December 31, 2017: 1.87%) and an inflation rate of 2% (December 31, 2017: 2%) were used to calculate the decommissioning obligations.

The following table reconciles the Company's decommissioning liabilities:

	As at December 31, 2018	As at December 31, 2017
	C$	*C$*
Balance, beginning of year	**2,172,148**	1,708,047
Change in estimate	**(19,405)**	(39,853)
Liabilities incurred	**—**	472,999
Accretion expense	**40,238**	30,955
Balance, end of year	**2,192,981**	2,172,148
Current	**205,836**	205,429
Long-term	**1,987,145**	1,966,719

15 OTHER LIABILITIES

	As at December 31, 2018	As at December 31, 2017
	C$	*C$*
Other liabilities	**4,225,734**	3,798,280

During the year ended December 31, 2017, the Company entered into the Master Turnkey Drilling and Completion Contract (the "**Contract**") with an arm's length private company. Based on the Contract, the Company shall pay the invoices either within 90 days from the date of the invoice, or by installments as follows: (i) 15% due six months from the date of invoice, (ii) 35% due 12 months from the date of invoice and (iii) 50% due 24 months from the date of invoice. Any invoice balance outstanding for more than 90 days will bear interest at 4.24% per annum, calculated annually and prorated for the number of months outstanding with no compounding. The outstanding balances are unsecured. The Company has committed to use the services of the private company to drill and complete a minimum of five wells or certain penalties would be incurred should the Company fail to do so.

As at December 31, 2018, the Company has completed one well per the Contract, incurring total capital expenditure of C$8,009,704 (which included capital expenditure of C$4,192,626 in 2017). In accordance with the payment terms, the Company has classified C$2,992,964 within current liabilities with the remaining C$4,225,734 as other liabilities.

16 SHARE CAPITAL

(a) Authorized:

The Company is authorized to issue an unlimited number of common shares.

(b) Issued:

	Common Shares Number	Common Shares Amount C$
At January 1, 2017	208,706,520	169,247,367
Shares issued for cash	69,580,000	38,131,133
Share issue costs	—	(3,011,817)
At December 31, 2017 and December 31, 2018	278,286,520	204,366,683

There were no share capital transactions during the year ended December 31, 2018.

During the year ended December 31, 2017, the Company conducted the following transactions:

(i) On March 10, 2017, the Company was successfully listed on the Stock Exchange and issued 69,580,000 new shares at a price of HK$3.16 per share (C$0.55 per share), raising gross proceeds of HK$219,872,800 (C$38,131,133). The costs associated with the issuance of new shares amounted to C$3,011,817.

(c) Warrants:

On May 16, 2018, the Company conditionally issued 8.0 million warrants to the SubLender for a consideration of C$750,000. The warrants were conditional on approval from the Stock Exchange and the Company's shareholders, which was obtained on August 13, 2018 through a special meeting of shareholders.

The warrants have an exercise price of HK$3.16 per warrant and a term of 5 years. The fair value of these warrants was estimated to be C$750,000 using the Black-Scholes-Merton option pricing model based on a volatility of 59.9%, risk-free interest rate of 2.12%, expected life of 5 years, no dividend yield and an exchange rate of HK$1 per C$0.1650. As at December 31, 2018, C$102,966 in costs were incurred for the sale of the warrants.

17 REVENUE

The Company sells its products pursuant to variable-price contracts. The transaction price for variable price contracts is based on the commodity price, adjusted for quality, location or other factors, whereby each component of the pricing formula can be either fixed or variable, depending on the contract terms. Commodity prices are based on market indices that are determined on a monthly or daily basis.

The contracts generally have a term of one year or less, whereby delivery takes place throughout the contract period. Revenues are typically collected on the 25th day of the month following production.

The amount of each significant category of revenue recognized for the years ended December 31, 2018 and 2017 is as follows:

	Year ended December 31,	
	2018	2017
	C$	*C$*
Production revenue from natural gas, natural gas liquids and condensate sales	**13,549,538**	19,961,130
Production revenue from crude oil sales	**1,814,756**	1,482,077
	15,364,294	21,443,207
Trading revenue from natural gas sales	**1,070,898**	1,240,648

For the year ended December 31, 2018, the Company's customer base includes two customers (2017: two customers), with whom transactions have exceeded 10% of the Company's revenues. For the year ended December 31, 2018, revenues from sales to these customers amounted to C$13,916,748 (December 31, 2017: C$18,043,366).

18 IMPAIRMENT LOSS

Impairment is assessed based on the recoverable amount compared with the asset's carrying amount to measure the amount of the impairment. In addition, where a non-financial asset does not generate largely independent cash inflows, the Company is required to perform its test at a CGU, which is the smallest identifiable grouping of assets that generates largely independent cash inflows.

As at December 31, 2018 and 2017, management identified impairment triggers for its Basing, Alberta CGU due to declines in forecasted natural gas prices, and no impairment triggers for its Dawson, Alberta CGU.

Based on its assessment as at December 31, 2018, the carrying amount of the Company's Basing CGU was higher than its recoverable amount. As such, the Company recognized an impairment loss of C$1,962,280 for the year ended December 31, 2018.

Based on the assessment as at December 31, 2017, the carrying amount of the Company's Basing CGU was lower than its recoverable amount. As such, no impairment loss was recognized.

The recoverable amount of each CGU was estimated based upon the higher of the value in use or FVLCD. In each case, the value in use methodology was used. In determining value in use, forecasted cash flows after tax discount rate at 12 percent was used, with escalated prices and future development costs, as obtained from the independent reserve report.

As at December 31, 2018, the Company utilized the following benchmark prices to determine the forecast prices in the value in use calculation:

Year	**Edmonton Oil** *(C$/Bbl)*	**AECO Gas** *(C$/mmbtu)*
2019	63.33	1.85
2020	75.32	2.29
2021	79.75	2.67
2022	81.48	2.90
2023	83.54	3.14
2024	86.06	3.23
2025	89.09	3.34
2026	92.62	3.41
2027	94.57	3.48
2028	96.56	3.54
2029[(1)]	+2.0%/yr	+2.0%/yr

[(1)] Approximate percentage change in each year after 2029 to the end of the reserve life.

As at December 31, 2017, the Company utilized the following benchmark prices to determine the forecast prices in the value in use calculation:

Year	**Edmonton Oil** *(C$/Bbl)*	**AECO Gas** *(C$/mmbtu)*
2018	70.25	2.20
2019	70.25	2.54
2020	70.31	2.88
2021	72.84	3.24
2022	75.61	3.47
2023	78.31	3.58
2024	81.93	3.66
2025	85.54	3.73
2026	88.35	3.80
2027	90.22	3.88
2028[(1)]	+2.0%/yr	+2.0%/yr

[(1)] Approximate percentage change in each year after 2028 to the end of the reserve life.

19 PERSONNEL COSTS, REMUNERATION POLICY AND AUDITORS' REMUNERATION

Personnel costs incurred during the years ended December 31, 2018 and 2017 were as follows:

	Year ended December 31,	
	2018	2017
	C$	*C$*
Personnel costs		
Salaries, wages and other benefits	**2,167,774**	2,289,072
Retirement benefits contribution	**33,392**	33,702
	2,201,166	2,322,774

The Company's remuneration and bonus policies are determined by the performance of individual employees.

The emolument of the executives are recommended by the remuneration committee of the Company, having regard to the Company's operating results, the executives' duties and responsibilities within the Company and comparable market statistics.

Phantom Unit Plan for independent non-executive directors

The Company has in place a phantom unit plan for its independent non-executive directors effective March 10, 2017 and applied retrospectively started from February 26, 2016 (the "**Phantom Unit Plan**"). In order for the eligible directors to receive the phantom units issued under the Phantom Unit Plan (the "**Phantom Units**"), they need to complete a participation form prior to the commencement of each fee period (i.e. twelve-month period commencing January 1 and ending on December 31). Since 2016, each eligible Director agreed in writing to receive 60% of their fees (i.e. the designated percentage) relating to future services as a director in the form of phantom units under the Phantom Unit Plan, and the eligible directors have agreed to receive C$15,000 quarterly under the Phantom Unit Plan (the "**Phantom Fee**").

Under the terms of the Phantom Unit Plan, the Company calculates the Phantom Units dividing the Phantom Fee by the weighted average-trading price of the Company's common shares for the five days preceding each quarter end multiplied by the number of Phantom Units awarded during the quarter. For the year ended December 31, 2018, total compensation accrued for each director under the Phantom Unit Plan is based on the total number of units awarded in the preceding quarters multiplied by the weighted average-trading price of the Company's common shares for the five days preceding the period end.

During the year ended December 31, 2018, the Company incurred C$110,809 (December 31, 2017: C$122,833) of directors' compensation per the Phantom Unit Plan. As at December 31, 2018, the accrued compensation for independent non-executive directors per the Phantom Unit Plan was C$373,642 (December 31, 2017: C$262,833).

Upon a director ceasing to be a member of the Board, their Phantom Units may be redeemed by the director for cash at an amount collected as the number of units redeemed multiplied by the trading price of the Company's shares of the redemption date.

Auditors' remuneration incurred during the years ended December 31, 2018 and 2017 were as follows:

	Year ended December 31,	
	2018	2017
	C$	*C$*
Auditors' remuneration		
— audit services	**174,525**	608,250
— non-audit services	**61,619**	14,648

20 DIRECTORS' EMOLUMENTS

Directors' emoluments disclosed pursuant to section 383(1) of the Companies Ordinance (Cap. 622 of the Laws of Hong Kong) and Part 2 of the Companies (Disclosure of Information about Benefits of Directors) Regulation is as follows:

Year ended December 31, 2018

	Directors' fees	Salaries, allowances and benefits in kind	Discretionary bonuses	Retirement scheme contributions	Sub-Total	Share-based payments	Total
	C$ ***(Note 1)***	**C$**	**C$**	**C$**	**C$**	**C$**	**C$**
Executive director							
Le Bo	**—**	**430,001**	**76,000**	**2,594**	**508,595**	**—**	**508,595**
Non-executive director							
Yuan Jing	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Independent non-executive directors							
Richard Dale Orman	**76,936**	**—**	**—**	**—**	**76,936**	**—**	**76,936**
Bryan Daniel Pinney	**76,936**	**—**	**—**	**—**	**76,936**	**—**	**76,936**
Peter David Robertson	**76,936**	**—**	**—**	**—**	**76,936**	**—**	**76,936**
	230,808	**430,001**	**76,000**	**2,594**	**739,403**	**—**	**739,403**

Note 1: Each of the Non-executive director's compensation is C$100,000 per year and the directors' fees reflect the adjustment for the fair value of the Phantom Unit component.

For the year ended December 31, 2018, there was no amount paid or payable by the Company to the directors (except the directors' compensation per the Phantom Unit Plan) or any of the five highest paid individuals as set out in Note 21 below as an inducement to join or upon joining the Company or as compensation for loss of office. There was no arrangement under which a director has waived or agreed to waive any remuneration during the year ended December 31, 2018.

Year ended December 31, 2017

	Directors' fees *C$*	Salaries, allowances and benefits in kind *C$*	Discretionary bonuses *C$*	Retirement scheme contributions *C$*	Sub-Total *C$*	Share-based payments *C$*	Total *C$*
Executive director							
Le Bo	—	430,001	275,000	2,564	707,565	—	707,565
Non-executive director							
Yuan Jing	—	—	—	—	—	—	—
Independent non-executive directors							
Richard Dale Orman	80,944	—	—	—	80,944	—	80,944
Bryan Daniel Pinney	80,944	—	—	—	80,944	—	80,944
Peter David Robertson	80,944	—	—	—	80,944	—	80,944
	242,832	430,001	275,000	2,564	950,397	—	950,397

21 INDIVIDUALS WITH HIGHEST EMOLUMENTS

Of the five individuals with the highest emoluments, one of them was a director (Le Bo) during both the years ended December 31, 2018 and 2017, whose emolument is disclosed in Note 20. The aggregate of the emoluments in respect of the other four individuals are as follows:

	Year ended December 31, 2018 *C$*	2017 *C$*
Salaries and other emoluments	**994,385**	884,110
Bonus	**74,000**	425,000
Retirement scheme contributions	**12,969**	10,256
	1,081,354	1,319,366

The emoluments of the above four individuals with the highest annual emoluments are within the following bands:

	Year ended December 31,	
	2018	2017
	Number of individuals	*Number of individuals*
Hong Kong dollars		
Nil–1,000,000	**—**	1
1,000,001–1,500,000	**4**	2
1,500,001–2,000,000	**—**	1
2,000,001–2,500,000	**—**	—
2,500,001–3,000,000	**—**	—
3,500,001–4,000,000	**—**	—
4,500,001–5,000,000	**—**	—

22 FINANCE EXPENSES

	Year ended December 31,	
	2018	2017
	C$	*C$*
Interest expense and financing fees	**2,696,790**	5,864,226
Amortization of debt issue costs	**169,422**	567,128
Loss/(gain) on foreign exchange	**(12,624)**	421,822
Accretion expense	**40,238**	30,955
Total finance expenses	**2,893,826**	6,884,131

23 INCOME TAXES

The provision for income taxes differs from the result that would have been obtained by applying the combined federal and provincial tax rates to the loss before income taxes. The difference results from the following items.

	Year ended December 31,	
	2018	2017
	C$	*C$*
Loss before income taxes	**(7,279,461)**	(11,636,792)
Combined Federal and Provincial tax rate	**27%**	27%
Expected tax benefit	**(1,965,454)**	(3,141,934)
Increase/(decrease) in taxes resulting from:		
— Non-deductible expenses	**2,246**	58,381
— Change in unrecognized deferred tax assets	**1,958,423**	3,083,803
— Change in enacted tax rate and others	**4,785**	(250)
Income tax expense	**—**	—

During the year ended December 31, 2018, the blended statutory tax rate was 27% (December 31, 2017: 27%).

The components of unrecognized deferred tax assets are as follows:

	Year ended December 31, 2018	Year ended December 31, 2017
	C$	*C$*
Deferred tax assets have not been recognized in respect of the following temporary differences:		
PP&E and E&E assets	**26,807,270**	18,412,877
Decommissioning liabilities	**2,192,981**	2,172,148
Non-capital losses and other	**13,954,608**	12,425,390
Share issue costs	**4,554,047**	4,233,255
Total	**47,508,906**	37,243,670

At December 31, 2018, the Company has approximately C$145 million of tax deductions, which include loss carry forwards of approximately C$13.4 million that will begin to expire in 2037.

24 LOSS PER SHARE

The calculation of basic loss per share is based on the loss and total comprehensive loss of C$7,279,461 and C$11,636,792 for the years ended December 31, 2018 and 2017 respectively is calculated as follows:

	Year ended December 31,	
	2018	2017
	Number of shares	*Number of shares*
Weighted average number of common shares		
At the beginning of the year	**278,286,520**	208,706,520
Effect of new shares issued	**—**	56,617,150
At the end of the year	**278,286,520**	265,323,670
	C$	*C$*
Loss and total comprehensive loss for the year	**(7,279,461)**	(11,636,792)
Loss per share		
Basic and diluted	**(0.03)**	(0.04)

There were no dilutive potential common shares for the years ended December 31, 2018 and 2017 due to the loss, therefore diluted loss per share is the same as basic loss per share.

25 DIVIDEND

The Board did not approve the payment of a dividend for the years ended December 31, 2018 and 2017.

26 RELATED PARTY TRANSACTIONS

(a) Transactions with key personnel

Key management compensation for the year ended December 31, 2018 totaled C$1,589,949 (December 31, 2017: C$2,026,932).

During the year ended December 31, 2018, the Company incurred C$110,809 (year ended December 31, 2017: C$122,833) of directors' compensation per the Phantom Unit Plan. As at December 31, 2018, the accrued compensation for independent non-executive directors per the Phantom Unit Plan was C$373,642 (December 31, 2017: C$262,833).

(b) Transactions with other related parties

There were no other related party transactions during the years ended December 31, 2018 and 2017.

27 FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Overview

The Company has exposure to credit risk, liquidity and market risk from its use of financial instruments. This note presents information about the Company's exposure to each of the risks, the Company's objectives, policies and processes for measuring and managing risk, and the Company's management of capital.

The Company's risk management policies are established to identify and analyze the risks faced by the Company, to set appropriate risk limits and controls, and to monitor risks and adherence to market conditions and the Company's activities.

(a) Credit risk

Credit risk is the risk of financial loss to the Company if a customer or counter-party to a financial instrument fails to meet its contractual obligations, and arises principally from the Company's receivables from purchasers of the Company's crude oil and natural gas, and joint venture partners and the counterparties to financial derivative contracts. As at December 31, 2018, the Company's accounts receivables consisted of C$1,196,062 (December 31, 2017: C$1,813,992) due from purchasers of the Company's crude oil and natural gas and C$nil (December 31, 2017: C$nil) of other receivables.

Receivables from purchasers of the Company's crude oil and natural gas when outstanding are normally collected on the 25th day of the month following production. The carrying amount of accounts receivable and cash balances represents the maximum credit exposure. The Company has determined that no allowance for doubtful accounts was necessary as at December 31, 2018. The Company has also not written off any receivables during the year ended December 31, 2018 as accounts receivables were subsequently collected in full. There are no material financial assets that the Company considers past due and at risk of collection. As at December 31, 2018, C$1,196,062 (December 31, 2017: C$1,799,127) of the trade receivables were less than 90 days old.

(b) Liquidity risk

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they become due. The Company will attempt to match its payment cycle with collection of crude oil and natural gas revenues on the 25th of each month.

The current challenging economic climate may lead to adverse changes in cash flow, working capital levels or debt balances, which may also have a direct impact on the Company's results and financial position. These and other factors may adversely affect the Company's liquidity and the Company's ability to generate profits in the future.

The following are the contractual maturities of financial liabilities:

		As at December 31, 2018		
	Total	**Less than 1 year**	**1–3 years**	**3–5 years**
	C$	***C$***	***C$***	***C$***
Accounts payable and accrued liabilities	**6,038,478**	**6,038,478**	**—**	**—**
Other liabilities	**4,225,734**	**—**	**4,225,734**	**—**
Long term debt	**23,063,945**	**—**	**4,164,243**	**18,899,702**
Total	**33,328,157**	**6,038,478**	**8,389,977**	**18,899,702**

		As at December 31, 2017		
	Total	Less than 1 year	1–3 years	3–5 years
	C$	*C$*	*C$*	*C$*
Accounts payable and accrued liabilities	8,230,602	8,230,602	—	—
Other liabilities	3,798,280	—	3,798,280	—
Long term debt	22,197,243	22,197,243	—	—
Total	34,226,125	30,427,845	3,798,280	—

(c) Market risk

Market risk is the risk that changes in market metrics, such as commodity prices, foreign exchange rates and interest rates that will affect the Company's valuation of financial instruments, the debt levels of the Company, as well as its profit and cash flow from operations. The objective of market risk management is to manage and control market risk exposures within acceptable limits, while maximizing returns.

Commodity price risk

Commodity price risk is the risk that the fair value or future cash flows will fluctuate as a result of changes in commodity prices. Commodity prices for crude oil and natural gas are impacted by not only the relationship between the Canadian and United States dollar but also world economic events that dictate the levels of supply and demand. The Company may utilize commodity contracts as a risk management technique to mitigate exposure to commodity price volatility.

The Company did not enter into any financial derivatives during the years ended December 31, 2018 and 2017.

Interest rate risk

As at December 31, 2018, the Company was exposed to changes in interest rates with respect to its bank loans. As at December 31, 2018, a one percent change in the prevailing interest rate for its bank loans would result in an estimated change to net loss of C$41,642 for the year ended December 31, 2018 (December 31, 2017: C$221,972), as a result of changes in interest expenses from variable rate borrowings under its Senior and SubDebt facilities.

Foreign currency risk

The Company manages foreign exchange risk by monitoring foreign exchange rates and evaluating their effects on using Canadian or Hong Kong vendors as well as timing of transactions. The Company recognizes a foreign exchange gain/loss based on the revaluation of monetary items held in Hong Kong Dollars and the value changes with the fluctuation in the HKD/CAD exchange rates. As at December 31, 2018, the Company held HK$0.17 million (C$0.03 million base on HKD/CAD exchange rate at the same date). Changes in the HKD/CAD foreign exchange rate of less than 10% would not materially change the Company's Financial Statements.

(d) Capital management

The Company's general policy is to maintain an appropriate capital base in order to manage its business in the most effective manner with the goal of increasing the value of its assets and thus its underlying share value. The Company's objectives when managing capital are to maintain financial flexibility in order to preserve its ability to meet financial obligations; to maintain a capital structure that allows the Company to favor the financing of its growth strategy using internally-generated cash flow and its debt capacity; and to optimize the use of its capital to provide an appropriate investment return to its shareholders.

The Company manages its capital structure and makes adjustments to it in light of changes in economic conditions and the risk characteristics of the underlying crude oil and natural gas assets. The Company considers its capital structure to include shareholders' equity, bank debt, subordinated debt, other liabilities and working capital. To assess capital and operating efficiency and financial strength, the Company continually monitors its net debt.

The Company has not paid nor declared any dividends since its inception.

As part of its capital management process, the Company prepares budgets and forecasts, which are used by management and the Board of Directors to direct and monitor the strategy and ongoing operations and liquidity of the Company. Budgets and forecasts are subject to significant judgment and estimates relating to activity levels, future cash flows and the timing thereof and other factors which may or may not be within the control of the Company.

The following represents the capital structure of the Company:

	As at December 31, 2018	As at December 31, 2017
	C$	*C$*
Long term debt	**23,063,945**	22,197,243
Other liabilities	**4,225,734**	3,798,280
Net working capital deficit *(Note 1)*	**1,645,799**	55,070
Net debt	**28,935,478**	26,050,593
Shareholders' equity	**68,060,664**	74,693,091
Total capital	**96,996,142**	100,743,684

Note 1: The bank loan in current liability was excluded in net working capital (surplus)/deficit calculation to avoid duplication.

(e) Performance services guarantee ("PSG") facility

On April 25, 2018, the Company obtained a PSG from EDC totaling C$4.4 million. Under the terms of the PSG facility, EDC will guarantee qualifying L/C's on behalf of the Company. Previously, these L/C's were cash collateralized, following approval by EDC the requirement of the Company to hold cash to underwrite the L/C is relieved for the duration of the PSG approval. Under the terms of the PSG facility, the L/C guarantee period is the lesser of one year or the term of the L/C if less than 12 months. The guarantee can be renewed annually for long term L/C's subject to subsequent approval by the EDC. As at December 31, 2018, the Company has PSG coverage for the following L/C's:

Amount	**Expiry**
C$3,223,500	March 15, 2019
C$110,000	January 5, 2019
C$294,000	May 29, 2019
C$264,000	May 29, 2019

For the year ended December 31, 2018, the Company incurred fees totaling C$70,000 in relation to the PSG facility.

28 COMMITMENTS

Commitments and contingencies exist under various agreements and operations in the normal course of the Company's business.

	Total	Less than 1 year	1–3 years	4–5 years	After 5 years
	C$	*C$*	*C$*	*C$*	*C$*
As at December 31, 2018					
Office premise lease	3,590,650	410,360	1,231,080	1,231,080	718,130
Lease of compressors	455,400	237,600	217,800	—	—
Transportation commitment	46,733,231	5,709,341	12,208,604	7,212,287	21,602,999
PSG facility	3,891,500	3,891,500	—	—	—
Total contractual obligations	54,670,781	10,248,801	13,657,484	8,443,367	22,321,129

Office premise lease:

— In June 2017, the Company entered into an office lease for a term starting January 2018 to February 2025. The rent payable is as follow:

- January 1, 2018, to December 31, 2018: rent payable of C$17,098 per month;
- January 1, 2019, to December 31, 2019: rent payable of C$34,197 per month; and
- January 1, 2020, to February 27, 2025: rent payable of C$51,295 per month.

Office premise lease costs include an estimate of the Company's share of operating costs for its office premises for the duration of the lease term.

Lease of compressors:

— The Company entered into a lease agreement for a compressor and the lease term is from December 1, 2017 to November 30, 2020 requiring monthly lease payments of C$19,800.

Transportation Commitment:

The Company entered into a take or pay firm service transportation agreement with committed transportation volumes as below:

Description	**Volume** *(MMcf/d)*	**Effective date**	**Expiring date**	**Duration**
Persta Existing FT-R with NGTL	8.00	2013-11-01	2021-10-31	8 years
Persta New FT-R with NGTL	102.00	2018-12-01	2026-12-31	8 years

The firm service transportation agreements cover the period from November 1, 2013 to December 31, 2026 (the firm service fee varies and is subject to review by the counter-party on an annual basis). The amounts presented in the Commitments table above for the transportation service commitment fee is based on fixed transportation capacity as per these agreements and management's best estimate of future transportation charges.

Under the terms of the New FT-R agreement for 102 MMcf/d, Persta's obligation commence December 2018 when NGTL completed and commissioned Persta's metering facility.

The Company also entered into the following fixed price physical commodity contracts to forward sell natural gas during the year ended December 31, 2018:

Commodity	Term	Quantity	Price
Natural gas	November 1, 2018 to March 31, 2019	1,000 GJ/day	C$2.14 per GJ
Natural gas	January 1, 2019 to December 31, 2019	6,900 GJ/day	C$2.08 per GJ
Natural gas	January 1, 2019 to March 31, 2019	1,000 GJ/day	C$2.23 per GJ

29 OTHER INCOME

On December 20, 2018, the Company monetized two in-the-money fixed price physical commodity contracts to forward sell natural gas in 2020 for C$752,000. The proceeds from the monetization were applied in full towards the New Facility.

30 SUBSEQUENT EVENTS

Subordinated debt agreement amendment

In March 2019, the Company and SubLender agreed to amend the SubDebt agreement. The amendment eliminated the TTM to EBITDA covenant for 2019, and implements a deferral of monthly interest payable for the SubDebt starting January 1, 2019 until the earlier of the repayment of the New Facility or January 1, 2020. The Company incurred a fee totalling C$1.0 million in relation to the amendment. The fee will be capitalized, increasing the SubDebt principal by C$1.0 million, and increasing the total SubDebt available, subject to SubLender approval, to C$26 million.

Performance services guarantee amendments

In March 2019, pursuant to its transportation commitments, the Company reduced its C$3.2 million L/C to C$1.39 million, guaranteed by the EDC on the same terms as the original L/C.

Private Placement

On March 25, 2019, the Company announced it entered into a subscription agreement with a subscriber to conditionally issue 23.6 million common shares at a price of HK$1.50 per share for gross proceeds of HK$35.4 million (approximately C$6 million). The Company intends to apply the net proceeds from the subscription for the expansion of its existing business, the development of new business, and general working capital. The subscription is scheduled to close on or before May 14, 2019.

Persta Resources Inc.

MANAGEMENT'S DISCUSSION AND ANALYSIS

For the three months and year ended December 31, 2018

MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis ("**MD&A**") should be read in conjunction with the Company's audited financial statements and notes thereto for the year ended December 31, 2018 and the audited annual financial statements and MD&A for the year ended December 31, 2017. All amounts in this MD&A are stated in thousands of Canadian dollars unless indicated otherwise.

FORWARD LOOKING INFORMATION

Certain statements in this MD&A are forward-looking statements that are, by their nature, subject to significant risks and uncertainties and the Company hereby cautions investors about important factors that could cause the Company's actual results to differ materially from those projected in a forward-looking statement. Any statements that express, or involve discussions as to expectations, beliefs, plans, objectives, assumptions or future events or performance (often, but not always, through the use of words or phrases such as "will", "expect", "anticipate", "estimate", "believe", "going forward", "ought to", "may", "seek", "should", "intend", "plan", "projection", "could", "vision", "goals", "objective", "target", "schedules" and "outlook") are not historical facts, are forward-looking and may involve estimates and assumptions and are subject to risks (including the risk factors detailed in this MD&A), uncertainties and other factors some of which are beyond the Company's control and which are difficult to predict. Accordingly, these factors could cause actual results or outcomes to differ materially from those expressed in the forward-looking statements.

Since actual results or outcomes could differ materially from those expressed in any forward-looking statements, the Company strongly cautions investors against placing undue reliance on any such forward-looking statements. Statements relating to "reserves" or "resources" are deemed to be forward-looking statements, as they involve the implied assessment, based on estimates and assumptions that the resources and reserves described can be profitably produced in the future. Further, any forward-looking statement speaks only as of the date on which such statement is made and the Company undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances after the date on which such statement is made or to reflect the occurrence of unanticipated events.

All forward-looking statements in this MD&A are expressly qualified by reference to this cautionary statement.

NON-IFRS FINANCIAL MEASURES

The financial information contained herein has been prepared in accordance with International Financial Reporting Standards ("**IFRS**") and sometimes referred to in this MD&A as Generally Accepted Accounting Principles ("**GAAP**") as issued by the International Accounting Standards Board ("**IASB**").

This MD&A also includes references to financial measures commonly used in the oil and natural gas industry. These financial measures are not defined by IFRS as issued by IASB and, therefore, are referred to as non-IFRS measures. The non-IFRS measures used by the Company may not be comparable to similar measures presented by other companies. See "Non-IFRS Financial Measures" of this MD&A for information regarding the following non-IFRS financial measures used in this MD&A: "operating netback", "adjusted EBITDA" and "total debt".

OVERVIEW

The Company was incorporated in Calgary, Alberta, Canada under the Business Corporations Act (Alberta) in 2005. Persta is an exploration and development company pursuing petroleum and natural gas production and reserves in Alberta, Canada. Persta focuses on long-term growth through acquisition, exploration, development and production in the Western Canadian Sedimentary Basin ("**WCSB**"). The Company's shares were listed on The Stock Exchange of Hong Kong Limited (the "**Stock Exchange**") on March 10, 2017 (the "**Listing Date**") pursuant to an initial public offering and trades under the stock code of "3395". The Company has been a reporting issuer under the Securities Act (Alberta) since October 2, 2018.

Persta commenced operations on March 11, 2005 with the objective of building a successful Canadian natural gas and crude oil exploration, development and production company with a long-term business strategy. The Company acquired its first 6,400 net acres of land in an area in the WCSB in January 2007 known as the Alberta Foothills and drilled and commercially produced liquids-rich natural gas from the Company's first deep well in this area in December 2008. Since then, the Company's natural gas and crude oil production rate has organically grown with average sales of 2,208 Boe/d for the year ended December 31, 2018. As at December 31, 2018, the Company held 118,807 net acres of land in the WCSB, which the Company intends to explore through drilling subject to capital availability.

Presently, the Company has four core areas of operations:

- Alberta Foothills, which includes natural gas properties in the five areas of Basing, Voyager, Kaydee, Columbia and Stolberg. Basing and Voyager are partially developed whilst Kaydee, Columbia and Stolberg are undeveloped;

- Deep Basin Devonian, which includes undeveloped natural gas properties in Hanlan-Peco in West Alberta;

- Peace River, which includes light oil properties in the Dawson area which is partially developed; and

- Progress-Montney, an underdeveloped natural gas and oil property in northern Alberta.

The Company's long-term business strategy is to increase shareholder value by continuing to exploit and develop its oil and natural gas asset base in the four core exploration and production areas to increase its reserves, production and cash flows. The Company believes that it has a number of key strengths that will help the Company to execute its long-term business strategies, which include:

- economics and quality of resource base;

- size of resources within the Company's acreage land position;

- location of resources and market access;

- holding sole operating control and land ownership; and

- an experienced management and technical team with a strong industry track record.

FUTURE PROSPECTS

The Company acquired Petroleum and Natural Gas Licenses for Basing, Voyager and Kaydee in the Alberta Foothills, Dawson near Peace River and Progress-Montney in northern Alberta between 2006 and 2018. In 2018, approximately 90% of the Company's revenue was generated from the Basing area. Voyager is geologically analogous and located approximately 30 kilometers ("**km**") from Basing.

The Company is evaluating development alternatives for Voyager, where it has four gas wells drilled and completed, awaiting tie-in and connection to our Basing network through a new pipeline. Subject to capital availability, this development is currently forecast to be completed in the first quarter of 2020. Voyager production is expected to increase the Company's revenue and cashflow which is intended to be used to fund new drilling.

The Company plans to develop its natural gas assets in Basing, Voyager and Progress-Montney through new drilling as capital is available, and constructing facilities to support future increases in production which would lower unit production costs in the long run.

Selected Annual Information

	Year ended December 31,				
	2018	2017	2016	2015	2014
AVERAGE DAILY PRODUCTION					
Natural gas (Mcf)	**12,251**	15,879	20,147	10,380	15,611
Crude oil (Bbls)	**75**	70	61	54	102
NGLs and Condensate (Bbls)	**91**	140	161	85	81
Oil Equivalent (Boe)	**2,208**	2,856	3,579	1,868	2,786
AVERAGE DAILY TRADING					
Natural gas (Mcf)	**190**	1,165	—	—	—
AVERAGE SALES PRICES					
Natural gas (C$ per Mcf)	**2.56**	2.98	2.72	3.61	4.70
Crude oil (C$ per Bbl)	**65.97**	58.02	49.53	49.09	93.50
NGLs (C$ per Bbl)	**35.54**	28.10	19.96	17.98	51.05
Condensate (C$ per Bbl)	**75.58**	62.77	52.81	61.81	88.92
FINANCIAL ($'000)					
Production and trading revenue	**16,435**	22,684	23,706	16,080	32,424
Royalties	**(1,164)**	(2,793)	(1,780)	(1,072)	(5,295)
Trading cost	**(409)**	(500)	—	—	—
Operating costs	**(5,354)**	(5,746)	(6,327)	(3,636)	(5,556)
Operating netback *(Note 1)*	**9,508**	13,645	15,599	11,372	21,573
Net (loss)/earnings	**(7,279)**	(11,637)	(2,286)	(2,485)	3,002
Net working capital *(Note 2)*	**(1,646)**	(22,252)	5,122	6,923	4,514
Total assets	**103,582**	111,091	91,431	100,547	105,078
Capital expenditures	**7,962**	18,864	1,412	5,374	18,208
(LOSS)/PROFIT PER SHARE					
Per basic share	**(0.03)**	(0.04)	(0.01)	(0.01)	0.02
Per diluted share	**(0.03)**	(0.04)	(0.01)	(0.01)	0.02

Notes:

(1) Non-IFRS measure — see discussion under the heading "Non-IFRS Financial Measures".

(2) Net working capital consists of current assets less current liabilities.

Selected Quarterly Information

	Q4 2018	Q3 2018	Q2 2018	Q1 2018	Q4 2017	Q3 2017	Q2 2017	Q1 2017
AVERAGE DAILY PRODUCTION								
Natural gas (Mcf)	10,786	9,236	11,090	17,987	13,708	12,196	17,266	20,429
Crude oil (Bbls)	64	75	69	94	73	77	46	84
NGLs and Condensate (Bbls)	95	66	72	133	131	129	148	151
Oil Equivalent (Boe)	1,957	1,680	1,989	3,225	2,490	2,239	3,072	3,639
AVERAGE DAILY TRADING								
Natural gas (Mcf)	1,177	1,207	1,765	418	2,009	2,485	—	—
FINANCIAL ($'000)								
Production revenue	3,286	3,164	3,480	5,434	4,772	4,501	5,393	6,777
Royalties	(266)	(319)	261	(840)	(591)	(396)	(1,040)	(766)
Trading revenue	256	293	426	95	562	679	—	—
Trading cost	(82)	(102)	(145)	(81)	(262)	(237)	—	—
Operating costs	(1,581)	(1,096)	(1,200)	(1,476)	(1,272)	(1,201)	(1,534)	(1,739)
Operating netback *(Note 1)*	1,614	1,940	2,823	3,132	3,209	3,345	2,819	4,272
Net (loss)/earnings	(5,322)	(1,071)	(342)	(545)	(2,859)	(1,579)	(3,586)	(3,613)
Net working capital *(Note 2)*	(1,646)	3,638	4,033	(2,639)	(22,252)	660	15,044	19,547
Total assets	103,582	111,604	113,438	110,406	111,091	115,238	110,188	112,251
Capital expenditures	13,762	18	201	(21,943)	507	3,728	1,743	(6)
(LOSS)/PROFIT PER SHARE								
Per basic share	(0.02)	(0.00)	(0.00)	(0.00)	(0.01)	(0.01)	(0.01)	(0.02)
Per diluted share	(0.02)	(0.00)	(0.00)	(0.00)	(0.01)	(0.01)	(0.01)	(0.02)

Notes:

1 Non-IFRS measure — see discussion under the heading "Non-IFRS Financial Measures".

2 Net working capital consists of current assets less current liabilities.

RESULTS OF OPERATIONS

Project Development and Production Volume

There are three phases in the Company's operations, comprising the exploration phase, the development phase and the production phase. During the exploration phase, the Company conducts geological and geophysical studies combined with seismic mapping to propose drilling locations which might generate natural gas and crude oil prospects on the undeveloped land the Company has acquired.

During the development and production phases, the Company's production volumes largely depend on its drilling and production schedule and access to transport and processing infrastructure to refine and deliver the Company's products to a sales point. During 2018 and 2017 the Company produced gas from 5 wells and crude oil from 3 wells.

Pricing directly affects the production volume of the Company. Producing wells may be shut in due to economic limit considerations, and the production plan may be delayed or scaled down should there be unfavorable forecast prices.

The natural gas market remained weakened in 2018, and in response the Company has strategically decreased production volumes to retain its reserves/resources for future recovery and long term growth. To fulfil its committed forward contracts for natural gas, the Company has taken advantage of the low price environment and purchased from the market, saving operating, transport and processing costs and arbitraging the price difference.

Natural gas liquids ("**NGLs**") and condensate are the by-products from the production of natural gas, their production volumes decreased commensurate with lower gas production in 2018 compared to 2017. The Company's crude oil production increased 7% while crude oil revenues increased 22% in 2018, as the Company increased production to exploit the higher oil price experienced this year.

For the three months ended December 31, 2018, the Company's total production volume decreased by 28,821 Boe to 180,018 Boe compared to 208,839 Boe for the same period in 2017. For the year ended December 31, 2018, the Company's total production volume decreased by 236,490 Boe to 806,081 Boe, compared to 1,042,571 Boe for the same period in 2017.

The following table shows the number of producing wells and production volume for the Company's natural gas, crude oil, NGLs and condensate for the three months and years ended December 31, 2018 and 2017:

	Three months ended December 31,			**Year ended December 31,**		
	2018	2017	Change %	**2018**	2017	Change %
Natural gas						
Producing wells (number of wells)	**5**	5	0%	**5**	5	0%
Production volume (Mcf)	**992,351**	1,137,062	(13%)	**4,471,584**	5,795,775	(23%)
Natural gas						
Trading volume (Mcf)	**108,251**	196,439	(45%)	**416,993**	425,075	(2%)

	Three months ended December 31,			Year ended December 31,		
	2018	2017	Change %	**2018**	2017	Change %
Crude oil						
Producing wells (number of wells)	**3**	3	0%	**3**	3	0%
Production volume (Bbl)	**5,879**	6,742	(13%)	**27,507**	25,546	8%
NGLs (by-product of natural gas)						
Producing wells (number of wells)	**5**	5	0%	**5**	5	0%
Production volume (Bbl)	**2,395**	3,342	(28%)	**10,207**	15,771	(35%)
Condensate (by-product of natural gas)						
Producing wells (number of wells)	**5**	5	0%	**5**	5	0%
Production volume (Bbl)	**6,352**	9,245	(31%)	**23,104**	35,291	(35%)
Total						
Producing wells (number of wells)	**8**	8	0%	**8**	8	0%
Production volume (Boe)	**180,018**	208,839	(14%)	**806,081**	1,042,571	(23%)
Trading volume (Boe)	**18,042**	32,740	(45%)	**69,499**	70,846	(2%)

Average Sales Price

The Company mainly sells its natural gas, natural gas related products (NGLs and condensate) and crude oil products to gas and oil trading companies. The sales price of its natural gas benchmarks to the Canadian Gas Price Reporter, which is also known as the Alberta Energy Company natural gas price ("**AECO natural gas price**"), while the natural gas related products (NGLs and condensate) and crude oil products benchmark to the Edmonton light, sweet crude oil commodity price. During the three months and year ended December 31, 2018, the Company also had in place one-year (January 1, 2018 to December 31, 2018) sales agreements to forward sell its natural gas at a specified price and volume. The value of these sales accounted for 70.3% and 63.5% of the Company's total production revenue from crude oil and natural gas sales for the three months and year ended December 31, 2018, compared with 59.2% and 65.3% for the same periods in 2017. The sales of remaining production accounted for 29.7% and 36.5% of its total revenue from crude oil and natural gas sales for the three months and year ended December 31, 2018, compared with 40.8% and 34.7% for the same periods in 2017.

The natural gas market remained weakened in 2018, and in response the Company has strategically decreased production volumes to retain its reserves/resources for future recovery and long term growth. To fulfil its committed forward contracts for natural gas, the Company has taken advantage of the low price environment and purchased from the market, saving operating, transport and processing costs and arbitraging the price difference.

The following table shows the average market prices and average sales prices for the Company's natural gas, crude oil, NGLs and condensate and the average realized price, average trading sales price and average forward sales price for the Company's natural gas for the three months and year ended December 31, 2018 and 2017:

	Three months ended December 31,			Year ended December 31,		
	2018	2017	Change	**2018**	2017	Change
	C$	*C$*	*%*	***C$***	*C$*	*%*
Natural gas						
Average market price (C$ per Mcf) *(Note 1)*	**2.31**	2.37	(2.2%)	**1.74**	2.33	(25.3%)
Average realized price (C$ per Mcf) *(Note 2)*	**2.83**	3.75	(24.4%)	**2.37**	2.79	(15.1%)
Average forward sales price (C$ per Mcf) *(Note 3)*	**2.52**	2.92	(13.6%)	**2.72**	3.02	(9.9%)
Average trading sales price (C$ per Mcf) *(Note 4)*	**1.79**	2.77	(35.4%)	**1.48**	2.92	(49.3%)
Average sales price (C$ per Mcf) *(Note 5)*	**2.54**	3.07	(17.1%)	**2.56**	2.98	(14.1%)
Crude oil						
Average market price (C$ per Bbl) *(Note 6)*	**51.41**	68.86	(25.3%)	**70.92**	62.78	13.0%
Average sales price (C$ per Bbl) *(Note 5)*	**44.20**	67.94	(34.9%)	**65.97**	58.02	13.7%
NGLs						
Average market price (C$ per Bbl) *(Note 7)*	**18.08**	47.71	(62.1%)	**29.94**	36.61	(18.2%)
Average sales price (C$ per Bbl) *(Note 5)*	**35.85**	41.05	(12.7%)	**35.54**	28.10	26.5%
Condensate						
Average market price (C$ per Bbl) *(Note 7)*	**67.71**	73.82	(8.3%)	**80.23**	66.80	20.1%
Average sales price (C$ per Bbl) *(Note 5)*	**62.95**	66.63	(5.5%)	**75.58**	62.77	20.4%

Notes:

(1) The average market price was the AECO same day spot price averaged over the period.

(2) The average realized price represents the average price of natural gas sales excluding the sales derived from forward sales and trading sales.

(3) The average forward sales price was the price agreed in the forward sales agreements to sell the Company's natural gas at a specified price and volume.

(4) The average trading sales price was the weighted average price of sales for trading business.

(5) The average sales price was the weighted average price calculated by the Company.

(6) The average market price was the average Edmonton light, sweet crude oil settlement price over the period.

(7) The average market price was the average Alberta natural gas liquids price over the period.

Natural Gas

The Company's average sales price of natural gas consists of two components: the weighted average of the realized price and the average forward sales price of natural gas. The average realized price represents the average price of natural gas sales excluding the sales derived from forward sales.

For the three months ended December 31, 2018, and comparing to the same period of 2017, the average market price of natural gas has decreased from C$2.37 per Mcf to C$2.31 per Mcf. To exploit weakness in the current market, the Company purchased natural gas from the market at C$0.76 per Mcf to fulfill the forward sales contracts with a weighted average price of C$2.52 per Mcf. The aforementioned factors collectively led to a 17.1% decrease of the average natural gas sales price from C$3.07 per Mcf to C$2.54 per Mcf for the three months ended December 31, 2018, compared to the same period of 2017.

For the year ended December 31, 2018, and comparing to the same period of 2017, the average market price of natural gas has decreased from C$2.33 per Mcf to C$1.74 per Mcf. To exploit weakness in the current market, the Company purchased natural gas from the market at C$0.98 per Mcf to fulfill the forward sales contracts with a weighted average price of C$2.72 per Mcf. The aforementioned factors collectively led to a 14.1% decrease of the average natural gas sales price from C$2.98 per Mcf to C$2.56 per Mcf for the year ended December 31, 2018, compared to the same period of 2017.

Crude oil

The average market price of light, sweet crude oil decreased from C$68.86 per Bbl for the three months ended December 31, 2017 to C$51.41 per Bbl for the same period in 2018. As a result, the Company's average sales price decreased by 34.9% from C$67.94 per Bbl for the three months ended December 31, 2017 to C$44.20 per Bbl for the same period in 2018.

The average market price of crude oil increased from C$62.78 per Bbl for the year ended December 31, 2017 to C$70.92 per Bbl for the same period in 2018. As a result, the Company's average sales price increased by 13.7% from C$58.02 per Bbl for the year ended December 31, 2017 to C$65.97 per Bbl for the same period in 2018.

NGLs

The average market price of NGLs decreased from C$47.71 per Bbl for the three months ended December 31, 2017 to C$18.08 per Bbl for the same period in 2018. In the meantime, the Company's average sales price decreased 12.7% from C$41.05 per Bbl for the three months ended December 31, 2017 to C$35.85 per Bbl for the same period in 2018 due to an increase in the sales volume in the days when the market price improved.

The average market price of NGLs decreased from C$36.61 per Bbl for the year ended December 31, 2017 to C$29.94 per Bbl for the same period in 2018. In the meantime, the Company's average sales price increased 26.5% from C$28.10 per Bbl for the year ended December 31, 2017 to C$35.54 per Bbl for the same period in 2018 due to effective planning of sales when the market price were high in certain days of the reporting period.

Condensate

The average market price of condensate decreased from C$73.82 per Bbl for the three months ended December 31, 2017 to C$67.71 per Bbl for the same period in 2018. As a result, the Company's average sales price decreased by 5.5% from C$66.63 per Bbl for the three months ended December 31, 2017 to C$62.95 per Bbl for the same period in 2018.

The average market price of condensate increased from C$66.80 per Bbl for the year ended December 31, 2017 to C$80.23 per Bbl for the same period in 2018. As a result, the Company's average sales price increased by 20.4% from C$62.77 per Bbl for the year ended December 31, 2017 to C$75.58 per Bbl for the same period in 2018.

The Company sells its natural gas benchmarked to the AECO natural gas price, crude oil benchmarked to the Edmonton light, sweet crude oil settlement price, and its NGLs and condensate benchmarked to the average Alberta natural gas liquids price. The Company also enters into forward sales agreements to sell its natural gas over a time period at a specified price and volume. Since the Company uses weighted average to calculate the average sales prices, the volatilities in price and volume sold each day will cause the average sales price of crude oil, NGLs and condensate and the average realized price of natural gas to be either lower or higher than the average market price for the same periods in 2018 and 2017.

Revenue

The following table shows the breakdown of the Company's revenue before royalties by types of natural resources for the three months and year ended December 31, 2018 and 2017:

	Three months ended December 31,			**Year ended December 31,**		
	2018	2017	Change	**2018**	2017	Change
	C$'000	*C$'000*	*%*	***C$'000***	*C$'000*	*%*
Natural gas	**2,798**	4,122	(32%)	**12,511**	18,543	(33%)
Crude oil	**260**	458	(43%)	**1,815**	1,482	22%
NGLs and Condensate	**485**	753	(36%)	**2,109**	2,659	(21%)
Total revenue	**3,543**	5,333	(34%)	**16,435**	22,684	(28%)

Sales of Natural Gas

The following table shows the sales volume and average sales price of the Company's natural gas for the three months and year ended December 31, 2018 and 2017:

	Three months ended December 31,			**Year ended December 31,**		
	2018	2017	Change	**2018**	2017	Change
			%			%
Sales volume (Mcf)	**1,100,603**	1,333,501	(17%)	**4,888,577**	6,220,850	(21%)
Realized sales volume	**58,471**	54,712	7%	**781,823**	891,425	(12%)
Forward sales volume	**933,881**	1,082,350	(14%)	**3,689,761**	4,904,350	(25%)
Trading sales volume	**108,251**	196,439	(45%)	**416,993**	425,075	(2%)
Average sales price (C$/Mcf)	**2.54**	3.09	(18%)	**2.56**	2.98	(14%)
Average Realized sales price	**2.83**	3.75	(24%)	**2.37**	2.79	(15%)
Average Forward sales price	**2.52**	2.92	(14%)	**2.72**	3.02	(10%)
Average Trading sales price	**1.79**	2.77	(35%)	**1.48**	2.92	(49%)

The revenue derived from the Company's sales of natural gas is a function of the average price and volume of natural gas sold. The Company's average sales price of natural gas consisted of the weighted average of the realized price and the forward sales price of natural gas. The sales volume of the Company's natural gas was dependent on the Company's production capacity influenced by its drilling plan and production wells in Alberta Foothills. Although the Company decreased its production volume in response to the soft market, the average sales price increased due to the forward sales contracts which fixed a sale price higher than the spot price.

Sales of Crude Oil

The following table shows the sales volume and average sales price of the Company's crude oil for the three months and year ended December 31, 2018 and 2017:

	Three months ended December 31,			Year ended December 31,		
	2018	2017	Change %	**2018**	2017	Change %
Sales volume (Bbl)	**5,879**	6,742	(13%)	**27,507**	25,546	8%
Average sales price (C$/Bbl)	**44.20**	67.94	(35%)	**65.97**	58.02	14%

The revenue derived from the Company's sales of crude oil is subject to the average sales price and the sales volume of crude oil. The average sales price of the Company's crude oil is highly sensitive to Edmonton light, sweet crude oil price; and the sales volume of its crude oil was dependent on the Company's production capacity influenced by its drilling plan and production wells from the Peace River area. Due to the improvement in the market price of crude oil, the average sales price increased, and the Company resumed the production from previously shut-in wells in the Dawson area, increasing its production volume and crude oil revenue.

Sales of NGLs

The following table shows the sales volume and average sales price of the Company's NGLs for the three months and year ended December 31, 2018 and 2017:

	Three months ended December 31,			Year ended December 31,		
	2018	2017	Change %	**2018**	2017	Change %
Sales volume (Bbl)	**2,395**	3,342	(28%)	**10,207**	15,771	(35%)
Average sales price (C$/Bbl)	**35.85**	41.05	(13%)	**35.54**	28.10	26%

Sales of Condensate

The following table shows the sales volume and average sales price of the Company's condensate for the three months and year ended December 31, 2018 and 2017:

	Three months ended December 31,			Year ended December 31,		
	2018	2017	Change %	**2018**	2017	Change %
Sales volume (Bbl)	**6,352**	9,245	(31%)	**23,104**	35,291	(35%)
Average sales price (C$/Bbl)	**62.95**	66.63	(6%)	**15.70**	62.77	(75%)

The average sales price of the Company's NGLs and condensate is highly sensitive to the Alberta natural gas liquids commodity price and demand of the petrochemical industry. The sales volume of its NGLs and condensate is dependent on the Company's production capacity influenced by its drilling plan and production wells in the Alberta Foothills area. Due to the improvement in the market price of NGLs and condensate, the average sales price increased, while the production volume decreased as a result of the decrease of natural gas production volume.

Trading Cost of Natural Gas

The following table shows the purchase volume and average purchase price of the Company's natural gas for the three months and year ended December 31, 2018 and 2017:

	Three months ended December 31,			Year ended December 31,		
	2018	2017	Change %	**2018**	2017	Change %
Purchase volume (Mcf)	**89,550**	187,704	(52%)	**416,993**	425,075	(2%)
Average purchase price (C$/Mcf)	**0.76**	1.40	(46%)	**0.98**	1.18	(17%)

Royalties

The following table shows the breakdown of the Company's royalties by types of natural resources for the three months and years ended December 31, 2018 and 2017:

	Three months ended December 31,			Year ended December 31,		
	2018	2017	Change	**2018**	2017	Change
	C$'000	*C$'000*	*%*	***C$'000***	*C$'000*	*%*
Natural gas, NGLs and condensate	**116**	433	(73%)	**516**	2,375	(78%)
Crude oil	**150**	157	(4%)	**648**	418	55%)
Total royalties	**266**	590	(55%)	**1,164**	2,793	(58%)

For the three months ended December 31, 2018, the effective average royalty rate decreased by 32.2% to 7.5%, compared to 11.1% in 2017. For the year ended December 31, 2018, the effective average royalty rate decreased by 42.5% to 7.1%, compared to 12.3% in 2017. The fluctuation of the effective average royalty rate was primarily due to the fluctuation in market price and well production of natural gas. Alberta requires royalties to be paid on the production of natural resources from lands for which it owns the mineral rights. In Alberta, royalties are a function of the royalty rate and royalty base, which are set by a sliding scale formula containing separate elements that account for market price and well production. Royalty rates will fluctuate to reflect change in production rates and market price.

During the three months and year ended December 31, 2018, the Company's royalty rate for natural gas ranged between 5% to 18%, the rate for NGLs (propane and butane) was 30%, the rate for condensate was 40%, and the rate for crude oil ranged between 5% to 20%. The Company's royalty rate was also influenced by the Modernizing Alberta's Royalty Framework under which a producer will pay a flat royalty of 5% on a well's early production until its total revenue, from all hydrocarbon products, equals the drilling and completion cost allowance.

Natural gas, NGLs and condensate

For the three months ended December 31, 2018, the royalties paid for natural gas, NGLs and condensate decreased by C$317,208 to C$115,890 compared to C$433,098 for the same period in 2017, representing 43.5% and 73.3% of the total royalties respectively. For the year ended December 31, 2018, the royalties paid for natural gas, NGLs and condensate decreased by C$1,859,185 to C$515,550 compared to C$2,374,735 for the same period in 2017, representing 44.3% and 85.0% of the total royalties respectively. The decrease of royalties was primarily due to the decrease in market price and well production of natural gas.

Crude oil

For the three months ended December 31, 2018, the royalties paid for crude oil decreased by C$7,661 to C$150,219 compared to C$157,880 for the same period in 2017, representing 56.5% and 26.7% of the total royalties respectively. For the year ended December 31, 2018, the royalties paid for crude oil increased by C$229,508 to C$648,254 compared to C$418,746 for the same period in 2017, representing 55.7% and 15.0% of the total royalties respectively. The increase of royalties paid was a function of the increase of production volumes in response to the improvement in the market price.

Operating Costs

The following table shows the breakdown of the Company's operating costs by types of natural resources for the three months and years ended December 31, 2018 and 2017:

	Three months ended December 31,			**Year ended December 31,**		
	2018	2017	Change	**2018**	2017	Change
Total operating costs	***C$'000***	*C$'000*	*%*	***C$'000***	*C$'000*	*%*
Natural gas, NGLs and condensate	**1,410**	1,189	19%	**4,741**	5,372	(12%)
Crude oil	**171**	83	107%	**613**	374	64%
Total	**1,581**	1,272	24%	**5,354**	5,746	(7%)
Average operating costs	***C$***	*C$*	*%*	***C$***	*C$*	*%*
Natural gas, NGLs and condensate (Per Boe)	**8.10**	5.88	38%	**6.09**	5.28	15%
Crude oil (Per Bbl)	**29.06**	12.25	137%	**22.29**	14.63	52%
Average Cost (Per Boe)	**8.78**	6.09	44%	**6.64**	5.51	21%

For the three months ended December 31, 2018, operating costs increased to C$1,581,178 compared to C$1,271,550 for the same period in 2017. For the year ended December 31, 2018, the operating costs decreased to C$5,353,764 compared to C$5,746,160 for the same period in 2017. In both periods, the decrease of operating costs compared to the prior year was primarily attributable to the decrease in production volumes of natural gas and NGLs and condensate.

Natural Gas, NGLs and Condensate

Approximately 90% Company's revenue was generated from the sales of natural gas, NGLs and condensate in 2018 ad 2017. As a result, the majority of operating costs come from the natural gas and associated liquids business.

The natural gas market remained weakened in 2018, and in response the Company has strategically decreased production volumes to retain its reserves/resources for future recovery and long term growth. To fulfil its committed forward contracts for natural gas, the Company has taken advantage of the low price environment and purchased from the market, saving operating, transport and processing costs and arbitraging the price difference.

Average operating costs for the three months ended December 31, 2018 increased by C$2.22 per Boe to C$8.10 per Boe, compared to C$5.88 per Boe for the same period in 2017. The average operating costs for the year ended December 31, 2018 increased by C$0.81 per Boe to C$6.09 per Boe compared to C$5.28 per Boe for the same period in 2017. The increase in average operating costs was primarily attributable to the payment of the firm services transport costs, which was higher than the actual production reflecting trading gas purchases over the periods.

Crude Oil

The market price of crude oil increased in the second half of 2017 and first half of 2018. As a result the Company increased production from the Dawson area, increasing total operating costs for the three months and year ended December 31, 2018.

The average operating costs for the three months ended December 31, 2018 increased by C$16.80 per Bbl to C$29.06 per Bbl compared to C$12.25 per Bbl for the same period in 2017. The average operating costs for the year ended December 31, 2018 increased by C$7.66 per Bbl to C$22.29 per Bbl compared to C$14.63 per Bbl for the same period in 2017. The increase in costs for both periods in 2018 was attributable to additional water disposal costs.

General and Administrative Costs

The following table shows the breakdown of the general and administrative costs for the three months and years ended December 31, 2018 and 2017:

	Three months ended December 31,			Year ended December 31,		
	2018	2017	Change	**2018**	2017	Change
	C$'000	*C$'000*	*%*	***C$'000***	*C$'000*	*%*
Staff costs	**583**	416	40%	**2,201**	2,323	(5%)
Accounting, legal and consulting fees	**977**	828	18%	**2,310**	2,370	(3%)
Office rent	**95**	267	(64%)	**252**	670	(62%)
Other	**264**	232	14%	**822**	787	4%
General and administrative costs	**1,919**	1,743	10%	**5,585**	6,150	(9%)
Capitalized staff costs	**119**	195	(39%)	**538**	721	(25%)

For the three months and years ended December 31, 2018 and 2017, general and administrative costs mainly consisted of staff costs, accounting, legal and consulting fees, office rent and others. Other costs include office supplies, insurance and travel and accommodation, etc.

For the three months ended December 31, 2018, general and administrative costs increased by C$176,458 to C$1,918,839 compared to C$1,742,381 for the same period in 2017. For the year ended December 31, 2018, general and administrative costs decreased by C$565,435 to C$5,584,534 compared to C$6,149,973 for the same period in 2017. 2017 general and administrative costs included a management bonus for the completion of the Company's initial public offering.

Phantom Unit Plan for independent non-executive Directors

The Company has in place the Phantom Unit Plan for its independent non-executive directors effective on March 10, 2017 and applied retrospectively starting from February 26, 2016. In order for the eligible directors to receive the Phantom Units, they need to complete a participation form prior to the commencement of each fee period (i.e. twelve-month period commencing January 1 and ending on December 31). For the years ended December 31, 2018 and 2017, each eligible Director agreed in writing to receive 60% of their fees (i.e. the designated percentage) relating to future services as a director in the form of phantom units under the Phantom Unit Plan. Since 2016, the eligible directors have agreed to receive C$15,000 quarterly under the Phantom Unit Plan.

Under the terms of the plan, the Company calculates the Phantom Units by dividing the Phantom Fee by the weighted average-trading price of the Company's common shares for the five days preceding each quarter end multiplied by the number of Phantom Units awarded during the quarter. For each period, total compensation accrued for each director under the Phantom Unit Plan is based on the total number of units awarded in the preceding quarters multiplied by the weighted average trading price of the Company's common shares for the five days preceeding the period end.

During the three months ended December 31, 2018, the Company reserved C$36,767 (December 31, 2017: incurred C$74,761) of directors' compensation per the Phantom Unit Plan. During the year ended December 31, 2018, the Company incurred C$110,809 (December 31, 2017: C$122,833) of directors' compensation per the Phantom Unit Plan. As at December 31, 2018, the accrued compensation for independent non-executive directors per the Phantom Unit Plan was C$373,642 (December 31, 2017: C$262,833).

Upon a director ceasing to be a member of the Board, their Phantom Units may be redeemed by the director for cash at an amount collected as the number of units redeemed multiplied by the trading price of the Company's shares of the redemption date.

Finance Expenses

The following table shows the breakdown of finance expenses for the three months and year ended December 31, 2018 and 2017:

	Three months ended December 31,			**Year ended December 31,**		
	2018	2017	Change	**2018**	2017	Change
	C$'000	*C$'000*	*%*	***C$'000***	*C$'000*	*%*
Interest expense and financing costs	**847**	251	236.9%	**2,684**	6,643	(59.6%)
Amortization of debt issuance costs	**60**	—	—	**170**	210	(13.0%)
Accretion expense	**(7)**	(33)	(79.7%)	**40**	31	29.0%
Total finance expenses	**900**	218	318.8%	**2,894**	6,884	(57.8%)

For the three months and year ended December 31, 2018, finance expenses consisted of interest expense on bank debt, foreign exchange gains and losses, financing costs, amortization of debt issuance costs and accretion expense. For the three months ended December 31, 2018, finance expenses increased by C$682,541 to C$900,823 compared to C$218,282 for the same period in 2017. The increase over 2017 is due to higher interest incurred for the SubDebt (refer to Long Term Debt). For the years ended December 31, 2018, finance expenses decreased by C$3,990,305 to C$2,893,826 compared to C$6,884,131 in 2017. The decrease in finance expenses was attributable to the termination fee associated with the Company's previous debt facility.

Amortization of debt issuance costs includes legal fees, commissions and commitment fees. Commitment costs were capitalized against the bank loan account and amortized as a debt issuance costs account. The Company amortized all the remaining amount of debt issuance costs as a result of termination of the existing facility and entering into the new facility in 2017.

Accretion expense is recognized when updating the present value of the decommissioning provision.

Depletion and Depreciation

The following table shows the breakdown of the depletion and depreciation expenses for the three months and year ended December 31, 2018 and 2017:

	Three months ended December 31,			**Year ended December 31,**		
	2018	2017	Change	**2018**	2017	Change
	C$'000	*C$'000*	*%*	***C$'000***	*C$'000*	*%*
Depletion	**1,146**	1,390	(18%)	**5,333**	6,171	(14%)
Depreciation	**9**	2	287%	**36**	8	350%
Total depletion and depreciation	**1,155**	1,392	(17%)	**5,369**	6,179	(13%)
	C$	*C$*	*%*	***C$***	*C$*	*%*
Average depletion and depreciation (Per Boe)	**6.42**	6.67	(4%)	**6.66**	5.93	12%

Depletion is calculated applying the depletion ratio to the depletion base. Depletion base is calculated from the net book value of developed and producing assets at the end of the period and future development costs, and the depletion ratio is calculated based upon the production volume for the period divided by the total proved and probable reserves at the beginning of the period.

For the three months and year ended December 31, 2018, the depletion expense comprised the depletion of developed and producing assets, and the depreciation expense comprised the depreciation of office fixed assets, including office furniture, office equipment, vehicles, computer hardware and computer software.

For the three months ended December 31, 2018, the Company's depletion expense decreased by C$243,777 to C$1,146,491 compared to C$1,390,268 for the same period in 2017. For the year ended December 31, 2018, the Company's depletion expense decreased by C$838,255 to C$5,332,516 compared to C$6,170,771 for 2017. The decrease of depletion expense reflected the lower production in 2018 compared to 2017.

Write-offs

Exploration and Evaluation ("E&E") Assets

For the three months and year ended December 31, 2018, there were C$1,790,883 and C$1,790,883 write-offs (December 31, 2017: nil and C$273,969) of E&E assets attributable to land lease expiries. As at December 31, 2018, the Company concluded that there were no triggers for impairment on its E&E assets.

Property, Plant and Equipment ("PP&E")

For the three months and year ended December 31, 2018, the Company recorded write-offs of evaluation and exploration lands totaling C$1,962,280 and C$1,962,280 (December 31, 2017: C$80,256 and C$118,863) as a result of the Company's decision to allow certain non-core lands with no future prospective value to expire.

Share-based Compensation

There was no share-based compensation during the three months and years ended December 31, 2018 and 2017.

Other income

On December 20, 2018, the company monotized two in-the-money fixed price physical commodity contracts to sell forward natural gas in 2020 for C$752,000.

Transaction Costs

Transaction costs represent listing expenses incurred in the process of getting the Company listed on the Stock Exchange. On March 10, 2017, the Company was successfully listed on the Stock Exchange and the Company issued 69,580,000 new common shares at HK$3.16 per share (C$0.55 per share), raising gross proceeds of HK$220 million (approximately C$38 million). C$3 million in costs were incurred pursuant to the listing.

There were no transaction costs during the three months and year ended December 31, 2018. For the year ended December 31, 2017, the Company incurred C$3,003,350 of transaction costs. There were no transaction costs incurred during the three months ended December 31, 2017.

Financial Instruments

The Company holds a number of financial instruments, the most significant of which are accounts receivable, accounts payable, cash and loans. Financial instruments are recorded at amortized cost on the balance sheet.

The Company did not enter into any financial derivatives contracts for the three months and years ended December 31, 2018 and 2017.

For the three months ended December 31, 2018, the foreign exchange gain decreased to C$5,681 compared to foreign exchange gain of C$406,813 for the same period in 2017. For the year ended December 31, 2018, the foreign exchange gain increased to C$12,624, compared to foreign exchange loss of C$421,822 in 2017. These foreign exchange gains and losses are related to the revaluation of monetary items held in Hong Kong Dollars, and the value changes with movement in the Hong Kong Dollars/Canadian Dollars exchange rate. The Company is exposed to the financial risk related to the fluctuation of foreign exchange rates for the monetary assets and liabilities denominated in the currencies other than the functional currencies to which they relate. The Company has not hedged its exposure to currency fluctuation and the Company currently does not have a foreign currency hedging policy. However, management closely monitors foreign exchange exposure and will consider hedging significant foreign currency exposure should the need arise.

Net Loss

As a result of the above mentioned reasons, the net loss for the three months ended December 31, 2018 increased by C$2,463,326 to C$5,321,887 compared to C$2,858,561 for the same period in 2017, the net loss for the year ended December 31, 2018 decreased by C$4,357,331 to C$7,279,461 compared to C$11,636,792 for the same period in 2017.

Dividend

The Board did not approve the payment of a final dividend for the year ended December 31, 2018 (year ended December 31, 2017: nil).

LIQUIDITY AND CAPITAL RESOURCES

Capital management

The Company's general policy is to maintain an appropriate capital base in order to manage its business in the most effective manner with the goal of increasing the value of its assets and thus its underlying share value. The Company's objectives when managing capital are to maintain financial flexibility in order to preserve its ability to meet financial obligations; to maintain a capital structure that allows the Company to favor the financing of its growth strategy using internally-generated cash flow and its debt capacity; and to optimize the use of its capital to provide an appropriate investment return to its shareholders.

The Company manages its capital structure and makes adjustments to it in light of changes in economic conditions and the risk characteristics of the underlying crude oil and natural gas assets. The Company considers its capital structure to include shareholders' equity, bank debt, subordinated debt, other liabilities and working capital. To assess capital and operating efficiency and financial strength, the Company continually monitors its net debt. The Company has not paid nor declared any dividends since its inception.

Capital Structure of the Company

The Company's capital structure is as follows:

	As at December 31, 2018	As at December 31, 2017
	C$'000	*C$'000*
Long term debt[(1)]	**23,064**	22,197
Other liabilities	**4,226**	3,798
Net working capital[(2)]	**1,646**	55
Net debt	**28,936**	26,050
Shareholders' equity	**68,061**	74,693
Total Capital	**96,997**	100,743
Net debt as a percentage of total capital (%)	**29.8**	25.9

Notes:

(1) This is long term debt amount including the unamortized debt issue cost.

(2) Net working capital consists of current assets less current liabilities.

Long term debt

(a) Bank loan

On August 24, 2017, the Company and its lender (the "**Lender**") agreed to early termination of its existing facility and then entered into a new facility (the "**New Facility**"). A financing fee totaling C$4.3 million was paid to the Lender upon termination of the old facility and it has been recognized under finance expenses.

The maximum debt available under the New Facility is C$100 million, maturing on September 22, 2020 (36 months) from closing, and is subject to a semi-annual review of the borrowing base by the Lender. The initial New Facility draw was capped at C$24 million, and reduced to C$18.5 million during the period. With the closing of the SubDebt (as defined below), the New Facility is capped at C$10 million until the Company has repaid the SubDebt in full.

The New Facility carries interest of 4% plus one month Canadian Dealer Offered Rate ("**CDOR**"means the arithmetic average of the yields to maturity for bankers' acceptances quoted on the Reuter's Canadian Deposit Offered Rate) calculated on a 365 day basis on drawn amounts and payable in cash on a monthly basis in arrears and a commitment fee equal to 1% per annum will be payable on all amounts committed but undrawn, payable quarterly in arrears. As at December 31, 2018, the applicable effective interest rate on the New Facility was 5.7%.

The New Facility is secured by fixed and floating first priority perfected security interests in the properties and all assets, tangible and intangible, owned by the Company and thereafter acquired by the Company, including, but not limited to, all real and personal property, goods, accounts, contract rights, assignable licenses and assignable permits. The New Facility is subject to the following financial covenants: (a) maintenance at the end of each fiscal quarter a working capital ratio not less than 1.0:1.0; and (b) as measured at the end of each fiscal quarter, total debt to adjusted EBITDA not exceeding 3.0/1.0 through the fiscal quarter ended September 30, 2018 and 2.5/1.0 thereafter (Total debt and EBITDA as defined in the loan agreement). The Company was in compliance with these covenants as at December 31, 2018.

Under the New Facility agreement "total debt" is defined as the consolidated debt of the Company and including any liability; and "adjusted EBITDA" is defined as earnings before deduction of finance expenses, income taxes, depletion and depreciation, write-offs, transaction costs and share-based compensation. With the closing of the SubDebt (as defined below), "total debt" is defined as the consolidated debt of the Company, including any liability and excluding debt defined as other liabilities.

The principal and all accrued and unpaid interest and fees are due on the maturity date or in accordance with the terms of the New Facility. The Company maintains no letters of credit, as at December 31, 2018 (December 31, 2017: C$558,000) for transportation services in relation to the New Facility.

(b) Subordinated debt

On May 16, 2018, the Company completed a subordinated debt (the "**SubDebt**") financing with an arm's length lender (the "**SubLender**") totaling C$25 million. The SubDebt has a term of 60 months, and bears interest at 12% per annum, compounded and payable monthly. The Company has the option to prepay as follows: (i) after 12 months, the right to prepay C$10 million subject to a prepayment fee of 1% of the amount prepaid; and (ii) after 18 and up to 36 months, the right to prepay any SubDebt amount outstanding in tranches of C$5 million, subject to a prepayment fee of 3% of the amount prepaid; and (iii) after 37 months, the right to prepay any SubDebt amount outstanding in tranches of C$5 million, subject to a prepayment fee of 1% of the amount prepaid. An exit fee of C$0.75 million is payable when the SubDebt facility is repaid or at maturity on May 16, 2023.

The SubDebt is secured by a general security agreement over all present and after-acquired property of the Company subject to the fixed and floating first priority held by the Lender. Prior to December 2018, the SubDebt was subject to the following covenants: (a) maintenance at the end of each fiscal quarter a working capital ratio not less than 1.0:1.0; and (b) as measured at the end of each fiscal quarter, net debt to run rate EBITDA not exceeding 4.0/1.0 through the fiscal quarter ending March 2019, and 3.0/1.0 through the fiscal quarter ending March 31, 2020 and 2.5/1.0 thereafter; and (c) net debt to total proved reserves not exceeding 0.75/1.0 through the fiscal quarter ending March 31, 2019, and not exceeding 0.60/1.0 thereafter; and (d) maintaining the Company's Alberta Energy liability management ratio above 2.0/1.0.

Pursuant to the SubDebt agreement, no later than September 30 in each year, the Company must enter into arrangements to protect against fluctuations in commodity prices for 80% of its forecast production volume from proved Developed Producing Reserves.

Effective December 31, 2018, the Company and SubLender amended the SubDebt agreement (the "**First Amending Agreement**") such that run rate EBITDA for the covenant calculation was changed to trailing twelve months ("**TTM**") EBITDA, and for the fiscal quarter ended December 31, 2018, net debt to TTM EBITDA would not exceed 4.75/1.0.

Under the terms of the SubDebt agreement, "net debt" is defined as the consolidated debt of the Company, less cash held, and excluding debt defined as other liabilities. Under the terms of the First Amending Agreement, TTM EBITDA is defined as the annualized earnings before deduction of interest expenses/income, income taxes, depletion and depreciation, write-offs, unrealized hedging gains/losses and share-based compensation for the four most recent fiscal quarters.

The Company was not in compliance with the net debt to run rate EBITDA covenant of the SubDebt agreement as at September 30, 2018 and obtained a waiver for that covenant breach. After giving effect to the First Amending Agreement, the Company is in compliance with all covenants for the New Facility and SubDebt as at December 31, 2018.

In connection with the SubDebt, the Company sold 8 million share purchase warrants to the SubLender for C$750,000. The Company completed an initial draw of C$20.0 million from the SubDebt at closing. Pursuant to the Second Amending Agreement, subject to approval by the SubLender, the Company has an additional C$5.0 million of SubDebt available.

C$1.25 million in costs have been incurred in relation to the SubDebt and such amounts have been paid to the SubLender. These costs have been capitalised in long term debt and amortised until the maturity of the SubDebt.

In March 2019, the Company and SubLender further amended the SubDebt agreement (the "**Second Amending Agreement**"). The Second Amending Agreement eliminates the TTM EBITDA covenant for 2019, and implements a deferral of the monthly interest payable to the SubLender starting January 1, 2019 until the earlier of the repayment of the New Facility or January 1, 2020. The Company incurred a fee of C$1.0 million pursuant to the Second Amending Agreement. The fee was deemed to be incurred with the signing of the agreement, but capitalized as an increase of the SubDebt principal, such that the total amount owed under the SubDebt increased to C$21 million, and the total SubDebt available subject to SubLender approval increases to C$26 million. As such, no cash cost will be incurred in relation to the fee in 2019.

In light of the current volatility in oil and gas prices and uncertainty regarding the timing for recovery in such prices as well as pipeline and transportation capacity constraints, management's ability to prepare financial forecasts is challenging.

Due to this volatile economic environment, it is possible that the Company could breach the covenants noted within its facility and SubDebt agreements in future periods. If a covenant violation does occur, this will represent an event of default under the facility and the lenders have the right to demand repayment of all amounts owed under the facility and SubDebt.

Performance services guarantee ("PSG") facility

On April 25, 2018, the Company obtained a PSG from Export Development Canada ("**EDC**") totaling C$4.4 million. Under the terms of the PSG facility, EDC will guarantee qualifying letters of credit ("**L/C**") on behalf of the Company. Previously, these L/C's were cash collateralized, following approval by EDC the requirement of the Company to hold cash to underwrite the L/C is relieved for the duration of the PSG approval. Under the terms of the PSG facility, the L/C guarantee period is the lesser of one year or the term of the L/C if less than 12 months. The guarantee can be renewed annually for long term L/C's subject to subsequent approval by the EDC. At December 31, 2018, the Company has PSG coverage for the following L/C's:

Amount	**Expiry**
C$3,223,500	March 16, 2019
C$110,000	January 5, 2019
C$294,000	May 29, 2019
C$264,000	May 29, 2019

For the three months and year ended December 31, 2018, the Company incurred fees totaling nil and C$70,000 in relation to the PSG facility.

Shareholders' Equity

There were 278,286,520 common shares outstanding as at March 29, 2019. The Company was successfully listed on the Stock Exchange on March 10, 2017 with the issuance of 69,580,000 new shares at a price of HK$3.16 per share, resulting in the gross proceeds of HK$220 million (approximately C$38 million).

Liquidity

During the three months and year ended December 31, 2018, the Company's principal sources of liquidity and capital resources were cash flows from operating activities and financing activities. For the year ended December 31, 2018 the principal use of liquidity was the completion and testing of one well at Voyager and acquisition of undeveloped land. For the three months ended December 31, 2018 the principal use of liquidity was working capital. For the three months and year ended December 31, 2017 the Company's principal use of liquidity and capital resources was for the drilling of four development wells at Voyager and purchase of undeveloped land. The following table shows the Company's cash flows during the three months and years ended December 31, 2018 and 2017:

	Three months ended December 31,			**Year ended December 31,**		
	2018	2017	Change	**2018**	2017	Change
	C$'000	*C$'000*	*%*	***C$'000***	*C$'000*	*%*
Cash flows						
Net cash generated from/(used in) operating activities	**459**	1,937	(76%)	**3,514**	(2,049)	(272%)
Net cash used in investing activities	**(872)**	(11,217)	(92%)	**(4,628)**	(22,197)	(79%)
Net cash generated from/(used in) financing activities	**(4,188)**	(357)	1073%	**1,344**	22,721	(94%)
Effect of exchange rate fluctuations on cash and cash equivalents	**6**	315	(98%)	**13**	(78)	(117%)
Net increase/(decrease) in cash and cash equivalents	**(4,595)**	(9,322)	(51%)	**243**	(1,603)	(115%)
Cash and cash equivalents at the beginning of the period	**7,201**	11,685	(38%)	**2,363**	3,966	(40%)
Cash and cash equivalents at the end of the period	**2,606**	2,363	10%	**2,606**	2,363	10%

Net Cash Generated from/(Used in) Operating Activities

The Company's cash flows generated from/(used in) operating activities primarily consisted of net earnings, the effect of changes in working capital including accounts receivable, prepaid expense, accounts payable and accrued liabilities, with an adjustment for non-cash income and expenses.

Net cash generated from operating activities for the three months ended December 31, 2018 decreased by C$1,477,841 to C$458,669, compared to C$1,936,510 of cash generated for the same period in 2017. Net cash generated from/(used in) operating activities which includes movement in working capital of C$823,582 for the three months ended December 31, 2018, compared to movement in working capital of C$641,941 for the same period in 2017.

Net cash generated from operating activities for the year ended December 31, 2018 increased by C$5,563,517 to C$3,514,045 compared to cash used of C$2,049,472 for 2017. Net cash generated from/(used in) operating activities which includes movement in working capital of C$1,474,482 for the year ended December 31, 2018 compared to movement of C$(381,231) for the same period in 2017.

Net Cash Used in Investing Activities

The cash outflows from investing activities during the three months and year ended December 31, 2018 were mainly attributable to the Company's investments (Guaranteed Investment Certificate), capital expenditures on PP&E and E&E assets.

For the three months ended December 31, 2018, net cash used in investing activities decreased by C$10,345,521 to C$871,661 compared to C$11,217,182 cash used in investing activities for the same period in 2017. The decrease was primarily due to the decrease in E&E expenditures assets in 2018.

For the year ended December 31, 2018, net cash used in investing activities decreased by C$17,568,674 to C$4,628,458 compared to C$22,197,132 cash used in investing activities for the same period in 2017. The decrease was primarily due to lower E&E expenditures in 2018.

Net Cash Generated from Financing Activities

The Company's financing activities during the three months and years ended December 31, 2018 and 2017 mainly comprised of proceeds from share issuance, proceeds from long term debt and repayment of bank loan.

For the three months ended December 31, 2018, net cash used in financing activities increased by C$3,830,671 to C$4,187,751, compared to C$357,080 of cash used for the three months ended December 31, 2017. The change over the comparative period reflects repayment of C$3,148,885 to the bank loan in the three months ended December 31, 2018.

For the year ended December 31, 2018, net cash generated from financing activities decreased by C$21,377,027 to C$1,344,315, compared to C$22,721,342 for the year ended December 31, 2017. 2017 proceeds included C$36 million (net of share issue costs) from the Company's IPO.

Gearing ratio

Gearing ratio is defined as the ratio of total debt to total equity. As at December 31, 2018, the Company's total debt was C$27,289,679 and the total equity was C$68,060,664. The Company's gearing ratio was 40.1%.

Use of net proceeds from listing

The net proceeds from listing, after deducting share issue cost of C$3.0 million and transaction costs of C$3.0 million, amounted to C$32.0 million. For the year ended December 31, 2018, the Company has utilized all of these net proceeds for the drilling of new wells and general working capital as per the development plan.

Capital Resources

The Company operates in a capital intensive industry. The Company's liquidity requirements arise principally from the need for financing the expansion, exploration and development activities and acquisition of land leases and PNG Licenses. The Company's principal sources of funds have been proceeds from bank borrowings, equity financings, and cash generated from operations. The Company's liquidity primarily depends on its ability to generate cash flow from its operations and to obtain external financing to meet its debt obligations as they become due, as well as the Company's future operating and capital expenditure requirements.

As at December 31, 2018, the Company had long term debt of C$23.1 million, other liabilities of C$4.2 million and a working capital deficit of C$1.6 million. The Company's cash balance as at December 31, 2018 was C$2.6 million. The Company has an additional C$5.0 million available under the SubDebt and C$1.2 million available under the New Facility, subject to approval from the Sub Lender and Lender.

The Company has developed a range of planned expenditures for 2019 and 2020 which will be funded from free cashflow, working capital, remaining debt capacity and the Master Turnkey Drilling and Completion Contract. Management believes that its forecast cash flows, working capital and remaining debt capacity is sufficient to cover the next 12 months of the Company's operations, including capital expenditures and current debt repayments.

On March 25, 2019, the Company announced it entered into a subscription agreement with a subscriber to conditionally issue 23.6 million common shares at a price of HK$1.50 per share for gross proceeds of HK$35.4 million (approximately C$6 million) (the "**Subscription**"). The subscriber is a company incorporated under the laws of the British Virgin Islands, and is principally engaged in the investment of clean energy worldwide.

The Company intends to apply the net proceeds from the Subscription for the expansion of its existing business, the development of new business, and general working capital. The Subscription is scheduled to close on or before May 14, 2019. Refer to the Company's announcement dated March 25, 2019 for additional information regarding the Subscription.

Capital Expenditures

The Company's capital expenditures primarily consisted of the addition of E&E assets and PP&E to increase the Company's operating efficiency and execution capacity. During the three months and year ended December 31, 2018, the Company's capital expenditures were principally funded by cash flows generated from the operations and SubDebt.

The following table shows the Company's capital expenditures during the three months and years ended December 31, 2018 and 2017:

	Three months ended December 31,		Year ended December 31,	
	2018	2017	**2018**	2017
	C$'000	*C$'000*	***C$'000***	*C$'000*
PP&E				
Well site	**45**	3	**69**	319
Facilities and pipeline	**83**	143	**122**	1,789
General and administrative costs ("**G&A**") capitalized	**11**	(8)	**13**	46
Office	**—**	154	**—**	162
Sub-total	**139**	292	**204**	2,316
E&E Assets				
Undeveloped lands	**62**	60	**342**	1,547
General and administrative costs capitalized	**110**	203	**525**	675
Unevaluated drilling and completion costs	**725**	8,546	**4,344**	24,181
Sub-total	**897**	8,809	**5,211**	26,403
Change in non-cash working capital	**(5,259)**	2,116	**(2,548)**	(9,855)
Total	**(4,223)**	11,217	**2,867**	18,864

For the three months ended December 31, 2018, the total capital expenditures (including change in non-cash working capital) decreased by C$15,440,648 to C$(4,223,698), compared to C$11,216,950 for the same period in 2017.

For the three months ended December 31, 2018, the capital expenditures on PP&E were mainly attributable to: (i) well site cost of C$44,794; and (ii) well facility and pipeline costs of C$82,588. The additions in E&E assets were due to: (i) purchase of land rights for C$61,675 in Montney area; (ii) capitalized G&A costs of C$109,869; and (iii) drilling and completion costs of C$725,492 on the new well drilled in the Alberta Foothills.

For the three months ended December 31, 2017, the capital expenditures on PP&E were mainly attributable to: (i) well facility and pipeline cost of C$142,783; and (ii) office fixed assets cost of C$153,507. The additions in E&E assets were due to: (i) purchase of land rights for C$59,987 in the Montney area; (ii) capitalized G&A costs of C$203,264; and (iii) an increase in unevaluated drilling and completion costs of C$8,545,840 on the new wells drilled in the Alberta Foothills.

For the year ended December 31, 2018, the total capital expenditures (including change in non-cash working capital) decreased by C$15,996,802 to C$2,866,598 compared to C$18,863,400 for the same period of 2017.

For the year ended December 31, 2018, the capital expenditures on PP&E were mainly attributable to: (i) well site cost of C$68,514; and (ii) well facility and pipeline costs of C$121,733. The additions in E&E assets were due to: (i) purchase of land rights for C$342,181 in Alberta Foothills and Dawson; (ii) capitalized G&A costs of C$524,571; and (iii) an increase in unevaluated drilling and completion costs of C$4,343,793 on the new well drilled in the Alberta Foothills.

For the year ended December 31, 2017, the capital expenditures on PP&E were mainly attributable to: (i) well site cost of C$318,546; and (ii) well facility and pipeline cost of C$1,835,332. The additions in E&E assets were due to: (i) purchase of land rights for C$1,547,181 in Alberta Foothills and Dawson; (ii) capitalized G&A costs of C$674,652; and (iii) an increase in unevaluated drilling and completion costs of C$24,181,147 on the new well drilled in the Alberta Foothills.

Decommissioning Liabilities

The total future decommissioning obligations were estimated based on the Company's net ownership interest in petroleum and natural gas assets including well sites, gathering systems and facilities, the estimated costs to abandon and reclaim the petroleum and natural gas assets and the estimated timing of the costs to be incurred in future periods. As at December 31, 2018, the Company estimated the total undiscounted amount of cash flows required to settle its decommissioning obligations to be approximately C$3.0 million which will be incurred between 2019 and 2067. The majority of these costs will be incurred by 2037. As at December 31, 2018, an average risk free rate of 2.04% (December 31, 2017: 1.87%) and an inflation rate of 2% (December 31, 2017: 2%) were used to calculate the decommissioning obligations.

The following reconciles the Company's decommissioning liabilities:

	As at December 31, 2018	As at December 31, 2017
	C$'000	*C$'000*
Balance, beginning of the year	**2,172**	1,708
Change in estimate	**(19)**	(40)
Liabilities incurred	**—**	473
Accretion expense	**40**	31
Balance, end of the year	**2,193**	2,172
Which includes:		
Less than 1 year	**206**	205
After 1 year	**1,987**	1,967

As at December 31, 2018, the Company's decommissioning liabilities increased by C$20,833 to C$2,192,981 compared to C$2,172,148 as at December 31, 2017.

The Company's Liability Management Rating ("**LMR**") with the Alberta Energy Regulator ("**AER**") was 28.71 as at March 2, 2019. The LMR reflects the results of a comparison of the corporation's deemed assets to its deemed liabilities and is updated monthly. An LMR rating less than 1.0 would require the Company to pay a deposit to the AER.

RELATED PARTY TRANSACTIONS

(a) Transactions with key personnel

Key management compensation for the three months and year ended December 31, 2018 totaled C$469,503 and C$1,574,385 respectively (December 31, 2017: C$345,321 and C$2,026,932).

During the three months ended December 31, 2018, the Company reversed C$36,767 (three months ended December 31, 2017: C$74,761) of directors' compensation per the Phantom Unit Plan. During the year ended December 31, 2018, the Company incurred C$110,809 (year ended December 31, 2017: C$122,833) of directors' compensation per the Phantom Unit Plan. As at December 31, 2018, the accrued compensation for independent non-executive directors per the Phantom Unit Plan was C$373,642 (December 31, 2017: C$262,833).

(b) Transactions with other related parties

There were no other related party transactions during the three months and year ended December 31, 2018.

OFF-BALANCE SHEET TRANSACTIONS

The Company was not involved in any off-balance sheet transactions during the three months and years ended December 31, 2018 and 2017.

PLEDGED ASSETS

As disclosed in this MD&A, all assets are pledged in support of the banking arrangements and there are no other pledges.

COMMITMENTS

Commitments and contingencies exist under various agreements and operations in the normal course of the Company's business. For a detailed discussion regarding the Company's commitments and contingencies, please refer to the Company's audited financial statements and notes thereto for the year ended December 31, 2018 and December 31, 2017.

	Total	**Less than 1 year**	**1–3 years**	**4–5 years**	**After 5 years**
	C$'000	*C$'000*	*C$'000*	*C$'000*	*C$'000*
As at December 31, 2018					
Office premise lease	3,590	410	1,231	1,231	718
Lease of compressors	456	238	218	—	—
Transportation commitment	46,733	5,709	12,209	7,212	21,603
PSG facility	3,892	3,892	—	—	—
Total contractual obligations	54,671	10,249	13,658	8,443	22,321

Office premise lease:

— In June 2017, the Company entered into an office lease for a term starting from January 2018 to February 2025. The rent payable is as follows:

- January 1, 2018 to December 31, 2018, rent payable of C$17,098 per month
- January 1, 2019 to December 31, 2019, rent payable of C$34,197 per month
- January 1, 2020 to February 27, 2025, rent payable of C$51,295 per month

In addition, office premise lease costs will include an estimate of the Company's share of operating costs for its office premises for the duration of the lease term.

Lease of compressors:

— The Company entered into a lease agreement for a compressor, term is from December 1, 2017 to November 30, 2020 requiring monthly lease payments of C$19,800.

Transportation Commitment:

— The Company entered into a take or pay firm service transportation agreement with committed transportation volumes as below:

Description	Volume (MMcf/d)	Effective date	Expiring date	Duration
Persta Existing FT-R with NGTL	8.00	2013-11-01	2021-10-31	8 years
Persta New FT-R with NGTL	102.00	2018-07-01	2026-06-30	8 years
Persta FT-R from ConocoPhillips — first agreement	7.24	2016-09-01	2018-08-31	2 years
Persta FT-R from ConocoPhillips — second agreement	3.40	2016-09-01	2018-04-30	1 year and 8 months

The firm service transportation agreements cover the period from November 1, 2013 to December 31, 2026 (the firm service fee varies and is subject to review by the counter-party on an annual basis). The amounts presented in the Commitments table above for the transportation service commitment fee is based on fixed transportation capacity as per these agreements and management's best estimate of future transportation charges.

The Company also entered into the following fixed price physical commodity contracts to forward sell natural gas during the year ended December 31, 2018:

Commodity	Term	Quantity	Price
Natural gas	November 1, 2018 to March 31, 2019	1,000 GJ/day	C$2.14 per GJ
Natural gas	January 1, 2019 to December 31, 2019	6,900 GJ/day	C$2.08 per GJ
Natural gas	January 1, 2019 to March 31, 2019	1,000 GJ/day	C$2.23 per GJ

CONTINGENT LIABILITIES

As at December 31, 2018 and up to the date of this MD&A, the Company had no material contingent liabilities.

EVENTS AFTER THE REPORTING PERIOD

Subordinated debt agreement amendment

In March 2019, the Company and SubLender agreed to amend the SubDebt agreement. The amendment eliminated the TTM to EBITDA covenant for 2019, and implements a deferral of monthly interest payable for the SubDebt starting January 1, 2019 until the earlier of the repayment of the New Facility or January 1, 2020. The Company incurred a fee totalling C$1.0 million in relation to the amendment. The fee will be capitalized, increasing the SubDebt principal by C$1.0 million, and increasing the total SubDebt available, subject to SubLender approval, to C$26 million.

Performance services guarantee amendments

In March 2019, pursuant to its transportation commitments, the Company reduced its C$3.2 million L/C to C$1.39 million, guaranteed by the EDC on the same terms as the original L/C.

Issue of new shares under general mandate

On March 25, 2019, the Company announced it entered into a subscription agreement with a subscriber to conditionally issue 23.6 million common shares at a price of HK$1.50 per share for gross proceeds of HK$35.4 million (approximately C$6 million). The Company intends to apply the net proceeds from the subscription for the expansion of its existing business, the development of new business, and general working capital. The subscription is scheduled to close on or before May 14, 2019.

NON-IFRS FINANCIAL MEASURES

This MD&A or documents referred to in this MD&A make reference to the terms "operating netback" and "adjusted EBITDA", which are not recognized measures under IFRS, and do not have a standardized meaning prescribed by IFRS. Accordingly, the Company's use of these terms may not be comparable to similarly defined measures presented by other companies. Management considers operating netback an important measure to evaluate the Company's operational performance, as it demonstrates its field level profitability relative to current commodity prices. Management uses adjusted EBITDA to measure the Company's efficiency and its ability to generate the cash necessary to fund a portion of its future growth expenditures or to repay debt. Investors are cautioned that the non-IFRS measures should not be construed as an alternative to net income determined in accordance with IFRS as an indication of the Company's performance.

Operating netback

	Three months ended December 31,			Year ended December 31,		
	2018	2017	Change	**2018**	2017	Change
	C$'000	*C$'000*	*%*	***C$'000***	*C$'000*	*%*
Revenue from crude oil and natural gas sales	**3,543**	5,334	(34%)	**16,435**	22,684	(28%)
Trading cost	**(82)**	(263)	(69%)	**(409)**	(500)	(18%)
Royalties	**(266)**	(590)	(55%)	**(1,164)**	(2,793)	(58%)
Operating costs	**(1,581)**	(1,271)	24%	**(5,354)**	(5,746)	(7%)
Operating netback	**1,614**	3,210	(50%)	**9,508**	13,645	(30%)

Adjusted EBITDA

	Three months ended December 31,			Year ended December 31,		
	2018	2017	Change	**2018**	2017	Change
	C$'000	*C$'000*	*%*	***C$'000***	*C$'000*	*%*
Revenue from crude oil and natural gas sales	**3,543**	5,334	(34%)	**16,435**	22,684	(28%)
Trading cost	**(82)**	(263)	(69%)	**(409)**	(500)	(18%)
Royalties	**(266)**	(590)	(55%)	**(1,164)**	(2,793)	(58%)
Operating costs	**(1,581)**	(1,271)	24%	**(5,354)**	(5,746)	(7%)
General and administrative costs	**(1,919)**	(1,742)	10%	**(5,585)**	(6,150)	(9%)
Other income	**793**	38	1,996%	**813**	49	1,559%
Adjusted EBITDA	**488**	1,506	(68%)	**4,736**	7,544	(37%)

The term "total debt" is not used by management in measuring performance but is used in the financial covenants under the Company's credit facility. Under the credit facility agreement, "total debt" is defined as the consolidated debt of the Company and including any liability.

FUTURE PLANS FOR MATERIAL INVESTMENTS AND CAPITAL ASSETS

Save as disclosed in this MD&A, the Company did not have other plans for material investments or capital assets as of the date of this MD&A.

SIGNIFICANT INVESTMENTS, ACQUISITIONS AND DISPOSALS OF SUBSIDIARIES, ASSOCIATES AND JOINT VENTURES

Save as disclosed in this MD&A, the Company has no significant investments or significant acquisitions, and has no subsidiaries, associates and joint ventures.

HUMAN RESOURCES

The Company had 10 employees as of December 31, 2018 and December 31, 2017. The employees of the Company are employed under employment contracts which set out, among other things, their job scope and remuneration. Further details of their employment terms are set out in the employee handbook of the Company. The Company determines the employees' salaries based on their job nature, scope of duty, and individual performance. The Company also provides reimbursements, allowances for site visits and a discretionary annual bonus for the employees. For details, please refer to note 19 to the audited annual financial statements for the years ended December 31, 2018 and 2017.

RISK FACTORS

The business of resource exploration, development and extraction involves a high degree of risk. Material risks and uncertainties affecting the Company, their potential impact and the Company's principal risk management strategies are substantially unchanged from those disclosed in the Company's Annual Information Form ("**AIF**") for the year ended December 31, 2018. The AIF is available at *www.sedar.com*.

DISCLOSURE CONTROLS AND PROCEDURES

Mr. Le Bo, Chairman of the Board and Chief Executive Officer, and Mr. Jesse Meidl, Chief Financial Officer, have designed, or caused to be designed under their supervision, disclosure controls and procedures ("**DC&P**") to provide reasonable assurance that: (i) material information relating to the Company is made known to the Company's chief executive officer and chief financial officer by others, particularly during the period in which the annual and quarterly filings are being prepared; and (ii) information required to be disclosed by the Company in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time period specified in securities legislation.

INTERNAL CONTROLS OVER FINANCIAL REPORTING

Mr. Le Bo, Chairman of the Board and Chief Executive Officer, and Mr. Jesse Meidl, Chief Financial Officer, have designed, or caused to be designed under their supervision, internal controls over financial reporting ("**ICFR**") to provide reasonable assurance regarding the reliability of the Company's financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. Furthermore, the Company used the criteria established in "Internal Control — Integrated Framework" published by the Committee of Sponsoring Organizations of the Treadway Commission (2013 COSO Framework).

No material changes in the Company's ICFR were identified during the year ended December 31, 2018 that have materially affected, or are reasonably likely to materially affect, the Company's ICFR. It should be noted that a control system, including the Company's disclosure and internal controls and procedures, no matter how well conceived, can provide only reasonable, but not absolute, assurance that the objectives of the control system will be met and it should not be expected that the disclosure and internal controls and procedures will prevent all errors or fraud. In reaching a reasonable level of assurance, management necessarily is required to apply its judgment in evaluating the cost/benefit relationship of possible controls and procedures.

DIVIDEND AND DIVIDEND POLICY

The Company has not paid any dividends since incorporation and does not currently have a fixed dividend policy. The Board of Directors will determine any future dividend policy on the basis of, among others things, the results of operations, cash flows and financial conditions, operating and capital requirements, the rules promulgated by the regulators affecting dividends in both Canada and Hong Kong, the Stock Exchange, the amount of distributable profits and other relevant factors.

Subject to the Business Corporations Act (Alberta), the Directors may from time to time declare and authorise payment of such dividends as they may deem advisable, including the amount thereof and the time and method of payment provided that the record date for the purpose of determining shareholders entitled to receive payment of the dividend must not precede the date on which the dividend is to be paid by more than 50 days.

A dividend may be paid wholly or partly by the distribution of cash, specific assets or of fully paid shares or of bonds, debentures or other securities of the Company, or in any one or more of those ways. No dividend may be declared or paid in money or assets if there are reasonable grounds for believing that the Company is insolvent or the payment of the dividend would render the Company insolvent.

REVIEW OF ANNUAL RESULTS

The annual results announcement of the Company for the year ended December 31, 2018, was reviewed by the audit and risk committee of the Company and approved by the Board. The financial figures in respect of the Company's financial statements for the year ended December 31, 2018 as set out in the announcement have been compared by the Company's auditor, KPMG LLP, Chartered Professional Accountants, to the amounts set out in the Company's financial statements for the year and the amounts were found to be in agreement. The work performed by KPMG LLP in this respect did not constitute an audit, review or other assurance engagement in accordance with International Standards on Auditing, International Standard on Review Engagements or International Standard on Assurance Engagements issued by the International Auditing and Assurance Standards Board and consequently no assurance has been expressed by the auditor.

OTHER INFORMATION

FINAL DIVIDEND

The Board does not recommend the payment of a final dividend for the year ended December 31, 2018 (year ended December 31, 2017: nil).

RECORD DATE

All registered shareholders of the Company as at 4:30 p.m. on May 6, 2019 (Hong Kong time) and 2:30 a.m. on May 6, 2019 (Calgary time), as the case may be, may vote in person at the annual general and special meeting or any adjournments thereof, or they (including a beneficial shareholder of the Company) may appoint another person (who need not be a shareholder) as their proxy to attend and vote in their place.

CORPORATE GOVERNANCE PRACTICES

The Company is committed to maintaining high standards of corporate governance to safeguard the interests of shareholders and to enhance corporate value and accountability. The Board has adopted the principles and the code provisions of the Corporate Governance Code (the "**CG Code**") contained in Appendix 14 to the Listing Rules to ensure that the Company's business activities and decision making processes are regulated in a proper and prudent manner.

Mr. Le Bo is the chairman of the Board and chief executive officer of the Company. Although this deviates from the practice under code provision A.2.1 of the CG Code, where it provides that the two positions should be held by two different individuals, as Mr. Bo has considerable experience in the enterprise operation and management of the Company, the Board believes that it is in the best interests of the Company and its shareholders as a whole to continue to have Mr. Bo as chairman of the Board so that it can benefit from his experience and capability in leading the Board in the long-term development of the Company. From a corporate governance point of view, the decisions of the Board are made collectively by way of voting and therefore the chairman should not be able to monopolize the decision-making of the Board. The Board considers that the balance of power between the Board and management can still be maintained under the current structure. The Board shall review the structure from time to time to ensure appropriate action be taken should the need arise.

Save as disclosed above, for the year ended December 31, 2018 (the "**Year**"), the Company has complied with the CG Code.

MODEL CODE FOR SECURITIES TRANSACTIONS

The Company has adopted the Model Code for Securities Transactions by Directors of Listed Issuers as set out in Appendix 10 to the Listing Rules (the "**Model Code**") as its code of conduct regarding dealings in the securities of the Company by the Directors and the Company's senior management who, because of his/her office or employment, is likely to possess inside information in relation to the Company's securities.

Upon specific enquiry, all Directors confirmed that they have complied with the Model Code during the Period. In addition, the Company is not aware of any non-compliance of the Model Code by the senior management of the Company during the Year.

PURCHASE, SALE OR REDEMPTION OF LISTED SECURITIES OF THE COMPANY

The Company has not purchased, redeemed or sold any of its listed securities during the Year.

PUBLICATION OF INFORMATION

This announcement is published on the websites of the Stock Exchange *(www.hkexnews.hk)* and the Company *(www.persta.ca)*.

This announcement is prepared in both English and Chinese and in the event of inconsistency, the English text of this announcement shall prevail over the Chinese text.