Persta Resources Inc.

(incorporated under the laws of Alberta with limited liability)

(Stock Code: 3395)

INTERIM RESULTS ANNOUNCEMENT FOR THE SIX MONTHS ENDED JUNE 30, 2018

SELECTED PRODUCTION AND FINANCIAL HIGHLIGHTS: FIRST HALF 2018 COMPARED TO FIRST HALF 2017

	Six months ended June 30,		Increase/
	2018	2017	**(Decrease)**
(UNAUDITED)	***C$***	*C$*	%
Production revenue from crude oil and natural gas sales	**8,913,957**	12,170,445	(26.8)
Trading revenue from natural gas sales	**521,018**	—	N/A
Operating Netback *(Note 1)*	**5,954,727**	7,090,246	(16.0)
Adjusted EBITDA *(Note 2)*	**3,402,095**	3,976,987	(14.5)
Loss and total comprehensive loss for the period attributable to owners of the Company	**(886,706)**	(7,199,125)	(87.7)
Loss per share	**(0.00)**	(0.03)	(100.0)
Total production volume (Boe)	**471,454**	607,118	(22.3)
Daily average production volume (Boe/d)	**2,605**	3,354	(22.3)

Note 1: Operating Netback is defined as revenue less royalties and operating costs. Operating Netback is a non-IFRS financial measure, see "Non-IFRS Financial Measures" on pages 28 to 30 of this announcement.

Note 2: Adjusted EBITDA is 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" on pages 28 to 30 of this announcement.

The board (the "**Board**") of directors (the "**Directors**") of Persta Resources Inc. ("**Persta**" or the "**Company**") hereby announces the unaudited interim results of the Company for the six months ended June 30, 2018 as follows:

CONDENSED INTERIM STATEMENT OF LOSS AND OTHER COMPREHENSIVE LOSS
For the six months ended June 30, 2018
(Expressed in Canadian dollars)
Unaudited

		Six months ended June 30,	
		2018	2017
	Note	***C$***	*C$*
Production revenue from crude oil and natural gas sales	*4*	**8,913,957**	12,170,445
Royalties		**(578,353)**	(1,806,701)
		8,335,604	10,363,744
Trading revenue from natural gas sales	*4*	**521,018**	—
Trading cost from natural gas purchases		**(225,570)**	—
		295,448	—
Net revenue		**8,631,052**	10,363,744
Operating costs		**(2,676,325)**	(3,273,498)
General and administrative costs	*5*	**(2,565,997)**	(3,123,289)
Depletion and depreciation		**(3,163,571)**	(3,501,167)
Direct write-offs of exploration and evaluation assets		**—**	(273,969)
Direct write-offs of property, plant and equipment		**—**	(38,607)
Income from operations		**225,159**	153,214
Other income		**13,365**	10,030
Transaction costs		**—**	(3,003,350)
Finance expenses		**(1,125,230)**	(4,359,019)
Loss before income taxes		**(886,706)**	(7,199,125)
Income taxes	*6*	**—**	—
Loss and total comprehensive loss for the period attributable to owners of the Company		**(886,706)**	(7,199,125)
Loss per share	*7*		
Basic and diluted		**(0.00)**	(0.03)

The accompanying notes form part of the interim financial information.

CONDENSED INTERIM STATEMENT OF FINANCIAL POSITION
As at June 30, 2018
(Expressed in Canadian dollars)

	Note	**As at June 30, 2018 *C$* (Unaudited)**	As at December 31, 2017 *C$* (Audited)
ASSETS			
Current assets			
Cash and cash equivalents		**8,580,713**	2,363,183
Investments		**—**	3,333,500
Accounts receivable	*2*	**1,040,808**	1,813,992
Prepaid expenses and deposits		**623,707**	870,286
		10,245,228	8,380,961
Non-current assets			
Exploration and evaluation assets		**43,705,172**	40,065,106
Property, plant and equipment		**59,487,904**	62,645,297
		103,193,076	102,710,403
Total assets		**113,438,304**	111,091,364
LIABILITIES AND TOTAL EQUITY			
Current liabilities			
Accounts payable and accrued liabilities	*3*	**6,006,642**	8,230,602
Current portion of long term debt		**—**	22,197,243
Decommissioning liabilities		**205,836**	205,429
		6,212,478	30,633,274
Non-current liabilities			
Other liabilities		**3,651,928**	3,798,280
Long term debt		**27,149,035**	—
Decommissioning liabilities		**1,965,978**	1,966,719
		32,766,941	5,764,999
Total liabilities		**38,979,419**	36,398,273
Total equity			
Share capital		**204,366,683**	204,366,683
Warrants		**652,500**	—
Accumulated deficit		**(130,560,298)**	(129,673,592)
Total equity		**74,458,885**	74,693,091
Total liabilities and total equity		**113,438,304**	111,091,364

The accompanying notes form part of the interim financial information.

NOTES TO THE UNAUDITED INTERIM FINANCIAL INFORMATION

For the six months ended June 30, 2018

(Expressed in Canadian dollars unless otherwise indicated)

1 BASIS OF PREPARATION AND ACCOUNTING POLICIES

The interim financial information set out in this announcement does not constitute the unaudited condensed interim financial statements of the Company for the six months ended June 30, 2018 but is extracted from those unaudited draft condensed interim financial statements which have been prepared in accordance with the applicable disclosure provisions of the Rules Governing the Listing of Securities on the Stock Exchange, including compliance with International Accounting Standard ("**IAS**") 34, Interim financial reporting, issued by the International Accounting Standards Board. The unaudited interim financial information was authorised for issue on August 30, 2018.

The Company's accounting policies are described in note 3 to the December 31, 2017 audited annual financial statements. Those accounting policies have been applied consistently to all periods presented in the condensed interim financial statements except as noted below.

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 ("**FVOCI**") 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, however there are additional required disclosures. Accounts receivable, accounts payable and 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 FVOCI.

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.

Revenue from the sale of natural gas, natural gas liquids, condensate and crude oil (collectively "**product**") is recognized based on the consideration specified in contracts with customers and when control of the product transfers to the customer 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 ("**lessee**") and the supplier ("**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 early stages of evaluating the impact of IFRS 16 on its financial statements and the extent of the impact has not yet been determined.

2 ACCOUNTS RECEIVABLE

	As at June 30, 2018	As at December 31, 2017
	C$	*C$*
Trade receivables	**1,040,808**	1,813,992

(a) Aging analysis of trade receivables

As at June 30, 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 June 30, 2018	As at December 31, 2017
	C$	*C$*
Within 1 month	**1,040,808**	1,798,983
1 to 2 months	**—**	144
2 to 3 months	**—**	—
Over 3 months	**—**	14,865
	1,040,808	1,813,992

Trade receivables are to be 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 impairment loss has been recognized in respect of trade receivables for the six months ended June 30, 2018 and 2017.

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.

3 ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

	As at June 30, 2018 *C$*	As at December 31, 2017 *C$*
Trade payables	**358,358**	182,386
Accrued liabilities	**926,911**	2,679,869
Accrued compensation for independent non-executive directors per Phantom Unit Plan *(Note)*	**331,467**	262,833
Subtotal	**1,616,736**	3,125,088
Other payables	**4,389,906**	5,105,514
Total	**6,006,642**	8,230,602

Note: The accrued compensation for independent non-executive directors per Phantom Unit Plan will be accrued quarterly and paid in accordance with the terms set out in the Phantom Unit Plan as set out in the Company's prospectus dated February 28, 2017.

As at June 30, 2018, there were C$3,447,085 of unpaid capital expenditures included in other payables (December 31, 2017: C$4,362,647).

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 June 30, 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 June 30, 2018	As at December 31, 2017
	C$	*C$*
Within 1 month	**314,009**	1,226,481
1 to 3 months	**971,260**	1,635,774
Over 3 months but within 6 months	**—**	—
	1,285,269	2,862,255

4 REVENUE

The Company sells its production 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 six months ended June 30, 2018 and 2017 is as follows:

	Six months ended June 30,	
	2018	2017
	C$	*C$*
Production revenue from natural gas, natural gas liquids and condensate sales	**7,899,919**	11,494,634
Production revenue from crude oil sales	**1,014,038**	675,811
	8,913,957	12,170,445
Trading revenue from natural gas sales	**521,018**	—

5 PERSONNEL COSTS AND REMUNERATION POLICY

Personnel costs incurred during the six months ended June 30, 2018 and 2017 were as follows:

	Six months ended June 30,	
	2018	2017
	C$	*C$*
Personnel costs		
Salaries, wages and other benefits	**1,022,971**	1,594,360
Retirement benefits contribution	**28,323**	24,322
	1,051,294	1,618,682

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. In order for the eligible directors to receive 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 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 5 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 5 days preceding the period end.

During the six months ended June 30, 2018, the Company incurred C$68,634 (June 30, 2017: C$105,735) of directors' compensation per the Phantom Unit Plan. As at June 30, 2018, the accrued compensation for independent non-executive directors per the Phantom Unit Plan was C$331,467 (December 31, 2017: C$262,833).

6 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.

	Six months ended June 30,	
	2018	2017
	C$	*C$*
Loss before income taxes	**(886,706)**	(7,199,125)
Combined Federal and Provincial tax rate	**27%**	27%
Expected tax benefit	**(239,411)**	(1,943,764)
Increase/(decrease) in taxes resulting from:		
— Non-deductible expenses	**1,282**	398
— Change in unrecognized deferred tax assets	**233,344**	1,943,617
— Change in enacted tax rate and others	**4,785**	(251)
Income tax expense	**—**	—

During the six months ended June 30, 2018, the blended statutory tax rate was 27% (June 30, 2017: 27%).

The components of unrecognized deferred tax assets are as follows:

	Six months ended June 30, 2018	Year ended December 31, 2017
	C$	*C$*
Deferred tax assets have not been recognized in respect of the following temporary differences:		
Property, plant and equipment and exploration and evaluation assets	**24,305,109**	18,412,877
Decommissioning liabilities	**2,171,814**	2,172,148
Share issue costs	**5,638,116**	12,425,390
Non-capital losses and other	**9,004,683**	4,233,255
Total	**41,119,722**	37,243,670

At June 30, 2018, the Company has approximately C$143 million of tax deductions, which include loss carry forwards of approximately C$8 million that will expire in 2037.

7 LOSS PER SHARE

The calculation of basic loss per share is based on the loss and total comprehensive loss of C$886,706 and C$7,199,125 for the six months ended June 30, 2018 and 2017 respectively and is calculated as follows:

	Six months ended June 30,	
	2018	2017
	Number of shares	*Number of shares*
Weighted average number of common shares		
At the beginning of the period	**278,286,520**	208,706,520
Effect of new shares issued	**—**	43,439,448
At the end of the period	**278,286,520**	252,145,968
	C$	*C$*
Loss and total comprehensive loss for the period	**(886,706)**	(7,199,125)
Loss per share		
Basic and diluted	**(0.00)**	(0.03)

There were no dilutive potential common shares for the six months ended June 30, 2018 and 2017 due to the loss and therefore, diluted loss per share is the same as basic loss per share.

8 DIVIDEND

The Board did not approve the payment of a dividend for the six months ended June 30, 2018 and 2017.

MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis ("**MD&A**") should be read in conjunction with the Company's unaudited condensed interim financial statements and notes thereto for the six months ended June 30, 2018 and the audited annual financial statement and MD&A for the year ended December 31, 2017. All amounts and tabular amounts in this MD&A are stated in thousands of Canadian dollars unless indicated otherwise.

SELECTED ABBREVIATIONS

In this MD&A, the abbreviations set forth below have the following meanings:

Crude Oil and Natural Gas Liquids

Bbls/d or Bbl/d	barrels of oil per day
Bbls or Bbl	barrels of oil or barrel of oil
Boe	barrel of oil equivalent
Boe/d	barrel of oil equivalent per day
C$/Bbl	Canadian dollars per barrel of oil
C$/Boe	Canadian dollars per barrel of oil equivalent
Mbbls or Mbbl	thousand barrels
Mboe	thousand barrels of oil equivalent
Mbpd	thousand barrels per day
MMbbls	million barrels of oil
MMbbls/d	million barrels of oil per day
MMboe	million barrels of oil equivalent
MMboe/d	million barrels of oil equivalent per day
US$/Bbl	US dollars per barrel of oil

Natural Gas

Bcf	billion cubic feet
Bcm	billion cubic meters
Cf	cubic feet
C$/Mcf	Canadian dollars per thousand cubic feet
C$/MMbtu	Canadian dollars per million British thermal units
GJ	gigajoule
GJ/d	gigajoules per day
Mcf	thousand cubic feet
Mcf/d	thousand cubic feet per day
Mcfe	thousand cubic feet of gas equivalent
Mcfe/d	thousand cubic feet of gas equivalent per day
MMbtu	million British thermal units
MMcf	million cubic feet

MMcf/d	million cubic feet per day
MMcfe	million cubic feet of gas equivalent
MMcfe/d	million cubic feet of gas equivalent per day
tcf	trillion cubic feet
US$/MMbtu	US dollars per million British thermal units

Other

km	kilometres
km^2	square kilometres
m	meters
m^3	cubic meters
mg	milligrams
^oC	degrees Celsius

Conversion Factors — Imperial to Metric

Bbl = 0.1590 cubic metres (m^3)

Mcf = 0.0283 cubic metres (10^3m^3)

acres = 0.4047 hectares (ha)

Btu = 1,054.615 joules (J)

feet (ft) = 0.3048 metres (m)

miles (mi) = 1.6093 kilometres (km)

pounds (Lb) = 0.4536 kilograms (kg)

Boe Conversions — Per barrel of oil equivalent amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil equivalent (6:1). Barrel of oil equivalents (boe) may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf:1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In addition, as the value ratio between natural gas and crude oil based on the current prices of natural gas and crude oil is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

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" 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”.

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 peak production of 3,297 Boe/d for the six months ended June 30, 2018. As at June 30, 2018, the Company held 118,807 net acres of land in the WCSB, which the Company intends to explore through drilling in locations listed in the Company’s multi-year inventory.

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, a 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 ("**PNG**") Licenses for Basing, Voyager and Kaydee in the Alberta Foothills, Dawson in Peace River and Progress, Montney in northern Alberta between 2006 and 2018. The Company plans to initially develop its natural gas and oil assets in Basing, Voyager and Progress, Montney as part of its three-year development plan in addition to constructing certain facilities to support future increases in production and to lower production costs in the long run.

The Company also intends to explore and develop its resources in Voyager and Kaydee in the Alberta Foothills to expand reserves and also the undeveloped lands in Stolberg, Columbia and Deep Basin Devonian in the future.

In 2018–2019 subject to capital availability, the Company will drill up to 8 wells on its Progress-Montney and Basing lands to increase the Company's production rate. The Company has 100% working interest in these 8 well locations. The cost per well are expected to be C$6 million.

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. There were 5 natural gas producing wells and 3 crude oil producing wells both as at June 30, 2017 and 2018.

Pricing forecasts directly affect 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 prices on the natural resources.

The natural gas market remains weakened in 2018, so the Company has strategically decreased production volume in response to the soft market, whilst retaining the reserves/resources for future recovery and long term growth. On the other hand, the Company has taken advantage of the low price environment and purchased from the market to fulfill the committed forward contracts for natural gas, saving operating costs and arbitraging from the price difference. The natural gas liquids ("**NGLs**") and condensate are the by-products from the production of natural gas and their production volumes decreased accordingly. In the meantime, the Company improved operating efficiency and increased the production volumes of crude oil in 2018, which was mainly due to the recovery of the market price of crude oil since the second half of 2017.

For the six months ended June 30, 2018, the Company's total production volume decreased by 135,664 Boe to 471,454 Boe compared to 607,118 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 six months ended June 30, 2018 and 2017:

	Six months ended June 30,		
	2018	2017	Change %
Natural gas			
Producing wells (number of wells)	**5**	5	0.0
Production volume (Mcf)	**2,629,241**	3,409,868	(22.9)
Natural gas			
Trading volume (Mcf)	**198,227**	—	N/A
Crude oil			
Producing wells (number of wells)	**3**	3	0.0
Production volume (Bbl)	**14,719**	11,739	25.4
NGLs (by-product of natural gas)			
Producing wells (number of wells)	**5**	5	0.0
Production volume (Bbl)	**5,766**	8,698	(33.7)
Condensate (by-product of natural gas)			
Producing wells (number of wells)	**5**	5	0.0
Production volume (Bbl)	**12,763**	18,370	(30.5)
Total			
Producing wells (number of wells)	**8**	8	0.0
Production volume (Boe)	**471,454**	607,118	(22.3)
Trading volume (Boe)	**33,038**	—	N/A

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 or companies involved in gas and oil trading. The selling price of its natural gas benchmarks to 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 six months ended June 30, 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. These sales values accounted for 75.1% of the Company's total production revenue from crude oil and natural gas sales for the six months ended June 30, 2018, compared with 63.6% for the same period in 2017. The sales of remaining production accounted for 24.9% of its total revenue from crude oil and natural gas sales for the six months ended June 30, 2018, compared with 36.4% for the same period in 2017.

During the six months ended June 30, 2018, the Company has taken advantage of the low price environment and purchased 198,227 Mcf of natural gas from the market to fulfill the committed forward contracts for natural gas, saving on operating costs and arbitraging from 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 six months ended June 30, 2018 and 2017:

	Six months ended June 30,		
	2018	2017	Change
	C$	*C$*	*%*
Natural gas			
Average market price (C$ per Mcf) *(Note 1)*	**1.76**	2.81	(37.4)
Average realized price (C$ per Mcf) *(Note 2)*	**1.92**	2.92	(34.2)
Average forward sales price (C$ per Mcf) *(Note 3)*	**2.76**	3.00	(8.0)
Average trading sales price (C$ per Mcf) *(Note 4)*	**2.63**	—	N/A
Average sales price (C$ per Mcf) *(Note 5)*	**2.56**	2.98	(14.1)
Crude oil			
Average market price (C$ per Bbl) *(Note 6)*	**74.33**	62.32	19.3
Average sales price (C$ per Bbl) *(Note 5)*	**68.89**	57.57	19.7
NGLs			
Average market price (C$ per Bbl) *(Note 7)*	**36.91**	32.92	12.1
Average sales price (C$ per Bbl) *(Note 5)*	**34.70**	27.34	26.9
Condensate			
Average market price (C$ per Bbl) *(Note 7)*	**82.09**	67.06	22.4
Average sales price (C$ per Bbl) *(Note 5)*	**78.03**	59.58	31.0

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 six months ended June 30, 2018, and comparing to the same period of 2017, the average market price of natural gas has decreased from C$2.81 per Mcf to C$1.76 per Mcf. To exploit weakness in the current market, the Company purchased natural gas from the market at C$1.14 per Mcf to fulfill the forward sales contracts with a weighted average price of C$2.63 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 six months ended June 30, 2018, compared to the same period of 2017.

Crude oil

The average market price of crude oil increased from C$62.32 per Bbl for the six months ended June 30, 2017 to C$74.33 per Bbl for the same period in 2018. As a result, the Company's average sales price increased by 19.7% from C$57.57 per Bbl for the six months ended June 30, 2017 to C$68.89 per Bbl for the same period in 2018.

NGLs

The average market price of NGLs increased from C$32.92 per Bbl for the six months ended June 30, 2017 to C$36.91 per Bbl for the same period in 2018. As a result, the Company's average sales price increased 26.9% from C$27.34 per Bbl for the six months ended June 30, 2017 to C$34.70 per Bbl for the same period in 2018.

Condensate

The average market price of condensate increased from C$67.06 per Bbl for the six months ended June 30, 2017 to C$82.09 per Bbl for the same period in 2018. As a result, the Company's average sales price increased by 31.0% from C$59.58 per Bbl for the six months ended June 30, 2017 to C$78.03 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 six months ended June 30, 2018 and 2017:

	Six months ended June 30,		
	2018	2017	Change
	C$'000	*C$'000*	*%*
Natural gas	**7,225**	10,162	(28.9)
Crude oil	**1,014**	676	50.0
NGLs	**200**	238	(16.0)
Condensate	**996**	1,094	(9.0)
Total revenue	**9,435**	12,170	(22.5)

Sales of Natural Gas

The following table shows the sales volume and average sales price of the Company's natural gas for the six months ended June 30, 2018 and 2017:

	Six months ended June 30,		
	2018	2017	Change %
Sales volume (Mcf)	**2,827,468**	3,409,868	(17.1)
Realized sales volume	**654,695**	875,868	(25.3)
Forward sales volume	**1,974,546**	2,534,000	(22.1)
Trading sales volume	**198,227**	—	N/A
Average sales price (C$/Mcf)	**2.56**	2.98	(14.1)
Average Realized sales price	**1.92**	2.92	(34.2)
Average Forward sales price	**2.76**	3.00	(8.0)
Average Trading sales price	**2.63**	—	N/A

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 market price.

Sales of Crude Oil

The following table shows the sales volume and average sales price of the Company's crude oil for the six months ended June 30, 2018 and 2017:

	Six months ended June 30,		
	2018	2017	Change %
Sales volume (Bbl)	**14,719**	11,739	25.4
Average sales price (C$/Bbl)	**68.89**	57.57	19.7

The revenue derived from the Company's sales of crude oil was mainly 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 its oil well in the Dawson area and increased its production volume in response to the improvement in the market price of crude oil.

Sales of NGLs

The following table shows the sales volume and average sales price of the Company's NGLs for the six months ended June 30, 2018 and 2017:

	Six months ended June 30,		
	2018	2017	Change
			%
Sales volume (Bbl)	**5,766**	8,698	(33.7)
Average sales price (C$/Bbl)	**34.70**	27.34	26.9

Sales of Condensate

The following table shows the sales volume and average sales price of the Company's condensate for the six months ended June 30, 2018 and 2017:

	Six months ended June 30,		
	2018	2017	Change
			%
Sales volume (Bbl)	**12,763**	18,370	(30.5)
Average sales price (C$/Bbl)	**78.03**	59.58	31.0

The revenue derived from the Company's sales of NGLs and condensate was mainly affected by the average sales price and sales volume of such products. Both the average sales price of the Company's NGLs and condensate are highly sensitive to the Alberta natural gas liquids commodity price and demand of the petrochemical industry, and the sales volume of its NGLs and condensate was 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, and as a by-product, 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 six months ended June 30, 2018 and 2017:

	Six months ended June 30,		
	2018	2017	Change
			%
Purchase volume (Mcf)	**198,227**	—	N/A
Average purchase price (C$/Mcf)	**1.14**	—	N/A

Royalties

The following table shows the breakdown of the Company's royalties by types of natural resources for the six months ended June 30, 2018 and 2017.

	Six months ended June 30,		
	2018	2017	Change
	C$'000	*C$'000*	%
Natural gas, NGLs and condensate	**247**	1,611	(84.7)
Crude oil	**331**	196	68.9
Total royalties	**578**	1,807	(68.0)

For the six months ended June 30, 2018, the effective average royalty rate decreased by 8.3% to 6.5% compared to 14.8% for the same period in 2017. The decrease of the effective average royalty rate was primarily due to the decrease 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 mainly subject to 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 drop reflecting declining production rates and market price.

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

Natural gas, NGLs and condensate

For the six months ended June 30, 2018, the royalties paid for natural gas, NGLs and condensate decreased by C$1,364,164 to C$247,015 compared to C$1,611,179 for the same period in 2017, representing 42.7% and 89.2% 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 six months ended June 30, 2018, the royalties paid for crude oil increased by C$135,816 to C$331,338 compared to C$195,522 for the same period in 2017, representing 57.3% and 10.8% of the total royalties respectively. The increase of royalties was primarily due to the increase of production volume 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 six months ended June 30, 2018 and 2017:

	Six months ended June 30,		
	2018	2017	Change
Total operating costs	***C$'000***	*C$'000*	*%*
Natural gas, NGLs and condensate	**2,357**	3,057	(22.9)
Crude oil	**319**	216	47.7
Total	**2,676**	3,273	(18.2)
Average operating costs	***C$***	*C$*	*%*
Natural gas, NGLs and condensate (Per Boe)	**5.16**	5.13	0.6
Crude oil (Per Bbl)	**21.67**	18.47	17.3
Average Cost (Per Boe)	**5.68**	5.39	5.4

For the six months ended June 30, 2018, the operating costs decreased to C$2,676,325 compared to C$3,273,498 for the same period in 2017, which was mainly due to the decrease in production volumes of natural gas and NGLs and condensate.

Natural Gas, NGLs and Condensate

Most of the Company's revenue was generated from the sales of natural gas, NGLs and condensate. As a result, the majority of the operating costs come from the natural gas related business.

For the six months ended June 30, 2018, and comparing to the same period of 2017, the market price of natural gas has decreased, and the Company has strategically shut-in some production in response to the soft market, whilst retaining the reserves/resources for future recovery and long term growth. The Company has taken advantage of the low price environment and purchased from the market to fulfill the committed forward contracts for natural gas, saving operating costs and arbitraging from the price difference.

The average operating costs for the six months ended June 30, 2018 increased by C$0.03 per Boe to C$5.16 per Boe compared to C$5.13 per Boe for the same period in 2017, attributable to the payment of extra gas transportation fee when the fixed FT-Volume is higher than the actual production for the same period accordingly.

Crude Oil

The market price of crude oil increased in the second half of 2017, therefore the Company resumed the production from the oil well in the Dawson area which then led to the increase in total operating costs for the six months ended June 30, 2018.

The average operating costs for the six months ended June 30, 2018 increased by C$3.20 per Bbl to C$21.67 per Bbl compared to C$18.47 per Bbl for the same period in 2017, which was due to the recovery of production and increase of unit cost of liquid tracking and treatment in the Dawson area.

General and Administrative Costs

The following table shows the breakdown of the general and administrative costs for the six months ended June 30, 2018 and 2017:

	Six months ended June 30,		
	2018	2017	Change
	C$'000	*C$'000*	*%*
Staff costs	**1,051**	1,619	(35.1)
Accounting, legal and consulting fees	**1,031**	852	21.0
Office rent	**100**	286	(65.0)
Others	**384**	366	4.9
General and administrative costs	**2,566**	3,123	(17.8)
Capitalized staff costs	**299**	331	(9.7)

For the six months ended June 30, 2018 and 2017, the general and administrative costs mainly consisted of staff costs, accounting, legal and consulting fees, office rental and others. Others mainly includes office supplies, insurance and travel and accommodation, etc.

For the six months ended June 30, 2018, the general and administrative costs decreased by C$557,292 to C$2,565,997 compared to C$3,123,289 for the same period in 2017. 2017 cost 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 a phantom unit plan for its independent non-executive directors effective on March 10, 2017 and applied retrospectively started from February 26, 2016 (the "**Phantom Unit Plan**"). In order for the eligible directors to receive 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 six months ended June 30, 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 (the "**Phantom Fee**").

Under the terms of the 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 5 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 5 days preceding the year end.

During the six months ended June 30, 2018, the Company incurred C$68,634 (June 30, 2017: C$105,735) of directors' compensation per the Phantom Unit Plan. As at June 30, 2018, the accrued compensation for independent non-executive directors per the Phantom Unit Plan was C$331,467 (December 31, 2017: C$262,833).

Finance Expenses

The following table shows the breakdown of the finance expenses for the six months ended June 30, 2018 and 2017:

	Six months ended June 30,		
	2018	2017	Change
	C$'000	*C$'000*	*%*
Interest expense and financing costs	**1,048**	4,171	(74.9)
Amortization of debt issuance costs	**35**	158	(77.8)
Accretion expense	**42**	30	40.0
Total finance expenses	**1,125**	4,359	(74.2)

For the six months ended June 30, 2018, the finance expenses mainly consisted of interest expense on bank debt, foreign exchange gains and losses, financing costs, amortization of debt issuance costs and accretion expense. For the six months ended June 30, 2018, finance expenses decreased by C$3,233,789 to C$1,125,230 compared to C$4,359,019 for the same period in 2017. The decrease of finance expenses was mainly due to the decrease of finance expenses upon termination of the existing facility and entering into the new facility in 2017.

Amortization of debt issuance costs represented legal fees, commissions and commitment fees, which had been incurred since the closing of the credit and term facility arrangement in 2014 and 2018. These 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.

The accretion expense is an expense 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 six months ended June 30, 2018 and 2017:

	Six months ended June 30,		
	2018	2017	Change
	C$'000	*C$'000*	*%*
Depletion	**3,145**	3,498	(10.1)
Depreciation	**19**	3	533.3
Total depletion and depreciation	**3,164**	3,501	(9.6)
	C$	*C$*	*%*
Average depletion and depreciation (Per Boe)	**6.71**	5.77	16.3

Depletion is calculated using the depletion base and the depletion ratio. Depletion base is based upon 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 six months ended June 30, 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 six months ended June 30, 2018, the Company's depletion expense decreased by C$352,783 to C$3,145,418 compared to C$3,498,201 for the same period in 2017, reflecting lower production in 2018 compared to 2017.

Write-offs

During the six months ended June 30, 2017, write-offs were mainly due to the expiry of certain Crown Leases and PNG Licenses. There were no write-offs for the six months ended June 30, 2018.

Exploration and Evaluation Assets

The Company had no write-offs of exploration and evaluation lands for the six months ended June 30, 2018.

Property, Plant and Equipment

The Company had no write-offs of developing and producing lands for the six months ended June 30, 2018.

There were no indicators of impairment identified at June 30, 2018.

Share-based Compensation

There was no share-based compensation during the six months ended June 30, 2018 and 2017.

Transaction Costs

Transaction costs represents listing expenses incurred in the process of getting the Company listed on the Stock Exchange.

There was no transaction costs during the six months ended June 30, 2018. For the six months ended June 30, 2017, the Company incurred C$3,003,350 of transaction costs due to the listing 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 shares at HK$3.16 per share (C$0.55 per share), raising gross proceeds of HK$220 million (approximately C$38 million). The costs associated with the issuance of new shares were approximately C$3 million and therefore the net amount to be recorded as share capital was approximately C$35 million.

Financial Instruments

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

The Company did not enter into any financial derivatives for the six months ended June 30, 2018 and 2017.

For the six months ended June 30, 2018, foreign exchange gain increased to C$10,519 compared to foreign exchange loss of C$342,373 for the same period in 2017. The gain is related to the revaluation of monetary items held in Hong Kong Dollars and the value changes with the fluctuation in the Hong Kong Dollars/Canadian Dollars exchange rates. 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 six months ended June 30, 2018 decreased by C$6,312,419 to C$886,706 compared to C$7,199,125 for the same period in 2017.

Dividend

The Board did not approve the payment of an interim dividend for the six months ended June 30, 2018 (six months ended June 30, 2017: nil).

NON-IFRS FINANCIAL MEASURES

This interim results announcement or documents referred to in this interim results announcement make reference to the terms "operating netback", "adjusted EBITDA" and "total debt" 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

	Six months ended June 30,		
	2018	2017	Change
	C$'000	*C$'000*	*%*
Revenue from crude oil and natural gas sales	**9,435**	12,170	(22.5)
Trading cost	**(226)**	—	N/A
Royalties	**(578)**	(1,807)	(68.0)
Operating costs	**(2,676)**	(3,273)	(18.2)
Operating netback	**5,955**	7,090	(16.0)

Adjusted EBITDA

	Six months ended June 30,		
	2018	2017	Change
	C$'000	*C$'000*	*%*
Revenue from crude oil and natural gas sales	**9,435**	12,170	(22.5)
Trading cost	**(226)**	—	N/A
Royalties	**(578)**	(1,807)	(68.0)
Operating costs	**(2,676)**	(3,273)	(18.2)
General and administrative costs	**(2,566)**	(3,123)	(17.8)
Other income	**13**	10	30.0
Adjusted EBITDA	**3,402**	3,977	(14.5)

The terms "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.

Total debt[1]

	As at June 30, 2018	As at December 31, 2017	Change
	C$'000	*C$'000*	%
Long term debt[2]	**27,149**	22,197	22.3
Other liabilities	**3,652**	3,798	(3.8)
Letter of credit	**558**	558	0.0
Total debt	**31,359**	26,553	18.1

Notes:

(1) As defined in Credit Agreement for the purposes of calculating financial based covenants.

(2) This amount only includes the actual drawdown from the credit facility.

CORPORATE GOVERNANCE PRACTICES

The Company is committed to maintaining high standards of corporate governance to safeguard the interests of its 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 Rules Governing the Listing of Securities on the Stock Exchange (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 the 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 six months ended June 30, 2018 (the "**Reporting Period**"), 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 Reporting 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 Reporting Period.

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 Reporting Period.

EVENTS AFTER THE REPORTING PERIOD

There was no significant event after the Reporting Period up to the date of this announcement.

REVIEW OF THE INTERIM RESULTS

The Company established an audit and risk committee of the Company (the "**Audit and Risk Committee**") with written terms of reference in compliance with the CG Code. As at the date of this announcement, the Audit and Risk Committee comprises three independent non-executive Directors, namely Mr. Bryan Daniel Pinney (Chairman), Mr. Richard Dale Orman and Mr. Peter David Robertson.

The Audit and Risk Committee has reviewed the Company's interim results for the six months ended June 30, 2018 and has also discussed with management the internal control, the accounting principles and practices adopted by the Company. The Audit and Risk Committee is of the opinion that the interim results have been prepared in accordance with the applicable accounting standards, laws and regulations and the Listing Rules and that adequate disclosures have been made.

PUBLICATION OF INFORMATION

This interim results 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.

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

Calgary, August 30, 2018

Hong Kong, August 30, 2018

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.