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	872	18	201	(6,871)	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 calculated 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 *C$'000*	As at December 31, 2017 *C$'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. 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 default 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.

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.

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.