You should read the following discussion and analysis with our audited financial information, including the notes thereto, as at and for the years ended December 31, 2013, 2014 and 2015 and the nine months ended September 30, 2016 included in the Accountants' Report set out in Appendix I to this Prospectus. The financial information as set out in the Accountants' Report has been prepared in accordance with IFRS issued by the International Accounting Standards Board ("IASB").

The following discussion and analysis and other parts of the Prospectus contain forward looking statements that reflect our current views with respect to future events and financial performance that involve risks, uncertainties and changes in circumstances. These statements are based on assumptions and analysis made by us in light of our experience and perception of historical events, current conditions and expected future developments, as well as other factors we believe are appropriate under the circumstances. In evaluating our business, you should carefully consider the information provided in the sections headed "Forward-Looking Statements" and "Risk Factors" in the Prospectus.

OVERVIEW

Our Company is based in Calgary and is principally engaged in natural gas and crude oil exploration and production, with a focus on natural gas. We focus on long-term growth through acquisition, exploration, development and production in WCSB.

We commenced operations in March 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. We acquired our first 6,400 net acres of land in an area in WCSB in January 2007 known as the Alberta Foothills and drilled and commercially produced liquids-rich natural gas from our first deep well in this area in December 2008. Since then, our natural gas and oil production rate has organically grown and reached approximately 3,363 Boe/d of average production in the first nine months of 2016. The exit production of 2016 is 4,500 Boe/d. As at the Latest Practicable Date, we held 114,528 net acres of land in WCSB which we intend to explore through drilling in locations listed in our Company's multi-year inventory.

Presently, we have three core areas:

- Alberta Foothills, which includes natural gas properties in the five areas of Basing, Voyager, Kaydee, Columbia and Stolberg. Basing is partially developed whilst Voyager, Kaydee, Columbia and Stolberg are undeveloped;
- Deep Basin Devonian, which includes undeveloped natural gas properties in Hanlan-Peco in West Alberta; and
- Peace River, which includes light oil properties in the Dawson area which is partially developed.

As at September 30, 2016, as estimated by GLJ, we held a total of 77 drilling locations, with five assigned to Proved, Probable plus Possible Reserves, eight assigned to Contingent Resources and 64 assigned to Prospective Resources. GLJ estimated our Company holds gross Proved Reserves of 12,099 Mboe (approximately 5.4% of which is crude oil, condensate and other NGLs with the remaining 94.6% being natural gas), gross Proved plus Probable Reserves of 17,666 Mboe (approximately 5.4% of which is crude oil, condensate and other NGLs, with the remaining 94.6% being natural gas), gross Proved plus Probable plus Possible Reserves of 22,562 Mboe (approximately 5.4% of which is crude oil, condensate and other NGLs, with the remaining 94.6% being natural gas), gross Best Estimate Unrisked Contingent Resources of 10,396 Mboe (approximately 4.9% of which is condensate and other NGLs, with the remaining 95.1% being natural gas), and gross Best Estimate Unrisked Prospective Resources of 67,526 Mboe (approximately 7.0% of which is crude oil, condensate and other NGLs, with the remaining 93.0% being natural gas). Please refer to the Competent Person's Report as set out in Appendix IV to this Prospectus for more information.

As at the Latest Practicable Date, we have five wells in production and one other well that had been voluntarily and temporarily shut-in in Basing, and we have two wells in production and another one well that had been voluntarily and temporarily shut-in in Dawson.

THREE-YEAR DEVELOPMENT PLAN

Our Company's Proved, Probable and Possible Reserves, Contingent Resources and Prospective Resources are located within Basing, Voyager and Kaydee in the Alberta Foothills and within Dawson in Peace River, encompassing approximately 54,400 net acres of land and estimated by GLJ to hold approximately 77 drilling locations.

We acquired the PNG Licences for Basing, Voyager and Kaydee in the Alberta Foothills and for Dawson in Peace River between 2006 and 2016. We plan to initially develop our natural gas assets in Basing as part of our three-year development plan in addition to constructing certain facilities to support future increases in production and to lower production cost in the long run.

We also intend to explore and develop our Resources in Voyager and Kaydee in the Alberta Foothills and Dawson in Peace River into Reserves and also our undeveloped lands in Stolberg, Columbia and Deep Basin Devonian.

We have established a three-year development plan to increase our current production from an average production of 3,363 Boe/d in the first nine months of 2016 to approximately 5,448 Boe/d based on Proved plus Probable Reserve and an additional 2,389 Boe/d based on Best Estimate Unrisked Contingent Resources in 2019.

According to our three-year development plan, we intend to focus on drilling a total of 13 well locations in Basing in the Alberta Foothills. These 13 drilling locations represent 100% of Proved plus Probable Reserves and Best Estimate Contingent Resources by GLJ.

The table below shows our three-year development plan by number of drilling locations in Basing in the Alberta Foothills.

Our Company's Three Year Development Plan by Drilling Location and Number*

	2017	2018	2019	Total
Alberta Foothills — Basing	3	2	8	13
Total number of wells to be drilled	3	2	8	13

* Key assumptions in determining the drilling location and the number in the above are based on those adopted by GLJ. Please refer to the Competent Person's Report in Appendix IV to this Prospectus for more information.

Based on the production forecast by GLJ, an average production volume forecast for 2017 to 2018 is as below:

Our Company's 2017–2019 Year Production Forecast by Volume*

		2017 (2P)	2018 (2P)	2019 (2P)	2019 (Best Estimated Unrisked Contingency)**
Alberta Foothills	Natural Gas (Mcf/d)	35,276	37,464	30,884	13,635
	Liquid (NGLs/ Condensate) (Bbls/d)	301	319	263	116
Peace River	Light Oil (Bbls/d)	65	49	37	
Production (Boe/d)		6,245	6,612	5,448	2,389

* Key assumptions in determining the drilling location and the production forecasts for above individual well are based on those adopted by GLJ. Please refer to the Competent Person's Report in Appendix IV to this Prospectus for more information.

** Production forecast of all new drilling locations in 2019 is based on best estimated unrisked Contingent Resources in the Competent Person's Report. If based on best estimated risked Contingent Resources to reflect a chance of development, a factor of 80% shall be applied to the production forecast.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Revenue Recognition

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

Derivative Financial Instruments

Our Company may utilize financial and non-financial derivatives, such as commodity sales contracts requiring physical delivery, to manage the price risk attributable to the anticipated sales of crude oil and natural gas production and foreign exchange exposures. Our Company does not enter into derivative financial instruments for trading or speculative purposes.

Our Company considers all of these transactions to be economic hedges; however, they have not been designated as hedges for accounting purposes. As a result, all derivative contracts are classified as fair value through profit or loss and are recorded on the statements of financial position at fair value, with changes in the fair value recognized in net income. The fair values of these derivative instruments are based on an estimate of the amounts that would have been received or paid to settle these instruments prior to maturity given future market prices and other relevant factors.

Exploration and Evaluation ("E&E") Assets

Exploration and evaluation ("**E&E**") assets includes costs capitalized by our Company in connection with the exploration for and evaluation of mineral resources before the technical feasibility and commercial viability of extracting mineral resources are demonstrable. Costs incurred before our Company has obtained the legal rights to explore an area are expensed.

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

Once the technical feasibility and commercial viability of the extraction of resources in an area of interest are demonstrable based on technical data available to support the possible recovery of reserves, E&E assets attributable to that area are assessed for impairment with any impairment loss recognized in profit or loss. The remaining carrying value of the relevant E&E assets are then reclassified as development and production assets within property, plant and equipment.

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

Property, Plant and Equipment ("PPE")

Property, plant and equipment ("**PPE**") of our Company consists of development and production assets and office fixture and equipment.

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

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

Impairments

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

The recoverable amount of an asset or a CGU is the greater of its value in use and its fair value less costs of disposals ("**FVLCD**").

Value in use is estimated by consideration of the following:

(i) net present value of the proved plus probable reserves using a pre-tax discount rate as determined by management's estimate; and

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

FVLCD is estimated by consideration of the following:

(i) net present value of proved plus probable reserves using a pre-tax discount rate as determined by management's estimate;

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

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

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

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

Depletion and Depreciation

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

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

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

Decommissioning Liability

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

SIGNIFICANT FACTORS AFFECTING OUR RESULTS OF OPERATIONS

Demand and Price of Natural Gas and Crude Oil in Canada

Our ability to achieve profitability depends largely on the demand for and price of natural gas and crude oil in Canada.

Our revenue and results of operations are substantially dependent on the prevailing prices of natural gas and oil which are unstable and subject to fluctuation. Fluctuations in natural gas or oil prices could have an adverse effect on our operations and financial condition and the value and amount of our reserves. Natural gas prices are influenced primarily by factors within North America, including North American supply and demand, economic performance, weather conditions and availability and pricing of alternative fuel sources. Crude oil prices are mainly driven by a few factors which include the supply from the Organization of Petroleum Exporting Countries (OPEC) and the supply from outside the OPEC, global crude oil demand and crude oil inventories. Furthermore, crude oil prices also react to a variety of geopolitical and economic events as well. In addition, the marketability of the production depends upon the availability, capacity and destinations of gathering systems, pipelines, and other transportation infrastructure, approval and regulation of federal and provincial infrastructure projects, effect of federal and provincial regulation on such production and general economic conditions. All of these factors are beyond our control. Adverse changes in general economic and market conditions could also negatively impact demand for natural gas and oil, production cost, results of financing efforts, fluctuations in interest rates, market competition, labor market supplies, timing and extent of capital expenditures or credit risk and counterparty risk.

Decrease in natural gas and oil prices typically results in a reduction of our Company's net production revenue and may change the economics of producing from some wells, which could result in a reduction in the volume of our Company's production. We have temporarily shut-in two producing oil wells in 2015 due to economic limit considerations. Any substantial declines in the prices of crude oil or natural gas could also result in delay or cancellation of existing or future drilling, development or construction programs or the curtailment of production. All of these factors could result in a material decrease in our net production revenue, cash flows and profitability and have a material adverse effect on our operations, financial condition and proved reserves and the level of expenditures for the development of its natural gas and oil reserves, causing a reduction in its oil and gas acquisition and development activities. In addition, bank borrowings available to us will in part be determined by our borrowing base. A sustained material decline in prices from historical average prices could further reduce such borrowing base, therefore reducing the bank credit available and could require that a portion of our bank debt be repaid.

Natural gas and oil prices are expected to remain volatile for the near future because of market uncertainties over the supply and the demand of these commodities due to the current state of the world economies. Volatile natural gas and oil prices make it difficult to estimate the value of producing properties for acquisitions and often cause disruption in the market for natural gas and oil producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for and project the return on acquisitions and development and exploitation projects.

We mainly sell our 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 our natural gas benchmarks to Canadian Gas Price Reporter, which is also known as Alberta Energy Company natural gas price ("**AECO natural gas price**"), while the natural gas related products and crude oil products benchmark to monthly average of WTI commodity price. During the Track Record Period, we also entered into sales agreements to sell our natural gas over a time period at a specified price and volume. The sales value accounted for 29.6%, 23.9%, 72.2% and 52.0% of our total revenue from crude oil and natural gas sales for the years ended December 31, 2013, 2014 and 2015 and the nine months ended September 30, 2016, respectively. Therefore, the sales of remaining production which accounted for 70.4%, 76.1%, 27.8% and 48.0% of our total revenue from crude oil and natural gas sales for the years ended December 31, 2013, 2014 and 2015 and the nine months ended September 30, 2016, respectively, were sensitive to the respective market price movements.

The table below shows the average market prices and average sales prices for our natural gas, crude oil, NGLs and condensate and the average realized sales price and forward sales price for our natural gas during the Track Record Period.

	Year ended December 31			Nine months ended September 30
	2013	**2014**	**2015**	**2016**
Natural gas				
Average market price (C$ per Mcf)*(Note 1)*	3.23	4.57	2.74	2.01
Average realized price (C$ per Mcf)*(Note 2)*	3.53	5.02	2.43	1.70
Average forward sales price (C$ per Mcf)*(Note 3)*	3.73	4.07	3.95	3.10
Average sales price (C$ per Mcf)*(Note 4)*	3.62	4.70	3.61	2.45
Crude oil				
Average market price (C$ per Bbl)*(Note 5)*	100.88	102.71	62.29	41.34
Average sales price (C$ per Bbl)*(Note 4)*	91.92	93.50	49.09	47.14
NGLs				
Average market price (C$ per Bbl)*(Note 5)*	53.85	57.37	21.62	20.44
Average sales price (C$ per Bbl)*(Note 4)*	48.16	51.05	17.98	17.66
Condensate				
Average market price (C$ per Bbl)*(Note 5)*	104.70	102.44	60.42	53.54
Average sales price (C$ per Bbl)*(Note 4)*	96.37	88.92	61.81	49.54

Notes:

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

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

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

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

(5) The average market price was the average WTI daily settlement price of the near month contract over the period price.

Our average sales price of natural gas consisted the weighted average of the average 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. Our average realized price of natural gas fluctuated from C$3.53 per Mcf in 2013 to C$5.02 per Mcf in 2014, and further to C$2.43 per Mcf in 2015 and C$1.70 per Mcf in the first nine months of 2016, mainly due to market price movement.

Our average sales price of crude oil fluctuated from C$91.92 per Bbl in 2013 to C$93.50 per Bbl in 2014, and further to C$49.09 per Bbl in 2015 and further to C$47.14 per Bbl for the nine months ended September 30, 2016, mainly due to market price movement.

Our average sales price of NGLs fluctuated from C$48.16 per Bbl in 2013 to C$51.05 per Bbl in 2014, and further to C$17.98 per Bbl in 2015 and further to C$17.66 per Bbl for the nine months ended September 30, 2016 while condensate decreased from C$96.37 per Bbl in 2013 to C$88.92 per Bbl in 2014, and further to C$61.81 per Bbl in 2015 and further to C$49.54 per Bbl for the nine months ended September 30, 2016, mainly due to market price movement.

We sold our natural gas benchmarked to AECO natural gas price and our crude oil and NGLs and condensate benchmarked to monthly average WTI commodity price. Our Company also entered into forward sales agreements to sell our natural gas over a time period at a specified price and volume. Since we used the weighted average to calculate the average sales prices, the volatilities in price and volume sold in each month led to the average sales price of crude oil, NGLs and condensate was lower than the average market price for the years ended December 31, 2013, 2014, 2015 and for the nine months ended September 30, 2016 and the average realized price of natural gas was lower than the average market price for the years ended December 31, 2015 and the nine months ended September 30, 2016.

For more information, please see the section headed "Industry Overview — Overview of the Global Natural Gas and Oil Industry". The outlook for natural gas, crude oil, NGLs and condensate prices is also one of the key factors impacting our reserve estimates and future investment plans, which in turn affect our expected production volumes and sales revenue for future periods.

Project Development and Production Volume

During the Track Record Period, production volume is affected by our Company's land acquisition and retention, seismic data study, drilling technique, natural resources price forecast and development plan.

There are three phases in the operations including the exploration phase, development phase and production phase. During the exploration phase, we conducted G&G study combined with seismic mapping to propose drilling locations which might generate natural gas and crude oil prospects on the undeveloped land we have acquired. As at September 30, 2016, as estimated by GLJ, our land held 77 drilling locations.

During the development and production phases, our production volume largely depended on our drilling and production schedule. As at January 1, 2013, our Company initially had 4 drilled natural gas wells. In 2013, one new natural gas well was drilled and turned into production. There are 5, 6, 5 and 5 producing wells as at December 31, 2013, 2014, 2015 and September 30, 2016, respectively. Accordingly, the production volume of natural gas fluctuated from 4,202,855 Mcf in 2013 to 5,697,904 Mcf in 2014, to 3,788,831 Mcf in 2015 and 5,183,384 Mcf in the first nine months of 2016. NGLs and condensate are the by-products from the production of natural gas. The production volume of NGLs and condensate fluctuated from 45,180 Bbl in 2013 to 29,682 Bbl in 2014, to 30,975 Bbl in 2015 and to 41,488 Bbl for the nine months ended September 30, 2016.

The price forecasts by management directly affect the production volume of our Company. Producing wells may be shut in due to economic limit considerations and production plan may be delayed or scaled down if management concluded an adverse price forecasts on the natural resources. During the Track Record Period, the number of wells of crude oil in production decreased from 4 in 2013 to 3 as at December 31, 2014 and further to 1 as at December 31, 2015 mainly due to economic limit considerations. Our production volume of crude oil decreased from 50,453 Bbl in 2013 to 37,395 Bbl in 2014 and further to 19,536 Bbl in 2015, mainly due to the decreasing number of wells in production during the Track Record Period.

During the Track Record Period, our total production volume were 796,109 Boe, 1,016,727 Boe, 681,983 Boe and 921,484 Boe, respectively.

The table below shows the number of producing wells and production volume for our natural gas, crude oil, NGLs and condensate during the Track Record Period:

	Year Ended December 31			Nine months ended September 30
	2013	2014	2015	2016
Natural Gas				
Producing wells	5	6	5	5
Production volume (Mcf)	4,202,855	5,697,904	3,788,831	5,183,384
Crude oil				
Producing wells	4	3	1	2
Production volume (Bbl)	50,453	37,395	19,536	16,098
NGLs and Condensate (by-product of natural gas)				
Producing wells	5	6	5	5
Production volume (Bbl)	45,180	29,682	30,975	41,488

We intend to explore our undeveloped land position of 111,168 net acres to upgrade our Resources to Reserves by drilling and developing our 77 drilling locations as estimated by GLJ. According to our Company's three-year development plan, our Company intends to focus on drilling a total of 13 drilling locations in Basing in the Alberta Foothills area.

Please refer to the section headed "Business — Three-year Development Plan" for more information on our three-year development plan.

Uncertainty of Reserve Estimates and Testing for Impairment

We prepare reserve estimates for each of our crude oil and natural gas resources areas with the help of our independent technical expert and include natural gas, crude oil and NGLs that our Competent Persons' Reports provide reserve estimates for each property at least annually and issue a report thereon. Proved Reserves are those quantities that by analysis of geoscience and engineering data can be estimated with reasonable certainty to be commercially recoverable from a given date forward and under defined economic conditions, operating methods and government regulations. Probable Reserves are those additional reserves that analysis of geoscience and engineering data indicate are less likely to be recovered than proved reserves but more certain to be recovered than possible reserves. Our independent technical expert prepared the reserve estimates based on judgments and decisions based on available geological, geophysical, engineering and economic data, including, but not limited to, current production estimates, prices and economic conditions. In addition to the primary economic assumptions, our reserve estimates are based on assumptions, including that geological and engineering estimates which have inherent uncertainties, the effects of regulation by governmental agencies such as initial production rates, production decline rates, ultimate recovery of reserves and contingent resources, historical production in the area and similar producing areas, timing and amount of capital expenditures, marketability of production, current and estimated future commodity prices, our ability to transport our product to various markets, production cost, abandonment and salvage values and royalties and other government levies that may be imposed over the productive life of the reserves. Therefore, reserve estimates may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance. In addition, as in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data.

The reserve estimates are important to us for making future development and production plans and estimating our expected recovery of production cost incurred and future gas revenue. Under IFRS, we accounted for the depletion of developed and producing asset based on the unit-of-production method for the years ended December 31, 2013, 2014 and 2015 and the nine months ended September 30, 2015 and 2016. We apply the unit-of-production method based mainly on proved and probable reserves as at December 31, 2013, 2014 and 2015 and September 30, 2016. Thus, changes in proved and probable reserves will affect unit-of-production depletion relating to developed and producing asset recorded in our financial statements. A reduction in proved and probable reserves will increase depletion charges for developed and producing asset, assuming constant production levels, and will reduce our profit accordingly. The reserve estimates are also an important element in our testing for impairment. The most significant cause of the annual revision of the estimated reserves tends to be changes in the technical maturity of reserves resulting from new information becoming available from exploration, development and producing well and changes in commodity price.

DESCRIPTION OF CERTAIN STATEMENTS OF PROFIT OR LOSS AND OTHER COMPREHENSIVE INCOME ITEMS

The following table sets forth our statements of profit or loss and other comprehensive income during the Track Record Period which has been extracted from the Accountants' Report of our Company set out in Appendix I to the Prospectus. The section should be read together with our Statements of Profit or Loss and Other Comprehensive Income and relevant notes to the Accountants' Report.

STATEMENTS OF PROFIT OR LOSS AND OTHER COMPREHENSIVE INCOME

	Year ended December 31			Nine months ended September 30	
	2013	2014	2015	2015	2016
	C$'000	C$'000	C$'000	C$'000 (unaudited)	C$'000
Revenue from crude oil and natural gas sales	23,497	32,424	16,080	12,320	15,151
Royalties	(3,715)	(5,295)	(1,072)	(1,639)	(1,103)
Net Revenue	19,782	27,129	15,008	10,681	14,048
Operating costs	(5,056)	(5,556)	(3,636)	(2,752)	(4,468)
General and administrative cost	(2,858)	(3,135)	(2,330)	(1,609)	(2,030)
Depletion and depreciation	(9,374)	(6,977)	(4,596)	(3,486)	(5,513)
Impairment losses and write-offs on exploration and evaluation assets	(363)	(1,786)	(2,364)	(2,359)	(812)
Impairment losses and write-offs on property, plant and equipment	(196)	(1,629)	(750)	(750)	—
Share-based compensation	—	(1,511)	—	—	(221)
Transaction costs	—	—	(542)	(61)	(2,260)
Profit/(loss) from operations	1,935	6,535	790	(336)	(1,256)
Other income	—	—	—	—	7
Finance expenses	(2,673)	(3,163)	(3,275)	(2,448)	(2,393)
Realized gain/(loss) on financial derivative instruments	84	(370)	—	—	—
(Loss)/profit before income taxes	(654)	3,002	(2,485)	(2,784)	(3,642)
Income taxes	—	—	—	—	—
(Loss)/profit and total comprehensive income for the year/period	(654)	3,002	(2,485)	(2,784)	(3,642)

Revenue

The following table shows the breakdown of our revenue before royalties by types of natural resources and their respective percentage of the total revenue during the Track Record Period:

	Year ended December 31						Nine months ended September 30			
	2013		2014		2015		2015		2016	
	C$'000	%	C$'000	%	C$'000	%	C$'000 (unaudited)	%	C$'000	%
Natural gas	15,211	64.7	26,795	82.6	13,683	85.1	10,670	86.6	12,712	83.9
Crude oil	4,638	19.7	3,496	10.8	959	6.0	578	4.7	759	5.0
NGLs and condensate	3,648	15.6	2,133	6.6	1,438	8.9	1,072	8.7	1,680	11.1
Total revenue	23,497	100	32,424	100	16,080	100	12,320	100	15,151	100

Our revenue was derived from sales of: (i) natural gas; (ii) crude oil; and (iii) NGLs and condensate.

Sales of Natural Gas

During the Track Record Period, our Company sold natural gas to customers which were gas and oil trading companies or companies who are involved in gas and oil trading. For the years ended December 31, 2013, 2014 and 2015 and the nine months ended September 30, 2016, our revenue from the sales of natural gas amounted to C$15,211,467, C$26,795,211, C$13,683,194 and C$12,711,794 respectively, representing 64.7%, 82.6%, 85.1% and 83.9% of the total revenue.

The revenue derived from our sales of natural gas was mainly subject to the average sales price and the sales volume of natural gas. During the Track Record Period, the sales volume of natural gas was 4,202,855 Mcf in 2013, 5,697,904 Mcf in 2014, 3,788,831 Mcf in 2015 and 5,183,384 Mcf in the first nine months of 2016. The sales volume of our natural gas was subject to the development projects in the Alberta Foothills.

During the Track Record Period, we also entered into forward sales contract to sell our natural gas at a specified price of C$3.73 per Mcf, C$4.07 per Mcf, C$3.95 per Mcf and C$3.10 per Mcf in 2013, 2014 and 2015 and the first nine months of 2016 respectively. Our Company sold the remaining gas to the market at market price corresponding to the time at which it was sold. The average realized price of our natural gas was highly sensitive to Canadian Gas Price Reporter, with a premium to the Canadian Gas Price Reporter due to higher heat value of the gas our Company produced. During the Track Record Period, the average realized price of natural gas was C$3.53 per Mcf in 2013, C$5.02 per Mcf in 2014 and C$2.43 per Mcf in 2015 and C$1.70 per Mcf in the first nine months of 2016. Our average sales price of natural gas consisted of the weighted average of the average realized price and the forward sales price of natural gas and amounted to C$3.62 per Mcf, C$4.70 per Mcf, C$3.61 per Mcf and C$2.45 per Mcf in 2013, 2014 and 2015 and the first nine months of 2016 respectively.

The following table shows the sales volume and average sales price of our natural gas during the Track Record Period:

	Sales volume	Average sales price
	Mcf	C$/Mcf
Year ended December 31, 2013	4,202,855	3.62
Year ended December 31, 2014	5,697,904	4.70
Year ended December 31, 2015	3,788,831	3.61
Nine months ended September 30, 2016	5,183,384	2.45

Sales of Crude Oil

During the Track Record Period, our Company sold crude oil to a customer which was a trading company in Canada. For the years ended December 31, 2013, 2014 and 2015 and the nine months ended September 30, 2016, our revenue from the sales of crude oil amounted to C$4,637,508, C$3,496,316, C$958,940 and C$758,908 respectively, representing 19.7%, 10.8%, 6.0% and 5.0% of the total revenue.

The revenue derived from our sales of crude oil was mainly subject to the average sales price and the sales volume of crude oil. During the Track Record Period, the sales volume of crude oil was 50,453 Bbl in 2013, 37,395 Bbl in 2014 and 19,536 Bb1 in 2015 and 16,098 Bbl for the nine months ended September 30, 2016. The sales volume of our crude oil was subject to the projects in Peace River.

The average sales price of our crude oil was highly sensitive to WTI crude oil price. The average sales price of crude oil was C$91.92 per Bbl in 2013, C$93.5 per Bbl in 2014, C$49.09 per Bbl in 2015 and C$47.14 per Bbl in the first nine months of 2016.

The following table shows the sales volume and average sales price of our crude oil during the Track Record Period:

	Sales volume	Average sales price
	Bbl	C$/Bbl
Year ended December 31, 2013	50,453	91.92
Year ended December 31, 2014	37,395	93.50
Year ended December 31, 2015	19,536	49.09
Nine months ended September 30, 2016	16,098	47.14

Sales of NGLs and Condensate

During the Track Record Period, our Company sold NGLs and condensate to customers which were oil and gas trading companies in Canada. For the years ended December 31, 2013, 2014 and 2015 and the nine months ended September 30, 2016, our revenue from the sales of NGLs and condensate amounted to C$3,648,074, C$2,132,340 and C$1,437,464 and C$1,680,553 respectively, representing 15.6%, 6.6% and 8.9% and 11.1% of the total revenue.

The revenue derived from our sales of NGLs and condensate was mainly affected by the average sales price and sales volume of such products. During the Track Record Period, the sales volume of NGLs and condensate was 45,180 Bbl in 2013, 29,682 Bbl in 2014, 30,975 Bbl in 2015 and 41,488 Bbl in the first nine months of 2016. The sales volume of our NGLs and condensate was subject to the development projects in the Alberta Foothills.

Both of the average sales price of our NGLs and condensate were highly sensitive to WTI commodity price. The average sales price of our NGLs was C$48.16 per Bbl in 2013, C$51.05 per Bbl in 2014, C$17.98 per Bbl in 2015 and C$17.66 per Bbl in the first nine months of 2016. The average sales price of our condensate was C$96.37 per Bbl in 2013, C$88.92 per Bbl in 2014, C$61.81 per Bbl in 2015 and C$49.54 per Bbl in the first nine months of 2016.

The following table shows the sales volume and average sales price of our NGLs and condensate during the Track Record Period:

	Sales volume	Average sales price
	Bbl	C$/Bbl
Year ended December 31, 2013	45,180	80.74
Year ended December 31, 2014	29,682	71.84
Year ended December 31, 2015	30,975	46.41
Nine months ended September 30, 2016	41,488	40.51

Production Costs and Total Cash Operating Costs

The production costs and total cash operating costs of our Company include royalties and operating costs as set out in the Accountants' Report in the Appendix I to the Prospectus.

Royalties

	Year ended December 31			Nine months ended September 30	
	2013	2014	2015	2015	2016
	C$'000	C$'000	C$'000	C$'000 (unaudited)	C$'000
Natural gas, NGLs and condensate	2,979	4,074	757	1,438	894
Crude oil	736	1,221	315	201	209
	3,715	5,295	1,072	1,639	1,103

For the years ended December 31, 2013, 2014 and 2015 and for the nine months ended September 30, 2016, royalties paid for natural gas, NGLs and condensate amounted to C$2,979,358, C$4,073,678, C$756,895 and C$893,715, representing 80.2%, 76.9%, 70.6% and 81.0% of the total royalties paid, respectively.

For the years ended December 31, 2013, 2014 and 2015 and for the nine months ended September 30, 2016, royalties paid for crude oil amounted to C$736,032, C$1,220,972, C$314,803 and C$209,232, representing 19.8%, 23.1%, 29.4% and 19.0% of the total royalties paid, respectively.

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.

During the Track Record Period, our Company's royalty rate for natural gas ranged from 5% to 33.01%, the royalty rate for NGLs (propane and butane) was 30% and the royalty rate for condensate was 40%. Our Company's royalty rate for natural gas was also influenced by the Natural Gas Deep Drilling Program ("**NGDDP**") under which the government would grant royalty incentives to natural gas well with a true vertical depth of greater than 2,000 meters.

During the Track Record Period, our Company's royalty rate for crude oil ranged from 0% to 40%.

Operating Costs

During the Track Record Period, the operating costs mainly consisted of: (i) fuel, electricity, water and other services; (ii) product marketing and transport; (iii) consumables; (iv) workforce employment; (v) environmental protection and monitoring; and (vi) non-income taxes and other governmental charges.

The following table shows the breakdown of operating cost during the Track Record Period:

	Year ended December 31			Nine months ended September 30	
	2013	2014	2015	2015	2016
	C$'000	C$'000	C$'000	C$'000 (unaudited)	C$'000
Natural gas, NGLs and condensate					
Workforce employment	589	739	531	396	609
Consumables	426	489	315	232	447
Fuel, electricity, water and other services	1,613	2,462	1,618	1,177	1,810
Environmental protection and monitoring	64	76	86	68	90
Product marketing and transport	911	1,124	693	534	1,113
Non-income taxes and other governmental charges	3	23	102	134	207
Sub-total	3,606	4,913	3,345	2,541	4,276
Average operating cost (C$ per Boe) for natural gas, NGLs and condensate	4.84	5.02	5.05	4.82	4.72
Crude oil					
Workforce employment	131	89	46	39	35
Consumables	281	176	21	19	7
Fuel, electricity, water and other services	394	23	52	26	35
Environmental protection and monitoring	7	—	—	—	—
Product marketing and transport	636	355	154	97	72
Non-income taxes and other governmental charges	1	—	18	30	43
Sub-total	1,450	643	291	211	192
Average operating cost (C$ per Bbl) for crude oil	28.74	17.20	14.94	17.66	11.92
Total	5,056	5,556	3,636	2,752	4,468
Average operating cost (C$ per Boe)	6.35	5.46	5.33	5.11	4.85

For the years ended December 31, 2013, 2014 and 2015 and the nine months ended September 30, 2016, operating cost amounted to C$5,055,775, C$5,556,029, C$3,636,433 and C$4,468,369 respectively. During the Track Record Period, most of the revenue was generated from the sales of natural gas, NGLs and condensate. As a result, the operating cost from the natural gas related business accounted for 71.3%, 88.4%, 92.0% and 95.7% of the total costs for the years ended December 31, 2013, 2014 and 2015 and the nine months ended September 30, 2016 respectively whereas the operating cost from the crude oil related business accounted for 28.7%, 11.6%, 8.0% and 4.3% respectively. The average operating cost per Boe for the years ended December 31, 2013, 2014 and 2015 and the nine months ended September 30, 2016 were C$6.35, C$5.46, C$5.33 and C$4.85 respectively.

Natural Gas, NGLs and Condensate

For the years ended December 31, 2013, 2014 and 2015 and the nine months ended September 30, 2016, the operating cost spent for the natural gas, NGLs and condensate business amounted to C$3,605,887, C$4,912,795, C$3,344,602 and C$4,276,494, representing 71.3%, 88.4%, 92.0% and 95.7% of the total operating costs, respectively. During the Track Record Period, the operating costs from the natural gas, NGLs and condensate related business mainly consisted of: (i) fuel, electricity, water and other services, which accounted for 44.7%, 50.1%, 48.4% and 42.3% of the operating cost from the natural gas, NGLs and condensate business; (ii) product marketing and transport, which accounted for 25.3%, 22.9%, 20.7% and 26.0% of the operating cost from the natural gas, NGLs and condensate business; and (iii) consumables, which accounted for 11.8%, 10.0%, 9.4% and 10.5% of the operating cost from natural gas, NGLs and condensate business. The average operating cost per Boe in the years ended December 31, 2013, 2014 and 2015 and the nine months ended September 30, 2016 were C$4.84, C$5.02, C$5.05 and C$4.72 respectively.

Crude Oil

For the years ended December 31, 2013, 2014 and 2015 and the nine months ended September 30, 2016, the operating costs spent for the crude oil related business amounted to C$1,449,888, C$643,234, C$291,831 and C$191,875, representing 28.7%, 11.6%, 8.0% and 4.3% of the total operating costs in years 2013, 2014 and 2015 and the nine months ended September 30, 2016 respectively. During the Track Record Period, the operating costs from crude oil related business mainly consisted of: (i) product marketing and transport, which accounted for 43.8%, 55.2%, 52.9% and 37.5% of the operating cost from the crude oil business; (ii) consumables, which accounted for 19.4%, 27.4%, 7.2% and 3.5% of the operating cost from the crude oil business; and (iii) fuel, electricity, water and other services, which accounted for 27.2%, 3.6%, 17.9% and 18.2% of the operating cost from the crude oil business. The average operating cost per Bbl for the years ended December 31, 2013, 2014 and 2015 and the nine months ended September 30, 2016 were C$28.74, C$17.20, C$14.94 and C$11.92 respectively.

General and Administrative Cost

The following table shows the breakdown of general and administrative cost during the Track Record Period:

	Year ended December 31			Nine months ended September 30	
	2013	2014	2015	2015	2016
	C$'000	C$'000	C$'000	C$'000 (unaudited)	C$'000
Staff costs	1,209	1,547	1,171	729	961
Accounting, legal and consulting fees	521	684	268	200	241
Office rent	494	423	480	351	393
Others	634	481	411	329	435
Total general and administrative cost	2,858	3,135	2,330	1,609	2,030

For the years ended December 31, 2013, 2014 and 2015 and the nine months ended September 30, 2016, the general and administrative cost amounted to C$2,857,929, C$3,135,459, C$2,330,164 and C$2,029,788 respectively. During the Track Record Period, the general and administrative cost mainly consisted of staff costs, accounting, legal and consulting fees, office rent and others. Others mainly included office supplies, insurance and travel & accommodation, etc.

During the Track Record Period, the staff costs (excluding share-based compensation) were C$1,209,449, C$1,547,193, C$1,171,435 and C$960,848 respectively, representing 42.3%, 49.3%, 50.3% and 47.3% of the total general and administrative cost for the years ended December 31, 2013, 2014 and 2015 and the nine months ended September 30, 2016.

During the Track Record Period, the accounting, legal and consulting fees were C$520,502, C$684,236, C$267,604 and C$241,439 respectively, representing 18.2%, 21.8%, 11.5% and 11.9% of the total general and administrative cost for the years ended December 31, 2013, 2014 and 2015 and the nine months ended September 30, 2016. The accounting, legal and consulting fees mainly include expenses spent on: (i) one-off IFRS transition fee; (ii) annual audit fee; (iii) lawyer's fee for all legal related matters; and (iv) reserve evaluation and reporting fees. The listing fees were reclassified as transaction cost and separately disclosed.

Finance Expenses

The following table shows the breakdown of the finance expenses during the Track Record Period:

	Year ended December 31			Nine months ended September 30	
	2013	2014	2015	2015	2016
	C$'000	C$'000	C$'000	C$'000 (unaudited)	C$'000
Interest expense and financing cost	2,637	3,071	2,937	2,195	2,143
Amortization of debt issuance costs	—	70	318	238	236
Accretion expense	36	22	20	15	14
Total finance expenses	2,673	3,163	3,275	2,448	2,393

For the years ended December 31, 2013, 2014 and 2015 and the nine months ended September 30, 2016, finance expenses amounted to C$2,673,373, C$3,162,897, C$3,275,010 and C$2,393,129 respectively. During the Track Record Period, the finance expenses consisted of interest expense on bank debt, interest expense on loan from a private lender, interest expense on loan from employees and contractors, financing cost, amortization of debt issuance costs and accretion expense.

Interest expenses represented the payment of interest for the loans which are used for the addition of new well sites, the purchase of land and the property, plant and equipment.

IAS 23 requires the capitalisation of borrowing costs as part of the cost of qualifying assets, one that necessarily take a substantial period of time to get ready for their intended use or sale. Our Company considers that requirements of IAS 23 do not override the exception in paragraph 9 of IFRS 6 that allows an entity to choose either expensing or capitalising each type of E&E expenditure. This is because IFRS 6 defines "E&E expenditure" as expenditure incurred in connection with E&E activities, which definition is broad enough to cover the related financing of such activities. In addition, our Company notes that during the Track Record Period, it usually took 45 to 60 days to drill a new well, so short that our Company is of the view that there were no asset which would take substantial period of time (a period well in excess of six months) to complete or get ready for its intended use. Accordingly, our Company chose to expense, instead of capitalising, our finance expenses in relation to acquisition of PPE and E&E assets during the Track Record Period in line with our accounting policy.

Amortization of debt issuance costs represented legal fees, commissions and commitment fees, which are incurred due to closing of the credit and term facility arrangement in year 2014. These costs were capitalized against the bank loan account and then amortized as a debt issuance costs account.

The accretion expense was an expense recognized when updating the present value of the decommissioning provision discounted at a discount rate applied. For details of decommissioning liabilities, please refer to Note 13 in the Accountants' Report set out in Appendix I to this Prospectus.

Depletion and Depreciation

The following table shows the breakdown of the depletion and depreciation expenses during the Track Record Period:

	Year ended December 31			Nine months ended September 30	
	2013	2014	2015	2015	2016
	C$'000	C$'000	C$'000	C$'000 (unaudited)	C$'000
Depletion	9,349	6,948	4,570	3,468	5,507
Depreciation	25	29	26	18	6
Total depletion and depreciation	9,374	6,977	4,596	3,486	5,513

Depletion

For the years ended December 31, 2013, 2014 and 2015 and the nine months ended September 30, 2016, depletion expense amounted to C$9,348,728, C$6,947,993, C$4,570,467 and C$5,506,655 respectively. During the Track Record Period, depletion expense comprised the depletion of developed and producing assets.

Depletion is calculated using depletion base and depletion ratio. Depletion base depended on net book value of developed and producing assets at the end of the year and future development cost, while depletion ratio depended on production volume for the year and total proved and probable reserves at the beginning of the year.

Depreciation

For the years ended December 31, 2013, 2014 and 2015 and the nine months ended September 30, 2016, depreciation expense amounted to C$24,969, C$28,794, C$25,636 and C$6,383 respectively. During the Track Record Period, depreciation expense comprised the depreciation of office fixed assets, such as office furniture, office equipment, vehicles, computer hardware and computer software.

Impairment Losses and Write-offs

For the years ended December 31, 2013, 2014 and 2015 and the nine months ended September 30, 2016, impairment losses and write-offs amounted to C$558,780, C$3,414,583, C$3,113,202 and C$812,452 respectively.

An impairment loss is recognized in the profit and loss account if the carrying amounts of the development and production assets exceed its estimated recoverable amount. During the Track Record Period, the fluctuation of impairment losses and write-offs was mainly due to the decline in forecasted price of our crude oil and natural gas resources and the expiry of certain Crown Leases and not renewing the leases of certain undeveloped assets as they were considered not to have further prospective value and PNG Licences.

Share-based Compensation

For the year ended December 31, 2014, share-based compensation amounted to C$1,510,908. During the year ended December 31, 2014, our Company issued Class B Shares to employees and consultants to settle the employees' loan; and issued Class B Shares to employees and consultants for cash proceeds. The deemed price of Class B Shares issued was higher than the actual price, which resulted in share-based compensation of C$1,510,908.

For the nine months ended September 30, 2016, share-based compensation amounted to C$221,332. During the nine months ended September 30, 2016, our Company issued Class B Shares to employees for cash proceeds. The deemed price of Class B Shares issued was higher than the actual price, which resulted in share-based compensation of C$221,332.

For details of employees' loan, please refer to Notes 12 and 14 in the Accountants' Report set out in Appendix I to this Prospectus.

Transaction Costs

During the year ended December 31, 2015, we incurred transaction costs of C$542,081 due to the preparation of the pending Stock Exchange listing. For the nine months ended September 30, 2016, we incurred transaction costs of C$2,260,123 attributable to the preparation of the application for Listing.

Realized Gain/(loss) on Financial Derivative Instruments

The following table shows the details of financial derivative instruments entered into during the Track Record Period:

Instrument	Term	Forward Sales Price	Reference	Quantity	Realized gain/(loss)
		C$		GJ/day	C$
December 31, 2013					
Swap	April 1, 2013 to October 31, 2013	3.26	C$ AECO	1,000	84,085
December 31, 2014					
Swap	January 1, 2014 to December 31, 2014	4.03	C$ AECO	4,500	(370,801)

Realized gain/(loss) on financial derivative instruments consisted of swaps with terms April 1, 2013 to October 31, 2013 and January 1, 2014 to December 31, 2014.

During the Track Record Period, our swaps were denominated in C$. The fair value of financial derivative contracts and swaps was derived from quoted prices received from financial institutions and was based on published forward price curves as at the measurement date, using the remaining contracted natural gas volumes. For the years ended December 31, 2013, 2014 and 2015 and the nine months ended September 30, 2016, the realized gain/(loss) on financial derivative amounted to C$84,085, C$(370,801), C$nil and C$nil respectively.

During the Track Record Period, the fluctuation of realized gain or loss on financial derivative was mainly attributable to the difference between the forward sales price at the time of entrance and the subsequent movement of AECO market price at the time of settlement and therefore the resulting difference in fair value of financial derivatives between the time periods.

REVIEW OF HISTORICAL OPERATING RESULTS

For the Nine Months Ended September 30, 2016 Compared with the Nine Months Ended September 30, 2015

Revenue

Our revenue increased by 23.0% from C$12,319,780 for the nine months ended September 30, 2015 to C$15,151,255 for the nine months ended September 30, 2016. The increase primarily reflected the increase of sales in both natural gas, crude oil and NGLs and condensate.

Sales of Natural Gas

Our revenue generated from the sales of natural gas business increased by 19.1% from C$10,669,099 for the nine months ended September 30, 2015 to C$12,711,794 for the nine months ended September 30, 2016. The increase in revenue was mainly due to the increase in the sales volume by 71.8% of natural gas from 3,017,496 Mcf for the nine months ended September 30, 2015 to 5,183,384 Mcf for the nine months ended September 30, 2016, partially offset by the decrease in average sales price of natural gas by 30.8% from C$3.54/Mcf to C$2.45/Mcf.

Sales of Crude Oil

Our revenue generated from the sales of crude oil increased by 31.0% from C$579,129 for the nine months ended September 30, 2015 to C$758,908 for the nine months ended September 30, 2016. The increase in revenue was mainly due to the increase in the sales volume of crude oil from 11,941 Bbl for the nine months ended September 30, 2015 to 16,098 Bbl for the nine months ended September 30, 2016, partially offset by the decrease in average sales price of crude oil by 2.8% from C$48.50/Bbl to C$47.14/Bbl.

Sales of NGLs and Condensate

Our revenue generated from the sales of NGLs and condensate increased by 56.8% from C$1,071,552 for the nine months ended September 30, 2015 to C$1,680,553 for the nine months ended September 30, 2016. The increase in revenue was mainly due to the increase in the sales volume of NGLs and condensate from 23,924 Bbl for the nine months ended September 30, 2015 to 41,488 Bbl for the nine months ended September 30, 2016. The increase was mainly due to higher demand for NGLs, which is an important input in petrochemical processing.

Royalties

For the nine months ended September 30, 2015 and 2016, royalties decreased by 32.7% from C$1,639,001 to C$1,102,947. Our Company's royalty rate went down from 13.3% for the nine months ended September 30, 2015 to 7.3% for the nine months ended September 30, 2016.

Operating Cost

For the nine months ended September 30, 2015 and 2016, operating costs increased by 62.4% from C$2,752,298 to C$4,468,369, which was, mainly due to the increase in production volumes of natural gas, crude oil and NGLs and condensate.

Natural Gas, NGLs and Condensate

For the nine months ended September 30, 2015 and 2016, the operating cost for the natural gas, NGLs and condensate related business increased by 68.3% from C$2,541,418 to C$4,276,494, which was, mainly due to the increase in production volume of natural gas and NGLs.

Crude Oil

For the nine months ended September 30, 2015 and 2016, the operating cost for the crude oil related business slightly decreased by 9.0% from C$210,880 to C$191,875, which was mainly due to the slight decrease in the product marketing and transport cost.

General and Administrative Cost

For the nine months ended September 30, 2015 and 2016, general and administrative cost increased by 26.1% from C$1,609,116 to C$2,029,788, which was mainly due to an increase in staff costs. The staff costs (excluding share-based compensation) increased by 31.8% from C$729,266 for the nine months ended September 30, 2015 to C$960,848 for the nine months ended September 30, 2016. The increase is mainly due to the increase in the number of staff and appointment of independent non-executive Directors.

Finance Expenses

For the nine months ended September 30, 2015 and 2016, finance expenses decreased slightly by 2.3% from C$2,448,416 to C$2,393,129.

Depletion and Depreciation

For the nine months ended September 30, 2015 and 2016, depletion and depreciation expense increased by 58.2% from C$3,485,693 for the nine months ended September 30, 2015 to C$5,513,038 for the nine months ended September 30, 2016, which was mainly due to the increase in production volumes of natural gas in the Alberta Foothills.

Depletion

For the Alberta Foothills, production volumes increased more than the increase in the total Proved plus Probable Reserves, causing the depletion ratio to decrease from 2.7% to 2.1%.

For Peace River, production volumes increased more than the increase in the total Proved plus Probable Reserves, causing the depletion ratio to decrease from 11.4% to 7.1%.

Depreciation

For the nine months ended September 30, 2015 and 2016, the depreciation expense decreased by 64.8% from C$18,110 to C$6,383, which was mainly due to some fixed assets having fully depreciated.

Impairment Losses and Write-offs

The impairment losses and write-offs decreased by approximately 73.9% from C$3,108,690 for the nine months ended September 30, 2015 to C$812,452 for the nine months ended September 30, 2016. The impairment losses and write-offs for the nine months ended September 30, 2015 and September 30, 2016 comprised direct write-offs of exploration and evaluation costs primarily related to exploration lands held by our Company which were allowed to expire in Kaydee in the Alberta Foothills and Otter in Peace River. There were no indicators of impairment to property, plant and equipment identified for our Basing and Dawson cash generating units at either September 30, 2016.

Income Taxes

For the nine months ended September 30, 2015 and 2016, there were no income taxes paid, which was mainly due to our Company having approximately C$116.0 million, C$115.0 million and C$112.0 million of tax pools for deductions as at December 31, 2014 and 2015 and September 30, 2016, respectively.

Net Loss

As a result of the abovementioned reasons, we recorded a net loss of C$2,784,233 for the nine months ended September 30, 2015 and a net loss of C$3,642,293 for the nine months ended September 30, 2016.

For the Year Ended December 31, 2015 Compared to the Year Ended December 31, 2014

Revenue

Our revenue decreased by 50.4% from C$32,423,867 for the year ended December 31, 2014 to C$16,079,598 for the year ended December 31, 2015. The decrease primarily reflected the decrease of sales in both natural gas and crude oil.

Sales of Natural Gas

Our revenue generated from the sales of natural gas business decreased by 48.9% from C$26,795,211 for the year ended December 31, 2014 to C$13,683,194 for the year ended December 31, 2015. The decrease in revenue compared to the same period in 2014 was mainly due to the decrease of the average sales price of natural gas from C$4.7/Mcf in 2014 to C$3.61/Mcf in 2015. At the same time, our Company shut in production from one gas well from January 2015 to August 2015 due to economic limit considerations and decreased the production volume from other gas wells due to the decreasing natural gas price and therefore the production volume decreased from 2014 to 2015.

Sales of Crude Oil

Our revenue generated from the sales of crude oil business decreased by 72.6% from C$3,496,316 for the year ended December 31, 2014 to C$958,940 for the year ended December 31, 2015. The decrease in revenue compared to the same period in 2014 was mainly due to the decrease of the average sales price of crude oil from C$93.50/Bbl in 2014 to C$49.09/Bbl in 2015. At the same time, our Company shut in production from two crude oil wells in year 2015, which together with the natural decline of the existing well, decreased the production volume from 2014 to 2015.

Sales of NGLs and Condensate

Our revenue generated from the sales of NGLs and condensate business decreased by 32.6% from C$2,132,340 for the year ended December 31, 2014 to C$1,437,464 for the year ended December 31, 2015. The decrease in revenue compared to the same period in 2014 was mainly due to the decline in sales price of NGLs from C$51.05/Bbl in 2014 to C$17.98/Bbl in 2015 and condensate from C$88.92/Bbl in 2014 to C$61.81/Bbl in 2015. The decrease was mainly due to lower NGLs and condensate demand, which are important inputs in petrochemical processing. With the decrease in oil prices, the petrochemical processing plants slowed down their production and therefore the market demand for NGLs and condensate dropped and price decreased in 2015.

Royalties

For the years ended December 31, 2014 and 2015, royalties decreased by 79.8% from C$5,294,650 to C$1,071,698, which was mainly due to the decreased production volume from 1,016,727 Boe in 2014 to 681,983 Boe in 2015. Therefore, our Company's royalty rate went down from 16.3% in 2014 to 6.7% in 2015. To a lesser extent, refunds totalling C$815,970 from NGDDP under which the government would grant royalty incentives to natural gas well with a true vertical depth greater than 2,000 metres also attributes to the decrease in royalty.

Operating Cost

For the years ended December 31, 2014 and 2015, operating costs decreased by 34.5% from C$5,556,029 to C$3,636,433, which was, mainly due to the decrease in operating costs of natural gas, NGLs and condensate.

Natural Gas, NGLs and Condensate

For the years ended December 31, 2014 and 2015, the operating cost for the natural gas, NGLs and condensate related business decreased by 31.9% from C$4,912,795 to C$3,344,602, which was, mainly due to the shut-in of one well in Alberta Foothills from January 2015 to August 2015 and hence reducing production volume due to the decreasing price of natural gas.

Crude Oil

For the years ended December 31, 2014 and 2015, the operating cost for the crude oil related business decreased by 54.6% from C$643,234 to C$291,831, which was mainly due to: (i) the declining production volume of crude oil, largely due to the shut in of production from three of the producing crude oil wells in Peace River in 2015; and (ii) the lower service cost from the oil service provider due to the decreasing oil price.

General and Administrative Cost

For the years ended December 31, 2014 and 2015, general and administrative cost decreased by 25.7% from C$3,135,459 to C$2,330,164, which was, mainly due to a decrease in staff costs.

The staff costs (excluding share-based compensation) decreased by 24.3% from C$1,547,193 in the year ended December 31, 2014 to C$1,171,435 in the year ended December 31, 2015. The decrease is due to the layoff of an engineer and capitalization of C$798,070 of payroll from general and administrative cost to E&E and development and production assets.

Finance Expenses

For the years ended December 31, 2014 and 2015, finance expenses increased by 3.5% from C$3,162,897 to C$3,275,010, which was mainly due to the amortization of debt issue costs increasing from 2 months amortized amount of C$70,000 in the year ended December 31, 2014 to 12 months amortized amount of C$317,613 in the year ended December 31, 2015. The capitalized debt issue costs include legal fees, commissions and fees commitment involved in the commencement of the credit facility arrangement with Macquarie Bank in 2014.

Depletion and Depreciation

For the years ended December 31, 2014 and 2015, depletion and depreciation expense decreased by 34.1% from C$6,976,787 in the year ended December 31, 2014 to C$4,596,103 in the year ended December 31, 2015, which was mainly due to the decrease in production volumes of natural gas in the Alberta Foothills and without new wells put into production.

Depletion

For Alberta Foothills, production volumes decreased more than the decrease of the total proved and probable reserves causing the depletion ratio to decrease from 4.7% to 3.5%. To a lesser extent, the lower depletion base in the Alberta Foothills was also attributable to the decrease in depletion which was mainly due to the suspension of new drilling in 2015 together with depletion and the impairment loss in 2014 which decreased the net book value of developed and producing assets.

For Peace River, production volumes decreased more than the decrease in the total Proved plus Probable Reserves, causing the depletion ratio to decrease from 17.0% to 10.7%. To a lesser extent, the lower depletion base in Peace River was also attributable to a decrease in depletion which was mainly due to the suspension of new drilling in 2015, together with depletion and impairment loss in 2014 which decreased the net book value of developed and producing assets.

Depreciation

For the years ended December 31, 2014 and 2015, the depreciation expense decreased by 11.0% from C$28,794 to C$25,636, which was mainly due to some fixed assets having fully depreciated.

Impairment Losses and Write-offs

The impairment losses and write-offs decreased approximately 8.8% from C$3,414,583 for the year ended December 31, 2014 to C$3,113,202 for the year ended December 31, 2015. The 2014 impairment losses and write-offs comprised direct write-offs of exploration and evaluation costs totalling C$1,786,080 which primarily related to exploration lands held by our Company which were allowed to expire and an impairment loss totalling C$1,628,503 relating to our Dawson cash generating unit primarily as a result of decreasing commodity prices. The 2015 impairment losses and write-offs comprised direct write-offs of exploration and evaluation costs totalling C$2,363,231 which primarily related to exploration lands held by our Company which were allowed to expire and a direct write-off of property, plant and equipment totalling C$541,966 and an impairment loss totalling C$208,005 relating to our Dawson cash generating unit primarily as a result of further decreasing commodity prices.

Realized gain/(loss) on Financial Derivative Instruments

For the years ended December 31, 2014 and 2015, realized loss on financial derivative instruments changed from C$370,801 to C$nil, as we did not enter into any financial derivative instruments in 2015.

Income Taxes

For the years ended December 31, 2014 and 2015, there were no income taxes paid, which was mainly due to our Company having approximately C$116 million and C$115 million of tax pools for deductions as at December 31, 2014 and 2015, respectively.

Net Profit/Loss

We recorded a net profit of C$3,001,753 for the year ended December 31, 2014 and a net loss of C$2,485,093 for the year ended December 31, 2015 mainly due to the decrease in revenue.

For the Year Ended December 31, 2014 Compared to the Year Ended December 31, 2013

Revenue

Our revenue increased by 38.0% from C$23,497,049 for the year 2013 to C$32,423,867 for the year 2014. The increase primarily reflected the increase in revenue from the sales of natural gas.

Sales of Natural Gas

Our revenue generated from the sales of natural gas business increased by 76.2% from C$15,211,467 for the year 2013 to C$26,795,211 for the year 2014. The increase in revenue compared to the same period in 2013 was mainly due to the increase of the average sales price of natural gas from C$3.62/Mcf for the year ended December 31, 2013 to C$4.7/Mcf for the year ended December 31, 2014. At the same time, our Company put two new wells into production in November 2013 and September 2014 and therefore increased the production volume from 2013 to 2014.

Sales of Crude Oil

Our revenue generated from the sales of crude oil business decreased by 24.6% from C$4,637,508 for the year 2013 to C$3,496,316 for the year 2014. The decrease in revenue compared to the same period in 2013 was mainly due to: (i) the decrease in production volumes as a result of our Company suspending production from one well in Peace River in June 2013 due to negative anticipation of the market environment of crude oil by the Company's management; and (ii) the natural decline of existing wells.

Sales of NGLs and Condensate

Our revenue generated from the sales of NGLs and condensate decreased by 41.5% from C$3,648,074 for 2013 to C$2,132,340 for 2014. The decrease in revenue was mainly due to the decline in sales volume of NGLs and condensate from 45,180 Bbl for 2013 to 29,682 Bbl for 2014. The decrease was due to the reallocation of products in the gas processing plant, which was an offset to the sales volume of our NGLs by an amount equal to the overallocated volume of NGLs by the gas processor due to the allocation error of the gas processor during the years from 2010 to 2013.

Royalties

For the years 2013 and 2014, royalties increased by 42.5% from C$3,715,390 to C$5,294,650, which was mainly due to increased production volume from 796,109 Boe in 2013 to 1,016,727 Boe in 2014. Our Company's effective royalty rate went up from 15.8% in 2013 to 16.3% in 2014. The increase was due to expiry of royalty holiday of oil wells and the higher increase in gas price and gas production volume as compared with the decrease in royalty due to NGDDP incentive credit on natural gas wells and the decrease in crude oil production in the Dawson area.

Operating Cost

Our operating cost increased by 9.9% from C$5,055,775 for the year ended December 31, 2013 to C$5,556,029 for the year ended December 31, 2014. The increase primarily reflected the increase in operating cost of natural gas, NGLs and condensate due to an increase of production volumes.

Natural Gas, NGLs and Condensate

For the years ended December 31, 2013 and 2014, the operating cost for the natural gas, NGLs and condensate related business increased by 36.2% from C$3,605,887 to C$4,912,795, which was mainly due to a new well commencing production in September 2014 and hence brought up the operating cost of natural gas, NGLs and condensate with new production volume from 2013 to 2014.

Crude Oil

For the years ended December 31, 2013 and 2014, the operating cost for the crude oil related business decreased by 55.6% from C$1,449,888 to C$643,234, which was mainly due to: (i) the declining production volume of crude oil after our Company decided to shut-in one of the crude oil producing wells in Peace River in June 2013; and (ii) an increase on the lower service cost from the oil service provider due to decreasing oil prices.

General and Administrative Cost

For the years ended December 31, 2013 and 2014, general and administrative cost increased by 9.7% from C$2,857,929 to C$3,135,459, which was mainly due to an increase in headcount, one-off IFRS transition fees and legal fees for legal related matters.

The staff costs (excluding share-based compensation) increased by 27.9% from C$1,209,449 in the year ended December 31, 2013 to C$1,547,193 in the year ended December 31, 2014. The increase primarily reflected the addition of two new full time employees hired, including one executive during the year ended December 31, 2014.

The accounting, legal and consulting fees increased by 31.5% from C$520,502 in the year ended December 31, 2013 to C$684,236 in the year ended December 31, 2014. The increase primarily reflected: (i) annual audit and one-off IFRS transition fee; (ii) legal fees in connection with the conversion of the shareholder, employee and contractor's loans into common shares in 2014; and (iii) an increase in reserve evaluation and reporting fees.

Finance Expenses

For the years ended December 31, 2013 and 2014, finance expenses increased by 18.3% from C$2,673,373 to C$3,162,897, which was mainly due to the increase in the interest bearing loan amount and the effective interest rate of the new long term bank loan in 2014 being higher than the effective interest rates on loans outstanding during 2013.

Please refer to the section headed "Financial Information — Indebtedness" for more information on the loan amount and the effective interest rate.

Depletion and Depreciation

For the years ended December 31, 2013 and 2014, depletion and depreciation expense decreased by 25.6% from C$9,373,697 to C$6,976,787, which was mainly due to the decrease in depletion in Alberta Foothills.

Depletion

For the years ended December 31, 2013 and 2014, depletion expense decreased by 25.7% from C$9,348,728 to C$6,947,993, which was mainly due to the depletion incurred in Alberta Foothills.

For the Alberta Foothills, production volumes increased less than the increase of the total proved and probable reserves, causing the depletion ratio to decrease from 6.5% to 4.7%. The increase of the total Proved and Probable Reserves in the Alberta Foothills was mainly due to a new well being put into production in September 2014. To a lesser extent, for Peace River, production volume decreased more than the total Proved and Probable Reserves, causing the depletion ratio to decrease from 18.8% to 17.0%. Also, the depletion base in Peace River also decreased from 2013 to 2014 which was mainly due to the suspension of new drilling in 2014, together with the depletion and impairment loss that decreased the net book value of developed and producing assets.

Depreciation

For the years ended December 31, 2013 and 2014, the depreciation expense increased by 15.3% from C$24,969 to C$28,794, which was mainly due to the depreciation of the newly purchased fixed assets during the period.

Impairment Losses and Write-offs

For the years ended December 31, 2013 and 2014, impairment losses and write-offs increased by 511% from C$558,780 to C$3,414,583, which was mainly due to: (i) declines in forecasted natural gas prices and forecasted crude oil prices in 2014 and certain E&E assets being determined to be non-recoverable due to the decision to suspend certain exploration activities in Peace River; and (ii) expiry of the certain licence rights of our lands in the Alberta Foothills.

Realized Gain/(loss) on Financial Derivative Instruments

For the years ended December 31, 2013 and 2014, we recognized a gain on financial derivative instruments of C$84,085 and a loss of C$370,801 respectively. A gain of C$84,085 is recorded for the year ended December 31, 2013 which was mainly due to the subsequent movement of AECO natural gas price down at the time of settlement compared with the forward sales price at the time of entrance during the year ended December 31, 2013. A loss of C$370,801 was recorded in 2014 mainly due to the subsequent movement of AECO market price up at the time of settlement compared with the forward sales price at the time of entrance.

Income Taxes

For the years ended December 31, 2013 and 2014, there were no income taxes paid, which was mainly due to our Company having approximately C$114 million and C$116 million of tax pools for deduction as at December 31, 2013 and 2014, respectively.

Net Loss/Profit

We recorded a net loss of C$653,810 for the year ended December 31, 2013 and a net profit of C$3,001,753 for the year ended December 31, 2014 mainly due to the increase in revenue.

DISCUSSION OF STATEMENTS OF FINANCIAL POSITION ITEMS

Net Current Assets and Liabilities

The below table shows our current assets and current liabilities as at the dates indicated:

	As at December 31,			As at September 30,	As at December 31,
	2013	2014	2015	2016	2016
	C$'000	C$'000	C$'000	C$'000	C$'000 (unaudited)
Current assets					
Cash and cash equivalents	—	4,975	5,413	3,215	3,966
Accounts receivable	2,864	4,526	2,298	3,688	3,228
Prepaid expenses and deposits	450	713	1,459	1,096	1,385
	3,314	10,214	9,170	7,999	8,579
Current liabilities					
Bank indebtedness	1,832	—	—	—	—
Bank loan	30,350	—	—	—	—
Shareholder's loan	69,419	—	—	—	—
Accounts payable and accrued liabilities	6,315	5,700	2,247	2,727	3,457
Other debt	9,277	—	—	—	—
	117,193	5,700	2,247	2,727	3,457
Net current (liabilities)/assets	(113,879)	4,514	6,923	5,272	5,122

Our Company had a net current liabilities position of C$113,879,030 and a net current asset position of C$4,514,170 as at December 31, 2013 and 2014 respectively. The change in net current assets position was mainly attributable to: (i) an increase in cash and cash equivalents of C$4,974,910; (ii) an increase in accounts receivable of C$1,661,793; (iii) a repayment in bank indebtedness of C$1,831,820; (iv) a decrease in C$30,350,000 of the short-term bank loan; (v) a capitalization of shareholder's loan of C$69,418,658; and (vi) a decrease in other debt of C$9,277,000.

As at December 31, 2014 and December 31, 2015, our Company recorded a net current asset position of C$4,514,170 and C$6,922,943 respectively. The change in net current assets position was mainly due to: (i) an increase in prepaid expenses and deposits of C$745,293; (ii) an increase in cash and cash equivalent of C$438,563; and (iii) a decrease in accounts payable and accrued liabilities of C$3,453,231.

Our Company had a net current asset position of C$6,922,943 as at December 31, 2015 and a net current asset position of C$5,271,986 as at September 30, 2016. The change in net current asset position was mainly attributable to the decrease in cash and cash equivalents from C$5,413,473 as at December 31, 2015 to C$3,215,362 as at September 30, 2016.

Our Company had a net current asset position of C$5,271,986 as at September 30, 2016 and a net current asset position of C$5,122,178 as at December 31, 2016, being the latest practicable date of ascertaining the net current asset position. The change in net current asset position was mainly attributable to the increase in account payable and accrual liabilities due to the increase in accrual expenses for listing fees.

Cash and Cash Equivalents

Our cash and cash equivalents increased from C$nil as at December 31, 2013 to C$4,974,910 as at December 31, 2014, which was mainly due to the change of bank loan arrangement.

In 2010, our Company entered into a bank loan arrangement that all cash received in the Company's chequing account would be directly drawn to repay the bank loan, therefore the chequing account balance as at December 31, 2013 was nil and all outstanding cheques were recorded into the bank indebtedness account. In October 2014, our Company terminated this arrangement and replaced with new bank loans. With such change, the chequing account balance at the end of 2014 was C$4,974,820.

Our cash and cash equivalents increased by 8.8% from C$4,974,910 as at December 31, 2014 to C$5,413,473 as at December 31, 2015, which was mainly contributed by the cash reservation for paying the expenses of development plans for the year ending December 31, 2016.

Our cash and cash equivalents decreased by 40.6% from C$5,413,473 as at December 31, 2015 to C$3,215,362 as at September 30, 2016, which was mainly due to the repayment of bank loans.

Accounts Receivable

The accounts receivable amounts represented trade receivables from our customers for the sales of our crude oil and natural gas products and other receivables. Turnover days of trade receivables were calculated based on average trade receivables net of impairment divided by revenue during the year and multiplied by 365 days.

Accounts receivable increased by 58.0% from C$2,864,269 as at December 31, 2013 to C$4,526,062 as at December 31, 2014. The increase in accounts receivable was mainly due to a NGDDP refund of C$1,607,077 being receivable from the Government of Alberta in the year 2014. Our trade debtors' turnover days decreased from 35 days as at December 31, 2013 to 30 days as at December 31, 2014, which was due to increase of revenue from sales of natural gas, natural gas related products (NGLs and condensate) and crude oil products.

Accounts receivable decreased by 49.2% from C$4,526,062 as at December 31, 2014 to C$2,297,748 as at December 31, 2015. The decrease in accounts receivables was mainly due to the NGDDP refund received during the year ended December 31, 2015 reduced to C$815,970 compared with that of C$1,607,077 in 2014. To a lesser extent, the decrease in revenue in December 2015 compared to December 2014 also causing the decrease in accounts receivable. The balance of the accounts receivable at month end is usually the accrual of the current month sales revenue, therefore the ending balance of accounts receivable as at December 31, 2015 was lower than that of December 31, 2014. The decrease in revenue in December 2015 compared to December 2014 was mainly due to: (i) the drop down of market price of our crude oil and natural gas in December 2015 compared to December 2014; and (ii) the decrease in total sales volume resulted from the shut-in of two of the crude oil producing wells in Peace River in 2015. Due to the decrease of revenue in 2015, our trade debtors' turnover days increased from 30 days as at December 31, 2014 to 45 days as at December 31, 2015.

Accounts receivable increased by 60.5% from C$2,297,748 as at December 31, 2015 to C$3,687,670 as at September 30, 2016. The increase in accounts receivable was mainly due to the increase in amount due from JLHY, resulting from the proceeds of issuance of Shares of our Company to certain individual investors, in which JLHY received the proceeds of C$1,135,925 on behalf of our Company. The amount due from JLHY will be settled before Listing. Our trade debtors' turnover days decreased from 45 days as at December 31, 2015 to 34 days as at September 30, 2016.

As at October 31, 2016, approximately C$2,381,025, or 99.4% of the account receivable outstanding at September 30, 2016 was collected.

As at December 31, 2013, 2014 and 2015 and September 30, 2016, the ageing analysis and turnover days of trade receivables is as follows:

	As at December 31			As at September 30
	2013	2014	2015	2016
	C$'000	C$'000	C$'000	C$'000
Within 1 month	2,671	2,607	1,312	2,381
1 to 2 months	—	—	—	—
2 to 3 months	—	51	—	—
Over 3 months	1	—	14	14
Total	2,672	2,658	1,326	2,395
Turnover days of trade receivables	35	30	45	34

During the Track Record Period, our trade receivables were mostly within 1 month. The sales of our crude oil and natural gas products are accrued in arrear and settled generally on the 25th of calendar day each month following the month in which sales accrued. During the Track Record

Period, the trade receivables exceeded 1 month was mainly due to the adjustment to the by-products sales revenue from our NGLs and condensate. Our customers buy our natural gas, NGLs and condensate via pipelines, from a pool with other producers' products that are transported and mixed together. Subsequent adjustment of sales would be made if there was discrepancy between the actual and estimate delivered volume of NGLs and condensate.

Accounts Payable and Accrued Liabilities

The following table shows the breakdown of accounts payable and accrued liabilities for the periods indicated:

	As at December 31			As at September 30
	2013	2014	2015	2016
	C$'000	C$'000	C$'000	C$'000
Trade payables	5,719	2,902	884	579
Accrued liabilities	478	2,158	701	1,520
Other payables	118	640	662	628
Total	6,315	5,700	2,247	2,727

Our accounts payable and accrued liabilities consisted of unpaid invoices for developing the newly drilled well and other payables. Turnover days of trade payables and accrued liabilities represented the average trade payables and accrued liabilities divided by revenue during the year and multiplied by 365 days.

Our accounts payable and accrued liabilities decreased by 9.7% from C$6,315,150 as at December 31, 2013 to C$5,699,959 as at December 31, 2014. The decrease in accounts payable and accrued liabilities was primarily due to the newly drilled well put into production in November 2013, leaving unpaid invoices causing the accounts payable and accrued liabilities balance at the end of year 2013. Whilst the newly added well during the year ended December 31, 2014 was put into production in September, most of the invoices had been settled by the end of the year ended December 31, 2014. Our turnover days of trade payables and accrued liabilities decreased from 70 days as at December 31, 2013 to 63 days as at December 31, 2014, which was due to an increase of revenue from sales of natural gas, natural gas related products (NGL and condensate) and crude oil products.

Our accounts payable and accrued liabilities decreased by 60.6% from C$5,699,959 as at December 31, 2014 to C$2,246,728 as at December 31, 2015. The decrease in accounts payable and accrued liabilities was primarily due to the fact our Company did not drill any new well in 2015 and the accounts payable and accrued liabilities as at December 31, 2015 only consisted of operating costs payable to vendors. Due to the decrease of revenue in 2015, our turnover days of trade payable increased from 63 days in 2014 to 75 days as at December 2015.

Our accounts payable and accrued liabilities increased by 21.4% from C$2,246,728 as at December 31, 2015 to C$2,726,654 as at September 30, 2016. The increase in accounts payable and accrued liabilities was mainly due to the increase in the accrued transaction costs and expenses.

As at October 31, 2016, approximately C$1,980,961, or 72.7% of the accounts payable and accrued liabilities outstanding at September 30, 2016 was settled.

As at December 31, 2013, 2014 and 2015 and September 30, 2016, the ageing analysis and turnover days of trade payables and accrued liabilities is as follows:

	As at December 31			As at September 30
	2013	2014	2015	2016
	C$'000	C$'000	C$'000	C$'000
Within 1 month	1,439	2,019	1,252	1,644
1 to 3 months	4,087	1,616	333	444
Over 3 months but within 6 months	671	1,425	—	11
Total	6,197	5,060	1,585	2,099
Turnover days of trade payables and accrued liabilities	70	63	75	33

The trade payables and accrued liabilities consisted of unpaid invoices from developing drilling wells and operating process.

Prepaid Expenses and Deposits

As at December 31, 2013, 2014 and 2015 and September 30, 2016, prepaid expenses and deposits amounted to C$449,329, C$713,157, C$1,458,450 and C$1,095,608 respectively. The fluctuation of deposits was mainly due to the change in the required royalty deposits imposed by the government.

The incremental amount from December 31, 2013 to December 31, 2014 was C$263,828, which was mainly due to the royalty deposit for the newly drilled well in November 2013.

The incremental amount from December 31, 2014 to December 31, 2015 was C$745,293, which was mainly due to the royalty deposit for the newly drilled well in September 2014 and the listing expense prepayment in year 2015.

The prepaid expenses and deposits decreased by 24.9% from C$1,458,450 as at December 31, 2015 to C$1,095,608 as at September 30, 2016. The decrease amount was C$362,842, which was due to the increase in the deferred financing costs, offset by the decrease of the royalty deposit for the nine months ended September 30, 2016.

E&E Assets

As at December 31, 2013, 2014 and 2015, and September 30, 2016 the breakdown of E&E assets by CGU is as follows:

	As at December 31			As at September 30
	2013	2014	2015	2016
	C$'000	C$'000	C$'000	C$'000
CGU Alberta Foothills & Deep Basin Devonian	8,194	11,764	13,500	13,933
CGU Peace River	1,241	1,276	920	450
Total	9,435	13,040	14,420	14,383

During the Track Record Period, E&E assets consisted of undeveloped lands and unevaluated drilling and completion costs on our Company's exploration projects which were pending the determination of proven or probable reserves. Transfers were made to property, plant and equipment as the technical feasibility and commercial viability of the extraction of proved or probable reserves were demonstrated. E&E assets were expensed due to non-economic drilling and completion activities and lease expiries.

Our E&E assets increased from C$9,435,054 as at December 31, 2013 to C$13,040,540 as at December 31, 2014 and C$14,419,800 as at December 31, 2015 and decreased to C$14,383,237 as at September 30, 2016. The increase from December 31, 2013 to December 31, 2014 was mainly due to our Company's newly leased land of 2,432 hectares in 2013 and 6,366 hectares in 2014, all of which have a 5-year initial term. The increase from December 31, 2014 to December 31, 2015 was mainly due to our Company's newly leased land of 30,016 hectares of land in Alberta Foothills in year 2015, all of which have a 4 to 5 year initial term.

Included within our E&E assets are lands totalling C$2,247,609 which were due to expire on January 1, 2017. Subsequent to September 30, 2016, our Company submitted applications and obtained approvals to extend the terms of our Company's lease of these lands to March 31, 2017. Our Company will be required to perform certain exploration and evaluation activities during the three months ending March 31, 2017.

Property, Plant and Equipment

During the Track Record Period, property, plant and equipment consisted of the developed and producing assets in relation to property acquisitions, development drilling, completion, gathering and infrastructure, asset retirement costs and transfers from E&E. The developed and producing assets are carried at cost less accumulated depletion, depreciation, amortization and impairment losses.

As at December 31, 2013, 2014 and 2015 and September 30, 2016, the breakdown of property, plant and equipment is as follows.

	As at December 31			As at September 30
	2013	2014	2015	2016
	C$'000	C$'000	C$'000	C$'000
CGU Alberta Foothills & Deep Basin Devonian	73,972	78,518	74,557	68,618
CGU Peace River	5,776	3,218	2,332	2,004
Office	100	88	68	75
Total	79,848	81,824	76,957	70,697

Our property, plant and equipment changed from C$79,847,950 as at December 31, 2013 to C$81,823,556 as at December 31, 2014 and C$76,957,111 as at December 31, 2015 and C$70,696,817 as at September 30, 2016. The increase by 2.5% from 2013 to 2014 was mainly due to the capital expenditure for the new drilled well is more than depletion of PPE in the year 2014.

Our property, plant and equipment decreased by 5.9% from C$81,823,556 as at December 31, 2014 to C$76,957,111 as at December 31, 2015 mainly due to no new well being drilled in the year ended December 31, 2015 so a lower amount of drilling and completion cost was capitalized to property, plant and equipment during the year ended December 31, 2015 and the impairment loss and land expiry decreased the net book value of the Peace River CGU in year 2015.

Our property, plant and equipment decreased by 8.1% from C$76,957,111 as at December 31, 2015 to C$70,696,817 as at September 30, 2016. The slight decrease was due to the provision of depletion and depreciation which reduced the net book value for the nine months ended September 30, 2016. Besides that, during the first half year of 2016, we received a cash payment of C$1,100,000 from a supplier in relation to remedial work for various capital related activities in the year ended December 31, 2013 and as such the recovery has been recorded as a reduction in property, plant and equipment.

There were no impairment indicators identified as at September 30, 2016. Management had identified impairment triggers as at September 30, 2015 and performed impairment tests. During the nine months ended September 30, 2015, our Company recorded an impairment loss of C$208,005 and a direct write-off of property, plant and equipment of C$541,966.

Please refer to the section headed "Financial Information — Liquidity and Capital Resources — Capital Expenditure" for more information on capital expenditure.

LIQUIDITY AND CAPITAL RESOURCES

Liquidity

During the Track Record Period, our Company's principal sources of liquidity and capital resources were generally cash flows from operating activities and financing activities. Our Company's principal use of liquidity and capital resources were mainly for the drilling of new production wells and purchase of undeveloped land. The following table shows our cash flows during the Track Record Period:

	Year ended December 31			Nine months ended September 30,	
	2013	2014	2015	2015	2016
	C$'000	C$'000	C$'000	C$'000 (unaudited)	C$'000
Cash flows					
Net cash generated from operating activities	8,692	14,919	5,363	4,282	3,885
Net cash (used in)/generated from investing activities	(8,980)	(18,208)	(5,374)	(4,808)	245
Net cash generated from/(used in) financing activities	288	8,264	449	(1,565)	(6,328)
Net increase/(decrease) in cash and cash equivalents	—	4,975	438	(2,091)	(2,198)
Cash and cash equivalents at the beginning of the year/period	—	—	4,975	4,975	5,413
Cash and cash equivalents at the end of the year/period	—	4,975	5,413	2,884	3,215

Net Cash Generated from Operating Activities

Our cash flows generated from operating activities primarily consisted of net earnings, the effect of changes in working capital such as accounts receivable, prepaid expense, account payable and accrued liabilities and adjustment for non-cash income and expenses.

We had net cash generated from operating activities of C$8,692,092 for the year ended December 31, 2013, which was primarily attributable to: (i) loss before income tax of C$653,810; and (ii) adjustment for certain non-cash expenses of C$9,968,201 mainly including depletion and depreciation of C$9,373,697 and impairment of C$558,780.

We had net cash generated from operating activities of C$14,919,400 for the year ended December 31, 2014, which was primarily attributable to: (i) profit before income tax of C$3,001,753; and (ii) adjustment for certain non-cash expenses of C$11,994,433 mainly including depletion and depreciation of C$6,976,787, share-based compensation of C$1,510,908 and impairment of C$3,414,583.

We had net cash generated from operating activities of C$5,363,600 for the year ended December 31, 2015, which was primarily attributable to: (i) loss before income tax of C$2,485,093; and (ii) adjustment for certain non-cash expenses of C$8,047,321 mainly including depletion and depreciation of C$4,596,103 and impairment of C$3,113,202.

We had net cash generated from operating activities of C$3,884,767 for the nine months ended September 30, 2016, which was attributable to (i) loss before income tax of C$3,642,293; and (ii) adjustment for certain non-cash expenses including depletion and depreciation of C$6,797,390.

Net Cash (Used in)/generated from Investing Activities

The major cash outflows from investing activities during the Track Record Period were mainly due to our capital expenditures on property, plant and equipment and E&E assets.

Funds used in investing activities for the year ended December 31, 2013 were C$8,979,922. The amount was mainly attributable to expenditures on property, plant and equipment of C$8,305,761 and E&E assets of C$674,161.

Funds used in investing activities for the year ended December 31, 2014 were C$18,208,328. The amount was mainly attributable to expenditures on property, plant and equipment of C$12,875,521 and E&E assets of C$5,332,807.

Funds used in investing activities for the year ended December 31, 2015 were C$5,374,055. The amount was mainly attributable to expenditures on property, plant and equipment of C$1,064,893 and E&E assets of C$4,309,162.

Funds generated from investing activities for the nine months ended September 30, 2016 were C$245,159. The amount was mainly attributable to recovery of expenditure on property, plant and equipment of C$1,100,000, offset by the expenditure on E&E assets of C$831,544.

Net Cash Generated from/(used in) Financing Activities

Our financing activities during the Track Record Period mainly comprised of proceeds from share issuance, proceeds from bank loan, repurchase shares and repayment of loans.

Net cash generated from financing activities was C$287,830 for the year ended December 31, 2013. The amount was mainly attributable to net proceeds from bank loan of C$7,489,620, and partially offset by: (i) the payment for bank indebtedness of C$401,790; and (ii) the repayment of loans for C$6,800,000.

Net cash generated from financing activities was C$8,263,838 for the year ended December 31, 2014. The amount was mainly attributable to: (i) net proceeds from share issuance of C$12,747,511; (ii) proceeds from bank loan of C$47,121,480 and (iii) proceeds from other debt of C$823,500 and partially offset by (i) the repayment of loans of C$45,952,898; (ii) the payment for bank indebtedness of C$1,831,820; (iii) debt issuance costs of C$1,270,000; and (iv) the repurchase of shares of C$3,373,935.

Net cash generated from financing activities was C$449,018 for the year ended December 31, 2015. The amount was mainly attributable to: (i) net proceeds from share issuance of C$3,032,037; and (ii) proceeds from bank loan of C$2,500,000 and partially offset by the repayment of loans of C$4,041,345.

Net cash used in financing activities was C$6,328,037 for the nine months ended September 30, 2016. The amount was mainly attributable to the repayment of bank loans of C$6,278,093.

Capital Expenditures

Our capital expenditures primarily consisted of the addition of exploration and evaluation assets and property, plant and equipment to increase our operating efficiency and excavation capacity. During the Track Record Period, our capital expenditures were principally funded by cash flows generated from the operation as well as our borrowings and equity issuance.

The following table shows our Company's capital expenditures during the Track Record Period:

	Year ended December 31			Nine months ended September 30
	2013	2014	2015	2016
	C$'000	C$'000	C$'000	C$'000
PPE				
Well site	9,654	9,466	210	278
Facilities and equipment	684	219	—	—
Office	40	16	7	12
Sub-total	10,378	9,701	217	290
E&E Assets				
Undeveloped lands	540	4,855	1,986	120
General and administrative costs capitalized	—	—	799	331
Unevaluated drilling and completion costs	69	1,186	1,092	325
Unevaluated seismic data	—	2	—	—
Sub-total	609	6,043	3,877	776
Total	10,987	15,744	4,094	1,066

The capital expenditures were C$10,987,318, C$15,744,302 and C$4,094,147 for the years ended December 31, 2013, 2014 and 2015 and C$1,065,884 for the nine months ended September 30, 2016.

Our Company has adopted IFRS "full cost method", under which capital expenditure in relation to the exploration and evaluation of our Junior Assets are not expensed in our Company's statements of profit or loss and other comprehensive income but capitalized as E&E assets in its statements of financial position. Our E&E assets, which consist of undeveloped lands and unevaluated drilling and completion costs on our exploration projects which were pending the determination of proven or probable reserves as capitalized by our Company. Transfers are made to or from property, plant and equipment as proven or probable reserves are determined.

For the year ended December 31, 2013, the capital expenditures on PPE was mainly attributable to: (i) capital expenditures on well sites of C$9,653,646 in Alberta Foothills, which was due to the new well put into production in November 2013; and (ii) capital expenditures on facilities and equipment of C$683,504 in the Alberta Foothills and Peace River. Capital expenditures on E&E assets related to the purchase of land of C$539,878 primarily in Alberta Foothills for 2,432 hectares of newly leased land.

For the year ended December 31, 2014, capital expenditures on PPE was mainly attributable to: (i) capital expenditures on well site of C$9,466,037 in Alberta Foothills, which was due to the new well put into production in September 2014; and (ii) the purchase of facilities and equipment of C$218,604 in the Alberta Foothills and Peace River. Capital expenditures on E&E assets were due to: (i) the purchase of land of C$4,855,306 in the Alberta Foothills for 6,366 hectares of newly leased land; and (ii) an increase in unevaluated drilling and completion costs of C$1,186,128 resulting from well site construction in the Alberta Foothills.

For the year ended December 31, 2015, capital expenditures on PPE was mainly attributable to installation of equipment of C$210,343 on well site in Peace River, and an increase in E&E due to: (i) purchase of land of C$1,985,903 in Alberta Foothills; and (ii) an increase in unevaluated drilling and completion costs of C$1,092,539 resulted from well site construction in Alberta Foothills.

For the nine months ended September 30, 2016, capital expenditures recovery on PPE was mainly attributable to the receipt from a supplier of C$1,100,000 resulting from remedial work for various capital related activities, and an increase in E&E assets due to an increase in capitalized general and administrative costs.

Net Current (Liabilities)/Assets Position

During the Track Record Period, our net current asset position was improving. We recorded a net current liabilities of C$113,879,030 as at December 31, 2013 and a net current assets of C$4,514,170, C$6,922,943 and C$5,271,986, as at December 31, 2014 and 2015 and September 30, 2016 respectively.

Working Capital Statement

We expect to be able to finance 125% of our working capital requirement for the 12 months following the date of this Prospectus as follows:

i. estimated cash inflow generated from the Company's sales revenues of C$48.5 million*(Note 1)*; and

ii. estimated cash inflow of C$38.1 million to be received by our Company from the Global Offering (assuming an Offer Price of HK$3.40 per Share, being the mid-point of the estimated price range)*(Note 2)*.

We expect to use our working capital for the 12 months following the date of this Prospectus mainly for:

i. estimated finance expenses of C$1.1 million;

ii. estimated cash outflow used in our operating activities of C$18.9 million*(Note 1)*;

iii. estimated capital expenditure for the drilling of the wells of C$25.5 million*(Note 1)*; and

iv. repayment of the borrowing of C$28.0 million.

Based on the above factors, the Directors are of the opinion that expected cash flows to be generated from operations, proceeds from bank loans, the estimated cash inflow from the Global Offering and opening cash on hand will be adequate to support currently planned business operations, commitments and other contractual obligations for at least the next 12 months from the date of this Prospectus and we have sufficient working capital for 125% of our present requirements, that is for at least the next 12 months from the date of this Prospectus.

Commitments

In October 2011, our Company entered into a lease for our office premise for a term starting October 2011 to December 2017. The average cost of the lease is approximately C$41,000 per month. Office premise lease costs include an estimate of our Company's share of production cost for its office premises for the duration of the lease term. Our Company entered into a firm service transportation agreement commencing from November 1, 2013 to October 31, 2026 (the firm service fee varies and is subject to review by the counter-party on an annual basis). Our Company

Note 1: Our Company made estimates based on the Competent Person's Report prepared by GLJ, an independent reservoir firm based in Canada, for estimates of production volumes, prices, operational cost, royalty rates and capital expenditures. The estimates are not expected to be significantly different from actual results.

Note 2: Transaction costs of approximately C$3.9 million has been incurred in 2015 and 2016. In the coming 12 months, the gross proceeds to be received by our Company from the Global Offering is approximately C$40.6 million and the estimated transactions costs to be incurred is approximately C$2.5 million. Without taking into account the transaction costs incurred in 2015 and 2016, the estimated cash inflow to be received by our Company in the coming 12 months is approximately C$38.1 million.

entered into lease agreements for two compressors; the lease of the first compressor runs from September 8, 2012 to September 7, 2017 requiring monthly lease payment of C$12,650 and the lease of the second compressor runs from August 12, 2013 to August 11, 2016 with a monthly lease payment of C$22,000. The amounts represented below for the transportation service commitment fee[note 5] is based on management's best estimate:

	As at December 31			As at September 30
	2013	2014	2015	2016
	C$'000	C$'000	C$'000	C$'000
Office premise lease				
Less than 1 year	504	511	587	587
1–3 years	1,098	1,108	587	147
4–5 years	521	—	—	—
Total	2,123	1,619	1,174	734
Transportation firm service				
Less than 1 year	484	431	483	1,157[Note 1]
1–3 years	967	842	967	15,927[Note 2]
4–5 years	967	820	967	12,881[Note 3]
After 5 years	1,330	752	363	23,161[Note 4]
Total	3,748	2,845	2,780	53,126
Lease of compressors				
Less than 1 year	416	416	314	127
1–3 years	833	418	104	—
4–5 years	—	—	—	—
Total	1,249	834	418	127

Notes:

1. The amount represents the transportation service commitment fee up to September 30, 2017.

2. The amount represents the transportation service commitment fee for the three-year period from October 1, 2017 to September 30, 2020.

   As the average gas transportation demand will be 35.3 MMcf/d and 37.5 MMcf/d in 2017 and 2018 respectively based on Proved plus Probable Reserves, and 44.5 MMcf/d in 2019 based on Proved plus Probable Reserves and Best Estimate Unrisked Contingent Resources under our Company's three-year development plan, we have been assigned FT-R service in NGTL for 18.6 MMcf/d, 65.0 MMcf/d on average for 2017 and 2018 respectively and 110.0 MMcf/d for 2019. Based on management's best estimate, the transportation service commitment fee in respect of the excess assigned FT-R service in NGTL amounts to nil, C$1.5 million and C$3.7 million for 2017, 2018 and 2019, respectively. Based on our experience that we have been able to arrange for transfers of FT-R service available from other producers to accommodate our production schedule, we are of the view that if we do not have sufficient production to fill up the assigned transportation capacity, we will be able to transfer these excess capacity to other third-party producers in the

NGTL System. Please refer to the sections headed "Business — Three-year Development Plan — Gas Processing Capacity, Transportation Support and Resources — (b) Transportation" and "Business — Transportation" in this Prospectus for details.

3. The amount represents the transportation service commitment fee for the two-year period from October 1, 2020 to September 30, 2022.

4. The amount represents the transportation service commitment fee from October 1, 2022 onwards.

5. The transportation service commitment fee is the sum of the monthly tariff during the period. The monthly tariff is calculated based on the contract volume and the rate schedule under FT-R service.

During the Track Record Period, our Company also entered into the following fixed price physical commodity contracts to forward sell natural gas:

Commodity	Term	Quantity	Price (C$)
Natural gas	January 1, 2016 to December 31, 2016	1,000 GJ/day	$2.92 per GJ
Natural gas	January 1, 2016 to December 31, 2016	1,000 GJ/day	$2.94 per GJ
Natural gas	January 1, 2016 to December 31, 2016	3,500 GJ/day	$2.95 per GJ
Natural gas	January 1, 2016 to December 31, 2016	1,000 GJ/day	$3.03 per GJ
Natural gas	January 1, 2016 to December 31, 2016	1,000 GJ/day	$3.05 per GJ
Natural gas	March 1, 2016 to December 31, 2016	900 GJ/day	$1.88 per GJ
Natural gas	October 1, 2016 to October 31, 2016	1,000 GJ/day	$2.59 per GJ
Natural gas	October 1, 2016 to October 31, 2016	1,000 GJ/day	$2.54 per GJ
Natural gas	October 1, 2016 to October 31, 2016	2,000 GJ/day	$2.53 per GJ
Natural gas	October 1, 2016 to October 31, 2016	2,000 GJ/day	$2.58 per GJ
Natural gas	November 1, 2016 to November 30, 2016	3,000 GJ/day	$3.02 per GJ
Natural gas	December 1, 2016 to December 31, 2016	2,000 GJ/day	$3.06 per GJ
Natural gas	December 1, 2016 to December 31, 2016	1,000 GJ/day	$3.21 per GJ
Natural gas	January 1, 2017 to December 31, 2017	1,000 GJ/day	$2.80 per GJ
Natural gas	January 1, 2017 to December 31, 2017	1,000 GJ/day	$2.82 per GJ
Natural gas	January 1, 2017 to December 31, 2017	1,000 GJ/day	$2.63 per GJ
Natural gas	January 1, 2017 to December 31, 2017	1,000 GJ/day	$2.54 per GJ
Natural gas	January 1, 2017 to December 31, 2017	4,400 GJ/day	$2.51 per GJ
Natural gas	January 1, 2017 to December 31, 2017	1,000 GJ/day	$3.00 per GJ
Natural gas	January 1, 2017 to December 31, 2017	2,000 GJ/day	$2.97 per GJ
Natural gas	January 1, 2017 to December 31, 2017	1,000 GJ/day	$3.03 per GJ
Natural gas	January 1, 2017 to December 31, 2017	2,000 GJ/day	$2.94 per GJ
Natural gas	January 1, 2017 to December 31, 2017	1,000 GJ/day	$3.10 per GJ
Natural gas	January 1, 2018 to December 31, 2018	1,000 GJ/day	$2.79 per GJ
Natural gas	January 1, 2018 to December 31, 2018	1,000 GJ/day	$2.66 per GJ
Natural gas	January 1, 2018 to December 31, 2018	6,400 GJ/day	$2.64 per GJ

INDEBTEDNESS

The following table shows our borrowings and other loans as at the dates indicated:

	As at December 31,			As at September 30,	As at December 31,
	2013	2014	2015	2016	2016
	C$'000	C$'000	C$'000	C$'000	C$'000 (unaudited)
Secured:					
Bank borrowings	30,350	47,121	45,580	39,302	35,622
Bank indebtedness	1,832	—	—	—	—
Non-secured:					
Shareholder's loan	69,418	—	—	—	—
Total bank loan and shareholder's loan	101,600	47,121	45,580	39,302	35,622
Other debt:					
Loan due to private lender	8,000	—	—	—	—
Amounts due to employees	1,277	—	—	—	—
Total other debts	9,277	—	—	—	—
Borrowings repayables:					
On demand or within one year	110,877	—	—	—	
More than one year but not exceeding two years	—	—	—	—	
More than two years but not exceeding five years	—	47,121	45,580	39,302	
Total borrowings	110,877	47,121	45,580	39,302	
Effective interest rates (per annum)	2.4%	6.8%	6.6%	6.5%	

As at December 31, 2013, 2014 and 2015 and September 30, 2016 our total borrowings amounted to C$110,877,478, C$47,121,480, C$45,580,135 and C$39,302,042 respectively.

At the close of business on December 31, 2016, being the latest practicable date for the purpose of this indebtedness statement, our total borrowings were C$35,622,328 and a letter of credit totaling C$558,000 was outstanding. As at December 31, 2016, being the latest practicable date for the purpose of this indebtedness statement, our total utilized banking facilities amounted to C$36,180,328 and total unutilized banking facilities amounted to C$13,819,672.

As at December 31, 2016, our total borrowings decreased by 21.8% from C$45,580,135 as at December 31, 2015 to C$35,622,328 as at December 31, 2016.

Bank Indebtedness

Our bank indebtedness decreased from C$1,831,820 as at December 31, 2013 to C$nil as at December 31, 2014 and remained as C$nil as at December 31, 2015 and September 30, 2016 and December 31, 2016.

Bank indebtedness is a specific account according to the loan arrangement our Company entered in 2013. According to the arrangement, all unpaid cheques are recorded into the bank indebtedness account. In October 2014, our Company terminated such arrangement. With such change, bank indebtedness decreased to nil as at December 31, 2014.

Bank Loan

Our bank borrowings are denominated in C$. During the Track Record Period, our bank borrowings generally contain terms and conditions that were customary for commercial bank loans. Our total bank borrowings increased from C$30,350,000 as at December 31, 2013 to C$47,121,480 as at December 31, 2014 and then decreased to C$45,580,135 as at December 31, 2015 and to C$39,302,042 as at September 30, 2016 and to C$35,622,328 as at December 31, 2016.

Secured bank borrowings increased by C$16,771,480 from December 31, 2013 to December 31, 2014 which was due to an increased total credit facility of the new bank loans obtained comparing to the old bank loan agreement. The increase in borrowings was used to repay the high interest loan from private lender and aligned with our Company's development strategy. Secured bank borrowings decreased by C$1,541,345 from C$47,121,480 as at December 31, 2014 to C$45,580,135 as at December 31, 2015 and to C$39,302,042 as at September 30, 2016 and to C$35,622,328 as at December 31, 2016 which was due to repayment of principal.

In 2014, our Company decided to repay the entire short-term loan and changed for long-term credit facility for the purpose of long-term development strategy. The long-term credit facility, granted by Macquarie Bank, consists of a C$100,000,000 revolving facility and a C$100,000,000 term facility. With respect to the term facility, it comprises Tranche A to a maximum of C$10,000,000 which can be used for Lender approved drilling, completion and acquisition of surface equipment and Tranche B to a maximum of C$90,000,000 for additional Lender approved future development plans. The Tranche A term facility expired during the nine months ended September 30, 2016. The Tranche B term facility expires on October 19, 2017. No amount was outstanding under the term facility as at December 31, 2014, 2015 and September 30, 2016. Advances under the long-term credit facility bore interest at a variable rate of interest per annum equal to the greater of: (i) the Canadian Dealer Offered Rate (CDOR); and (ii) 1%, plus a margin of

(i) in the case of the revolving facility, 5.5%, and (ii) in the case of the term facility, 7.0%. As at December 31, 2014, we had drawn down C$47,121,480 under the revolving facility, bearing an effective interest rate of 6.773%, and C$nil under the term facility.

All principal amounts outstanding under the facility are due on maturity being October 20, 2018. The available level of credit is subject to a semi-annual review by the lender to be completed by March 1 and September 1 of any given year. The credit facility and the borrowing base may be adjusted by the lender for changes in reserves, commodity prices and other factors. A decrease in the borrowing base could result in a reduction of the credit facility. If the credit facility is reduced, our Company has 60 days to pay any shortfall irrespective of the maturity date of the credit facility, or pledge additional collateral to the lender in an amount sufficient to cover, in lender's sole opinion, such borrowing base shortfall. Our Company is required to meet certain financial based covenants under the terms of this facility as follows: (1) maintain a working capital ratio (the ratio of current assets to current liabilities) of greater than 1 to 1; (2) maintain a debt coverage ratio (the ratio of total debt to net operating cash flow, as defined in the facility agreement) of less than 4 to 1 (reducing to 3 to 1 commencing January 1, 2016); (3) maintain an interest coverage ratio (the ratio of net operating cash flow, as defined in the facility agreement, to interest expenses) of greater than 4 to 1; and (4) maintain an adjusted present value ratio (reserve based) of greater than 1.7 to 1 (increasing to 2.0 to 1 commencing January 1, 2016). In addition, our Company cannot exceed a maximum of general and administrative expenses equal to 11% of net operating cash flows, as defined in the facility agreement, unless funded through advances of equity (the "**G&A cap**"). As at December 31, 2014 and 2015 and September 30, 2016, our Company was in compliance with all covenants and terms under the facility. On December 22, 2016, our Company obtained a one-time increase to the G&A cap for the three month period ended December 31, 2016 whereby general and administrative expenses could exceed the 11% of net operating cash flows to a maximum of C$200,000. All terms included in the covenants and terms described above are as defined by the lender.

The long-term credit facility was secured by, among other things: (i) a security interest over all present and after-acquired real and personal property (including our major producing natural gas and oil reserves) and a fixed charge against certain of our PNG Licences granted by our Company; and (ii) a limited recourse guarantee and a share pledge provided by Aspen, our Controlling Shareholder (which will be released prior to the Listing). Please refer to the section headed "Relationship with Controlling Shareholders — Independence from Controlling Shareholders — Financial Independence" for further details of the security provided by Aspen.

The credit facility also contains certain covenants, including financial covenants related to our working capital, debt coverage, interest coverage and present value. It is also an event of default under the credit facility if a change of control occurs which is not consented by the lender. A change of control is determined in the facility to mean that: (i) any person, other than the Controlling Shareholders, acquires (directly or indirectly) more than 35% of the total issued shares of our Company or the power to elect a majority of the Directors; or (ii) any of Mr. Bo or Mr. Pingzai Wang ceases to be a Director or an officer of our Company.

As at December 31, 2015, we had drawn down C$45,580,135 under the revolving facility, bearing an effective interest rate of 6.6%, and C$nil under the term facility.

As at September 30, 2016, we had drawn down C$39,302,042 under the revolving facility, bearing an effective interest rate of 6.5%, and C$nil under the term facility. Our Company intends to reduce our bank borrowings throughout the year in accordance with our working capital requirements and development plan in order to lower our overall financial costs.

Shareholder's Loan and Loans from Employees and Contractors

As at December 31, 2013, our shareholder's loan was C$69,418,658. The shareholder's loan has been fully converted to common shares during the year ended December 31, 2014. The shareholder's loan was due to JLHY and was unsecured and non-interest bearing and due on demand. Our Company then converted C$56,201,687 of the loan outstanding to JLHY through issuing Class C Shares to JLHY. The remaining balance owed to JLHY of C$6,652,339 was repaid in cash during the year 2014. To settle the C$6,244,632 assigned to 164 Co, our Company issued Class B Shares during the year ended December 31, 2014.

Below is the reconciliation of the amount of shareholder's loan converted to Common Shares and/or repaid by cash.

	C$
Shareholder's loan from JLHY	63,174,026
Shareholder's loan from 164 Co	6,244,632
Total Shareholder's loan	69,418,658
Repayment of Shareholder's loan	69,418,658
Issue Class B Shares to 164 Co	(6,244,632)
Issue Class C Shares to JLHY	(56,201,687)
Cash repayment to JLHY	(6,652,339)
Offset against other receivable	(320,000)
Total balance as at 31 December 2014	—

The loans from employees and contractors of C$1,277,000 were also converted to Class B shares during the year ended December 31, 2014.

Loan from Private Lender

To align with our Company's long-term development strategies and lower the financing cost, the loan from private lender of C$8,000,000 was repaid in full during the year ended December 31, 2014.

The weighted average interest rates of short-term bank borrowings were 5.50%, 4.8% and 0% and 0% for the years ended December 31, 2013, 2014 and 2015 and nine months ended September 30, 2016, respectively. The weighted average interest rates of long-term bank borrowings were 0%, 6.773% and 6.6% and 6.5% for the years 2013, 2014 and 2015 and nine months ended September 30, 2016, respectively. For other borrowings, the weighted average interest rates were 12.4%, 13.0% and 0% and 0% for the years ended December 31, 2013, 2014 and 2015 and nine months ended September 30, 2016, respectively.

Our Directors have confirmed that we have not experienced difficulties in meeting obligations and historically we have been able to repay or refinance our bank borrowings as and when they have fallen due. As at the Latest Practicable Date, our Directors have confirmed that we have no breach of the existing financial covenants during the Track Record Period.

Decommissioning Liabilities

During the Track Record Period, the decommissioning obligations were estimated based on our 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.

The following reconciles our Company's decommissioning liabilities:

	As at December 31,			As at September 30,
	2013	**2014**	**2015**	**2016**
	C$'000	**C$'000**	**C$'000**	**C$'000**
Balance, beginning of the year/period	1,397	1,366	1,617	1,765
Change in estimate	(277)	108	128	63
Liabilities incurred	210	121	—	—
Accretion expense	36	22	20	14
Balance, end of the year/period	1,366	1,617	1,765	1,842

Our decommissioning liabilities increased from C$1,366,299 as at December 31, 2013 to C$1,616,614 as at December 31, 2014. The increase from 2013 to 2014 was mainly due to the addition of one well. Our decommissioning liabilities increased from C$1,616,614 as at December 31, 2014 to C$1,764,990 as at December 31, 2015. The increase from 2014 to 2015 was mainly due to the increase in the estimated costs to abandon and reclaim the petroleum and natural gas assets. Our decommissioning liabilities increased from C$1,764,990 as at December 31, 2015 to C$1,841,816 as at September 30, 2016. The increase was mainly due to the increase in the estimated costs to abandon and reclaim the natural gas and crude oil assets.

Contingent Liabilities

As at the Latest Practicable Date, we had no material contingent liabilities.

Off-balance Sheet Transactions

As at the Latest Practicable Date, save for the operating lease commitments and physical commodity contracts as disclosed in the sub-section headed "Commitments" in this section to this Prospectus, our Company had not entered into any material off-balance sheet transactions or arrangements.

FINANCIAL RISK

Credit Risk

Credit risk is the risk of financial loss to our Company if a customer or counter-party to a financial instrument fails to meet its contractual obligations, and arises principally from our Company's receivables from purchasers of our Company's crude oil and natural gas, joint venture partners and the counterparties to financial derivative contracts. As at December 31, 2013, 2014 and 2015 and September 30, 2016, the accounts receivable consisted of C$2,671,816, C$2,657,939 and C$1,326,217 and C$2,395,462 respectively due from purchasers of the crude oil and natural gas and C$192,453, C$1,868,123 and C$971,531 and C$1,292,208 respectively of other receivables. As at December 31, 2013, 2014 and 2015 and September 30, 2016, 69.4%, 81.5% and 74.9% and 74.3% of trade receivables was due from our largest customer respectively, and 88.7%, 99.9% and 82.3% and 94.4% of trade receivables was due from our three largest customers respectively.

The carrying amount of accounts receivable and cash balances in excess of guaranteed minimum amounts represents the maximum credit exposure. Our Company did not have any material allowance for doubtful accounts as at December 31, 2013, 2014 and 2015 and September 30, 2016, nor was it required to write-off any material receivables during the years ended December 31, 2013, 2014 and 2015 and September 30, 2016. There were no material financial assets that our Company considered past due and at risk of collection. As at December 31, 2013, 2014 and 2015 and September 30, 2016, C$2,671,473, C$2,657,816 and C$1,311,734 and C$2,381,025 respectively of the trade receivables were less than 90 days old.

Interest Risk

As at December 31, 2013, 2014 and 2015 and September 30, 2016, our Company was exposed to changes in interest rates with respect to its bank loans. As at December 31, 2013, 2014 and 2015 and September 30, 2016, a one percent change in the prevailing interest rate for its bank loans would result in an estimated C$303,500, C$471,000 and C$455,800 and C$393,020 change to its annual income. As at December 31, 2013, 2014 and 2015 and September 30, 2016, our Company had no interest rate swap contracts in place.

Market Risk

Market risk changes in market metrics, such as commodity prices, foreign exchange rates and interest rates will affect our Company's valuation of financial instruments, the debt levels of our Company, as well as its profit and cash flow from operations. The objective of market risk management is to manage and control market risk exposures within acceptable limits, while maximizing returns. Commodity price risk is the risk that the fair value or future cash flows will fluctuate as a result of changes in commodity prices. In years 2013 and 2014, our Company utilized commodity contracts as a risk management technique to mitigate exposure to commodity price volatility. The following table shows the financial derivatives entered into during the years 2013 and 2014:

Instrument	Term	Price	Reference	Quantity	Realized gain/(loss)
		C$		GJ/d	C$
December 31, 2013					
Swap	April 1, 2013 to October 31, 2013	3.26	C$ AECO	1,000	84,085
December 31, 2014					
Swap	January 1, 2014 to December 31, 2014	4.03	C$ AECO	4,500	(370,801)

Our Company did not enter into any financial derivatives during the year ended December 31, 2015 and the nine months ended September 30, 2016.

SENSITIVITY ANALYSIS AND RISK EXPOSURE MANAGEMENT

Sales of natural gas was the major business segment and accounted for the majority of our revenue. In the below sensitivity analyses, our Company illustrates the hypothetical fluctuations impact on financial performance using the major external factors affecting our net profit. The factors are: (i) sales volume of our natural gas sales; and (ii) average selling price of our natural gas sales.

Sales Volume

The following sensitivity analysis illustrates impacts of hypothetical fluctuations in sales volume to the market of natural gas on our net profit. Fluctuations in our sales volume to the market are hypothetically assumed to be 30%, 60%, and 90%, which are determined by reference to historical change in our sales volume to the market during the Track Record Period.

	Year ended December 31,			Nine months ended September 30,
	2013	2014	2015	2016
Increase in sales volume	**Increase in net profit**	**Increase in net profit**	**Increase in net profit**	**Increase in net profit**
30%	4,558,977	8,038,511	4,104,958	3,813,600
60%	9,117,954	16,077,023	8,209,916	7,627,200
90%	13,676,931	24,115,534	12,314,875	11,440,800
Decrease in sales volume	**Decrease in net profit**	**Decrease in net profit**	**Decrease in net profit**	**Decrease in net profit**
(30%)	(4,558,977)	(8,038,511)	(4,104,958)	(3,813,600)
(60%)	(9,117,954)	(16,077,023)	(8,209,916)	(7,627,200)
(90%)	(13,676,931)	(24,115,534)	(12,314,875)	(11,440,800)

For illustrative purposes of breakeven analysis only, for the years ended December 31, 2013 and 2015 and the nine months ended September 30, 2016, if the sales volume of our natural gas were increased by 4.3% and 18.2% and 28.7%, respectively, our net profit would become breakeven. For the year ended December 31, 2014, if the sales volume of our natural gas decreased by 11.2%, our net profit would become breakeven.

Average Selling Price

The following sensitivity analysis illustrates the impacts of hypothetical fluctuations in average selling price of our natural gas on our net profit. Fluctuations are assumed that the average selling price would be C$3, C$4, C$5 and C$6, which correspond to the historical natural gas price of Canadian Gas Price Reporter during the Track Record Period.

	Year ended December 31,			Nine months ended September 30,
	2013	2014	2015	2016
C$/Mcf	**Increase/ (decrease) in net profit**	**Increase/ (decrease) in net profit**	**Increase/ (decrease) in net profit**	**Increase/ (decrease) in net profit**
3.00	(2,588,025)	(9,701,326)	(2,316,701)	2,838,152
4.00	1,614,830	(4,003,422)	1,472,130	8,021,536
5.00	5,817,685	1,694,482	5,260,961	13,204,920
6.00	10,020,540	7,392,386	9,049,792	18,388,304

For illustrative purposes of breakeven analysis only, for the years ended December 31, 2013, 2014 and 2015 and the nine months ended September 30, 2016, if the average selling price of our natural gas was C$3.77, C$4.18, C$4.27 and C$3.16 respectively, our net profit would become breakeven.

In order to protect ourselves against downward movements in the price of natural gas, we have entered into forward sales agreements against a fixed daily production volume for various time intervals with Macquarie Energy. Our maximum potential exposure under any sales agreement is the amount equal to the differences in the fixed price under the sales agreement and the average spot price. For more information about our sales agreements, please refer to the section headed "Business — Sales and Marketing — Natural Gas Sales Arrangement" in this Prospectus.

KEY FINANCIAL RATIOS

The following table shows our key financial ratios during the Track Record Period:

		As at December 31,			As at September 30,
	Formula	**2013**	**2014**	**2015**	**2016**
Current ratio	current assets/current liabilities	0.03x	1.79x	4.08x	2.93x
Quick ratio	(current assets — inventories)/current liabilities	0.03x	1.79x	4.08x	2.93x
Return on assets	(loss)/profit and total comprehensive income for the year/period/total assets x 100%	–0.7%	2.9%	–2.5%	–3.9%
Return on equity	(loss)/profit and total comprehensive income for the year/period attributable to owners of the Company/total equity x 100%	2.5%	5.8%	–4.8%	–7.3%
Gearing ratio	total debt/total equity x 100%	–427.1%	90.9%	87.9%	78.8%

Current Ratio and Quick Ratio

Our current ratio, calculated by dividing current assets by current liabilities, was 0.03x, 1.79x and 4.08x and 2.93x as at December 31, 2013, 2014 and 2015 and September 30, 2016 respectively. Our quick ratio, calculated by dividing current assets after subtraction of inventories by current liabilities, was 0.03x, 1.79x and 4.08x and 2.93x as at December 31, 2013, 2014 and 2015 and September 30, 2016 respectively. The increase in our current ratio and quick ratio from 2013 to 2015 was due to the replacement of the entire short term loan and changed for long-term credit facility for the purpose of long-term development strategy. The decrease in our current ratio and quick ratio for the nine months ended September 30, 2016 was due to the reduction of cash.

Return on Assets

Return on assets is (loss)/profit and total comprehensive income for the year divided by total assets at the year end. Our return on assets was –0.7%, 2.9% and –2.5% and –3.9% for the years 2013, 2014 and 2015 and for the nine months ended September 30, 2016 respectively. The fluctuation in our return on assets from 2013 to 2014 was due to the fluctuation of the net profit.

We recorded a loss and total comprehensive income of C$653,810 for the year 2013, a profit and total comprehensive income of C$3,001,753 for the year 2014 and a loss and total comprehensive income of C$2,485,093 for the year 2015 and a loss and total comprehensive income of C$3,642,293 for the nine months ended September 30, 2016.

Return on Equity

Return on equity is (loss)/profit and total comprehensive income attributable to owners of our Company for the year divided by total equity at the year end. Our return on equity was 2.5%, 5.8% and –4.8% and –7.3% for the years 2013, 2014 and 2015 and the nine months ended September 30, 2016 respectively. The increase in return on equity from 2.5% as at December 31, 2013 to 5.8% as at December 31, 2014 was due to the turnaround from a loss and total comprehensive income attributable to owners of our Company amounting to C$653,810 for the year 2013 to a profit and total comprehensive income attributable to owners of our Company amounting to C$3,001,753 for the year 2014. The decrease in return on equity from 5.8% as at December 31, 2014 to -4.8% as at December 31, 2015 was due to the turnaround from a profit and total comprehensive income attributable to owners of our Company amounting to C$3,001,753 for the year 2014 to a loss and total comprehensive income attributable to owners of our Company amounting to C$2,485,093 for the year 2015 and a loss and total comprehensive income of C$3,642,293 for the nine months ended September 30, 2016.

Gearing Ratio

Gearing ratio represents total debt as a percentage of total equity. Total debt represents bank indebtedness, bank loan, Shareholder's loan and other debts as at December 31, 2013, 2014 and 2015 and September 30, 2016. Our gearing ratio was –427.1%, 90.9% and 87.9% and 78.8% as at December 31, 2013, 2014 and 2015 and September 30, 2016 respectively. The improvement in our gearing ratio from –427.1% as at December 31, 2013 to 90.9% as at December 31, 2014 was due to the capitalization of the shareholders' loan and the employees' loans by the issue of Class B and Class C non-voting common shares in the year 2014. The gearing ratio as at December 31, 2014 was 90.9% and as at December 31, 2015 was 87.9% and the slight decrease was due to proceeds from new share issuance which increased total equity meanwhile repayment of bank loan which decreased total debt. The decrease in gearing ratio for the nine months ended September 30, 2016 was due to the repayment of bank loans.

DIVIDEND

Our Board may declare dividends in the future after taking into account our operations, earnings, financial condition, cash requirements and availability and other factors as it may deem relevant at such time. Any declaration and payment as well as the amount of dividends will be subject to our constitutional documents and the ABCA. In addition, our Directors may from time to time pay such interim dividends as appear to our Board to be justified by our profits, or special dividends of such amounts and on such dates as they think fit. No dividend shall be declared or payable except out of our profits and reserves lawfully available for distribution. Our future declarations of dividends will be at the absolute discretion of the Board.

Our Company did not declare or pay any dividends during the Track Record Period. We do not have a fixed dividend payout ratio.

DISTRIBUTABLE RESERVES

Our Company did not have any distributable reserves as at September 30, 2016.

LISTING EXPENSES

Legal, professional and other fees, together with the SFC transaction levy and Stock Exchange trading fee were incurred with respect to the Listing. Based on the midpoint of the indicative price range set out in the Prospectus, the total listing fee borne by us amounted to approximately C$6.4 million, of which approximately C$2.4 million is expected to be capitalized after the Listing in 2017. The remaining amount includes approximately C$4.0 million, of which approximately C$0.5 million was charged to profit and loss in 2015, approximately C$2.3 million was charged to profit and loss for the nine months ended September 30, 2016, C$0.7 million was estimated to be charged to profit and loss for the three months ended December 31, 2016 and C$0.5 million will be charged to profit and loss for the year ending December 31, 2017.

NO ADDITIONAL DISCLOSURE REQUIRED UNDER LISTING RULES

Our Directors confirm that as at the Latest Practicable Date, there has been no circumstance that would give rise to the disclosure requirement under Rule 13.13 to Rule 13.19 of the Listing Rules had the Shares been listed on the Stock Exchange.

NO MATERIAL ADVERSE CHANGE

Our Directors confirm that, up to the Latest Practicable Date, there has been no material adverse change in our financial and trading conditions or prospect since September 30, 2016 and there is no event since September 30, 2016, including the three months ended December 31, 2016 which would materially affect the information shown in the Accountant's Report set out in Appendix I to this Prospectus.

LOSS ESTIMATE FOR THE YEAR ENDED DECEMBER 31, 2016

Our Directors estimate that, on the bases set out in Appendix III to this Prospectus, and in the absence of unforeseen circumstances, the estimated loss attributable to owners of our Company for the year ended December 31, 2016 as follows:

Estimated loss attributable to owners of our Company(1)	not more than C$2.5 million
Unaudited pro forma estimated loss per Share of our Company(2)	not more than C$0.009

Notes:

(1) The loss estimate, for which our Directors are solely responsible for, has been prepared by them based on the audited results of our Company for the nine months ended September 30, 2016 and the unaudited results based on the management accounts of our Company for the three months ended December 31, 2016. The loss estimate has been prepared on a basis consistent in all material respects with the accounting policies normally adopted by the Company as set out in the Accountants' Report, the text of which is set out in Appendix I to this Prospectus.

(2) The calculation of the unaudited pro forma estimated loss per Share is based on the estimated results for the year ended December 31, 2016 attributable to owners of the Company and a total of 278,174,636 shares. The calculation of the estimated loss per Share does not take into account any Shares which may be issued upon the exercise of the Over-allotment Option.

UNAUDITED PRO FORMA ADJUSTED NET TANGIBLE ASSETS

Please refer to the section headed "Appendix II — Unaudited Pro Forma Financial Information" to this Prospectus for details.

KPMG LLP AS A FIRM OF ACCOUNTANTS ACCEPTABLE TO THE STOCK EXCHANGE UNDER RULE 19.20(2) OF THE LISTING RULES

Rule 19.20 of the Listing Rules provides that the annual accounts of an overseas issuer must be audited by a person, firm or company who must be a practising accountant of good standing. Such person, firm or company must also be independent of the overseas issuer to the same extent as that required of an auditor under the Companies Ordinance and in accordance with the statements on independence issued by the International Federation of Accountants and, if the overseas issuer's primary listing is or is to be on the Stock Exchange, must be either:

(a) qualified under the Professional Accountants Ordinance (Chapter 50 of the Laws of Hong Kong, the "**PAO**") for appointment as an auditor of a company; or

(b) a firm of accountants acceptable to the Stock Exchange which has an international name and reputation and is a member of a recognized body of accountants.

KPMG LLP, *Chartered Professional Accountants, Calgary, Canada*, has been the auditor of our Company since 2012. The statutory financial statements of our Company for the Track Record Period were prepared in accordance with IFRS issued by the International Accounting Standards Board. These statutory financial statements were audited by KPMG LLP. KPMG LLP will continue to serve as the auditor of our Company until the next annual meeting of the Shareholders.

Our Company considers that KPMG LLP is a firm of accountants acceptable to the Stock Exchange in accordance with the requirements of Rule 19.20(2) of the Listing Rules on the basis that:

(a) both KPMG LLP and KPMG, *Certified Public Accountants, Hong Kong*, are member firms of KPMG International Cooperative. KPMG LLP is a member firm of the KPMG network of independent member firms affiliated with KPMG International Cooperative;

(b) KPMG LLP's chartered professional accountants ("**CPA's**") are governed by the professional standards promulgated by the various provincial CPA institutes across Canada and CPA Canada. CPA Canada is the national organization established to support a unified Canadian accounting profession. CPA Canada supports a number of independent boards and oversight councils. The boards establish and maintain standards on accounting and auditing to serve the public interest. The oversight councils appoint board members and oversee and provide input into the boards' activities to ensure that the process for setting standards functions properly;

(c) KPMG LLP is registered with, among others, the Canadian Public Accountability Board in Canada and the Public Company Accounting Oversight Board in the United States and is subject to their inspections. KPMG LLP is subject to the independent oversight of the Canadian Public Accountability Board, being the regulatory body in Alberta. Alberta is itself a signatory to the IOSCO Multilateral Memorandum of Understanding Concerning Consultation and Cooperation and the Exchange of Information.

(d) KPMG LLP has confirmed that they are independent with respect to our Company within the meaning of the relevant rules and related interpretations prescribed by the relevant professional bodies in Canada and the International Ethics Standards Board for Accountants.

Our Company will prepare our annual accounts in accordance with IFRS. The annual accounts will be audited under International Standards on Auditing as issued by the International Auditing and Assurance Standards Board ("**IAASB**").