OVERVIEW

Our Company is based in Alberta, Canada 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 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 key area of Dawson 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 and 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) with an assessed net present value (post-tax, discounted at 10% and based on GLJ's forecast prices) of approximately C$119.4 million, 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.

Our long-term business strategy is to increase shareholder value by continuing to exploit and develop our natural gas and oil asset base in the three core exploration and production areas to increase our reserves, production and cash flow.

The map below shows the locations of our three core areas for growth in Alberta, Canada.

Our Three Core Areas for Growth

We believe that we have a number of key strengths that will help us execute our long-term business strategies, which include:

- economics and quality of resource base;
- size of resources within our Company's acreage land position;
- location of resources and market access;
- holding sole operating control and land ownership; and
- an experienced management and technical team with a strong industry track record.

Our Company has established the viability of our certain oil and gas assets in WCSB and is in the early stage of a three-year development plan. We focus on:

- developing our inventory of liquids-rich resources by drilling exploration and development wells in our projects; and
- establishing further opportunities to maximize value for our shareholders.

We aim to increase our gas and oil production rate from the first nine months of 2016 with an average production rate of 3,363 Boe/d to approximately 5,448 Boe/d based on Proved plus Probable Reserves and an additional 2,389 Boe/d based on Best Estimate Unrisked Contingent Resources in 2019.

OUR KEY STRENGTHS

We believe that the following strengths will contribute to our growth and differentiate us from our competitors:

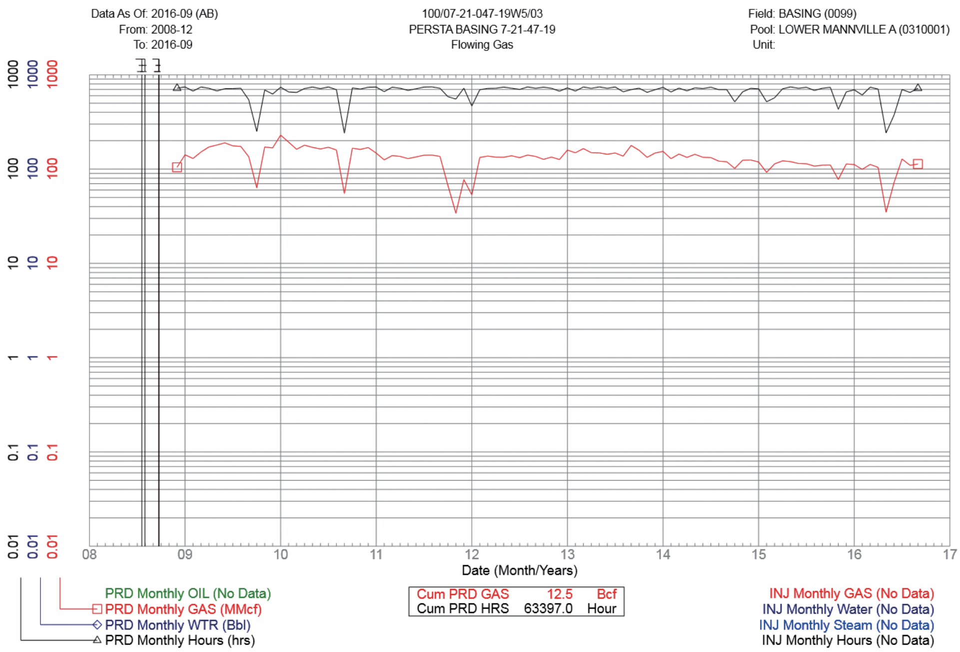
Economics and Quality of Resource Base

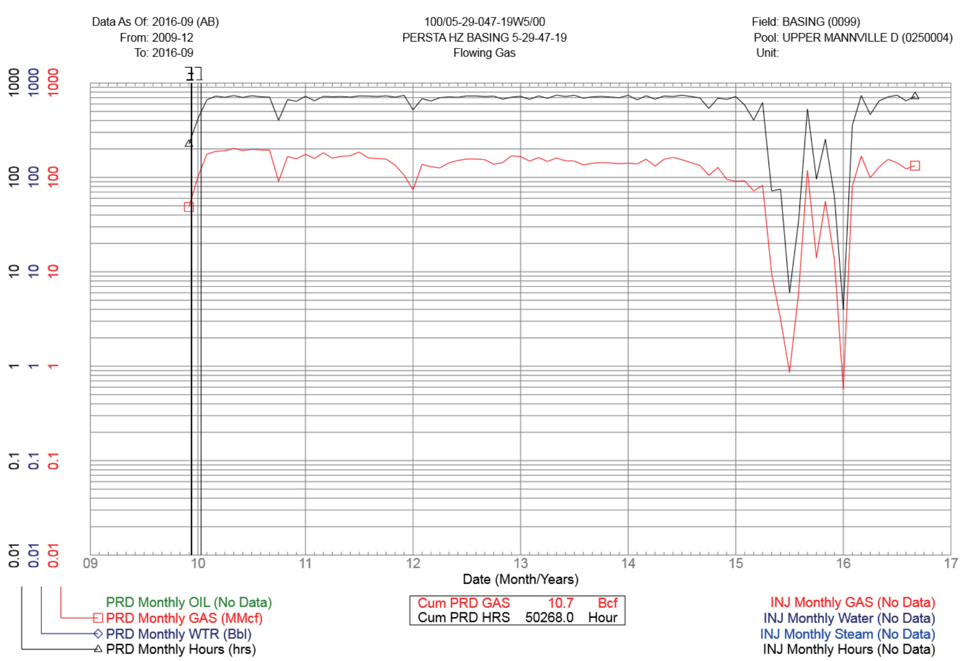
The formation in WCSB, known as the Spirit River Group (which includes formations known as Wilrich and Mountain Park), is a resource play located in Western Canada in respect of natural gas and oil. Spirit River Group is our primary development target for natural gas in the Alberta Foothills.

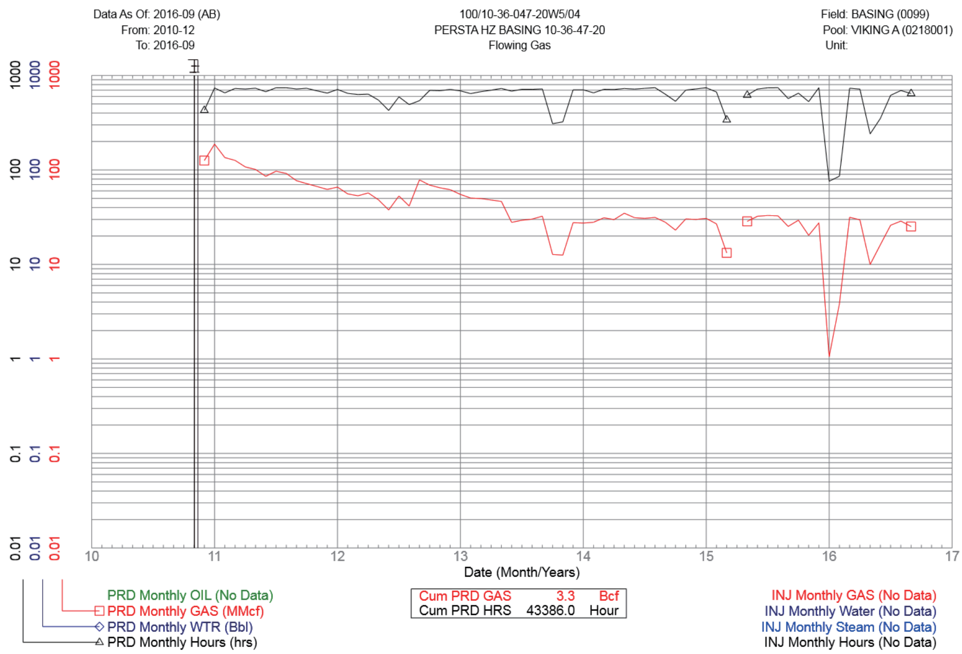
Our wells in Basing in the Alberta Foothills have exhibited economic features with high production rates and low decline rates.

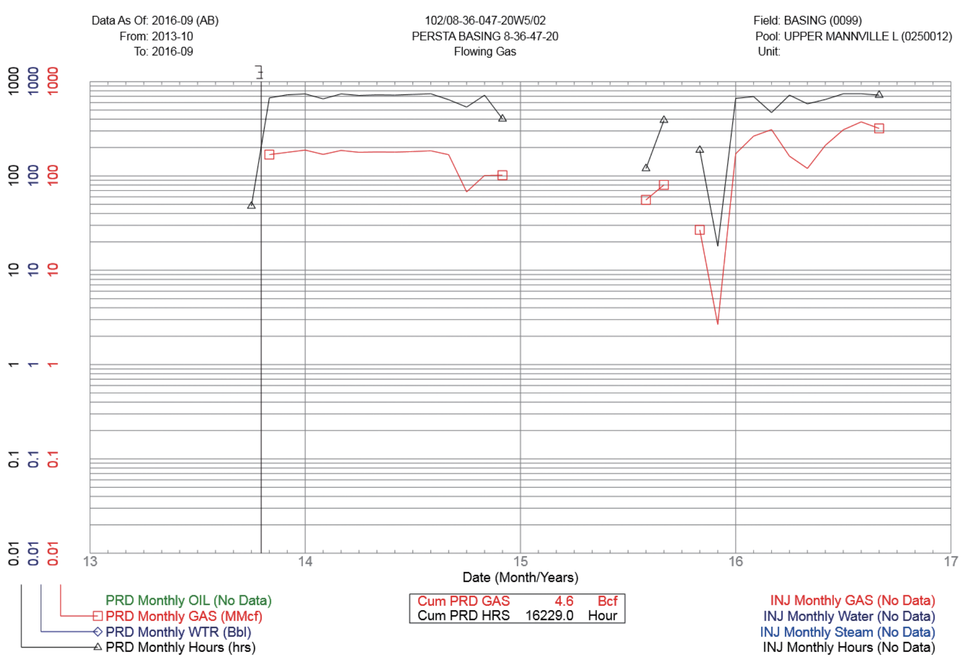
Our production of natural gas in the Alberta Foothills area commenced in December 2008. As at September 30, 2016, we cumulatively produced approximately 34.2 Bcf of sweet natural gas and approximately 289,332 Bbls of condensate and NGLs. The diagrams below show the trends of our natural gas production from our five producing wells in Basing from December 2008 to September 2016.

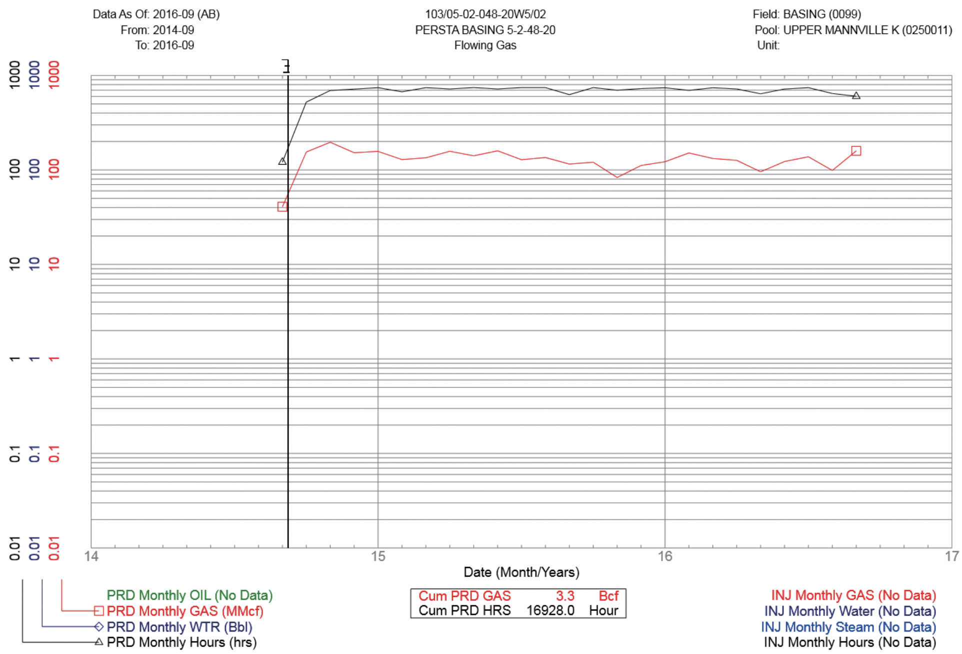
Trend of Our Five Gas Wells' Production from December 2008 to September 2016






Data As Of: 2016-09 (AB)
From: 2010-12
To: 2016-09
100/10-36-047-20W5/04
PERSTA HZ BASING 10-36-47-20
Flowing Gas
Field: BASING (0099)
Pool: VIKING A (0218001)
Unit:
Date (Month/Years)
PRD Monthly OIL (No Data)
PRD Monthly GAS (MMcf)
PRD Monthly WTR (Bbl)
PRD Monthly Hours (hrs)
Cum PRD GAS 3.3 Bcf
Cum PRD HRS 43386.0 Hour
INJ Monthly GAS (No Data)
INJ Monthly Water (No Data)
INJ Monthly Steam (No Data)
INJ Monthly Hours (No Data)

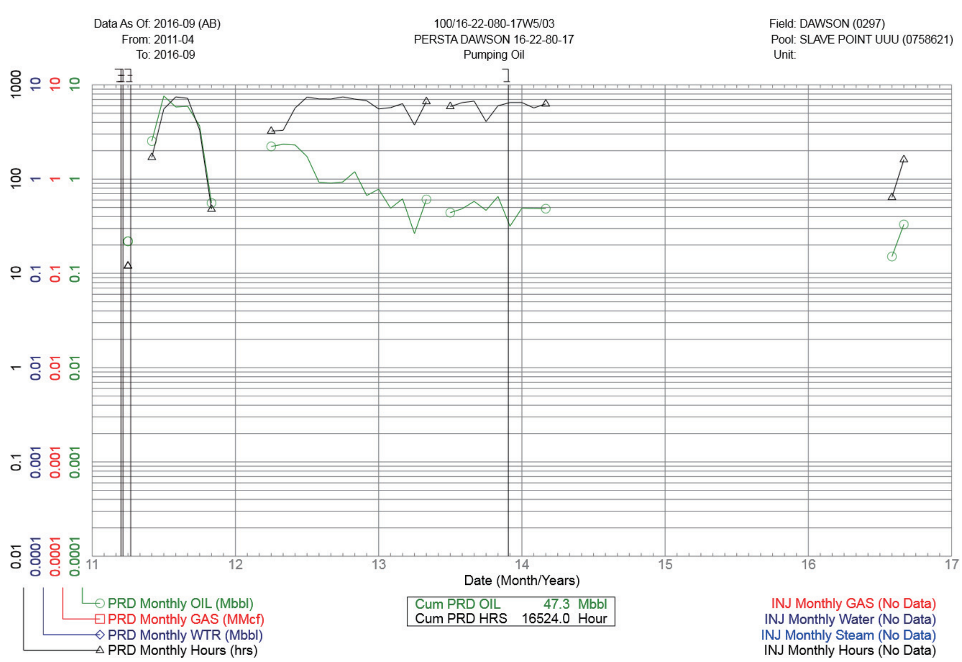

Data As Of: 2016-09 (AB)
From: 2013-10
To: 2016-09
102/08-36-047-20W5/02
PERSTA BASING 8-36-47-20
Flowing Gas
Field: BASING (0099)
Pool: UPPER MANNVILLE L (0250012)
Unit:
Date (Month/Years)
PRD Monthly OIL (No Data)
PRD Monthly GAS (MMcf)
PRD Monthly WTR (Bbl)
PRD Monthly Hours (hrs)
Cum PRD GAS 4.6 Bcf
Cum PRD HRS 16229.0 Hour
INJ Monthly GAS (No Data)
INJ Monthly Water (No Data)
INJ Monthly Steam (No Data)
INJ Monthly Hours (No Data)

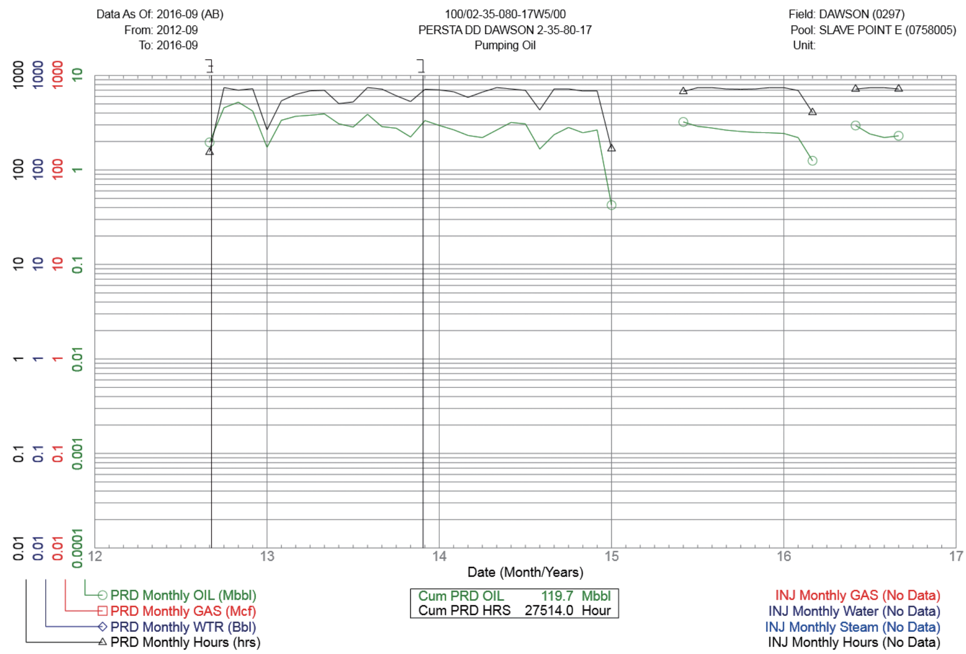


Our light oil production in Dawson in Peace River has cumulatively produced approximately 201,928 Bbls of light oil as at September 30, 2016.

The diagrams below show the trends of our light oil production from two producing wells in Dawson from April 2011 to September 2016.

Trend of Our Two Light Oil Wells' Production from April 2011 to September 2016





Size of Resources within Our Company's Acreage Land Position

As at the Latest Practicable Date, we controlled 114,528 net acres of land (being approximately 111,168 net acres of undeveloped land).

We developed a multi-year location inventory which outlines proposed drilling locations for our undeveloped land in WCSB which we intend to explore. According to the Competent Person's Report, as at September 30, 2016, we held a total of 77 drilling locations whereby five locations have been assigned to Proved plus Probable Reserves, eight to Contingent Resources, and 64 to Prospective Resources. As at September 30, 2016, GLJ has estimated that we hold 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) with an assessed net present value (post-tax, discounted at 10% and based on GLJ's forecast prices) of approximately C$119.4 million, 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 crude oil, 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).

The table below shows the data of Reserves and Resources as at September 30, 2016 based on GLJ's price forecast effective on October 1, 2016:

	Total		Producing Wells			Drilling Locations			
Reserve Data	**Gross**	**Net**	**No. of Producing Wells**	**Gross**	**Net**	**No. of Drilling Locations Inventory*** **	**Gross**	**Net**	**Post-tax NPV 10%***
	(Mboe)	**(Mboe)**		**(Mboe)**	**(Mboe)**	**(as at Latest Practicable Date)**	**(Mboe)**	**(Mboe)**	**(C$ Millions)**
Proved (1P)**	12,099	10,294	7	5,333	4,419	4	6,766	5,875	87.4
Proved + Probable (2P)**	17,666	14,680	7	7,444	6,073	5	10,222	8,607	119.4
Proved + Probable + Possible (3P)**	22,562	18,430	7	9,581	7,727	5	12,981	10,703	
Contingent Resources** (Unrisked Best Estimate)	10,396	9,061				8	10,396	9,061	
Prospective Resources** (Unrisked Best Estimate)	67,526****	58,486****				64****	67,526****	58,486****	

* This represents future net revenue, after additions for cost recovery and deductions for value-added taxes, royalties, future capital costs and operating expenses have been made. Future net revenue is presented after deduction of income taxes and has been discounted at an annual rate of 10% (which is shown to indicate the effect of time on the value of money) to determine its net present value. Future net revenue presented in this Prospectus should not be construed as being the fair market value of our Company's properties. The expected capital is accounted for in determining the post-tax NPV10% in two ways. Firstly, the capital is included as an expense which is discounted annually and reduces the net cash flow accordingly. Secondly, the development capital increases the unused tax deduction for our Company. For further information on the bases and assumptions used in determining future net revenue and post-tax NPV 10%, please see page IV-71 of the Competent Person's Report in Appendix IV to this Prospectus. For risks associated with the net present values, please see the section headed "Risk Factors — The reserves and resources data, volumes and present value calculations as presented in this Prospectus are only estimates and actual results may differ" in this Prospectus.

** As at September 30, 2016, 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, a total of 77 drilling locations are held by our Company. 5 drilling locations have been assigned to Proved, Probable and Possible Reserves (which include 4 locations assigned to Proved Reserves and 1 location assigned to Probable and Possible Reserves only). 8 drilling locations have been assigned to Contingent Resources. 64 drilling locations have been assigned to Prospective Resources.

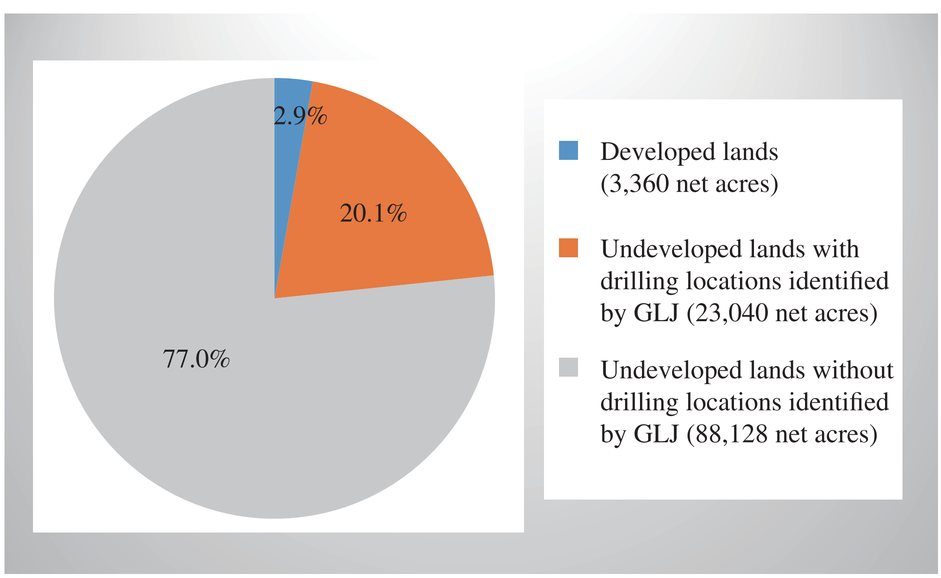
**** 1 Crown Lease in Dawson has expired in November 2016 (with 4 prospective drilling locations and 599 Mbbls of gross Best Estimated Unrisked prospective Resources assigned by GLJ as at September 30, 2016). Our Company directly wrote off C$100,000 of E&E assets as a result of the aforesaid Crown Lease expiry for the nine months ended 30 September 2016 because they were considered not to have further prospective value. Therefore its expiration will not have further financial impact on our Company.

The reporting standard adopted by GLJ in evaluating our Company's Reserves and Resources was in accordance with the Resources and Reserves definitions, standards and procedures contained in PRMS published by the Society of Petroleum Engineers as modified by Chapter 18 of the Listing Rules. The Competent Person's Report in Appendix IV to this Prospectus uses GLJ (2016-10) pricing assumptions and royalty regulations as of September 30, 2016, being the effective date of the Competent Person's Report.

The four undeveloped locations assigned Proved Reserves are all drilling locations which target the Wilrich formation and immediately offset currently producing Wilrich wells. According to GLJ, Proved undeveloped Reserves are warranted as the Wilrich formation has been mapped to show geological continuity where these drilling locations will be situated and the locations are robustly economic based on Reserves estimates and current market conditions. The single Notikewin location in Basing assigned Reserves immediately offsets a producing well. However, according to GLJ, it does not meet the economic hurdles to be classified as Proved Reserves, and is therefore only considered to be Probable Reserves. GLJ has confirmed that the methodology utilized is consistent with that utilized by other oil and gas companies in Alberta.

The chart below shows our net land acreage position as at the Latest Practicable Date, being a total of 114,528 net acres of land. Of this amount, 2.9% or 3,360 net acres comprise developed land, 20.1% or 23,040 net acres comprise undeveloped land with drilling locations identified by GLJ and 77.0% or 88,128 net acres comprise undeveloped land without drilling locations identified by GLJ.

Our Land Position as at the Latest Practicable Date

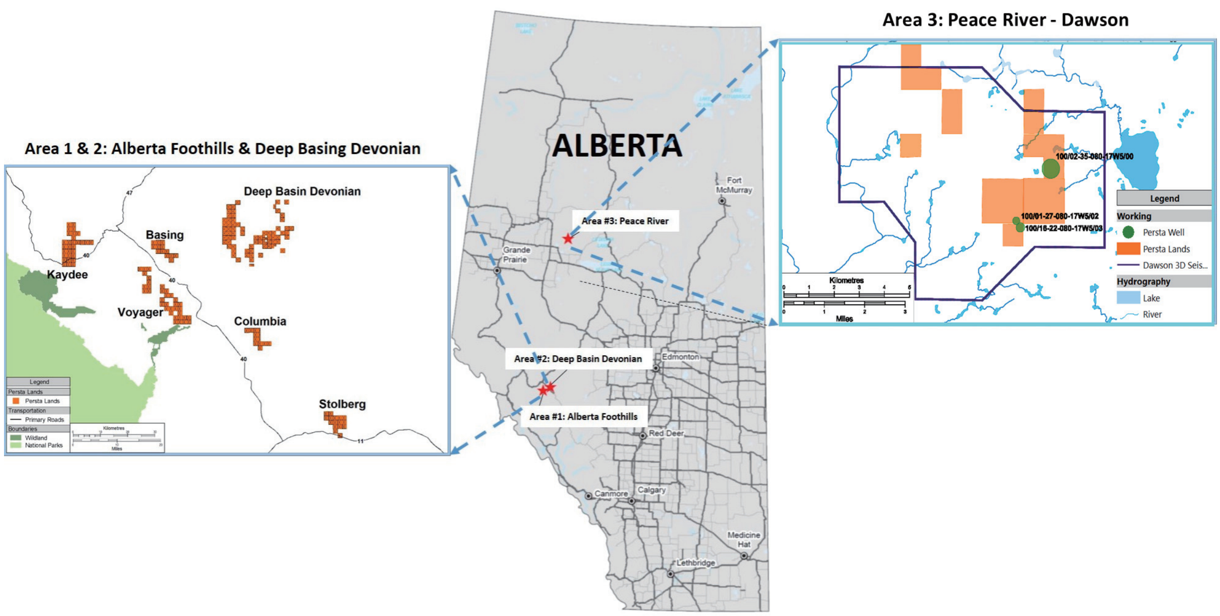


As we continue to operate in our three core areas, we will continue to expand our land position and update our multi-year drilling locations in our inventory to the extent we consider necessary.

Location of Resources and Market Access

All lands controlled by us are subject to Crown Leases or PNG Licences, which has a well-established and competitive royalty framework and land tenure system. The diagrams below show the geographical locations of land controlled by us and subject to Crown Leases and PNG Licences.

Geographical Locations of Our PNG Licences and Crown Leases

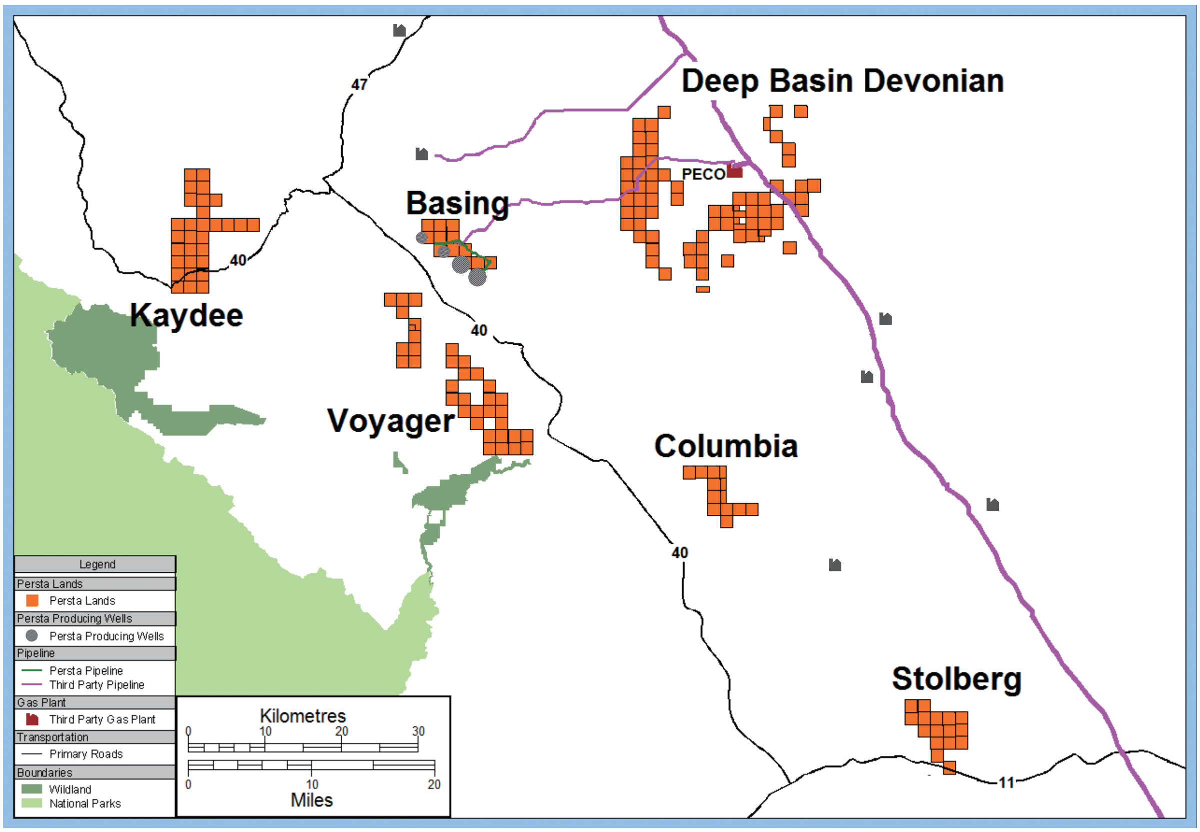


We have predominantly year-round access to our lands. Alberta Provincial Highway 40 provides year-round access to our Alberta Foothills core areas. We have also obtained leases or access rights in respect of some private access roads to drill, complete and produce from our wells, and maintain these roads for year-round use. The closest Canadian National Railway station is around 20km north of the Alberta Foothills, which we may use for transportation of our oil and NGLs, if required in the future.

Our lands are close to the third party processing facilities and regional gathering systems for sweet natural gas, oil and other NGLs. These facilities include the NGTL System that provides transportation capacity for our natural gas. Our gas gathering system has access to the ConocoPhillips Peco Plant. The NGTL System connects to major North America gas consumption markets including Eastern Canada, Northeast USA, Midwestern USA, Pacific Northwest and California, and has the ability to support potential NGL exports to the Asian market.

The map below shows the location of the NGTL System and nearby third party processing plants including the ConocoPhillips Peco Plant, as compared to our core areas of Alberta Foothills and Deep Basin Devonian.

Our Alberta Foothills & Deep Basin Devonian Natural Gas Projects & Nearby Third Party Processing Facilities and the NGTL System



Holding Sole Operating Control and Land Ownership

Other than the Stolberg JV and Viking JV, we own 100% working interests in our natural gas and oil assets. We have sole operating control over our assets, which enables us to independently implement strategies to optimize well performance and provides flexibility for us to directly adjust our operations when necessary, in order to take advantage of various market opportunities or to respond to changing market conditions.

We were in control of approximately 114,528 net acres of land as at the Latest Practicable Date. Please refer to the paragraph headed "Joint Ventures" of this section for more information about our joint ventures.

An Experienced Management and Technical Team with Strong Industry Track Record

We have assembled an experienced management and technical team with specialized expertise in resource play identification, capture, development and production. The team has a track record of organically growing production, acquiring reserves and generating funds from our operations, in particular with respect to horizontal well drilling, completions and constructing gathering and processing facilities.

Our management team has extensive experience in the natural gas and oil industry generally and in Western Canada. Mr. Bo, our President and Chief Executive Officer, oversees our management and operations and has over 11 years of experience in the oil and gas industry in Alberta. Mr. Pingzai Wang, our Senior Vice President, Exploration, has over 28 years of experience in the natural gas and oil industry (with over 10 years of experience in Alberta), especially in exploration project management. Mr. Binyou Dai has over 24 years of experience in facilities development, production, operations and project management in the natural gas and oil industry (with over 11 years of experience in Alberta). Ms. Jun Xiang, our Interim Chief Financial Officer, has over 5 years of financial management experience in the natural gas and oil industry. Mr. Lei Song, our Production Engineer, has over 5 years of working experience in the natural gas and oil industry. For more information about our management team, please refer to the section headed "Directors and Senior Management" in this Prospectus.

OUR STRATEGIES

We believe that we can maintain our competitiveness and growth and increase shareholder value by implementing the following strategies:

Enhancing the Value of Our Natural Gas and Oil Assets through Increased Operational Efficiency, Effective Well Placement and Field Development

We will seek to optimize the value of our existing natural gas and oil assets through efficient field development, drilling and completion by adopting the following measures:

- minimizing total drilling capital cost per meter by optimizing well placement locations and applying the most efficient well design to each drilling area, conducting G&G studies and leveraging on our past operational experience in our core areas;

- pursuing commercial arrangements with third parties to sell and deliver our natural gas and oil or in relation to infrastructure projects to enhance our operational efficiency; and

- applying our experience from our ten-year operations in WCSB and the completion of our six wells in Basing in the Alberta Foothills and three wells in Dawson in Peace River, to the development of our other projects.

We intend to evolve our multi-year drilling location inventory and well design to enhance the value of our natural gas and oil assets.

Upgrading Our Reserves by Drilling and Developing Our Undeveloped Land Position

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. We have developed a multi-year drilling location inventory and intend to continue to convert our Contingent and Prospective Resources in our undeveloped land into Reserves, and to migrate Possible Reserves into Proved plus Probable Reserves, by ongoing development of our assets, including additional development drilling and construction of surface facilities. As at September 30, 2016, we have accumulated net Proved Reserves of 10,294 Mboe and net Proved Plus Probable Reserves of 14,680 Mboe, and 18,430 Mboe of net Proved plus Probable plus Possible Reserves, as estimated by GLJ. We will primarily develop low-risk and high-potential locations as identified by 3D seismic data, especially in the Basing area in the Alberta Foothills, to provide a solid platform of predictable cash flow with a long reserve life and stable production rates. We also intend to carry out additional exploration drilling in our undeveloped land, including in the areas of Kaydee, Voyager, Stolberg and Columbia in the Alberta Foothills, Deep Basin Devonian and Peace River, to increase our resource base and maximize our Reserves.

Improving Our Drilling and Completion Techniques

We intend to adopt and employ improved drilling and well completion techniques in our natural gas and oil assets. These techniques are based on our experience in WCSB in which we have identified and developed drilling and completion technologies suitable for the areas where we drill. We also intend to continue improving our drilling and well completion techniques through our operations and observing and monitoring other operators in the regions which we operate. We intend to continue improving our drilling and well completion techniques to increase production rates and EUR per well through the implementation of techniques such as horizontal drilling and multi-stage completion as well as lowering our drilling and production costs.

Pursuing Potential Acquisition Opportunities with Significant Value Appreciation

We intend to evaluate and selectively pursue value-adding land and other asset acquisition opportunities that meet our strategic and financial objectives. Our potential acquisition targets include:

- land surrounding our existing lands which exhibit similar geological and geophysical characteristics which could lead to a significant expansion in recoverable resources to provide additional drilling locations and resources value; and

- highly prospective assets which may be profitable and commercially developable with relatively low threshold costs of acquisition and development. This would take into account potential efficiencies by using our existing marketing and transportation arrangements or infrastructure.

As at the Latest Practicable Date, we had not identified any potential acquisition target.

Exploration Drilling for New Pool Discoveries

We intend to look for potential opportunities to maximize long-term growth through exploration drilling for new pool discoveries, including in the Mississippian and Devonian formations. We believe exploration drilling opportunities exist in the Alberta Foothills, Deep Basin Devonian and Peace River core areas based on the fundamental G&G study results and, if such opportunities are ultimately successful, they could extend our resource base for future development and production growth.

OUR PRODUCTS

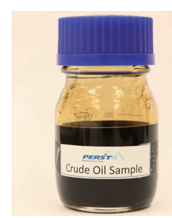
Our main products sold during the Track Record Period and as at the Latest Practicable Date were: (i) natural gas; (ii) crude oil; (iii) NGLs; and (iv) condensate. Our products do not have a product life cycle nor are they subject to seasonality. There was no significant change in our product mix during the Track Record Period.

Our products during the Track Record Period comprised:

1. Natural gas

Our sweet natural gas contains no hydrogen sulfide and approximately 90% methane.

2. Crude oil



Our sweet crude oil is light sweet crude oil with API gravity ⩾37 and sulfur ⩽0.42% by weight.

3. NGLs

Our NGLs are a by-product of natural gas from the gas plant and contain elements including ethane, propane, butane and natural gasoline.

4. Condensate

Our condensate comprises light liquid hydrocarbons recovered from natural gas at the well site and gas plant. Our condensate contains 0% hydrogen sulfide.

The following table shows information regarding our revenue, sales volume, average selling price and price range of natural gas, crude oil, NGLs and condensate for the periods indicated.

	For the year ended December 31			For the nine months ended September 30
	2013	**2014**	**2015**	**2016**
Natural gas				
Revenue (C$)	15,211,467	26,795,211	13,683,194	12,711,794
Sales volume (Mcf)	4,202,855	5,697,904	3,788,831	5,183,384
Average selling price (C$/Mcf)	3.62	4.70	3.61	2.45
Price range (C$/Mcf)	1.90–4.56	2.97–28.59 *Note 1*	2.63–3.95	0.44–3.51 *Note 2*
Crude oil				
Revenue (C$)	4,637,508	3,496,316	958,940	758,908
Sales volume (Bbl)	50,453	37,395	19,536	16,098
Average selling price (C$/Bbl)	91.92	93.50	49.09	47.14
Price range (C$/Bbl)	72.1–104.2	53.8–106.1	45.2–69.9	32.74–56.59
NGLs				
Revenue (C$)	705,368	683,336	195,697	207,508
Sales volume (Bbl)	14,646	13,386	10,885	11,752
Average selling price (C$/Bbl)	48.16	51.05	17.98	17.66
Price range (C$/Bbl)	37.5–55.3	39.1–66.7	7.8–20.6	13.73–18.74
Condensate				
Revenue (C$)	2,942,706	1,449,004	1,241,767	1,473,045
Sales volume (Bbl)	30,534	16,296	20,090	29,736
Average selling price (C$/Bbl)	96.37	88.92	61.81	49.54
Price range (C$/Bbl)	75.5–110.1	52.0–112.5	42.2–70.6	30.80–65.56

Notes:

1. This includes the exceptional price of C$28.59/Mcf which only occurred once on February 6, 2014. If this price was to be excluded, the price range would be C$2.97/Mcf–C$9.07/Mcf.

2. This includes the exceptional price of C$0.44/Mcf which only occurred once on May 9, 2016 due to the sudden drop in gas demand following the reduction in oil production from oil sands in connection with the massive wildfire in Alberta on that date. If this short term price drop (which has no material impact on the operations and the financial results of our Company for the nine months ended September 30, 2016) was to be excluded, the price range would be C$0.93/Mcf – C$3.51/Mcf.

The upper or lower price ranges reflect the highest and lowest price recorded on any one single trading day during the period indicated. The upper range of the price of natural gas has increased from C$4.56/Mcf in 2013 to C$28.59/Mcf in 2014. The material increase in the upper price range was due to the higher sales price recorded in February 2014 in light of the dramatic increase in natural gas demand under the extreme cold weather during the winter of 2013 to 2014 and the average selling price of natural gas for the year of 2014 was C$4.7/Mcf. The price of crude oil had decreased from the range of C$53.8/Bbl–C$106.1/Bbl in 2014 to the range of C$45.2/Bbl–C$69.9/Bbl in 2015 and further to the range of C$32.74/Bbl–C$56.59/Bbl for the nine months ended September 30, 2016. The price of NGLs had decreased from the range of C$39.1/Bbl–C$66.7/Bbl in 2014 to the range of C$7.8/Bbl–C$20.6/Bbl in 2015 and further to the range of C$13.73/Bbl–C$18.74/Bbl for the nine months ended September 30, 2016. The price of condensate had decreased from the range of C$52.0/Bbl–C$112.50/Bbl in 2014 to the range of C$42.2/Bbl–C$70.6/Bbl in 2015 and further to the range of C$30.80/Bbl–C$65.56/Bbl for the nine months ended September 30, 2016. The foregoing decreases in the price ranges of NGLs and condensate were due to the decrease in market prices, as we sold these products at prices benchmarked to monthly average of WTI commodity price.

According to GLJ's price forecast effective October 1, 2016, AECO/NIT Spot gas price may increase from approximately C$2.95/MMBtu* in the fourth quarter of 2016 to approximately C$3.21/MMBtu* in 2019, the price for crude oil (NYMEX WTI) may increase from approximately C$64/Bbl in the fourth quarter of 2016 to approximately C$76.36/Bbl in 2019, and the price for condensate may increase from approximately C$63.0/Bbl in the fourth quarter of 2016 to approximately C$75.5/Bbl in 2019. Please refer to page IV-49 of the Competent Person's Report in Appendix IV to this Prospectus for GLJ's price forecast as at October 1, 2016.

Please refer to the section headed "Financial Information" in this Prospectus for more information about the trends in our revenue and sales volume. Please also refer to the section headed "Risk Factors — Risks Relating to the Alberta Natural Gas and Oil Industry — Revenue and results of operations are sensitive to changes in natural gas and oil prices and general economic conditions" in this Prospectus.

OUR KEY ASSETS

Our major assets and operations are concentrated in Western Canada with three core areas:

- Alberta Foothills liquids-rich natural gas properties;
- Deep Basin Devonian natural gas properties; and
- Peace River light oil properties.

* 1 Mcf = 1.08 MMbtu according to GLJ's forecast in Appendix IV to this Prospectus

The Alberta Foothills

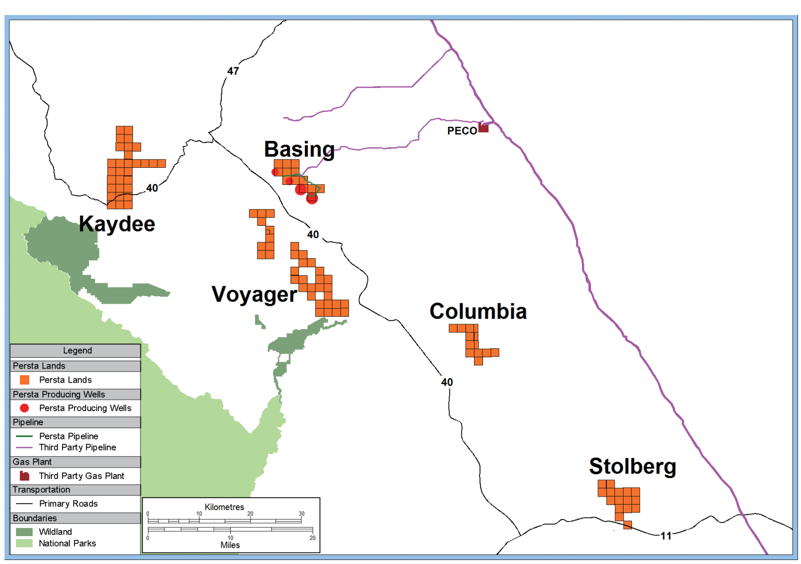
The Alberta Foothills is located approximately 230 km south west of Edmonton, Alberta. Our primarily targeted reservoirs in the Alberta Foothills area are within the lower Cretaceous, Wilrich and Mountain-park formations of Spirit River Group.

The Alberta Foothills asset consists of lands with PNG rights covering 67,008 net acres as at the Latest Practicable Date, with five areas namely: Basing, Voyager, Kaydee, Columbia and Stolberg. Basing is partially developed, whilst Voyager, Kaydee, Columbia and Stolberg are undeveloped. There are five liquids-rich natural gas wells in production in Basing with an average production rate of approximately 20.0 MMcf/d and approximately 184 Bbls/d of condensate and NGLs in the first nine months of 2016, and there is one other producing well that was voluntarily and temporarily shut-in due to economic limit considerations in order to maintain our operating cash flow and to preserve our ability to realize the full economic potential of the wells in light of the changes in gas prices. As at September 30, 2016, the gross Proved Reserves, Proved plus Probable Reserves and Proved plus Probable plus Possible Reserves had been estimated to be 12,030 Mboe, 17,567 Mboe and 22,427 Mboe, respectively. There are 71 potential drilling locations targeting a multi-zone stacked sandstone reservoir in the Wilrich and Mountain Park formations of Spirit River Group as estimated by GLJ. Other than the Stolberg JV and Viking JV, we own a 100% working interest in the PNG Licences and Crown Leases covering the Alberta Foothills area.

The map below shows our land position and wells, major pipeline and road locations within the Alberta Foothills, one of our core areas.

Our Primary Liquids-rich Natural Gas Areas for Growth — Basing, Voyager, Kaydee, Columbia and Stolberg in the Alberta Foothills

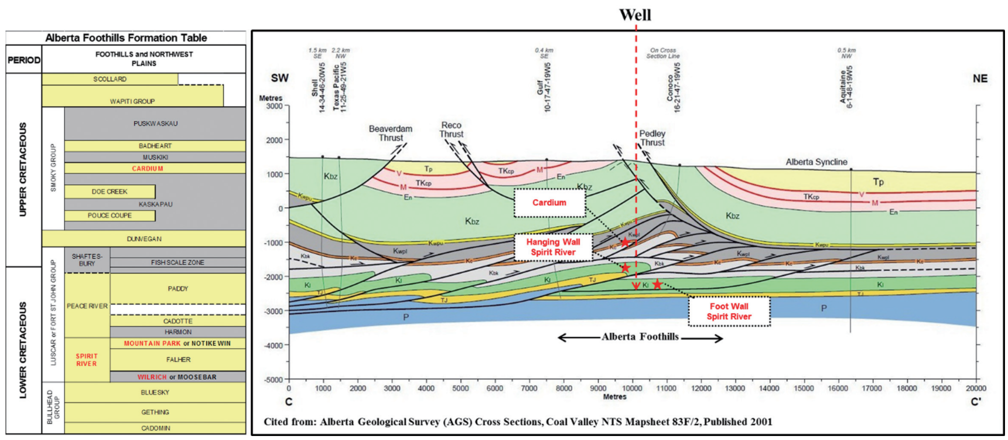
Our Alberta Foothills Project Map



Note: The shaded small squares in the map depict the land controlled by our Company, in the five areas of Basing, Voyager, Kaydee, Columbia and Stolberg, within the Alberta Foothills. PECO refers to a nearby third party processing plant.

The map below shows a typical cross section of a multi-zone stacked sandstone reservoir in the Alberta Foothills showing multiple layers of formation. Our primarily targeted reservoirs are within the lower Cretaceous, Wilrich and Mountain Park formations of Spirit River Group.

Alberta Foothills Formation Table and Cross Section Map



We commenced productions from our first well in the Wilrich formation of Basing in Alberta in December 2008. Since then, we have drilled and added another five deep gas wells in Basing and acquired more lands. Observations and findings from seismic data show that the quality and characteristics of assets in those areas are potentially similar to those in Basing. Furthermore, those areas have been estimated to contain a natural gas accumulation presence by offsetting wells. According to GLJ, as at September 30, 2016, a total of 71 drilling locations have been assigned Reserves or Resources, with five drilling locations assigned to gross Proved Reserves of 38,617 MMcf natural gas and 329 Mbbl NGLs, gross Proved plus Probable Reserves of 58,344 MMcf natural gas and 497 Mbbl NGLs, and gross Proved plus Probable plus Possible Reserves of 74,094 MMcf natural gas and 633 Mbbl NGLs in Basing, eight drilling locations assigned to gross Best Estimate Unrisked Contingent Resources of 59,342 MMcf natural gas and 506 Mbbl NGLs in Basing, and 58 drilling locations which have been assigned to gross Best Estimate Unrisked Prospective Resources of 380 Bcf natural gas and 3,243 Mbbl NGLs in the areas of Voyager and Kaydee.

We acquired a total of 8,448 net acres of land in Stolberg from April 2014 to February 2015. Four sections of such land are owned as to 30% by our Company and 70% by our joint venture partner pursuant to the Stolberg JV. Please refer to the paragraph headed "Joint Ventures" of this section for more information about our joint ventures.

As at the Latest Practicable Date, our Company was in control of approximately 68,800 gross acres (or 67,008 net acres) of land in the Alberta Foothills.

Production Facilities

As at the Latest Practicable Date, we built five multi-well sites with full surface production facilities, including two compressors leased from an independent third party supplier, two dehydration units with a total design capacity of 40–50 MMcf/d and approximately 15 km gas gathering pipeline.

The table below shows the well number, production date, initial flow rate, flow rate and accumulated production as at September 30, 2016, reserve life, well status and recovery method of our wells in Basing:

UWID	Production date	Initial flow rate	Flow rate on September 30, 2016	Accumulated production as at September 30, 2016	Remaining 2P reserve life (Years) as at September 30, 2016 *(Note 1)*	Well status as at September 30, 2016	Recovery method
100/07-21-047-19W5/03	December 2008	3.5 MMcf/d	3.5 MMcf/d	12.5 Bcf of sweet natural gas and 106,625 Bbls of condensate and NGLs	24.4	Producing	Drilling
100/05-29-047-19W5/00	December 2009	5.2 MMcf/d	4.1 MMcf/d	10.7 Bcf of natural gas and 91,271 Bbls of condensate and NGLs	38.5	Producing	Drilling
100/10-36-047-20W5/04	December 2010	7.1 MMcf/d	0.9 MMcf/d	3.3 Bcf of natural gas and 28,149 Bbls of condensate and NGLs	20.2	Producing	Drilling
100/16-29-047-19W5/00 *(Note 2)*	January 2012	0.6 MMcf/d	0	0.02 Bcf of natural gas	N/A	Shut-in	Drilling
102/08-36-047-20W5/02	November 2013	6.0 MMcf/d	8.8 MMcf/d	4.6 Bcf of natural gas and 39,238 Bbls of condensate and NGLs	16.2	Producing	Drilling
103/05-02-048-20W5/02	September 2014	8.1 MMcf/d	7.4 MMcf/d	3.3 Bcf of natural gas and 28,149 Bbls of condensate and NGLs	25.5	Producing	Drilling

Note 1: Reserve life is based on GLJ's current economic forecast utilizing Proved plus Probable Reserves. Please refer to page IV-133 – IV-134 of the Competent Person's Report in Appendix IV to this Prospectus for more information.

Note 2: GLJ has not assigned any Reserves to this well due to economic limit considerations.

We have entered into tie-in agreements and a gas handling agreement with ConocoPhillips, an Independent Third Party, to tie-in our natural gas from Basing into its pipeline and to use its gas plant to process the natural gas. We have also entered into road usage agreements with third party private road owners for our Company to access well sites in this area.

Other than third party gas plants, rented pipeline and rented compressors and private access roads, all facilities used by our Company in Basing are owned by us.

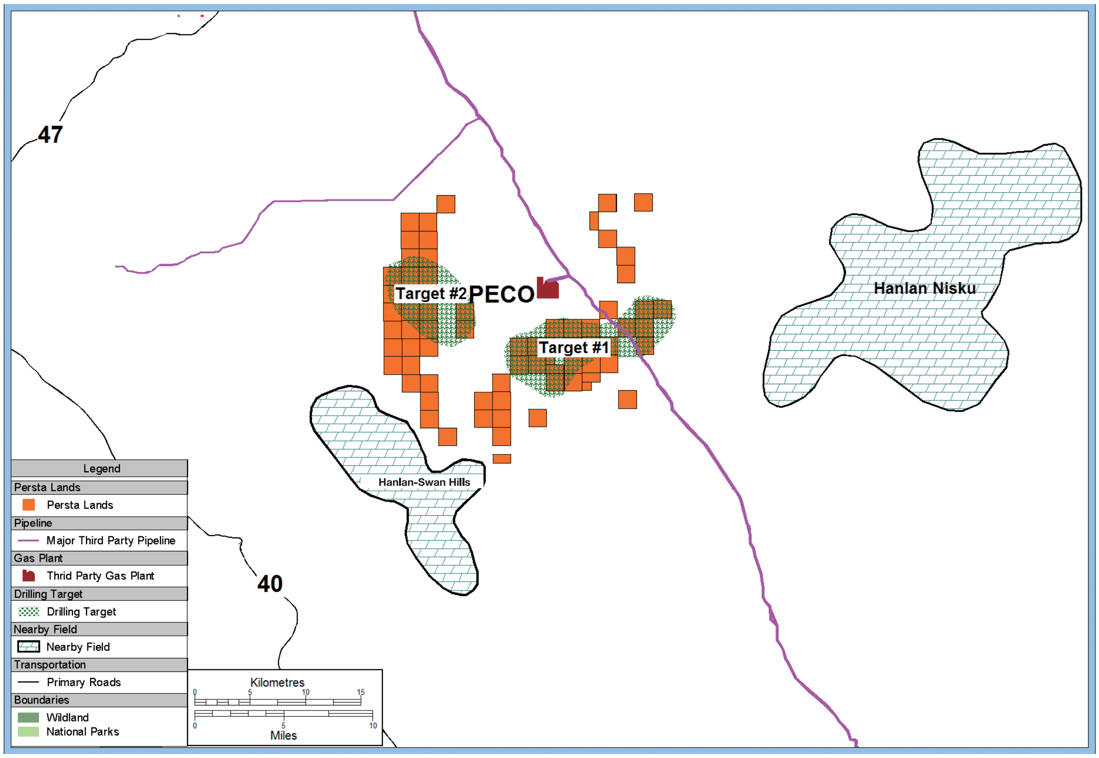
Major terms of the gas compressor equipment rental agreement

As at the Latest Practicable Date, we entered into two gas compressor equipment rental agreements ("**Compressor Rental Agreements**") with a third party lessor ("**Lessor**") in 2012 and 2013 respectively for the lease of the two gas compressors to our Company. Rental fees are charged at C$12,650 per month for a minimum term of 60 months for one compressor, and C$22,000 per month for a minimum term of 36 months for the other compressor and are payable monthly upon receipt of invoice. The Compressor Rental Agreements will be continuing on a month-to-month basis upon expiration of the minimum term, and a party may terminate the Compressor Rental Agreement by giving to the other party a thirty (30) days' prior written notice.

Deep Basin Devonian

Deep Basin Devonian is located approximately 200 km west of Edmonton, Alberta. The Deep Basin Devonian natural gas assets consist of approximately 44,320 net acres of land with PNG rights in an area known as Hanlan-Peco. Although GLJ has not assigned any Reserves or Resources to Hanlan-Peco and the area is undeveloped, our management team identified two natural gas targets based on seismic interpretation and information gathered from nearby producing wells. We own a 100% working interest in our PNG Licences and Crown Leases in this area. The map below shows the locations of our two natural gas targets in Hanlan-Peco in Deep Basin Devonian.

Our Natural Gas Targets in Hanlan-Peco in the Deep Basin Devonian Area



We believe that the Devonian target within Deep Basin has shown natural gas and oil reserve potential as demonstrated by nearby producing wells, with 240 Bcf of natural gas produced from one nearby single well in this area as at December 31, 2015. Regional Devonian potential has also been revealed by nearby developed fields owned by other operators such as Hanlan-Swan Hills which cumulatively produced a total of 1,260 Bcf of natural gas from 19 wells and Hanlan-Nisku which cumulatively produced a total of 1,410 Bcf of natural gas plus 157 MMbbl of oil from 46 wells as at December 31, 2015.

Production Facilities

As at the Latest Practicable Date, we did not have any surface facilities in Deep Basin Devonian, but we have access to the major pipelines in this area.

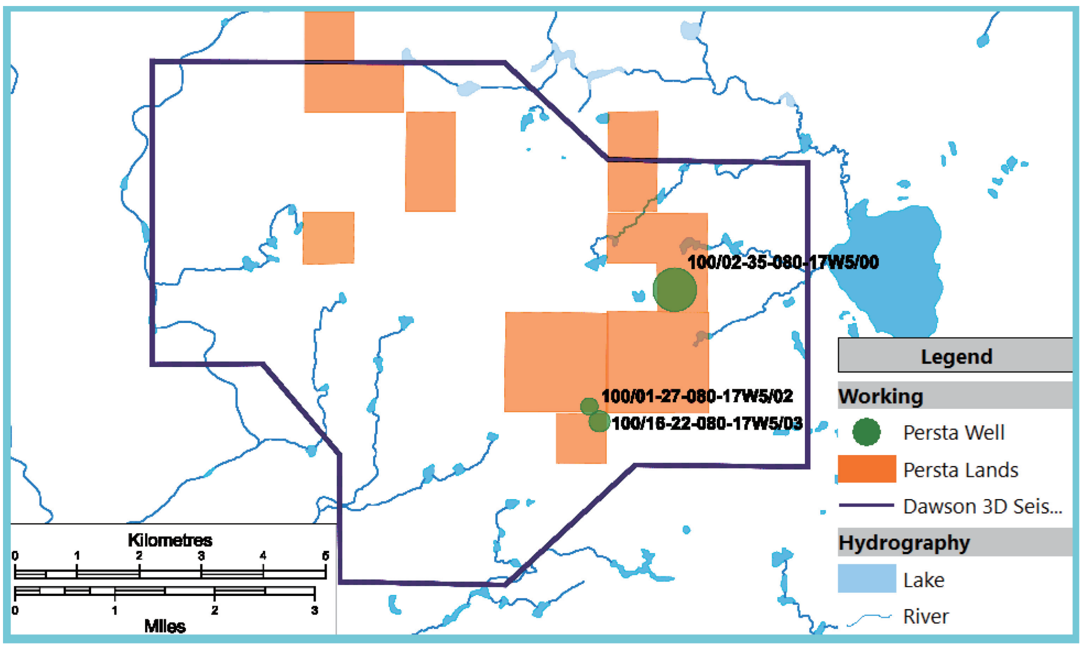
Peace River

As at the Latest Practicable Date, the Peace River light oil assets consist of approximately 3,200 net acres of land in Dawson with PNG rights, and is partially developed. There are two light oil wells in production in Dawson with a production rate of 126 Bbls/d as at September 30, 2016. There is one other producing well which was voluntarily and temporarily shut-in due to economic limit considerations in order to maintain our operating cash flow and to preserve our ability to realize the full economic potential of the wells in light of the changes in oil prices. As at September 30, 2016, the gross Proved Reserves, Proved plus Probable Reserves and Proved plus Probable plus

Possible Reserves are estimated to be approximately 69,000 Bbl, 99,000 Bbl and 135,000 Bbl, respectively. As at the Latest Practicable Date, there are 6 drilling locations with an estimated 899 Mbbls of gross Best Estimate Unrisked Prospective Resources identified by 3D seismic data as estimated by GLJ.

The map below shows the location of our PNG Licences and Crown Leases in Peace River.

Our Light Oil Area for Growth in Dawson in the Peace River Area

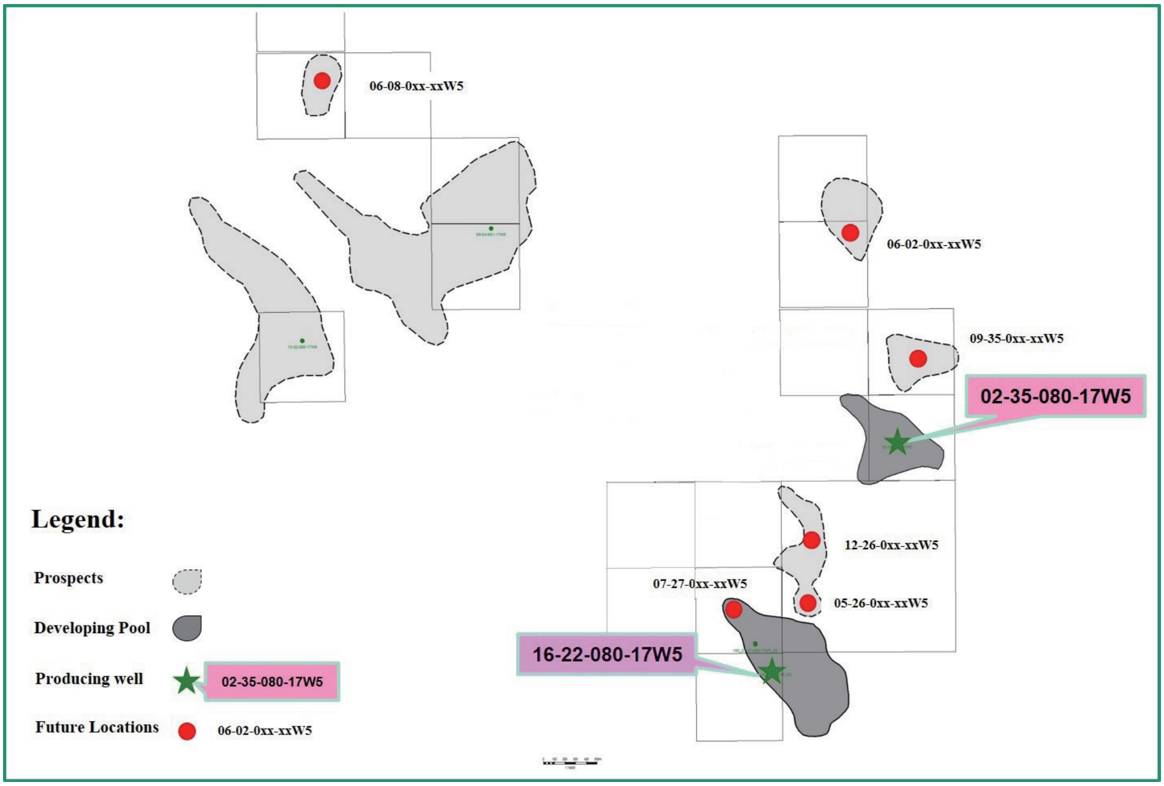


The Peace River light oil properties at Dawson are located approximately 50-60 km east of Peace River, Alberta. As at the Latest Practicable Date, we held 3,200 net acres of lands under Crown Leases or PNG Licences in this area and 6 drilling locations in Dawson as identified by GLJ.

As at September 30, 2016, there were two wells in production and one other producing well which was voluntarily and temporarily shut-in.

The map below shows the location of our two producing wells which have been assigned Reserves as well as 6 prospective drilling locations in Dawson as identified by GLJ. Please refer to the Competent Person's Report in Appendix IV to this Prospectus for more information.

Our Producing Wells and Drilling Locations in Dawson in Peace River



Production Facilities

As at the Latest Practicable Date, we installed three well sites including surface production facilities approximately 4 km of field roads and 0.5 km of pipeline. The designed capacities for each of our three wells in Peace River is approximately 250 Bbl/d. One of our wells had been subject to a Maximum Rate Limitation ("**MRL**") of 8.5 m^3/d immediately before the grant of the Good Production Practice (GPP) status by the AER in February 2013. Since February 2013 and up to the Latest Practicable Date, production from the aforesaid well is no longer subject to any maximum rate and accordingly we may produce without any permitted production volume. The other two wells are subject to a MRL of 8.5 m^3/d as at April 2016. As advised by our Canadian Legal Advisers, we complied with all Canadian laws and regulations and local authority requirements in relation to the permitted production volume applicable to our oil wells. We entered into a master road usage agreement with a third party (the "**Road Usage Agreement**") for our access to its private roads in this area.

The table below shows the well number, production date, initial flow rate, flow rate and accumulated production as at September 30, 2016, reserve life, well status and recovery method of our wells in Dawson.

UWID	Production Date	Initial flow rate	Flow rate on September 30, 2016	Accumulated production as at September 30, 2016	Remaining 2P reserve life (Years) as at September 30, 2016 *(Note 1)*	Well Status as at September 30, 2016	Recovery method
100/16-22-080-17W5/03 *(Note 2)*	April 2011	438 Bbl/d	49 Bbl/d	47,250 Bbl of light oil	11.7	Producing	Drilling
100/01-27-080-17W5/02 *(Note 3)*	October 2011	375 Bbl/d	0	34,425 Bbl of light oil	N/A	Shut-in	Drilling
100/02-35-080-17W5/00	September 2012	305 Bbl/d	77 Bbl/d	119,740 Bbl of light oil	16.5	Producing	Drilling

Note 1: Reserve life is based on GLJ's current economic forecast utilizing Proved plus Probable Reserves. Please refer to page IV-248 of the Competent Person's Report in Appendix IV to this Prospectus for more information.

Note 2: According to GLJ, this well resumed production in September 2016 at higher forecast future oil prices with a remaining 2P reserve life.

Note 3: According to GLJ, this well has not been assigned any Reserves as it is considered to be uneconomic to resume production due to economic limit considerations as resuming production will result in negative cumulative before tax cash flow.

Junior Assets

As disclosed above, as at the Latest Practicable Date, a total of 77 drilling locations have been assigned to Reserves and Resources. These drilling locations together with certain undeveloped land of our Company (which has no Reserves or Resources assigned by GLJ yet) are considered by our Company as Junior Assets, being oil and gas assets yet to be developed.

Below is the table summarising the Junior Assets in each of the three core areas:

	Junior Assets		
Location	**Nature**	**Area**	**Details**
Alberta Foothills	Liquid rich natural gas assets	Basing	• A total of 7,040 net acres of undeveloped land. Of this amount, 3,200 net acres of undeveloped land with drilling locations identified by GLJ.
			• 5 drilling locations assigned to gross Proved Reserves of 38,617 MMcf natural gas and 329 Mbbl NGLs, gross Proved plus Probable Reserves of 58,344 MMcf natural gas and 497 Mbbl NGLs, and gross Proved plus Probable plus Possible Reserves of 74,094 MMcf natural gas and 633 Mbbl NGLs
			• 8 drilling locations assigned to gross Best Estimate Unrisked Contingent Resources of 59,342 MMcf natural gas and 506 Mbbl NGLs
		Voyager and Kaydee	• A total of 41,600 net acres of undeveloped land. Of this amount, 17,920 net acres of undeveloped land with drilling locations identified by GLJ.
			• 58 drilling locations assigned to gross Best Estimate Unrisked Prospective Resources of 380 Bcf natural gas and 3,243 Mbbl NGLs
		Stolberg	• A total of 8,448 net acres of undeveloped land
			• No Reserves or Resources were assigned by GLJ

	Junior Assets		
Location	**Nature**	**Area**	**Details**
		Columbia	• A total of 7,360 net acres of undeveloped land • No Reserves or Resources were assigned by GLJ
Peace River	Light oil assets	Dawson	• A total of 2,400 net acres of undeveloped land. Of this amount, 1,920 net acres of undeveloped land with drilling locations identified by GLJ. • 6 drilling locations with an estimated 899 Mbbls of gross Best Estimate Unrisked Prospective Resources
Deep Basin Devonian	Natural gas assets	Hanlan-Peco	• A total of 44,320 net acres of undeveloped land • No Reserves or Resources were assigned by GLJ • Two natural gas targets were identified by our Company based on seismic interpretation and information gathered from nearby producing wells

OUR DEVELOPMENT

Our management team is focused on improving our drilling and completion techniques. We have assembled an experienced management and technical team with specialized expertise in resource play identification, capture, development and production. We continuously evaluate our drilling results and monitor the results of other operators to improve our operating practices and implement various drilling and completion techniques such as horizontal drilling and multi-stage completion. Our Company expects that our drilling and completion techniques will continue to evolve. We believe that this continued evolution has the potential to significantly enhance our Company's ultimate reserve recovery, deliverability, production and rate of return on invested capital.

In respect of the timeline of our operations by main stages, please refer to the section headed "Corporate Structure and History — Key Milestones" in this Prospectus for details.

Our Operational Activities:

	For the year ended December 31,			For the nine months ended September 30,
	2013	2014	2015	2016
Number of wells drilled in aggregate:				
— Natural gas	1	1	0	0
— Crude oil	0	0	0	0
Number of producing wells in aggregate:				
— Natural gas	5	6	5	5
— Crude oil	4	3	1	2

During the Track Record Period, two new horizontal wells in Basing in the Alberta Foothills commenced production for natural gas in November 2013 and September 2014 respectively without fracture stimulation.

THREE-YEAR DEVELOPMENT PLAN

Our 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 77 drilling locations.

We acquired the PNG Licences and Crown Leases in Basing in the Alberta Foothills 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.

Our three-year development plan aims to increase our current production from an average production of approximately 3,363 Boe/d in the first nine months of 2016 to approximately 5,448 Boe/d based on Proved plus Probable Reserves 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 drilling locations in Basing in the Alberta Foothills area. 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 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 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.

Details of the timeline for drilling, completion and tie-in for commercial production for each drilling location are set out below:

Year	No.	Drilling Location	Area	Well Type	Activity	Start	Complete	2017				2018				2019			
								Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
2017	1	XX/08-21-047-19W5/WILR	Alberta Foothills (Basing)	Gas	Drilling Completion Tie-In	2017-03-10 2017-04-05 2017-04-10	2017-04-03 2017-04-09 2017-04-21	RIG-1											
	2	XX/14-29-047-19W5/WILR	Alberta Foothills (Basing)	Gas	Drilling Completion Tie-In	2017-03-10 2017-04-05 2017-04-10	2017-04-03 2017-04-09 2017-04-21	RIG-2											
	3	XX/02-36-047-20W5/WILR	Alberta Foothills (Basing)	Gas	Drilling Completion Tie-In	2017-04-03 2017-04-27 2017-05-02	2017-04-26 2017-05-01 2017-05-14		RIG-2										
2018	1	XX/11-02-048-20W5/WILR	Alberta Foothills (Basing)	Gas	Drilling Completion Tie-In	2018-01-02 2018-01-27 2018-02-01	2018-01-26 2018-01-31 2018-02-11					RIG-1							
	2	XX/02-36-047-20W5/NOT	Alberta Foothills (Basing)	Gas	Drilling Completion Tie-In	2018-01-28 2018-02-22 2018-02-27	2018-02-21 2018-02-26 2018-03-10					RIG-1							
2019	1	XX/XX-32-047-19W5/WILR	Alberta Foothills (Basing)	Gas	Drilling Completion Tie-In	2019-06-17 2019-07-14 2019-07-20	2019-07-13 2019-07-18 2019-08-04										RIG-1		
	2	XX/XX-06-048-19W5/WILR	Alberta Foothills (Basing)	Gas	Drilling Completion Tie-In	2019-07-19 2019-08-17 2019-08-23	2019-08-15 2019-08-22 2019-09-06											RIG-1	
	3	XX/XX-01-048-20W5/WILR	Alberta Foothills (Basing)	Gas	Drilling Completion Tie-In	2019-06-25 2019-07-21 2019-07-26	2019-07-20 2019-07-25 2019-08-11										RIG-2		
	4	X1/XX-11-048-20W5/WILR	Alberta Foothills (Basing)	Gas	Drilling Completion Tie-In	2019-07-21 2019-08-17 2019-08-22	2019-08-16 2019-08-21 2019-09-08											RIG-2	
	5	X2/XX-11-048-20W5/WILR	Alberta Foothills (Basing)	Gas	Drilling Completion Tie-In	2019-06-17 2019-07-14 2019-07-20	2019-07-13 2019-07-18 2019-08-04										RIG-3		
	6	XX/XX-12-048-20W5/WILR	Alberta Foothills (Basing)	Gas	Drilling Completion Tie-In	2019-07-19 2019-08-17 2019-08-23	2019-08-15 2019-08-22 2019-09-06											RIG-3	
	7	XX/05-02-048-20W5/NOT	Alberta Foothills (Basing)	Gas	Drilling Completion Tie-In	2019-06-25 2019-07-21 2019-07-26	2019-07-20 2019-07-25 2019-08-11										RIG-4		
	8	XX/XX-02-048-20W5/NOT	Alberta Foothills (Basing)	Gas	Drilling Completion Tie-In	2019-07-21 2019-08-17 2019-08-22	2019-08-16 2019-08-21 2019-09-08											RIG-4	

Note 1: RIG-1, RIG-2, RIG-3 and RIG-4 stand for Rig No.1, Rig No.2, Rig No.3 and Rig No.4 respectively.

Note 2: Rig Numbers are shown in each year to show the demand of rigs and drilling crews, and the drilling workflow.

Our development plan schedules, production ramp-ups and assumptions for the Alberta Foothills have been reviewed by GLJ, who has given its opinion as to the credibility and validity of the aforementioned aspects based on GLJ's industry experience.

Development Status of the 2017 Drilling Locations

We intend to drill a total of three wells in the Alberta Foothills. As at the Latest Practicable Date, geological and geophysical studies combined with 3D seismic mapping, drilling location proposal, preparation of drilling programs for the three drilling locations for 2017 have already been completed.

The three gas wells in Basing are located at the two existing wellsites with producing well(s). One wellsite was built for the drilling of one new well, whilst the other wellsite needs to be extended for the drilling of the other two wells and currently the lease extension application is in process. There are also existing access roads for the three gas wells in Basing.

Well licences for the three wells to be drilled in 2017 have been received from AER.

Two rigs will be deployed for the drilling of the three wells, each operated by a separate drilling crew. We expect that the drilling for each well will take not more than 30 days, and thereafter, completion and tie-in activities will be performed to prepare the wells for commercial production.

Development Plan for the 2018 and 2019 Drilling Locations

We intend to drill two and eight wells in the Alberta Foothills in 2018 and 2019 respectively. As at the Latest Practicable Date, geological and geophysical studies combined with 3D seismic mapping, drilling location proposal for the ten wells have already been completed.

The two wells to be drilled in 2018 are located at two existing wellsites with existing access roads. The eight wells to be drilled in 2019 will be located at new wellsites which have not been built yet.

As per AER's requirement, a well licence application must be submitted with a survey plan which should not be more than one year old from the date on which it is certified. Therefore, a well licence is generally applied for a drilling location planned to be drilled within one year from the date of the application. Given the well licence only has a one year valid period before expiry, meaning that once a well licence has been issued, the related well must be spudded within one year otherwise the well licence will expire and be cancelled. In this regard, well licence applications for the two wells in 2018 and the eight wells in 2019 will be submitted in late 2017 and late 2018 respectively. Based on our past experience that, as we had submitted the required documentation with the applications, we were always able to obtain the well licences in order to proceed with the drilling of our wells, we are of the view that we are able to obtain the well licences for these wells as we are holding the related PNG licences. Our Canadian Legal Advisers confirm that the well licence application is an administrative procedure, and there is no material legal impediment for our Company to obtain the well licences for the drilling locations under our three-year development plan*(Note)*. It normally takes one week for well licence renewal or new application.

One rig will be deployed for the drilling of the two wells in 2018. When the first one has been drilled, the rig and its crew will be relocated to drill the second well.

Four rigs will be used for the drilling of the eight wells in 2019, each operated by a separate drilling crew. We expect that the drilling for each well will take no more than 30 days, and thereafter, completion and tie-in activities will be performed to prepare the wells for commercial production.

A chart summarising the development status of the 2017–2019 drilling locations as at the Latest Practicable Date is set out below:

				Stages/Activities of Development									
Year of Drilling	**No.**	**Drilling Location**	**Well Type**	**3D Seismic**	**Location Proposed**	**Drilling Program**	**Access Road** *(Note 1)*	**Well Site**	**Well Licence** *(Note 2)*	**Drilling**	**Completion** *(Note 3)*	**Tie-in** *(Note 4)*	**Expiry Date of PNG Licence/ Crown Lease**
2017	1	XX/08-21-047-19W5/WILR	Gas	Completed	Completed	Completed	Completed	Completed	Completed	Not Start	Not Start	Not Start	Indefinite*(Note 5)*
	2	XX/14-29-047-19W5/WILR	Gas	Completed	Completed	Completed	Completed	Completed	Completed	Not Start	Not Start	Not Start	Indefinite*(Note 5)*
	3	XX/02-36-047-20W5/WILR	Gas	Completed	Completed	Completed	Completed	Completed	Completed	Not Start	Not Start	Not Start	Indefinite*(Note 5)*
2018	1	XX/11-02-048-20W5/WILR	Gas	Completed	Completed	Completed	Completed	Not Start	Not Start	Not Start	Not Start	Not Start	Indefinite*(Note 5)*
	2	XX/02-36-047-20W5/NOT	Gas	Completed	Completed	Completed	Completed	Not Start	Not Start	Not Start	Not Start	Not Start	Indefinite*(Note 5)*
2019	1	XX/XX-32-047-19W5/WILR	Gas	Completed	Completed	Not Start	Not Start	Not Start	Not Start	Not Start	Not Start	Not Start	March 20, 2018
	2	XX/XX-06-048-19W5/WILR	Gas	Completed	Completed	Not Start	Not Start	Not Start	Not Start	Not Start	Not Start	Not Start	March 20, 2018
	3	XX/XX-01-048-20W5/WLR	Gas	Completed	Completed	Not Start	Not Start	Not Start	Not Start	Not Start	Not Start	Not Start	Indefinite*(Note 5)*
	4	X1/XX-11-048-20W5/WLR	Gas	Completed	Completed	Not Start	Not Start	Not Start	Not Start	Not Start	Not Start	Not Start	January 11, 2018
	5	X2/XX-11-048-20W5/WLR	Gas	Completed	Completed	Not Start	Not Start	Not Start	Not Start	Not Start	Not Start	Not Start	January 11, 2018
	6	XX/XX-12-048-20W5/WILR	Gas	Completed	Completed	Not Start	Not Start	Not Start	Not Start	Not Start	Not Start	Not Start	January 11, 2018
	7	XX/05-02-048-20W5/NOT	Gas	Completed	Completed	Not Start	Not Start	Not Start	Not Start	Not Start	Not Start	Not Start	Indefinite*(Note 5)*
	8	XX/XX-02-048-20W5/NOT	Gas	Completed	Completed	Not Start	Not Start	Not Start	Not Start	Not Start	Not Start	Not Start	Indefinite*(Note 5)*

Note 1: All year 2017 drilling locations are located at existing producing well sites and with existing access roads.

Note 2: It normally takes one week for a new well license application or a well licence renewal.

Note 3: Completion will be done after drilling.

Note 4: Tie-in will be done after completion and the well will then be ready for producing.

Note 5: "Indefinite" is a term adopted in Alberta land system pursuant to section 15 of the Petroleum and Natural Gas Tenure Regulation of the Mines and Minerals Act. An indefinite expiry date of a lease/licence means the lease/licence will have an indefinite term until the related well becomes non-productive. The indefinite term relates to 2 PNG Licences covering a total of 8 of our drilling locations in 2017, 2018 and 2019 which had initially expired on January 11, 2017 and were renewed with an indefinite expiry date.

Note: The Competent Person is unable to provide its view on whether (a) the well license application is an administrative procedure; and (b) there is any material legal impediment for our Company to obtain the well license for the wells under the three-year development plan as these matters are out of their scope. Though the well license application process is beyond the scope of its expertise of assessment and evaluation of natural gas and oil reserves and resources, based on its observation, the Competent Person believes the well licence application is an administrative procedure and foresees no material legal impediment for our Company to obtain the well licenses for the drilling locations under our three-year development plan.

Production Forecast

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	
Total Production (Boe/d)		6,245	6,612	5,448	2,389

* Key assumptions in determining the production forecasts by volume in the above are based on those adopted by GLJ. Please refer to page IV-127 – IV-129 and IV-246 of the Competent Person's Report in Appendix IV to this Prospectus for more information. The above production forecast includes the current producing wells.

** Production forecast of all new drilling locations in 2019 is based on Best Estimate Unrisked Contingent Resources as stated at page IV-142 of the Competent Person's Report. If based on Best Estimate Risked Contingent Resources to reflect a chance of development, a factor of 80% shall be applied to the production forecast.

The annual production forecast of each drilling location is based on the average daily production rate of each drilling location provided by GLJ and the forecast production days of each drilling location. A breakdown of the annual production volume forecast of each existing well and new drilling locations for 2017 to 2019 are set out below:

					2017 Annual Production Forecast				2018 Annual Production Forecast				2019 Annual Production Forecast				Estimated		
Year of Drilling	No.	Drilling Location	Area	Well Type	Producing Days	Annual Gas (MMcf)	Annual Liquids (Bbl)	Annual Total (BOE)	Producing Days	Annual Gas (MMcf)	Annual Liquids (Bbl)	Annual Total (BOE)	Producing Days	Annual Gas (MMcf)	Annual Liquids (Bbl)	Annual Total (BOE)	Payout Period (Year)	2P Reserves/ Resources Life (Years)	Risk of payback period and Reserves/ Resources Life
Existing Wells	1	00/07-21-047-19W5/3	Alberta Foothills-Basing	Gas	365	1,125	9,589	197,016.67	365	959	8,176	167,985	365	818	6,972	143,238	1.8	24.4	Low
	2	00/05-29-047-19W5/0	Alberta Foothills-Basing	Gas	365	1,336	11,388	233,977.27	365	1,203	10,258	210,765	365	1,084	9,244	189,919	1.5	38.5	Low
	3	02/08-36-047-20W5/2	Alberta Foothills-Basing	Gas	365	2,963	25,263	519,047.15	365	2,179	18,578	381,692	365	1,602	13,660	280,658	1.4	16.2	Low
	4	00/10-36-047-20W5/4	Alberta Foothills-Basing	Gas	365	272	2,319	47,639.54	365	224	1,911	39,263	365	187	1,597	32,804	4.8	20.2	Low
	5	03/05-02-048-20W5/2	Alberta Foothills-Basing	Gas	365	1,190	10,146	208,462.94	365	1,019	8,693	178,600	365	873	7,445	152,958	1.9	25.5	Low
	6	00/16-22-080-17W5/3	Peace River-Dawson	Oil	365		3,650	3,650	365		3,285	3,285	365		2,555	2,555	0.8	11.7	Low
	7	00/02-35-080-17W5/0	Peace River-Dawson	Oil	365		20,075	20,075	365		14,600	14,600	365		10,950	10,950	0.6	16.5	Low
2017	1	XX/08-21-047-19W5/WILR	Alberta Foothills-Basing	Gas	253	2,341	19,960	410,084	365	2,163	18,441	378,878	365	1,825	15,562	319,728	0.9	42.5	Low
	2	XX/14-29-047-19W5/WILR	Alberta Foothills-Basing	Gas	253	2,308	19,676	404,265	365	2,070	17,650	362,636	365	1,697	14,472	297,347	0.9	36.0	Low
	3	XX/02-36-047-20W5/WILR	Alberta Foothills-Basing	Gas	232	1,343	11,450	235,256	365	1,349	11,500	236,279	365	1,125	9,595	197,145	1.2	33.9	Low
2018	1	XX/11-02-048-20W5/WILR	Alberta Foothills-Basing	Gas					323	1,459	12,440	255,591	365	1,340	11,429	234,809	0.7	35.0	Low
	2	XX/02-36-047-20W5/NOT	Alberta Foothills-Basing	Gas					296	1,050	8,954	183,972	365	721	6,147	126,293	2	35.5	Low
2019	1	XX/XX-32-047-19W5/WILR	Alberta Foothills-Basing	Gas									149	691	5,895	121,113	1.9	27.1	Medium
	2	XX/XX-06-048-19W5/WILR	Alberta Foothills-Basing	Gas									116	557	4,753	97,645	1.9	28.0	Medium
	3	XX/XX-01-048-20W5/WILR	Alberta Foothills-Basing	Gas									142	694	5,917	121,561	1.9	29.3	Medium
	4	X1/XX-11-048-20W5/WILR	Alberta Foothills-Basing	Gas									114	557	4,753	97,645	1.9	27.9	Medium
	5	X2/XX-11-048-20W5/WILR	Alberta Foothills-Basing	Gas									149	692	5,901	121,241	1.9	27.9	Medium
	6	XX/XX-12-048-20W5/WILR	Alberta Foothills-Basing	Gas									116	556	4,743	97,453	1.9	26.5	Medium
	7	XX/05-02-048-20W5/NOT	Alberta Foothills-Basing	Gas									142	614	5,238	107,621	4.1	38.5	Medium
	8	XX/XX-02-048-20W5/NOT	Alberta Foothills-Basing	Gas									114	614	5,238	107,621	4.1	38.5	Medium

Note 1: Annual Liquids means NGLs and Condensate for gas wells.

Note 2: Annual production is based on GLJ's Report effective on September 30, 2016.

Note 3: Production forecast of all new drilling locations in 2019 is based on Best Estimate 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.

Note 4: Estimated payout period and Reserves/Resources Life of each drilling location is provided by GLJ. GLJ utilized Proved plus Probable Reserves, product price and market forecasts, current royalty regime, and actual operating cost data in determining the payout period for all new drilling locations in 2017 and 2018, GLJ utilized Best Estimate Unrisked Contingent Resources, product price and market forecasts, current royalty regime and actual operating cost data in determining the payout period for all new drilling locations in 2019.

Note 5: The payout period of the existing wells (No. 1 to No. 7) are calculated based on our Company's unaudited management accounts.

According to the Industry Consultant, demand for natural gas is likely to expand for new natural gas production in Alberta due to rising demand of electricity generation, and crude oil production from oil sands. Based on annual gas production estimates by our Company, our production is forecast to increase from 0.364 bcm (12,876 MMcf) in 2017 to 0.387 bcm (13,674 MMcf) in 2018 and 0.460 bcm (16,249 MMcf) in 2019. This translates to 0.34%, 0.37% and 0.45% in 2017, 2018 and 2019 respectively as a percentage to Alberta's marketable natural gas production estimates. Accordingly, our Company expects that there will be sufficient market demand for the increased production volume following the implementation of our three-year development plan.

Capital Expenditure

Our expected capital expenditure budget for drilling, well completion and tie-in costs and for potential land acquisition in 2017, 2018 and 2019 in Basing in the Alberta Foothills is set out in the table below:

Locations/Capital Expenditure	2017	2018	2019	Total
Drilling, completion and tie-ins costs	C$18.0 million	C$12.0 million	C$59.2 million	C$89.2 million
Land acquisition and geology & geophysics evaluation	C$1.5 million	—	C$2.0 million	C$3.5 million
Total number of wells to be drilled	3	2	8	13
Total capital expenditure	C$19.5 million	C$12.0 million	C$61.2 million	C$92.7 million

Notes:

(1) The above costs for drilling completion and tie-ins are based on individual well costs adopted by GLJ. Please refer to page IV-145 of the Competent Person's Report in Appendix IV to this Prospectus for more information.

(2) The total capital expenditure estimates of C$92.7 million for future development were provided to GLJ by our Company. The key factors in the projection of the expected capital expenditure are based on third parties quotes including rig costs, directional drilling costs, mud costs, cementing costs and optional fracturing costs for which vendor quotes were not provided. GLJ has considered that these estimates are reasonable based on the supporting vendor's cost estimates and GLJ's non-confidential files, which include publicly available data from third party programs including Geo Scout, AccuMap and geoLogic. These programs provide information such as drilling times, sand tonnage, number of fracturing stages, and occasionally drilling and completion costs for wells.

We intend to apply approximately 52.6% (which amounts to C$18 million) of the net proceeds of the Global Offering (assuming an Offer Price of HK$3.40 per Share, being the mid-point of the estimated Offer Price range) and our existing working capital to fund the expected capital expenditure of approximately C$19.5 million for our development of 3 wells in 2017. We expect to finance the capital expenditure of approximately C$73.2 million for our development of 2 wells in 2018 and 8 wells in 2019 with the following sources of funding:

(i) approximately 38.4% of the net proceeds of the Global Offering of approximately C$13.0 million (assuming an Offer Price of HK$3.40 per Share, being the mid-point of the estimated Offer Price range).

(ii) net cash inflow generated from our operating activities of approximately C$56.3 million, which includes[(Note 1)]:

— the cash inflow generated from our sales revenue for the years ending 31 December 2018 and 2019 of approximately C$96.5 million;

— the cash outflow from our royalty, operating cost for the years ending 31 December 2018 and 2019 of approximately C$32.6 million;

— the cash outflow from our Company's general and administrative cost of approximately C$7.3 million; and

— the cash outflow from our finance expenses of approximately C$0.2 million.

(iii) new bank borrowings which will be approximately C$8.0 million.

Given that the new bank borrowings is of a limited scale as compared to the amount of operating cash inflow generated from our producing wells, we believe that our track record of fundraising on a standalone basis (as detailed in the section headed "Relationship with Controlling Shareholders — Financial Independence" in this Prospectus) has demonstrated our ability to obtain new financing from Independent Third Parties on a standalone basis. Based on the above, our Company considers that there will be sufficient funding to finance our development of the 10 wells and bring them to the stage of commercial production by the end of 2019, and no further fundraising exercise or bank borrowings of considerable scale will be required.

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.

Alberta Foothills

Basing

Our interests in the Basing area in the Alberta Foothills include PNG Licences covering 9,600 net acres and are located within WCSB, approximately 230 km southwest of Edmonton, Alberta. According to our three-year development plan, Basing is expected to be capable of producing up to approximately 6,180 Boe/d in year 2017, approximately 6,563 Boe/d in year 2018 of natural gas, NGLs and condensate based on Proved plus Probable Reserves production forecast, and approximately 5,411 Boe/d in year 2019 of natural gas, NGLs and condensate based on Proved plus Probable Reserves production forecast and an additional 2,389 Boe/d of natural gas, NGLs and condensate based on Best Estimate Unrisked Contingent Resources production forecast. The average 2P reserve life is approximately 30 years. Multiple well pairs will be drilled from individual well pads to reduce surface disturbance. In the Competent Person's Report, Basing has been assigned an estimated 17,567 Mboe of gross Proved plus Probable Reserves and 10,396 Mboe of gross Best Estimate Unrisked Contingent Resources. Please refer to the Competent Person's Report in Appendix IV to this Prospectus for more information.

In 2007, we drilled our first exploration well in Basing in order to assess the resource potential of the site. At the Latest Practicable Date, we have five wells in production, and the other one well had been voluntarily and temporarily shut-in due to economic limit considerations. We intend to further drill three wells in 2017, two wells in 2018 and eight wells in 2019. We intend to drill a total of 13 wells in the next three years with a focus on the Wilrich and Mountain-Park formations, in areas which have the same or similar geological characteristics as our current producing reservoir. After completion of these wells, they can be tied-in to our Company's existing gas gathering system to begin producing natural gas and liquids.

In the Basing area, approximately C$18.0 million will be allocated to drilling, completion and tie-ins in 2017, and approximately C$12.0 million and C$59.2 million will be allocated to drilling, completion and tie-ins in 2018 and 2019, respectively.

Voyager and Kaydee

Our interests in the Voyager and Kaydee areas in the Alberta Foothills cover approximately 22,400 and approximately 19,200 net acres respectively as at the Latest Practicable Date and are located within the WCSB region, approximately 76 km southwest of Edson, Alberta. The Voyager and Kaydee areas benefit from some similar geological characteristics, and according to the Competent Person's Report, the Voyager and Kaydee areas have been assigned an estimated 69,571 Mboe of gross Best Estimate Unrisked Prospective Resources. Please refer to the Competent Person's Report set out in Appendix IV to this Prospectus for more information.

The Spirit River Group which consists of the Wilrich and Mountain Park formations is the main producing target formation, similar to Basing. The geological characteristics including its formation thickness, naturally fractured reservoir and structure style as displayed by 3D seismic data and the nearby wells is very similar to the geological and geophysical characteristics in Basing.

We have no immediate plans to drill wells in Voyager and Kaydee areas in the next three years but will conduct further exploration activities with a view to upgrade the Resources into Reserves in the area.

Peace River

Dawson

Our interests in Dawson cover 3,200 net acres at the Latest Practicable Date and is located within the WCSB region, approximately 45 km northwest of Peace River, Alberta. Dawson has been assigned an estimated 69 Mbbls of Proved Reserves, 99 Mbbls of Proved plus Probable Reserves, 135 Mbbls of Proved plus Probable plus Possible and 899 Mbbls of gross Best Estimate Unrisked Prospective Resources by the Competent Person. Please refer to the Competent Person's Report set out in Appendix IV to this Prospectus for more information.

As at the Latest Practicable Date, we had two wells in production and one well that had been voluntarily and temporarily shut-in due to economic limit considerations. A total of 6 locations have been assigned as prospective drilling locations by GLJ. We can resume production of the shut-in wells in Dawson at any time at no incremental cost, subject to the recovery of the market price for oil. We have no immediate plans to drill wells in the next three years but will conduct further exploration activities with a view to upgrade the Resources into Reserves in the area.

Production and Operating Costs

As stated in the Competent Person's Report, the unit cash operating cost of our natural gas and oil operations is estimated at C$4.75/Boe and C$15.17/Boe between 2017 and 2019, respectively. For more information regarding our operating costs, please refer to the section headed "Financial Information — Statements of Profit or Loss and Other Comprehensive Income — Production Costs and Total Cash Operating Costs" in this Prospectus.

The tables below show a summary and breakdown of our Company's actual operating costs between 2013 and 2016 and the forecast operating costs between 2017 and 2019 for our projects:

Natural Gas, NGL and Condensate

	2013 Actual	2014 Actual	2015 Actual	2016[1] Actual	2017 Forecast	2018 Forecast	2019 Forecast
	C$/Boe	*C$/Boe*	*C$/Boe*	*C$/Boe*	*C$/Boe*	*C$/Boe*	*C$/Boe*
Fixed	0.51	0.85	0.92	0.54	0.72	0.72	0.72
Variable	0.47	0.58	0.38	0.34	0.45	0.45	0.45
Transportation	3.86	3.59	3.75	3.81	3.57	3.57	3.57
Total operating cost	4.84	5.02	5.05	4.69	4.74	4.74	4.74

	Actual				Forecast		
	2013	2014	2015	2016[1]	2017	2018	2019
	C$/Boe	*C$/Boe*	*C$/Boe*	*C$/Boe*	*C$/Boe*	*C$/Boe*	*C$/Boe*
Workforce employment	0.79	0.75	0.80	0.66	0.74	0.74	0.74
Consumables	0.57	0.50	0.48	0.49	0.49	0.49	0.49
Fuel, electricity, water and other services	2.16	2.51	2.44	2.02	2.28	2.28	2.28
Environmental protection and monitoring	0.09	0.08	0.13	0.10	0.09	0.09	0.09
Product marketing and transport	1.22	1.15	1.05	1.25	1.09	1.09	1.09
Non-income taxes, royalties and other governmental charges	0.01	0.03	0.15	0.17	0.05	0.05	0.05
Total operating cost[(Note)]	4.84	5.02	5.05	4.69	4.74	4.74	4.74

Crude Oil

	2013 Actual	2014 Actual	2015 Actual	2016[1] Actual	2017 Forecast	2018 Forecast	2019 Forecast
	C$/Bbl	*C$/Bbl*	*C$/Bbl*	*C$/Bbl*	*C$/Bbl*	*C$/Bbl*	*C$/Bbl*
Fixed	3.16	2.90	3.51	4.01	2.59	2.59	2.59
Variable	12.98	4.79	3.47	3.54	4.87	4.87	4.87
Transportation	12.60	9.51	7.96	4.63	7.71	7.71	7.71
Total operating cost	28.74	17.20	14.94	12.18	15.17	15.17	15.17

	Actual				Forecast		
	2013	2014	2015	2016[1]	2017	2018	2019
	C$/Bbl	*C$/Bbl*	*C$/Bbl*	*C$/Bbl*	*C$/Bbl*	*C$/Bbl*	*C$/Bbl*
Workforce employment	2.59	2.37	2.34	2.16	1.69	1.69	1.69
Consumables	5.57	4.69	1.07	0.70	3.04	3.04	3.04
Fuel, electricity, water and other services	7.81	0.63	2.64	2.11	2.98	2.98	2.98
Environmental protection and monitoring	0.15	—	—	—	0.05	0.05	0.05
Product marketing and transport	12.60	9.51	7.96	4.63	7.29	7.29	7.29
Non-income taxes, royalties and other governmental charges	0.02	—	0.93	2.58	0.12	0.12	0.12
Total operating cost[2]	28.74	17.20	14.94	12.18	15.17	15.17	15.17

Notes:

1. Based on audited figures from January to September 2016 and unaudited figures from October to December 2016.

2. The following items which are required under Rule 18.03(3) of the Listing Rules are not applicable to our operating costs for the following reasons:

   (1) on and off-site administration: we engage Independent Third Party contractors and consultants to supply services for a majority of our operations, including inspection and maintenance, pressure vessel integrity management, supplies of packaged equipment and facilities operation. Costs associated with the engagement of contractors and consultants are included in the costs associated with workforce employment.

   (2) transportation of workforce: we engage Independent Third Party contractors and consultants to supply services for a majority of our operations, including drilling and well completion consulting, seismic data, geological and geophysics consulting, engineering and design, regulation and environmental consulting, inspection and maintenance, pressure vessel integrity management, supplies of packaged equipment and facilities operation. These contractors and consultants are responsible for their own transportation costs and, accordingly, estimate of cash operating cost associated with transportation of workforce is not applicable.

   (3) contingency allowances: we maintain various insurance policies for our operations. They include (i) insurance on our properties and equipment, including wells, gas gathering stations, pipelines, well site and wellhead equipment, and other machinery and supplies; (ii) workers compensation board insurance for our on-site workers; (iii) insurance for drilling and completion operation, including redrilling, seepage and pollution; (iv) general workplace injury insurance; and (v) excess liability insurance. In

this regard, we believe that our level of insurance is sufficient to cover additional costs in the event of unforeseen circumstances which may occur in our operations and therefore no contingency allowance is required to be made.

Our forecast operating costs may differ from the actual future operating costs due to numerous factors, including the factors described in the section headed "Risk Factors" in this Prospectus. In addition, you should also refer to the section headed "Forward-looking Statements" in this Prospectus for the risks of placing undue reliance on any forward-looking information.

The actual operating costs between 2013 and 2016 and the forecast operating costs between 2017 and 2019 with details on their breakdown are shown on a per Boe/Bbl basis in the tables above and are based on the following:

(i) costs estimates in the Competent Person's Report which is based on the number of producing wells and the production forecast of our three-year development plan; and

(ii) an analysis of our actual operating costs between 2013 and 2016.

Based on GLJ's forecast selling prices and operating costs, we expect that our producing assets will be self-sufficient in working capital and funding for our cash flow once production has commenced.

During the Track Record Period, 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. For more information regarding our operating costs, please refer to the section headed "Financial Information — Operating Costs" in this Prospectus.

During the Track Record Period, the amount of expenditure on exploration and evaluation assets for the years ended December 31, 2013, 2014, and 2015 and for the nine months ended September 30, 2016 were approximately C$0.6 million, C$6.0 million, C$3.9 million and C$0.8 million, respectively. For more information regarding our exploration expenses and how they were accounted for in our financial statements, please refer to the section headed "Financial Information — Exploration and Evaluation Assets" in this Prospectus.

The following sensitivity analysis shows the impact of hypothetical fluctuations in the actual average selling price and the forecast average selling price (including market sales and contract sales) of our natural gas on our revenue for illustration purpose only. Fluctuations are assumed to be C$2/Mcf, C$3/Mcf, C$4/Mcf, C$5/Mcf and C$6/Mcf, which correspond to the historical natural gas price of Canadian Gas Price Reporter during the Track Record Period and the forecast natural gas price during the forecast period.

	Year ended December 31,				Year ending December 31,		
	2013	2014	2015	2016	2017	2018	2019
	Actual				Forecast		
					2P	2P	2P plus Best Estimate Unrisked Contingency*
Volume (Mcf)	4,202,855	5,697,904	3,788,831	7,388,370	12,875,375	13,674,360	16,249,800
Actual Average Selling price/ Forecast Average Selling price (C$/Mcf)	3.62	4.70	3.61	2.70***	3.17**	3.19**	3.46**
Revenue (C$'000)	15,211	26,795	13,683	19,982***	40,815	43,621	56,224

	Increase/ (decrease) in revenue	Increase/ (decrease) in revenue	Increase/ (decrease) in revenue	Increase/ (decrease) in revenue	Increase/ (decrease) in revenue	Increase/ (decrease) in revenue	Increase/ (decrease) in revenue
C$/Mcf	C$'000	C$'000	C$'000	C$'000	C$'000	C$'000	C$'000
2.0	(6,809)	(15,384)	(6,100)	(5,205)	(15,064)	(16,272)	(23,725)
3.0	(2,606)	(9,686)	(2,311)	2,183	(2,189)	(2,598)	(7,475)
4.0	1,597	(3,989)	1,478	9,571	10,687	11,076	8,775
5.0	5,800	1,709	5,266	16,960	23,562	24,751	25,025
6.0	10,003	7,407	9,055	24,348	36,437	38,425	41,274

* *For illustration only*

** *Based on GLJ report. For details, please refer to page IV-79 of Appendix IV to this Prospectus.*

*** *Based on audited figures from January to September 2016 and unaudited figures from October to December 2016.*

Sales of natural gas was the major business segment and accounted for the majority of our revenue, royalties and operating costs. In the below analysis, our Company illustrates the breakeven analysis with respect to selling price and sales volume of natural gas with respect to our Company's net profit during the Track Record Period as well as the forecast period of 2017 to 2019 based on the Development Plan.

Breakeven analysis with respect to net profit

	Year ended December 31,				Year ending December 31,		
	2013	2014	2015	2016***	2017	2018	2019
	Actual				Forecast		
					2P	2P	2P plus Best Estimate Unrisked Contingency*
Volume (Mcf)	4,202,855	5,697,904	3,788,831	7,388,374	12,875,375	13,674,360	16,249,800
Actual Average Selling price/ Forecast Average Selling price (C$/Mcf)	3.62	4.7	3.61	2.70	3.17**	3.19**	3.46**
	C$/Mcf	C$/Mcf	C$/Mcf	C$/Mcf	C$/Mcf	C$/Mcf	C$/Mcf
Breakeven selling price	3.77	4.18	4.27	3.03	2.10	2.01	2.01(1)
	Mcf	Mcf	Mcf	Mcf	Mcf	Mcf	Mcf
Breakeven sales volume	4,383,411	5,059,633	4,476,859	8,284,372	8,538,264	8,628,254	9,454,266(2)
	%	%	%	%	%	%	%
Breakeven sales volume as a % of the total natural gas production volume	104.3	88.8	118.2	112.1	66.3	63.1	58.2(3)

* *For illustration only*

** *Based on GLJ report. For details, please refer to page IV-79 of Appendix IV to this Prospectus.*

*** *Based on audited figures from January to September 2016 and unaudited figures from October to December 2016.*

Notes:

(1) For 2019, if the Best Estimate Unrisked Contingency production volume is not included, the breakeven selling price is C$2.24/Mcf.

(2) For 2019, if the Best Estimate Unrisked Contingency production volume is not included, the breakeven sales volume is 7,302,099 Mcf.

(3) For 2019, if the Best Estimate Unrisked Contingency production volume is not included, the breakeven sales volume as a % of the total natural gas production volume is 64.8%.

The following table sets forth the actual/forecast selling price and market price for illustration:

	Year ended December 31,			2016		Year ending December 31,		
	2013	2014	2015	Q1–Q3	2016 Q4	2017	2018	2019
Actual/forecast average selling price *(C$/Mcf)*	3.62	4.70	3.61	2.45	3.30	3.17	3.19	3.46
— Forward sales price *(C$/Mcf)*	3.73	4.07	3.95	3.10	3.24	—	—	—
— Realized price *(C$/Mcf)***	3.53	5.02	2.43	1.70	3.35	—	—	—
Actual/forecast market price* *(C$/Mcf)*	3.23	4.57	2.74	2.01	3.34	3.24	3.24	3.46

* *Actual average market price from 2013 to 2016 was the AECO same day spot price averaged over the period; Forecast average market price from 2017 to 2019 is the AECO/NIT Spot gas price based on GLJ's forecast in Appendix IV (1 Mcf=1.08 MMBtu)*

** *The average realised price represents the average price of natural gas sales excluding the sales derived from forward sales.*

Gas Processing Capacity, Transportation Support and Resources

We have highlighted below gas processing capacity, transportation support and resources for our implementation of our three-year development plan.

(a) *Gas Processing*

During the Track Record Period, we engaged ConocoPhillips for processing our untreated natural gas with its Peco Plant ready to be sold. We have a firm gas processing capacity contract for 8 MMcf/d at the Peco Plant until February 2019. ConocoPhilips has provided us with the following Peco Plant processing capacity forecast potentially available to us.

Below is the table setting out our Company's available gas processing capacity:

Year	Production Forecast *(Note 1)* (A)	Assigned Capacity at Peco Plant *(Note 2)* (B)	Forecast Available Capacity at Peco Plant *(Note 3)* (C)	Assigned Plus Forecast Available Capacity/ Production Forecast (B+C)/A
2017	35.3 MMcf/d	8.0 MMcf/d	37.8 MMcf/d	130%
2018	37.5 MMcf/d	8.0 MMcf/d	41.5 MMcf/d	132%
2019	44.5 MMcf/d	8.0 MMcf/d	41.5 MMcf/d	110%

Note 1: Production forecast is extracted from our three-year development plan based on 2P Reserves for 2017 and 2018, and on aggregating 2P Reserves and Best Estimate Unrisked Contingent Resources for 2019 for illustration only.

Note 2: Our Company expects to renew its engagement with ConocoPhillips on similar terms after the expiry of its existing contract in February 2019.

Note 3: Given the past and present available capacity at Peco plant was provided at similar prices, upon reasonable enquiry, our Directors are of the view that the forecast available capacity at Peco plan will also be provided at similar prices as that currently assigned.

Apart from the Peco Plant, if required, we may engage another gas processing plant operated by an Independent Third Party located at 12 km north of our Company's producing locations in Basing. To the best knowledge of our management, as at September 30, 2016, the plant was operating at approximately 36% of its design capacity at approximately 400 MMcf/d. In light of this, our Company believes that there is sufficient gas processing capacity available for our increased production volume following the implementation of our three-year development plan.

(b) *Transportation*

Natural Gas and NGLs

During the Track Record Period, we engaged NGTL for transportation of our natural gas, including both Firm Transportation-Receipt (FT-R) and Interruptible Transportation Receipt (IT-R). 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 and 65.0 MMcf/d on average for 2017 and 2018 respectively and 110.0 MMcf/d for 2019. NGTL will also provide IT-R service to our Company.

Below is the table setting out our Company's available transportation capacity:

Year	**Production Forecast** *(Note 1)*	**Assigned FT-R Service in NGTL**	**Expected available FT-R service from other third parties and IT-R service from NGTL** *(Note 2)*	**Total Transportation Capacity Available**
2017	35.3 MMcf/d	18.6 MMcf/d	>20 MMcf/d	>38.6 MMcf/d
2018	37.5 MMcf/d	65.0 MMcf/d	Not Required	65.0 MMcf/d
2019	44.5 MMcf/d	110.0 MMcf/d	Not Required	110.0 MMcf/d

Notes:

1. Production forecast is extracted from our three-year development plan based on 2P Reserves for 2017 and 2018, and on aggregating 2P Reserves and Best Estimate Unrisked Contingent Resources for 2019 for illustration only.

2. The expected available FT-R service from other third parties, as well as the expected IT-R service from NGTL, if necessary, will make up for the shortage in transportation capacity in 2017. This is based on our past experience, including that from January to November 2016, the monthly average and highest FT-R service we received from other third parties were 9.7 MMcf/d and 17.8 MMcf/d respectively. In 2017 we intend to carry on the same arrangement to cover the shortage which will be further covered by some expected available IT-R service from NGTL based on 100% IT-R service provided by NGTL before its Short Term Operational Plan ("**STOP**") commenced in December 2014 and the improving IT-R service along with the progress of the STOP as well as its Monthly Outage Forecast covering for a period of up to the end 2017.

   Our estimate on the expected available NGTL IT-R is based on our historical records of IT-R service usage as well as NGTL's information on transportation capacity and demand in our core operating areas. The expected availability of IT-R service provided by NGTL is subject to the demand for transportation capacity of gas producers and NGTL supply-demand flexibility. NGTL System is a pipeline system which has many hundreds of receipt, delivery, extraction locations. As noted in NGTL's publication, the NGTL System is "*dynamic and unpredictable throughput dictated primarily by gas consumption and export, dynamic and unpredictable supply sourced from gas producers, interconnects and commercial storage locations, and dynamic and unpredictable system linepack dictated by interconnects and NGTL supply-demand flexibility*". Accordingly, the Industry Consultant and the Competent Person are unable to provide its view on the IT-R forecast in 2017.

In light of the above, our Company believes that there is sufficient transportation capacity for our production volume following the implementation of our three-year development plan.

Crude Oil and Condensate

During the Track Record Period, our Company has entered into written agreements with VNW and Springburn for engaging them to truck out the condensate and crude oil and then be sold in the Alberta market. The term of these agreements will be renewed and extended automatically. Besides, there are also many transportation providers in Alberta and our Company is able to get alternatives from the local market.

In light of the above, our Company believes that there is sufficient transportation capacity for our production volume following the implementation of our three-year development plan.

(c) *Labor, Equipment, Contractor and Utilities*

During the Track Record Period, our Company has been engaging Independent Third Party contractors and consultants to supply services for a majority of our operations, including amongst others, drilling and well completion consulting, inspection and maintenance, pressure vessel integrity management, supplies of packaged equipment and facilities operation.

Our production facilities need limited utility supplies from external providers. Equipment such as compressors, pump jacks and field generators are driven by gas engines mainly using the sweet natural gas produced by us as fuel gas. Our operations only require limited amount of water and we normally drill local water wells to meet our operational demands or with support from alternative suppliers of electricity and water at market rates if we do not have sufficient electricity and water to support our operations. Our operations have not been interrupted by any shortage of electricity, water or fuel and gas supply during the Track Record Period.

According to our three-year development plan, the main demand on labor and equipment will be drilling rigs, drilling and completion crews, workers and equipment for tie-ins. Our Company will use two rigs, one rig and four rigs in 2017, 2018 and 2019 respectively for drilling the wells. Based on the industry experience and to the best knowledge of our management, there is an excess supply of rigs available in Western Canada which are available at our Company's expense, and each of the rigs will be operated by a team of drilling crew, engineers and consultants from the local labor market. In this regard, our Company is able to get the requisite rigs and equipment, workers, engineers and consultants to carry out the drilling, completion and tie-ins activities.

As at the Latest Practicable Date, we have a total of 10 full time employees working in our management, engineering, accounting and human resources divisions. We also engage Independent Third Party contractors and consultants to supply services for a majority of our operations. We are of the view that the number of employees is currently sufficient for our operations.

In view of the above, we believe that we have the sufficient support and resources for implementing our three-year development plan. Further details regarding gas processing, transportation, labour, equipment, contractors and utilities are fully disclosed in the section headed "Business — Operations, Transportation, Our Suppliers and Contractors, Utilities and Employees and Employee Relations" of this Prospectus.

Possible adjustment to our three-year development plan

It is the current plan of our Company that we shall continue to implement our three-year development plan under the current natural gas price and GLJ future forecast natural gas price.

However, in the unlikely event that the natural gas price falls back and stays below C$2.04/ Mcf (our average breakeven price, with respect to our net profit including of the Best Estimate Unrisked Contingent production volume in 2019, for the years ending December 31, 2017, 2018 and 2019) for a long period of time than our management now anticipates, our Company may defer the drilling of some drilling locations or temporarily shut-in the producing wells which will be uneconomic to remain in production. Whilst this may adversely affect the level of production and thus our future income, this will help our Company to minimize our capital expenditure and the impact on our cash flow during the low price period in order to reserve our financial resources for resumption of full scale development when the market price improves.

RESERVES AND RESOURCES EVALUATION

Independent Report

We engaged the Competent Person, an Independent Third Party, to prepare the Competent Person's Report as set out in Appendix IV to this Prospectus, which is an independent assessment and evaluation of our natural gas and oil reserves and resources effective as at September 30, 2016. Specifically, GLJ evaluated our assets at Basing, Voyager and Kaydee in the Alberta Foothills and at Dawson in Peace River. GLJ also evaluated our assets in Stolberg in the Alberta Foothills, Hanlan-Peco in Deep Basin Devonian, although GLJ has not assigned any Reserves or Resources to these areas at this time. In the Competent Person's Report, GLJ adopted the current royalty regime as certain aspects of the new royalty framework were not made public until after the effective date of the report. Since September 30, 2016, being the effective date of the Competent Person's Report, 1 Crown Lease in Dawson covering approximately 640 net acres of land has expired in November 2016. Our Company confirms that no other material changes have occurred in relation to our Reserves and Resources since September 30, 2016.

GLJ is a private Canadian company established in 1972, which provides independent energy resource engineering and geological consulting services. GLJ is permitted to practice engineering and geoscience by APEGA and its services include economic evaluations, technical studies, advice and opinions.

The information set forth below relating to our Reserves and Resources constitutes forward-looking information which is subject to certain risks and uncertainties. Please refer to the sections headed "Forward-Looking Statements" and "Risk Factors" in this Prospectus.

Reserve Disclosure

Under the Competent Person's Report, Reserves are those quantities of crude oil and natural gas anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must further satisfy four criteria: they must be discovered, recoverable, commercial, and remaining (as at the evaluation date) based on the development project(s) applied. Reserves are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by development and production status.

Resources Disclosure

Under the Competent Person's Report, Contingent Resources are those quantities of crude oil and natural gas estimated, as at a given date, to be potentially recoverable from known accumulations but the applied project(s) are not yet considered mature enough for commercial development due to one or more contingencies. Contingent Resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent Resources are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity.

Under the Competent Person's Report, Prospective Resources are those quantities of crude oil and natural gas estimated, as at a given date, to be potentially recoverable from undiscovered accumulations by the application of future development projects. Prospective Resources have both an associated chance of discovery and a chance of development. Prospective Resources are further subdivided in accordance with the level of certainty associated with recoverable estimates assuming their discovery and development and may be sub-classified based on project maturity.

Under the Competent Person's Report, the estimates of the Resources are both risked and unrisked. Contingent Resources have been adjusted for risk based on the chance of development. Prospective Resources have been adjusted for risk based on the chance of discovery and the chance of development. Also, best estimate is considered to be the best estimate of the quantity that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. If probabilistic methods are used, there should be at least a 50 percent probability (P50) that the quantities actually recovered will equal or exceed the best estimate.

The following sensitivity analysis provided by the Competent Person illustrates the impact of commodity prices and exchange rate on the NPV of our Reserves based on low, best and high estimates:

		Proved Producing (in C$M)	Total Proved (in C$M)	Total Proved Plus Probable (in C$M)
GLJ (2016–10)	Before Tax (10%)	$50,640	$91,081	$132,990
	After Tax (10%)	$50,640	$87,420	$119,370
	After Tax (15%)	$44,812	$73,337	$99,057
	After Tax (20%)	$40,348	$62,999	$84,529
WTI + C$10	Before Tax (10%)	$52,340	$94,257	$137,330
	After Tax (10%)	$52,340	$89,996	$122,674
	After Tax (15%)	$46,336	$75,679	$101,944
	After Tax (20%)	$41,737	$65,160	$87,119
WTI – C$l0	Before Tax (10%)	$48,859	$87,819	$128,539
	After Tax (10%)	$48,859	$84,728	$115,922
	After Tax (15%)	$43,210	$70,877	$96,017
	After Tax (20%)	$38,886	$60,725	$81,785
AECO + C$1	Before Tax (10%)	$67,033	$114,092	$161,531
	After Tax (10%)	$67,033	$105,242	$140,481
	After Tax (15%)	$59,270	$87,956	$115,313
	After Tax (20%)	$53,360	$75,358	$97,517
AECO – C$1	Before Tax (10%)	$32,553	$47,177	$72,817
	After Tax (10%)	$32,553	$47,177	$70,881
	After Tax (15%)	$28,802	$37,266	$55,489
	After Tax (20%)	$25,914	$30,152	$44,608
FX + C$0.05	Before Tax (10%)	$46,633	$82,749	$121,569
	After Tax (10%)	$46,633	$80,597	$110,581
	After Tax (15%)	$41,303	$67,300	$91,549
	After Tax (20%)	$37,210	$57,545	$77,902
FX – C$0.05	Before Tax (10%)	$55,029	$100,263	$145,563
	After Tax (10%)	$55,029	$94,763	$128,892
	After Tax (15%)	$48,651	$79,799	$107,125
	After Tax (20%)	$43,779	$68,827	$91,610
HH + C$1	Before Tax (10%)	$66,229	$123,753	$177,367
	After Tax (10%)	$66,229	$113,114	$152,839
	After Tax (15%)	$58,536	$96,075	$127,699
	After Tax (20%)	$52,679	$83,594	$109,858
HH – C$1	Before Tax (10%)	$33,528	$54,802	$84,188
	After Tax (10%)	$33,528	$54,802	$80,815
	After Tax (15%)	$29,697	$44,540	$65,360
	After Tax (20%)	$26,745	$37,119	$54,311

Note: WTI — NYMEX West Texas Intermediate Near Month Contract; AECO — AECO/NIT Spot; FX — Exchange Rate; HH — NYMEX Henry Hub Near Month Contract

Key Assumptions

The schedules, production ramp-ups and assumptions of our three-year development plan for Basing in the Alberta Foothills core area have been reviewed by GLJ, who has given its opinion as to the credibility and validity of these plans based on its industry experience.

For the assumptions used in our three-year development plan and the assessment and evaluation of our natural gas and oil reserves and resources, please refer to the Competent Person's Report in Appendix IV to this Prospectus.

WORKFLOW AND PRODUCTION

Our Company's oil and gas projects acquired during the Crown Land auction process will generally go through the following processes: (1) evaluation; (2) acquisition; (3) exploration; (4) development; (5) production; and (6) marketing and delivery.

Evaluation

Once the Crown advertises parcels of Crown Land for sale by public auction, we evaluate a pre-selected area to determine if we wish to make a bid to acquire the land. Evaluation involves trading in 2D or 3D seismic data and conducting geological and geophysical studies, field scouting and environmental assessment. It usually takes 2 to 3 months for us to evaluate the parcel of Crown Land advertised.

Acquisition

The Government of Alberta currently advertises Crown Land for sale by public auction twice a month and interested parties are welcome to bid during these auctions. Crown Land is usually advertised for sale by public auction 8 weeks before the bidding date. After we have evaluated the potential of Crown Land for sale, we may place a bid during the auction, taking into account our view of demand for the land from other potential bidders and the historical bidding prices for the adjacent areas. To maintain the confidentiality of our bid and in accordance with common industry practice in the oil and gas industry in Alberta, we may appoint a broker to bid for the land on trust for our Company as beneficiary. Alternatively, we may use our name to bid for the land as well. In the case where a broker has been engaged, legal title to the acquired land and to the Crown Lease can be transferred from the broker to our Company at any time prior to the submission of a well licence application by us to the AER. From successful bidding to the holding of legal title, it may take one to two days. We may also acquire other oil and gas assets through private sale and the process is generally similar except that there is no public auction.

Exploration

After the acquisition of Crown Land, our Company will begin to commence trade in or shoot further seismic data from a third party seismic data provider. Shooting seismic data can take between 2 to 3 months to complete, whilst trading in seismic data usually takes between 2 to 4 weeks to acquire.

Seismic data must be processed using technical software by a third party geophysicist engaged by us in order to interpret and assess the subsurface structure or other subsurface information. Seismic processing usually takes between 2 to 3 weeks or may be longer depending on the size of the project.

After seismic processing, we will interpret the processed seismic volume in order to map and to propose potential drilling locations. Based on our prior experience, seismic interpretation usually takes between 4 to 8 weeks, depending on the size of the area involved.

Our geologist will conduct a geological and geophysical study combined with seismic mapping to propose drilling locations in the area. After a drilling location has been proposed, our engineer will commence preparing a drilling program which includes details of the drilling plan and preparation of the surface lands package. A drilling program normally takes between 2 to 4 weeks to complete whilst a surface lands package usually requires 3 to 6 months to complete.

Once the surface lands package has been prepared, we must apply to AER for a well licence. A well licence application usually takes one week to process, assuming there are no objections or requisitions from AER.

Well site construction usually takes between 3 to 4 weeks. As well site construction progresses, we may run a bidding process to select potential service providers to provide drilling and ancillary services. The bidding process normally runs for 1 to 2 weeks. After the service providers are selected and engaged, our Company will commence the drilling of wells. Based on our prior experience, drilling a well in the Alberta Foothills usually takes between 40 to 70 days whilst drilling a well in the Peace River light oil area usually takes between 10 to 30 days.

After the drilling rig has been released, the well needs to be completed which usually involves testing the well and preparing for extraction and production. Based on our prior experience, completing a well in the Alberta Foothills usually takes 1 to 3 weeks. Completing a well in the Peace River light oil area usually takes 3 to 6 days, depending on whether any stimulation including fracturing is required to improve the flow of hydrocarbons.

Development and Production

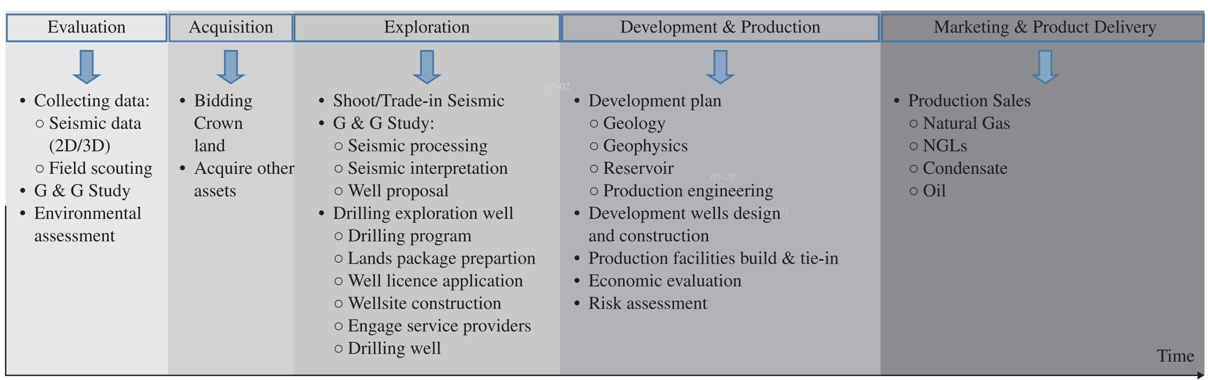
Based on the result of the exploration well, one or more delineation wells could be drilled to evaluate the size of the reservoir in order to make further plans for development. The commencement of the development stage is subject to the success of exploration.

The development stage comprises all activities and processes required to develop discovered oil or gas fields, including geology, geophysics, reservoir and production engineering, infrastructure development, development wells design and construction, completion design, surface facilities, and economics and risk assessment. Once a development well has been completed, it must be connected or tied-in to production or pipeline facilities to allow for production. Based on our Company's prior experience, tie-in of a well in the Alberta Foothills usually takes between 4 to 8 weeks whilst tie-in of a well in the Peace River area usually takes between 2 to 4 weeks. These timeframes are dependent on the proximity of established pipelines or production facilities to the wells. We usually engage contractors to supply these services to us.

Marketing and Product Delivery

Following tie-in of a well, natural gas and oil is then produced and can usually be promptly delivered to our customers, subject to marketing arrangements and the terms of our Company's sale and purchase agreements. Our natural gas, NGLs, condensate and oil products are considered duly delivered upon delivery of our products into the major pipelines. We engage contractors and other transportation service providers to transport our products.

Set out below is a flow chart explaining our Company's workflow and production.



Due to the nature of our natural gas and oil production business, we were not required to maintain any inventory for our operations during the Track Record Period. Our products are delivered into the pipelines to our customers once they are produced and processed.

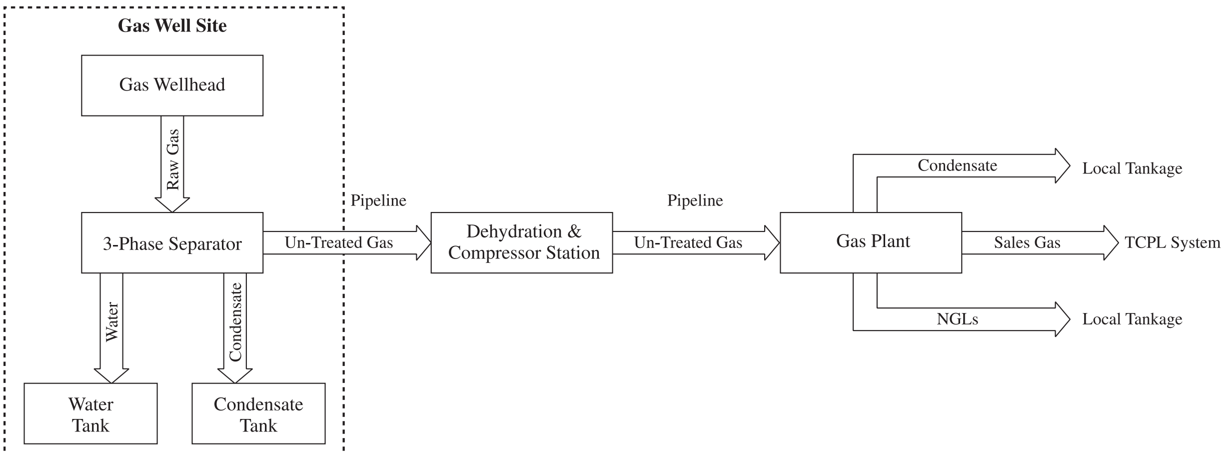
OPERATIONS

Set out below is a description of our Company's gathering and processing operations for natural gas, NGLs, condensate and oil.

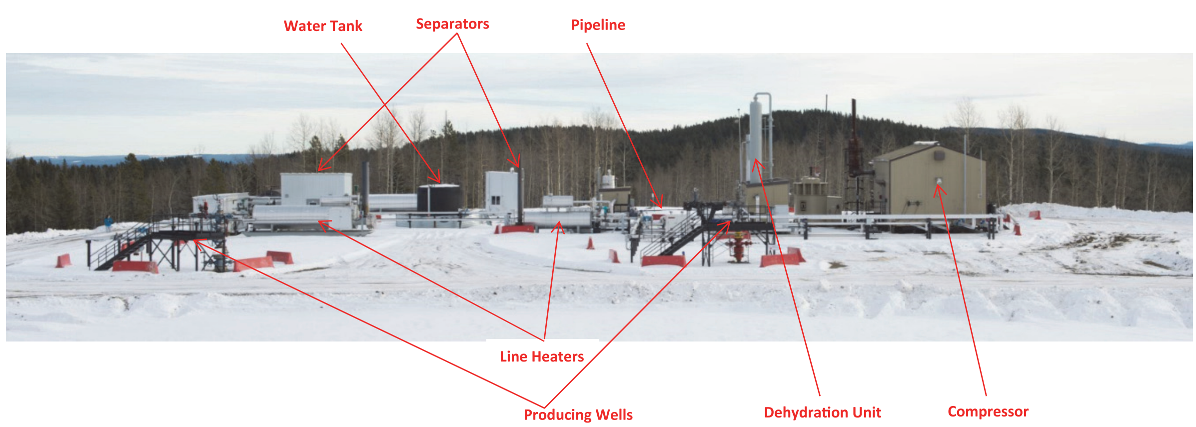
Gas Gathering Systems

The natural gas from the wellheads is initially collected at the well sites and then transported to third party gas processing plants through our gas gathering systems. At the well sites, raw natural gas from the wellhead is choked and reheated in line heaters, and then flows through a 3-phase separator for the separation and metering of the natural gas, condensate and produced water respectively. Thereafter, the produced water is stored in on-site tankage and trucked out for disposal. The condensate is either stored in on-site tankage for trucking out or re-injected into the stream of gas which flows down to the compressor and dehydration station for gas compression and a further step of water removal. Gas compression at the well site is normally not required in the first few years from initial production since the wellhead pressure is sufficiently high. The gas leaving the station is then collected by gas gathering pipelines and transported to third party gas processing plants for further processing.

Set out below is a simplified flowchart outlining the above gas gathering system:



Our Gas Gathering System:



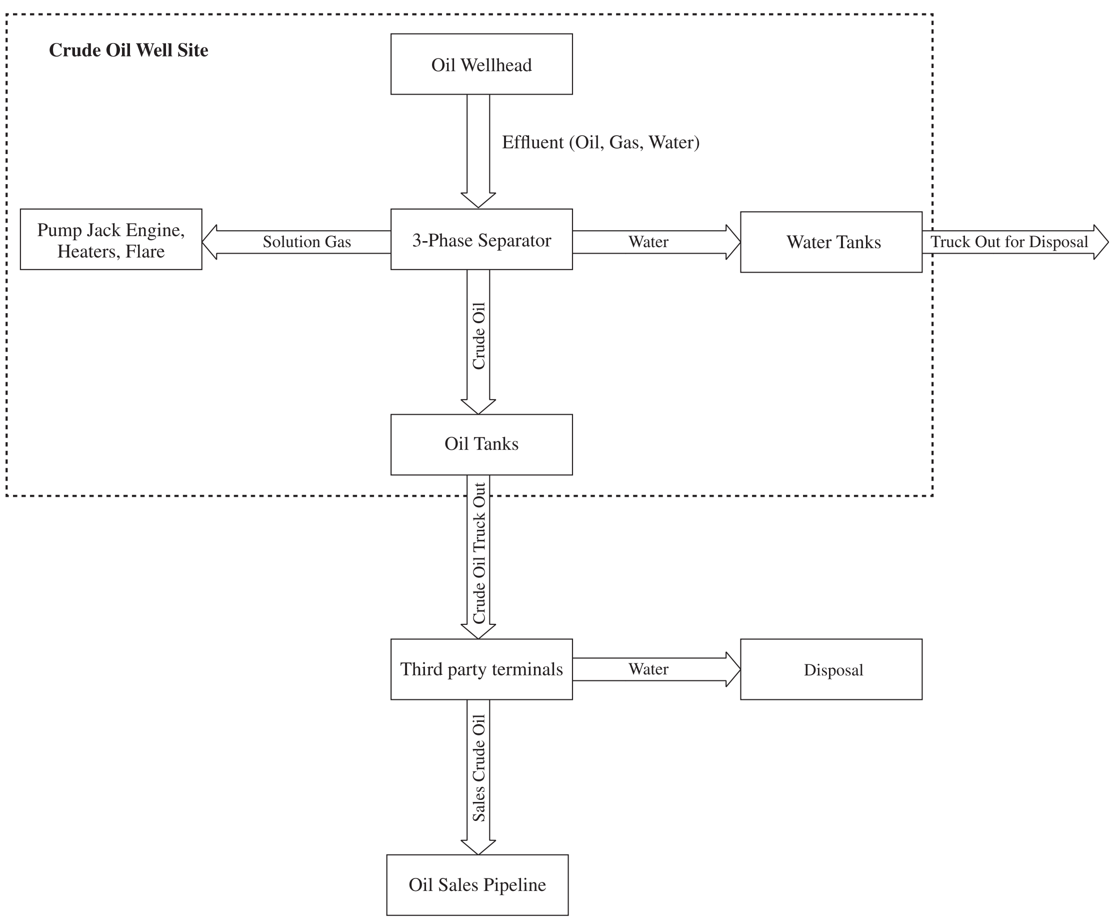
Gas Processing

Our natural gas produced from the Alberta Foothills is sweet natural gas and contains 0% hydrogen sulfide (H_2S) and less than 2% carbon dioxide (CO_2). Our untreated natural gas flows through our gas gathering systems into the shallow-cut facilities owned by ConocoPhillips in their Peco Plant, where entrained water and NGLs will be removed and retrieved from the untreated natural gas. NGLs include propane (C_3H_8) and higher molecular weight hydrocarbons. Once treated, our natural gas ready to be sold to our customers will be predominantly made up of methane (CH_4) and ethane (C_2H_6), residual volumes of propane and butane/iso-butanes, and less than 65 mg/m^3 of water. At this stage, the natural gas we sell has a hydrocarbon dew point of –10°C or lower and will be sent to the NGTL System for delivery to our customers. NGLs removed from the raw gas are stored in the pressurized NGLs storage tanks before transmission to customers.

Crude Oil Gathering and Processing Systems

Our crude oil product produced in Dawson in the Peace River area is a blend of light sweet crude oil containing sulfur less than 0.42% by weight and has an API gravity of between 37 and 42. Our crude oil pumped from the oil wellheads flow through a 3-phase separator for the separation and metering of oil, water and gas respectively. The crude oil and water will be stored in the tanks at the well sites, and the crude oil will be trucked out for further processing, whereas the produced water is trucked out for disposal. Our crude oil is trucked out to third party terminals where the BS&W in crude oil is removed to be 0.5% or lower. Next, our crude oil will be pumped into the third party pipeline system to deliver our crude oil to our customers. The solution gas collected from our wellsite separator is used as the fuel gas for our wellsite pump jack engines and heaters. Any unused solution gas will be flared on our well site in compliance with the relevant laws and regulations in Canada.

Set out below is a simplified flowchart of the crude oil gathering and processing by our Company:



TRANSPORTATION

The Alberta Foothills and Deep Basin Devonian are located in the service area of the NGTL System. The NGTL System consists of more than 32,000 km of natural gas pipeline, associated compressors and other facilities located in Alberta and Northeastern British Columbia. During the Track Record Period and up to the Latest Practicable Date, notwithstanding as disclosed below we have not experienced any shortage of transportation capacity of our natural gas and crude oil, NGLs and condensate.

Due to the ongoing maintenance and repairs of pipelines and other facilities of the NGTL System, NGTL may announce Short Term Operational Plan ("**STOP**") for near term outage plans and the Monthly Outage Forecast for longer term outage plans in relation to the NGTL System. The outage plans since December 2014 has affected the short-term delivery capability of the Basing area. The delivery capability of interruptible transportation receipt (IT-R) has fluctuated from approximately 100% to 0%, whereas the firm transportation receipt (FT-R) has fluctuated from approximately 100% to 82%. IT-R has gradually been improved to 50% and 100% in part of August 2016. However, the outage plans did not have a material adverse impact on our operations and financial conditions as we had voluntarily shut-in production from one gas well due to economic limit considerations and decreased the production volume from other gas wells due to the decreasing natural gas price, and we were able to get additional temporary FT-R service transferred from other third-party producers in the NGTL System, such that we did not experience any shortage of transportation capacity for our natural gas product. We are of the view that, apart from our existing assignments of IT-R and FT-R services from NGTL, we would continue to be able to get additional FT-R service transferred from other third party producers in the NGTL System to satisfy our future needs. We believe that, based on the longer term outage plans and the transportation commitments from NGTL and other third party producers, our Company is able to secure sufficient transportation capacity for our development plan.

Natural Gas and NGLs

We predominantly use the NGTL System to transport our natural gas. As at the Latest Practicable Date, the NGTL System was transporting approximately 10 Bcf of natural gas per day to the Canadian Mainline system and a transcontinental pipeline network that carries natural gas from Alberta to North America and interconnecting markets. In November 2015, NGTL, the operator of the NGTL System, announced that it will spend C$570 million to expand the NGTL System to be completed by 2018.

As our plan to secure sufficient access to pipeline transmission, in 2013, we entered into a Firm Transportation Receipt (FT-R) Service Agreement for natural gas transportation capacity of 8 MMcf/d with NGTL at Dismal Creek as the receipt point. This agreement has since been extended to October 31, 2021 and may be further extended. In September 2015, our Company entered into a Project and Expenditure Authorization with NGTL (the "**PEA**") increasing the contracted transportation capacity under FT-R service by 102 MMcf/d to a total of 110 MMcf/d. As stipulated in the First Amendment to the PEA entered into in July 2016, NGTL also plans to construct and put a new metering station into service at South Dismal Creek for us by the third quarter of 2018. The Metering Station will be constructed at the cost of NGTL to provide our Company with contracted FT-R service of 102 MMcf/d.

In August 2016, our Company also entered into an agreement with ConocoPhillips under which we were assigned additional 7.24 MMcf/d permanent FT-R Service from September 2016 to August 2018 and additional 3.4 MMcf/d permanent FT-R Service from September 2016 to April 2018.

During the Track Record Period, we also arranged for transfers of FT-R service available from other producers including ConocoPhillips on a month to month basis to accommodate our production schedule. The monthly basis FT-R services transferred from other producers were assigned free of charge or at very low costs by these other producers and provided by NGTL at lower transportation fees as compared to IT-R services under their standard terms. The average assigned monthly basis FT-R from January to December 2016 is 9.4 MMcf/d. We will carry on these arrangements in the future if necessary.

The table below shows the amount of FT-R service respectively assigned by NGTL and ConocoPhillips in 2016, 2017, 2018 and 2019:

	January 2016 to August 2016	September 2016 to April 2018	May 2018 to July 2018	August 2018	September 2018 to December 2019
FT-R from ConocoPhillips (MMcf/d)[1]	—	10.6	7.2	7.2	—
FT-R with NGTL (MMcf/d)[2]	8.0	8.0	8.0	110.0	110.0

Notes:

1. Short-Term FT-R transferred from ConocoPhillips. This includes 7.24 MMcf/d from September 2016 to August 2018 and 3.4 MMcf/d from September 2016 to April 2018.

2. Long-Term FT-R executed with NGTL. This includes 8 MMcf/d up to October 2021 and 102 MMcf/d from July 2018 to June 2026.

In summary, we have been assigned 18.6 MMcf/d, 18.6 MMcf/d and 65.0 MMcf/d FT-R Service on average in Q4 2016 and the full years of 2017 and 2018 respectively and 110.0 MMcf/d in 2019, and we believe that we have secured access to sufficient pipeline transportation capacity for our natural gas through the NGTL System for the foreseeable future.

Our NGLs are produced when our untreated natural gas is processed in Peco Plant, which is owned by ConocoPhillips. NGLs removed from the untreated natural gas are stored in pressurized NGLs storage tanks at Peco Plant. During the Track Record Period all of our NGLs produced during the processing of our untreated natural gas at Peco Plant was sold to ConocoPhillips. To the best knowledge of our management, ConocoPhillips uses third-party pipelines to transport the NGLs to their customers.

Crude Oil and Condensate

Our condensate and crude oil have been trucked out by VNW and Springburn, respectively, both being Independent Third Parties. Once trucked out, the crude oil and condensate will enter into the third party pipeline system and be sold in the Alberta market. If possible, our Company will notify the transporters two months in advance to deliver oil to their pipelines.

During the Track Record Period and as at the Latest Practicable Date, we entered into separate transportation services agreements with VNW and Springburn for their services of transporting and trucking out our condensate and crude oil in Basing and Dawson respectively ("**Transportation Agreements**"). As advised by our Canadian Legal Advisers, the Transportation Agreements are legally binding and enforceable under Canadian laws. The Transportation Agreements generally contain the following material terms:

Compensation	When the services have been successfully performed by the transporter, we will pay the transporter the service fees within 3 months from the date of the invoice.
Term	An initial term commencing on December 11, 2015 until December 31, 2016 ("**Initial Term**"); provided that the Transportation Agreements will be automatically renewed and extended to December 31, 2017, unless either party gives notice of termination to the other in writing at least 10 days prior to the end of the Initial Term or the Transportation Agreements are terminated in accordance with the termination clauses therein. In principle, we will arrange the transporter to perform the services as possible in our respective fields, however we have the right to engage other contractors to perform the same assignments.
Termination	We have the right to terminate the Transportation Agreements if the transporter is not able to provide enough trucks and/or qualified drivers to perform the services or the transporter is unable to provide the service safely and on schedule.
Liability Insurance	The transporter will obtain and maintain in force general liability insurance during the term of the Transportation Agreements.

Indemnity	The transporter will defend, indemnify and hold us harmless from and against any claims, lawsuits, losses, damages, assessments, penalties, costs or expenses, including reasonable attorneys' fees and litigation costs, arising out of any breach of the Transportation Agreements by the transporter or the negligent performance by the transporter of its services thereunder. We shall defend, indemnify and hold the transporter harmless from and against any claims, lawsuits, losses, damages, assessments, penalties, costs or expenses, including reasonable attorney's fees and litigation costs, arising out of any breach of the Transportation Agreements by our Company or the negligent performance by us of our services hereunder.

We plan to continue entering into additional long-term transportation arrangements with pipeline and third-party midstream operators and third-party transporters to ensure we have sufficient access to transportation infrastructure over the longer term. According to the production forecast by GLJ, our total daily condensate and NGLs production volume in the Alberta Foothills is expected to increase to approximately 263 Bbl/d based on Proved plus Probable Reserves and an additional 116 Bbl/d based on Best Estimate Unrisked Contingent Resources by 2019. Please refer to the Competent Person's Report in Appendix IV to this Prospectus for more information. We believe that we will continue to have access to sufficient transmission infrastructure as we ramp up production since the existing transportation capacity of our third party transporter can be increased by increasing the frequency of their trucking out services.

Road Usage

We have already entered into various road usage agreements for the use of private roads to access our well sites. While there may not be alternative roads available at comparable charges for access to our well sites, we believe that the risk under which we may not be able to access to our well sites is remote. In case where an agreement cannot be reached with the licence holders for the use of such roads in the future, we can ask the AER to consider the request for use of roads to access our well sites. Please refer to the section headed "Laws and Regulations — Obtaining Mineral Rights and Leases" of this Prospectus for more information.

Major terms of the road usage agreements

As at the Latest Practicable Date, we entered into various road usage agreements ("**Road Usage Agreements**") with third party providers for access to our sites. As advised by our Canadian Legal Advisers, the Road Usage Agreements are legally binding and enforceable under Canadian laws. These Road Usage Agreements are effective from the date of execution and remain in effect for as long as the user requires the use of the roads unless otherwise terminated upon a thirty (30) days' prior written notice given by either party to the other. If categorized by the number of wells, the road usage fees generally range from approximately C$650/km to C$800/km for each initial well and approximately C$325/km to C$400/km for each subsequent well. If categorized by the specific road rate, the road usage fees generally range from approximately C$350/km to C$450/km per month for well construction, completion and pipelining works, and C$350/km per month for maintenance and well production works. The road usage fees are payable within thirty (30) days of the invoice date or our receipt of the invoice. We have maintained automobile liability and comprehensive general liability insurance.

The amount of road usage fee incurred during the Track Record Period was approximately C$8,112.01, C$17,529.84, C$39,838.10 and C$38,625.27 for the year ended December 31, 2013, 2014 and 2015 and the nine months ended September 30, 2016, respectively.

OUR SUPPLIERS AND CONTRACTORS

We engage Independent Third Party contractors and consultants to supply services for a majority of our operations, including drilling and well completion consulting, seismic data, geological and geophysics consulting, engineering and design, regulation and environmental consulting, inspection and maintenance, pressure vessel integrity management, supplies of packaged equipment and facilities operation. As at December 31, 2013, 2014 and 2015 and September 30, 2016, we engaged a total of 210, 194, 105 and 77 contractors respectively, and incurred total contracting fees of C$16.4 million, C$17.0 million, C$5.9 million and C$5.2 million, respectively. All contractors engaged by us are Independent Third Parties. We require our contractors and consultants to obtain all licences and permits necessary to conduct their activities.

The table below sets out the breakdown of the number of our contractors for each type of activity during the Track Record Period.

	Number of Contractors			
	For the year ended December 31			For the nine months ended September 30
Type of Activity	2013	2014	2015	2016
Evaluation	4	4	3	2
Acquisition (Land acquisition)	0	1	1	—
Exploration	1	2	3	—
Development	151	138	55	13
Production	51	46	39	60
Marketing and delivery	3	3	4	2
Total	210	194	105	77

We typically procure materials, equipment and services from our suppliers and contractors through obtaining quotations, placing purchase orders or via a bidding process. We may use an open bidding process when procuring well-drilling services for major projects. We consider cost, work quality, track record, proposed delivery schedule, and most importantly, technical expertise in our supplier and contractor selection process. We also conduct detailed due diligence on service providers such as reviewing their qualifications, track record and necessary licences, permits and approvals for their operations. We usually do not enter into long-term supply contracts with our suppliers, given the availability of similar service providers in the industry on similar terms. We continuously monitor our contractors, suppliers and consultants to ensure compliance with their contracts.

We require our contractors to confirm in their quotations and proposals that they possess appropriate qualifications in their contracted tasks and will comply with operational and safety requirements and laws. In addition, we require our contractors to undertake appropriate safety measures.

We did not experience any material delays, quality issues or safety issues with our suppliers or contractors during the Track Record Period. Should any of our existing suppliers or contractors be unable or unwilling to continue providing their services to us, we believe that we would be able to identify replacement service providers or contractors on a timely basis and enter into services contracts with them on commercially reasonable terms without significantly affecting our business operations.

For the years ended December 31, 2013, 2014 and 2015 and the nine months ended September 30, 2016, the aggregate purchases from our five largest suppliers amounted to approximately C$6.1 million, C$6.8 million, C$4.1 million and C$3.7 million, respectively, representing approximately 40.0%, 33.7%, 56.1% and 49.6% of our total purchases, respectively. Purchases from our largest supplier accounted for approximately 11.4%, 9.7%, 28.2% and 25.5%, respectively, of our total purchases for the same periods.

Set out below is a breakdown of our total purchases by major suppliers during the Track Record Period:

For the year ended December 31, 2013

Rank	Supplier	C$'000	% of total purchases	Products/services purchased	Business of relationship with our Group commenced since	Length of relationship
1	A	1,741	11.4%	Drilling equipment and services	2007	9
2	ConocoPhillips	1,691	11.1%	Gas processing	2009	7
3	B	1,370	9.0%	Drilling mud services	2013	2
4	C	672	4.4%	Directional services & drilling bits	2008	8
5	NGTL	633	4.1%	Gas transportation	2008	8
Five largest suppliers combined		6,107	40.0%			

For the year ended December 31, 2014

Rank	Supplier	C$'000	% of total purchases	Products/services purchased	Business of relationship with our Group commenced since	Length of relationship
1	ConocoPhillips	1,959	9.7%	Gas processing	2009	7
2	D	1,743	8.6%	Drilling equipment and services	2013	2
3	E	1,208	5.9%	Drilling mud services	2011	5
4	F	1,160	5.7%	Casing & pipeline	2010	6
5	NGTL	768	3.8%	Gas transportation	2008	8
Five largest suppliers combined		6,838	33.7%			

For the year ended December 31, 2015

Rank	Supplier	C$'000	% of total purchases	Products/services purchased	Business of relationship with our Group commenced since	Length of relationship
1	ConocoPhillips	2,078	28.2%	Gas processing	2009	7
2	NGTL	650	8.8%	Gas transportation	2008	8
3	G	514	7.0%	Office rental	2010	6
4	Johnson & Herbert Construction Inc.	470	6.4%	Well construction service	2009	7
5	Ironline Compression Limited Partnership	416	5.6%	Compressor service	2012	4
Five largest suppliers combined		4,128	56.0%			

For the nine months ended September 30, 2016

Rank	Supplier	C$'000	% of total purchases	Products/services purchased	Business of relationship with our Group commenced since	Length of relationship
1	ConocoPhillips	1,927	25.5%	Gas processing	2009	7
2	NGTL	832	11.0%	Gas transportation	2008	8
3	G	437	5.8%	Office rental	2010	6
4	Ironline Compression Limited Partnership	327	4.3%	Compressor service	2012	4
5	Midwest Surveys Inc.	226	3.0%	Predrilling service	2007	9
Five largest suppliers combined		3,749	49.6%			

We have entered into a number of contracts with our contractors and suppliers during the Track Record Period the majority of which are purchase orders. As advised by our Canadian Legal Advisers, the purchase orders that we entered into with our contractors and suppliers up to the Latest Practicable Date are legally binding and enforceable under Canadian laws and generally include the following material terms:

Duration	For purchase of goods: usually a one-off transaction. For purchase of services: one year or continuing until terminated.
Extension	The order will be extended for a period of twelve months from the date of commencement or the date of successful field performance testing (as relevant).
Price	Negotiated between the parties.
Payment date	Before shipment to 30 days after shipment, within 3 months of the invoice date or the invoice date, as the case may be.
Termination	We may terminate at any time but we will be liable for goods or services that have been provided up to date.
Indemnity	Supplier indemnifies us against all claims arising out of intellectual property infringement and violation of law in connection with the goods or services supplied, as the case may be.
Warranties	Supplier warrants the goods or services supplied are, among others, of good quality and free from fault in design.
Insurance	Supplier must carry appropriate insurance and require each of its subcontractors to carry appropriate insurance.

For other supply contracts that are not in the form of purchase orders, the material terms are generally as follows:

Duration	One year, or continuing until terminated by purchaser.
Renewal	If the contract is not continuing, the contract may be renewed by both parties.
Price	Negotiated between the parties on a monthly or hourly rate basis for service contracts.
Payment date	Within 30 days after receipt of invoice.

Termination	We may terminate if the contractor fails to perform, or performs unsatisfactorily in certain cases.
Liability and indemnity	The extent of liabilities and indemnities of each party depend on the relevant breach or non-performance, for example: (a) for well and facilities operation contracts, in the event of the contractor's gross negligence or wilful misconduct, the contractor will be liable and shall indemnify us against all the claims or losses arising from the gross negligence or wilful misconduct; and (b) for other contracts, the party in breach will be liable and indemnify the other party against all claims or losses arising from the breach.
Insurance	Contractor must carry appropriate insurance. The required insurance coverage usually includes workers' compensation insurance, employer's liability insurance and comprehensive general liability insurance.

As at the Latest Practicable Date, to the best knowledge of our Directors, none of our Directors, their close associates, or any Shareholders holding more than 5% of the total issued Shares held any interest in any of our five largest suppliers for the years ended December 31, 2013, 2014 and 2015 and the nine months ended September 30, 2016. All of our five largest suppliers during the Track Record Period are Independent Third Parties.

SALES AND MARKETING

During the Track Record Period, we sold natural gas, crude oil, NGLs and condensate to our customers in Canada. We directly negotiate with potential customers before we enter into sales contracts with them, and hence we can choose the terms and price in line with industry standards. We can make direct sales of natural gas, NGLs and condensate, and oil to our customers in addition to using the marketing services provided by a third party service provider as described below to arrange these sales for us.

We have engaged Phoenix Energy Marketing Consultants Inc., an Independent Third Party, to provide natural gas, crude oil and NGLs marketing services to us since February 2013. The marketing services provided to us include:

- evaluation and selection of creditworthy purchasers and establishing purchase contracts;
- attending marketing and operations meetings;

- periodic marketing intelligence on plant and/or transport outages; and
- providing recommendations in enhancing marketing services.

Under the marketing services agreement with Phoenix Energy Marketing Consultants Inc., it must optimize our Company's gas transport requests by researching alternative delivery arrangements. The agreement may be terminated by either party on two (2) months' written notice and our third party service provider is paid a fixed monthly service fee for their services.

Other than Macquarie Energy, all our current customers were introduced by Phoenix Energy Marketing Consultants Inc.

Customers

For the years ended December 31, 2013, 2014 and 2015 and the nine months ended September 30, 2016, our revenue contributed by our top five customers was approximately C$23.5 million, C$32.4 million, C$16.0 million and C$14.9 million respectively, representing approximately 99.9%, 100%, 99.2% and 98.4% of our total revenue respectively. All top five customers are gas and oil trading companies or are involved in gas and oil trading. The length of our business relationship with our top five customers ranges from 1 to 9 years.

For the years ended December 31, 2013, 2014 and 2015 and the nine months ended September 30, 2016, our revenue contributed by our largest customer was approximately C$14.5 million, C$26.7 million, C$11.6 million and C$8.6 million respectively, representing approximately 61.7%, 82.5%, 72.2% and 56.9% of our total revenue respectively.

Set out below is a breakdown of our revenue by major customers during the Track Record Period:

For the year ended December 31, 2013

Rank	Customer	C$'000	% of total revenue	Products sold	Business of relationship with our Group commenced since	Length of relationship
1	A	14,490	61.7%	Natural Gas	2007	9
2	PetroLama	4,638	19.7%	Crude Oil	2011	5
3	ConocoPhillips	3,322	14.1%	Condensate & NGLs	2010	6
4	B	736	3.1%	Natural Gas	2010	5
5	C	295	1.3%	Condensate	2009	7
Five largest customers combined		23,481	99.9%			

For the year ended December 31, 2014

Rank	Customer	C$'000	% of total revenue	Products sold	Business of relationship with our Group commenced since	Length of relationship
1	A	26,749	82.5%	Natural Gas	2007	9
2	PetroLama	3,496	10.8%	Crude Oil	2011	5
3	ConocoPhillips	1,278	3.9%	Condensate & NGLs	2010	6
4	C	901	2.8%	Natural Gas	2009	7
Four largest customers combined		32,424	100.0%			

For the year ended December 31, 2015

Rank	Customer	C$'000	% of total revenue	Products sold	Business of relationship with our Group commenced since	Length of relationship
1	Macquarie Energy	11,616	72.2%	Natural Gas	2015	1
2	A	1,940	12.1%	Natural Gas	2007	9
3	ConocoPhillips	1,207	7.5%	Condensate & NGLs	2010	6
4	PetroLama	959	6.0%	Crude Oil	2011	5
5	C	232	1.4%	Condensate	2009	7
Five largest customers combined		15,954	99.2%			

For the nine months ended September 30, 2016

Rank	Customer	C$'000	% of total revenue	Products sold	Business of relationship with our Group commenced since	Length of relationship
1	Macquarie Energy	8,622	56.9%	Natural Gas	2015	1
2	D	4,089	27.0%	Natural Gas	2015	1
3	ConocoPhillips	1,259	8.3%	Condensate & NGLs	2010	6
4	E	521	3.4%	Crude oil	2016	1
5	C	422	2.8%	Condensate	2009	7
Five largest customers combined		14,913	98.4%			

We believe our existing business relationship with our customers and the quality and potential of our Reserves have demonstrated to potential customers our ability to provide a steady supply to target customers.

We have never incurred any bad debts in relation to the sale and purchase of our products with our customers. We do not have any rebate, advertising, sale incentive, promotion or discount arrangements with our customers.

As natural gas, crude oil, NGLs and condensate are fungible products with well-established markets and numerous purchasers, should any of the top five customers terminate their business relationship with us, we are of the view that we would be able to identify alternative customers on a timely basis and enter into sale and purchase agreements with them on commercially reasonable terms without significantly affecting our business operations.

During the Track Record Period and up to the Latest Practicable Date, we have not experienced any difficulty with our customers for the sales of our products.

During the Track Record Period, each of Mr. Peter David Robertson and Mr. Bryan Daniel Pinney, our independent non-executive Directors, respectively held a certain number of shares in one of our five largest customers for the year ended December 31, 2013, which amounted to approximately less than 0.02% of the outstanding shares of such customer. Save as disclosed above, as at the Latest Practicable Date, to the best knowledge of our Directors, none of our Directors, their close associates, or any Shareholders holding more than 5% of the total issued Shares of our Company held any interest in any of our five largest customers for the years ended December 31, 2013, 2014 and 2015 and the nine months ended September 30, 2016. All of our five largest customers during the Track Record Period are Independent Third Parties.

ConocoPhillips, one of our top five customers, was also one of our top five suppliers during the Track Record Period. Sales to ConocoPhillips attributed to approximately 14.1%, 3.9%, 7.5% and 8.3%, respectively, of our total revenue for the years ended December 31, 2013, 2014 and 2015 and the nine months ended September 30, 2016. Purchases from ConocoPhillips attributed to approximately 11.1%, 9.7%, 28.2% and 25.5%, respectively, of our total purchases for the years ended December 31, 2013, 2014 and 2015 and the nine months ended September 30, 2016. Products sold to ConocoPhillips mainly include NGLs and condensate. Services supplied by ConocoPhillips mainly include the processing of the natural gas produced from our well sites. The by-products of gas processing including NGLs and condensate were sold to ConocoPhillips. Our sales of products to ConocoPhillips less our purchases from ConocoPhillips were approximately C$1.6 million, C$(0.7) million, C$(0.9) million and C$(0.7) million for the years ended December 31, 2013, 2014 and 2015 and the nine months ended September 30, 2016, respectively.

Pricing Model

We have entered into a number of sales agreements with our customers, based on the General Terms and Conditions of the GasEDI Base Contract for Sale and Purchase of Natural Gas as published by GasEDI on August 31, 2005 ("**GasEDI Contract and Terms**"), which is commonly used in the industry for sales of natural gas and is common market practice in Alberta. The spot price of natural gas is usually by reference to the Canadian Gas Price Reporter or the Gas Daily Mid Point.

We have also entered into sales agreements for the sale of our crude oil, condensate and NGLs. The reference price for crude oil, condensate and other NGLs is typically tied to WTI.

Natural Gas Sales Agreements

We sell all of our natural gas to our customers with reference to the GasEDI Contract and Terms. The cover page of the GasEDI Contract and Terms allows parties to select different options for some of the standard terms and conditions in the GasEDI Contract and Terms, which usually relate to pricing, risk, termination and force majeure, among others. We negotiate with our customers in selecting the options for our GasEDI Contract and Terms. As advised by our Canadian Legal Advisers, the GasEDI Contracts and Terms that we entered into with our customers up to the Latest Practicable Date are legally binding and enforceable under Canadian laws.

Unless otherwise specified and other than our natural gas sales agreement with Macquarie Energy, the natural gas sales agreements that we entered into provide the following material terms based on the GasEDI Contract and Terms:

Price	The GasEDI Contract and Terms allows parties to choose between (i) the spot price as published by the Canadian Gas Price Reporter and (ii) the Gas Daily Mid Point.
Payment method	Wire transfer.
Payment date	Within 10 Business Days upon receipt of invoice.
Duration and termination	Continuing unless terminated by either party with 30 days' notice but the GasEDI Contract and Terms remains in effect for outstanding transactions.
Volume	A volume of natural gas equal to the daily contract quantity.
Risk	Risk passes to the purchaser at the delivery point.
Breach of contract and damages amount	The difference between the contract price and the price paid/received under a replacement transaction or the gas price published by the Canadian Gas Price Reporter or the Gas Daily Mid Point.
Force majeure	The GasEDI Contract and Terms allow parties to choose the events of force majeure. Depending on the delivery point, events of force majeure usually include an event that prevents delivery or receipt of the natural gas by interruption, curtailment, or pro-rationing by a transporter, compliance with a court order, laws or regulations, and acts of God.

Indemnity	The seller will indemnify the buyer against all losses, liabilities and claims, arising from claims of title, personal injury or property damages from the gas or other charges that attached to the gas before title passes to the buyer. The buyer will indemnify the seller against all claims arising from payment, personal injury or property damage from the gas or other charges attached to the gas after the title passes to the buyer.

During the Track Record Period and as at the Latest Practicable Date, we were not in material breach of any of our natural gas sales agreements and natural gas sales agreements.

Natural Gas Sales Arrangement

Sales Arrangement

From 2013 to 2014, we entered into commodity swap transactions with a commercial bank in Canada. All commodity swap and hedge arrangements with the foregoing commercial bank in Canada had been terminated as at December 31, 2014. We do not intend to engage in hedging arrangements in the near future and are of the view that the current sales arrangement as described below is appropriate for our needs.

During 2013 and 2014, with a view to protect downward movements in the price of natural gas, we entered into one-year sales agreements with a company who is involved in gas and oil trading to sell our natural gas over the year after at a specified price and volume.

Since 2015, we also have entered into natural gas forward sales agreements with Macquarie Energy based on the GasEDI Contract and Terms. Each sales agreement establishes a fixed selling price against a fixed daily volume, which was determined with reference to the then production forecasts of our Proved developed producing Reserves, for each of the years ended/ending December 31, 2015, 2016, 2017 and 2018 in order to protect against downward movements in the price of natural gas. For the year ended December 31, 2015 and the nine months ended September 30, 2016, the sales volume under the sales arrangements with Macquarie Energy were 9,260 GJ/d and 11,659 GJ/d, respectively, and the weighted average forward selling prices were C$3.44/GJ and C$2.70/GJ, respectively. The weighted average forward selling prices for Q4 2016, 2017 and 2018 under all existing sales agreements with Macquarie Energy as at December 31, 2016 will be at C$2.83/GJ, C$2.78/GJ and C$2.66/GJ, respectively, which are determined with reference to the forecast of future AECO prices for gas sales and delivery. However, we may receive less revenue than selling the natural gas at the spot price if the spot price of natural gas becomes higher than the price fixed by our sales agreements. We deliver natural gas to Macquarie Energy according to the terms of the sales agreements. The agreements entered for the years 2016, 2017 and 2018 will expire on December 31, 2016, 2017 and 2018, respectively, being the end date of the delivery period for each agreement. There are no renewal clauses in these agreements. During the Track Record Period, we performed our obligations under these agreements without any material default on or breach of any terms in the sales agreements.

The sales value accounted for 29.6%, 23.9%, 72.2% and 56.9% of our total revenue from crude oil and natural gas sales to the abovementioned gas and oil trading company and Macquarie Energy for the years ended December 31, 2013, 2014 and 2015 and the nine months ended September 30, 2016, respectively. All sales to Macquarie Energy during the year ended December 31, 2015 and the nine months ended September 30, 2016, which amounted to C$11.6 million and C$8.6 million respectively, were made pursuant to the aforesaid sales arrangement. For the year ended December 31, 2015 and the nine months ended September 30, 2016, the sales volume under the sales arrangements with Macquarie Energy amounted to approximately 77.6% and 50.2% of our total sales volume, respectively.

We may enter into new forward sales agreements against our daily production volume for various time intervals. For instance, we entered into forward sales agreements with Macquarie Energy against our daily production volume on a monthly basis from July 1, 2016 up to December 9, 2016. Between July 1, 2016 and September 30, 2016, we also entered into a forward sales agreement with Macquarie Energy for the year ending December 31, 2017 at a selling price of C$3.0/GJ against our daily production volume of approximately 1,000 GJ/d. It is estimated that under this forward sales agreement, the sales volume to be delivered will amount to approximately 2.5% of our 2017 gas production forecast and the revenue generated will amount to C$1.1 million for the year ending December 31, 2017.

Since October 31, 2016 and up to December 9, 2016, we also entered into further forward sales agreements with Macquarie Energy for the year ending December 31, 2017 at a weighted average selling price of C$3.0/GJ against our daily production volume of approximately 6,000 GJ/d.

Based on the existing sales arrangements with Macqurie Energy as at December 31, 2016, it is estimated that the annual sales volume to be delivered under the sales arrangements with Macquarie Energy will amount to approximately 45.4%, 38.2% and 19.7% of our actual gas production for the three months ended December 31, 2016 and the gas production forecast for each of the years ending December 31, 2017 and 2018 based on 2P, respectively, following the implementation of our three-year development plan. Based on the existing sales arrangements with Macqurie Energy as at December 31, 2016, the revenue that will be generated for Q4 2016, 2017 and 2018 under the natural gas forward sales agreements with Macquarie Energy will amount to approximately C$3.2 million, C$15.6 million and C$8.1 million, respectively.

The table below summarizes the daily production volume, the total amount of sales volume under all of our existing sales arrangements with Macquarie Energy as at December 31, 2016 as a percentage to the total actual gas production/gas production forecast (based on 2P) and the total amount of such revenue for the three months ended December 31, 2016 and each of the years ending December 31, 2017 and 2018:

	Q4 2016	2017	2018
Daily volume	12,411 GJ/d*	15,400 GJ/d	8,400 GJ/d
% of sales volume	45.4	38.2	19.7
Revenue	C$3.2 million	C$15.6 million	C$8.1 million
Average selling price	C$2.83/GJ	C$2.78/GJ	C$2.66/GJ

* *Weighted average*

We selected Macquarie Energy as our counterparty of these sales agreements as it is a reputable and well-capitalized institution in Canada. Based on the expertise of our management and our constant monitoring of other market information and news, we choose the most appropriate natural gas price and decide on the quantity of daily production volume to be covered by the sales arrangement transaction, before entering into these sales agreements. We also consider a lock-in price, payment and other terms of the agreement and the time frame for the sales arrangement to be instituted. We will then enter into one to two-year sales arrangements to manage the risks associated with a downside movement in natural gas prices. All natural gas sales arrangement transactions must first be discussed between and agreed by our management.

A sales arrangement is entered into to cover a reasonable portion of our daily natural gas production volume. Our management and executive Director takes into account factors including annual natural gas production and the demand for natural gas in North America, forward curve rates of natural gas prices, expected investments into drilling each year and the production derived from such investments and tax and government policies, among others. Our sales arrangement transactions are restricted to cover a reasonable period, usually up to one year and also focus on protection against downside risk. Our management team also holds frequent meetings to review trends in natural gas prices and the effectiveness of our sales arrangements. Our sales arrangements are usually terminated automatically when the term of the sales agreement expires, usually one year after the date of the relevant agreement.

Crude Oil Sales Agreement

During the Track Record Period and as at the Latest Practicable Date, we sold all of our crude oil to our customer, PetroLama, under the terms of a wellhead purchase agreement which was subsequently assigned to Secure Energy Services with effect from June 2016 following the acquisition of PetroLama's certain assets by Secure Energy Services. The agreement incorporates by reference BP's General Terms and Conditions (Form C-7032 November 2009) ("**BP's General**

Terms”). BP’s General Terms are commonly used as a base contract for crude oil sales in Alberta. As advised by our Canadian Legal Advisers, the wellhead purchase agreement and BP’s General Terms are legally binding and enforceable under Canadian Laws.

The wellhead purchase agreement for the sale of crude oil includes the following material terms:

Base Price	With reference to the monthly average NYMEX WTI, less the industry standard (MSW) blended stream differential index, less PetroLama’s monthly crude oil marketing and service charge. PetroLama has the right to adjust the base price with reference to the WTI price, foreign exchange rate, and WTI stream differential for crude oil for significant differences between volumes forecasted and actual deliveries. To the best knowledge of our management, the primary consideration for PetroLama when deciding whether to exercise the right to adjust the base price is the overall financial impact of the differences on PetroLama’s overall pool for the month concerned. The same base price adjustment is applicable to unforecasted volumes if there is no forecasted volume. There had been no adjustment to the base price exercised by PetroLama due to the differences of up to 50% between volumes forecasted and actual deliveries pursuant to the wellhead purchase agreement during the Track Record Period and up to the Latest Practicable Date.
Payment date	25th day of the month following the delivery month.
Duration and termination	Continuing unless terminated by either party with one month’s written notice.
Volume	Ranges from approximately 200 to 500 m^3 per month.
Risk	Risk passes to the purchaser at delivery point.
Force majeure	Neither party will be liable when failure to deliver or delay is due to force majeure. Events of force majeure include acts of God, accident or breakage to machinery or equipment, compliance with orders or requests of the government, and imposition of requirements or conditions by government.
Indemnity	Each party will indemnify the other party against claims, demands and causes of action for personal injury, for loss of or damage to property, or for violations of law resulting from the wilful or negligent acts or omissions of the indemnifying party in connection with the performance of the agreement.

If the delivered products do not meet any quality specification, the seller will indemnify the buyer against all costs, dangers, losses, claims, liabilities and other expenses incurred by the buyer as a direct result of the delivery of non-conforming products.

Sales of Condensate and other NGLs

During the Track Record Period, our Company has entered into the following agreements for the sale of condensate and other NGLs:

1 Gas Handling Agreement with ConocoPhillips

We and ConocoPhillips entered into a new gas handling agreement in March 2016 (the "**Gas Handling Agreement**") pursuant to which we deliver to the facility owned and controlled by ConocoPhillips (the "**Facility**") gas and all associated substances (the "**Producer Inlet Substances**") for ConocoPhillips' handling as our supplier. ConocoPhillips shall deliver to us the treated gas, NGLs and condensate (the "**Producer Outlet Substances**"). The material terms in relation to the purchase of gas handling services from ConocoPhillips are set out below:

Price	Firm handling charge: approximately C$0.44/Mcf for 8 MMcf/d Non-firm handling charge: approximately C$0.43/Mcf
Payment date	ConocoPhillips shall bill us on or before the 30th day of each month for the payable charges incurred in the preceding month. We shall pay all bills payable within 30 days after receiving them.
Duration and termination	Termination effective from February 2019 unless otherwise agreed in writing.
Volume	8 MMcf/d for firm handling charge; additional volume available at non-firm handling charge
Specifications	All Producer Inlet Substances delivered shall be of a kind, quality and composition and at a temperature and pressure within the design and operating parameters of the Facility, and free of substances in quantities that may obstruct, damage or be detrimental to the operation of the Facility.

Force majeure	If an event of force majeure prevents a party from fulfilling any obligations, that obligation will be suspended during the event of force majeure. A party prevented from fulfilling any obligation by the force majeure shall promptly give the other party notice of the force majeure and the affected obligations.
Indemnity	ConocoPhillips and its related persons shall not be liable to us or our related persons for any losses or liabilities suffered or incurred resulting from or arising out of any act or omission of ConocoPhillips and its related persons in the handling of Producer Inlet Substances except where such losses and liabilities are a direct result of or are directly attributable to the gross negligence or wilful misconduct of ConocoPhillips or its related persons.

ConocoPhillips shall deliver to us the treated gas, NGLs and condensate (the "**Producer Outlet Substances**").

We also sell our NGLs and condensate to ConocoPhillips in accordance with the Gas Handling Agreement, the material terms pertaining to which are set out below:

Price	For NGLs and condensate, the sale price of each of the foregoing products is calculated with reference to the buyer's realized market price, less relevant deductions and charges.
Payment date	On or around the 25th day of the month following the month of delivery.
Duration and termination	Termination effective from February 2019 unless otherwise agreed in writing.
Allocation	The volume of Outlet Substances shall be determined by ConocoPhillips each month in a manner consistent with the Allocation Procedure and based on analysis and measured volumes of Producer Inlet Substances. We have the right to examine at all reasonable times the records of ConocoPhillips relating to our share of Outlet Substances.

Volume	All NGLs mix of our outlet substances.
Risk	Risk passes to the purchaser at the Facility.
Force majeure	If an event of force majeure prevents a party from fulfilling any obligations, that obligation will be suspended during the event of force majeure. An event of force majeure means an occurrence beyond the reasonable control of a party which has not been caused by the party's negligence and which the party was unable to prevent or provide against by the exercise of reasonable diligence at a reasonable cost.
Indemnity	Seller will indemnify the buyer from all actions, claims and demands made by any person, firm or corporation who has, or who claims to have an interest in the sale products. Buyer will fully indemnify the seller from all claims, demands, loss or damage caused or attributable to the sale products or their transportation, handling or care following the point of purchase.

2 Condensate Purchase Agreement

We also sell our condensate to a third party customer in various terminals. The agreement incorporates general terms and conditions of our third party customer. The purchase agreement for the sale of condensate to our third party customer includes the following material terms:

Price	The price is calculated with reference to either (i) the daily settlement prices of the NYMEX near month light sweet crude oil contract, the NGX and Net Energy trade month WTI index prices at Edmonton, Alberta, the Enbridge MSW WADF and the Enbridge Condensate WADF; or (ii) posting by companies such as BP and Flint Hill for Western Canada Condensate and the NetThruPut's monthly trade posting for Condensate at Edmonton.
Payment method	Wire transfer.
Payment date	On or before the 25th of the month following the month of delivery.
Duration and termination	Continuing unless terminated by either party with 30 days' written notice.
Volume	Ranges from approximately 200 to 400 m^3 per month.

Product Returns and Warranty

All of our top five customers are involved in natural gas and crude and oil trading. Our products must meet the quality specifications of our pipeline providers before entering the pipeline systems and due to the nature of our products themselves, product returns and warranties are generally not applicable. Accordingly, we do not accept any return of our products nor do we accept any warranty claims after our products have been transported to the pipeline systems or trucked out which is the time when the associated risks are passed to our customers. During the Track Record Period and up to the Latest Practicable Date, we had not: (i) incurred any expenses as a result of return of any of our products or warranty claims; and (ii) received any material complaints or product liability claims from our customers.

JOINT VENTURES

We have entered into two joint ventures in the Viking and Stolberg areas respectively.

Viking JV

We have participated in the joint venture development of our joint venture partner's PNG Licence in Viking, Alberta. Under the Viking JV, we spudded a test well ("**Test Well**") in February 2006 and the cost of the well was borne as to 50% each by our joint venture partner and us. We also developed the PNG Licence in return for 50% of the working interest of the PNG Licence held by our joint venture partner. We receive the revenues from the Viking JV and share costs and any losses proportionate to the percentage of our respective working interest. For the years ended December 31, 2013, 2014 and 2015 and the nine months ended September 30, 2016, we received total revenue of approximately C$16,371, C$16,310, C$11,408 and C$5,658, respectively, from the Viking JV.

The Viking JV contains the following material terms:

Test Well	We will earn the following interests in the lands: (a) 100% of our joint venture partners' working interest prior to any earnings under the Viking JV agreement (its working interest being 50%), in the Test Well spacing unit; and (b) 50% of our joint venture partners' working interest (its working interest being 50%) in the balance of the agreed lands, excluding the Test Well spacing unit.
Operating procedure	Our joint venture partner will be the initial operator under the incorporated 1990 Canadian Association of Petroleum Landmen ("**CAPL**") Operating Procedure, during the drilling of the Test Well, subject to certain revisions and elections.

	The parties' initial working interests in the Test Well drilling spacing unit under the 1990 CAPL Operating Procedure earned under the Viking JV agreement are as follows: (a) Before payout: Our joint venture partner retains overriding royalty in the Test Well drilling spacing unit of 2% and 50% working interest; and us, 50% of the working interest. (b) After payout: Our joint venture partner retains 75% of the working interest in the Test Well drill spacing unit; and us 25% of the working interest.
Area of mutual interest	There will be an area of mutual interest encompassing lands within one mile of the boundaries of the joint venture lands and will expire one year from the rig release date of the Test Well. If the parties agree to mutually acquire an interest in such an area, then our joint venture partner and us will acquire 75% and 25% of the interest in the area, respectively.

Stolberg JV

We hold a 30% working interest in four sections of land in Stolberg in the Alberta Foothills. The remaining 70% working interest is held by our joint venture partner. We receive the revenues from the Stolberg JV and share costs and any losses proportionate to the percentage of our respective working interests. No fees are payable by us to our joint venture partner and vice versa. We have not received any revenue from the Stolberg JV during the Track Record Period. We acquired our interest in this land for the purpose of obtaining geological and geophysical information of nearby areas. No well has been drilled in this area as at the Latest Practicable Date.

The Stolberg JV Agreement contains the following material terms:

Title	We represent that the lands are encumbered by the applicable lessor royalty and that it has complied with terms of the relevant grant of its interest in the lands to the extent necessary to keep them in full force as of January 25, 2011.
Interest earned	Our joint venture partner earned and we assigned an undivided 70% working interest in our licence and lands as of January 25, 2011. The licence and lands are recognized as joint lands. If our joint venture partner proposes the drilling of a well on our licence before such well information is available publicly, it will provide said well information to allow us to make an informed decision on participation in drilling.

Operation procedure and operator	Our joint venture partner is appointed as the initial operator and acts as operator under the 2007 CAPL Operating Procedure as of January 25, 2011, subject to certain revisions and elections.
Insurance	Pursuant to the elections under the 2007 CAPL Operating Procedure, both the joint venture partner and the Company must obtain and maintain for its sole account and expense, operator's extra expense insurance covering the parties' proportionate share of costs to regain control of a well and pollution liability, the costs of such insurance are borne solely by each party.

QUALITY CONTROL AND CONTROL MEASURES

Our products are natural gas, crude oil, condensate and other NGLs which are raw materials. These products must meet the quality specifications specified by third party pipeline providers before they can enter into the pipeline system for transportation.

Our crude oil must meet the quality specifications of the relevant third party pipeline. The main requirements under the specifications of the relevant third party pipeline include density, moisture and contaminant content and a maximum hydrogen sulphur requirement.

Quality control of these products is achieved by using a series of processing facilities either owned by us or by third parties to ensure all of our oil and gas products comply with the pipeline standards set forth by NGTL for natural gas and a third party pipeline provider for crude oil respectively before entering the pipeline system.

Our selection criteria and process for the engagement of suppliers, contractors and consultants is set out in the section "Suppliers and Contractors", in addition to our ongoing monitoring of their services and work to ensure quality control. This is set out further in the paragraph headed "Occupational Health and Safety" in this section. We did not engage any subcontractors during the Track Record Period.

UTILITIES

Our production facilities only rely on limited external utility supplies. Our equipment such as compressors, pump jacks and field generators are driven by gas engines mainly using the sweet natural gas produced by us as fuel gas. There is also a limited requirement for the use of water for our operations, and we normally drill water wells locally to meet our operational demands. Alternative suppliers of electricity and water are available to support our operational needs at market rates if we do not have sufficient electricity and water to support our operations. Accordingly, we have not entered into any utility contracts at competitive prices. During the Track Record Period, our operations had not been interrupted by any shortages of electricity, water or fuel and gas supply.

MARKET AND COMPETITION

The natural gas and oil industry in which our Company operates is highly competitive. According to the Industry Consultant, Alberta contains one of the largest natural gas and oil reserves in Canada and is home to over 2,000 natural gas and oil producing companies. As a junior natural gas and oil company, our competitors include some large and integrated natural gas and oil companies with access to a substantial capital base and more revenue streams, as well as numerous other intermediate, junior and emerging natural gas and oil companies in Alberta. Alberta's natural gas export to the US market has declined by 16.9% CAGR from 2010–2015 and is expected to decline further during the forecast period as gas from the Marcellus and Utica Shale in the US finds its way into the US domestic market replacing the gas supplied by Alberta. Although decrease in demand in the export market may increase competition in domestic markets, it may have little impact on the demand of Alberta's natural gas since the demand within Canada is growing gradually. The major domestic uses of natural gas in Alberta are for crude oil production (from oil sands) and electricity generation, which are expected to grow at an annual average of 5.0% and 3.0%, respectively. The oil sands are expected to be the primary source of demand for Alberta's natural gas production, offsetting some of the demand loss in export markets. In addition to this, demand for natural gas is expected to rise due to the likely switch from coal to gas as a fuel for the province's electricity generation as a result of Government of Alberta's Climate Leadership Plan and pre-existing federal regulations. Therefore, it is expected that the total consumption of natural gas in Alberta is likely to increase to 60.2 bcm by 2020.

We compete with our competitors for the acquisition, exploration, production and development of natural gas and oil reserves and for skilled personnel, equipment and capital to operate and finance such activities. The large and integrated natural gas and oil companies, with more financial resources, would be better prepared to weather low natural gas and oil prices as well as being able to spend more to evaluate and bid for properties and recruit skilled personnel than our financial or human resources permit. Ultimately, we need to focus on costs and efficiencies, especially during periods of low natural gas and oil prices, and our key to competing with the large producers will depend on our access to high-quality conventional natural gas resources and our ability to maintain low costs of production. Please refer to the sections headed "Industry Overview" and "Business — Our Key Strengths" in this Prospectus for details of the competitive landscape and our key strengths.

ENVIRONMENTAL PROTECTION, LAND REHABILITATION AND SOCIAL MATTERS

Environmental Protection

Our operations in Alberta are subject to a variety of Canadian provincial and federal environmental protection laws and regulations, all of which are subject to governmental review and revision from time to time. For further details, please see the section headed "Laws and Regulations" in this Prospectus. The Canadian government may adopt stricter standards and other new changes to environmental protection laws and regulations, which could have a material adverse effect on our financial condition and results of operations. For a discussion of this risk, please refer to the paragraph headed "Risk Factors — Risks relating to the Alberta Natural Gas and Oil Industry — Our business operations are subject to and may be adversely affected by present and any future laws and regulations and substantial changes to those regulations" in this Prospectus.

Costs of compliance with environmental laws and regulations for the years ended December 31, 2013, 2014 and 2015 and the nine months ended September 30, 2016 were approximately C$146,000, C$239,000, C$82,000 and C$90,000, respectively. Based on our experience and the current environmental regulatory environment, we expect that the estimated costs of compliance with environmental laws and regulations for the years ending December 31, 2016, 2017 and 2018 will be approximately C$120,000, C$180,000 and C$180,000, respectively.

We have implemented various measures to address environmental issues arising in our operations and to minimize the impact of our operations on the environment. We have formulated detailed environmental protection policies and procedures to cover every major step in our operations. We have set up an emergency response team and developed emergency response plans. We work closely with local authorities, emergency services and our communities in order to respond efficiently to any environmental incident should it arise. The environmental measures that are being implemented, or will be implemented upon the launch of our operations, include without limitation:

Waste Water Management

For our gas and oil production activities, we have in place effective produced water management practices. Produced water coming out from the wellheads along with the gas or oil contain elevated levels of dissolved ions (salts), hydrocarbons, and trace elements. Discharge of any produced water would be harmful to the surrounding environment. We have implemented produced water management procedures for the collection and storage of the produced water with on-site water tankage. The produced water in the water tanks will be trucked out for disposal to third parties authorized by the local governmental authority.

Noise Control

We have implemented various measures to reduce the noise level in our well site operations, such as use of mufflers, noise and vibration dampening and absorbing materials, and isolation and enclosure of noisy equipment. During the Track Record Period, we also engaged a third party service provider to conduct noise impact assessments for the compressors at our facility locations. The results of these assessments indicated that the predicted cumulative sound levels from our facilities were within the daytime and night-time permissible sound levels requirements of the AER and the Alberta Utilities Commission. Based on these assessments, the AER issued to us facility licences permitting us to operate our facilities. We will continue to implement and conduct the aforesaid noise control measures and noise impact assessments in our future well site operations. Furthermore, personal protection equipment is also required to be used by our operating personnel at all times.

The Liability Management Rating ("**LMR**") is the ratio of a licensee's eligible deemed assets to its deemed liabilities under the various liability management programs implemented by the AER. The LMR released by the Government of Alberta on February 4, 2017 showed that our Company had a LMR of 51.61 as compared to the industry average of 4.45. The LMR assessment is designed to assess a licensee's ability to address its suspension, abandonment, remediation and reclamation liabilities. If our LMR is lower than 1.0, we may be required by the AER to pay a security deposit to cover the cost of compliance. We intend to continue implementing our control measures to ensure that we continue to meet our environmental compliance obligations, including monitoring our LMR. Further details about the liability management program are set out in the section headed "Laws and Regulations — Laws and Regulations Relating to the Canadian Natural Gas and Oil Industry — Liability Management Rating Program" in this Prospectus.

Compliance

As advised by our Canadian Legal Advisers, we are not in any material breach of any relevant Canadian laws and regulations regarding our environmental protection compliance, including those in relation to waste water management and noise control, that would have adversely affected our operations during the Track Record Period and up to the Latest Practicable Date. As at the Latest Practicable Date, we were not subject to any environmental protection or safety claims, lawsuits, penalties or administrative sanctions, and we believe that our environmental management policy and systems do not have any material weaknesses or deficiencies and are adequate for us to comply with national and local environmental protection regulations.

Land Rehabilitation

Pursuant to the relevant Canadian laws and regulations, we are responsible for the rehabilitation of any well sites damaged by our drilling activities, and are required to submit an environmental site assessment report to the AER for approval when applying for our PNG Licence and Crown Lease. Before commencing drilling activities, we are required to obtain approval of our environmental site assessment reports before the overall development plan can be submitted to the local authority for approval. The filing must demonstrate that the site conforms to applicable environmental standards. Once we obtain the approval from the AER, the local environmental protection agency supervises our compliance with environmental protection laws and regulations and conducts inspections of our sites from time to time.

During the Track Record Period and as at the Latest Practicable Date, our Company has not reclaimed and restored any well site. We have not made provision for land rehabilitation and restoration costs. Any provisional amount of rehabilitation costs (if any) will depend on the area of land that we utilized and will be determined by the costs for future rehabilitation works that a third party may be required to perform, including material costs and labor costs. Environmental site assessment reports are one basis of cost estimation for the reclamation of surface soil and underground.

We confirm that there has been no material environmental concern from the local community and we have had a good relationship with the local community. As advised by our Canadian Legal Advisers, we are not aware of any material breach of the relevant Canadian laws and regulations in relation to natural gas and oil resources and land rehabilitation.

Social and Local Community Concern

We respect the history, heritage and culture of the First Nations communities in the Alberta Foothills, Deep Basin Devonian and Peace River regions and seek to engage and consult with stakeholders in these regions.

Prior to the launch of any site development, we will consult stakeholders, including members of the public, regulatory bodies and local and aboriginal communities who are, or may be, affected by the proposed exploration and/or development activities. We will seek to ensure that a transparent and respectful relationship is built and maintained with neighbours and relevant stakeholders. We confirm that they are not aware of any concerns of local communities which are relevant and material to our business operations.

During the Track Record Period and up to the Latest Practicable Date, in dealing with Canadian laws and regulations and practices which are relevant and material to our business operations, we maintained regular contact with the local government authorities to keep abreast of the local government practices in enforcing and interpreting the laws and regulations applicable to our business operations.

Regarding local community concerns, during the Track Record Period and up to the Latest Practicable Date, we had not received any historical or current non-compliance notices and/or other documented regulatory directives, in relation to the development of our sites in the Alberta Foothills, Deep Basin Devonian and Peace River areas, which is relevant and material to our business operations. We are not aware of any concerns of local governments and communities on the development of our sites in the Alberta Foothills, Deep Basin Devonian and Peace River areas, which are relevant and material to our business operations.

During the Track Record Period and up to the Latest Practicable Date, we had not received any notices in relation to any actual or potential impacts of non-governmental organizations on the sustainability of our sites in the Alberta Foothills, Deep Basin Devonian and Peace River which is relevant to and material to our business operations.

OCCUPATIONAL HEALTH AND SAFETY

We operate in a responsible manner to ensure the health and safety of our employees, third-party contractors and the communities in which we operate. We are committed to meeting applicable legal requirements and where possible seek to implement leading international industry standards in our operations. Our commitment to occupational health and safety extends to the members of our management who report directly to our Board.

We are subject to Alberta health and safety laws and regulations including the OHSA, the OHSR and the OHSC. The OHSA sets standards to protect and promote the health and safety of workers throughout Alberta. The OHSR addresses the requirements related to government policy and administrative matters. The OHSC specifies all the mandatory technical standards and safety rules that employers and workers have to comply with to fulfil their obligations. The OHSC covers areas such as general safety, noise, chemical hazards and first aid.

The OHSA, the OHSR and the OHSC are enforced by occupational health and safety officers from the workplace, health and safety section of the Alberta Department of Employment and Immigration. No enforcement action had been taken by the occupational health and safety officers against our Company during the Track Record Period and up to the Latest Practicable Date.

We have adopted operational occupational health and safety policies, which contain guidelines with respect to occupational safety, covering drilling and completions, well servicing, transportation of dangerous goods, procedures for handling chemicals and explosive materials and emergency plans. Our site operators are required to be properly licensed, and our safety management employees are certified by the relevant safety regulatory authorities. We have implemented a system to monitor and record employee occupation health and safety statistics. To avoid any potential accident in the course of our operations, we have implemented certain safety measures and adopted a corporate emergency response plan. In particular we will conduct trainings for our operational staff on occupational safety.

During the Track Record Period and up to the Latest Practicable Date, we did not have any material accidents in the course of our operations nor any accidents related to the health or safety of our employees or contractors and we had not received any claims for personal or property damage by our employees nor paid any compensation as a result.

As advised by our Canadian Legal Advisers, we are not aware of any material breach of the relevant occupational health and safety laws and regulations applicable to our business in material respects.

INSURANCE

We maintain insurance coverage on our properties and equipment, including wells, gas gathering stations, pipelines, well site and wellhead equipment, and other machinery and supplies. We maintain property damage insurance, insurance for workers compensation for on-site operator's extra expenses such as limited redrilling, seepage and pollution expenses and third party liability insurance, workplace injury insurance for our operations and insurance for commercial general liability, excess liability, workers' compensation liability and office content liability. We also maintain directors' and officers' liability insurance for our Directors and officers. We will continue to review and assess our risk portfolio and make necessary and appropriate adjustments to our insurance policies. Based on our knowledge of insurance practices within the oil and gas industry in Alberta, we believe that our level of insurance is adequate and comparable to that maintained by comparable oil and gas companies in Alberta. In addition, we shall procure construction insurance policies consistent with industry practice for our interests in case we engage in any major construction projects. We did not make any material claim under our insurance policies during the Track Record Period.

EMPLOYEES AND EMPLOYEE RELATIONS

As at December 31, 2013, 2014 and 2015 and September 30, 2016, we had a total of 7, 8, 9 and 10 full-time employees, respectively. All of our employees are located in Canada. The relationship and cooperation between our management team and employees has been positive and is expected to remain positive in the future. There has not been any incidence of work strikes or labor disputes which have had an adverse impact on our operations. There are no labor unions associated with our Company's employees.

As at the Latest Practicable Date, there were 10 full time employees employed by our Company and 3 consultants were engaged to work at the Calgary head office. None of the employees are union employees.

The functional distribution of our Company's employees as at the Latest Practicable Date was as follows:

Division	**Number of employees**	**Percentage of total employees**
Management	4	40%
Engineering	2	20%
Accounting	3	30%
Human resources	1	10%
Total	10	100%

For the years ended December 31, 2013, 2014 and 2015 and the nine months ended September 30, 2016, our total staff costs (including share-based compensation) were approximately C$1.2 million, C$2.9 million, C$1.2 million and C$1.2 million, respectively, which accounted for approximately 5.1%, 9.1%, 7.3% and 7.8% of our revenue, respectively.

Our employees are employed under employment contracts which set out, among other things, their job scope and remuneration. We have not engaged any employment agent. Further details of their employment terms are set out in our employee handbook. We determine our employees' salaries based on their job nature, scope of duty, and individual performance. We also provide reimbursements, allowances for site visits and a discretionary annual bonus for our employees. We also provide employees with welfare benefits in accordance with the applicable laws and our internal policies. We issued Class B Shares to our employees and consultants which resulted in share-based compensation during the Track Record Period. Please refer to the section headed "Financial Information — Statements of Profit or Loss and Other Comprehensive Income — Shared-based Compensation" in this Prospectus for more details.

We consider our employees to be one of our key competitive advantages in the oil and gas industry in Alberta. We are committed to providing regular on-the-job training to our employees. We generally sponsor all training programs related to an employee's role to ensure the development of talented and motivated employees to contribute to the continuing performance and growth of our business. Investing in the career development of our employees has been a priority in our human resources development plan.

We are in compliance with the statutory requirements in relation to retirement and employment insurance contributions. Subject to very few exceptions, every person over the age of 18 who works in Canada, as well as each employer, must contribute to the employment insurance ("**EI**") program and to the Canada Pension Plan ("**CPP**"). Each employee must pay half of the required contributions for CPP and each employer pays the remaining half. Each employee and employer pays their respective portion of the EI premiums. For the years ended December 31, 2013, 2014 and 2015 and the nine months ended September 30, 2016, our retirement benefits contributions amounted to approximately C$16,000, C$20,000, C$24,000 and C$25,000, respectively.

Our success depends largely on certain key personnel. We have also maintained full time employees' total and permanent disability insurance through a group benefits program provided by a reputable insurer.

We have complied with all laws, regulations and requirements relating to our employees during the Track Record Period. During the Track Record Period, we did not encounter any material difficulties in recruiting and retaining our employees and we have not experienced any material interruption to our operations as a result of labor disputes. We also review annually the compensation packages of our management and other key employees to ensure their compensation remains competitive in the market. We have also established internal procedures and designated responsible personnel to ensure our ongoing compliance.

PROPERTIES

As at the Latest Practicable Date, we or our brokers (who hold the legal title of certain leased lands on our behalf) are the registered holders of all leased lands and own facilities on those leased lands for the development of our oil and gas assets. We also lease our office premises in Calgary. Please refer to the section headed "Appendix VI — Statutory and General Information — B. Further Information About Our Business — 4. Properties" to this Prospectus for more details about our properties.

Licences and Permits

We are required by laws and regulations in Alberta to obtain a number of licences, permits and approvals from the relevant authorities to conduct natural gas and crude oil exploration and production activities in Western Canada. During the Track Record Period and up to the Latest Practicable Date, we have obtained all key licences, permits and approvals necessary for the respective development stages of our core areas in the Alberta Foothills and Peace River, including PNG Licences.

PNG Licences and Crown Leases

Alberta provides a system through which mineral rights owned by the Crown (i.e. public land owned by the Government of Alberta), which include PNG Licences and Crown Leases, are sold and administered under the Mines and Minerals Act and its regulations. The public offering process is referred to as "sales" or "land sales", although there is no sale per se as the Government of Alberta retains title to its minerals. The public offering process provides the right to extract the minerals associated with a particular piece of land for a set term, in exchange for which a third party must make a bonus payment, a one-time fee of C$625, an annual rental fee and royalties on any minerals that are recovered.

During the initial term of a PNG Licence or Crown Lease, an annual rental expense equal to C$3.50 per hectare, or a minimum amount of C$50.00, is payable. The average monthly rental expense of our PNG Licences and Crown Leases was approximately C$11,501, C$11,489, C$10,880 and C$20,666 for the years ended December 31, 2013, 2014 and 2015 and the nine months ended September 30, 2016, respectively.

Summary of our PNG Licences and Crown Leases

As at the Latest Practicable Date, other than the Viking JV and Stolberg JV, our Company had a 100% working interest in PNG Licences and was the registered licensee or lessee of 62 PNG Licences and Crown Leases in Alberta, Canada, of which 36 PNG Licences and 5 Crown Leases related to the Alberta Foothills and 17 Crown Leases related to Peace River and 4 PNG Licences related to Deep Basin Devonian.

The following table shows the number of our PNG Licences and Crown Leases, the number of sections and the amount of hectares corresponding to each area as at the Latest Practicable Date:

			Land Section		Land Area			
					Gross		Net	
Property	PNG Licences	Crown Leases	Gross	Net	Acres	Hectares	Acres	Hectares
Alberta Foothills	**36**	**5**	**108**	**105**	**68,800**	**27,520**	**67,008**	**26,803**
Basing	8	3	15	15	9,600	3,840	9,600	3,840
Voyager	21	0	35	35	22,400	8,960	22,400	8,960
Kaydee	3	0	30	30	19,200	7,680	19,200	7,680
Stolberg	3	2	16	13	10,240	4,096	8,448	3,379
Colombia	1	0	12	12	7,360	2,944	7,360	2,944
Peace River	**0**	**17**	**5**	**5**	**3,200**	**1,280**	**3,200**	**1,280**
Dawson	0	17	5	5	3,200	1,280	3,200	1,280
Deep Basin Devonian	**4**	**0**	**69**	**69**	**44,320**	**17,728**	**44,320**	**17,728**
Total	**40**	**22**	**182**	**179**	**116,320**	**46,528**	**114,528**	**45,811**

Note: 1 Section = 256 Ha

Please refer to the paragraph headed "Our Key Assets" in this section for a summary of the geographical locations of each of our PNG Licences and Crown Leases. For more information about our PNG Licences and Crown Leases, please refer to the section headed "Appendix VI — Statutory and General Information — 4. Properties — (b) PNG Licences and Crown Leases" to this Prospectus.

Key Terms of PNG Licences and Crown Leases

We acquired all our PNG Licences and Crown Leases from the Government of Alberta in accordance with applicable regulations and procedures. Our PNG Licences have an initial term of either 4 years or 5 years, depending on the region in which the lands are located. Once a well has been drilled on an area covered by the relevant PNG Licence, we may validate the PNG Licence for an intermediate term of another 5 years. Our Crown Leases have an initial term of 5 years. We plan to continue our PNG Licences and Crown Leases that are in their initial terms before they reach the end of such term. As advised by our Canadian Legal Advisers, there are no facts or circumstances that would call into question the validity or enforceability of any of our PNG Licences and Crown Leases and our Company has complied with all relevant requirements relating to our PNG Licences and Crown Leases.

The following are the key common terms of our PNG Licences and Crown Licences in Alberta:

- the licensee or lessee has an exclusive right to recover the leased substances within the location. In the case of the PNG Licence or Crown Lease, the leased substance is natural gas and crude oil;
- the licensee or lessee is obligated to pay such yearly rentals and royalties as prescribed by the Mines and Minerals Act;
- the licensee or lessee is obligated to comply with the Mines and Minerals Act and other applicable laws and regulations; and
- the licensee or lessee is required to indemnify the Crown against all claims brought against the Crown by reason of any acts or omissions of the licensee or lessee in respect of its rights or duties.

Renewal of our PNG Licences and Crown Leases

When a PNG Licence or a Crown Lease reaches the end of its primary term, our Company can renew the PNG Licence or Crown Lease if we can show that the land to which the relevant PNG Licence or Crown Lease related is productive of natural gas and/or crude oil. Crown Lease and PNG Licence continuations are subject to the specific terms of the Crown Lease or PNG Licence, and the provisions of the Mines and Minerals Act.

Based on our past experience, it generally takes up to one year to renew our PNG Licences and Crown Leases. When considering whether to approve a renewal application, Alberta Energy may consider factors such as the level of drilling activities completed before the renewal application, the capability of well production, and restrictions and delay caused by any extreme weather conditions.

Our decision whether to renew or relinquish the PNG Licence or Crown Lease is primarily based on our estimate of the prospective value of the subject land. Generally, we will initially conduct an assessment and evaluation which include seismic interpretation, G&G studies and review of the recent nearby drilling activities on the upcoming expiry lands. Once we decide to renew, we will prepare the geological discussion and renewal application package. We will submit the renewal application package within three months before expiry date. For instance, our PNG Licences and Crown Leases in relation to a total of 480 acres of land in Dawson in Peace River were renewed in March 2016. As at the Latest Practicable Date, we submitted applications and obtained approval to extend the 4 PNG Licences which expired in January 2017 to March 31, 2017. For the remaining PNG Licences and Crown Leases which will expire in 2017, they are still under our Company's internal assessment and evaluation. Our Canadian Legal Advisers have advised us that there will be no material legal impediment for us in renewing our PNG Licences and Crown Leases.

The table below shows the number of our Company's PNG Licences and Crown Leases for our existing wells, drilling locations assigned by GLJ and undeveloped land that will expire in 2017, 2018 and 2019 and thereafter respectively.

Year of Expiration	PNG Licences and Crown Leases for Existing Wells		PNG Licences and Crown Leases for Drilling Locations Assigned by GLJ		PNG Licences and Crown Leases for Undeveloped Land Not Assigned any Drilling Locations by GLJ	
	PNG Licences	Crown Leases	PNG Licences	Crown Leases	PNG Licences	Crown Leases
2017	0	2	1[1]	2	4[1]	5
2018	0	0	4[2]	2	3	3
2019 and thereafter (including indefinite term)	2	1	13[3]	0	13	7
Total	2	3	18	4	20	15

Notes:

1. Our Company submitted applications and obtained approvals to extend the terms of our Company's lease of these lands to March 31, 2017. None of these leases cover any of the 13 drilling locations under the three-year development plan. Our Company will be required to perform certain exploration and evaluation activities during the three months ending March 31, 2017.

2. 3 of these PNG Licences cover 5 of our drilling locations in 2019 under our three-year development plan. We will submit the renewal application package within three months before expiry date. Our Canadian Legal Advisers have advised us that there will be no material legal impediment for us in renewing our PNG Licences.

3. 2 of these PNG Licences cover 5 of our drilling locations in 2017 & 2018 and 3 of our drilling locations in 2019 under our three-year development plan, which have indefinite terms until the related well becomes non-productive. The indefinite term relates to the aforesaid 2 PNG Licences covering a total of 8 of our drilling locations in 2017, 2018 and 2019 which had initially expired on January 11, 2017 and were renewed with an indefinite expiry date.

During the Track Record Period, we also decided not to pursue the renewal application further and to relinquish certain PNG Licences and Crown Leases of our undeveloped assets, as they were still in early exploration stages and considered by our Company not to have further prospective value after having conducted seismic interpretation, G&G studies and evaluation. For instance, regarding a total of 6,400 acres of land in Otter and a total of 48,640 acres of land in Cadotte, both in Peace River, despite these lands being located within the Peace River Arch fringing reef complex area which our management considered to hold some development potential, based on our subsequent G&G study and evaluation, there were lots of uncertainties in terms of subsurface geology and prospect as only few of very scarce 2D seismic lines lay across these lands. Given their associated high exploration risk and having further considered the Competent Person's evaluation that no future prospective value can be assigned to these lands at this early exploration stage, our management was of the view that these properties were not in our priority for conducting further exploration and development activities on these lands. Therefore we decided not to pursue the renewal application further and to relinquish those PNG Licences in relation to the 6,400 acres of land in Otter and the 48,640 acres of land in Cadotte after receiving responses from Alberta Energy in June 2016 and in August 2016 respectively that these lands did not meet the required level of drilling activities for renewal. We incurred impairment losses as a result.

The write-offs for E&E assets amounted to C$362,804, C$1,786,080, C$2,363,231 and C$812,452 for the years ended December 31, 2013, 2014 and 2015 and the nine months ended September 30, 2016, respectively. Our PNG Licences in relation to a total of 3,840 acres of land in Kaydee in the Alberta Foothills expired in January 2016 and a write-off of C$339,114 was recognized during the nine months ended September 30, 2016 in this regard. Our PNG Licences in relation to a total of 6,400 acres of land in Otter in Peace River expired in May 2016 and a write-off of C$108,412 was recognized during the nine months ended September 30, 2016 in this regard. Our PNG Licences in relation to a total of 48,640 acres of land in Cadotte in Peace River expired in July 2016 and its associated E&E assets of C$262,391, which was written-off during the nine months ended September 30, 2016 in this regard after we decided to relinquish this PNG Licence in August 2016 as disclosed above. Our Company also directly wrote off C$100,000 of E&E assets for the nine months ended September 30, 2016 as a result of the expiry of 1 Crown Lease in Dawson in November 2016 because they were considered to have no further prospective value. In addition, 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. None of these leases cover any of the 13 drilling locations under our three-year development plan. Our Company will be required to perform certain exploration and evaluation activities during the three months ending March 31, 2017. In this regard, our Company has performed certain exploration and evaluation activities, including seismic interpretation, geology and geophysics study, reservoir study and environmental assessment. According to our latest communication with the Alberta Department of Energy, we are requested to spud a validation well before March 31, 2017 in order to obtain extension of the term of these leases. Our Company is planning to spud the well before March 31, 2017. Once the validation well has been drilled to the target formation, a well completion report and a validation request will be submitted to Alberta Department of Energy to obtain the extension. Our Company is of the view that we will be able to fulfil the conditions for extension in order to obtain successful extension of the leases of these lands. In such circumstance, our Company needs not to write-off the exploration and evaluation assets totalling C$2,247,609 during the three months ending March 31, 2017 assuming no other factors or conditions exist. We do not expect any other significant impairment for our remaining Junior Assets for the three months ended December 31, 2016. Our Company believes that this is in line with the common practice of other natural gas and oil companies in Alberta. Our Company may acquire these expired PNG Licences and Crown Leases in the future. The expiry of the PNG Licences and Crown Leases in relation to these lands had no impact on our development plan or reserve base.

In respect of the Drilling Locations, our Company has been able to successfully renew their respective Licences historically.

Encumbrances in relation to our PNG Licences and Crown Leases

As at the Latest Practicable Date, certain of our PNG Licences had been subject to security interests granted by our Company to Macquarie Bank to secure our Company's obligations under the Macquarie Bank Credit Agreement. Please refer to the section headed "Financial Information — Indebtedness — Bank Loan" in this Prospectus for more information.

Other Licences

In addition to obtaining Crown Leases or PNG Licences, we are required to obtain well licences for drilling new oil, gas or water wells, and facility licences for operating our facilities. A pipeline licence is also required to construct and operate a new pipeline, change the parameters of existing pipelines or construct pipeline installations. These will be applied as part of our three-year development plan.

No party may drill or produce from a well, construct or operate a facility, or construct or operate a pipeline unless it has a related well licence, facility licence and pipeline licence issued by the AER to do so. As per AER's requirement, a well license application must be submitted with a survey plan which should not be more than one year old from the date on which it is certified. Issuance may be refused, or granted subject to any conditions, restrictions and stipulations as determined in the reasonable discretion of the AER. This would occur where the AER has reasonable grounds to believe that: (i) there has been a contravention of any law, rule or regulation or rules under its jurisdiction in respect of the operations of the holder; (ii) the holder ceases to meet the eligibility requirements for holding the well licence; or (iii) where the party has contravened or failed to comply with an order of the AER, or has an outstanding debt to the AER or to the account of the orphan fund in respect of suspension, abandonment or reclamation costs, and the AER has made a declaration setting out the nature of the contravention, failure to comply or failure to pay. Despite the aforesaid, our management confirms that as we have submitted the required documentation with the applications, we have always been able to obtain the well licences for our drilling locations. Our Canadian Legal Advisers confirm that the well licence application is an administrative procedure.

Once a well licence has been issued, the project must commence work within one year, otherwise the well licence will expire and be cancelled. If the project has not commenced work within one year, the well licence may be extended, but this is evaluated on a case by case basis and is at the discretion of the AER. Where projects have not started work, the well licence will not normally be extended beyond two years from the date of issuance. Once the project has commenced work, the well licences do not expire and do not need to be renewed.

As at the Latest Practicable Date, we held a total of 9 well licences, 2 facility licences and 3 pipeline licences. All of these licences will not expire until we cease operations and abandon these licences.

INTELLECTUAL PROPERTY AND KNOW-HOW

Technology and Know-How

We believe our strong commitment to improving operational and technical excellence is an important factor in our success. The industry in which we operate is characterized by intense competition and one key differentiating factor is our ability to identify the best Reserves and apply the appropriate technology to cost-efficiently extract reserves on a cost-efficient basis. Our Chief Executive Officer, Mr. Bo, has more than 10 years of experience managing and developing our Company. Mr. Pingzai Wang, our Senior Vice President, Exploration, has over 28 years of experience in the natural gas and oil industry generally and over 10 years of experience in North America. Mr. Binyou Dai, our Vice President, Engineering, has over 24 years of experience in the natural gas and oil industry generally and over 11 years of experience in North America. Mr. Lei Song, our Production Engineer, has 5 years of working experience in the natural gas and oil industry in North America. Collectively this team and other essential members of our Company provide the foundation for our technical expertise and continued growth. For more information about our management team, please refer to the section headed "Directors and Senior Management" in this Prospectus.

We have focused our technology and know-how on the following major areas:

- having devoted over 10 years to the acquisition of geological and geophysical data that is essential to understanding our Reserves and surrounding areas;
- employing a number of tools to help complete our geological understanding including West Canadian Database Software and geology and geophysics and reservoir engineering software; and
- improving well design and decreasing operating costs by applying the most efficient well design to each drilling area.

Other Intellectual Property

We use operating practices that we believe are of significant value in developing our business. In particular, we believe that our drilling, completion and production techniques related to multi-stage completion and horizontal drilling, integration of infrastructure and other aspects of our business have to date provided us with a competitive advantage among other factors. These have in large been developed by our engineers, technicians and independent contractors in the course of their work.

As at the Latest Practicable Date, we held 2 registered trademarks in Hong Kong and had registered 3 domain names which are material to our business. We also applied for four trademark registrations bearing our name "PERSTA" (both text and design marks) with the Canadian Intellectual Property Office, which is still under review. Siepmann-Werke GmbH & CO. KG. ("**Siepmann**"), an Independent Third Party, is the registered owner of certain Canadian trademark registrations bearing the name of "PERSTA" (both text and design marks) for, amongst other goods and services, die-forged and/or welded valves, pipelines and water level indicators. We have received Siepmann's consent to our abovementioned applications' registration for use in association with the goods and services in relation to crude oil, natural gas, liquefied petroleum gas and natural gas liquids, and we have executed an agreement with Siepmann that the trademarks to be registered by us can coexist in the Canadian marketplace with their trademark registrations without causing confusion to the goods and services provided by the parties in the Canadian marketplace.

Please refer to the section headed "Appendix VI — Statutory and General Information — B. Further Information About Our Business — 2. Intellectual Property Rights" to this Prospectus for more information on our intellectual property rights.

We recognize the importance of protecting and enforcing our intellectual property rights. We believe that we have taken all reasonable measures to prevent any infringement of our intellectual property rights. We are currently not aware of any pending or threatened claims against us relating to any alleged infringement by us of any intellectual property rights owned by third parties. Our letters of appointment, consulting agreements and key business contracts contain confidentiality provisions to protect our confidential information.

During the Track Record Period and up to the Latest Practicable Date, there had not been any disputes nor incident of material infringement involving our intellectual property rights.

INTERNAL CONTROL AND RISK MANAGEMENT

We have implemented a series of measures to manage the risks that we face in our operations. We are going to appoint an external internal control consultant who reports directly to our Audit and Risk Committee to perform regular review on the internal control systems over financial reporting. Our management team actively monitors and promptly reacts to changes in the industry's laws and regulations that impact our operations. Each of our financial management, production and human resources team members regularly report to our management with respect to any compliance issues. We have also engaged external legal counsel to handle our various legal and regulatory matters regarding our operations.

LEGAL PROCEEDINGS, COMPLIANCE AND REGULATORY MATTERS

Legal Proceedings

Our Directors confirm to the best of their knowledge that, during the Track Record Period and up to the Latest Practicable Date, there was no legal, arbitral or administrative proceedings pending or threatened against us or our Directors that could individually or in the aggregate, have a material effect on our business, financial condition or results of operations and there was no legal claim or proceeding that may have an influence on our rights to exploration.

Compliance and Regulatory Matters

With the exception of the Viking JV and Stolberg JV, we hold a 100% working interest in the mineral rights for all our PNG Licences and Crown Leases. However, it is possible for the Crown to grant different mineral rights over a given parcel of land in separate geological horizons. It is not uncommon to have rights to specific geological horizons granted to different parties on different dates. As a result, the different rights of different parties on the same parcel of land can see conflicts arise as a result of competing interests. Where this occurs, the parties may work together to negotiate a compromise that maximizes recovery for both parties. Where such a compromise is unattainable the authority of one of a number of administrative bodies such as the AER or the Surface Rights Board will be determinative while the ultimate result will be decided by the nature and particular characteristics of the conflict. The ultimate result of such conflicts cannot therefore be predicted in advance but may include the temporary suspension of the ability of a party to pursue its mineral rights.

We rely on the Government of Alberta's departments, boards and agencies as the mechanism to monitor and protect our reserves and resources. We monitor all land and resource postings to protect our resources and reserves. As at the Latest Practicable Date, we did not anticipate any issues with any third parties with rights over different geographical horizons of our PNG Licences and Crown Leases.

We confirm that we have complied with all applicable material laws and regulations during the Track Record Period and up to the Latest Practicable Date.