CARDINAL
ENERGY LTD.

2016 Annual Information Form

March 31, 2017

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GLOSSARY

Capitalized terms in this Annual Information Form have the meanings set forth below:

Entities

Board or **Board of Directors** means our board of directors.

Cardinal, we, us or **our** means Cardinal Energy Ltd.

Reserves

COGE Handbook means the Canadian Oil and Gas Evaluation Handbook maintained by the Society of Petroleum Evaluation Engineers (Calgary chapter).

CSA 51-324 means Staff Notice 51-324 – *Glossary to NI 51-101 Standards of Disclosure for Oil and Gas Activities* of the Canadian Securities Administrators.

GLJ means GLJ Petroleum Consultants Ltd., independent petroleum consultants of Calgary, Alberta.

GLJ Report means the report prepared by GLJ dated March 8, 2017, evaluating our crude oil, natural gas and natural gas liquids reserves attributable to approximately 65 percent of our total proved plus probable reserves as at December 31, 2016.

NI 51-101 means National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities*.

Reports mean, collectively, the GLJ Report and the Sproule Report.

Sproule means Sproule Associates Limited, independent petroleum consultants of Calgary, Alberta.

Sproule Report means the report prepared by Sproule dated March 6, 2017, evaluating our crude oil, natural gas and natural gas liquids reserves attributable to approximately 35 percent of our total proved plus probable reserves as at December 31, 2016.

Securities and Other terms

Common Shares means our common shares as presently constituted.

Computershare means Computershare Trust Company of Canada.

Credit Facility means our $150 million syndicated credit facility, as more particularly described under the heading "*Description of our Capital Structure – Credit Facility*".

Current Market Price is defined in the Indenture to mean, on any day, the volume weighted average trading price of the Common Shares on the Toronto Stock Exchange (or such other recognized stock exchange) for the 20 consecutive trading days ending on the fifth trading day preceding such date.

Debentures means our 5.50% extendible convertible unsecured subordinated debentures, as more particularly described under the heading "*Description of our Capital Structure – Debentures*".

Indenture means the indenture between us and Computershare under which the Debentures are issued.

Pre-Consolidated Shares means our common shares as constituted immediately prior to being consolidated on a basis of 3 to 1 on September 9, 2013.

Shareholders mean the holders of Common Shares from time to time.

ABBREVIATIONS

Oil and Natural Gas Liquids		**Natural Gas**	
Bbl	Barrel	Mcf	thousand cubic feet
Bbls	Barrels	MMcf	million cubic feet
Bbls/d	barrels per day	Bcf	billion cubic feet
Mbbls	thousand barrels	Mcf/d	thousand cubic feet per day
MMbbls	million barrels	MMcf/d	million cubic feet per day
Mstb	thousand stock tank barrels of oil	MMbtu	million British Thermal Units
NGLs	natural gas liquids	GJ	gigajoule

Other

AECO	the natural gas storage facility located at Suffield, Alberta, connected to TransCanada's Alberta System
API	American Petroleum Institute
°API	an indication of the specific gravity of crude oil measured on the API gravity scale
BOE or Boe	barrel or barrels of oil equivalent, using the conversion factor of 6 Mcf of natural gas being equivalent to one barrel of oil
Boe/d	barrels of oil equivalent per day
$Cdn	Canadian dollars
m^3	cubic metres
MBoe	thousand barrels of oil equivalent
MMBoe	million barrels of oil equivalent
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for the crude oil standard grade
$000s	thousands of dollars
$MM	millions of dollars

CONVERSIONS

The following table sets forth certain conversions between Standard Imperial Units and the International System of Units (or metric units).

To Convert From	**To**	**Multiply By**
Mcf	cubic metres	28.317
cubic metres	cubic feet	35.315
Bbls	cubic metres	0.159
cubic metres	Bbls	6.289
Feet	metres	0.305
Metres	feet	3.281
Miles	kilometres	1.609
Kilometres	miles	0.621
Acres	hectares	0.405
Hectares	acres	2.471
Gigajoules	MMbtu	0.950
MMbtu	gigajoules	1.0526

CONVENTIONS

Certain terms used herein but not defined herein are defined in NI 51-101 and CSA 51-324 and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101 and CSA 51-324. Unless otherwise indicated, references herein to "$" or "dollars" are to Canadian dollars. All financial information herein has been presented in Canadian dollars in accordance with generally accepted accounting principles in Canada.

FORWARD-LOOKING INFORMATION AND STATEMENTS

This Annual Information Form contains forward-looking information and statements (collectively, "**forward-looking statements**"). These forward-looking statements relate to future events or our future performance. All information and statements, other than statements of historical fact, contained in this Annual Information Form are forward-looking statements. Such forward-looking statements may be identified by looking for words such as "about", "approximately", "may", "believe", "expects", "will", "intends", "should", "could", "plan", "budget", "predict", "potential", "projects", "anticipates", "forecasts", "estimates", "continues" or similar words or the negative thereof or other comparable terminology. In addition, there are forward looking statements in this Annual Information Form under the headings: "*General Development of Our Business – Recent Developments*" as to our 2017 focus and capital spending plans; "*General Description of Our Business*" as to our business plan, strategy and objectives; "*Statement of Reserves Data and Other Oil and Natural Gas Information – Disclosure of Reserves Data*" as to our reserves and future net revenue from our reserves, income taxes and pricing, exchange and inflation rates; "*Statement of Reserves Data and Other Oil and Natural Gas Information – Additional Information Relating to Reserves Data*" as to the development of our proved undeveloped reserves and probable undeveloped reserves, future developments costs, our plans to fund future developments costs through a combination of internally generated cash flow, debt and equity issuances; "*Statement of Reserves Data and Other Oil and Natural Gas Information – Other Oil and Natural Gas Information*" as to our exploration and development plans and opportunities, decline rates, anticipated land expiries, hedging and marketing policies, abandonment and reclamation obligations, tax horizon and future production; and "*Dividend Policy*" as to our dividend policy and the future payment of dividends.

In addition to the forward-looking statements identified above, this Annual Information Form contains forward-looking statements pertaining to the following:

- waterflood optimization opportunities and the results therefrom;
- the performance characteristics of our oil and natural gas properties;
- expectations regarding the renewal of our Credit Facility;
- expectation of future production rates, volumes and product mixes;
- projections of market prices and costs, and exchange and inflation rates;
- supply and demand for oil and natural gas;
- expectations regarding our ability to raise capital and to continually add to reserves through acquisitions, development and optimization;
- treatment under governmental regulatory regimes and tax laws;
- productive capacity of wells, anticipated or expected production rates and anticipated dates of commencement of production and timing of results therefrom;
- fluctuations in depletion, depreciation and accretion rates;
- expected changes in regulatory regimes in respect of royalty curves and regulatory improvements and the effects of such changes;
- plans to expand recovery from certain of our properties; and
- our business plans and strategy.

Statements relating to "reserves" are also deemed to be forward looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described exist in the quantities predicted or estimated and that the reserves can be profitably produced in the future.

Forward-looking statements are subject to risks, uncertainties and assumptions, including those discussed below and elsewhere in this Annual Information Form. Although we believe that the expectations represented in such forward-looking statements are reasonable, there can be no assurance that such expectations will prove to be correct. Some of the risks which could affect future results and could cause results to differ materially from those expressed in the forward-looking statements contained herein include the following:

- depressed market prices for oil and natural gas
- volatility of foreign exchange rates;
- operational risks and liabilities inherent in oil and natural gas operations;
- uncertainties associated with estimating crude oil and natural gas reserves;
- competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel;
- incorrect assessments of the value of acquisitions;
- geological, technical, drilling and processing problems;
- fluctuation in foreign exchange or interest rates;
- stock market volatility;
- environmental risks;
- the inability to access sufficient capital from internal and external sources;
- changes in general economic, market and business conditions;
- the accuracy of crude oil and natural gas reserves estimates and estimated production levels as they are affected by exploration and development drilling and estimated decline rates;
- the uncertainties in regard to the timing of our exploration and development program;
- fluctuations in the costs of borrowing;
- political or economic developments;
- ability to obtain regulatory and other third party approvals;
- the occurrence of unexpected events;
- the results of litigation or regulatory proceedings that may be brought against us;
- changes in income tax laws or changes in tax laws and incentive programs relating to the oil and gas industry;
- cyber-security issues; and
- the other factors discussed under "*Risk Factors*".

With respect to forward-looking statements contained in this Annual Information Form, we have made assumptions regarding, among other things: the timing of obtaining regulatory approvals; commodity prices and royalty regimes; availability of skilled labour; timing and amount of capital expenditures; future exchange rates; the price of oil and natural gas; the impact of increasing competition; conditions in general economic and financial markets; access to capital; availability of drilling and related equipment; effects of regulation by governmental agencies; royalty rates; and future operating costs.

We have included the above summary of assumptions and risks related to forward-looking statements provided in this Annual Information Form in order to provide investors with a more complete perspective on our current and future operations and such information may not be appropriate for other purposes.

You are further cautioned that the preparation of financial statements in accordance with generally accepted accounting principles in Canada requires management to make certain judgments and estimates that affect the reported amounts of assets, liabilities, revenues and expenses. Estimating reserves is also critical to several accounting estimates and requires judgments and decisions based on available geological, geophysical, engineering and economic data. These estimates may change, having either a negative or positive effect on net earnings as further information becomes available and as the economic environment changes. **The information contained in this Annual Information Form, including the documents incorporated by reference herein, identifies additional factors that could affect our operating results and performance. We urge you to carefully consider those factors.**

The forward-looking statements contained herein are expressly qualified in their entirety by this cautionary statement. The forward-looking statements included in this Annual Information Form are made as of the date of this

Annual Information Form and we undertake no obligation to publicly update such forward-looking statements to reflect new information, subsequent events or otherwise unless required by applicable securities laws.

OIL AND GAS ADVISORY

This Annual Information Form contains certain oil and gas metrics, prepared by management, such as finding and development costs and finding development and acquisition costs which do not have standardized meanings or standard methods of calculation and therefore such measures may not be comparable to similar measures used by other companies and should not be used to make comparisons. Such metrics have been included in this Annual Information Form to provide readers with additional measures to evaluate the performance of our oil and gas activities however, such measures are not reliable indicators of our future performance and future performance may not compare to our performance in previous periods and therefore such metrics should not be unduly relied upon.

The term "Boe" may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet of natural gas to barrels of oil (6 Mcf: 1 Bbl) is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. **Given the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6 Mcf: 1 Bbl, utilizing a conversion ratio at 6 Mcf: 1 Bbl may be misleading as an indication of value.**

NON-GAAP MEASURES

Throughout this Annual Information Form we use the term "netback" (as defined in the COGE Handbook) which does not have a standardized prescribed meaning under generally accepted accounting principles in Canada and may not be comparable with the calculation of similar measurements by other entities. "Netback" is calculated on a boe basis and is determined by deducting royalties and operating expenses from petroleum and natural gas revenue. We use netback to better analyze the operating performance of our oil and natural gas assets against prior periods.

CARDINAL ENERGY LTD.

We were incorporated under the *Business Corporations Act* (Alberta) as 1577088 Alberta Ltd. on December 21, 2010. On May 25, 2012, we changed our name to "Cardinal Energy Ltd.". On June 28, 2012 we amended our Articles to change the rights, privileges, restrictions and conditions in respect of our Common Shares, including enabling us to issue stock dividends declared on our Common Shares. On July 27, 2012 we amended our Articles to remove our private company restrictions. See "*Description of our Capital Structure*". On September 9, 2013, we filed Articles of Amendment to consolidate our Pre-Consolidated Shares on a basis of three Pre-Consolidated Shares for each one Common Share and to amend the percentage of the average market price used when calculating a stock dividend on our Common Shares. See "*Description of our Capital Structure*". During the year ended December 31, 2015 we completed the following vertical amalgamations with our then wholly owned subsidiaries: (i) on January 1, 2015, we amalgamated with Muirfield Resources Ltd., a private company we acquired on October 29, 2014; (ii) April 15, 2015 we amalgamated with Pinecrest Energy Inc.; and (iii) on September 12, 2015 we amalgamated with Wildhorse Oil Corporation. See "*General Development of Our Business – History and Development*".

Our head office is located at Suite 600, 400 – 3rd Avenue SW, Calgary, Alberta T2P 4H2 and our registered office is located at Suite 2400, 525 – 8th Avenue SW, Calgary, Alberta T2P 1G1. We do not have any subsidiaries.

GENERAL DEVELOPMENT OF OUR BUSINESS

History and Development

We commenced operations in May of 2012 and through a series of acquisitions, we successfully established two core operating areas in Chauvin and Wainwright. In the third quarter of 2013, we completed an acquisition of assets in the Bantry area of Alberta, a new focus area in which we identified development drilling opportunities. On December 17, 2013, we completed an acquisition of assets located in Southeast Alberta, closed our initial public offering and our Common Shares commenced trading on the Toronto Stock Exchange.

Since becoming a public company, we have continued to complete accretive and strategic acquisitions to establish our current core areas of Bantry, Wainwright and Mitsue. See "*Statement of Reserves Data and Other Oil and Natural Gas Information – Other Oil and Natural Gas Information – Principal Oil and Natural Gas Properties* ".

Developments in 2014

On January 7, 2014 we announced that our Board of Directors approved a dividend policy of $0.05417 per Common Share per month for the first quarter of 2014. See "*Dividend Policy*".

On January 28, 2014, we closed two acquisitions in the Bantry area of Alberta for an aggregate price of $27 million before closing adjustments.

On February 10, 2014, we closed a bought deal private placement of 2,187,500 Common Shares at a price of $12.80 per share for gross proceeds of $28 million.

On July 29, 2014, we announced that our Board of Directors had approved a 30% increase to our monthly dividend from $0.05417 to $0.07 per Common Share beginning with the October 2014 dividend payment.

On August 22, 2014, we closed an acquisition of assets in our core area of Wainwright, Alberta for cash consideration of $165 million, after giving effect to closing adjustments. The majority of the purchase price was funded through the proceeds of a public offering of Common Shares at a price of $18.50 per share for gross proceeds of approximately $162.8 million. The public offering closed on August 15, 2014. We filed a business acquisition report with respect to this acquisition on August 29, 2014 which is available on SEDAR at www.sedar.com.

On August 29, 2014, we completed the acquisition of all of the issued and outstanding shares of Muirfield Resources Ltd. for a purchase price of $12 million.

On September 30, 2014, we completed an additional acquisition of assets in our Wainwright core area for cash consideration of $233 million, after giving effect to closing adjustments. The majority of the purchase price was funded through the proceeds of a public offering of Common Shares at a price of $19.75 per share for gross proceeds of approximately $197.5 million. The public offering closed on September 23, 2014. We filed a business acquisition report with respect to this acquisition on October 9, 2014 which is available on SEDAR at www.sedar.com.

Developments in 2015

On April 15, 2015 we acquired all of the issued and outstanding common shares of Pinecrest Energy Inc. for aggregate consideration of approximately $23.5 million.

On July 15, 2015 we announced an increase to our Credit Facility from $125 million to $150 million.

On September 12, 2015, we acquired all of the issued and outstanding common shares of Wildhorse Oil Corporation, a private oil and gas company with properties that complemented our existing assets in Wainwright. Total consideration was $7.8 million consisting of 669,936 Common Shares valued at $8.69 per share and cash of $2.0 million.

On October 30, 2015 we closed an acquisition of assets in the Slave Lake (Mitsue) area of Alberta for a total purchase price of approximately $144 million before closing adjustments. The purchase price was partially funded through the proceeds of a public offering of subscription receipts at a price of $8.30 per subscription receipt for gross proceeds of approximately $55 million and $50 million aggregate principal amount of Debentures, for combined gross proceeds of $105 million which closed on October 6, 2015. In accordance with the terms of the subscription receipts, each subscription receipt automatically converted into a Common Share on the closing of the acquisition. We filed a business acquisition report with respect to this acquisition on December 8, 2015 which is available on SEDAR at www.sedar.com.

On November 17, 2015 we disposed of a gas plant and related facilities acquired in the acquisition of assets in the Slave Lake (Mitsue) area for proceeds of $12.8 million.

Developments in 2016

On January 14, 2016 we reduced our dividend from $0.07 per Common Share per month to $0.035 per Common Share per month effective for the January 2016 dividend payable in February. See "*Dividend Policy*".

On June 15, 2016, we closed a bought deal public offering of 7,150,000 Common Shares (which included the full exercise of the over-allotment option) through a syndicate of underwriters at a price of $9.35 per Common Share for gross proceeds of approximately $67 million.

Connie Shevkenek was appointed as Vice President of Engineering as of September 1, 2016 and Dale Orton was appointed Vice President effective December 1, 2016.

On December 6, 2016, we closed an acquisition of assets within our Wainwright operating area. Total consideration was $32.5 million, before closing adjustments, consisting of $27.7 million in cash and 500,000 Common Shares valued at $9.68 per Common Share.

Recent Developments

On January 24, 2017, our Board of Directors approved a capital expenditure budget for 2017 that focuses on balance sheet strength, maintaining a sustainable dividend and development of our core areas. In addition, with recent improvements of commodity prices, the 2017 budget focuses on further development and growth in each of our three core operating areas.

On March 13, 2017, we announced that we are suspending our dividend reinvestment plan and our stock dividend plan effective for our May 15, 2017 dividend payment to Shareholders of record on April 28, 2017.

On March 17, 2017, we closed an acquisition of assets within our North (Mitsue) operating area. Total consideration was $31.6 million, before closing adjustments, consisting of 4,033,708 Common Shares valued at $6.85 per Common Share (based on the closing price of the Common Shares on the date of closing) and cash of $4 million.

GENERAL DESCRIPTION OF OUR BUSINESS

Stated Business Objectives and Strategy

We are an oil focused Canadian company built to provide investors with total returns comprised of yield plus growth through the ownership of crude oil production focused in all season access areas in Alberta. Our objective is to build core operating areas with sufficient scale of production as well as organic and acquisition growth prospects to achieve operational cost and production efficiency in each core area. We manage exploration, production and marketing risks through the expertise of our experienced technical and management personnel.

We commenced operations in May of 2012 with the goal of building a dividend paying junior oil focused company from the ground up. Since we commenced operations, we have acquired several low decline crude oil properties. These acquisitions have provided us with a solid base of low decline oil and natural gas production, along with a large multi-year drilling inventory. The acquisitions included extensive operating infrastructure and they are located on all season access lands primarily in the Bantry, Slave Lake (Mitsue), Wainwright and Jenner areas of Alberta. See "*Statement of Oil and Gas Data – Other Oil and Natural Gas Information – Principal Oil and Natural Gas Properties*".

Specialized Skill and Knowledge

We employ individuals with various professional skills in the course of pursuing our business plan. In addition, various specialized consultants are available to assist us in areas where we feel we don't need full time employees. These professional skills include, but are not limited to, geology, geophysics, engineering, financial and business skills, which are widely available in the industry. Drawing on significant experience in the oil and natural gas business, we believe our management team has a demonstrated track record of bringing together all of the key components to a successful exploration and production company: strong technical skills; expertise in planning and financial controls; ability to execute on business development opportunities; capital markets expertise; and an entrepreneurial spirit that allows us to effectively identify, evaluate and execute on value added initiatives.

Competitive Conditions

The oil and natural gas industry is intensely competitive and we are required to compete with a substantial number of other entities which may have greater technical or financial resources. With the maturing nature of the Western Canadian Sedimentary Basin, the access to new prospects is becoming more and more competitive and complex. We believe that we have a strong competitive position in the areas in which we operate, see "*Statement of Reserves Data and Other Oil and Natural Gas Information – Principal Oil and Natural Gas Properties*".

We attempt to enhance our competitive position by operating in areas where we believe our technical personnel are able to reduce some of the risks associated with exploration, production and marketing because they are familiar with the areas of operation. We believe that we will be able to explore for and develop new production and reserves with the objective of increasing our cash flow and reserve base. See "*Risk Factors – Competition*".

Cycles

Our business is generally not cyclical. However our operational results and financial condition are dependent on prices received for oil and natural gas production. Oil and natural gas prices have fluctuated dramatically during recent years and were on a decline in 2014 and 2015. Oil and natural gas prices are determined by a number of factors, including global and local supply and demand factors, weather, general economic conditions as well as conditions in other oil and natural gas producing and consuming regions. See "*Risk Factors – Prices, Markets and Marketing*".

In addition, the exploration for and the development of crude oil and natural gas reserves is dependent on access to areas where drilling is to be conducted. Seasonal weather variations, including "freeze up" and "break up", affect access in certain circumstances. Consequently, during periods when weather which makes the ground unstable, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. See "*Risk Factors – Seasonality*".

Environmental Protection

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation. Compliance with such legislation may require significant expenditures or result in operational restrictions. Breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage and the imposition of material fines and penalties, all of which might have a significant negative impact on our earnings and our overall competitiveness. For a description of the financial and operational effects of environmental protection requirements on our capital expenditures, earnings and competitive position, see: "*Industry Conditions – Environmental Regulation*" and "*Risk Factors*".

Employees

As at December 31, 2016, we had 46 full-time employees located at our head office and 78 full-time employees located in the field.

Environmental, Health and Safety Policies

We promote safety and environmental awareness and protection through the implementation and communication of our environmental management and employee occupational health and safety programs, policies and procedures. Committee structures are established in our operations which are designed to allow for employee participation and development of policies and programs which provide employees with job orientation, training, instruction and supervision to assist them in conducting their activities in an environmentally responsible and safe manner.

We develop emergency response teams and preparedness plans in conjunction with local authorities, emergency services and the communities in which we operate in order to effectively respond to an environmental incident should it arise. Environmental assessments are undertaken for new projects or when acquiring new properties or facilities in order to identify, assess and minimize environmental risks and operational exposures. We conduct audits of our operations to confirm compliance with internal standards and to stimulate improvement in practices where needed. Documentation is maintained to support internal accountability and measure operational performance against recognized industry indicators to assist us in achieving the objectives of the described policies and programs.

We also face environmental, health and safety risks in the normal course of our operations due to the handling and storage of hazardous substances. Our environmental and occupational health and safety management systems are designed to manage such risks in our business and allow action to be taken to mitigate the extent of any environmental, health or safety impacts from such operations. A key aspect of these systems is the performance of annual environmental and occupational health and safety audits.

STATEMENT OF RESERVES DATA AND OTHER OIL AND NATURAL GAS INFORMATION

The statement of reserves data and other oil and natural gas information set forth below is dated March 6, 2017 with respect to the Sproule Report and March 8, 2017 with respect to the GLJ Report. The statement is effective as of December 31, 2016. The Report of Management And Directors On Oil and Gas Disclosure in Form 51-101F3 and the Report on Reserves Data By Independent Qualified Reserves Evaluators in Form 51-101F2 are attached as Appendices A and B, respectively, to this Annual Information Form.

Disclosure of Reserves Data

The reserves data set forth below is based upon evaluations by Sproule and GLJ with an effective date of December 31, 2016 as contained in the Sproule Report and the GLJ Report. The reserves data summarizes our crude oil, natural gas liquids and natural gas reserves and the net present value of future net revenue for these reserves using forecast prices and costs, not including the impact of any price risk management activities. The Reports have been prepared in accordance with the standards contained in the COGE Handbook and the reserve definitions contained in NI 51-101 and CSA 51-324. We engaged Sproule to provide an evaluation of approximately 35 percent of our proved and proved plus probable reserves and no attempt was made to evaluate possible reserves. We also engaged GLJ to provide an evaluation of approximately 65 percent of our proved and proved plus probable reserves and no attempt was made to evaluate possible reserves. GLJ prepared the consolidation of the two Reports. All of our reserves are in Canada.

We determined the future net revenue and net present value of future net revenue after income taxes by utilizing the before income tax future net revenue from the Reports and our estimate of income tax. Our estimates of the after income tax value of future net revenue have been prepared based on before income tax reserves information and include assumptions and estimates of our tax pools and the sequences of claims and rates of claim thereon. The values shown may not be representative of future income tax obligations, applicable tax horizon or after tax valuation. The after tax net present value of our oil and gas properties reflects the tax burden of our properties on a stand-alone basis. It does not provide an estimate of our value as a business entity, which may be significantly different. Our financial statements for the year ended December 31, 2016 should be consulted for additional information regarding our future income taxes.

Future net revenue is a forecast of revenue, estimated using forecast prices and costs arising from the anticipated development and production of resources, net of associated royalties, operating costs, development costs and abandonment and reclamation costs. Abandonment and reclamation costs include the costs to reclaim all our wells, gas plants, batteries and other facilities. The estimated future net revenue contained in the following tables does not necessarily represent the fair market value of our reserves. There is no assurance that the forecast price and cost assumptions contained in the Reports will be attained and variations could be material. Other assumptions and qualifications relating to costs and other matters are summarized in the notes to or following the tables below. Readers should review the definitions and information contained in "*Definitions and Notes to Reserves Data Tables*" below in conjunction with the following tables and notes. The recovery and reserve estimates on our properties described herein are estimates only. The actual reserves on our properties may be greater or less than those calculated. See "*Risk Factors*".

Reserves Data (Forecast Prices and Costs)

SUMMARY OF OIL AND NATURAL GAS RESERVES
AS OF DECEMBER 31, 2016
FORECAST PRICES AND COSTS

	RESERVES (1)							
	LIGHT AND MEDIUM CRUDE OIL		HEAVY CRUDE OIL		CONVENTIONAL NATURAL GAS (2)		NATURAL GAS LIQUIDS	
RESERVES CATEGORY	Gross (Mbbls)	Net (Mbbls)	Gross (Mbbls)	Net (Mbbls)	Gross (MMcf)	Net (MMcf)	Gross (Mbbls)	Net (Mbbls)
PROVED:								
Developed Producing	16,432	14,330	23,353	21,174	25,876	22,858	1,320	1,001
Developed Non-Producing	583	519	367	339	4,399	3,630	536	344
Undeveloped	656	542	928	707	1,123	889	45	40
TOTAL PROVED	17,671	15,391	24,647	22,220	31,398	27,377	1,901	1,384
PROBABLE	6,883	5,725	8,451	7,305	11,762	10,023	729	558
TOTAL PROVED PLUS PROBABLE	24,554	21,116	33,099	29,525	43,159	37,399	2,630	1,943

Notes:

(1) Excludes 66 Mboe of proved plus probable royalty interest reserves.
(2) Includes solution gas.

SUMMARY OF NET PRESENT VALUE OF FUTURE NET REVENUE AS OF DECEMBER 31, 2016
BEFORE INCOME TAXES DISCOUNTED AT (%/year)

RESERVES CATEGORY	0% ($000s)	5% ($000s)	10% ($000s)	15% ($000s)	20% ($000s)	Unit Value Before Income Tax Discounted at 10% per Year $/Boe (1)
PROVED:						
Developed Producing	700,417	770,616	653,138	551,343	475,374	16.20
Developed Non-Producing	62,133	33,483	22,029	16,396	13,082	12.19
Undeveloped	26,019	19,812	15,108	11,547	8,820	10.52
TOTAL PROVED	788,568	823,911	690,275	579,286	497,277	15.85
PROBABLE	564,422	278,874	169,493	116,690	86,805	11.11
TOTAL PROVED PLUS PROBABLE	1,352,990	1,102,785	859,768	695,976	584,082	14.62

Note:

(1) Based on net reserves.

SUMMARY OF NET PRESENT VALUE OF FUTURE NET REVENUE AS OF DECEMBER 31, 2016
AFTER INCOME TAXES DISCOUNTED AT (%/year)

RESERVES CATEGORY	0% ($000s)	5% ($000s)	10% ($000s)	15% ($000s)	20% ($000s)
PROVED:					
Developed Producing	677,723	758,839	646,768	547,770	473,304
Developed Non-Producing	50,892	27,346	18,437	14,189	11,677
Undeveloped	18,930	15,118	11,955	9,396	7,330
TOTAL PROVED	747,544	801,303	677,160	571,355	492,312
PROBABLE	441,763	212,259	129,334	90,599	68,924
TOTAL PROVED PLUS PROBABLE	1,189,308	1,013,562	806,494	661,954	561,235

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
AS OF DECEMBER 31, 2016
FORECAST PRICES AND COSTS

RESERVES CATEGORY	REVENUE [1] ($000s)	ROYALTIES [2] ($000s)	OPERATING COSTS ($000s)	DEVELOPMENT COSTS ($000s)	ABANDONMENT AND RECLAMATION COSTS [3] ($000s)	FUTURE NET REVENUE BEFORE FUTURE INCOME TAX EXPENSES ($000s)	FUTURE INCOME TAX EXPENSES ($000s)	FUTURE NET REVENUE AFTER FUTURE INCOME TAX EXPENSES ($000s)
Total Proved	3,441,757	407,572	1,638,073	34,166	573,378	788,568	41,024	747,544
Total Proved plus Probable	5,010,083	646,313	2,370,553	64,928	575,299	1,352,990	163,682	1,189,308

Notes:

(1) Total revenue includes company revenue before royalties and includes other income.
(2) Royalties include Crown, freehold and overriding royalties, freehold mineral tax and Saskatchewan Resource Surcharge.
(3) Represents abandonment and reclamation costs with respect to all our non-producing and producing wells (including wells to which no reserves have been assigned), gas plants, batteries and other facilities deducted in the consolidation of the Reports. See "*Significant Factors or Uncertainties Affecting Reserves Data – Additional Information concerning Abandonment and Reclamation Costs*".

FUTURE NET REVENUE
BY PRODUCT TYPE
AS OF DECEMBER 31, 2016
FORECAST PRICES AND COSTS

RESERVES CATEGORY	PRODUCT TYPE [1]	FUTURE NET REVENUE BEFORE FUTURE INCOME TAX EXPENSES (discounted at 10%/year) ($000s)	UNIT VALUE [4] ($/Boe)
Proved	Light and Medium Crude Oil [2]	364,384	16.58
	Heavy Crude Oil [2]	324,194	15.22
	Conventional Natural Gas [3]	1,697	6.01
	Total	690,275	15.85
Proved plus Probable	Light and Medium Crude Oil [2]	460,602	15.43
	Heavy Crude Oil [2]	397,168	13.87
	Conventional Natural Gas [3]	1,998	5.81
	Total	859,768	14.62

Notes:

(1) Other company revenue and costs not related to a specific product type have been allocated proportionately to product types listed.
(2) Including solution gas and other by-products.
(3) Including by-products but excluding solution gas.
(4) Unit values are based on net reserves.

Definitions and Notes to Reserves Data Tables

In the tables set forth above in "*Reserves Data (Forecast Prices and Costs)*" and elsewhere in this Annual Information Form the following definitions and other notes are applicable:

1. **gross** means:

   (a) in relation to our interest in production and reserves, our working interest (operating and non-operating) share before deduction of royalties and without including any of our royalty interests;

   (b) in relation to wells, the total number of wells in which we have an interest; and

   (c) in relation to properties, the total area of properties in which we have an interest.

2. **net** means:

   (a) in relation to our interest in production and reserves, our interest (operating and non-operating) share after deduction of royalty obligations, plus our royalty interest in production or reserves;

   (b) in relation to wells, the number of wells obtained by aggregating our working interest in each of our gross wells; and

   (c) in relation to our interest in a property, the total area in which we have an interest multiplied by our working interest.

3. Definitions used for reserve categories are as follows:

   Reserve Categories

   Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on:

   (a) analysis of drilling, geological, geophysical and engineering data;

   (b) the use of established technology; and

   (c) specified economic conditions (see the discussion of "Economic Assumptions" below).

   Reserves are classified according to the degree of certainty associated with the estimates.

   (a) Proved reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

   (b) Probable reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

4. **economic assumptions** are the forecast prices and costs used in the estimate.

   Development and Production Status

   Each of the reserve categories (proved and probable) may be divided into developed and undeveloped categories:

(a) Developed reserves are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for example, when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.

(i) Developed producing reserves are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

(ii) Developed non-producing reserves are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.

(b) Undeveloped reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable) to which they are assigned.

Levels of Certainty for Reported Reserves

The qualitative certainty levels referred to in the definitions above are applicable to individual reserve entities (which refers to the lowest level at which reserves calculations are performed) and to reported reserves (which refers to the highest level sum of individual entity estimates for which reserves are presented). Reported reserves should target the following levels of certainty under a specific set of economic conditions:

(a) at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves; and

(b) at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves.

A qualitative measure of the certainty levels pertaining to estimates prepared for the various reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, the majority of reserves estimates will be prepared using deterministic methods that do not provide a mathematically derived quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

5. **exploratory well** means a well that is not a development well, a service well or a stratigraphic test well.

6. **development costs** mean costs incurred to obtain access to our reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas from our reserves. More specifically, development costs, including applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(a) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground draining, road building and relocating public roads, gas lines and power lines, pumping equipment and wellhead assembly to the extent necessary in developing the reserves;

(b) drill and equip development wells, development type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and wellhead assembly;

(c) acquire, construct and install production facilities such as flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and

(d) provide improved recovery systems.

7. **development well** means a well drilled inside the established limits of an oil and gas reservoir, or in close proximity to the edge of the reservoir, to the depth of a stratigraphic horizon known to be productive.

8. **exploration costs** mean costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects that may contain oil and gas reserves, including costs of drilling exploratory wells and exploratory type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property and after acquiring the property. Exploration costs, which include applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(a) costs of topographical, geochemical, geological and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews and others conducting those studies;

(b) costs of carrying and retaining unproved properties, such as delay rentals, taxes (other than income and capital taxes) on properties, legal costs for title defence and the maintenance of land and lease records;

(c) dry hole contributions and bottom hole contributions;

(d) costs of drilling and equipping exploratory wells; and

(e) costs of drilling exploratory type stratigraphic test wells.

9. **service well** means a well drilled or completed for the purpose of supporting production in an existing field. Wells in this class are drilled for the following specific purposes: gas injection (natural gas, propane, butane or fuel gas), water injection, steam injection, air injection, salt water disposal, water supply for injection, observation or injection for combustion.

10. **forecast prices and costs**

These are prices and costs that are:

(a) generally acceptable as being a reasonable outlook of the future; and

(b) if and only to the extent that, there are fixed or presently determinable future prices or costs to which we are legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in paragraph (a).

11. Numbers may not add due to rounding.

12. The estimates of future net revenue presented in the tables above do not represent fair market value.

13. We do not have any synthetic oil or other products from non-conventional oil and gas activities.

Pricing Assumptions

The forecast cost and price assumptions in this Annual Information Form assume primarily increases in wellhead selling prices and take into account inflation with respect to future operating and capital costs. Crude oil and natural gas benchmark reference pricing, inflation and exchange rates utilized in the Reports were as follows:

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
FORECAST PRICES AND COSTS
AS AT DECEMBER 31, 2016

	OIL				NATURAL GAS	NATURAL GAS LIQUIDS			
Year	**WTI Cushing Oklahoma ($US/Bbl)**	**Canadian Light Sweet 40° API ($Bbl)**	**Western Canada Select 20.5 API ($Bbl)**	**Hardisty Heavy 12° API ($Bbl)**	**AECO Gas Price ($MMbtu)**	**Edmonton Propane ($/Bbl)**	**Edmonton Butane ($/Bbl)**	**Inflation Rates %/Year (1)**	**Exchange Rate ($US/$) (2)**
Forecast									
2017	55.00	65.58	53.12	48.53	3.44	22.74	47.60	0.0	0.78
2018	65.00	74.51	61.85	56.63	3.27	28.04	55.49	2.0	0.82
2019	70.00	78.24	64.94	59.46	3.22	30.64	57.65	2.0	0.85
2020	71.40	80.64	66.93	61.29	3.91	32.27	58.80	2.0	0.85
2021	72.83	82.25	68.27	62.51	4.00	33.95	59.98	2.0	0.85
2022	74.28	83.90	69.64	63.76	4.10	35.68	61.18	2.0	0.85
2023	75.77	85.58	71.03	65.04	4.19	37.46	62.40	2.0	0.85
2024	77.29	87.29	72.45	66.34	4.29	39.30	63.65	2.0	0.85
2025	78.83	89.03	73.90	67.67	4.40	41.19	64.92	2.0	0.85
2026	80.41	90.81	75.38	69.02	4.50	43.13	66.22	2.0	0.85
2027	82.02	92.63	76.88	70.40	4.61	45.14	67.54	2.0	0.85
Thereafter			Escalation Rate of 2.0%						

Notes:

(1) Inflation rate for operating costs.
(2) Exchange rate used to generate the benchmark reference prices in this table.

Weighted average historical prices we realized for the year ended December 31, 2016, excluding price risk management activities, were $45.02/Bbl for light and medium crude oil, $36.00 for heavy crude oil, $2.32/Mcf for natural gas and $16.01/Bbl for NGLs.

Reserves Reconciliation

RECONCILIATION OF
GROSS RESERVES
BY PRINCIPAL PRODUCT TYPE
FORECAST PRICES AND COSTS

	LIGHT AND MEDIUM CRUDE OIL			HEAVY CRUDE OIL		
	Gross Proved (Mbbls)	Gross Probable (Mbbls)	Gross Proved Plus Probable (Mbbls)	Gross Proved (Mbbls)	Gross Probable (Mbbls)	Gross Proved Plus Probable (Mbbls)
December 31, 2015	15,978	5,093	21,070	22,575	8,525	31,100
Product Type Change [(1)]	1,522	967	2,489	(1,522)	(967)	(2,489)
Adjusted December 31, 2015	17,500	6,059	23,559	21,053	7,558	28,611
Discoveries	-	-	-	-	-	-
Extensions and Improved Recovery	1,127	682	1,809	478	441	919
Technical Revisions	1,545	258	1,804	3,901	99	4,000
Acquisitions [(2) (3)]	161	47	209	1,804	482	2,286
Dispositions	-	-	-	-	-	-
Economic Factors	(392)	(164)	(556)	(305)	(129)	(434)
Production	(2,271)	-	(2,271)	(2,284)	-	(2,284)
December 31, 2016	17,671	6,883	24,554	24,647	8,451	33,099

	CONVENTIONAL NATURAL GAS			NATURAL GAS LIQUIDS		
	Gross Proved (MMcf)	Gross Probable (MMcf)	Gross Proved Plus Probable (MMcf)	Gross Proved (Mbbls)	Gross Probable (Mbbls)	Gross Proved Plus Probable (Mbbls)
December 31, 2015	25,209	8,550	33,759	1,237	492	1,729
Discoveries	-	-	-	-	-	-
Extensions and Improved Recovery	1,936	865	2,801	54	86	141
Technical Revisions	8,516	2,312	10,828	723	153	876
Acquisitions	661	225	886	5	2	7
Dispositions	-	-	-	-	-	-
Economic Factors	(879)	(190)	(1,069)	(7)	(4)	(10)
Production	(4,044)	-	(4,044)	(111)	-	(111)
December 31, 2016	31,398	11,762	43,159	1,901	729	2,630

Notes:

(1) Product type change based on clarification on oil quality.
(2) The acquisition amount is the estimate of reserves at December 31, 2016 plus any production since the acquisition dates.
(3) Excludes 66 Mboe of proved plus probable royalty interest reserves.

Additional Information Relating to Reserves Data

Undeveloped Reserves

Undeveloped reserves are attributed by Sproule and GLJ in accordance with standards and procedures contained in the COGE Handbook. Proved undeveloped reserves are those reserves that can be estimated with a high degree of certainty and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. Probable undeveloped reserves are those reserves that are less certain to be recovered than proved reserves and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production.

In some cases, it will take longer than two years to develop these reserves. There are a number of factors that could result in delayed or cancelled development, including the following: (i) changing economic conditions (due to pricing, operating and capital expenditure fluctuations); (ii) changing technical conditions (including production anomalies, such as water breakthrough or accelerated depletion); (iii) multi-zone developments (for instance, a prospective formation completion may be delayed until the initial completion is no longer economic); (iv) a larger development program may need to be spread out over several years to optimize capital allocation and facility utilization; and (v) surface access issues (including those relating to land owners, weather conditions and regulatory approvals). For more information, see "*Risk Factors*".

Proved Undeveloped Reserves

The following table discloses, for each product type, the volumes of proved undeveloped reserves that were attributed in each of the most recent three financial years.

Year	Light and Medium Crude Oil (Mbbls)		Heavy Crude Oil (Mbbls)		Conventional Natural Gas (MMcf)		Natural Gas Liquids (Mbbls)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
2014	398	1,356	299	299	192	807	3	13
2015	-	-	801	1,251	385	585	6	8
2016	510	656	361	928	627	1,123	39	45

The majority of our proved undeveloped reserves evaluated in the Reports are attributable to our Bantry and Mitsue properties. Proved undeveloped reserves have been assigned in areas where the reserves can be estimated with a high degree of certainty. In most instances, proved undeveloped reserves will be assigned on lands immediately offsetting existing producing wells within the same accumulation or pool. Sproule and GLJ have collectively assigned 1.8 MMBoe of proved undeveloped reserves in the Reports with $28 million of associated undiscounted capital, of which $26.3 million is forecast to be spent in the first two years.

Probable Undeveloped Reserves

The following table discloses, for each product type, the volumes of probable undeveloped reserves that were first attributed in each of the three most recent financial years.

Year	Light and Medium Crude Oil (Mbbls)		Heavy Crude Oil (Mbbls)		Conventional Natural Gas (MMcf)		Natural Gas Liquids (Mbbls)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
2014	746	989	189	189	391	580	6	9
2015	-	-	730	1,421	362	684	5	10
2016	839	1,074	400	1,446	1,052	2,006	89	101

Probable undeveloped reserves have been assigned in areas where the reserves can be estimated with less certainty. It is equally likely that that the actual remaining quantities recovered will be greater or less than the proved plus probable reserves. In most instances probable undeveloped reserves have been assigned on lands in the area with existing producing wells but there is some uncertainty as to whether they are directly analogous to the producing accumulation or pool. Sproule and GLJ have collectively assigned 3.0 MMBoe of probable undeveloped reserves in the Reports with $29.4 million of associated undiscounted capital, of which $11.8 million is forecast to be spent in the first two years.

Significant Factors or Uncertainties Affecting Reserves Data

Changes in future commodity prices relative to the forecasts provided under "*Pricing Assumptions*" above could have a negative impact on our reserves and in particular the development of our undeveloped reserves unless future development costs are adjusted in parallel. Other than the foregoing and the factors disclosed or described in the tables above, we expect to fund the development costs of our reserves through a combination of internally generated cash flow, debt and equity issuances. There can be no guarantee that funds will be available or that our Board of Directors will allocate funding to develop all of the reserves attributed in the Reports. Failure to develop those reserves could have a negative impact on our future cash flow. Interest or other costs of external funding are not included in our reserves and future net revenue estimates and would reduce reserves and future net revenue to some degree depending upon the funding sources utilized. We do not anticipate that interest or other funding costs would make development of any of our properties uneconomic. We do not anticipate any significant economic factors or significant uncertainties will affect any particular components of our reserves data. However, our reserves can be affected significantly by fluctuations in product pricing, capital expenditures, operating costs, royalty regimes and well performance that are beyond our control. See "*Risk Factors*".

Additional Information Concerning Abandonment and Reclamation Costs

We estimate the costs to abandon and reclaim all our non-producing and producing wells, gas plants, batteries, and other facilities. No estimate of salvage value is netted against the estimated cost. Our model for estimating the amount of future abandonment and reclamation expenditures is done on an individual well and facility level. Each well and facility is assigned an average cost for abandonment and reclamation over its useful life. Timing of expenditures is based on budgets and estimates of such annual activities. Facility reclamation costs are generally scheduled to begin shortly before the end of the reserve life of our associated reserves and continue beyond the reserve life under the assumption that plant/facilities are generally mobile assets with a long useful life.

As at December 31, 2016 we had 3,322 net wells for which we expect to incur abandonment and reclamation costs. The estimates of the future net revenues disclosed in this Annual Information Form were consolidated by GLJ from the two Reports from which $575 million (undiscounted) and $59 million (10% discount) was deducted for abandonment and reclamation costs with respect to all our non-producing and producing wells (including wells to which no reserves have been assigned), gas plants, batteries and other facilities. The individual Reports did not deduct abandonment and reclamation costs from the future net revenues disclosed in the Form 51-101F2 which is attached as Appendix B to this Annual Information Form.

Future Development Costs

The following table sets forth development costs deducted in the estimation of our future net revenue attributable to the reserve categories noted below using forecast prices and costs.

	FORECAST PRICES AND COSTS	
Year	**Proved Reserves ($000s)**	**Proved Plus Probable Reserves ($000s)**
2017	13,629	25,061
2018	17,108	18,872
2019	1,873	13,825
2020	-	3,820
2021	-	1,793
Remaining	1,556	1,556
Total (Undiscounted)	34,166	64,928

We expect to fund the development costs of our reserves through a combination of internally generated cash flow, debt and equity issuances. There can be no guarantee that funds will be available or that our Board of Directors will allocate funding to develop all of the reserves attributed in the Reports. Failure to develop those reserves could have a negative impact on our future cash flow.

Interest or other costs of external funding are not included in our reserves and future net revenue estimates and would reduce reserves and future net revenue to some degree depending upon the funding sources utilized. We do not anticipate that interest or other funding costs would make development of any of our properties uneconomic.

Other Oil and Natural Gas Information

Principal Oil and Natural Gas Properties

The following is a description of our principal oil and natural gas properties on production or under development as at December 31, 2016. Information in respect of current production is average production, net to our working interest, except where otherwise indicated. We operate approximately 90% of our production. The estimates of reserves for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties due to the effects of aggregation.

Bantry, Alberta

Bantry is located near Brooks, Alberta. Bantry currently produces approximately 4,765 Boe/d with 78% of the production being crude oil. The property is characterized by a low base production decline of 9% per year.

The majority of the crude oil production is from the Lower Mannville Ellerslie formation. The primary controlling factor for the deposition of the Ellerslie sandstone was the pre-cretaceous unconformity surface. The Mannville "A" Ellerslie sandstone has been deposited within a valley on the unconformity surface during a major transgressive sequence. The trapping mechanism for the pool is stratigraphic in nature and as porosity diminishes toward the up dip edge of the pool. The pools have been developed to date with vertical production and injection wells. The majority of the producing oil reservoirs on the lands are maintained by waterflood and/or water disposal. We have identified areas where we can optimize the existing waterflood to enhance oil recoveries.

In 2016, we continued our successful drilling program in Bantry, drilling 9 net Glauconite horizontal wells. Average well results in 2016 exceeded the average total proved plus probable undeveloped reserves evaluated in our 2015 independent reserves report. Production from these wells offset the low production decline of our oil and gas properties and enabled us to maintain our total average corporate production at approximately 14,600 Boe/d in 2016. Decreases in drilling and completion costs resulted in realized capital efficiencies of $13,900/Boe/d in 2016 for our Bantry drilling program, a reduction of 5% compared to 2015.

We plan to drill 8 (7.75 net) horizontal wells in Bantry in 2017.

Slave Lake (Mitsue), Alberta

Our Slave Lake (Mitsue) property is located approximately 280 kilometres north of Edmonton, Alberta. This property currently produces approximately 3,600 Boe/d (80% light crude oil and NGLs) with a low decline production profile. The majority of the production is from the Mitsue Gilwood Sand Units. These wells are pipeline connected to a main oil battery where the oil and natural gas are connected to sales pipelines. We operate the wells and facilities within the Mitsue Gilwood Sand Units.

The Mitsue Gilwood A Pool was discovered in 1964 and produces from the Gilwood sandstone of the Middle Devonian Watt Mountain formation. The Gilwood Sandstone is stratigraphically contained within the Watt Mountain Shale and the reservoir is approximately 120,000 acres in size. It is one of the largest sandstone reservoirs in Canada still drilled on less than a quarter section spacing. In 2016, we began drilling our first horizontal well at Mitsue. We plan to drill 4 (2.58 net) horizontal wells in this area in 2017.

Wainwright, Alberta

Wainwright is located 195 kilometres southeast of Edmonton, Alberta. The Wainwright properties (including the Chauvin, Forestburg and Hayter areas) currently produce approximately 5,230 Boe/d of predominantly heavy crude oil and associated natural gas. Crude oil makes up 98% of the production and 96% of the reserves are proved plus probable producing reserves. The base production in Wainwright has a low production decline of 8% per year. The majority of production is pipeline connected.

The Wainwright properties primarily produce from the Middle Mannville Sparky formation which is a sandstone shale sequence deposited in a shallow-water progradational delta environment. The productive interval of the Sparky formation consists of coarsening-upward sequences with sandstones both fine and coarse grained. The Sparky sandstone responds favorably to enhanced recovery. Our producing reservoirs are currently water injected for enhanced waterflood recovery.

Further upside in this area exists in the exploitation of the Waseca sandstone by drilling horizontally into this channel facies at the base of the Upper Mannville. There are also infill horizontal drilling prospects in the Cummings formation in the Hayter area where we intend to drill 1 (1 net) well in 2017.

Jenner, Alberta

The Jenner property is located 60 kilometers northwest of Medicine Hat, Alberta. This property currently produces 1,025 Boe/d of heavy crude oil and associated natural gas from the Mannville formation. Our production is pipeline connected and we have access to transportation by rail.

The Jenner properties primarily produce from the Upper Mannville Glauconitic sandstone which was deposited in an estuarine environment. The sands were originally believed to be Glauconite Channel sands likely due to thickness of the deposit of up to 50 meters. Recent geological studies indicate these are massive barrier beach deposits oriented in a north south direction for distances of up to 50 kilometers. These Glauconite age beach sands are also observed to repeat themselves as the ancient sea transgressed in an easterly direction. The reservoir sand exhibits a coarsening upward sequence typical of an estuarine beach deposit. Tidal channels passing transversally through these beaches helped to define these pools that exist today in the Jenner area. Subsequent to the sand deposition, the estuary was flooded as sea level rose and filled with fine grained non porous silty sand which provides the trapping mechanism on the top and flanks of the reservoir.

Oil And Natural Gas Wells

The following table sets forth the number and status of wells in which we had a working interest as at December 31, 2016.

	OIL WELLS				NATURAL GAS WELLS			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	1,686	1,380	1,094	865	158	92	229	151
Saskatchewan	2	2	14	12	-	-	1	1
Total	1,688	1,382	1,108	877	158	92	230	152

Note:

(1) Does not include 938 gross (819 net) service wells.

Of the non-producing wells, 57 gross (46.9 net) were capable of production and had reserves assigned to them. As of the date of this Annual Information Form these wells have had production within the last 24 months and we have capital allocated to restore production from these wells within the next 24 months.

Developed and Undeveloped Lands

The following table sets out our developed and undeveloped land holdings as at December 31, 2016.

	UNDEVELOPED ACRES		DEVELOPED ACRES		TOTAL ACRES (1)	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Alberta	290,345	158,489	401,412	269,506	691,757	427,995
Saskatchewan	454	234	1,256	1,128	1,710	1,362
Total	290,799	158,723	402,668	270,634	693,467	429,357

Notes:

(1) Includes our interest in approximately 11,840 gross (10,176 net) acres of unproved property land holdings.

(2) Rights to explore, develop and exploit 11,272 net acres of our land holdings could expire by December 31, 2017 if not continued. We have no material work commitments on these properties.

(3) When determining gross and net acreage for two or more leases covering the same lands but different rights, the acreage is reported only once. Where there are multiple discontinuous rights in a single lease, the acreage is reported only once.

Significant Factors or Uncertainties Relevant to Properties With no Attributed Reserves

Our asset base focuses on sustainable low decline production with little to no capital allocated to the acquisition, exploration or development of our properties with no attributed reserves. We do not anticipate any significant economic factors or significant uncertainties will affect any particular components of our properties with no attributed reserves. However, our decision to develop our properties with no attributed reserves can be affected significantly by fluctuations in product pricing, capital expenditures, operating costs and royalty regimes, all of which are beyond our control. There are no unusually significant abandonment and reclamation costs with our properties with no attributed reserves. See "*Significant Factors or Uncertainties Affecting Reserves Data – Additional Information Concerning Abandonment and Reclamation Costs*" and "*Risk Factors*".

Forward Contracts

Our operational results and financial condition are dependent upon the prices received for oil and natural gas production. Oil and natural gas prices have fluctuated widely in recent years and have recently experienced a sharp decline. Such prices are primarily determined by economic and political factors, supply and demand factors, as well as weather and conditions in other oil and natural gas regions of the world. Any upward or downward movement in oil and natural gas prices could have an effect on our financial condition.

We have implemented a hedging policy using, amongst others, collars and fixed price swaps which allows us to hedge our gross oil, NGLs and natural gas forward production profile of 3 years, of up to 75% of average forward 12 months production and up to 50% and 30% of the following 12 and 24 months, respectively. These hedging activities could expose us to losses or gains. See "*Risk Factors – Hedging*".

For further information, see note 15 to our financial statements for the year ended December 31, 2016.

Tax Horizon

Based on the current tax regime, our tax pools, expected funds from operating activities and capital expenditures, we do not expect income taxes to become payable until 2020.

Costs Incurred

The following table summarizes the costs incurred related to our activities for the year ended December 31, 2016.

Expenditure	**Year Ended December 31, 2016 ($000s)**
Property acquisition costs – Unproved properties (1)	278
Property acquisition costs – Proved properties (2)	34,235
Exploration costs (3)	3,609
Development costs (4)	37,474
Total	75,596

Notes:

(1) Cost of land acquired and non-producing lease rentals on those lands.
(2) Net of dispositions.
(3) Geological and geophysical capital expenditures and drilling costs for exploration wells.
(4) Development costs include development drilling costs and equipping, tie-in and facility costs for all wells.
(5) Expenditures do not include capitalized general and administrative costs and related share based compensation or non-cash expenditures for the abandonment and decommissioning obligation. See "*Significant Factors or Uncertainties Affecting Reserves Data - Additional Information Concerning Abandonment and Reclamation Costs*".

Exploration and Development Activities

The following table sets forth the gross and net development wells in which we participated during the year ended December 31, 2016.

	Development		**Exploratory**	
	Gross	**Net**	**Gross**	**Net**
Conventional Natural Gas	-	-	-	-
Light and Medium Crude Oil	9.0	9.0	-	-
Dry	-	-	2.0	2.0
Service	-	-	-	-
Total	9.0	9.0	2.0	2.0

In 2017, we expect to drill a minimum of 11.3 net oil wells in Alberta. We are committed to incur $0.8 million of qualifying Canadian Exploration Expense prior to December 31, 2017.

Production Estimates

The following table sets out the volumes of our working interest production estimated for the year ended December 31, 2017, which is reflected in the estimate of future net revenue disclosed in the forecast price tables contained above under the subheading "*Disclosure of Reserves Data*".

	Light and Medium Crude Oil (Bbls/d)	**Heavy Crude Oil (Bbls/d)**	**Conventional Natural Gas (Mcf/d)**	**Natural Gas Liquids (Bbls/d)**	**BOE (Boe/d)**
Proved	5,779	6,798	10,519	413	14,743
Probable	374	413	575	31	914
Proved plus Probable	6,153	7,211	11,094	444	15,657

Note:

(1) No one field represents more than 20% of our forecast production.

Finding and Development Costs

The following table summarizes our finding, development and acquisition costs and finding and development costs for the periods indicated.

(1)(2)(3)(4)	2016	Three Year Average (5)
Total capital expenditures including net acquisitions ($000s)	75,595	750,668
Exploration and development capital expenditures ($000s)	41,360	114,514
Acquisition capital expenditures ($000s)	34,235	636,154
Finding, Development and Acquisition Cost (FD&A)		
Proved Reserves		
Change in future development costs ($000s)	7,655	14,064
Reserve additions (Mboe)	10,802	48,197
FD&A ($/Boe)	7.71	15.87
Proved plus Probable Reserves		
Change in future development costs ($000s)	20,886	26,584
Reserve additions (Mboe)	13,291	58,805
FD&A ($/Boe)	7.26	13.22
Finding and Development Cost (F&D)		
Proved Reserves		
Change in future development costs ($000s)	9,574	21,899
Reserve additions (Mboe)	8,721	14,547
F&D ($/Boe)	5.59	9.38
Proved plus Probable Reserves		
Change in future development costs ($000s)	24,347	34,168
Reserve additions (Mboe)	10,641	14,740
F&D ($/Boe)	5.80	10.09

Notes:

(1) We have presented both F&D and FD&A costs. Acquisitions and dispositions have a significant impact on our ongoing reserve replacement costs and disclosing only F&D could result in an inaccurate portrayal of our cost structure.

(2) The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development capital expenditures generally will not reflect total F&D related to reserves additions for that year.

(3) F&D and FD&A excludes capital related to fair value adjustments on acquisitions, capitalized overhead and non-cash expenditures for the decommissioning obligation and capitalized share-based compensation.

(4) F&D and FD&A are oil and gas metrics, see "*Oil and Gas Advisory*".

(5) The three year average represents the weighted average of F&D and FD&A using the three year totals of the inputs used to calculate the F&D and FD&A.

Production History

The following table indicates our average daily production for the year ended December 31, 2016.

	Light and Medium Crude Oil (Bbls/d)	Heavy Crude Oil (Bbls/d)	Natural Gas Liquids (Bbls/d)	Conventional Natural Gas (Mcf/d)	BOE (Boe/d)
Bantry(1)	3,168	554	56	5,746	4,735
Wainwright(2)	425	4,720	2	674	5,259
Slave Lake (Mitsue)	2,618	-	249	4,387	3,599
Jenner	13	966	-	235	1,018
Total	6,224	6,240	307	11,042	14,611

Notes:

(1) Includes Duchess, Rosemary and Kinnivie areas.

(2) Includes Chauvin, Forestburg and Hayter areas.

The following tables summarize certain information in respect of our production, product prices received, royalties, operating costs and resulting netback for the periods indicated below:

	Quarter Ended 2016				Year Ended
	Mar. 31	**June 30**	**Sept. 30**	**Dec. 31**	**Dec. 31, 2016**
Average Daily Production (1)					
Light and Medium Crude Oil (Bbls/d)	5,894	6,191	6,512	6,295	6,224
Heavy Crude Oil (Bbls/d)	6,432	6,407	6,145	5,978	6,240
Natural Gas Liquids (Bbls/d)	271	272	370	313	307
Conventional Natural Gas (Mcf/d)	9,886	10,506	11,578	12,178	11,042
Combined (Boe/d)	14,245	14,621	14,957	14,616	14,611
Average Prices Received					
Light and Medium Crude Oil ($/Bbl)	31.95	49.62	43.37	54.37	45.02
Heavy Crude Oil ($/Bbl)	24.31	35.08	43.51	41.69	36.00
Natural Gas Liquids ($/Bbl)	11.87	12.37	17.01	21.53	16.01
Conventional Natural Gas ($/Mcf)	1.96	1.48	2.36	3.29	2.32
Combined ($/Boe)	25.78	37.67	39.01	43.67	36.64
Royalties					
Light and Medium Crude Oil ($/Bbl)	4.42	5.88	6.66	7.84	6.24
Heavy Crude Oil ($/Bbl)	3.15	3.75	4.36	4.33	3.89
Natural Gas Liquids ($/Bbl)	6.24	8.14	6.75	8.36	7.36
Conventional Natural Gas ($/Mcf)	0.28	(0.03)	0.16	0.29	0.18
Combined ($/Boe)	3.57	4.26	4.98	5.57	4.61
Operating Costs (2)(3)					
Light and Medium Crude Oil ($/Bbl)	23.85	22.41	22.39	27.00	23.88
Heavy Crude Oil ($/Bbl)	24.10	22.55	22.80	25.63	23.78
Natural Gas Liquids ($/Bbl)	5.56	6.26	5.50	7.02	6.11
Conventional Natural Gas ($/Mcf)	0.93	1.04	0.92	1.17	1.02
Combined ($/Boe)	21.50	20.23	19.96	23.24	21.23
Netback Received					
Light and Medium Crude Oil ($/Bbl)	3.68	21.33	14.32	19.53	14.90
Heavy Crude Oil ($/Bbl)	(2.94)	8.78	16.35	11.73	8.33
Natural Gas Liquids ($/Bbl)	0.07	(2.03)	4.76	6.15	2.54
Conventional Natural Gas ($/Mcf)	0.75	0.47	1.28	1.83	1.12
Combined ($/Boe)	0.71	13.18	14.07	14.86	10.80

Notes:

(1) Before the deduction of royalties.

(2) Operating costs are composed of direct costs incurred to operate both oil and natural gas wells. A number of assumptions are required to allocate these costs between product types.

(3) Operating recoveries associated with operated properties are charged to operating costs and accounted for as a reduction to general and administrative costs.

DESCRIPTION OF OUR CAPITAL STRUCTURE

Share Capital

We are authorized to issue an unlimited number of Common Shares without nominal or par value and an unlimited number of first preferred shares. A description of our share capital is set forth below. For a completed description of our share capital, reference should be made to our Articles, a copy of which has been filed on SEDAR at www.sedar.com.

Common Shares

The Common Shares have the following rights, privileges, restrictions and conditions:

Voting Rights: Holders of Common Shares are entitled to notice of, to attend and to one vote per share held at any meeting of our Shareholders (other than meetings of a class or series of shares other than our Common Shares).

Dividends: Holders of Common Shares are entitled to receive dividends as and when declared by our Board of Directors on the Common Shares as a class, subject to the prior satisfaction of all preferential rights to dividends attached to other classes of shares ranking in priority to the Common Shares in respect of dividends.

Ranking: In the event of any liquidation, dissolution or winding-up of us, whether voluntary or involuntary, or any other distribution of our assets among our Shareholders for the purpose of winding-up our affairs, and subject to prior satisfaction of all preferential rights to return of capital on dissolution attached to all other classes of shares ranking in priority to the Common Shares in respect of return of capital on dissolution, holders of Common Shares are entitled to share rateably, together with the holders of shares of any other class of shares ranking equally with the Common Shares, in respect of a return of capital on dissolution, in such of our assets as are available for distribution.

If our Board of Directors declare a dividend on the Common Shares payable in whole or in part in fully paid and non-assessable Common Shares (the portion of the dividend payable in Common Shares referred to as a "stock dividend"), the following provisions shall apply:

(a) unless otherwise determined by the Board of Directors in respect of a particular stock dividend: (i) the number of Common Shares (which shall include any fractional Common Shares) to be issued in satisfaction of the stock dividend shall be determined by dividing (A) the dollar amount of the particular stock dividend, by (B) the "Average Market Price" of a Common Share on the Toronto Stock Exchange, with the "Average Market Price" calculated by dividing the total value of Common Shares traded on the Toronto Stock Exchange (or if the Common Shares are not traded on the Toronto Stock Exchange, on any other recognized exchange or market on which the Common Shares are traded) by the total volume of Common Shares traded on the Toronto Stock Exchange (or if the Common Shares are not traded on the Toronto Stock Exchange, on any other recognized exchange or market on which the Common Shares are traded) over the five trading day period immediately prior to the payment date of the applicable stock dividend on the Common Shares; and (ii) the value of a Common Share to be issued for the purposes of each stock dividend declared by the Board of Directors shall be deemed to be the Average Market Price of a Common Share;

(b) to the extent that any stock dividend paid on the Common Shares represents one or more whole Common Share payable to a registered holder of Common Shares, such whole Common Shares shall be registered in the name of such holder. Common Shares representing in the aggregate all of the fractions amounting to less than one whole Common Share which might otherwise have been payable to registered holders of Common Shares by reason of such stock dividend shall be issued to our transfer agent as the agent of such registered holders of Common Shares. Our transfer agent shall credit to an account for each such registered holder all fractions of a Common Share amounting to less than one whole share issued by us by way of stock dividends in respect of the

Common Shares registered in the name of such holder. From time to time, when the fractional interests in a Common Share held by our transfer agent for the account of any registered holder of Common Shares are equal to or exceed in the aggregate one additional whole Common Share, the transfer agent shall cause such additional whole Common Share to be registered in the name of such registered holder and thereupon only the excess fractional interest, if any, will continue to be held by the transfer agent for the account of such registered holder. Common Shares held by the transfer agent representing fractional interests shall not be voted;

(c) if at any time we have reason to believe that tax should be withheld and remitted to a taxation authority in respect of any stock dividend paid or payable to a Shareholder in Common Shares, we have the right to sell, or to require our transfer agent in each case as agent of such Shareholder, to sell all or any part of the Common Shares or any fraction thereof so issued to such holder in payment of that stock dividend or one or more subsequent stock dividends through the facilities of the Toronto Stock Exchange or other stock exchange on which the Common Shares are listed for trading, and to cause our transfer agent to remit the cash proceeds from such sale to such taxation authority (rather than such holder) in payment of such tax to be withheld. This right of sale may be exercised by notice given by us to such holder and to us or our transfer agent stating the name of the holder, the number of Common Shares to be sold and the amount of the tax which we have reason to believe should be withheld. Upon receipt of such notice the transfer agent shall, unless a certificate or other evidence of registered ownership for the Common Shares has at the relevant time been issued in the name of the holder, sell the Common Shares as aforementioned and Cardinal or our transfer agent as applicable, shall be deemed for all purposes to be the duly authorized agent of the holder with full authority on behalf of such holder to effect the sale of such Common Shares and deliver the proceeds therefrom to the applicable taxation authority on behalf of us. Any balance of the cash sale proceeds not remitted by us in payment of the tax to be withheld shall be payable to the holder whose Common Shares were so sold by the transfer agent;

(d) if at any time we shall have reason to believe that the payment of a stock dividend to any holder who is resident in or otherwise subject to the laws of a jurisdiction outside Canada might contravene the laws or regulations of such jurisdiction, or could subject us to any penalty thereunder or any legal or regulatory requirements not otherwise applicable to us, we shall have the right to sell, or to require our transfer agent in each case, as agent of such Shareholder, to sell through the facilities of the Toronto Stock Exchange or other stock exchange on which the Common Shares are listed for trading, the Common Shares or any fraction thereof so issued and to cause our transfer agent to pay the cash proceeds from such sale to such holder. The right of sale shall be exercised in the manner provided in subparagraph (c) above except that in the notice there shall be stated, instead of the amount of the tax to be withheld, the nature of the law or regulation which might be contravened or which might subject us to any penalty or legal or regulatory requirement. Upon receipt of the notice, we or our transfer agent shall, unless a certificate or other evidence of registered ownership for the Common Shares has at the relevant time been issued in the name of the holder, sell the Common Shares as aforementioned and we or our transfer agent, as applicable, shall be deemed for all purposes to be the duly authorized agent of the holder with full authority on behalf of such holder to effect the sale of such Common Shares and to deliver the proceeds therefrom to such holder;

(e) upon any registered holder of Common Shares ceasing to be a registered holder of one or more Common Shares, such holder shall be entitled to receive from our transfer agent, and the transfer agent shall pay as soon as practicable to such holder, an amount in cash equal to the proportion of the value of one Common Share that is represented by the fraction less than one whole Common Share at that time held by our transfer agent for the account of such holder and, for the purpose of determining such value, each Common Share shall be deemed to have the value equal to the Average Market Price in respect of the last stock dividend paid by us prior to the date of such payment; and

(f) for the purposes of the foregoing: (i) the calculation of a fraction of a Common Share payable to a Shareholder by way of a stock dividend and the calculation of the Average Market Price shall be computed to six decimal places, and shall be rounded to the nearest sixth decimal place; and (ii) neither us nor our transfer agent shall have any obligation to register any Common Share in the name of a person, to deliver a certificate or other document representing Common Shares registered in the name of a Shareholder or to make a cash payment for fractions of a Common Share, unless all applicable laws and regulations to which we and/or our transfer agent are, or as a result of such action may become, subject, shall have been complied with to their reasonable satisfaction.

First Preferred Shares

Voting Rights: Holders of first preferred shares shall be entitled to receive notice of, to attend and to one vote per first preferred share held at any meeting of the Shareholders (other than meetings of a class or series of shares of Cardinal other than the first preferred shares as such).

Dividends: Holders of first preferred shares shall be entitled to receive if, as and when declared by our Board of Directors out of the monies of our applicable to the payment of dividends, such dividends in any financial year as the Board of Directors in its absolute discretion may by resolution determine, and the directors may, subject to certain restrictions on dividends, declare dividends on any other class of share at different times or at the same time in different amounts than dividends declared on the first preferred shares.

Ranking: In the event of the liquidation, dissolution or winding up of us or other distribution of our assets among Shareholders for the purpose of winding up our affairs, the holders of first preferred shares shall be entitled to receive the redemption value of the first preferred shares per share, together with any accrued and unpaid dividends thereon up to the date of commencement of any such liquidation, dissolution, winding up or other distribution of our assets and to be paid all such money before any money shall be paid or property or assets distributed to the holders of any Common Shares or other shares in our capital ranking junior to the first preferred shares with respect to return of capital. After payment to the holders of the first preferred shares of the amounts so payable to them in accordance, the holders of first preferred shares shall not be entitled to share in any further distribution of our property or assets.

Debentures

The Debentures are issued under and pursuant to the provisions of the Indenture. The following is a summary of the material attributes and characteristics of the Debentures. This summary does not purport to be complete and is subject to and qualified in its entirety by reference to the terms of the Indenture which may be viewed under our profile on SEDAR at www.sedar.com.

General

The Debentures are limited to an aggregate principal amount of $50 million. We may, however, from time to time, without the consent of the holders of any outstanding Debentures, issue debentures in addition to the Debentures outstanding. The Debentures are issued in denominations of $1,000 and integral multiples thereof. The Debentures are dated October 6, 2015 and have a maturity date of December 31, 2020.

The Debentures bear interest from October 6, 2015 at 5.50% per annum, payable semi-annually on June 30 and December 31 in each year computed on the basis of a 365-day year. The first payment occurred on December 31, 2015 and represented accrued interest for the period from October 6, 2015 up to, but excluding, December 31, 2015. Interest on the Debentures is payable in lawful money of Canada.

Conversion Privilege

Each Debenture is convertible at any time at the option of the holder into fully paid and non-assessable Common Shares at any time prior to 5:00 p.m. (Toronto time) on the earliest of: (i) December 31, 2020; (ii) the last Business Day immediately preceding a redemption date; and (iii) the last Business Day immediately preceding the date specified for purchase in a Debenture Offer (as defined herein), in each case, at the conversion price of $10.50 per Debenture, representing a conversion rate of approximately 95.2381 Common Shares per $1,000 principal amount of Debentures, subject to adjustment in accordance with the Indenture. Upon conversion of any Debentures, the holder will be eligible to receive, in addition to the applicable number of Common Shares, accrued and unpaid interest thereon in cash up to, but excluding, the date of conversion.

The Indenture provides for the adjustment of the conversion price in certain events including: (i) the subdivision or consolidation of the outstanding Common Shares; (ii) the issuance of Common Shares or securities convertible into Common Shares by way of stock dividend or otherwise to the holders of all or substantially all of the outstanding Common Shares other than an issue of Common Shares to holders of Common Shares who have elected to receive dividends in the form of Common Shares in lieu of receiving cash dividends not in excess of $0.07 per Common Share per month; (iii) the issuance of options, rights or warrants to all or substantially all the holders of Common Shares entitling them to acquire Common Shares or other securities convertible into Common Shares at less than 95% of the then Current Market Price of the Common Shares; (iv) the distribution to all holders of Common Shares of any securities or assets (other than securities or assets in respect of any event described in (ii), (iii), (v) or (vi)); (v) the payment to all holders of Common Shares in respect of an issuer bid for Common Shares us to the extent that the market value of the payment exceeds the then market price of the Common Shares on the date of expiry of the bid; and (vi) the payment of cash dividends to holders of Common Shares in excess of $0.07 per Common Share per month.

Subject to prior regulatory approval, if required, there will be no adjustment of the conversion price in respect of any event described in (ii), (iii) or (iv) above if, the holders of the Debentures are allowed to participate as though they had converted their Debentures prior to the applicable record date or effective date. We will not be required to make adjustments to the conversion price unless the cumulative effect of such adjustments would change the conversion price by at least 1%. However, any adjustments that are less than 1% of the conversion price will be carried forward and taken into account when determining subsequent adjustments.

In the case of: (i) any reclassification, capital reorganization or change (other than a change resulting only from consolidation or subdivision) of the Common Shares; (ii) our amalgamation, arrangement, consolidation or merger with or into any other entity; (iii) any sale, transfer or other disposition of our properties and assets as, or substantially as, an entirety to any other entity; or (iv) our liquidation, dissolution or winding-up, the terms of the conversion privilege will be adjusted so that each Debenture will, after such reclassification, capital reorganization, change, amalgamation, arrangement, consolidation, merger, sale, transfer, disposition, liquidation, dissolution or winding-up, be exercisable for the kind and amount of our securities or property, or of such continuing, successor or purchaser entity, as the case may be, which the holder thereof would have been entitled to receive as a result of such reclassification, capital reorganization, change, amalgamation, arrangement, consolidation, merger, sale, transfer, disposition, liquidation, dissolution or winding-up if on the effective date thereof it had been the holder of the number of Common Shares into which the Debenture was convertible prior to the effective date thereof.

No fractional Common Shares will be issued upon conversion of the Debentures. In lieu thereof, we will satisfy such fractional interest by a cash payment equal to the relevant fraction of the Current Market Price of a whole Common Share. Upon conversion, we may offer, and the converting holder may agree to the delivery of, cash for all or a portion of the Debentures surrendered in lieu of Common Shares.

Redemption and Purchase

The Debentures are not be redeemable by us before December 31, 2018 except in certain limited circumstances following a Change of Control (as defined herein). See "*Debentures – Repurchase upon a Change of Control*" below. On or after December 31, 2018 and prior to December 31, 2019, the Debentures may be redeemed by us, in whole or in part from time to time, at our option on not more than 60 days and not less than 30 days prior written notice, at a redemption price equal to the principal amount plus accrued and unpaid interest thereon, if any, up to but excluding the date set for redemption, provided that the Current Market Price of the Common Shares on the date on which notice of redemption is given is not less than 125% of the conversion price. On or after December 31, 2019 and prior to December 31, 2020, the Debentures may be redeemed by us, in whole or in part from time to time, on not more than 60 days and not less than 30 days prior written notice, at a redemption price equal to the principal amount thereof plus accrued and unpaid interest thereon.

In the case of redemption of less than all of the Debentures, the Debentures to be redeemed will be selected by Computershare on a *pro rata* basis or in such other manner as Computershare deems equitable, subject to the consent of the Toronto Stock Exchange (or such other recognized exchange on which the Common Shares may be listed).

We will have the right to purchase Debentures for cancellation in the market, by tender or by private contract, at any time, subject to regulatory requirements.

Payment upon Redemption or Maturity

On any date set for redemption or the maturity date of December 31, 2020 as applicable, we will repay the indebtedness represented by the Debentures by paying to Computershare in lawful money of Canada an amount equal to the principal amount of the outstanding Debentures, together with accrued and unpaid interest thereon, if any, up to but excluding the date set for redemption or December 31, 2020. On any date set for redemption or the maturity date, as applicable, we may, at our option, on not more than 60 days and not less than 40 days prior written notice and subject to any required regulatory approvals, provided that no event of default has occurred and is continuing, elect to satisfy our obligation to repay, in whole or in part, the principal amount of the Debentures which are to be redeemed or which have matured by issuing and delivering Common Shares to the holders of the Debentures. Payment for such Debentures subject to the election would be satisfied by delivering that number of Common Shares obtained by dividing the principal amount of the Debentures subject to the election which are to be redeemed or have matured by 95% of the Current Market Price of the Common Shares on such date. In the event a holder of Debentures exercises its conversion right following delivery of a notice of redemption by us, such holder shall be entitled to receive the applicable number of Common Shares to be received on conversion on the Business Day immediately preceding the date set for redemption, plus any accrued and unpaid interest for the period from the latest interest payment date to but excluding date of conversion. Any accrued and unpaid interest will be paid in cash.

No fractional Common Shares will be issued upon redemption or maturity of the Debentures; in lieu thereof, we will satisfy such fractional interest by a cash payment equal to the relevant fraction of the Current Market Price of a whole Common Share.

Cancellation

All Debentures converted, redeemed or purchased will be cancelled and may not be reissued or resold.

Rank

The Debentures are direct, unsecured obligations of us and are fully subordinated to all Senior Indebtedness (as defined below). The Debentures rank equally with one another and, other than Senior Indebtedness, with all our other existing and future unsecured indebtedness and will rank *pari passu* with all of our other existing and future unsecured subordinated indebtedness to the extent that it is subordinated on the same terms, and have priority over the payment of any declared but unpaid dividends on the Common Shares, as more particularly described below under "*Subordination*". The Indenture does not restrict our ability from incurring additional indebtedness, including Senior Indebtedness, or from mortgaging, pledging or charging their respective properties to secure any indebtedness or liabilities, including Senior Indebtedness.

Subordination

The payment of the principal and premium, if any, of, and interest on, the Debentures will be subordinated and postponed, and subject in right of payment to the full and final payment of all of our Senior Indebtedness. "**Senior Indebtedness**" is defined in the Indenture, as the principal of and premium, if any, and interest on and other amounts in respect of all indebtedness of us (whether outstanding as at the date of the Indenture or thereafter incurred), other than indebtedness evidenced by the Debentures and all other existing and future indebtedness or other instruments of us which, by the terms of the instrument creating or evidencing the indebtedness, is expressed to be *pari passu* with, or subordinate in right of payment to, the Debentures.

The Indenture provides that in the event of any insolvency or bankruptcy proceedings, or any receivership, liquidation, reorganization or other similar proceedings relative to us, or to our property or assets, or in the event of any proceedings for voluntary liquidation, dissolution or other winding-up of us, whether or not involving insolvency or bankruptcy, or any marshalling of the assets and liabilities of us, then holders of Senior Indebtedness will receive payment in full before the holders of Debentures will be entitled to receive any payment or distribution of any kind or character, whether in cash, property or securities, which may be payable or deliverable in any such event in respect of any of the Debentures or any unpaid interest accrued thereon. The Indenture also provides that we will not make any payment, and the holders of the Debentures will not be entitled to demand, institute proceedings for the collection of, or receive any payment or benefit (including, without any limitation, by set-off, combination of accounts or realization of security or otherwise in any manner whatsoever) on account of indebtedness represented by the Debentures: (a) in a manner inconsistent with the terms (as they exist on the date of issue) of the Debentures; or (b) at any time when a default or an event of default has occurred under the Senior Indebtedness and is continuing or upon the acceleration of Senior Indebtedness and the notice of such default, event of default or acceleration has been given by or on behalf of holders of Senior Indebtedness to us, unless such notice has been revoked, such default or event of default has been cured or the Senior Indebtedness has been repaid or satisfied in full.

We and Computershare are also authorized (and obligated upon a request from us) under the Indenture to enter into subordination agreements on behalf of the holders of Debentures with any holder of Senior Indebtedness.

Repurchase upon a Change of Control

Within 30 days following the occurrence of a change of control, we will be required to make a cash offer to purchase all of the Debentures (the "**Debenture Offer**") at an offer price equal to 100% of the principal amount thereof plus accrued and unpaid interest thereon. A change of control shall include: (i) an acquisition by a person or group of persons acting jointly or in concert (within the meaning of Multilateral Instrument 62-104 – *Take-Over Bids and Issuer Bids* and in Ontario, the *Securities Act* (Ontario) and Ontario Securities Commission Rule 62-504 – *Take-Over Bids and Issuer Bids*) of ownership of, or voting control or direction over, 50% or more of the issued and outstanding Common Shares; or (ii) the sale or other transfer of all or substantially all of our consolidated assets, excluding a sale, merger, reorganization or similar transaction if the previous holders of Common Shares immediately prior to such transaction hold at least 50% of the voting control or direction in such merged, reorganized, arranged, combined or other continuing entity (and in the case of a sale of all or substantially all of the assets, in the entity which has acquired such assets) (each a "**Change of Control**").

The Indenture contains notification and repurchase provisions requiring us to give written notice to Computershare of the occurrence of a Change of Control within 30 days of such event together with the Debenture Offer. Computershare will thereafter promptly mail to each holder of Debentures a notice of the change of control together with a copy of the Debenture Offer to repurchase all outstanding Debentures.

If Debentures representing 90% or more of the aggregate principal amount of the Debentures outstanding on the date of the giving of notice of the Change of Control are tendered for purchase following a Change of Control (other than Debentures held at the date of the take-over bid by or on behalf of the offeror, associates or affiliates of the offeror or any one acting jointly or in concert with the offeror), we will have the right to redeem all remaining Debentures in cash on the purchase date at the offer price. Notice of such redemption must be given to Computershare by us within ten days following expiry of the right of the holders of the Debentures to require repurchase after the Change of

Control and, as soon as possible thereafter, by Computershare to the holders of Debentures not tendered for purchase.

We will comply with the requirements of Canadian securities laws and regulations to the extent such laws and regulations are applicable in connection with the repurchase of Debentures in the event of a Change of Control.

Cash Change of Control

In addition to the requirement for us to make a Debenture Offer in the event of a Change of Control, if a Change of Control occurs on or before December 31, 2020 in which 10% or more of the consideration for the Common Shares in the transaction or transactions constituting a change of control consists of: (i) cash (other than cash payments for fractional Common Shares and cash payments made in respect of dissenters' appraisal rights); (ii) equity securities that are not traded or intended to be traded immediately following such transactions on a recognized stock exchange; or (iii) other property that is not traded or intended to be traded immediately following such transactions on a recognized stock exchange, then subject to regulatory approvals, during the period beginning ten trading days before the anticipated date on which the Change of Control becomes effective and ending 30 days after the Debenture Offer is delivered, holders of Debentures will be entitled to convert their Debentures, subject to certain limitations, and receive, subject to and upon completion of the Change of Control, in addition to the number of Common Shares they would otherwise be entitled to receive as set out under "*Debentures – Conversion Privilege*" above, a make-whole premium of an additional number of Common Shares per $1,000 principal amount of Debentures as set out below.

The number of additional Common Shares per $1,000 principal amount of Debentures constituting the relevant make-whole premium will be determined by reference to the table below and is based on the date on which the Change of Control becomes effective and the offer price paid per Common Share in the transaction constituting the Change of Control. If holders of Common Shares receive (or are entitled and able in all circumstances to receive), only cash in the transaction, the offer price will be the cash amount paid per Common Share. Otherwise, the offer price will be equal to the Current Market Price of the Common Shares immediately preceding the effective date of such transaction.

The following table shows what the make-whole premium would be for each hypothetical offer price and effective date set out below, expressed as additional Common Shares per $1,000 principal amount of Debentures. For greater certainty, we will not be obliged to pay the make-whole premium other than by issuance of Common Shares upon conversion, subject to the provision relating to adjustment of the conversion price in certain circumstances and following the completion of certain types of transactions described under "*Debentures – Conversion Privilege*" above.

Make-Whole Premium Upon a Change of Control
(Number of Additional Common Shares per $1,000 Debenture)

	Effective Date			
Offer Price	**Dec 31/16**	**Dec 31/17**	**Dec 31/18**	**Dec 31/19**
$8.30	25.2438	25.2438	25.2438	25.2438
$8.50	24.0703	23.7271	22.4090	22.4090
$8.75	21.9984	21.6011	19.5760	19.0476
$9.00	20.0843	19.6311	17.5078	15.8730
$9.50	16.6578	16.0789	13.8916	10.0251
$10.00	13.6789	12.9560	10.8770	4.7619
$10.50	11.1794	10.3867	8.3724	1.6114
$11.00	9.0615	8.2545	6.3155	0.7300
$12.00	5.6778	5.0017	3.3125	0.3533
$13.00	3.9562	2.7677	1.4762	0.0
$14.00	2.2100	1.2850	0.5679	0.0
$15.00	1.0467	0.3927	0.1927	0.0
$16.00	0.3356	0.0144	0.0	0.0
$17.00	0.0159	0.0	0.0	0.0
$18.00	0.0	0.0	0.0	0.0

The actual offer price and effective date may not be set out in the table, in which case:

(a) if the actual offer price on the effective date is between two offer prices in the table or the actual effective date is between two effective dates in the table, the make-whole premium will be determined by a straight-line interpolation between the make-whole premiums set out for the two offer prices and the two effective dates in the table based on a 365-day year, as applicable;

(b) if the offer price on the effective date is equal to or exceeds $18.00 per Common Share, subject to adjustment as described below, the make-whole premium will be zero; and

(c) if the offer price on the effective date is less than $8.30 per Common Share, subject to adjustment as described below, the make-whole premium will be zero.

The offer prices set out in the previous table will be adjusted as of any date on which the conversion price of the Debentures is adjusted. The adjusted offer prices will equal the offer prices applicable immediately prior to such adjustment multiplied by a fraction, the numerator of which is the conversion price as so adjusted and the denominator of which is the conversion price immediately prior to the adjustment giving rise to the offer price adjustment. The number of additional Common Shares set out in the table above will be adjusted in the same manner as the conversion price as set out above under "*Debentures – Conversion Privilege*", other than by operation of an adjustment to the conversion price by adding the make-whole premium as described above.

Interest Payment Election

We may elect, from time to time, subject to applicable regulatory approval, to satisfy our obligation to pay interest on an interest payment date, (i) in cash; (ii) unless an event of default has occurred and is continuing, by delivering sufficient Common Shares to Computershare for sale, to satisfy an obligation to pay interest on the interest payment date, in which event holders of the Debentures will be entitled to receive a cash payment equal to the interest payable from the proceeds of the sale of such Common Shares; or (iii) any combination of (i) and (ii) above.

The Indenture provides that, upon us making the election to satisfy interest in Common Shares, Computershare will: (i) accept delivery from us of Common Shares; (ii) accept bids with respect to, and consummate sales of, such Common Shares, each as we shall direct in our absolute discretion through investment banks, brokers or dealers identified by us; (iii) invest the proceeds of such sales in securities issued or guaranteed by the Government of Canada which mature prior to the applicable interest payment date, and use the proceeds received from investment in such permitted government securities, together with any additional cash provided by us, to satisfy the interest payable; and (iv) perform any other action necessarily incidental thereto.

The Indenture sets out the procedures to be followed by us and Computershare in order to effect the payment of interest in Common Shares. If such election is made, the sole right of a holder of Debentures in respect of interest will be to receive a cash payment equal to the interest owed on his Debentures from Computershare out of the proceeds of the sale of Common Shares (plus any amount received by Computershare from us) in full satisfaction of the interest payable, and the holder of such Debentures will have no further recourse to us in respect of the interest payable.

Notwithstanding the foregoing, neither the making the election nor the consummation of sales of Common Shares will: (i) result in the holders of the Debentures not being entitled to receive, on the applicable interest payment date, cash in an aggregate amount equal to the interest payable on such interest payment date; or (ii) entitle or require such holders to receive any Common Shares in satisfaction of the interest payable.

Modification

The rights of the holders of Debentures as well as any other series of debentures that have been or may be issued under the Indenture may be modified in accordance with the terms of the Indenture. For that purpose, among others, the Indenture contains certain provisions which make binding on all holders of outstanding Debentures, resolutions passed at meetings of the holders of outstanding Debentures by votes cast thereat by holders of not less than 66⅔% of the principal amount of the then-outstanding Debentures present at the meeting or represented by proxy, or rendered by instruments in writing signed by the holders of not less than 66⅔% of the principal amount of the then-outstanding Debentures. In certain cases, the modification will, instead or in addition, require assent by the holders of the required percentage of each particularly-affected series of debentures, as the case may be. Under the Indenture, certain amendments of a technical nature or which are not prejudicial to the rights of the holders of the Debentures may be made to the Indenture without the consent of the holders of the Debentures.

Consolidation, Mergers or Sales of Assets

The Indenture provides that we may not, without the consent of the holders of the Debentures, consolidate or amalgamate with or merge into any person or sell, convey, transfer or lease all or substantially all of our properties and assets to another person (other than our direct or indirect wholly-owned subsidiaries) unless:

(a) the resulting, surviving, continuing or transferee person expressly assumes all of our obligations under the Debentures and Indenture;

(b) if such resulting, surviving, continuing or transferee person is organized otherwise than under the laws of Canada, any province or territory thereof, the United States or any state or district thereof, it attorns to the jurisdiction of the courts of Alberta;

(c) the Debentures will be valid and binding obligations of the resulting, surviving, continuing or transferee person entitling the holders thereof, as against such person, to all the rights of holders of Debentures under the Indenture; and

(d) after giving effect to the transaction, no event of default, and no event that, after notice or lapse of time, or both, would become an event of default, will occur; and

(e) such other conditions as may be described in the Indenture are met.

Although such transactions are permitted under the Indenture, certain of the foregoing transactions could constitute a Change of Control, which would require us to offer to purchase the Debentures as described above.

Events of Default

The Indenture provides that an event of default in respect of the Debentures will occur if certain events described in the Indenture occur, including if any one or more of the following events has occurred and is continuing with respect to the Debentures: (i) failure for 15 days to pay interest on the Debentures when due; (ii) failure to pay principal or premium, if any (whether by payment in cash or delivery of Common Shares), on the Debentures when due, whether at maturity, upon redemption, on a change of control, by declaration or otherwise; (iii) default in the delivery, when due, of any Common Shares or other consideration, including any make-whole premium, payable upon conversion with respect to the Debentures, which default continues for 15 days; (iv) default in the observance or performance of any covenant or condition of the Indenture and the failure to cure (or obtain a waiver for) such default for a period of 30 days after notice in writing has been given by Computershare or from holders of not less than 25% of the aggregate principal amount of the Debentures specifying such default and requiring us to rectify or obtain a waiver for same; and (v) certain events of bankruptcy, insolvency or reorganization of us under bankruptcy or insolvency laws.

If an event of default has occurred and is continuing, Computershare may, in its discretion, and will, upon the request of holders of not less than 25% in principal amount of the then outstanding Debentures (declare the principal of (and premium, if any) and interest on all outstanding Debentures to be immediately due and payable.

Offers for Debentures

The Indenture contains provisions to the effect that if an offer is made for the Debentures which is a take-over bid within the meaning of Multilateral Instrument 62-104 – *Take-Over Bids and Issuer Bids*, the Debentures are considered equity securities, and not less than 90% of the principal amount of the then outstanding Debentures (other than Debentures held at the date of the take-over bid by or on behalf of the offeror or associates or affiliates of the offeror) are taken up and paid for by the offeror, the offeror will be entitled to acquire the Debentures held by those who did not accept the offer on the terms offered by the offeror.

Credit Facility

The Credit Facility consists of a $130 million syndicated borrowing base credit facility and a $20 million operating credit facility. The available lending limits of the Credit Facility are reviewed semi-annually based on our reserves, future commodity prices and costs. In connection with the most recent review of the Credit Facility, the lenders determined our borrowing base to be $250 million. Since our total borrowing limit is set at 60% of the borrowing base, management believes that there will not be a change in the amount of the Credit Facility available to us.

The Credit Facility has a 364 day revolving period and the option, at our request and with the consent of the lenders, renewable on an annual basis until May 26, 2017 and may be extended for a further 364 day period, subject to approval of the syndicate. If not extended, the Credit Facility will automatically convert to a one year non-revolving term loan and all obligations under the Credit Facility will be required to be repaid at the end of the one-year period. Advances under the Credit Facility are available by way of either prime rate loans which bear interest at the banks' prime lending rate plus 0.7 to 2.0% and bankers' acceptances and/or LIBOR loans, which are subject to fees and margins ranging from 1.7 to 3.0%. Interest and standby fees on the undrawn amounts of the Credit Facility depend upon certain financial ratios. As security for the provision of the Credit Facility, we have provided the lenders a debenture securing a first floating charge on all of our present and after acquired property. There are no financial or other restrictive covenants related to the Credit Facility (provided we are not in default). See "*Risk Factors – Credit Facility Risk*".

MARKET FOR OUR SECURITIES

Trading Price and Volume

Common Shares

Our Common Shares trade on the Toronto Stock Exchange under the trading symbol "CJ" and commenced trading on the Toronto Stock Exchange on December 17, 2013. The following sets out the high and low trading prices and aggregate volume of trading for the periods noted below for our Common Shares:

Period	High	Low	Volume
2016			
January	8.94	5.59	11,642,315
February	7.28	5.78	8,318,272
March	9.72	6.93	11,312,474
April	9.69	7.67	10,297,958
May	10.31	8.21	11,030,752
June	10.92	9.20	9,495,211
July	10.02	8.76	6,245,854
August	9.95	8.51	6,667,460
September	8.79	7.37	13,129,414
October	9.91	8.42	10,929,477
November	9.98	8.39	7,421,315
December	10.71	9.51	8,347,165

Period	High	Low	Volume
2017			
January	10.815	8.32	7,450,211
February	8.88	8.05	8,342,013
March (to March 30)	8.23	6.37	12,643,461

Debentures

Our Debentures trade on the Toronto Stock Exchange under the trading symbol "CJ.DB" and commenced trading on the Toronto Stock Exchange on October 6, 2015. The following set out the high and low trading price and aggregate volume of trading for the periods noted below for our Debentures.

Period	High	Low	Volume
2016			
January	103.00	89.20	5,454,000
February	97.00	89.50	1,809,000
March	110.00	99.00	1,121,000
April	111.00	105.00	527,000
May	115.00	105.50	667,000
June	117.01	112.00	974,000
July	113.26	109.50	832,000
August	117.50	109.00	726,000
September	110.02	106.00	634,000
October	112.01	110.00	3,690,000
November	112.01	109.00	538,000
December	119.00	114.23	348,000
2017			
January	118.12	107.80	383,000
February	110.00	108.00	300,000
March (to March 30)	110.00	103.00	875,000

Prior Sales

During the year ended December 31, 2016 we granted a total of 1,882,960 bonus awards pursuant to our restricted bonus award plan. On the payment date of the bonus awards, we have the sole discretion as to whether the bonus awards shall be paid in cash, Common Shares from treasury or Common Shares purchased on the Toronto Stock Exchange. No other share-based compensation was granted by us during the year ended December 31, 2016. See note 13 of our annual financial statements for the year ended December 31, 2016 for further information.

DIRECTORS AND OFFICERS

Summary Information

The following table sets forth certain summary information in respect of our directors and executive officers as at the date of this Annual Information Form.

Name, Province and Country of Residence	Position Held	Principal Occupation for the Last Five Years	Director Since	Common Share Ownership (5)(6)
M. Scott Ratushny (3) Alberta, Canada	Chief Executive Officer and Chairman	Our Chief Executive Officer since July 6, 2012. Prior thereto, Chairman and Chief Executive Officer of Midway Energy Ltd., a public oil and gas company.	May 2011	1,330,102
John A. Brussa (2) Alberta, Canada	Director	Mr. Brussa is a partner and Chairman of Burnet, Duckworth & Palmer LLP.	July 2012	699,291

Name, Province and Country of Residence	Position Held	Principal Occupation for the Last Five Years	Director Since	Common Share Ownership (5)(6)
David D. Johnson (1)(2)(3)(4) Alberta, Canada	Director	Independent Businessperson. Mr. Johnson was the Chairman of Progress Energy Resources Corp., a public oil and gas company, prior to its sale on December 12, 2012.	July 2012	357,238
James C. Smith (1)(2)(3)(4) Alberta, Canada	Director	Independent director and consultant to a number of public and private oil and gas companies.	July 2012	203,489
Gregory T. Tisdale (1)(2)(4) Alberta, Canada	Director	Mr. Tisdale is currently director and founder of Enercapita Energy Ltd., a private junior oil and gas company. Prior thereto he was the Chief Financial Officer of Crescent Point Energy Ltd., a public oil and gas company.	January 2014	26,518
Shane Peet Alberta, Canada	President	Our President since May, 2014, prior thereto our Chief Operating Officer since July, 2012. Prior thereto, Chief Operating Officer of Midway Energy Ltd.	N/A	1,134,309
Douglas Smith Alberta, Canada	Chief Financial Officer	Our Chief Financial Officer since July 6, 2012. Prior thereto Chief Financial Officer of Midway Energy Ltd., a public oil and gas company.	N/A	561,176
Craig Kolochuk Alberta, Canada	Vice President, Land	Our Vice President Land since July, 2012. Prior thereto, Land Manager of Midway Energy Ltd., a public oil and gas company.	N/A	130,961
Timothy Hyde Alberta, Canada	Vice President, Exploration	Our Vice President, Exploration since July 31, 2012. Prior thereto, Consulting Technical Advisor to Livingstone Energy Management, a private equity firm affiliated with Lime Rock Partners.	N/A	398,574
Laurence Broos Alberta, Canada	Vice President, Finance	Our Vice President, Finance since February 10, 2015. Prior thereto, Treasurer of PennWest Petroleum Ltd., a public oil and gas company.	N/A	13,681
Connie Shevkenek Alberta, Canada	Vice President, Engineering	Our Vice President, Engineering since September 1, 2016. Prior thereto, our Manager of Engineering since February 2014.	N/A	44,253
Dale Orton	Vice President	Our Vice President since December 1, 2016. Prior thereto, Senior Vice President, Development for Long Run Exploration Ltd., a public oil and gas company.	N/A	10,000

Notes:

(1) Member of our Audit Committee. Mr. James C. Smith is the Chair of the Audit Committee.
(2) Member of our Corporate Governance & Compensation Committee. Mr. John A. Brussa is the Chair of the Corporate Governance & Compensation Committee.
(3) Member of the Reserves Committee. Mr. David D. Johnson is the Chair of the Reserves Committee.
(4) Independent director.
(5) Represents Common Shares and other securities beneficially owned, controlled or directed (directly or indirectly) by the director or officer as of the date hereof based on information provided by such individuals.
(6) Includes Common Shares held by David Johnson, James Smith, Doug Smith and Tim Hyde's spouse and/or minor children.

All of our directors' terms of office will expire at the earliest of their resignation, the close of the next annual shareholder meeting called for the election of directors, or on such other date as they may be removed according to the *Business Corporations Act* (Alberta). Each director will devote the amount of time as is required to fulfill his obligations to us. Our officers are appointed by and serve at the discretion of the Board of Directors.

Cease Trade Orders, Bankruptcies, Penalties or Sanctions

Other than as discussed below, and to our knowledge, none of our directors or executive officers (nor any personal holding company of any of such persons) is, as of the date of this Annual Information Form, or was within ten years before the date of this Annual Information Form, a director, chief executive officer or chief financial officer of any company (including us), that: (a) was subject to a cease trade order (including a management cease trade order), an order similar to a cease trade order or an order that denied the relevant company access to any exemption under securities legislation, in each case that was in effect for a period of more than 30 consecutive days (collectively, an "**Order**"), that was issued while the director or executive officer was acting in the capacity as director, chief executive officer or chief financial officer; or (b) was subject to an Order that was issued after the director or executive officer ceased to be a director, chief executive officer or chief financial officer and which resulted from an event that occurred while that person was acting in the capacity as director, chief executive officer or chief financial officer. During the time Mr. Smith was a director of Penn West Petroleum Ltd. ("**Penn West**"), a public oil and gas company, Penn West applied for and received a management cease trade order ("**MCTO**") on August 5, 2014 from the Alberta Securities Commission ("**ASC**"). The MCTO prohibited the directors and executive officers of Penn West from trading in or purchasing securities of Penn West, subject to certain limited circumstances, until two full business days after Penn West's second quarter filings and certain restated historical financials were filed. The MCTO did not affect the ability of other persons to trade in the common shares or other securities of Penn West. The MCTO was revoked by the ASC on September 23, 2014.

Other than as discussed below, to our knowledge, none of our directors or executive officers (nor any personal holding company of any of such persons), or Shareholder holding a sufficient number of our securities to affect materially our control: (a) is, as of the date of this Annual Information Form, or has been within the ten years before the date of this Annual Information Form, a director or executive officer of any company (including us) that, while that person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets; or (b) has, within the ten years before the date of this prospectus, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of the director, executive officer or Shareholder. Mr. Brussa was formerly a director of Calmena Energy Services Inc. ("**Calmena**"), a public oilfield service company which was placed in receivership on January 20, 2015. Mr. Brussa resigned as a director of Calmena on June 30, 2014. Messrs. Brussa, Ratushny and Tisdale were directors of Enseco Energy Services Corp. ("**Enseco**"), a public oilfield service company, which was placed in receivership on October 14, 2015 and, in connection therewith, a receiver was appointed under the *Bankruptcy and Insolvency Act* (Canada). Each of Messrs. Brussa, Ratushny and Tisdale resigned as directors of Enseco on October 14, 2015. On December 21, 2015 Enseco was assigned into bankruptcy by the receiver. Mr. Brussa was a director of Argent Energy Ltd. which was the administrator of Argent Energy Trust ("**Argent Trust**"), a public energy trust. On February 17, 2016, Argent Trust and its Canadian and United States holding companies (collectively "**Argent**") commenced proceedings under the *Companies' Creditors Arrangement Act* ("**CCAA**") for a stay of proceedings until March 19, 2016. On the same date, Argent filed voluntary petitions for relief under Chapter 15 of the *United States Bankruptcy Code* ("**Chapter 15**"). On March 9, 2016, the stay of proceedings under the CCAA was extended until May 17, 2016. Additionally on March 10, 2016 the U.S. Bankruptcy Court approved an order recognizing the CCAA as the foreign main proceedings under Chapter 15. On April 26, 2016, Argent made an application seeking approval for the sale of its oil and gas assets, the distribution of the net proceeds from the sale and an extension to the stay of proceedings, which was re-scheduled for May 4 and 5, 2016. On May 10, 2016, two orders were granted approving the sale of Argent's oil and gas assets and the distribution of net proceeds from the sale. On May 11, 2016, both orders were recognized by the U.S. court within the Chapter 15 proceedings. On June 27, 2016, an order was granted which, among other things, extended the stay of proceedings under the CCAA until August 31, 2016. Mr. Brussa resigned on June 30, 2016. Mr. Brussa resigned as a director of Twin Butte Energy Ltd. ("**Twin Butte**"), a public oil and gas company, on September 1, 2016. On the same day, the senior lenders of Twin Butte (the "**Senior Lenders**") made an application to the Court of Queen's Bench of Alberta ("**Court**") to appoint a receiver and manager over the assets, undertakings and property of Twin Butte under the *Bankruptcy and Insolvency Act*

(Canada) and trading in the common shares of Twin Butte was suspended by the Toronto Stock Exchange. On September 1, 2016, the Senior Lenders were granted a receivership order by the Court. Messrs. Brussa and Johnson were directors of Virginia Hills Oil Corp. ("**VHO**"), a public oil and gas company. On February 13, 2017, VHO received a demand notice and notice of intention to enforce security from its lenders and agreed to consent to the early enforcement of the lenders' security and the appointment of a receiver over all of the current and future assets, undertakings and properties of VHO. The receiver was appointed on February 13, 2017. Mr. Brussa and Mr. Johnson resigned as directors of VHO on February 24, 2017.

To our knowledge, none of our directors or executive officers (nor any personal holding company of any of such persons), or Shareholder holding a sufficient number of our securities to affect materially our control has been subject to: (a) any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority; or (b) any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

Conflicts of Interest

Certain of our officers and directors are also officers and/or directors of other companies engaged in the oil and gas business generally. As a result, situations may arise where the interest of such directors and officers conflict with their interests as directors and officers of other companies. The resolution of such conflicts is governed by applicable corporate laws, which require that directors act honestly, in good faith and with a view to our best interests. Conflicts, if any, will be handled in a manner consistent with the procedures and remedies set forth in the *Business Corporations Act* (Alberta). The *Business Corporations Act* (Alberta) provides that in the event that a director has an interest in a contract or proposed contract or agreement, the director shall disclose his interest in such contract or agreement and shall refrain from voting on any matter in respect of such contract or agreement unless otherwise provided by the *Business Corporations Act* (Alberta).

AUDIT COMMITTEE

Audit Committee Mandate

The Board has adopted a written mandate and terms of reference for our Audit Committee, which sets out the Audit Committee's responsibility for, among other things, reviewing our financial statements and our public disclosure documents containing financial information and reporting on such review to the Board, ensuring our compliance with legal and regulatory requirements, overseeing qualifications, engagement, compensation, performance and independence of our external auditors, and reviewing, evaluating and approving the internal control and risk management systems that are implemented and maintained by management. A copy of the Audit Committee mandate is attached to this Annual Information Form as Appendix C.

Composition of the Audit Committee and Relevant Education and Experience

The Audit Committee consists of Messrs. Smith (Chair), Tisdale and Johnson. Each of the members of the Audit Committee is considered "financially literate" and "independent" within the meaning of National Instrument 52-110 – *Audit Committees*.

We believe that each of the members of our Audit Committee possesses: (a) an understanding of the accounting principles used by us to prepare financial statements; (b) the ability to assess the general application of such accounting principles in connection with the accounting for estimates, accruals and reserves; (c) experience preparing, auditing, analyzing or evaluating financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of issues that can reasonably be expected to be raised by our financial statements, or experience actively supervising one or more individuals engaged in such activities; and (d) an understanding of internal controls and procedures for financial reporting. The relevant education and experience of each audit committee member is outlined below.

James C. Smith:

Mr. Smith is a Chartered Professional Accountant with over 40 years of experience in public accounting and industry. While Mr. Smith was the Vice President and Chief Financial Officer of Crestar Energy Inc. from its inception in 1992 until 1998, the company completed an initial public offering, was listed on the Toronto Stock Exchange and completed several major debt and equity financing transactions. From 1998 to 2006, he was a business consultant to a number of public and private companies operating in the oil and gas industry. Since 2004 he has been a director and audit committee chairman for a number of public and private companies.

Greg Tisdale:

Mr. Tisdale is currently director and founder of Enercapita Energy Ltd., a private junior oil and gas company, prior thereto he held the position of Chief Financial Officer of Crescent Point Energy Ltd. During the past ten years he has managed all aspects of Crescent Point's finances. Mr. Tisdale has worked in the oil and gas industry since 1995 and has served and currently serves on the board of directors of several junior oil and gas companies. Mr. Tisdale holds a Bachelor of Commerce degree (with distinction) from the University of Alberta and is a Chartered Professional Accountant.

David D. Johnson:

Mr. Johnson has over 35 years of diverse experience in the oil and gas industry including a background in production, reservoir evaluation and operations. He has a B.Sc. in Petroleum Engineering, is a member of the Association of Professional Engineers and Geoscientists of Alberta and has served twice as a governor of the Canadian Association of Petroleum Producers.

Pre-Approval Policies and Procedures for the Engagement of Non-Audit Services

The Audit Committee must pre-approve all non-audit services to be provided to us by our external auditors. The Audit Committee may delegate to one or more members the authority to pre-approve non-audit services, provided that the member reports to the Audit Committee at the next scheduled meeting such pre-approval and the member complies with such other procedures as may be established by the Audit Committee from time to time.

External Audit Service Fees

The following table summarizes the fees paid by us to our auditors, KPMG LLP, for external audit and other services during the period indicated.

Year	**Audit Fees** (1)	**Audit-Related Fees**	**Tax Fees**	**All Other Fees**
	($)	**($)**	**($)**	**($)**
2015	150,000	190,500	8,240	-
2016	150,000	149,500	3,400	-

Notes:

(1) Represents the aggregate fees billed by KPMG LLP in the last two fiscal years for the audit of financial statements.

DIVIDEND POLICY

Dividends and Dividend Policy

On January 7, 2014 our Board of Directors adopted our dividend policy. Our long-term objective is to set a dividend policy at prudent levels while withholding sufficient funds to finance capital expenditures required to grow our current production base by a target of 5% to 10% annually. This in turn, is expected to provide a stronger base of cash flow leading to consistent dividends into the future. Cash dividends are paid on the 15th day (or if such date is not a business day, on the next business day) following the end of each calendar month to Shareholders of record on the last business day of each such calendar month or such other date as determined from time to time by us.

The amount of future cash dividends, if any, will be in the sole discretion of the Board after considering a variety of factors and conditions existing from time to time, including current and future commodity prices, foreign exchange rates, our hedging program, current operations including production levels, operating costs, royalty burdens and debt service requirements, available investment opportunities and the satisfaction of the liquidity and solvency tests imposed by the *Business Corporations Act* (Alberta) for the declaration and payment of dividends.

We carefully monitor the impact of all issues affecting our business and the necessity to adjust our monthly dividends and our capital programs as conditions evolve. See "*General Development of our Business – Recent Developments*".

We have implemented a dividend reinvestment plan which enables eligible Shareholders to reinvest their cash dividends into additional Common Shares which will be purchased through the facilities of the Toronto Stock Exchange at prevailing market prices or issued from treasury at 100 percent of the average market price (as defined in the plan) on the applicable dividend payment date. We have also activated our stock dividend program which enables us to issue Common Shares as payment of all or a portion of dividends declared on the Common Shares for those Shareholders who elect to receive stock dividends instead of cash dividends. See "*Description of our Capital Structure*". We have suspended both the dividend reinvestment plan and the stock dividend program effective for the May 15, 2017 dividend payment to Shareholders of record on April 28, 2017.

Our Credit Facility contains restrictions on our ability to pay dividends in certain circumstances. In addition, the payment of dividends by a corporation is governed by the liquidity and insolvency tests described in the *Business Corporations Act* (Alberta). Pursuant to the *Business Corporations Act* (Alberta), after the payment of a dividend, we must be able to pay our liabilities as they become due and the realizable value of our assets must be greater than our liabilities and the legal stated capital of our outstanding securities.

Cash dividends are not guaranteed. Although we intend to make dividends in the amount indicated to Shareholders, these cash dividends may be reduced or suspended. The actual amount distributed will depend on numerous factors and conditions existing from time to time, including fluctuations in commodity prices, production levels, capital expenditure requirements, debt service requirements, operating costs, royalty burdens, foreign exchange rates and the satisfaction of solvency tests imposed by the *Business Corporations Act* (Alberta) for the declaration and payment of dividends applicable law and other factors beyond our control. See "*Risk Factors*".

The following monthly cash dividends on our Common Shares were declared by our Board for the periods indicated:

Period	Dividend per Common Share
January 2014 – August 2014	$0.05417
September 2014 – December 2015	$0.07
January 2016 – March 2017	$0.035

Unless otherwise specified, all dividends paid or to be paid by us are designated as "eligible dividends" under the *Income Tax Act* (Canada).

INDUSTRY CONDITIONS

Companies operating in the oil and natural gas industry are subject to extensive regulation and control of operations (including land tenure, exploration, development, production, refining and upgrading, transportation, and marketing) as a result of legislation enacted by various levels of government with respect to the pricing and taxation of oil and natural gas, including the governments of Canada and Alberta, all of which investors in the oil and gas industry should carefully consider. It is not expected that any of these regulations or controls will affect our operations in a manner materially different than they will affect other oil and gas companies of similar size. All current legislation is a matter of public record and we are unable to predict what additional legislation or amendments governments may enact in the future. The majority of our reserves and oil and natural gas operations are in Alberta. The following comprises some of the principal aspects of legislation, regulations and agreements governing the oil and gas industry in Canada and Alberta.

Pricing and Marketing

Oil

In Canada, producers of oil are entitled to negotiate sales contracts directly with oil purchasers, which results in the market determining the price of oil. Worldwide supply and demand factors primarily determine oil prices; however, regional market and transportation issues also influence prices. The specific price depends in part on oil quality, prices of competing fuels, distance to market, availability of transportation, value of refined products, the supply/demand balance and contractual terms of sale. Oil exporters are also entitled to enter into export contracts with terms not exceeding one year in the case of light crude oil and two years in the case of heavy crude oil, provided that an order approving such export has been obtained from the National Energy Board of Canada (the "**NEB**"). Any oil export to be made pursuant to a contract of longer duration (to a maximum of 25 years) requires an exporter to obtain an export licence from the NEB. The NEB underwent a consultation process to update the current regulations governing the issuance of export licences. The updating process was necessary to meet the criteria set out in the federal *Jobs, Growth and Long-term Prosperity Act (Canada)* (the "**Prosperity Act**") which received Royal Assent on June 29, 2012. The *Regulations Amending the National Energy Board Act Part VI (Oil and Gas) Regulations* came into effect on July 31, 2015 and provides the requirements for obtaining long-term licences.

Natural Gas

Alberta's natural gas market has been deregulated since 1985. Supply and demand determine the price of natural gas and price is calculated at the sale point, being the wellhead, the outlet of a gas processing plant, on a gas transmission system such as the Alberta "NIT" (Nova Inventory Transfer), at a storage facility, at the inlet to a utility system or at the point of receipt by the consumer. Accordingly, the price for natural gas is dependent upon such producer's own arrangements (whether long or short term contracts and the specific point of sale). As natural gas is also traded on trading platforms such as the Natural Gas Exchange, Intercontinental Exchange or the New York Mercantile Exchange in the United States, spot and future prices can also be influenced by supply and demand fundamentals on these platforms. Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet certain other criteria prescribed by the NEB and the Government of Canada. Natural gas (other than propane, butane and ethane) exports for a term of less than two years or for a term of two to 20 years (in quantities of not more than 30,000 m^3/day) must be made pursuant to an NEB order. Natural gas export contracts of a longer duration (to a maximum of 40 years) or that deal with larger quantities of natural gas require an exporter to obtain an export licence from the NEB.

The North American Free Trade Agreement

The North American Free Trade Agreement ("**NAFTA**") among the governments of Canada, the United States and Mexico came into force on January 1, 1994. In the context of energy resources, Canada continues to remain free to determine whether exports of energy resources to the United States or Mexico will be allowed, provided that any export restrictions do not: (i) reduce the proportion of energy resources exported relative to the total supply of goods of the party maintaining the restriction as compared to the proportion prevailing in the most recent 36 month period;

(ii) impose an export price higher than the domestic price (subject to an exception with respect to certain measures which only restrict the volume of exports); and (iii) disrupt normal channels of supply.

All three signatory countries are prohibited from imposing a minimum or maximum export price requirement in any circumstance where any other form of quantitative restriction is prohibited. The signatory countries are also prohibited from imposing a minimum or maximum import price requirement except as permitted in enforcement of countervailing and anti-dumping orders and undertakings. NAFTA requires energy regulators to ensure the orderly and equitable implementation of any regulatory changes and to ensure that the application of those changes will cause minimal disruption to contractual arrangements and avoid undue interference with pricing, marketing and distribution arrangements, all of which are important for Canadian oil and natural gas exports. NAFTA contemplates the reduction of Mexican restrictive trade practices in the energy sector and prohibits discriminatory border restrictions and export taxes. The new administration in the United States has indicated an intention to seek renegotiation of NAFTA, the impact of which on the oil and gas industry is uncertain.

Royalties and Incentives

General

In addition to federal regulation, each province has legislation and regulations that govern royalties, production rates and other matters. The royalty regime in a given province is a significant factor in the profitability of oil sands projects, crude oil, natural gas liquids, sulphur and natural gas production. Royalties payable on production from lands where the Crown does not hold the mineral rights are determined by negotiation between the mineral freehold owner and the lessee, although production from such lands is subject to certain provincial taxes and royalties. Royalties from production on Crown lands are determined by governmental regulation and are generally calculated as a percentage of the value of gross production. The rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date, method of recovery and the type or quality of the petroleum product produced. Other royalties and royalty-like interests are carved out of the working interest owner's interest, from time to time, through non-public transactions. These are often referred to as overriding royalties, gross overriding royalties, net profits interests or net carried interests.

Occasionally the governments of the western Canadian provinces create incentive programs for exploration and development. Such programs often provide for royalty rate reductions, royalty holidays or royalty tax credits and are generally introduced when commodity prices are low to encourage exploration and development activity by improving earnings and cash flow within the industry.

The Canadian federal government has signaled that it will *inter alia* phase out subsidies for the oil and gas industry, which include only allowing the use of the Canadian Exploration Expenses tax deduction in cases of successful exploration, implementing stringent reviews for pipelines and establishing a pan-Canadian framework for combating climate change. These changes could affect earnings of companies operating in the oil and natural gas industry.

Alberta

In Alberta, the Crown owns 81% of the province's mineral rights. The remaining 19% are 'freehold' mineral rights owned by the federal government on behalf of First Nations or in National Parks, and by individuals and companies. Provincial government royalty rates apply to Crown-owned mineral rights. On January 29, 2016, the Government of Alberta released and accepted the Royalty Review Advisory Panel's recommendations, which outlined the implementation of a "Modernized Royalty Framework" for Alberta (the "**MRF**"). The MRF formally took effect on January 1, 2017 for wells drilled after this date. Wells drilled prior to January 1, 2017 will continue to be governed by the "New Royalty Framework" (implemented by the *Mines and Minerals (New Royalty Framework*) *Amendment Act, 2008*) (the "**Alberta Royalty Framework**") for a period of 10 years until January 1, 2027. The MRF is structured in three phases: (i) Pre-Payout; (ii) Mid-Life; and (iii) Mature. During the Pre-Payout phase, a fixed 5% royalty will apply until the well reaches payout. Well payout occurs when the cumulative revenue from a well is equal to the Drilling and Completion Cost Allowance (determined by a formula that approximates drilling and completion costs for wells based on total depth, length and proppant placed). The new royalty rate for Pre-Payout under the MRF will be payable on gross revenue generated from all production streams (oil, gas, and natural gas liquids), eliminating the need to label a well as "oil" or "gas". Post-payout, the Mid-Life phase will apply a higher royalty rate than the Pre-Payout phase. Depending on the commodity price of the substance the well is producing, the royalty rate could range from 5% - 40%. The metrics for calculating the Mid-Life phase royalty are based on commodity prices and are intended, on average, to yield the same internal rate of return as under the Alberta Royalty Framework. In the Mature phase of the MRF, once a well reaches the tail end of its cycle and production falls below a maturity threshold, currently the equivalent of 194 m^3 (40 Boe/d or 345,500 m^3 of gas per month), the royalty rate will move to a sliding scale (based on volume and price) with a minimum royalty rate of 5%. The downward adjustment of the royalty rate in the Mature phase is intended to account for the higher per-unit fixed cost involved in operating an older well.

On July 11, 2016, the Government of Alberta released details of the Enhanced Hydrocarbon Recovery Program and the Emerging Resources Program. These programs, that came into effect on January 1, 2017, are a part of the MRF and account for the higher costs associated with enhanced recovery methods and with developing emerging resources in an effort to make difficult investments economically viable and to increase royalties. Certain eligibility criteria must be satisfied in order for a proposed project to fall under each program. Enhanced recovery scheme applications can be submitted to the Alberta Energy Regulator ("**AER**").

Oil sands projects are also subject to Alberta's royalty regime. The MRF does not change the oil sands royalty framework, however, the Government of Alberta plans to increase transparency in the method and figures by which the royalties are calculated. Prior to payout of an oil sands project, the royalty is payable on gross revenues of oil sands projects. Gross revenue royalty rates range between 1% and 9% depending on the market price of oil, determined using the average monthly price, expressed in Canadian dollars, for WTI crude oil at Cushing, Oklahoma. Rates are 1% when the market price of oil is less than or equal to $55 per barrel and increase for every dollar of market price of oil increase to a maximum of 9% when oil is priced at $120 or higher. After payout, the royalty payable is the greater of the gross revenue royalty based on the gross revenue royalty rate of between 1% and 9% and the net revenue royalty based on the net revenue royalty rate. Net revenue royalty rates start at 25% and increase for every dollar of market price of oil increase above $55 up to 40% when oil is priced at $120 or higher.

Currently, producers of oil and natural gas from Crown lands in Alberta are required to pay annual rental payments, at a rate of $3.50 per hectare, and make monthly royalty payments in respect of oil and natural gas produced.

Royalties, for wells drilled prior to January 1, 2017 are paid pursuant to the Alberta Royalty Framework until January 1, 2027. Royalty rates for conventional oil are set by a single sliding scale formula, which is applied monthly and incorporates separate variables to account for production rates and market prices. The maximum royalty payable under the royalty regime is 40%. Royalty rates for natural gas under the royalty regime depends on the price of each of the components of the gas stream, the productivity of the well, its acid gas factor and the depth of the producing zone. These factors are employed on a sliding scale formula to determine the natural gas royalty rate per well with the maximum royalty payable under the royalty regime set at 36% and a minimum royalty rate of 5%.

Producers of oil and natural gas from freehold lands in Alberta are required to pay freehold mineral tax. The freehold mineral tax is a tax levied by the Government of Alberta on the value of oil and natural gas production from lands where the Crown does not hold the rights to mines and minerals and is derived from the *Freehold Mineral Rights Tax Act* (Alberta). The freehold mineral tax is levied on an annual basis on calendar year production using a tax formula that takes into consideration, among other things, the amount of production, the hours of production, the value of each unit of production, the tax rate and the percentages that the owners hold in the title. The basic formula for the assessment of freehold mineral tax is: revenue less allocable costs equals net revenue divided by wellhead production equals the value based upon unit of production. If payors do not wish to file individual unit values, a default price is supplied by the Crown. On average, the tax levied is 4% of revenues reported from freehold mineral title properties.

The Government of Alberta has from time to time implemented drilling credits, incentives or transitional royalty programs to encourage oil and gas development and new drilling. For example, the Innovative Energy Technologies Program has the stated objectives of increasing recovery from oil and gas deposits, finding technical solutions to the gas over bitumen issue, improving the recovery of bitumen by in-situ and mining techniques and improving the recovery of natural gas from coal seams. The Innovative Energy Technologies Program provides royalty adjustments to specific pilot and demonstration projects that utilize new or innovative technologies to increase recovery from existing reserves.

In addition, the Government of Alberta has implemented certain initiatives intended to accelerate technological development and facilitate the development of unconventional resources. These initiatives apply to wells drilled before January 1, 2017, for a ten year period until January 1, 2027. Specifically:

- Coalbed methane wells will receive a maximum royalty rate of 5% for 36 producing months up to 750 MMcf of production, retroactive to wells that began producing on or after May 1, 2010;
- Shale gas wells will receive a maximum royalty rate of 5% for 36 producing months with no limitation on production volume, retroactive to wells that began producing on or after May 1, 2010;
- Horizontal gas wells will receive a maximum royalty rate of 5% for 18 producing months up to 500 MMcf of production, retroactive to wells that commenced drilling on or after May 1, 2010; and
- Horizontal oil wells and horizontal non-project oil sands wells will receive a maximum royalty rate of 5% with volume and production month limits set according to the depth of the well (including the horizontal distance), retroactive to wells that commenced drilling on or after May 1, 2010.

Land Tenure

The respective provincial governments predominantly own the rights to crude oil and natural gas located in the western provinces. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licences, and permits for varying terms, and on conditions set forth in provincial legislation including requirements to perform specific work or make payments. Private ownership of oil and natural gas also exists in such provinces and rights to explore for and produce such oil and natural gas are granted by lease on such terms and conditions as may be negotiated.

Alberta has implemented legislation providing for the reversion to the Crown of mineral rights to deep, non-productive geological formations at the conclusion of the primary term of a lease or licence. Alberta also has a policy of "shallow rights reversion" which provides for the reversion to the Crown of mineral rights to shallow, non-productive geological formations for all leases and licences issued subsequent to January 1, 2009, at the conclusion of the primary term of the lease or licence.

Production and Operation Regulations

The oil and natural gas industry in Canada is highly regulated and subject to significant control by provincial regulators. Regulatory approval is required for, among other things, the drilling of oil and natural gas wells, construction and operation of facilities, the storage, injection and disposal of substances and the abandonment and reclamation of well-sites. In order to conduct oil and gas operations and remain in good standing with the applicable provincial regulator, we must comply with applicable legislation, regulations, orders, directives and other directions (all of which are subject to governmental oversight, review and revision, from time to time). Compliance with such legislation, regulations, orders, directives or other directions can be costly and a breach of the same may result in fines or other sanctions.

Environmental Regulation

The oil and natural gas industry is currently subject to environmental regulation under a variety of Canadian federal, provincial, territorial and municipal laws and regulations, all of which is subject to governmental review and revision from time to time. Such legislation provides for, among other things, restrictions and prohibitions on the spill, release or emission of various substances produced in association with certain oil and gas industry operations, such as sulphur dioxide and nitrous oxide. The regulatory regimes set out the requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment and reclamation of well and facility sites. Compliance with such legislation can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licences and authorizations, civil liability and the imposition of material fines and penalties. In addition to these specific, known requirements, future changes to environmental legislation, including anticipated legislation for air pollution and greenhouse gas ("**GHG**") emissions, may impose further requirements on operators and other companies in the oil and natural gas industry.

Federal

Canadian environmental regulation is the responsibility of the federal government and provincial governments. Where there is a direct conflict between federal and provincial environmental legislation in relation to the same matter, the federal law will prevail, however, such conflicts are uncommon. The federal government has primary jurisdiction over federal works, undertakings and federally regulated industries such as railways, aviation and interprovincial transport. The *Canadian Environmental Protection Act, 1999* and the *Canadian Environmental Assessment Act, 2012* provide the foundation for the federal government to protect the environment and cooperate with provinces to do the same.

Pursuant to the Prosperity Act, the Government of Canada amended or repealed several pieces of federal environmental legislation and in addition, created a new federal environmental assessment regime that came into force on July 6, 2012. The changes to the environmental legislation under the Prosperity Act are intended to provide for more efficient and timely environmental assessments of projects that previously had been subject to overlapping legislative jurisdiction.

On June 20, 2016, the federal government launched a review of current environmental and regulatory processes with a focus on rebuilding trust in the environmental assessment processes, modernizing the NEB, and introducing modernized safeguards to both the *Fisheries Act* and the *Navigation Protection Act*. An expert panel has been convened and is expected to complete its work by mid 2017. At such time, the Minister of Environment and Climate Change will consider the recommendations in the panel's report and identify next steps to improve federal environmental processes, which is expected to take place during the summer/fall of 2017. Until this process is complete, the federal government's interim principles released January 27, 2016 will continue to guide decision-making authorities for projects currently undergoing environmental assessment. The federal government has not provided any indication on what changes—if any—will be implemented or when, but increased delays and uncertainty surrounding the environmental assessment process should be expected for large projects.

In a further development, on November 29, 2016, the Government of Canada announced that it would introduce legislation by spring 2017 to formalize a moratorium for crude oil tankers on British Columbia's north coast. It is unclear how the proposed moratorium may affect ongoing liquid natural gas export projects currently under consideration and development. On the same day, the Government of Canada also approved, subject to a number of conditions, the Trans Mountain Pipeline system expansion backed by Kinder Morgan Canada as well as the replacement of Enbridge Inc.'s plan to replace its Line 3 pipeline system, while also rejecting Enbridge Inc.'s proposed Northern Gateway project. On January 11, 2017, the Government of British Columbia confirmed that the conditions to the approval of the Trans Mountain Pipeline have been satisfied. Additionally, the new administration in the United States has indicated a willingness to revisit other pipeline projects that had been previously rejected.

Alberta

The AER is the single regulator responsible for all energy development in Alberta. The AER ensures the safe, efficient, orderly, and environmentally responsible development of hydrocarbon resources including allocating and conserving water resources, managing public lands, and protecting the environment. The AER's responsibilities exclude the functions of the Alberta Utilities Commission and the Surface Rights Board, as well as Alberta Energy's responsibility for mineral tenure. The objective behind a single regulator is an enhanced regulatory regime that is efficient, attractive to business and investors, and effective in supporting public safety, environmental management and resource conservation while respecting the rights of landowners.

The Government of Alberta relies on regional planning to accomplish its responsible resource development goals. The following frameworks, plans and policies form the basis of Alberta's Integrated Resource Management System. The Integrated Resource Management System method to natural resource management provides for engagement and consultation with stakeholders and the public and examines the cumulative impacts of development on the environment and communities, by incorporating the management of all resources, including energy, minerals, land, air, water and biodiversity. While the AER is the primary regulator for energy development, several other governmental departments and agencies may be involved in land use issues, including Alberta Environment and Parks, Alberta Energy, the Policy Management Office, the Aboriginal Consultation Office, and the Land Use Secretariat.

In December 2008, the Government of Alberta released a new land use policy for surface land in Alberta, the Alberta Land Use Framework (the "**ALUF**"). The ALUF sets out an approach to manage public and private land use and natural resource development in a manner that is consistent with the long-term economic, environmental and social goals of the province. It calls for the development of seven region-specific land use plans in order to manage the combined impacts of existing and future land use within a specific region and the incorporation of a cumulative effects management approach into such plans.

Proclaimed in force in Alberta on October 1, 2009, the *Alberta Land Stewardship Act* (the "**ALSA**") provides the legislative authority for the Government of Alberta to implement the policies contained in the ALUF. Regional plans established under the ALSA are deemed to be legislative instruments equivalent to regulations and will be binding on the Government of Alberta and provincial regulators, including those governing the oil and gas industry. In the event of a conflict or inconsistency between a regional plan and another regulation, regulatory instrument or statutory consent, the regional plan will prevail. Further, the ALSA requires local governments, provincial departments, agencies and administrative bodies or tribunals to review their regulatory instruments and make any appropriate changes to ensure that they comply with an adopted regional plan. The ALSA also contemplates the amendment or extinguishment of previously issued statutory consents such as regulatory permits, licences, registrations, approvals and authorizations for the purpose of achieving or maintaining an objective or policy resulting from the implementation of a regional plan. Among the measures to support the goals of the regional plans contained in the ALSA are conservation easements, which can be granted for the protection, conservation and enhancement of land; and conservation directives, which are explicit declarations contained in a regional plan to set aside specified lands in order to protect, conserve, manage and enhance the environment.

On August 22, 2012, the Government of Alberta approved the Lower Athabasca Regional Plan ("**LARP**") which came into force on September 1, 2012. The LARP is the first of seven regional plans developed under the ALUF. LARP covers a region in the northeastern corner of Alberta that is approximately 93,212 square kilometres in size. The region includes a substantial portion of the Athabasca oil sands area, which contains approximately 82% of the province's oil sands resources and much of the Cold Lake oil sands area.

LARP establishes six new conservation areas and nine new provincial recreation areas. In conservation and provincial recreation areas, conventional oil and gas companies with pre-existing tenure may continue to operate. Any new petroleum and gas tenure issued in conservation and provincial recreation areas will include a restriction that prohibits surface access. In contrast, oil sands companies' tenure has been (or will be) cancelled in conservation areas and no new oil sands tenure will be issued. While new oil sands tenure will be issued in provincial recreation areas, new and existing oil sands tenure will prohibit surface access.

In July 2014, the Government of Alberta approved the South Saskatchewan Regional Plan ("**SSRP**") which came into force on September 1, 2014. The SSRP is the second regional plan developed under the ALUF. The SSRP covers approximately 83,764 square kilometres and includes 44% of the provincial population.

The SSRP creates four new and four expanded conservation areas, and two new and six expanded provincial parks and recreational areas. Similar to LARP, the SSRP will honour existing petroleum and natural gas tenure in conservation and provincial recreational areas. However, any new petroleum and natural gas tenures sold in conservation areas, provincial parks, and recreational areas will prohibit surface access. However, oil and gas companies must minimize impacts of activities on the natural landscape, historic resources, wildlife, fish and vegetation when exploring, developing and extracting the resources. Freehold mineral rights will not be subject to this restriction.

Phase 1 Consultation of the North Saskatchewan Region Plan has been completed and the Regional Advisory Council is currently preparing its Recommendation to Government report. The North Saskatchewan Region Plan is located in central Alberta and is approximately 85,780 square kilometres in size and affects activities in central Alberta, and encompasses an area between the province's borders with British Columbia and Saskatchewan. The Upper Peace Region Plan, Lower Peace Region Plan, Red Dear Region Plan and Upper Athabasca Region Plan have not been started.

Liability Management Rating Programs

Alberta

In Alberta, the AER administers the Licensee Liability Rating Program (the "**AB LLR Program**"). The AB LLR Program is a liability management program governing most conventional upstream oil and gas wells, facilities and pipelines. Alberta's *Oil and Gas Conservation Act* establishes an orphan fund (the "**Orphan Fund**") to pay the costs to suspend, abandon, remediate and reclaim a well, facility or pipeline included in the AB LLR Program if a licensee or working interest participant becomes defunct or is unable to meet its obligations. The Orphan Fund is funded by licensees in the AB LLR Program through a levy administered by the AER. The AB LLR Program is designed to minimize the risk to the Orphan Fund posed by unfunded liability of licences and to prevent the taxpayers of Alberta from incurring costs to suspend, abandon, remediate and reclaim wells, facilities or pipelines. The AB LLR Program requires a licensee whose deemed liabilities exceed its deemed assets to provide the AER with a security deposit. The ratio of deemed assets to deemed liabilities is assessed once each month and failure to post the required security deposit may result in the initiation of enforcement action by the AER. The AER publishes the liability management rating for each licensee on a monthly basis.

Made effective in three phases, from May 1, 2013 to August 1, 2015, the AER implemented important changes to the AB LLR Program that resulted in a significant increase in the number of oil and gas companies in Alberta that are required to post security. The changes affect the deemed parameters and costs used in the formula that calculates the ratio of deemed assets to deemed liabilities under the AB LLR Program, increasing a licensee's deemed liabilities and rendering the industry average netback factor more sensitive to asset value fluctuations. The changes stem from concern that the previous regime significantly underestimated the environmental liabilities of licensees.

On June 20, 2016, the AER issued *Bulletin 2016-16, Licensee Eligibility—Alberta Energy Regulator Measures to Limit Environmental Impacts Pending Regulatory Changes to Address the Redwater Decision* ("**Bulletin 16**") in an urgent response to a decision from the Court, which is currently under appeal with the Court of Appeal of Alberta. In *Redwater Energy Corporation (Re)*, 2016 ABQB 278 ("**Redwater**"), Chief Justice Wittman found that there was an operational conflict between the abandonment and reclamation provisions of Alberta's *Oil and Gas Conservation Act* and the *Bankruptcy and Insolvency Act*, and that receivers and trustees have the right to renounce assets within insolvency proceedings. Such a conflict renders the AER's legislated authority unenforceable to impose abandonment orders against licensees or to require a licensee to pay a security deposit before approving a transfer when such a licensee is insolvent. Effectively, this means that abandonment costs will be borne by the industry-funded Orphan Fund or the province in these instances because any resources of the insolvent licensee will first be used to satisfy secured creditors under the BIA. Bulletin 16 provides interim rules to govern while the case is appealed and while the Government of Alberta can develop appropriate regulatory measures to adequately address environmental liabilities. Three changes were implemented to minimize the risk to Albertans:

- The AER will consider and process all applications for licence eligibility under *Directive 067: Applying for Approval to Hold EUB Licences* as non-routine and may exercise its discretion to refuse an application or impose terms and conditions on a licencee eligibility approval if appropriate in the circumstances.
- For holders of existing but previously unused licence eligibility approvals, prior to approval of any application (including licence transfer applications), the AER may require evidence that there have been no material changes since approving the licence eligibility. This may include evidence that the holder continues to maintain adequate insurance and that the directors, officers, and/or shareholders are substantially the same as when licence eligibility was originally granted.

- As a condition of transferring existing AER licences, approvals, and permits, the AER will require all transferees to demonstrate that they have a liability management rating ("**LMR**"), being the ratio of a licensee's assets to liabilities, of 2.0 or higher immediately following the transfer.

In order to clarify and revise the interim rules in Bulletin 16, the AER issued *Bulletin 2016-21: Revision and Clarification on Alberta Energy Regulator's Measures to Limit Environmental Impacts Pending Regulatory Changes to Address the Redwater Decision* ("**Bulletin 21**") on July 8, 2016 and reaffirmed its position that an LMR of 1.0 is not sufficient to ensure that licensees will be able to address their obligations throughout the life cycle of energy development, and 2.0 remains the requirement for transferees. However, Bulletin 21 did provide the AER with additional flexibility to permit licensees to acquire additional AER-licensed assets if:

- The licensee already has an LMR of 2.0 or higher;
- The acquisition will improve the licensee's LMR to 2.0 or higher; or
- The licensee is able to satisfy its obligations, notwithstanding an LMR below 2.0, by other means.

The AER provided no indication of what other means would be considered. In the short term the interim measures caused delays in completing transactions and reduced the pool of possible purchasers, however, transactions have been approved following a more rigorous review by the AER, despite a transferee's LMR not meeting the interim requirement. The Alberta Court of Appeal heard the appeal of the Redwater decision on October 11, 2016, with the Court reserving its decision.

The AER implemented the Inactive Well Compliance Program (the "**IWCP**") to address the growing inventory of inactive wells in Alberta and to increase the AER's surveillance and compliance efforts under *Directive 013: Suspension Requirements for Wells* ("**Directive 013**"). The IWCP applies to all inactive wells that are noncompliant with Directive 013 as of April 1, 2015. The objective is to bring all inactive noncompliant wells under the IWCP into compliance with the requirements of Directive 013 within 5 years. As of April 1, 2015, each licensee is required to bring 20% of its inactive wells into compliance every year, either by reactivating or by suspending the wells in accordance with Directive 013 or by abandoning them in accordance with *Directive 020: Well Abandonment*. The list of current wells subject to the IWCP is available on the AER's digital submission system. The AER has announced that from April 1, 2015 to April 1, 2016, the number of noncompliant wells subject to the IWCP fell from 25,792 to 17,470, with 76% of licensees operating in the province having met their annual quota

Climate Change Regulation

Federal

Climate change regulation at both the federal and provincial level has the potential to significantly affect the regulatory environment of the oil and natural gas industry in Canada. Such regulations, surveyed below, impose certain costs and risks on the industry.

On April 26, 2007, the Government of Canada released "Turning the Corner: An Action Plan to Reduce Greenhouse Gases and Air Pollution" (the "**Action Plan**") which set forth a plan for regulations to address both GHG and air pollution. An update to the Action Plan, "Turning the Corner: Regulatory Framework for Industrial Greenhouse Gas Emissions" was released on March 10, 2008 (the "**Updated Action Plan**"). The Updated Action Plan outlines emissions intensity-based targets, for application to regulated sectors on a facility-specific basis, sector-wide basis or company-by-company basis. Although the intention was for draft regulations aimed at implementing the Updated Action Plan to become binding on January 1, 2010, the only regulations being implemented are in the transportation and electricity sectors.

As a signatory to the *United Nations Framework Convention on Climate Change* (the "**UNFCCC**") and a participant to the Copenhagen Accord (a non-binding agreement created by the UNFCCC), the Government of Canada announced on January 29, 2010 that it will seek a 17% reduction in GHG emissions from 2005 levels by 2020; however, the GHG emission reduction targets are not binding. In May 2015, Canada submitted its Intended Nationally Determined Contribution ("**INDC**") to the UNFCCC. INDCs were communicated prior to the 2015 United Nations Climate Change Conference, held in Paris, France, which led to the Paris Agreement that came into force November 4, 2016 (the "**Paris Agreement**"). Among other items, the Paris Agreement constitutes the actions and targets that individual countries will undertake to help keep global temperatures from rising more than 2° Celsius and to pursue efforts to limit below 1.5° Celsius. The Government of Canada ratified the Paris Agreement on December 12, 2016, and pursuant to the agreement, Canada's INDC became its Nationally Determined Contributions ("**NDC**"). As a result, the Government of Canada replaced its INDC of a 17% reduction target established in the Copenhagen Accord with an NDC of 30% reduction below 2005 levels by 2030.

On June 29, 2016, the North American Climate, Clean Energy and Environment Partnership was announced among Canada, Mexico and the United States, which announcement included an action plan for achieving a competitive, low-carbon and sustainable North American economy. The plan includes setting targets for clean power generation, committing to implement the Paris Agreement, setting out specific commitments to address certain short-lived climate pollutants, and the promotion of clean and efficient transportation.

Additionally, on December 9, 2016, the Government of Canada formally announced the Pan-Canadian Framework on Clean Growth and Climate Change. As a result, the federal government will implement a Canada-wide carbon pricing scheme beginning in 2018. This may be implemented through either a cap and trade system or a carbon tax regime at the option of each province or territory. The federal government will impose a price on carbon of $10 per tonne on any province or territory which fails to implement its own system by 2018. This amount will increase by $10 annually until it reaches $50 per tonne in 2022 at which time the program will be reviewed.

In general, there is some uncertainty with regard to the impacts of federal or provincial climate change and environmental laws and regulations, as it is currently not possible to predict the extent of future requirements. Any new laws and regulations, or additional requirements to existing laws and regulations, could have a material impact our operations and cash flow.

Alberta

As part of its efforts to reduce GHG emissions, Alberta introduced legislation to address GHG emissions: the *Climate Change and Emissions Management Act* enacted on December 4, 2003 and amended through the *Climate Change and Emissions Management Amendment Act*, which received royal assent on November 4, 2008. The accompanying regulations include the *Specified Gas Emitters Regulation* ("**SGER**"), which imposes GHG limits, and the *Specified Gas Reporting Regulation*, which imposes GHG emissions reporting requirements. Alberta is the first jurisdiction in North America to impose regulations requiring large facilities in various sectors to reduce their GHG emissions. The SGER applies to facilities emitting more than 100,000 tonnes of GHG emissions in 2003 or any subsequent year ("**Regulated Emitters**"), and requires reductions in GHG emissions intensity (e.g. the quantity of GHG emissions per unit of production) from emissions intensity baselines established in accordance with the SGER.

On June 25, 2015, the Government of Alberta renewed the SGER for a period of two years with significant amendments while Alberta's newly formed Climate Advisory Panel conducted a comprehensive review of the province's climate change policy. As of 2015, Regulated Emitters are required to reduce their emissions intensity by 2% from their baseline in the fourth year of commercial operation, 4% of their baseline in the fifth year, 6% of their baseline in the sixth year, 8% of their baseline in the seventh year, 10% of their baseline in the eighth year, and 12% of their baseline in the ninth or subsequent years. These reduction targets will increase, meaning that Regulated Emitters in their ninth or subsequent years of commercial operation must reduce their emissions intensity from their baseline by 15% in 2016 and 20% in 2017.

A Regulated Emitter can meet its emissions intensity targets through a combination of the following: (1) producing its products with lower carbon inputs, (2) purchasing emissions offset credits from non-regulated emitters (generated through activities that result in emissions reductions in accordance with established protocols), (3) purchasing emissions performance credits from other Regulated Emitters that earned credits through the reduction of their emissions below the 100,000 tonne threshold, (4) cogeneration compliance adjustments, and (5) by contributing to the Climate Change and Emissions Management Fund. Contributions to the fund are made at a rate of $15 per tonne of GHG emissions, increasing to a rate of $20 per tonne of GHG emissions in 2016 and $30 per tonne of GHG emissions in 2017. Proceeds from the fund are directed at testing and implementing new technologies for green energy production.

On November 22, 2015, as a result of the Climate Advisory Panel's Climate Leadership report, the Government of Alberta announced its Climate Leadership Plan. On June 7, 2016, the *Climate Leadership Implementation Act* ("**CLIA**") was passed into law. The CLIA enacted the *Climate Leadership Act* ("**CLA**") introducing a carbon tax on all sources of GHG emissions, subject to certain exemptions. An initial economy-wide levy of $20 per tonne was implemented on January 1, 2017, increasing to $30 per tonne in January of 2018. All fuel consumption—including gasoline and natural gas—will be subject to the levy, with certain exemptions, and directors of a corporation may be held jointly and severally liable with a corporation when the corporation fails to remit an owed carbon levy. Regulated Emitters will remain subject to the SGER framework until the end of 2017 and are exempt from paying the carbon levy on fuels used in operations until this time. Upon the expiry of the SGER, the Government of Alberta intends to transition to a proposed *Carbon Competitiveness Regulation*, in which sector specific output-based carbon allocations will be used to ensure competitiveness. A 100 megatonne per year limit for GHG emissions was implemented for oil sands operations, which currently emit roughly 70 megatonnes per year. This cap exempts new upgrading and cogeneration facilities, which are allocated a separate 10 megatonne limit.

There are certain exemptions to the carbon levy imposed by the CLA. Until 2023, fuels consumed, flared or vented in a production process by conventional oil and gas producers will be exempt from the carbon levy. An exemption also applies for biofuels and fuels sold for export. In addition, marked fuels used in farming operations as well as personal and band uses by First Nations are exempt.

The passing of the CLIA is the first step towards executing the Climate Leadership Plan (other legislation is still pending). In addition to enacting the CLA, the CLIA also enacted the *Energy Efficiency Alberta Act*, which enables the creation of Energy Efficiency Alberta, a new Crown corporation to support and promote energy efficiency programs and services for homes and businesses.

The Government of Alberta also signaled its intention through its Climate Leadership Plan to implement regulations that would lower methane emissions by 45% by 2025. Regulations are planned to take effect in 2020 to ensure the 2025 target is met.

Alberta is also the first jurisdiction in North America to direct dedicated funding to implement carbon capture and storage technology across industrial sectors. Alberta has committed $1.24 billion over 15 years to fund two large-scale carbon capture and storage projects that will begin commercializing the technology on the scale needed to be successful. On December 2, 2010, the Government of Alberta passed the *Carbon Capture and Storage Statutes Amendment Act, 2010*. It deemed the pore space underlying all land in Alberta to be, and to have always been the property of the Crown and provided for the assumption of long-term liability for carbon sequestration projects by the Crown, subject to the satisfaction of certain conditions.

RISK FACTORS

Investors should carefully consider the risk factors set out below and consider all other information contained herein and in our other public filings before making an investment decision. The risks set out below are not an exhaustive list, and should not be taken as a complete summary or description of all the risks associated with our business and the oil and natural gas business generally.

Exploration, Development and Production Risks

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. Our long-term commercial success depends on our ability to find, acquire, develop and commercially produce oil and gas reserves. Without the continual addition of new reserves, our existing reserves, and the production from them, will decline over time as we produce from such reserves. A future increase in our reserves will depend on both our ability to explore and develop our existing properties and on our ability to select and acquire suitable producing properties or prospects. There is no assurance that we will be able continue to find satisfactory properties to acquire or participate in. Moreover, our management may determine that current markets, terms of acquisition, participation or pricing conditions make potential acquisitions or participation uneconomic. There is also no assurance that we will discover or acquire further commercial quantities of oil and natural gas.

Future oil and natural gas exploration may involve unprofitable efforts from dry wells as well as from wells that are productive but do not produce sufficient petroleum substances to return a profit after drilling, completing (including hydraulic fracturing), operating and other costs. Completion of a well does not ensure a profit on the investment or recovery of drilling, completion and operating costs.

Drilling hazards, environmental damage and various field operating conditions could greatly increase the cost of operations and adversely affect the production from successful wells. Field operating conditions include, but are not limited to, delays in obtaining governmental approvals or consents, shut-ins of wells resulting from extreme weather conditions, insufficient storage or transportation capacity or geological and mechanical conditions. While diligent well supervision and effective maintenance operations can contribute to maximizing production rates over time, it is not possible to eliminate production delays and declines from normal field operating conditions, which can negatively affect revenue and cash flow levels to varying degrees.

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including, but not limited to, fire, explosion, blowouts, cratering, sour gas releases, spills and other environmental hazards. These typical risks and hazards could result in substantial damage to oil and natural gas wells, production facilities, other property, the environment and personal injury. Particularly, we may explore for and produce sour natural gas in certain areas. An unintentional leak of sour natural gas could result in personal injury, loss of life or damage to property and may necessitate an evacuation of populated areas, all of which could result in liability to us.

Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including encountering unexpected formations or pressures, premature decline of reservoirs and the invasion of water into producing formations. Losses resulting from the occurrence of any of these risks may have a material adverse effect on our business, financial condition, results of operations and prospects.

As is standard industry practice, we are not fully insured against all risks, nor are all risks insurable. Although we maintain liability insurance in an amount that we consider consistent with industry practice, liabilities associated with certain risks could exceed policy limits or not be covered. In either event, we could incur significant costs.

Weakness in the Oil and Gas Industry

Recent market events and conditions, including global excess oil and natural gas supply, recent actions taken by the Organization of the Petroleum Exporting Countries ("**OPEC**"), slowing growth in emerging economies, market volatility and disruptions in Asia, sovereign debt levels and political upheavals in various countries have caused significant weakness and volatility in commodity prices. These events and conditions have caused a significant decrease in the valuation of oil and gas companies and a decrease in confidence in the oil and gas industry. These difficulties have been exacerbated in Canada by the recent changes in government at a federal level and, in the case of Alberta, at the provincial level, and the resultant uncertainty surrounding regulatory, tax, royalty changes and environmental regulation that have been announced or may be implemented by the new governments. In addition, the inability to get the necessary approvals to build pipelines and other facilities to provide better access to markets for the oil and gas industry in Western Canada has led to additional downward price pressure on oil and gas produced in Western Canada and uncertainty and reduced confidence in the oil and gas industry in Western Canada. Lower commodity prices may also affect the volume and value of our reserves, rendering certain reserves uneconomic. In addition, lower commodity prices have restricted, and are anticipated to continue to restrict, our cash flow resulting in a reduced capital expenditure budget. Consequently, we may not be able to replace our production with additional reserves and both our production and reserves could be reduced on a year over year basis. Any decrease in value of our reserves may reduce the borrowing base under our credit facilities, which, depending on the level of our indebtedness, could result in having to repay a portion of our indebtedness. Given the current market conditions and the lack of confidence in the Canadian oil and gas industry, we may have difficulty raising additional funds or if we are able to do so, it may be on unfavourable and highly dilutive terms. If these conditions persist, our cash flow may not be sufficient to continue to fund our operations and to satisfy our obligations when due and our ability to continue as a going concern and discharge our obligations will require additional equity or debt financing and/or proceeds or reduction in liabilities from asset sales. There can be no assurance that such equity or debt financing will be available on terms that are satisfactory or at all. Similarly, there can be no assurance that we will be able to realize any or sufficient proceeds or reduction in liabilities from asset sales to discharge our obligations.

Prices, Markets and Marketing

Numerous factors beyond our control do, and will continue to affect the marketability and price of oil and natural gas acquired, produced or discovered by us. Our ability to market our oil and natural gas may depend upon our ability to acquire capacity on pipelines that deliver natural gas to commercial markets or contract for the delivery of crude oil by rail. Deliverability uncertainties related to the distance of our reserves are from pipelines, railway lines, processing and storage facilities, operational problems affecting pipelines, railway lines and facilities and government regulation relating to prices, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and many other aspects of the oil and natural gas business may also affect us.

Prices for oil and natural gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty and a variety of additional factors beyond our control. These factors include economic and political conditions, in the United States, Canada, Europe, China and emerging markets the actions of OPEC, governmental regulation, political stability in the Middle East, Northern Africa and elsewhere, the foreign supply and demand of oil and natural gas, risks of supply disruption, the price of foreign imports and the availability of alternative fuel sources. Prices for oil and natural gas are also subject to the availability of foreign markets and our ability to access such markets. Oil prices are expected to remain volatile as a result of global excess supply due, in part, to the increased growth of shale oil production in the United States, the decline in global demand for exported crude oil commodities, OPEC's recent decisions pertaining to the oil production of OPEC member countries and non-OPEC member countries' decisions on production levels, among other factors. A material decline in oil prices could result in a reduction of our net production revenue. The economics of producing from some wells may change because of lower prices, which could result in reduced production of oil or natural gas and a reduction in the volumes and the value of our reserves. We might also elect not to produce from certain wells at lower prices.

All these factors could result in a material decrease in our expected net production revenue and a reduction in our oil and natural gas production, development and exploration activities. Any substantial and extended decline in the price of oil and natural gas would have an adverse effect on the carrying value of our reserves, borrowing capacity, revenues, profitability and cash flows from operations and may have a material adverse effect on our business, financial condition, results of operations and prospects.

Oil and natural gas prices are expected to remain volatile for the near future because of market uncertainties over the supply and the demand of these commodities due to the current state of the world economies, OPEC actions, political uncertainties, sanctions imposed on certain oil producing nations by other countries and ongoing credit and liquidity concerns. Volatile oil and natural gas prices make it difficult to estimate the value of producing properties for acquisitions and often cause disruption in the market for oil and natural gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for, and project the return on, acquisitions and development and exploitation projects. See "*Weakness in the Oil and Gas Industry*".

Risks Associated with Forecast Prices

Our reserves as at December 31, 2016 are estimated using forecast pricing escalating prices as set forth under "*Statement of Reserves Data and Other Oil and Natural Gas Information – Disclosure of Reserves Data – Pricing Assumptions*". These prices are substantially above current oil and natural gas prices. If oil and gas prices stay at current levels our reserves may be substantially reduced as economic limits of developed reserves are reached earlier and undeveloped reserves become uneconomic at such prices. Even if some reserves remain economic at lower price levels, sustained low prices may compel us to re-evaluate our development plans and reduce or eliminate various projects with marginal economics.

Market Price of our Common Shares

The trading price of our securities is subject to substantial volatility often based on factors related and unrelated to our financial performance or prospects. Factors unrelated to our performance could include macroeconomic developments nationally, within North America or globally, domestic and global commodity prices, or current perceptions of the oil and gas market. Similarly, the market price of our Common Shares could be subject to significant fluctuations in response to variations in our operating results, financial condition, liquidity and other internal factors. Accordingly, the price at which our Common Shares will trade cannot be accurately predicted.

Dividends

The amount of future cash dividends paid by us, if any, will be subject to the discretion of our Board of Directors and may vary depending on a variety of factors and conditions existing from time to time, including fluctuations in commodity prices, production levels, capital expenditure requirements, debt service requirements, operating costs, royalty burdens, foreign exchange rates and the satisfaction of the liquidity and solvency tests imposed by the *Business Corporations Act* (Alberta) for the declaration and payment of dividends. Depending on these and various other factors, many of which will be beyond our control, our dividend policy may vary from time to time and, as a result, future cash dividends could be reduced or suspended entirely.

The market value of our Common Shares may deteriorate if dividends are reduced or suspended. Furthermore, the future treatment of dividends for tax purposes will be subject to the nature and composition of dividends paid by us and potential legislative and regulatory changes. Dividends may be reduced during periods of lower funds from operating activities, which result from lower commodity prices and any decision by us to finance capital expenditures using funds from operating activities.

To the extent that external sources of capital, including the issuance of additional Common Shares, become limited or unavailable, our ability to make the necessary capital investments to maintain or expand petroleum and natural gas reserves and to invest in assets, as the case may be, will be impaired. To the extent that we are required to use funds from operating activities to finance capital expenditures or property acquisitions, the cash available for dividends may be reduced.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

We consider acquisitions and dispositions of businesses and assets in the ordinary course of business. Achieving the benefits of acquisitions depends on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner and our ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with ours. The integration of acquired businesses may require substantial management effort, time and resources diverting management's focus from other strategic opportunities and operational matters. Management continually assesses the value and contribution of services provided by third parties and assets required to provide such services. In this regard, non-core assets may be periodically disposed of so that we can focus our efforts and resources more efficiently. Depending on the state of the market for such non-core assets, certain of our non-core assets may realize less on disposition than their carrying value on our financial statements.

Political Uncertainty

In the last several years, the United States and certain European countries have experienced significant political events that have cast uncertainty on global financial and economic markets. During the recent presidential campaign, in the United States, a number of election promises were made and the new American administration has begun taking steps to implement certain of these promises. Included in the actions that the administration has discussed are the renegotiation of the terms of NAFTA, withdrawal of the United States from the Trans-Pacific Partnership, imposition of a tax on the importation of goods into the United States, reduction of regulation and taxation in the United States, and introduction of laws to reduce immigration and restrict access into the United States for citizens of certain countries. It is presently unclear exactly what actions the new administration in the United States will implement, and if implemented, how these actions may impact Canada and in particular the oil and gas industry. Any actions taken by the new United States administration may have a negative impact on the Canadian economy and on the businesses, financial conditions, results of operations and the valuation of Canadian oil and gas companies, including us.

In addition to the political disruption in the United States, the citizens of the United Kingdom recently voted to withdraw from the European Union and the Government of the United Kingdom has begun taken steps to implement such withdrawal. Some European countries have also experienced the rise of anti-establishment political parties and public protests held against open-door immigration policies, trade and globalization. To the extent that certain political actions taken in North America, Europe and elsewhere in the world result in a marked decrease in free trade, access to personnel and freedom of movement it could have an adverse effect on our ability to market our products internationally, increase costs for goods and services required for our operations, reduce access to skilled labour and negatively impact our business, operations, financial conditions and the market value of our Common Shares.

Operational Dependence

Other companies operate some of the assets in which we have an interest. We have limited ability to exercise influence over the operation of those assets or their associated costs, which could adversely affect our financial performance. Our return on assets operated by others depends upon a number of factors that may be outside of our control, including, but not limited to, the timing and amount of capital expenditures, the operator's expertise and financial resources, the approval of other participants, the selection of technology and risk management practices.

In addition, due to the current low and volatile commodity prices, many companies, including companies that may operate some of the assets in which we have an interest, may be in financial difficulty, which could impact their ability to fund and pursue capital expenditures, carry out their operations in a safe and effective manner and satisfy regulatory requirements with respect to abandonment and reclamation obligations. If companies that operate some of the assets in which we have an interest fail to satisfy regulatory requirements with respect to abandonment and reclamation obligations we may be required to satisfy such obligations and to seek reimbursement from such companies. To the extent that any of such companies go bankrupt, become insolvent or make a proposal or institute any proceedings relating to bankruptcy or insolvency, it could result in such assets being shut-in, the potential of us becoming subject to additional liabilities relating to such assets and us having difficulty collecting revenue due from such operators or recovering amounts owing to us from such operators for their share of abandonment and reclamation obligations. Any of these factors could have a material adverse affect on our financial and operational results.

Project Risks

We manage a variety of small and large projects in the conduct of our business. Project delays may delay expected revenues from operations. Significant project cost overruns could make a project uneconomic. Our ability to execute projects and market oil and natural gas depends upon numerous factors beyond our control, including:

- the availability of processing capacity;
- the availability and proximity of pipeline capacity;
- the availability of storage capacity;
- the availability of, and the ability to acquire, water supplies needed for drilling, hydraulic fracturing and waterfloods or our ability to dispose of water used or removed from strata at a reasonable cost and in accordance with applicable environmental regulations;
- the effects of inclement weather;
- the availability of drilling and related equipment;
- unexpected cost increases;
- accidental events;
- currency fluctuations;
- regulatory changes;
- the availability and productivity of skilled labour; and
- the regulation of the oil and natural gas industry by various levels of government and governmental agencies.

Because of these factors, we could be unable to execute projects on time, on budget, or at all, and may be unable to market the oil and natural gas that we produce effectively.

Gathering and Processing Facilities, Pipeline Systems and Rail

We deliver our products through gathering, processing facilities, pipeline systems and, in certain circumstances, by rail. The amount of oil and natural gas that we can produce and sell is subject to the accessibility, availability, proximity and capacity of these gathering and processing facilities, pipeline systems and railway lines. The lack of availability of capacity in any of the gathering and processing facilities, pipeline systems and railway lines, could result in our inability to realize the full economic potential of our production or in a reduction of the price offered for our production. The lack of firm pipeline capacity continues to affect the oil and natural gas industry and limit the ability to transport produced oil and gas to market. In addition, the pro-rationing of capacity on inter-provincial pipeline systems also continues to affect the ability to export oil and natural gas. Unexpected shut downs or curtailment of capacity of pipelines for maintenance or integrity work or because of actions taken by regulators could also affect our production, operations and financial results. As a result, producers are increasingly turning to rail as an alternative means of transportation. In recent years, the volume of crude oil shipped by rail in North America has increased dramatically. Any significant change in market factors or other conditions affecting these infrastructure systems and facilities, as well as any delays or uncertainty in constructing new infrastructure systems and facilities could harm our business and, in turn, our financial condition, operations and cash flows. In addition, the federal government has signaled that it plans to review the NEB approval process for large federally regulated projects. This may cause the timeframe for project approvals to increase for current and future applications.

Following major accidents in Lac-Megantic, Quebec and North Dakota, the Transportation Safety Board of Canada and the U.S. National Transportation Board have recommended additional regulations for railway tank cars carrying crude oil. In June 2015, as a result of these recommendations, the Government of Canada passed the *Safe and Accountable Rail Act* which increased insurance obligations on the shipment of crude oil by rail and imposed a per tonne levy of $1.65 on crude oil shipped by rail to compensate victims and for environmental cleanup in the event of a railway accident. In addition to this legislation, new regulations have implemented the TC-117 standard for all rail tank cars carrying flammable liquids which formalized the commitment to retrofit, and eventually phase out DOT-111 tank cars carrying crude oil. The increased regulation of rail transportation may reduce the ability of railway lines to alleviate pipeline capacity issues and adds additional costs to the transportation of crude oil by rail. On July 13, 2016, the Minister of Transport (Canada) issued Protective Direction No. 38, which directed that the shipping of crude oil on DOT-111 tank cars end by November 1, 2016. Tank cars entering Canada from the United States will be monitored to ensure they are compliant with Protective Direction No. 38.

A portion of our production may, from time to time, be processed through facilities owned by third parties and over which we do not have control. From time to time, these facilities may discontinue or decrease operations either as a result of normal servicing requirements or as a result of unexpected events. A discontinuation or decrease of operations could have a material adverse effect on our ability to process our production and to deliver the same for sale.

Competition

The petroleum industry is competitive in all of its phases. We compete with numerous other entities in the exploration, development, production and marketing of oil and natural gas. Our competitors include oil and natural gas companies that have substantially greater financial resources, staff and facilities than ours. Our ability to increase our reserves in the future will depend not only on our ability to explore and develop our present properties, but also on our ability to select and acquire other suitable producing properties or prospects for exploratory drilling. Competitive factors in the distribution and marketing of oil and natural gas include price, process, and reliability of delivery and storage.

Cost of New Technologies

The petroleum industry is characterized by rapid and significant technological advancements and introductions of new products and services utilizing new technologies. Other companies may have greater financial, technical and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before us. There can be no assurance that we will be able to respond to such competitive pressures and implement such technologies on a timely basis or at an acceptable cost. If we do implement such technologies, there is no assurance that we will do so successfully. One or more of the technologies currently utilized by us or implemented in the future may become obsolete. In such case, our business, financial condition and results of operations could be materially adversely affected. If we are unable to utilize the most advanced commercially available technology, or we are unsuccessful in implementing certain technologies, our business, financial condition and results of operations could be materially adversely affected.

Alternatives to and Changing Demand for Petroleum Products

Full conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas, and technological advances in fuel economy and energy generation devices could reduce the demand for oil, natural gas and liquid hydrocarbons. We cannot predict the impact of changing demand for oil and natural gas products, and any major changes may have a material adverse effect on our business, financial condition, results of operations and cash flows.

Regulatory

Various levels of governments impose extensive controls and regulations on oil and natural gas operations (including exploration, development, production, pricing, marketing and transportation). Governments may regulate or intervene with respect to exploration and production activities, prices, taxes, royalties and the exportation of oil and natural gas. Amendments to these controls and regulations may occur from time to time in response to economic or political conditions. See "*Industry Conditions*". The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for crude oil and natural gas and increase our costs, either of which may have a material adverse effect on our business, financial condition, results of operations and prospects. In order to conduct oil and natural gas operations, we require regulatory permits, licences, registrations, approvals and authorizations from various governmental authorities at the provincial and federal level. There can be no assurance that we will be able to obtain all of the permits, licences, registrations, approvals and authorizations that may be required to conduct operations that we may wish to undertake. In addition, certain federal legislation such as the *Competition Act* (Canada) and the *Investment Canada Act* (Canada) could negatively affect our business, financial condition and the market value of our Common Shares or our assets, particularly when undertaking, or attempting to undertake, acquisition or disposition activity.

Royalty Regimes

There can be no assurance that the federal government and the provincial governments of the western provinces will not adopt a new royalty regime or modify the existing royalty regimes which may have an impact on the economics of our projects. An increase in royalties would reduce our earnings and could make future capital investments, or our operations, less economic. On January 29, 2016, the Government of Alberta adopted a new royalty regime which took effect on January 1, 2017. See "*Industry Conditions* - *Royalties and Incentives*".

Hydraulic Fracturing

Hydraulic fracturing involves the injection of water, sand and small amounts of additives under pressure into rock formations to stimulate the production of oil and natural gas. Specifically, hydraulic fracturing enables the production of commercial quantities of oil and natural gas from reservoirs that were previously unproductive. Any new laws, regulations or permitting requirements regarding hydraulic fracturing could lead to operational delays, increased operating costs, third party or governmental claims, and could increase our costs of compliance and doing business as well as delay the development of oil and natural gas resources from shale formations, which are not commercial without the use of hydraulic fracturing. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that we are ultimately able to produce from our reserves.

Waterflood

We undertake or intend to undertake certain waterflooding programs which involve the injection of water or other liquids into an oil reservoir to increase production from the reservoir and to decrease production declines. To undertake such waterflooding activities we need to have access to sufficient volumes of water, or other liquids, to pump into the reservoir to increase the pressure in the reservoir. There is no certainty that we will have access to the required volumes of water. In addition, in certain areas there may be restrictions on water use for activities such as waterflooding. If we are unable to access such water we may not be able to undertake waterflooding activities, which may reduce the amount of oil and natural gas that we are ultimately able to produce from our reservoirs. In addition, we may undertake certain waterflood programs that ultimately prove unsuccessful in increasing production from the reservoir and as a result have a negative impact on our results of operations.

Environmental

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on the spill, release or emission of various substances produced in association with oil and gas industry operations. In addition, such legislation sets out the requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment and reclamation of well and facility sites.

Compliance with environmental legislation can require significant expenditures and a breach of applicable environmental legislation may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require us to incur costs to remedy such discharge. Although we believe that we are in material compliance with current applicable environmental legislation, no assurance can be given that environmental compliance requirements will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise have a material adverse effect on our business, financial condition, results of operations and prospects.

Liability Management

Alberta, Saskatchewan and British Columbia have developed liability management programs designed to prevent taxpayers from incurring costs associated with suspension, abandonment, remediation and reclamation of wells, facilities and pipelines in the event that a licensee or permit holder is unable to satisfy its obligation. These programs generally involve an assessment of the ratio of a licensee's deemed assets to deemed liabilities. If a licensee's deemed liabilities exceed its deemed assets, a security deposit is required. Changes to the required ratio of our deemed assets to deemed liabilities or other changes to the requirements of liability management programs may result in significant increases to our compliance requirements. In addition, the liability management system may prevent or interfere with our ability to acquire or dispose of assets as both the vendor and the purchaser of oil and gas assets must be in compliance with the liability management programs (both before and after the transfer of the assets) for the applicable regulatory agency to allow for the transfer of such assets. The Redwater decision, found an operational conflict between the *Bankruptcy and Insolvency Act* and the AER's abandonment and reclamation powers when the licensee is insolvent. The AER appealed this decision and issued interim rules to administer the liability management program and until the Alberta Government can develop new regulatory measures to adequately address environmental liabilities. The decision from this appeal has not been released. There remains a great deal of uncertainty as to what new regulatory measures will be developed or what the impact of the court decision will have on other provinces. See, "*Industry Conditions – Liability Management Rating Programs*".

Climate Change

Our exploration and production facilities and other operations and activities emit GHGs and which may require us to comply with GHG emissions legislation at the provincial or federal level. Climate change policy is evolving at regional, national and international levels, and political and economic events may significantly affect the scope and timing of climate change measures that are ultimately put in place. As a signatory to the UNFCCC and as a participant to the Copenhagen Agreement (a non-binding agreement created by the UNFCCC), the Government of Canada announced on January 29, 2010 that it would seek a 17% reduction in GHG emissions from 2005 levels by 2020; however, these GHG emission reduction targets were not binding. As a result of the UNFCCC adopting the Paris Agreement on December 12, 2015, which Canada ratified on October 3, 2016, the Government of Canada implemented new GHG emission reduction targets of a 30% reduction from 2005 levels by 2030. In addition, the

Government of Canada announced it would implement a Canada wide price on carbon to further reduce its GHG emissions. In addition, on January 1, 2017 the CLA come into effect in the Province of Alberta introducing a carbon tax on almost all sources of GHG emissions at a rate of $20 per tonne, increasing to $30 per tonne in January 2018. The direct or indirect costs of compliance with these regulations may have a material adverse effect on our business, financial condition, results of operations and prospects. Some of our significant facilities may ultimately be subject to future regional, provincial and/or federal climate change regulations to manage GHG emissions. In addition, concerns about climate change have resulted in a number of environmental activists and members of the public opposing the continued exploitation and development of fossil fuels. Given the evolving nature of the debate related to climate change and the control of GHGs and resulting requirements, it is not possible to predict the impact on us and our operations and financial condition. See "*Industry Conditions – Climate Change Regulation*".

Variations in Foreign Exchange Rates and Interest Rates

World oil and natural gas prices are quoted in United States dollars. The Canadian/United States dollar exchange rate, which fluctuates over time, consequently affects the price received by Canadian producers of oil and natural gas. Material increases in the value of the Canadian dollar relative to the United States dollar will negatively affect our production revenues. Accordingly, exchange rates between Canada and the United States could accordingly affect the future value of our reserves as determined by independent evaluators. Although a low value of the Canadian dollar relative to the United States dollar may positively affect the price we receive for our oil and natural gas production, it could also result in an increase in the price for certain goods used for our operations, which may have a negative impact on our financial results.

To the extent that we engage in risk management activities related to foreign exchange rates, there is a credit risk associated with counterparties with which we may contract.

An increase in interest rates could result in a significant increase in the amount we pay to service debt, resulting in a reduced amount available to fund our exploration and development activities, and if applicable, the cash available for dividends and could negatively impact the market price of our Common Shares.

Substantial Capital Requirements

We anticipate making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. As future capital expenditures will be financed out of cash generated from operations, borrowings and possible future equity sales, our ability to do so is dependent on, among other factors:

- the overall state of the capital markets;
- our credit rating (if applicable);
- commodity prices;
- interest rates;
- royalty rates;
- tax burden due to current and future tax laws; and
- investor appetite for investments in the energy industry and our securities in particular.

Further, if our revenues or reserves decline, we may not have access to the capital necessary to undertake or complete future drilling programs. The current conditions in the oil and gas industry have negatively impacted the ability of oil and gas companies to access additional funding. There can be no assurance that debt or equity financing, or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to us. We may be required to seek additional equity financing on terms that are highly dilutive to existing Shareholders. Our inability to access sufficient capital for our operations could have a material adverse effect on our business financial condition, results of operations and prospects.

Additional Funding Requirements

Our cash flow from our reserves may not be sufficient to fund our ongoing activities at all times and from time to time, we may require additional financing in order to carry out our oil and natural gas acquisition, exploration and development activities. Failure to obtain financing on a timely basis could cause us to forfeit our interest in certain properties, miss certain acquisition opportunities and reduce or terminate our operations. Due to the conditions in the oil and gas industry and/or global economic and political volatility, we may from time to time have restricted access to capital and increased borrowing costs. The current conditions in the oil and gas industry have negatively impacted the ability of oil and gas companies to access additional financing.

As a result of global economic and political volatility, we may from time to time have restricted access to capital and increased borrowing costs. Failure to obtain such financing on a timely basis could cause us to forfeit our interest in certain properties, miss certain acquisition opportunities and reduce or terminate our operations. If our revenues from our reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect our ability to expend the necessary capital to replace our reserves or to maintain our production. To the extent that external sources of capital become limited, unavailable, or available on onerous terms, our ability to make capital investments and maintain existing assets may be impaired, and our assets, liabilities, business, financial condition and results of operations may be affected materially and adversely as a result. In addition, the future development of our petroleum properties may require additional financing and there are no assurances that such financing will be available or, if available, will be available upon acceptable terms. Failure to obtain any financing necessary for our capital expenditure plans may result in a delay in development or production on our properties.

Credit Facility Arrangements

The amount authorized under our Credit Facility is determined by our lenders. We are required to comply with certain non-financial covenants under our Credit Facility which from time to time either affect the availability, or price, of additional funding and in the event that we do not comply with these covenants, our access to capital could be restricted or repayment could be required. Events beyond our control may contribute to our failure to comply with such covenants. A failure to comply with covenants could result in the default under the Credit Facility, which could result in us being required to repay amounts owing thereunder. The acceleration of our indebtedness under one agreement may permit acceleration of indebtedness under other agreements that contain cross default or cross-acceleration provisions. In addition, our Credit Facility may impose operating and financial restrictions on us that could include restrictions on, the payment of dividends, repurchase or making of other distributions with respect to our securities, incurring of additional indebtedness, the provision of guarantees, the assumption of loans, making of capital expenditures, entering into of amalgamations, mergers, take-over bids or disposition of assets, among others.

Our lenders use our reserves, commodity prices, applicable discount rate and other factors, to periodically determine our borrowing base. Commodity prices improved in the second half of 2016 however they have fallen dramatically since 2014. There is a significant amount of uncertainty as to when and if commodity prices will fully recover. Depressed commodity prices could reduce our borrowing base, reducing the funds available to us under our Credit Facility which could result in the requirement to repay a portion, or all, of our bank indebtedness.

Issuance of Debt

From time to time, we may enter into transactions to acquire assets or shares of other entities. These transactions may be financed in whole or in part with debt, which may increase our debt levels above industry standards for oil and natural gas companies of similar size. Depending on future exploration and development plans, we may require additional debt financing that may not be available or, if available, may not be available on favourable terms. Neither our articles nor our by-laws limit the amount of indebtedness that we may incur. The level of our indebtedness from time to time, could impair our ability to obtain additional financing on a timely basis to take advantage of business opportunities that may arise.

Hedging

From time to time, we may enter into agreements to receive fixed prices on our oil and natural gas production to offset the risk of revenue losses if commodity prices decline. However, to the extent that we engage in price risk management activities to protect us from commodity price declines, we may also be prevented from realizing the full benefits of price increases above the levels of the derivative instruments used to manage price risk. In addition, our hedging arrangements may expose us to the risk of financial loss in certain circumstances, including instances in which:

- production falls short of the hedged volumes or prices fall significantly lower than projected;
- there is a widening of price-basis differentials between delivery points for production and the delivery point assumed in the hedge arrangement;
- the counterparties to the hedging arrangements or other price risk management contracts fail to perform under those arrangements; or
- a sudden unexpected event materially impacts oil and natural gas prices.

Similarly, from time to time we may enter into agreements to fix the exchange rate of Canadian to United States or dollars or other currencies in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to other currencies. However, if the Canadian dollar declines in value compared to such currencies, we will not benefit from the fluctuating exchange rate.

Availability of Drilling Equipment and Access

Oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment (typically leased from third parties) as well as skilled personnel trained to use such equipment in the areas where such activities will be conducted. Demand for such limited equipment and skilled personnel, or access restrictions, may affect the availability of such equipment and skilled personnel to us and may delay exploration and development activities.

Title to Assets

Although title reviews may be conducted prior to the purchase of oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that a defect in the chain of title will not arise. Our actual interest in properties may accordingly vary from our records. If a title defect does exist, it is possible that we may lose all or a portion of the properties to which the title defect relates, which may have a material adverse effect on our business, financial condition, results of operations and prospects. There may be valid challenges to title, or proposed legislative changes which affect title, to the oil and natural gas properties we control that, if successful or made into law, could impair our activities on them and result in a reduction of the revenue received by us.

Reserve Estimates

There are numerous uncertainties inherent in estimating quantities of crude oil, natural gas and natural gas liquids reserves and the future cash flows attributed to such reserves. The reserve and associated funds from operating activities information set forth in this Annual Information Form are estimates only. Generally, estimates of economically recoverable crude oil and natural gas reserves and the future net cash flows from such estimated reserves are based upon a number of variable factors and assumptions, such as:

- historical production from the properties;
- production rates;
- ultimate reserve recovery;
- timing and amount of capital expenditures;
- marketability of oil and natural gas;
- royalty rates; and

- the assumed effects of regulation by governmental agencies and future operating costs (all of which may vary materially from actual results).

For those reasons, estimates of the economically recoverable crude oil and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves prepared by different engineers, or by the same engineers at different times, may vary. Our actual production, revenues, taxes and development and operating expenditures with respect to our reserves will vary from estimates thereof and such variations could be material.

The estimation of proved reserves that may be developed and produced in the future is often based upon volumetric calculations and upon analogy to similar types of reserves rather than actual production history. Recovery factors and drainage areas are often estimated by experience and analogy to similar producing pools. Estimates based on these methods are generally less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history and production practices will result in variations in the estimated reserves. Such variations could be material.

In accordance with applicable securities laws, our independent reserves evaluator has used forecast prices and costs in estimating the reserves and future net cash flows as summarized herein. Actual future net cash flows will be affected by other factors, such as actual production levels, supply and demand for oil and natural gas, curtailments or increases in consumption by oil and natural gas purchasers, changes in governmental regulation or taxation and the impact of inflation on costs.

Actual production and funds from operations derived from our crude oil and natural gas reserves will vary from the estimates contained in the reserve evaluation, and such variations could be material. The reserve evaluation is based in part on the assumed success of activities we intend to undertake in future years. The reserves and estimated funds from operating activities to be derived therefrom and contained in the reserve evaluation will be reduced to the extent that such activities do not achieve the level of success assumed in the reserve evaluation. The reserve evaluation is effective as of a specific effective date and, except as may be specifically stated, has not been updated and thus does not reflect changes in our reserves since that date.

Insurance

Our involvement in the exploration for and development of oil and natural gas properties may result in us becoming subject to liability for pollution, blow outs, leaks of sour natural gas, property damage, personal injury or other hazards. Although we maintain insurance in accordance with industry standards to address certain of these risks, such insurance has limitations on liability and may not be sufficient to cover the full extent of such liabilities. In addition, certain risks are not, in all circumstances, insurable or, in certain circumstances, we may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or other reasons. The payment of any uninsured liabilities would reduce the funds available to us. The occurrence of a significant event that we are not fully insured against, or the insolvency of the insurer of such event, may have a material adverse effect on our business, financial condition, results of operations and prospects.

Geopolitical Risks

Political events throughout the world that cause disruptions in the supply of oil continuously affect the marketability and price of oil and natural gas acquired or discovered by us. Conflicts, or conversely peaceful developments, arising outside of Canada, including changes in political regimes or the parties in power, have a significant impact on the price of oil and natural gas. Any particular event could result in a material decline in prices and result in a reduction of our net production revenue.

In addition, our oil and natural gas properties, wells and facilities could be the subject of a terrorist attack. If any of our properties, wells or facilities are the subject of terrorist attack it may have a material adverse effect on our business, financial condition, results of operations and prospects. We do not have insurance to protect against the risk from terrorism.

Dilution

We may make future acquisitions or enter into financings or other transactions involving the issuance of our securities which may be dilutive.

Management of Growth

We may be subject to growth related risks including capacity constraints and pressure on our internal systems and controls. Our ability to manage growth effectively will require us to continue to implement and improve our operational and financial systems and to expand, train and manage our employee base. Our inability to deal with this growth may have a material adverse effect on our business, financial condition, results of operations and prospects.

Expiration of Licences and Leases

Our properties are held in the form of licences and leases and working interests in licences and leases. If we or the holder of the licence or lease fails to meet the specific requirement of a licence or lease, the licence or lease may terminate or expire. There can be no assurance that any of the obligations required to maintain each licence or lease will be met. The termination or expiration of our licences or leases or the working interests relating to a licence or lease may have a material adverse effect on our business, financial condition, results of operations and prospects.

Litigation

In the normal course of our operations, we may become involved in, named as a party to, or be the subject of, various legal proceedings, including regulatory proceedings, tax proceedings and legal actions, relating to personal injuries, including resulting from exposure to hazardous substances, property damage, property taxes, land and access rights, environmental issues, including claims relating to contamination or natural resource damages and contract disputes. The outcome with respect to outstanding, pending or future proceedings cannot be predicted with certainty and may be determined adversely to us and as a result, could have a material adverse effect on our assets, liabilities, business, financial condition and results of operations. Even if we prevail in any such legal proceedings, the proceedings could be costly and time-consuming and may divert the attention of management and key personnel from business operations, which could have an adverse effect on our financial condition.

Aboriginal Claims

Aboriginal peoples have claimed aboriginal title and rights in portions of Western Canada. We are not aware that any claims have been made in respect of our properties and assets. However, if a claim arose and was successful such claim may have a material adverse effect on our business, financial condition, results of operations and prospects. In addition, the process of addressing such claims, regardless of the outcome, is expensive and time consuming and could result in delays which could have a material adverse effect on our business and financial results.

Breach of Confidentiality

While discussing potential business relationships or other transactions with third parties, we may disclose confidential information relating to our business, operations or affairs. Although confidentiality agreements are generally signed by third parties prior to the disclosure of any confidential information, a breach could put us at competitive risk and may cause significant damage to our business. The harm to our business from a breach of confidentiality cannot presently be quantified, but may be material and may not be compensable in damages. There is no assurance that, in the event of a breach of confidentiality, we will be able to obtain equitable remedies, such as injunctive relief, from a court of competent jurisdiction in a timely manner, if at all, in order to prevent or mitigate any damage to our business that such a breach of confidentiality may cause.

Income Taxes

We file all required income tax returns and believe that we are in full compliance with the provisions of the *Income Tax Act* (Canada) and all other applicable provincial tax legislation. However, such returns are subject to reassessment by the applicable taxation authority. In the event of a successful reassessment of us, whether by re-characterization of exploration and development expenditures or otherwise, such reassessment may have an impact on current and future taxes payable.

Income tax laws relating to the oil and natural gas industry, such as the treatment of resource taxation or dividends, may in the future be changed or interpreted in a manner that adversely affects us. Furthermore, tax authorities having jurisdiction over us may disagree with how we calculate our income for tax purposes or could change administrative practices to our detriment.

Seasonality

The level of activity in the Canadian oil and natural gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Certain oil and natural gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. In addition, extreme cold weather, heavy snowfall and heavy rainfall may restrict our ability to access our properties and cause operational difficulties. Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity and corresponding decreases in the demand for our goods and services.

Third Party Credit Risk

We may be exposed to third party credit risk through our contractual arrangements with our current or future joint venture partners, marketers of our petroleum and natural gas production and other parties. In addition, we may be exposed to third party credit risk from operators of properties in which we have a working interest or royalty interest. In the event such entities fail to meet their contractual obligations to us, such failures may have a material adverse effect on our business, financial condition, results of operations and prospects. In addition, poor credit conditions in the industry and of joint venture partners may impact a joint venture partner's willingness to participate in our ongoing capital program, potentially delaying the program and the results of such program until we find a suitable alternative partner. To the extent that any of such third parties go bankrupt, become insolvent or make a proposal or institute any proceedings relating to bankruptcy or insolvency, it could result in us being unable to collect all or portion of any money owing from such parties. Any of these factors could materially adversely affect our financial and operational results.

Conflicts of Interest

Certain of our directors or officers may also be directors or officers of other oil and natural gas companies and as such may, in certain circumstances, have a conflict of interest. Conflicts of interest, if any, will be subject to and governed by procedures prescribed by the *Business Corporations Act* (Alberta) which require a director or officer of a corporation who is a party to, or is a director or an officer of, or has a material interest in any person who is a party to, a material contract or proposed material contract with us to disclose his or her interest and, in the case of directors, to refrain from voting on any matter in respect of such contract unless otherwise permitted under the *Business Corporations Act* (Alberta). See "*Directors and Officers – Conflicts of Interest*".

Reliance on Key Personnel

Our success depends in large measure on certain key personnel. The loss of the services of such key personnel may have a material adverse effect on our business, financial condition, results of operations and prospects. We do not have any key personnel insurance in effect. The contributions of the existing management team to our immediate and near term operations are likely to be of central importance. In addition, the competition for qualified personnel in the oil and natural gas industry is intense and there can be no assurance that we will be able to continue to attract and retain all personnel necessary for the development and operation of our business. Investors must rely upon the ability, expertise, judgment, discretion, integrity and good faith of our management.

Information Technology Systems and Cyber-Security

We have become increasingly dependent upon the availability, capacity, reliability and security of our information technology infrastructure and our ability to expand and continually update this infrastructure, to conduct daily operations. We depend on various information technology systems to estimate reserve quantities, process and record financial data, manage our land base, analyze seismic information, administer our contracts with our operators and lessees and communicate with employees and third-party partners.

Further, we are subject to a variety of information technology and system risks as a part of our normal course operations, including potential breakdown, invasion, virus, cyber-attack, cyber-fraud, security breach, and destruction or interruption of our information technology systems by third parties or insiders. Unauthorized access to these systems by employees or third parties could lead to corruption or exposure of confidential, fiduciary or proprietary information, interruption to communications or operations or disruption to our business activities or our competitive position. Further, disruption of critical information technology services, or breaches of information security, could have a negative effect on our performance and earnings, as well as on our reputation. We apply technical and process controls in line with industry-accepted standards to protect our information assets and systems; however, these controls may not adequately prevent cyber-security breaches. The significance of any such event is difficult to quantify, but may in certain circumstances be material and could have a material adverse effect on our business, financial condition and results of operations.

Expansion into New Activities

Our operations and the expertise of our management are currently focused primarily on oil and gas production, exploration and development in the Western Canada Sedimentary Basin. In the future we may acquire or move into new industry related activities or new geographical areas, may acquire different energy related assets, and as a result may face unexpected risks or alternatively, significantly increase our exposure to one or more existing risk factors, which may in turn result in our future operational and financial conditions being adversely affected.

Forward-Looking Information May Prove Inaccurate

Shareholders and prospective investors are cautioned not to place undue reliance on our forward-looking information. By its nature, forward-looking information involves numerous assumptions, known and unknown risks and uncertainties, of both a general and specific nature, that could cause actual results to differ materially from those suggested by the forward-looking information or contribute to the possibility that predictions, forecasts or projections will prove to be materially inaccurate.

Additional information on the risks, assumption and uncertainties are found under the heading "*Forward-Looking Information and Statements*" of this Annual Information Form.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

There are no legal proceedings we are or were a party to, or that any of our property is or was the subject of, during our most recent financial year, nor are any such legal proceedings known to us to be contemplated, that involves a claim for damages, exclusive of interest and costs, exceeding 10% of our current assets.

There are no: (a) penalties or sanctions imposed against us by a court relating to securities legislation or by a securities regulatory authority since our inception; (b) other penalties or sanctions imposed by a court or regulatory body against us that would likely be considered important to a reasonable investor in making an investment decision; and (c) settlement agreements we entered into before a court relating to securities legislation or with a securities regulatory authority since our inception.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

There is no material interest, direct or indirect, of any: (a) director or executive officer; (b) person or company that beneficially owns, or controls or directs, directly or indirectly, more than 10% of any class or series of our voting securities; and (c) associate or affiliate of any of the persons or companies referred to in (a) or (b) above in any transaction since our inception in 2011 that has materially affected or is reasonably expected to materially affect us.

AUDITORS, TRANSFER AGENT AND REGISTRAR

Our auditors are KPMG LLP, Chartered Professional Accountants, Suite 3100, 205 – 5th Avenue S.W., Calgary, Alberta, T2P 4B9. KPMG LLP has been our auditors since inception.

The transfer agent and registrar for the Common Shares is Computershare Trust Company of Canada at its principal offices in Calgary, Alberta and Toronto, Ontario.

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business, the only material contracts that we have entered into prior to the date of this Annual Information Form, which can reasonably be regarded as presently material, are the following:

1. the Credit Facility; and

2. the Restricted Bonus Award Plan.

Copies of these contracts may be viewed at the website maintained by the Canadian Securities Administrators at www.sedar.com.

EXPERTS

Interests of Experts

Sproule prepared the Sproule Report and GLJ prepared the GLJ report. None of the designated professionals of Sproule or GLJ have any registered or beneficial interests, direct or indirect, in any of our securities or other property or of our associates or affiliates either at the time they prepared the statements, reports or valuations prepared by it, at any time thereafter or to be received by them.

KPMG LLP are our auditors. KPMG LLP have confirmed that they are independent with respect to us within the meaning of the relevant rules and related interpretations prescribed by the relevant professional bodies in Canada and any applicable legislation or regulations.

In addition, none of the aforementioned persons or companies, nor any director, officer or employee of any of the aforementioned persons or companies, is or is expected to be elected, appointed or employed as a director, officer or employee of us or of any of our associates or affiliates, except for John A. Brussa, one of our directors, is the Chairman and a partner at Burnet, Duckworth & Palmer LLP, which law firm renders legal services to us.

ADDITIONAL INFORMATION

Additional information relating to us can be found on our SEDAR profile at www.sedar.com and on our website at www.cardinalenergy.ca. Additional information, including directors' and officers' remuneration and indebtedness, principal holders of our securities and securities issued and authorized for issuance under our equity compensation plans will be contained in our proxy materials relating to our annual shareholders meeting to be held on May 11, 2017. Additional financial information is contained in our financial statements for the year ended December 31, 2016 and the related management's discussion and analysis.

For additional copies of this Annual Information Form and the materials listed in the preceding paragraphs, please contact:

Cardinal Energy Ltd.
600, 400 - 3 Avenue SW
Calgary AB T2P 4H2
Tel: (403) 234-8681
Fax: (403) 234-0603

APPENDIX A

REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE FORM 51-101F3

Management of Cardinal Energy Ltd. ("**Cardinal**") is responsible for the preparation and disclosure of information with respect to Cardinal's oil and natural gas activities in accordance with securities regulatory requirements. This information includes reserves data.

An independent qualified reserves evaluator has evaluated Cardinal's reserves data. The report of the independent qualified reserves evaluator is presented below.

The Reserves Committee of the Board of Directors of Cardinal has:

(a) reviewed Cardinal's procedures for providing information to the independent qualified reserves evaluator;

(b) met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation; and

(c) reviewed the reserves data with management and the independent qualified reserves evaluator.

The Reserves Committee of the Board of Directors has reviewed Cardinal's procedures for assembling and reporting other information associated with oil and natural gas activities and has reviewed that information with management. The Board of Directors has, on the recommendation of the Reserves Committee, approved

(d) the content and filing with securities regulatory authorities of Form 51-101F1 containing reserves data and other oil and gas information;

(e) the filing of Form 51-101F2 which is the report of the independent qualified reserves evaluator on the reserves data, contingent resources data, or prospective resources data; and

(f) the content and filing of this report.

Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

(signed) "*M. Scott Ratushny*"
M. Scott Ratushny
Chairman and Chief Executive Officer

(signed) "*David D. Johnson*"
David D. Johnson
Director, Chair of the Reserves Committee and member of the Audit Committee and the Corporate Governance & Compensation Committee

(signed) "*Shane Peet*"
Shane Peet
President

(signed) "*James C. Smith*"
James C. Smith
Director and Chair of the Audit Committee and member of the Reserves Committee and the Corporate Governance & Compensation Committee

March 31, 2017

APPENDIX B

REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR
FORM 51-101F2

To the board of directors of Cardinal Energy Ltd. (the "**Company**"):

1. We have evaluated the Company's reserves data as at December 31, 2016. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2016, estimated using forecast prices and costs.

2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

3. We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook as amended from time to time (the "**COGE Handbook**") maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter).

4. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.

5. The following table shows the net present value of future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated for the year ended December 31, 2016, and identifies the respective portions thereof that we have evaluated and reported on to the Company's board of directors:

Independent Qualified Reserves Evaluator	Effective Date of Evaluation Report	Location of Reserves (County or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate – $000s)			
			Audited	**Evaluated**	**Reviewed**	**Total**
Sproule Associates Limited	December 31, 2016	Canada	-	316,577	-	316,577
GLJ Petroleum Consultants Ltd.	December 31, 2016	Canada	-	601,730	-	601,730

6. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied.

7. We have no responsibility to update our reports referred to in paragraph 5 for events and circumstances occurring after the effective date of our reports.

8. Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material.

Executed as to our report referred to above:

Sproule Associates Limited, Calgary, Alberta, Canada, March 6, 2017.

"Originally Signed"
Weldon D, Dueck, P. Eng.
Senior Petroleum Engineer and Associate

"Originally Signed"
Derek A. Holst, P. Eng
Senior Petroleum Engineer and Partner

"Originally Signed"
Alec Kovaltchouk, P.Geo
Manager, Geosciences and Partner

"Originally Signed"
Nora T. Stewart, P. Eng.
Vice-President, Reserves Certification and Director

GLJ Petroleum Consultants Ltd. Calgary Alberta March 8, 2017

"Originally Signed"
Bryan M. Joa, P.Eng
Vice-President

APPENDIX C

CARDINAL ENERGY LTD.

AUDIT COMMITTEE

MANDATE AND TERMS OF REFERENCE

Establishment of Committee

The board of directors (the "**Board**") of Cardinal Energy Ltd. ("**Cardinal**" or the "**Corporation**") hereby establishes a committee of the Board to be called the Audit Committee (the "**Committee**").

Role and Objectives

1. The purpose of the Committee is to assist the Board in fulfilling its responsibility for:

   (a) oversight of the nature and scope of the annual audit;

   (b) oversight of the Corporation's management ("**Management**") reporting on internal financial and accounting standards and practices;

   (c) the review of the adequacy of Cardinal's financial information, accounting systems and procedures;

   (d) the review of financial reporting and statements;

   and the Board has charged the Committee with the responsibility of recommending, for Board approval, the interim and annual audited financial statements and other mandatory disclosure releases containing financial information.

2. The primary objectives of the Committee are as follows:

   (a) to assist the directors of the Corporation ("Directors") in meeting their responsibilities (especially for accountability) in respect of the preparation and disclosure of the financial statements of Cardinal and related matters;

   (b) to facilitate communication between the Directors and external auditor;

   (c) to strengthen the external auditor's independence;

   (d) to strengthen the credibility and objectivity of Cardinal's financial reports; and

   (e) to facilitate discussions and communication between Directors on the Committee, Management and the external auditor.

Membership of Committee

1. The Committee shall be comprised of at least three (3) Directors or all of whom shall be "independent" (as such term is used in National Instrument 52-110 – *Audit Committees* (as amended from time to time) ("**NI 52-110**") unless the Board determines that the exemption contained in NI 52-110 is available and determines to rely thereon.

2. All of the members of the Committee must be "financially literate" (as defined in NI 52-110) unless the Board determines that an exemption under NI 52-110 from such requirement in respect of any particular member is available and determines to rely thereon in accordance with the provisions of NI 52-110.

3. The Board shall have the power to appoint the Committee Chairman and other members of the Committee.

Specific Duties and Responsibilities

To carry out its responsibilities, the Committee shall:

1. oversee the work of the external auditor, including the resolution of any disagreements between Management and the external auditor regarding financial reporting.

2. satisfy itself on behalf of the Board with respect to the integrity of Cardinal's internal control and management information systems by:

   (a) monitoring compliance with legal, ethical and regulatory requirements including the certification process;

   (b) review Cardinal's process for testing its internal controls;

   (c) reviewing the external auditor's (and internal auditor if one is appointed by Cardinal) assessment of the internal controls of Cardinal, their written reports containing recommendations for improvement, and Management's response and follow-up to any identified weaknesses.

3. review the annual and interim financial statements of Cardinal and related management's discussion and analysis ("**MD&A**") prior to Board approval and before Cardinal publicly discloses this information. The process should include but not be limited to:

   (a) reviewing the appropriateness of significant accounting principles and any changes in accounting principles, or in their application, which may have a material impact on the current or future years' quarterly unaudited and annual audited financial statements;

   (b) reviewing significant accruals, reserves or other estimates such as impairment and asset retirement obligations;

   (c) reviewing the accounting treatment of unusual or non-recurring transactions;

   (d) reviewing compliance with covenants under loan agreements;

   (e) reviewing significant or unusual transactions outside of the normal course of business of Cardinal;

   (f) reviewing disclosure requirements for commitments and contingencies;

   (g) reviewing adjustments raised by the external auditor, whether or not included in the financial statements;

   (h) reviewing unresolved differences or disagreements between Management and the external auditor;

   (i) reviewing Cardinal's risk management policies and procedures including hedging policies, litigation matters, and insurance program;

   (j) reviewing non-recurring transactions;

   (k) reviewing significant or unusual transactions outside of the normal course of business of Cardinal

(l) reviewing related party transactions;

(m) obtaining explanations of significant variances with comparative reporting periods; and

(n) reviewing and approving Cardinal's hiring policies regarding partners, employees and former partners and employees of Cardinal's present and former external auditor.

4. The Committee must review or be satisfied that adequate procedures are in place for the review of Cardinal's public disclosure of financial information extracted or derived from Cardinal's financial statements, including prospectuses, annual information forms and business acquisition reports, other than the public disclosures referred to in subsection (3), prior to their release, and must periodically assess the adequacy of those procedures.

5. With respect to the appointment of external auditor by the Board, the Committee shall:

(a) recommend to the Board the appointment of the external auditor;

(b) recommend to the Board the terms of engagement of the external auditor, including the compensation of the auditor and confirmation that the external auditor will report directly to the Committee;

(c) on an annual basis, review and discuss with the external auditor all significant relationships such auditors have with Cardinal to determine the auditor independence;

(d) when there is to be a change in auditor, review the issues related to the change and the information to be included in the required notice to securities regulators of such change, if required; and

(e) review and pre-approve any non-audit services to be provided to Cardinal or its subsidiaries by the external auditor and consider the impact on the independence of such auditor.

6. The Committee must pre–approve all non–audit services to be provided to Cardinal or its subsidiaries by the external auditor. The Committee may delegate to one or more members the authority to pre–approve non–audit services, provided that the member report to the Committee at the next scheduled meeting such pre–approval and the member complies with such other procedures as may be established by the Committee from time to time.

7. The Committee will annually review with the external auditor their plan for their audit and, upon completion of the audit, their reports upon the financial statements of Cardinal and its subsidiaries (if any).

8. The Committee shall establish a procedure for:

(a) the receipt, retention and treatment of complaints received by Cardinal regarding accounting, internal accounting controls or auditing matters; and

(b) the confidential, anonymous submission by employees of Cardinal of concerns regarding questionable accounting or auditing matters.

9. The Committee shall have the authority to investigate any financial activity of Cardinal. All employees of Cardinal are to cooperate as requested by the Committee.

10. The Committee shall meet periodically with the external auditor, independent of Management. The issues for consideration should include, but are not limited to:

(a) obtain feedback on competencies, skill sets and performance of key members of the financial reporting team;

(b) enquire as to significant differences from prior year period audits or reviews;

(c) enquire as to transactions accounted for in an acceptable manner but not a basis which, in the opinion of the external auditor was not the preferable accounting treatment;

(d) enquire as to any differences between Management and the external auditor;

(e) enquire as to material differences in accounting policies, disclosures or presentation from prior periods;

(f) enquire as to deficiencies in internal controls identified in the course of the performance of the procedures by the external auditor;

(g) enquire as to any other matters or observations that the external auditor would like to bring to the attention of the Committee.

Meetings and Administrative Matters

1. At all meetings of the Committee every resolution shall be decided by a majority of the votes cast. In case of an equality of votes, the Chairman of the meeting shall be entitled to a second or casting vote.

2. The Chairman will preside at all meetings of the Committee, unless the Chairman is not present, in which case the members of the Committee that are present will designate from among such members the Chairman for purposes of the meeting.

3. A quorum for meetings of the Committee will be a majority of its members. No business may be transacted by the Committee except at a meeting of its members at which a quorum of the Committee is present or by a resolution in writing signed by all the members of the Committee. Meetings may occur via telephone or teleconference.

4. The time at which and place where the meetings of the Committee shall be held and the calling of meetings and the procedure in all respects at such meetings shall be determined by the Committee, unless otherwise determined by the by-laws of the Corporation or by resolution of the Board.

5. Meetings of the Committee should be scheduled to take place at least four times per year and at such other times as the Chairman may determine. The Chief Financial Officer of Cardinal will attend meetings of the Committee, unless otherwise excused from all or part of any such meeting by the Chairman.

6. The Committee will meet with the external auditor at least once per year (in connection with the preparation of the year-end financial statements) and at such other times as the external auditor and the Committee consider appropriate.

7. Agendas, approved by the Chairman, will be circulated to Committee members along with background information on a timely basis prior to the Committee meetings.

8. The Committee may invite such officers, directors and employees of Cardinal and its subsidiaries as it sees fit from time to time to attend at meetings of the Committee and assist in the discussion and consideration of the matters being considered by the Committee.

9. Minutes of the Committee will be recorded and maintained.

10. If determined appropriate, following meetings of the Audit Committee, a list of tasks or matters to be followed up upon shall be prepared including the time table for completion thereof and the responsibility for completion, the status of which matter shall be reviewed at the next meeting of the Committee or as otherwise determined by the Committee.

11. The Committee may retain persons having special expertise and/or obtain independent professional advice to assist in fulfilling its responsibilities at such compensation as established by the Committee and at the expense of Cardinal without any further approval of the Board.

12. Any members of the Committee may be removed or replaced at any time by the Board and will cease to be a member of the Committee as soon as such member ceases to be a Director. The Board may fill vacancies on the Committee by appointment from among its members. If and whenever a vacancy exists on the Committee, the remaining members may exercise all its powers so long as a quorum remains. Subject to the foregoing, following appointment as a member of the Committee each member will hold such office until the Committee is reconstituted.

13. Any issues arising from these meetings that bear on the relationship between the Board and Management should be communicated to the Chairman of the Board by the Chairman.

Approved by the Board of Directors on March 15, 2016.