2013 ANNUAL INFORMATION FORM

MARCH 28, 2014

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GLOSSARY OF TERMS

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

Entities

Board of Directors means the Board of Directors of NuVista.

NuVista, **we**, **us, our** or the **Corporation** means NuVista Energy Ltd. and, where the context requires, all its controlled entities on a consolidated basis.

Shareholders means holders of our Common Shares.

Reserves

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 Reserve Report means the report of GLJ evaluating as of December 31, 2013, our crude oil, natural gas and natural gas liquids reserves dated February 12, 2014.

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

Securities

Common Shares means our common shares, as presently constituted.

Other

Credit Facility means our extendible revolving term credit facility available from a syndicate of Canadian chartered banks.

CONVENTIONS

Certain terms used herein are defined in the "*Glossary of Terms*". Certain other 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. All operational information contained in this Annual Information Form relates to our consolidated operations unless the context otherwise requires.

RESERVES AND RESOURCE DISCLOSURE

The reserves and resources estimates prepared herein have been evaluated by an independent qualified reserves evaluator in accordance with NI 51-101 and the COGE Handbook. The reserves and resources have been categorized accordance with the reserves and resource definitions as set out in the COGE Handbook. See "*Statement Of Reserves Data And Other Oil And Natural Gas Information – Disclosure of Reserves Data – Definitions and Notes to Reserves Data Tables*".

This Annual Information Form contains disclosure of Contingent Resources (as defined herein). See "*General Development of our Business – History and Development - Recent Developments - Wapiti Montney Play Resource Evaluation*". The primary contingency that prevents the classification of ECR (as defined herein) as reserves is for additional drilling, completion and testing of the reservoir in the area where the Contingent

Resources have been assigned to occur and confirm viable commercial rates. Proved or proved and probable reserves were assigned by GLJ for areas in the immediate vicinity of producing or tested wells and ECR were assigned by GLJ beyond areas that were assigned reserves but within 3 miles of existing wells. The presence of a hydrocarbon bearing reservoir has been confirmed by existing wells but beyond the 3 mile radius all resources are considered undiscovered. For additional information, see note 5 to the table appearing under the heading "*General Development of our Business – History and Development - Recent Developments - Wapiti Montney Play Resource Evaluation*".

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	Tcf	trillion 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 six Mcf of natural gas being equivalent to one barrel of oil
Boe/d	barrels of oil equivalent per day
Tcfe	trillion cubic feet equivalent
m^3	cubic metres
Mboe	thousand barrels of oil equivalent
Mcfe	thousand cubic feet of gas equivalent, using the conversion factor of six Mcf of natural gas being equivalent to one barrel of oil
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

FORWARD-LOOKING INFORMATION AND STATEMENTS

This Annual Information Form, including documents incorporated by reference or referred to herein, contains forward-looking information and statements (collectively, "**forward-looking statements**"). These forward-looking statements relate to our 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", "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 – History and Development – Recent Developments*" as to our 2014 guidance including our proposed 2014 capital and operating programs, strategy and focus, the allocation of our 2014 capital program, anticipated 2014 and 2015 cash flow and average production volumes, future drillings and divestiture plans; "*General Description of Our Business – Stated Business Objectives and Strategy*" as to our business plan and strategy; "*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; "*Development of Our Business – History and Development – Wapiti Montney Plan Resource Evaluation*" as to our ECR and DPIIP; "*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 ability to fund future developments costs through cash flow and debt and equity issuances and anticipated funding costs; "*Statement of Reserves Data and Other Oil and Natural Gas Information – Other Oil and Natural Gas Information*" as to our exploration and development activities and opportunities and plans, anticipated treatment under government royalty regimes, anticipated production and operating costs, anticipated land expiries, hedging and marketing policies, reclamation and abandonment obligations, tax horizon anticipated increases in our reserves; and "*Dividends*" as to our dividend policy.

These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. Forward-looking statements are based on the estimates and opinions of our management at the time the statements were made. In addition, forward-looking statements may include statements attributable to third party industry sources. There can be no assurance that the plans, intentions or expectations upon which such forward-looking statements are based will occur.

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

- the performance characteristics of our oil and natural gas properties;
- expectations of future production rates, volumes and product mixes;
- projected costs and plans and objectives;
- projections of market prices and trading liquidity;
- our capital expenditure program, the timing of expenditures and the sources of funding;
- our access to credit facilities, ability to raise capital and financial flexibility;
- supply and demand for oil, natural gas and natural gas liquids;
- commodity prices; and
- expected royalty rates and the anticipated benefits of royalty incentive programs.

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

- volatility of commodity prices;
- liabilities inherent in oil and natural gas operations;
- imprecision of reserve and resource estimates;
- risks associated with refinancing our Credit Facility;
- competition from other industry participants;
- lack of processing and transportation infrastructure;
- the lack of availability of qualified personnel or management or oilfield services;
- incorrect assessments of the value of acquisitions;
- geological, technical, drilling and processing problems;
- fluctuation in foreign exchange or interest rates;
- stock market volatility;
- general economic and industry conditions;
- environmental risks;
- unforeseen title claims or defects;
- the inability to access sufficient capital from internal and external sources;
- governmental regulation, applicable royalty rates and tax laws; 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 requires management to make certain judgments and estimates that affect the reported amounts of assets, liabilities, revenues and expenses. Estimating reserves and resources 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 or referred to 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.

BARREL OF OIL EQUIVALENCY

We have adopted the standard of 6 Mcf:1 Bbl when converting natural gas to oil equivalent and 1 Bbl:6 Mcf when converting oil to natural gas equivalent. Boes, MMBoes, Mcfes and Tcfes may be misleading, particularly if used in isolation. A Boe conversion ratio of 6 Mcf:1 Bbl and an Mcfe conversion ratio of 1 Bbl:6 Mcf 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 that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.**

NON-GAAP MEASURES

Within this Annual Information Form, references are made to terms commonly used in the oil and natural gas industry, which we have included in order to provide investors with a more complete perspective on our current and future operations. We use funds from operations to analyze operating performance and leverage. Funds from operations does not have any standardized meaning prescribed by generally accepted accounting principles applicable to us and therefore it may not be comparable with the calculation of similar measures for other entities. Funds from operations as presented is not intended to represent operating cash flow or operating profits for the period nor should it be viewed as an alternative to cash flow from operating activities, net earnings (loss) or other measures of financial performance calculated in accordance with generally accepted accounting principles. All references to funds from operations throughout this Annual Information Form are based on cash flow from operating activities before changes in non-cash working capital and asset retirement expenditures. For more information, see our management's discussion and analysis for the year ended December 31, 2013, which includes a reconciliation of "funds from operations" to cash provided by operating activities, which has been filed on SEDAR at *www.sedar.com*.

The term "netback" in this Annual Information Form is not a recognized measure under generally accepted accounting principles. We use "netback" as a key performance indicator and it is used by us to evaluate the operating performance of our petroleum and natural gas assets and is determined by deducting royalties, transportation charges and operating expenses from petroleum and natural gas revenue. Readers are cautioned; however, that this measure should not be construed as an alternative to net earnings or cash flow from operating activities determined in accordance with generally accepted accounting principles as an indication of our performance.

NUVISTA ENERGY LTD.

Summary Description of our Business

We are an independent oil and natural gas company engaged in the exploration for, and the development, production and acquisition of oil and natural gas reserves in the provinces of Alberta, British Columbia and Saskatchewan. See "*General Development of Our Business*" and "*Statement of Reserves Data and Other Oil and Natural Gas Information*" in this Annual Information Form.

We were incorporated under the *Business Corporations Act* (Alberta) as 1040491 Alberta Ltd. on April 7, 2003. On May 20, 2003, we changed our name to "NuVista Energy Ltd." and on June 24, 2003 we amended our Articles to create our performance shares and remove our private company restrictions.

On January 1, 2009, we amalgamated with Rider Resources Ltd. and immediately thereafter amalgamated with Roberts Bay Resources Ltd., a wholly-owned subsidiary.

Our head office is located at Suite 3500, 700 – 2nd Street S.W., Calgary, Alberta T2P 2W2 and our registered office is located at Suite 2400, 525 – 8th Avenue S.W., Calgary, Alberta, T2P 1G1.

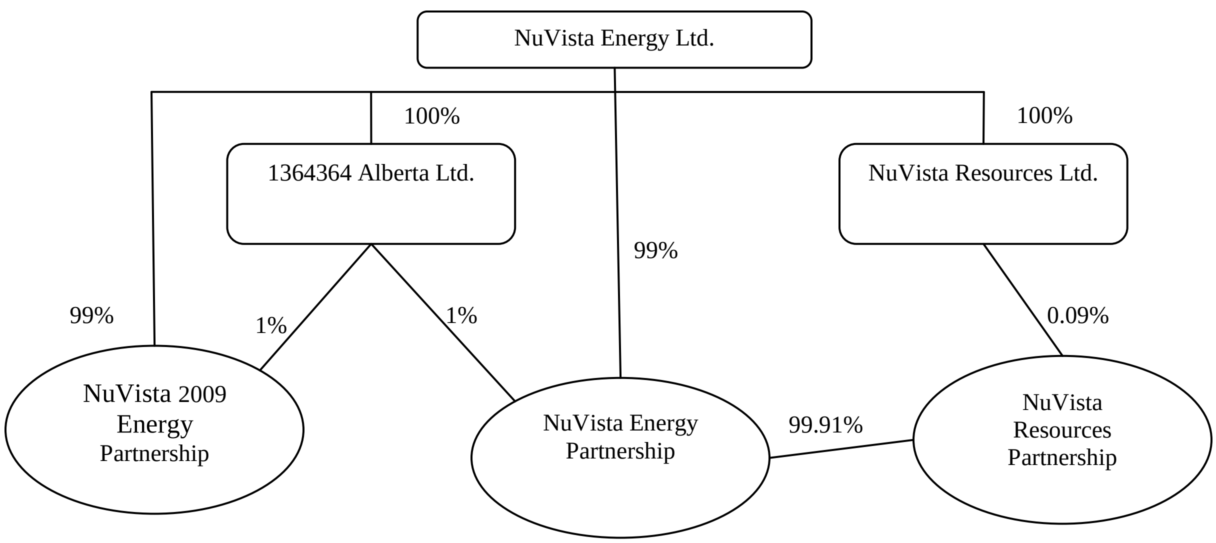
Inter-Corporate Relationships

The following table provides the name, the percentage of voting securities owned by us and the jurisdiction of incorporation, continuance or formation of our subsidiaries and partnerships either, direct and indirect, as at the date hereof:

	Percentage of voting securities (directly or indirectly)	**Nature of Entity**	**Jurisdiction of Incorporation/Formation**
NuVista Energy Partnership	100%	General Partnership	Alberta
NuVista Resources Partnership	100%	General Partnership	Alberta
NuVista Resources Ltd.	100%	Corporation	Alberta
NuVista 2009 Energy Partnership	100%	General Partnership	Alberta
1364364 Alberta Ltd.	100%	Corporation	Alberta

Organizational Structure

The following diagram describes the inter-corporate relationships among us and our material subsidiaries and partnerships as of the date hereof:



GENERAL DEVELOPMENT OF OUR BUSINESS

History and Development

On July 2, 2003, we completed a plan of arrangement with Bonavista Petroleum Ltd. pursuant to which we acquired certain assets of Bonavista Petroleum Ltd. and our Common Shares were distributed to the former holders of common shares of Bonavista Petroleum Ltd. Since the completion of the plan of arrangement, we have grown our business through a combination of exploration, development and optimization of our assets.

The following provides a summary of how our business has developed over the last three years.

Management and Board of Directors

Effective May 9, 2011, Mr. Jonathan Wright joined us as our President and Chief Executive Officer and we concurrently completed a private placement of 114,000 Common Shares to Mr. Wright for gross proceeds of approximately $1.0 million. Mr. Wright also joined our Board of Directors on May 12, 2011.

On November 10, 2011, we announced a reorganization of our executive team which included the consolidation of the positions of Vice President Engineering and Vice President Exploration into a new role called Vice President Development. As a result of these changes, Mr. Kevin Christie, formerly our Vice President Exploration, and Mr. Steve Dalman, formerly Vice President Business Development, resigned. Mr. Dan McKinnon, formerly our Vice President Engineering took on the new role of Manager, Planning & Reserves and Acting Vice President, Development. Mr. Craig Burton was appointed as our Vice President, Business Development & New Plays effective December 1, 2011 and in January of 2012, Mr. Mike Lawford joined us as Vice President, Development.

On March 5, 2013 Mr. Ron Eckhardt and Mr. Sheldon Steeves joined our Board. On December 31, 2013, due to the cumulative effects of NuVista’s property dispositions and their overall impact on NuVista’s head office operations, Mr. Wayne Olmstead our Vice President, Human Resources and Office Administration left NuVista. His duties were assumed by Mr. Robert Froese our CFO and Vice President, Finance.

Asset Dispositions

On February 2, 2011, we entered into a series of transactions with Bonavista Energy Corporation to separate our joint ownership of certain crude oil and natural gas assets held through NuVista Energy Partnership and NuVista Resources Partnership. Under these transactions: (a) we and Bonavista Energy Corporation retained our respective pro-rata share of all crude oil properties; (b) we and Bonavista Energy Corporation retained our pro-rata share of certain natural gas properties; and (c) we and Bonavista Energy Corporation swapped certain natural gas properties with a value of approximately $37 million to rationalize our respective interests in certain eastern Alberta and northwest Saskatchewan properties. These transactions resulted in us, directly and indirectly, holding 100% of the general partnership interests in NuVista Energy Partnership and 100% of the general partnership interests in NuVista Resources Partnership. These transactions were approved by our disinterested directors after considering, among other things, the recommendation of management, a reserve report prepared by an independent reserve evaluator, the benefits of a simplified legal and tax structure, simplified banking arrangements and the ability of both parties to independently make decisions with respect to their assets. The results of the transactions had no material impact on our total production, cash flow or reserves.

On April 28, 2011, we completed the sale of 250 Boe/d of Pembina Cardium properties for total cash consideration of $37.2 million.

On October 17, 2012, we announced that we had closed the disposition of three property packages for gross proceeds of approximately $236 million which included a large portion of our W5 natural gas assets plus selected W4 heavy oil assets. Specific assets in the dispositions included Ferrier, Alder Flats and Easyford in the W5 operating area; and Chauvin, Auburndale and Wildmere in the W4 operating area. Proceeds from the dispositions were used to reduce bank indebtedness. These dispositions provided us with increased flexibility regarding the pace of our development as lease expiries can be addressed by the ongoing drilling activity of only one rig.

On December 11, 2013 we announced the disposition of non-core assets in the W3/W4 operating areas for gross proceeds of approximately $30.2 million. The disposed assets include the Northwest Saskatchewan natural gas area and the West Central Saskatchewan Provost heavy oil areas. The proceeds of the disposition were used to reduce bank indebtedness and ultimately re-deployed into our Wapiti Montney plan.

Dividends

On February 14, 2011, our Board of Directors determined that we would no longer pay a dividend to Shareholders but would redirect this cash flow to fund our drilling program and growth opportunities. As a result, we also terminated our dividend reinvestment plan. See "*Dividends*".

Equity Offerings

On March 8, 2011, we issued an aggregate of 10,500,000 Common Shares pursuant to a private placement and a concurrent public offering for gross proceeds of approximately $99.8 million.

On December 11, 2012, we completed a public offering of 5,350,000 Common Shares, including 1,110,000 Common Shares issued on a "flow-through" basis, with a syndicate of underwriters led for gross proceeds of $27.3 million. On the same day, we also completed a private placement offering of 590,000 "flow-through" Common Shares to certain of our directors and officers for gross proceeds of $3.5 million and a private placement of 13,060,000 Common Shares to other investors for gross proceeds of $64 million.

On October 29, 2013, we completed a private placement and public offering of an aggregate of 5,129,000 Common Shares issued on a "flow-through" basis pursuant to the Income Tax Act (Canada) for gross proceeds of approximately $39.7 million. The offering consisted of: (i) a public offering of 3,200,000 Common Shares issued on a "flow-through" basis in respect of Canadian exploration expense through a syndicate of underwriters for gross proceeds of $25.6 million; and (ii) a private placement of 254,000 Common Shares issued on a "flow-through" basis in respect of Canadian exploration and 1,675,000 Common Shares issued on a "flow-through" basis with respect to Canadian development expense for aggregate gross proceeds of approximately $14.1 million.

On December 3, 2013 we completed a public offering of 11,000,000 Common Shares with a syndicate of underwriters for gross proceeds of $78.1 million.

Credit Facility

In November 2010, our lenders completed the semi-annual review of the borrowing base under our Credit Facility and the borrowing base remained at a commitment amount of $510 million. Primarily as a result of lower natural gas price, the borrowing base was reduced in May 2011 to $470 million, in November 2011 to $440 million and in April 2012 to $380 million. Concurrent with the closing of our asset dispositions on October 17, 2012, the borrowing base under our Credit Facility was redetermined by our lenders at $240 million. In November 2013, our Credit Facility was reconfirmed by our lenders at a commitment amount of $240 million with a maximum borrowing amount of $220 million.

Wapiti Montney Play Resource Evaluation

On November 5, 2013 we announced the results of an independent resource evaluation of our Wapiti Montney asset. GLJ evaluated the Discovered Petroleum Initially-In-Place and the Economic Contingent Resources associated with the in-place petroleum. The evaluation was performed in accordance with NI 51-101 and the COGE Handbook and is effective October 31, 2013.

GLJ's Best Estimate of the total DPIIP is 5.6 Tcf and GLJ's Best Estimate of the ECR is 2.6 Tcfe or 425 MMBoe. DPIIP and ECR was recognized on 55,000 net acres in the C zone of the Middle Montney and 64,000 net acres in the B zone of the Middle Montney, leaving approximately 50% of our land-holdings that have not been assigned contingent resource in the Montney B zone and Montney C zone. GLJ’s Best Estimate of the condensate component of the ECR is 102.7 MMBoe or 24% of the ECR on a Boe basis. The total NGL component including propane, butane and condensate is 140.4 MMBoe in the Best Estimate case.

Based on GLJ's October 1, 2013 forecast prices, the before-tax net present value, discounted at 10%, associated with the Best Estimate of the ECR is $2.35 billion compared to $1.25 billion at September 1, 2012. See "*Statement of Reserves Data and Other Oil and Natural Gas Information – Disclosure of Reserves Data – Definitions and Notes to Reserves Data Tables*" and "*Abbreviations*".

DPIIP is typically broken down into four components including Cumulative Production, Reserves, Contingent Resources and Unrecoverable DPIIP. The following table presents a breakdown of the DPIIP associated with our Montney properties into the component categories:

Discovered Petroleum Initially-In-Place(1)		
Cumulative Production(2)	1.2 MMBoe	0.007 Tcfe
Reserves (Proved + Probable)(2)(3)	29 MMboe	0.174 Tcfe
Economic Contingent Resources (Best Estimate)(4)(5)	425 MMboe	2.550 Tcfe
Unrecoverable DPIIP(6)	478 MMboe	2.869 Tcf
DPIIP (Best Estimate)(7)	934 MMboe	5.603 Tcf

Notes:

(1) All estimates of resources and reserves in the above table represent our gross resources, reserves or production before the deduction of any royalties and without including any of our royalty interests. There is no certainty that it will be commercially viable to produce any portion of the resources. The resource estimates presented above use the resource categories set out in the COGE Handbook. See "*Statement of Reserves Data and Other Oil and Natural Gas Information – Disclosure of Reserves Data – Definitions and Notes to Reserves Data Tables*".

(2) The Cumulative Production numbers represent production to October 31, 2013 whereas the Proved plus Probable Reserves numbers are as of December 31, 2012. From December 31, 2012 to October 31, 2013, total Cumulative Production from our Montney properties in the December 31, 2012 reserve report was approximately 0.003 Tcfe.

(3) The Proved plus Probable Reserves estimate is effective as of December 31, 2012 and is based on an independent evaluation by GLJ using January 1, 2013 forecast pricing.

(4) Resources from our Montney properties are considered economic using GLJ's October 1, 2013 forecast prices.

(5) The primary contingency that prevents the classification of the ECR as reserves is the additional drilling, completion and testing required to occur and confirm viable commercial rates. Proved or Proved plus Probable Reserves were assigned by GLJ for areas in the immediate vicinity of producing or tested wells. ECR were assigned by GLJ beyond areas that were assigned reserves but within 3 miles of existing wells. As continued delineation drilling occurs, some resources currently classified as ECR are expected to be re-classified as reserves. An additional contingency is the lack of infrastructure to facilitate full development in the short term, including the necessary facilities for gas gathering and processing and for the extraction of NGLs. The re-classification of the ECR as reserves is also subject to various non-technical contingencies which we must overcome such as lack of markets, legal, environmental and political concerns surrounding the possible banning of hydraulic fracturing, a technology required to develop the ECR, and other operational risks applicable to oil and gas issuers. See "*Statement of Reserves Data and Other Oil and Natural Gas Information – Disclosure of Reserves Data – Definitions and Notes to Reserves Data Tables*" and the disclosure under the heading "*Risk Factors*" in this Annual Information Form.

(6) All of the DPIIP that has not been classified as Cumulative Production, reserves or Contingent Resources may be considered unrecoverable at this time. A portion of the Unrecoverable DPIIP may in the future be determined to be recoverable and reclassified as Contingent Resources or reserves as additional technical studies are performed, commercial circumstances change or technological developments occur; the remaining portion may never be recovered due to the physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks. The Unrecoverable DPIIP has been calculated by subtracting Cumulative Production, Proved plus Probable Reserves and Contingent Resources from DPIIP. Since the Proved plus Probable Reserves are estimated as of December 31, 2012 and all other numbers are as of October 31, 2013 the Unrecoverable DPIIP may be greater or less than the number in the above table due to increases or decreases in Proved plus Probable Reserves between December 31, 2012 and October 31, 2013.

(7) The sum of Cumulative Production, Reserves, Contingent Resources and Unrecoverable DPIIP do not add to DPIIP as Cumulative Production, Reserves and Contingent Resources have been reduced to marketable sales volumes that have been shrunk to account for surface loss. DPIIP and Unrecoverable DPIIP volumes are in-place volumes that have not been reduced due to surface loss.

Recent Developments

2014 Guidance

2014 is the year where we will enter full development mode in the Wapiti Montney resource play. We have increased our capital budget in 2014 compared to 2013, to the range of $240 million to $260 million with a commensurate increase in rig count to three rigs for most of the year. Capital will be focused approximately 90% in the Wapiti area, with approximately 80% of that in the condensate rich Bilbo development block. We expect to drill and complete 16 to 18 horizontal wells in the year, complete and start up the Bilbo compressor station, and begin delivering to the Keyera Simonette plant late in the second quarter of 2014. This new infrastructure will provide the capacity for significant growth over the next few years.

Our entrance production rate in 2014 after the previously announced December divestitures was approximately 16,500 Boe/d. Production for 2014 is expected to be in the range of 17,500 to 18,500 Boe/d. Behind pipe capacity is continuing to build in order to accommodate the increase in infrastructure capacity later in the year. Our fourth quarter production is expected to be in the range of 20,000 to 21,000 Boe/d. Funds from operations for 2014 are expected in the range of $130 million to $140 million based on current strip prices of $4.50/GJ AECO for natural gas and US$98/Bbl for WTI.

Looking beyond 2014, we are excited about our ability to drive and internally fund growth with an increased pace of drilling and facility capacity. For 2015, we anticipate annual production of approximately 23,000 Boe/d which, at $3.50/GJ AECO gas and US$85/Bbl WTI oil prices, would drive funds from operations to approximately $170 million.

With corporate netbacks and production rising and efficiencies continuing to be built into our Wapiti Montney play, we are confident to continue accelerating the pace of activity in the future. We will continue to work with area midstreamers to provide an ever-increasing facility capacity to underpin long-term profitable growth.

GENERAL DESCRIPTION OF OUR BUSINESS

Stated Business Objectives and Strategy

Our primary focus is the development and delineation of its primary operating area, the Wapiti Montney. The Wapiti Montney is a condensate-rich natural gas resource play that provides us with significant profitable growth potential into the future. We continue to employ a disciplined approach to our business plan which focuses on strong economics to provide positive near and long term operating and financial results.

We apply our technical and operating expertise within the Montney area with a disciplined approach based on the following principles:

- focus - establish technical expertise in key focus areas;
- invest in plays with scalability and repeatability, and strong economics;
- operate our production and hold a high working interest;
- create a culture of capital discipline, strong execution, and performance;
- attract and retain a talented team;
- control our business plan and be opportunity driven; and
- maintain financial flexibility.

We have created an organization in which operational and technical excellence and idea generation are encouraged in a culture that emphasizes accountability and performance. Our employees are all rewarded with an ownership stake in us, closely aligning their interests with those of our Shareholders. By focusing in an operating area, our teams become experts in identifying opportunities and improving economics. Over time, this intimate knowledge enables us to extract maximum value from the asset. Our goal is to operate with a high working-interest ownership. This enables us to control the pace of development, minimize costs and cycle times between ideas and cash flow, and allows us to accurately forecast the timing and magnitude of our efforts.

We continue to enforce stringent cost controls to maintain our financial flexibility throughout the commodity price cycles. We believe that stewardship of our capital spending over the long-term is the single biggest factor in our ability to grow profitably.

We have successfully transitioned from a junior exploration and production company with a focus on shallow natural gas in eastern Alberta to a company with a focus on our longer-life condensate-rich natural gas Wapiti Montney play with significant scale, repeatability and upside.

Cyclical and Seasonal Impact of Industry

Our operational results and financial condition are dependent on the prices we receive for oil and natural gas production. Oil and natural gas prices have fluctuated widely during recent years and are determined by supply and demand factors, including weather and general economic conditions, as well as conditions in other oil and natural gas regions. Any decline in oil and natural gas prices could have an adverse effect on our financial condition. We mitigate such price risk through closely monitoring the various commodity markets and establishing price risk management programs, as deemed necessary and through maintaining financial flexibility. See "*Risk Factors – Prices, Markets and Marketing*" and "*Risk Factors – Hedging*".

Environment Policies

We are committed to managing and operating in a safe, efficient, environmentally responsible manner in association with our industry partners and are committed to continually improving our environmental, health, safety and social performance. To fulfill this commitment, our operating practices and procedures are consistent with the requirements established for the oil and gas industry. We support and endorse the Environmental Operating Procedures developed by the Canadian Association of Petroleum Producers. Key environmental considerations include air quality and climate change, water conservation, spill management, waste management plans, lease and right-of-way management, natural and historic resource protection, and liability management (including site assessment and remediation). These practices and procedures apply to our employees and we monitor all activities and make reasonable efforts to ensure that companies who provide services to us will operate in a manner consistent with our environmental policy.

We believe that we meet all existing environmental standards and regulations and include sufficient amounts in our capital expenditure budget to continue to meet current environmental protection requirements. These requirements apply to all operators in the oil and gas industry; therefore it is not anticipated that our competitive position within the industry will be adversely affected by changes in applicable legislation. We have internal procedures designed to ensure that detailed due diligence reviews to assess environmental liabilities and regulatory compliance are completed prior to proceeding with new acquisitions and developments.

Our environmental management plan and operating guidelines focus on minimizing the environmental impact of our operations while meeting regulatory requirements and corporate standards. Our environmental program includes: an internal environmental compliance audit and inspection program; a suspended well inspection program to support future development or eventual abandonment; appropriate reclamation and decommissioning standards for wells and facilities ready for abandonment; an effective surface reclamation program; a groundwater monitoring program; a spill prevention, response, and clean-up program; a fugitive emission survey and repair program, and an environmental liability assessment program.

We expect to incur abandonment and reclamation costs as existing oil and gas properties are abandoned. In 2013, expenditures for normal compliance with environmental regulations were not material.

We participate in both the Canadian federal and provincial regulated greenhouse gas emissions reporting programs and continue to quantify annual greenhouse gas emissions for internal reporting purposes. We also participate in the Canadian Association of Petroleum Producers Responsible Canadian Energy Program. Our participation in this program demonstrates a commitment to mitigate our environmental impact through monitoring metrics, identifying areas of improvement, and implementing new processes and procedures for key environmental consideration areas.

Renegotiation or Termination of Contracts

As at the date hereof, we do not anticipate that any aspect of our business will be materially affected in the remainder of 2014 by the renegotiation or termination of contracts or subcontracts other than with respect to our Credit Facility which has an annual renewal date of April 28, 2014. See "*Risk Factors – Refinancing Risk and Increased Debt Service Charges*".

Competitive Conditions

We are a member of the petroleum industry, which is highly competitive at all levels. We compete with other companies for all of our business inputs, including exploration and development prospects, access to commodity markets, acquisition opportunities, available capital and staffing. See "*Risk Factors – Competition*".

We strive to be competitive by maintaining financial flexibility and by utilizing current technologies to enhance optimization, development and operational activities.

Human Resources

At December 31, 2013, we employed 102 full-time employees, including 93 office and 9 field employees.

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 February 12, 2014. The statement is effective as of December 31, 2013 and the preparation date of the statement is February 10, 2014. 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 Evaluator in Form 51-101F2 are attached as Appendices A and B to this Annual Information Form.

Disclosure of Reserves Data

The reserves data set forth below is based upon an evaluation by GLJ with an effective date of December 31, 2013, as contained in the GLJ Reserve Report. The reserves data summarizes our crude oil, natural gas liquids and natural gas reserves and the net present values of future net revenue for these reserves using forecast prices and costs, not including the impact of any price risk management activities. The GLJ Reserve Report has 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 GLJ to provide an evaluation of our proved and proved plus probable reserves and no attempt was made to evaluate possible reserves.

All of our reserves are in Canada and, specifically, in the Provinces of Alberta, British Columbia and Saskatchewan.

We determined the future net revenue and present value of future net revenue after income taxes by utilizing GLJ's before income tax future net revenue 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 the value of us as a business entity, which may be significantly different. Our consolidated financial statements for the year ended December 31, 2013 and the associated management's discussion and analysis should be consulted for additional information regarding our taxes.

All evaluations of future net revenue are after the deduction of future income tax expenses (unless otherwise noted in the tables), royalties, development costs, production costs and well abandonment costs but before consideration of indirect costs such as administrative, overhead and other miscellaneous expenses. 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 GLJ Reserve Report 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 Resource 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
AND NET PRESENT VALUES OF FUTURE NET REVENUE
AS OF DECEMBER 31, 2013
FORECAST PRICES AND COSTS**

	RESERVES							
	LIGHT AND MEDIUM OIL		HEAVY OIL		NATURAL GAS		NATURAL GAS LIQUIDS	
RESERVES CATEGORY	Gross (Mbbls)	Net (Mbbls)	Gross (Mbbls)	Net (Mbbls)	Gross (MMcf)	Net (MMcf)	Gross (Mbbls)	Net (Mbbls)
PROVED:								
Developed Producing	1,112	907	317	294	115,174	103,816	7,015	5,226
Developed Non-Producing	199	160	51	49	42,210	38,503	2,335	1,836
Undeveloped	719	599	218	204	173,124	161,935	13,406	10,516
TOTAL PROVED	2,029	1,667	586	547	330,507	304,253	22,756	17,578
PROBABLE	1,590	1,225	654	585	236,152	216,879	17,172	12,664
TOTAL PROVED PLUS PROBABLE	3,620	2,891	1,240	1,132	566,659	521,133	39,928	30,243

	NET PRESENT VALUES OF FUTURE NET REVENUE BEFORE INCOME TAXES DISCOUNTED AT (%/year)					UNIT VALUE BEFORE INCOME TAXES DISCOUNTED AT 10% (1)	
RESERVES CATEGORY	0 ($000s)	5 ($000s)	10 ($000s)	15 ($000s)	20 ($000s)	($/Boe)	($/Mcfe)
PROVED:							
Developed Producing	582,967	459,645	384,406	333,945	297,665	16.20	2.70
Developed Non-Producing	203,305	144,308	112,384	92,564	79,041	13.28	2.21
Undeveloped	822,104	507,563	336,135	232,200	164,008	8.77	1.46
TOTAL PROVED	1,608,377	1,111,517	832,925	658,709	540,715	11.81	1.97
PROBABLE	1,412,833	775,960	489,796	336,491	243,541	9.68	1.61
TOTAL PROVED PLUS PROBABLE	3,021,210	1,887,477	1,322,722	995,200	784,255	10.92	1.82

Note:
(1) Unit values are based on net reserve volumes.

	NET PRESENT VALUES OF FUTURE NET REVENUE AFTER INCOME TAXES DISCOUNTED AT (%/year)				
RESERVES CATEGORY	0 ($000s)	5 ($000s)	10 ($000s)	15 ($000s)	20 ($000s)
PROVED:					
Developed Producing	582,967	459,645	384,406	333,945	297,665
Developed Non-Producing	194,978	141,528	111,389	92,186	78,890
Undeveloped	615,829	380,867	250,849	170,807	117,584
TOTAL PROVED	1,393,775	982,040	746,645	596,937	494,138
PROBABLE	1,058,915	571,548	351,358	233,111	161,532
TOTAL PROVED PLUS PROBABLE	2,452,690	1,553,588	1,098,003	830,049	655,670

TOTAL FUTURE NET REVENUE (UNDISCOUNTED) AS OF DECEMBER 31, 2013 FORECAST PRICES AND COSTS [1][2]

RESERVES CATEGORY	REVENUE ($000s)	ROYALTIES ($000s)	OPERATING COSTS ($000s)	DEVELOPMENT COSTS ($000s)	ABANDONMENT AND RECLAMATION COSTS ($000s)	FUTURE NET REVENUE BEFORE INCOME TAXES ($000s)	INCOME TAXES ($000s)	FUTURE NET REVENUE AFTER INCOME TAXES ($000s)
Total Proved	3,959,658	582,462	1,150,510	587,069	31,240	1,608,377	214,602	1,393,775
Total Proved plus Probable	7,241,916	1,136,449	2,016,104	1,027,761	40,393	3,021,210	568,520	2,452,690

Notes:

(1) Total revenue includes company revenue before royalty and includes other income.

(2) Royalties include Crown, freehold and overriding royalties and mineral tax.

FUTURE NET REVENUE BY PRODUCTION GROUP AS OF DECEMBER 31, 2013 FORECAST PRICES AND COSTS

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) ($000s)	UNIT VALUE [1]	
			($/Boe)	($/Mcfe)
Proved	Light and Medium Crude Oil (including solution gas and other by-products)	40,967	19.85	3.31
	Heavy Oil (including solution gas and other by-products)	12,127	20.05	3.34
	Natural Gas (including by-products but excluding natural gas from oil wells)	779,831	11.50	1.92
	Total	832,925	11.81	1.97
Proved plus Probable	Light and Medium Crude Oil (including solution gas and other by-products)	68,129	19.72	3.29
	Heavy Oil (including solution gas and other by-products)	20,581	17.32	2.89
	Natural Gas (including by-products but excluding natural gas from oil wells)	1,234,012	10.59	1.77
	Total	1,322,722	10.92	1.82

Note:

(1) Unit values are based on net reserve volumes.

Definitions and Notes to Reserves Data Tables

In the tables set forth above in "*Reserves Data (Forecast Prices and Costs)*", "*General Development of Our Business – History and Development – Wapiti Montney Play Resource Evaluation*" 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 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.

"**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.

4. Definitions used for resource disclosure in this Annual Information Form are as follows:

"**Best Estimate**" of a resource represents the best estimate of the quantity that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. If probabilistic methods are used, there should be at least a 50 percent probability (P50) that quantities actually recovered will equal or exceed the best estimate;

"**Contingent Resources**" means those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include such factors as economic, legal, environmental, political and regulatory matters or a lack of markets. It is also appropriate to classify as Contingent Resources the estimated discovered recoverable quantities associated with a project in the early evaluation stage. Contingent Resources are further classified in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their economic status. There is no certainty that it will be commercially viable to produce any portion of the Contingent Resources or that any portion of the volumes currently classified as Contingent Resources will be produced. The recovery and resource estimates provided herein are estimates. Actual Contingent Resources (and any volumes that may be classified as Reserves) and future production from such Contingent Resources may be greater than or less than the estimates provided herein;

"**Cumulative Production**" means the cumulative quantity of petroleum that has been recovered at a given date;

"**Discovered Petroleum Initially-In-Place**" or "**DPIIP**" means that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production. The recoverable portion of discovered petroleum initially-in-place includes Cumulative Production, Reserves, and Contingent Resources; the remainder is categorized as unrecoverable;

"**Economic Contingent Resources**" or "**ECR**" means those Contingent Resources that are currently economically recoverable based on specific forecasts of commodity prices and costs;

"**Unrecoverable Discovered Petroleum Initially-In-Place**" or "**Unrecoverable DPIIP**" means that portion of DPIIP which is estimated, as of a given date, not to be recoverable by future development projects. A portion of these quantities may become recoverable in the future as commercial circumstances change or technological developments occur; the remaining portion may never be recovered due to the physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks.

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

6. "**Development costs**" means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas from 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;

   (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**" means 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 flue 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 section assume 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 GLJ Reserve Report were as follows:

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
FORECAST PRICES AND COSTS (1)

	OIL				NATURAL GAS	NATURAL GAS LIQUIDS	NATURAL GAS LIQUIDS		
Year	**WTI Cushing Oklahoma ($US/Bbl)**	**Edmonton Par Price 40° API ($Cdn/ Bbl)**	**Hardisty Heavy 12° API ($Cdn/ Bbl)**	**Cromer Medium 29. 3° API ($Cdn/ Bbl)**	**AECO Gas Price ($Cdn/ MMbtu)**	**Edmonton Propane ($Cdn/Bbl)**	**Edmonton Butane ($Cdn/Bbl)**	**INFLATION RATES %/Year (2)**	**EXCHANGE RATE ($US/$Cdn)(3)**
Forecast									
2014	97.50	92.76	65.72	86.27	4.03	57.83	73.22	2.0	0.95
2015	97.50	97.37	70.03	90.55	4.26	58.42	75.95	2.0	0.95
2016	97.50	100.00	72.85	93.00	4.50	60.00	78.00	2.0	0.95
2017	97.50	100.00	72.85	93.00	4.74	60.00	78.00	2.0	0.95
2018	97.50	100.00	72.85	93.00	4.97	60.00	78.00	2.0	0.95
2019	97.50	100.00	72.85	93.00	5.21	60.00	78.00	2.0	0.95
2020	98.54	100.77	73.42	93.71	5.33	60.46	78.60	2.0	0.95
2021	100.51	102.78	74.90	95.58	5.44	61.67	80.17	2.0	0.95
2022	102.52	104.83	76.42	97.49	5.55	62.90	81.77	2.0	0.95
2023	104.57	106.93	77.97	99.44	5.66	64.16	83.40	2.0	0.95
2024+	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	2.0	0.95

Notes:
(1) As at January 1, 2014.
(2) Inflation rate for costs.
(3) Exchange rate used to generate the benchmark reference prices in this table.

Weighted average historical prices realized by us for the year ended December 31, 2013, excluding financial derivative commodity contracts were $3.21/Mcf for natural gas, $86.67/Bbl for light and medium oil, $74.33/Bbl for heavy oil and $60.05/Bbl for NGLs.

Reserves Reconciliation

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

	LIGHT AND MEDIUM OIL			HEAVY OIL		
	Proved (Mbbls)	Probable (Mbbls)	Proved Plus Probable (Mbbls)	Proved (Mbbls)	Probable (Mbbls)	Proved Plus Probable (Mbbls)
December 31, 2012	2,205	1,715	3,920	3,266	1,834	5,100
Discoveries	-	-	-	-	-	-
Extensions	30	25	55	-	-	-
Infill Drilling	-	-	-	29	(29)	-
Improved Recovery	-	-	-	-	-	-
Technical Revisions	19	(195)	(176)	35	(108)	(72)
Acquisitions	-	-	-	-	-	-
Dispositions	-	-	-	(2,382)	(1,061)	(3,442)
Economic Factors	(45)	45	-	(8)	17	9
Production	(179)	-	(179)	(354)	-	(354)
December 31, 2013	2,029	1,590	3,620	587	654	1,240

	ASSOCIATED AND NON-ASSOCIATED GAS			NATURAL GAS LIQUIDS		
	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)	Proved (Mbbls)	Probable (Mbbls)	Proved Plus Probable (Mbbls)
December 31, 2012	254,179	147,177	401,356	11,320	6,839	18,159
Discoveries	-	-	-	-	-	-
Extensions	116,602	110,417	227,018	11,139	9,841	20,980
Infill Drilling	-	-	-	-	-	-
Improved Recovery	-	-	-	-	-	-
Technical Revisions	6,295	(7,460)	(1,165)	1,716	576	2,291
Acquisitions	-	-	-	-	-	-
Dispositions	(22,168)	(9,914)	(32,082)	(31)	(30)	(61)
Economic Factors	1,730	(4,067)	(2,337)	33	(54)	(21)
Production	(26,131)	-	(26,131)	(1,421)	-	(1,421)
December 31, 2013	330,507	236,152	566,660	22,756	17,172	39,928

Additional Information Relating to Reserves Data

Undeveloped Reserves

Undeveloped reserves are attributed by 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. We plan to develop approximately 70% of the proved undeveloped reserves in the GLJ Reserve Report over the next two years and the significant majority of the probable undeveloped reserves over the next five years. 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 our most recent three financial years and, in the aggregate, before that time:

Year	Light and Medium Oil (Mbbls)		Heavy Oil (Mbbls)		Natural Gas (MMcf)		NGLs (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**
Prior	2,345	2,345	725	1,076	40,349	54,139	1,547	1,803
2011	142	1,674	1,123	1,138	9,089	52,199	535	1,904
2012	-	729	83	882	31,451	97,679	2,179	5,166
2013	30	719	-	218	81,879	173,124	7,462	13,406

Of our total proved plus probable reserves, 43,197 MBoe or 31% are proved undeveloped reserves. These well locations are allocated reserves because they are within the defined distances to proved reserve accumulations. The Wapiti Montney play accounts for 34,202 MBoe or 79% of the proved undeveloped reserves. Capital expenditures of $173 million in 2014 and $183 million in 2015 will be invested in developing our Wapiti Montney proved undeveloped reserves. The remaining undeveloped reserves are planned to be mostly developed within an additional two year time period subject to capital availability and allocation and regulatory and gas processing considerations.

Probable Undeveloped Reserves

The following table discloses, for each product type, the volumes of probable undeveloped reserves that were first attributed in each of our most recent three financial years and, in the aggregate, before that time:

Year	Light and Medium Oil (Mbbls)		Heavy Oil (Mbbls)		Natural Gas (MMcf)		NGLs (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**
Prior	1,907	1,907	539	835	49,374	76,814	2,069	2,620
2011	34	1,836	846	1,040	23,626	88,911	1,019	3,309
2012	-	1,085	142	1,152	32,705	89,054	2,237	4,630
2013	25	1,090	-	516	96,008	184,674	8,402	14,142

Of our total proved plus probable reserves, 46,527 Mboe or 33% are probable undeveloped reserves. These well locations are allocated reserves because they are within the defined distances to proved reserve accumulations. The Wapiti Montney play accounts for 34,784 MBoe or 75% of the proved undeveloped reserves. Capital expenditures of $257 million in 2014 and $313 million in 2015 will be invested developing our Wapiti Montney proved plus probable undeveloped reserves. The remaining undeveloped reserves are planned to be mostly developed within an additional three year time period subject to capital availability and allocation and regulatory and gas processing considerations.

Significant Factors or Uncertainties

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*".

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:

FORECAST PRICES AND COSTS

Year	**Proved Reserves ($000s)**	**Proved Plus Probable Reserves ($000s)**
2014	199,356	287,843
2015	241,271	415,117
2016	116,556	281,374
2017	23,469	24,424
2018	1,000	8,766
2019	56	846
2020	1,014	1,440
2021	-	-
2022	-	-
2023	1,362	1,456
2024	85	85
2025	408	124
Remaining	2,493	6,286
Total (Undiscounted)	587,069	1,027,761

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 to us or that our Board of Directors will allocate funding to develop all of the reserves attributed in the GLJ Reserve Report. Failure to develop those reserves could have a negative impact on our future cash flow. See "*Risk Factors*".

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, 2013. Information in respect of current production is average production, net to our working interest, except where otherwise indicated.

Wapiti Operating Area

Wapiti, our largest operating area is located south of Grande Prairie, Alberta, approximately 520 kilometers northwest of Calgary. The stratigraphy underlying the Wapiti operating area falls largely within the deep basin gas window and is characterized as having multiple stacked prospective Cretaceous–Triassic gas bearing formations that lend themselves both to vertical and horizontal drilling and multi stage fracturing technology. The greater Wapiti area has a land base of approximately 197,000 net acres with an average working interest of 65%. This operating area is poised to play an important role in our future growth with over 90% of our projected 2014 capital budget expected to be spent in this region.

Wapiti - Montney

We hold rights in approximately 113,000 net acres of land with an approximate working interest of 91% that are prospective for the Triassic Montney zone resource play. This formation is typified by high rate condensate-rich natural gas. In the fourth quarter of 2013, we commenced construction of a 100% owned compressor and dehydration station. The facility will have initial gross throughput capacity of up to 50 MMcf/d and is expected to be expanded to 80 MMcf/d later in 2014. Production from the Wapiti Montney zone is currently processed at either of two large area processing plants, the SemCams K3 plant at 3-15-59-18W5M and the CNRL Gold Creek plant at 13-26-67-5W6M.

In 2013, we drilled and completed 16 (15.6 net) wells resulting in 16 (15.9 net) gas wells. We commenced pad drilling operations in the latter half of 2013, drilling our first 2 well pad. We will utilize pad drilling in 2014 expanding to 3 and 4 well pads at the appropriate time. At the end of 2013, we had 16 Wapiti Montney wells on production. Production in the Wapiti Montney is condensate-rich with current liquid yields averaging 81 Bbls/MMcf, of which 61 Bbls/MMcf are condensate.

On November 5, 2013 we announced the results of an independent resource evaluation of our condensate-rich Wapiti Montney asset. GLJ evaluated the Discovered Petroleum Initially-In-Place and the Economic Contingent Resources associated with the in-place petroleum of our condensate-rich Wapiti Montney asset. The evaluation was performed in accordance with NI 51-101 and the COGE Handbook and is effective October 31, 2013. See "*General Development of Our Business – History and Development – Wapiti Montney Play Resource Evaluation" and "Statement Of Reserves Data And Other Oil And Natural Gas Information – Disclosure of Reserves Data – Definitions and Notes to Reserves Data Tables*".

In 2013, Montney production averaged approximately 4,668 Boe/d (17.2 MMcf/d of natural gas, 1,381 Bbls/d of condensate and 420 Bbls/d of natural gas liquids).

Wapiti - Other

In addition to the Montney formations, we have working interests in numerous other shallower potential productive zones including the Falher, Wilrich, Nikanassin and Cardium. The Falher and Wilrich formations are Cretaceous targets that are seeing increasing development with the use of horizontal multi-stage fracturing. These high-rate, liquid-rich natural gas wells are very economic in today's economic environment.

Our 2013 average production rate was approximately 4,854 Boe/d (19.8 MMcf/d of natural gas and 1,559 Bbls/d of oil and liquids). In 2013, we drilled 1 (1 net) well in the area yielding 1 (1 net) natural gas well. We plan to drill at least one Falher location in 2014. Sweet natural gas production in the Wapiti area is processed at third party operated facilities where we own a working interest, primarily at the Devon South Wapiti 16-36-67-9W6 with a 3.7% working interest and the Devon Elmworth Deep Cut 4-8-69-8W6 where we hold a 2.2% working interest. These large plants provide both favorable liquid recoveries and low operating costs for our production.

W5 Operating Area

Our Deep Basin core operating area is located approximately 100 kilometers southeast of Grande Prairie and includes our Kaybob/Fir properties and other minor areas in the Pembina region. Currently, this operating area has a land base of approximately 52,500 net acres with an average working interest of 67%. Our 2013 average production rate was approximately 2,225 Boe/d (10.5 MMcf/d of natural gas and 482 Bbls/d of oil and liquids). Production from the Kaybob/Waskahigan operating area is characterized by multi-zone stacked oil and gas formations with hyperbolic production decline rates decreasing to less than 10% per year over time. This type of production profile is positive from a reserve life index and royalty perspective. In addition, we have a 100% owned compressor station with throughput capacity of up to 20 MMcf/d.

We drilled no wells in this area in 2013.

W3/W4 Operating Area

Our W3/W4 operating area is comprised primary of our Oyen core region. The Oyen core region is located approximately 250 kilometers southeast of Calgary. Currently, its primary product is dry shallow gas production. This operating area contains 390,500 net acres of land with an average working interest of 83%. We control the majority of the infrastructure in this region and have an extensive seismic database to drive further exploration and development. Our 2013 average production rate was approximately 1,067 Boe/d (5.6 MMcf/d of natural gas and 138 Bbls/d of oil and liquids).

In our Oyen operating area, our 2013 drilling resulted in 1 (1 net) well that produced 1 net detrital oil well. This well was successfully fractured in late 2013 and was placed on production in early 2014. We are currently monitoring its production profile. We are planning at least one detrital oil well in 2014.

In December 2013, we disposed of our interests in our Saskatchewan and the Provost operating areas within the W3/W4 Region to a private oil and gas company. These disposed assets averaged 1,923 Boe/d (6.7 MMcf/d of natural gas and 804 Bbls/d of oil and liquids) in 2013.

Northwest Alberta and British Columbia Operating Area

Our Martin Creek, Black and Conroy properties are located approximately 100 kilometres northwest of Fort St. John, British Columbia. This property is in the winter drilling area which requires all drilling, completion and tie in activities to occur essentially between January 1 and the end of March each season. Wells typically target multiple zones including the Cretaceous Bluesky Formation as well as reservoirs within the Triassic Charlie Lake and Baldonnel Formations. These zones occur at moderate depths between 800 to 1,300 metres. We own a 60% to 100% working interest in key facilities, including five compressor stations, one gas plant and over 290 kilometres of gathering systems.

Our Northwestern Alberta operating area is located 150 kilometres south/southeast of the Northwest Territories/British Columbia/Alberta border near the town of Rainbow Lake. Productive zones on this property are primarily oil and gas from the Devonian Keg River, Sulphur Point and Slave Point formations as well as gas in the shallow Cretaceous Bluesky and Mississippian Debolt formations. We own and operate three sour oil batteries, complete with treaters, tanks, oil pumping station and solution gas compression. The area also has a number of gas gathering systems comprised of seven owned and operated compressors complete with a sour gas processing facility, two refrigeration plants, three dehydration facilities and numerous sales points. Additional processing and compression capacity is available for further development of our lands.

This operating region contains 298,500 net acres with an average working interest of 74%. Our 2013 production averaged 2,344 Boe/d (11.2 MMcf/d of natural gas and 475 Bbls/d of oil and liquids) from this region.

No drilling is planned in this area in 2014.

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, 2013.

	Oil Wells				**Natural Gas Wells**			
	Producing		**Non-Producing**		**Producing**		**Non-Producing**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Alberta	82.0	34.0	124.0	96.6	648.0	380.0	1,076.0	832.0
British Columbia	3.0	1.8	2.0	1.6	79.0	59.1	88.0	70.5
Saskatchewan	23.0	7.8	7.0	2.4	5.0	3.0	17.0	12.5
Total	108.0	43.6	133.0	100.6	732.0	442.1	1,181.0	915.0

Developed and Undeveloped Lands

The following table sets out our developed and undeveloped land holdings as at December 31, 2013.

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Alberta	617,982	420,245	463,891	393,112	1,081,873	813,357
British Columbia	82,054	59,908	66,786	46,853	148,840	106,761
Saskatchewan	9,252	5,311	13,710	13,065	22,962	18,376
Total	709,288	485,464	544,387	453,030	1,253,675	938,494

Rights to explore, develop and exploit 96,650 net acres of these undeveloped land holdings could expire by December 31, 2014 if not continued.

Forward Contracts

We are exposed to market risks resulting from fluctuations in commodity prices, foreign exchange rates and interest rates in the normal course of operations. A variety of derivative instruments are used by us to reduce our exposure to fluctuations in commodity prices and foreign exchange rates. We are exposed to losses in the event of default by the counterparties to these derivative instruments. We manage this risk by diversifying our derivative portfolio amongst a number of financially sound counterparties. For information in relation to our marketing arrangements, see "*Marketing Arrangements*" below.

For details of our material commitments to sell natural gas and crude oil which were outstanding as at December 31, 2013 see Note 16 to our consolidated financial statements for the year ended December 31, 2013.

Marketing Arrangements

Natural Gas

We have established a natural gas transportation and sales portfolio, which will ensure receipt capacity at reasonable cost and provide an appropriate customer base. Our marketing objectives also include protecting or securing minimum prices for up to 100% of our net after royalty production for the term March 1, 2014 to December 31, 2014 and up to 50% and 40% of our net after royalty production for 2015 and 2016, respectively. Our price risk management program is comprised of costless collars, differentials, fixed price and put option contracts. In order to control and manage credit risk and ensure competitive bids, we engage a number of reputable counterparties for our natural gas transactions. The integration and application of these strategies resulted in an average realized price (excluding financial derivative commodity contracts) of $3.28/Mcf for the year ended December 31, 2013.

Oil and NGLs

We sell our oil and liquids production to a variety of purchasers. This enables us to benefit from specific regional advantages, while maintaining price and delivery flexibility. We are continually monitoring global and regional crude oil and NGL markets and look for opportunities to enter into price risk management contracts for up to 60% of net after royalty production for 2014 and up to 50% and 40% of our net after royalty production for 2015 and 2016, respectively. In 2013, our average realized oil price (excluding financial derivative commodity contracts) was $78.48/Bbl and our average realized price for natural gas liquids was $60.05/Bbl.

For additional details on our price risk management program see Note 16 to our consolidated financial statements for the year ended December 31, 2013.

Processing and Transportation

Most of our natural gas and associated natural gas liquids production requires processing to meet sales quality specifications. We require pipeline transportation to deliver our raw natural gas and natural gas liquids to these processing facilities. Access to processing and pipeline transportation is critical to the development of our Wapiti Montney condensate-rich natural gas play. We have entered into long-term take-or-pay contracts to ensure access to processing and pipelines for current and future production. We have made the strategic decision to own most of the gathering and compression facilities required for production from our Wapiti Montney play but we rely on third-party owned infrastructure for the processing and transportation of our production.

We have committed to a five year firm take-or-pay transportation agreement with SemCAMS for 10 MMcf/d of raw natural gas production starting July 1, 2012, increasing to 17 MMcf/d starting July 1, 2013 and expiring in 2017. To access incremental processing and transportation capacity for 2013 and 2014 production volumes, we entered into an agreement with a third-party operator in the Wapiti area to access their gathering and compression for 15 MMcf/d on a on a take-or-pay basis starting April 1, 2013 for a period of one year. These volumes deliver into the SemCAMS pipeline and are processed at the SemCAMS gas processing plant. We committed to a further one year firm transportation agreement with SemCAMS on a take-or-pay basis starting on April 1, 2013 to match these volumes.

In April 2013, we entered into a 10 year processing, transportation and marketing agreement with Keyera Corp. with an expected start-up date late in the second quarter of 2014 for 35 MMcf/d of raw natural gas, increasing to 65 MMcf/d late in the fourth quarter of 2014. In early 2014, we entered into an agreement to increase these volumes to 80 MMcf/d in the third quarter of 2015. In addition to these raw natural gas processing and transportation arrangements, we have entered into agreements for the transportation and fractionation of our natural gas liquids produced from the above raw gas processing arrangements. We continue to pursue other processing and transportation agreements as we develop our Wapiti Montney play to provide line-of-sight to future capacity and production growth.

Most of the condensate produced from our Wapiti Montney play is extracted in the field at compressor stations. These condensate volumes are either transported by pipeline or truck to sales points. We have entered into long-term condensate pipeline transportation agreements to access additional pipeline capacity and reduce the need for higher cost trucking transportation of condensate production.

Additional Information Concerning Abandonment and Reclamation Costs

Our overall abandonment and reclamation costs are based on well bore abandonment and reclamation costs and liability issues such as flare pit remediation, facility decommissioning, remediation, and reclamation costs. These costs were estimated using our experience conducting abandonment and reclamation programs. We review suspended or standing well bores for reactivation, recompletion or sale and conduct systematic abandonment programs for those well bores that do not meet our criteria. A portion of our liability issues are retired every year and facilities are decommissioned when all the wells producing to them have been abandoned. All of our liability reduction programs take into account seasonal access, high priority and stakeholder issues, and opportunities for multi-location programs to reduce costs.

As at December 31, 2013, we had approximately 1,500 net wells for which we expect to incur abandonment and reclamation costs.

The total amount of abandonment and reclamation costs, net of estimated salvage values, that we expect to incur, are summarized in the following table:

Period	Abandonment and Reclamation Costs Escalated at 2% Undiscounted ($000s)	Abandonment and Reclamation Costs Escalated at 2% Discounted at 10% ($000s)
Total liability as at December 31, 2013	179,000	41,000
Anticipated to be paid in 2014	1,000	900
Anticipated to be paid in 2015	1,500	1,300
Anticipated to be paid in 2016	1,600	1,500

The future net revenues disclosed in this Annual Information Form based on the GLJ Reserve Report do not contain an allowance for abandonment and reclamation costs for surface leases, facilities and pipelines. The GLJ Reserve Report only deducted $31.2 million (undiscounted) and $11.9 million (10% discount using forecast prices and costs) for abandonment costs of wells with proved reserves, in estimating the future net revenue disclosed in this Annual Information Form.

Tax Horizon

Based on estimated 2014 cash flow and capital expenditures, we do not expect to be cash taxable in 2014. Projecting taxability beyond 2014 is subject to many uncertainties including commodity prices, capital spending, acquisitions, divestments and government regulations and guidelines, and as a result, we are unable to predict taxability beyond the current year.

Costs Incurred

The following table summarizes the costs incurred related to our activities for the year ended December 31, 2013:

Expenditure	Year Ended December 31, 2013 ($000s)
Property acquisition costs – Unproved properties (1)	2,505
Property acquisition costs – Proved properties	8,011
Exploration costs (2)	14,368
Development costs (3)	200,743
Other	945
Total	226,572

Notes:

(1) Cost of land acquired and non-producing lease rentals on those lands.

(2) Geological and geophysical capital expenditures and drilling costs for exploration wells.

(3) Development costs include development drilling costs and equipping, tie-in and facility costs for all wells.

Exploration and Development Activities

The following table sets forth the gross and net exploratory and development wells in which we participated during the year ended December 31, 2013:

	Development		**Exploratory**	
	Gross	**Net**	**Gross**	**Net**
Natural Gas	11.0	9.9	7.0	6.7
Oil	3.0	1.6	-	-
Dry	-	-	-	-
Total	14.0	11.5	7.0	6.7

In 2014, we expect to drill approximately 20 to 25 wells with a focus on our condensate-rich natural gas wells within our Wapiti Montney resource play. See "*Statement of Reserves Data and Other Oil and Natural Gas Information – Other Oil and Natural Gas Information – Principal Oil and Natural Gas Properties*".

Finding and Development Costs

The following table summarizes our finding and development costs for the periods indicated:

	2013		**2012**		**Three Year Average**	
($/Boe)	**Proved**	**Proved plus Probable**	**Proved**	**Proved plus Probable**	**Proved**	**Proved plus Probable**
Finding and Development [(1)]	$14.51	$12.31	$19.17	$15.53	$17.48	$14.43

Notes:

(1) Including changes in future development capital expenditures.

(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 finding and development costs related to reserves additions for that year.

Production Estimates

The following table sets out the volumes of our working interest production estimated for the year ended December 31, 2014, which is reflected in the estimates of future net revenue disclosed in the forecast price tables contained above under the subheading "*Reserves Data (Forecast Prices and Costs)*":

	Light and Medium Oil (Bbls/d)	**Heavy Oil (Bbls/d)**	**Natural Gas (Mcf/d)**	**Natural Gas Liquids (Bbls/d)**	**BOE (Boe/d)**
Total Proved	610	171	96,817	7,059	23,977
Total Proved plus Probable	750	187	113,850	8,478	28,390

Production History

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

	Quarter Ended 2013				Year Ended
	Mar. 31	**June 30**	**Sept. 30**	**Dec. 31**	**Dec. 31, 2013**
Average Daily Production [1]					
Light and Medium Oil (Bbls/d)	597	464	531	401	498
Heavy Oil (Bbls/d)	1,135	890	1,019	879	980
Natural Gas (MMcf/d)	62,793	73,452	76,679	73,898	71,750
NGLs (Bbls/d)	2,706	4,202	4,202	4,438	3,893
Combined (Boe/d)	14,904	17,799	18,532	18,034	17,329
Average Net Production Prices Received					
Light and Medium Oil ($/Bbl)	81.10	87.66	100.39	75.41	86.67
Heavy Oil ($/Bbl)	59.05	78.56	91.34	69.68	74.33
Natural Gas ($/Mcf)	3.24	3.41	3.04	3.40	3.28
NGLs ($/Bbl)	53.55	55.41	65.95	62.69	60.05
Combined ($/Boe)	31.13	33.44	35.44	34.44	33.75
Royalties Paid					
Light and Medium Oil ($/Bbl)	15.65	18.52	18.92	22.31	18.55
Heavy Oil ($/Bbl)	4.98	4.52	5.50	7.96	5.69
Natural Gas ($/Mcf)	0.18	0.25	0.16	0.15	0.19
NGLs ($/Bbl)	6.83	8.12	7.64	7.19	7.50
Combined ($/Boe)	3.02	3.65	3.25	3.29	3.32
Production Costs [2][3]					
Light and Medium Oil ($/Bbl)	26.10	29.13	25.37	37.98	29.02
Heavy Oil ($/Bbl)	18.44	21.39	17.35	20.69	19.33
Natural Gas ($/Mcf)	1.84	1.87	1.76	1.67	1.78
NGLs ($/Bbl)	11.04	11.21	10.58	10.02	10.69
Combined ($/Boe)	12.20	12.19	11.37	11.16	11.70
Transportation					
Light and Medium Oil ($/Bbl)	2.71	3.66	1.46	2.31	2.51
Heavy Oil ($/Bbl)	3.68	4.15	2.73	1.94	3.14
Natural Gas ($/Mcf)	0.13	0.10	0.10	0.09	0.10
NGLs ($/Bbl)	0.04	0.08	4.18	2.46	1.67
Combined ($/Boe)	0.95	0.75	1.53	1.10	1.09
Netback Received [4]					
Light and Medium Oil ($/Bbl)	36.64	36.35	54.64	12.81	36.59
Heavy Oil ($/Bbl)	31.95	48.50	65.76	39.09	46.17
Natural Gas ($/Mcf)	1.09	1.20	1.02	1.49	1.21
NGLs ($/Bbl)	35.64	36.00	43.55	43.02	40.19
Combined ($/Boe)	14.96	16.85	19.29	18.89	17.64

Notes:

(1) Before deduction of royalties.

(2) Production costs are composed of direct costs incurred to operate both oil and gas wells. A number of assumptions are required to allocate these costs between oil, natural gas and natural gas liquids production.

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

(4) Netbacks are calculated by subtracting royalties, production costs and transportation from revenues.

The following table indicates our average daily production (including production from our major areas) for the year ended December 31, 2013:

	Light and Medium Oil (Bbls/d)	Heavy Oil (Bbls/d)	Natural Gas Liquids (Bbls/d)	Natural Gas (Mcf/d)	BOE (Boe/d)
Wapiti – Montney	-	-	1,801	17,203	4,668
Wapiti – other	69	-	1,490	19,770	4,854
W5	131	-	351	10,456	2,225
W3/W4 (1)	28	904	10	12,284	2,990
NE BC/NW Alberta	257	-	218	11,212	2,344
Non-core/other	13	76	25	825	252
Total	498	980	3,895	71,750	17,329

Note:
(1) Includes W3/W4 properties sold in December 2013.

DIVIDENDS

On February 14, 2011, our Board of Directors determined that we will no longer pay a dividend to Shareholders but rather use this cash flow to fund our drilling program and growth opportunities. We have not declared dividends on our Common Shares since November of 2010.

Any decision to pay dividends on the Common Shares will be made by our Board of Directors on the basis of our earnings, financial requirements and other conditions that the Board of Directors may consider appropriate in the circumstances. It is not intended that dividends will be paid in the foreseeable future.

DESCRIPTION OF OUR CAPITAL STRUCTURE

Credit Facility

We have a $240 million extendible revolving term Credit Facility from a syndicate of Canadian chartered banks. Borrowing under the Credit Facility may be made by prime loans, bankers' acceptances and/or US LIBOR advances and is limited to $220 million. These advances bear interest at the bank's prime rate and/or at money market rates plus a borrowing margin. The Credit Facility is secured by a first floating charge debenture, general assignment of book debts and our oil and natural gas properties and equipment.

The Credit Facility has a 364-day revolving period and is subject to an annual review by the lenders, at which time a lender can extend the revolving period or can request conversion to a one year term loan. During the revolving period, a review of the maximum borrowing amount occurs semi-annually on or before October 31. During the term period, no principal payments would be required until April 28, 2015.

During the revolving period, a determination of the maximum borrowing amount occurs semi-annually at approximately October 31. The annual renewal date of our Credit Facility is April 28, 2014. Although we have no reason to believe that we will be unable to extend our Credit Facility after April 28, 2014, if not renewed, the facility will be available on a non-revolving basis for a period of one year thereafter, at which time the facility would be due and payable. See "*Risk Factors – Refinancing Risk and Increased Debt Service Charges*".

Share Capital

The following is a description of the rights, privileges, restrictions and conditions attaching to our share capital.

Common Shares

We are authorized to issue an unlimited number of Common Shares without nominal or par value. Holders of our Common Shares are entitled to one vote per share at meetings of our Shareholders. Subject to the rights of the holders of preferred shares and any other shares having priority over the Common Shares, holders of Common Shares are entitled to dividends if, as and when declared by the Board of Directors and upon liquidation, dissolution or winding-up to receive, our remaining property.

Performance Shares

We are authorized to issue 1,200,000 performance shares without nominal or par value. The performance shares rank junior to the Common Shares and preferred shares, other than as set forth below. These were initially issued at the time we completed the plan of arrangement in 2003.

Each issued and outstanding performance share was initially issued at a price of $0.01 per share and was convertible into the fraction of a Common Share equal to the closing trading price of the Common Shares on the Toronto Stock Exchange or such other stock exchange on which the Common Shares are listed on the trading day prior to such conversion less $2.00, if positive, divided by such closing price. All of the issued and outstanding performance shares have been converted into Common Shares or cancelled and we no longer have any performance shares outstanding.

MARKET FOR OUR SECURITIES

Our Common Shares are listed and posted for trading on the Toronto Stock Exchange and trade under the symbol "NVA". The following sets forth the price range and trading volume of our Common Shares on the Toronto Stock Exchange for the periods indicated.

	Price Range		
	High	**Low**	**Volume**
2013			
January	5.95	5.17	4,236,730
February	5.69	5.16	2,071,586
March	6.75	5.42	6,642,569
April	7.50	6.30	6,785,492
May	8.40	6.36	12,351,023
June	8.33	6.96	3,356,032
July	7.66	6.46	4,841,663
August	7.50	6.12	6,688,236
September	7.69	6.55	16,044,109
October	7.04	6.11	9,831,605
November	7.57	6.42	8,649,782
December	7.49	6.93	9,022,694
2014			
January	8.40	6.79	12,217,733
February	9.39	8.07	11,249,972
March (1 – 27)	9.58	8.51	6,063,065

DIRECTORS AND OFFICERS

The names, municipalities of residence, any offices held with us, the period served as a director and principal occupations of our directors and officers are set out below.

Name and Municipality of Residence	Position with NuVista	Director or Officer Since	Principal Occupation
Keith A. MacPhail (2)(3)(5) Calgary, Alberta	Chairman and Director	May 2003	Our Chairman and Executive Chairman of Bonavista Energy Corporation.
W. Peter Comber (1)(3) Toronto, Ontario	Director	May 2004	Managing Director of Barrantagh Investment Management Inc. (an investment counselling firm).
Ronald J. Eckhardt (2) Calgary, Alberta	Director	March 2013	Former Executive Vice-President, North American Operations for Talisman Energy Inc.
Pentti O. Karkkainen (1)(3)(6) Calgary, Alberta	Director	July 2003	General Partner, KERN Partners Ltd. (a private equity firm and partnership).
Ronald J. Poelzer (1)(4)(5) Calgary, Alberta	Director	May 2003	Executive Vice Chairman of Bonavista Energy Corporation.
Sheldon B. Steeves (2)(4) Calgary, Alberta	Director	March 2013	Former CEO and Chairman of Echoex Ltd., a private oil and natural gas exploration and production company.
Grant A. Zawalsky (4)(5) Calgary, Alberta	Director	May 2003	Managing Partner of Burnet, Duckworth & Palmer LLP (barristers and solicitors).
Jonathan A. Wright (5) Calgary, Alberta	President and Chief Executive Officer and a Director	May 2011	Our President and Chief Executive Officer and a Director since May 2011. Prior thereto, Mr. Wright was Senior Vice-President of Talisman Energy Ltd.'s North American Conventional Production Division since January 2010. Prior thereto, he was the Senior Vice President and Country Manager, Malaysia/Vietnam/Australia/PNG working out of Talisman Malaysia.
Robert F. Froese Calgary, Alberta	Vice President, Finance, Chief Financial Officer and Corporate Secretary	May 2006	Our Vice President, Finance and Chief Financial Officer since May 2006 and our Corporate Secretary since March 2010. Mr. Froese also acted as our Interim President and Chief Executive Officer from November, 2010 to May, 2011.
Ross L. Andreachuk Calgary, Alberta	Vice President and Controller	May 2009	Our Vice President and Controller since May 2009. Prior thereto, Mr. Andreachuk was our Controller commencing August 2006.
Kevin G. Asman Calgary, Alberta	Vice President, Marketing	January 2010	Our Vice President, Marketing since January 2010. Prior thereto, Mr. Asman was our Marketing Manager commencing July 2008.

Name and Municipality of Residence	Position with NuVista	Director or Officer Since	Principal Occupation
Craig W. Burton Calgary, Alberta	Vice President, Business Development & New Plays	December 2011	Our Vice President, Business Development & New Plays since December 1, 2011. Prior thereto, Mr. Burton has been our Manager, Acquisitions in our Business Development group, and has served in the position of Senior Exploitation Engineer in various of our operating areas since joining us in October 2004.
Mike J. Lawford Calgary, Alberta	Vice President, Development	January 2012	Our Vice President, Development since January 2012. Prior thereto, Mr. Lawford was Executive Project Management Officer and Manager – New Plays at Talisman Energy Ltd. from 2009 and Senior Geologist at Northpoint Energy Ltd. from 2004 to 2009.
D. Chris McDavid Calgary, Alberta	Vice President, Operations	August 2006	Our Vice President, Operations since August 2006.
Joshua T. Truba Calgary, Alberta	Vice President, Land	January 2009	Our Vice President, Land since January 2009.

Notes:
(1) Member of our audit committee.
(2) Member of our reserves committee.
(3) Member of our compensation committee.
(4) Member of our governance and nominating committee.
(5) Member of our executive committee.
(6) Our Lead Director.

The term of office of each of our directors expires at the next annual meeting of our Shareholders.

As at March 24, 2014 our directors and officers, as a group, beneficially owned, or directed or controlled, directly or indirectly, approximately 6,178,584 million Common Shares or approximately 4.6% of our issued and outstanding Common Shares.

Corporate Cease Trade Orders, Bankruptcies or Penalties or Sanctions

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 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 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.

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 the control of us 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, other than Mr. Zawalsky who was a former director of Efficient Energy Resources Ltd. (a private electrical generation company) which agreed to the voluntary appointment of a receiver in 2005 and Mr. MacPhail who was formerly a director of The Resort at Copper Point Ltd. (a private real estate development company) which was placed in receivership in February 2009.

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 the control of us is, has, within the ten years before the date of this Annual Information Form, 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.

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 the control of us, has been subject to 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 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

Our directors and officers may, from time to time, be involved with the business and operations of other oil and natural gas issuers, in which case a conflict may arise. See "*Risk Factors*".

Circumstances may arise where members of our Board of Directors serve as directors or officers of corporations which are in competition to our interests. No assurances can be given that opportunities identified by such Board of Directors members will be provided to us.

The *Business Corporations Act* (Alberta) provides that in the event 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 under the *Business Corporations Act* (Alberta). To the extent that conflicts of interests arise, such conflicts will be resolved in accordance with the provisions of the *Business Corporations Act* (Alberta).

AUDIT COMMITTEE INFORMATION

Audit Committee Charter

The full text of our Audit Committee charter is included in Appendix C of this Annual Information Form.

Composition of the Audit Committee

The members of our Audit Committee are Mr. Comber (Chair), Mr. Karkkainen and Mr. Poelzer, each of whom are independent and financially literate. We have adopted the definition of "independence" as set out in Section 1.4 of National Instrument 52-110 – *Audit Committees*. The relevant education and experience of each Audit Committee member is outlined below.

W. Peter Comber: *Barrantagh Investment Management Inc.*

Mr. Comber has more than 40 years experience in various aspects of the financial services industry. Mr. Comber is a chartered accountant and has worked in corporate finance and investment management both in Toronto and Calgary. Mr. Comber is the managing director of Barrantagh Investment Management Inc., investment counselors based in Toronto, Ontario, a position he has held since August, 1999. Mr. Comber was the President of Newtonhouse Investment Management Ltd., investment counselors located in Toronto, Ontario from May 1993 to August 1999. Between June 1989 and December 1991, Mr. Comber was Senior Vice-President, Thornmark Capital Corporation, an investment holding company, and principal officer of Thornmark Capital Funding Corporation, merchant bank. Prior thereto, Mr. Comber was Senior Vice President and Managing Director of Prudential-Bache Securities Canada Limited, an investment dealer in Toronto, Ontario.

Mr. Comber is a chartered accountant and holds a Bachelor of Arts degree from the University of Toronto and a Masters of Business Administration from York University.

Pentti O. Karkkainen: *KERN Partners Ltd.*

Mr. Karkkainen has more than 29 years of investment management, energy sector research and investment banking experience, as well as four years of industry experience with Gulf Canada Resources. Mr. Karkkainen is a founding and General Partner of KERN Partners Ltd., a Calgary based energy sector private equity firm that was established in late 2000. KERN Partners has $1.1 billion of capital under management from a variety of North American and European pension funds, endowments, family offices and other financial institutions. Prior to establishing KERN Partners, Mr. Karkkainen was Managing Director and Head of Oil and Gas Equity Research at RBC Capital Markets.

Mr. Karkkainen holds a Bachelor of Science (Honours) degree in Geology from Carleton University in Ottawa and a Masters of Business Administration degree from Queen's University in Kingston.

Mr. Karkkainen is also a director of several Calgary based private energy infrastructure and oil and gas exploration and development companies including Altex Energy Ltd., Connaught Oil & Gas Ltd. and Dolomite Energy Inc.

Ronald J. Poelzer: *Bonavista Energy Corporation*

Mr. Poelzer has more than 29 years of experience in the oil and gas industry and is currently Executive Vice Chairman of Bonavista Energy Corporation. Prior thereto, Mr. Poelzer was Executive Vice President and Vice Chairman of Bonavista Energy Corporation and its predecessor Bonavista Energy Trust, responsible for various strategic planning, business development, financial and capital market roles. Prior to joining Bonavista in 1997, Mr. Poelzer was with Poco Petroleums Ltd. as Vice President, Business Development. Prior thereto, Mr. Poelzer was in public accounting practice.

Mr. Poelzer holds a Bachelor of Commerce (Distinction) degree from the University of Saskatchewan and has been a member of the Institute of Chartered Accountants of Alberta.

Mr. Poelzer is also a member of the board of various private companies and a charitable foundation.

Pre-Approval of Policies and Procedures

Our 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 our Audit Committee from time to time.

External Auditor Service Fees

Audit Fees

The aggregate fees billed by our external auditor in each of the last two fiscal years for audit services were $413,000 in 2013 and $343,000 in 2012.

Audit-Related Fees

The aggregate fees billed in each of the last two fiscal years for assurance and related services by our external auditor were $87,500 in 2013 and $nil in 2012.

Tax Fees

The aggregate fees billed in each of the last two fiscal years for professional services rendered by our external auditor for tax compliance, tax advice, tax planning and review of tax returns were $44,200 in 2013 and $30,725 in 2012.

All Other Fees

Our auditors did not provide any other products or services not reported above in 2013 and 2012.

Reliance on Exemptions

At no time since the commencement of our most recently completed financial year have we relied on any of the exemptions contained in National Instrument 52-110 – *Audit Committees* with respect to independence or composition of our Audit Committee.

Audit Committee Oversight

At no time since the commencement up to the most recently completed financial year has a recommendation of the Audit Committee to nominate or compensate an external auditor not been adopted by our Board of Directors.

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 and with respect to the pricing and taxation of oil and natural gas through agreements among the governments of Canada, Alberta, British Columbia and Saskatchewan, all of which should be carefully considered by investors in the oil and gas industry. 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 natural 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 may be enacted. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the oil and gas industry in western Canada.

Pricing and Marketing

Oil

The producers of oil are entitled to negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. Worldwide supply and demand factors primarily determine oil prices; however, prices are also influenced by regional market and transportation issues. 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. 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 National Energy Board. The National Energy Board is currently undergoing a consultation process to update the regulations governing the issuance of export licences. The updating process is necessary to meet the criteria set out in the federal *Jobs, Growth and Long-term Prosperity Act* which received Royal Assent on June 29, 2012. In this transitory period, the National Energy Board of Canada has issued, and is currently following an "Interim Memorandum of Guidance concerning Oil and Gas Export Applications and Gas Import Applications under Part VI of the *National Energy Board Act*".

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 (NGX), Intercontinental Exchange or the New York Mercantile Exchange (NYMEX) 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. Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 25 years) or for a larger quantity requires an exporter to obtain an export licence from the National Energy Board.

The North American Free Trade Agreement

The North American Free Trade Agreement or "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.

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 other than Crown lands 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.

Alberta

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

Royalties are currently paid pursuant to "The New Royalty Framework" (implemented by the *Mines and Minerals (New Royalty Framework) Amendment Act, 2008*) and the "Alberta Royalty Framework", which was implemented in 2010. Royalty rates for conventional oil are set by a single sliding rate 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 are similarly determined using a single sliding rate formula with the maximum royalty payable under the royalty regime set at 36%

Oil sands projects are also subject to Alberta's royalty regime. Prior to payout of an oil sands project, the royalty is payable on gross revenues of an oil sands project. Gross revenue royalty rates range between 1-9% 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 1-9% 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. In addition, concurrent with the implementation of The New Royalty Framework, the Government of Alberta renegotiated existing contracts with certain oil sands producers that were not compatible with the new royalty regime.

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 non-Crown lands 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 fee simple 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 an Emerging Resource and Technologies Initiative intended to accelerate technological development and facilitate the development of unconventional resources. Specifically:

- Coalbed methane wells will receive a maximum royalty rate of 5% for 36 producing months on 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 on 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.

The Emerging Resource and Technologies Initiative will be reviewed in 2014, and the Government of Alberta has committed to providing industry with three years notice if it decides to discontinue the program.

British Columbia

Producers of oil and natural gas from Crown lands in British Columbia are required to pay annual rental payments, and make monthly royalty payments in respect of oil and natural gas produced. The amount payable as a royalty in respect of oil depends on the type and vintage of the oil, the quantity of oil produced in a month and the value of that oil. Generally, oil is classified as either light or heavy and the vintage of oil is classified as either "old oil" which is produced from a pool discovered before October 31, 1975, "new oil" produced from a pool discovered between October 31, 1975 and June 1, 1998, and "third-tier oil" produced from a pool discovered after June 1, 1998 or through an enhanced oil recovery scheme. The royalty calculation takes into account the production of oil on a well-by-well basis, the specified royalty rate for a given vintage of oil, the average unit selling price of the oil and any applicable royalty exemptions. Royalty rates are reduced on low-productivity wells, reflecting the higher unit costs of extraction, and are the lowest for third-tier oil, reflecting the higher unit costs of both exploration and extraction.

The royalty payable in respect of natural gas produced on Crown lands is determined by a sliding scale formula based on a reference price, which is the greater of the average net price obtained by the producer and a prescribed minimum price. For non-conservation gas (not produced in association with oil), the royalty rate depends on the date of acquisition of the oil and natural gas tenure rights and the spud date of the well and may also be impacted by the select price, a parameter used in the royalty rate formula to account for inflation. Royalty rates are fixed for certain classes of non-conservation gas when the reference price is below the select price. Conservation gas is subject to a lower royalty rate than non-conservation gas. Royalties on natural gas liquids are levied at a flat rate of 20% of the sales volume.

Producers of oil and natural gas from freehold lands in British Columbia are required to pay monthly freehold production taxes. For oil, the level of the freehold production tax is based on the volume of monthly production. It is either a flat rate, or, beyond a certain production level, is determined using a sliding scale formula based on the production level. For natural gas, the freehold production tax is either a flat rate, or, at certain production levels, is determined using a sliding scale formula based on the reference price similar to that applied to natural gas production on Crown land, and depends on whether the natural gas is conservation gas or non-conservation gas. The production tax rate for freehold natural gas liquids is a flat rate of 12.25%.

British Columbia maintains a number of targeted royalty programs for key resource areas intended to increase the competitiveness of British Columbia's low productivity natural gas wells. These include both royalty credit and royalty reduction programs, including the following:

- *Deep Well Royalty Credit Program* providing a royalty credit for natural gas wells defined in terms of a dollar amount applied against royalties, is well specific and applies to drilling and completion costs for vertical wells with a true vertical depth greater than 2,500 metres and horizontal wells with a true vertical depth greater than 1,900 metres (or 2,300 metres if spud before September 1, 2009) and if certain other criteria are met and is intended to reflect the higher drilling and completion costs. Effective on April 1, 2014, the Deep Well Royalty Credit Program will have two tiers—"tier one" and "tier two". The existing Deep Well Royalty Credit Program, as described above, will comprise tier two of the program. Tier one of the Deep Well Royalty Credit Program will apply to shallower horizontal wells with a true vertical depth less than 1,900 meters if spud after March 31, 2014;

- *Deep Re-Entry Royalty Credit Program* providing a royalty credit for deep re-entry wells with a true vertical depth to the top of pay of the re-entry well event that is greater than 2,300 metres and a re-entry date after November 30, 2003; or if the well was spud on or after January 1, 2009, with a true vertical depth to the completion point of the re-entry well event being greater than 2,300 metres;

- *Deep Discovery Royalty Credit Program* providing the lesser of a 3-year royalty holiday or 283,000,000 m^3 of royalty free gas for deep discovery wells with a true vertical depth greater than 4,000 metres whose surface locations are at least 20 kilometres away from the surface location of any well drilled into a recognized pool within the same formation;

- *Coalbed Gas Royalty Reduction and Credit Program* providing a royalty reduction for coalbed gas wells with average daily production less than 17,000 m^3 as well as a royalty credit for coalbed gas wells equal to $50,000 for wells drilled on Crown land and a tax credit equal to $30,000 for wells drilled on freehold land;

- *Marginal Royalty Reduction Program* providing a monthly royalty reduction for low productivity natural gas wells with an average daily rate of production less than 23 m^3 for every metre of marginal well depth in the first 12 months of production. To be eligible, wells must have been spudded after May 31, 1998 and the first month of marketable gas production must have occurred between June 2003 and August 2008. Once a well passes the initial eligibility test, a reduction is realized in each month that average daily production is less than 25,000m^3;

- *Ultra-Marginal Royalty Reduction Program* providing royalty reductions for low productivity, shallow natural gas wells. Vertical wells must be less than 2,500 metres and horizontal wells less than 2,300 metres to be eligible. Production in the first 12 months ending after January 2007 must be less than 17m^3 per metre of depth for exploratory wildcat wells and less than 11m^3 per metre of depth for development wells and exploratory outpost wells. The well must have been spudded or re-entered after December 31, 2005. A reduction is realized in each month that average daily production is less than 60,000m^3. Effective on April 1, 2014, the Ultra-Marginal Royalty Reduction Program will no longer apply to horizontal wells due to the potential for overlap with shallower horizontal wells eligible for a royalty credit under the Deep Well Royalty Credit Program; and

- *Net Profit Royalty Reduction Program* providing reduced initial royalty rates to facilitate the development and commercialization of technically complex resources such as coalbed gas, tight gas, shale gas and enhanced-recovery projects, with higher royalty rates applied once capital costs have been recovered.

Oil produced from an oil well that is located on either Crown or freehold land and completed in a new pool discovered subsequent to June 30, 1974 may also be exempt from the payment of a royalty for the first 36 months of production or 11,450 m^3 of production, whichever comes first.

The Government of British Columbia also maintains an Infrastructure Royalty Credit Program that provides royalty credits for up to 50% of the cost of certain approved road construction or pipeline infrastructure projects intended to facilitate increased oil and gas exploration and production in under-developed areas and to extend the drilling season.

The Petroleum and Natural Gas Royalty and Freehold Production Tax Regulation has been amended effective April 1, 2013 to provide for a 3% minimum royalty on affected wells with deep well/deep re-entry credits. The 3% minimum royalty applies to deep wells when the net royalty payable would otherwise be zero for a production month.

Saskatchewan

In Saskatchewan, the amount payable as a Crown royalty or a freehold production tax in respect of oil depends on the type and vintage of oil, the quantity of oil produced in a month, the value of the oil produced and specified adjustment factors determined monthly by the provincial government. For Crown royalty and freehold production tax purposes, conventional oil is divided into "types", being "heavy oil", "southwest designated oil" or "non-heavy oil other than southwest designated oil". The vintage of oil being "fourth tier oil", "third tier oil", "new oil" and "old oil", depends on the finished drilling date of a well and is applied to each of the three crude oil types slightly differently. Heavy oil is classified as third tier oil (produced from a vertical well having a finished drilling date on or after January 1, 1994 and before October 1, 2002 or incremental oil from new or expanded waterflood projects with a commencement date on or after January 1, 1994 and before October 1, 2002), fourth tier oil (having a finished drilling date on or after October 1, 2002 or incremental oil from new or expanded waterflood projects with a commencement date on or after October 1, 2002) or new oil (conventional oil that is not classified as "third tier oil" or "fourth tier oil"). Southwest designated oil uses the same definition of fourth tier oil but third tier oil is defined as conventional oil produced from a vertical well having a finished drilling date on or after February 9, 1998 and before October 1, 2002 or incremental oil from new or expanded waterflood projects with a commencement date on or after February 9, 1998 and before October 1, 2002 and new oil is defined as conventional oil produced from a horizontal well having a finished drilling date on or after February 9, 1998 and before October 1, 2002. For non-heavy oil other than southwest designated oil, the same classification as heavy oil is used but new oil is defined as conventional oil produced from a vertical well completed after 1973 and having a finished drilling date prior to 1994, conventional oil produced from a horizontal well having a finished drilling date on or after April 1, 1991 and before October 1, 2002, or incremental oil from new or expanded waterflood projects with a commencement date on or after January 1, 1974 and before 1994 whereas old oil is defined as conventional oil not classified as third or fourth tier oil or new oil. Production tax rates for freehold production are determined by first determining the Crown royalty rate and then subtracting the "Production Tax Factor" applicable to that classification of oil. Currently the Production Tax Factor is 6.9 for "old oil", 10.0 for "new oil" and "third tier oil" and 12.5 for "fourth tier oil". The minimum rate for freehold production tax is zero.

Base prices are used to establish lower limits in the price-sensitive royalty structure for conventional oil and apply at a reference well production rate of 100 m^3 for "old oil", "new oil" and "third tier oil", and 250 m^3 per month for "fourth tier oil". Where average wellhead prices are below the established base prices of $100 per m^3 for third and fourth tier oil and $50 per m^3 for new oil and old oil, base royalty rates are applied. Base royalty rates are 5% for all fourth tier oil, 10% for heavy oil that is third tier oil or new oil, 12.5% for southwest designated oil that is third tier oil or new oil, 15% for non-heavy oil other than southwest designated oil that is third tier or new oil, and 20% for old oil. Where average wellhead prices are above base prices, marginal royalty rates are applied to the proportion of production that is above the base oil price. Marginal royalty rates are 30% for all fourth tier oil, 25% for heavy oil that is third tier oil or new oil, 35% for southwest designated oil that is third tier oil or new oil, 35% for non-heavy oil other than southwest designated oil that is third tier or new oil, and 45% for old oil.

The amount payable as a Crown royalty or a freehold production tax in respect of natural gas production is determined by a sliding scale based on the monthly provincial average gas price published by the Saskatchewan government, the quantity produced in a given month, the type of natural gas, and the classification of the natural gas. Like conventional oil, natural gas may be classified as "non-associated gas" (gas produced from gas wells) or "associated gas" (gas produced from oil wells) and royalty rates are determined according to the finished drilling date of the respective well. Non-associated gas is classified as new gas (having a finished drilling date before February 9, 1998 with a first production date on or after October 1, 1976), third tier gas (having a finished drilling date on or after February 9, 1998 and before October 1, 2002), fourth tier gas (having a finished drilling date on or after October 1, 2002) and old gas (not classified as either third tier, fourth tier or new gas). A similar classification is used for associated gas except that the classification of old gas is not used, the definition of fourth tier gas also includes production from oil wells with a finished drilling date prior to October 1, 2002, where the individual oil well has a gas-oil production ratio in any month of at least 3,500 m^3 of gas for every m^3 of oil, and new gas is defined as oil produced from a well with a finished drilling date before February 9, 1998 that received special approval, prior to October 1, 2002, to produce oil and gas concurrently without gas-oil ratio penalties.

On December 9, 2010, the Government of Saskatchewan enacted the *Freehold Oil and Gas Production Tax Act, 2010* with the intention to facilitate the efficient payment of freehold production taxes by industry. Two new regulations with respect to this legislation are: (i) *The Freehold Oil and Gas Production Tax Regulations, 2012* which sets out the terms and conditions under which the taxes are calculated and paid; and (ii) *The Recovered Crude Oil Tax Regulations*, 2012 which sets out the terms and conditions under which taxes on recovered crude oil that was delivered from a crude oil recovery facility on or after March 1, 2012 are to be calculated and paid.

As with conventional oil production, base prices based on a well reference rate of 250 10^3 m^3/month are used to establish lower limits in the price-sensitive royalty structure for natural gas. Where average field-gate prices are below the established base prices of $1.35 per gigajoule for third and fourth tier gas and $0.95 per gigajoule for new gas and old gas, base royalty rates are applied. Base royalty rates are 5% for all fourth tier gas, 15% for third tier or new gas, and 20% for old gas. Where average well-head prices are above base prices, marginal royalty rates are applied to the proportion of production that is above the base gas price. Marginal royalty rates are 30% for all fourth tier gas, 35% for third tier and new gas, and 45% for old gas**.** The current regulatory scheme provides for **c**ertain differences with respect to the administration of "fourth tier gas" which is associated gas.

The Government of Saskatchewan currently provides a number of targeted incentive programs. These include both royalty reduction and incentive volume programs, including the following:

- *Royalty/Tax Incentive Volumes for Vertical Oil Wells Drilled on or after October 1, 2002* providing reduced Crown royalty (a Crown royalty rate of the lesser of "fourth tier oil" Crown royalty rate and 2.5%) and freehold tax rates (a freehold production tax rate of 0%) on incentive volumes of 8,000 m^3 for deep development vertical oil wells, 4,000 m^3 for non-deep exploratory vertical oil wells and 16,000 m^3 for deep exploratory vertical oil wells (more than 1,700 metres or within certain formations) and after the incentive volume is produced, the oil produced will be subject to the "fourth tier" royalty tax rate;

- *Royalty/Tax Incentive Volumes for Exploratory Gas Wells Drilled on or after October 1, 2002* providing reduced Crown royalty (a Crown royalty rate of the lesser of "fourth tier oil" Crown royalty rate and 2.5%) and freehold tax rates (a freehold production tax rate of 0%) on incentive volumes of 25,000,000 m^3 for qualifying exploratory gas wells;

- *Royalty/Tax Incentive Volumes for Horizontal Oil Wells Drilled on or after October 1, 2002* providing reduced Crown royalty (a Crown royalty rate of the lesser of "fourth tier oil" Crown royalty rate and 2.5%) and freehold tax rates (a freehold production tax rate of 0%) on incentive volumes of 6,000 m^3 for non-deep horizontal oil wells and 16,000 m^3 for deep horizontal oil wells (more than 1,700 metres total vertical depth or within certain formations) and after the incentive volume is produced, the oil produced will be subject to the "fourth tier" royalty tax rate;

- *Royalty/Tax Incentive Volumes for Horizontal Gas Wells drilled on or after June 1, 2010 and before April 1, 2013* providing for a classification of the well as a qualifying exploratory gas well and resulting in a reduced Crown royalty (a Crown royalty rate of the lesser of "fourth tier oil" Crown royalty rate and 2.5%) and freehold tax rates (a freehold production tax rate of 0%) on incentive volumes of 25,000,000 m^3 for horizontal gas wells and after the incentive volume is produced, the gas produced will be subject to the "fourth tier" royalty tax rate;

- *Royalty/Tax Regime for Incremental Oil Produced from New or Expanded Waterflood Projects Implemented on or after October 1, 2002* whereby incremental production from approved waterflood projects is treated as fourth tier oil for the purposes of Crown royalty and freehold tax calculations;

- *Royalty/Tax Regime for Enhanced Oil Recovery Projects (Excluding Waterflood Projects) Commencing prior to April 1, 2005* providing lower Crown royalty and freehold tax determinations based in part on the profitability of Enhance Oil Recovery projects during and subsequent to the payout of the Enhance Oil Recovery operations;

- *Royalty/Tax Regime for Enhanced Oil Recovery Projects (Excluding Waterflood Projects) Commencing on or after April 1, 2005* providing a Crown royalty of 1% of gross revenues on Enhance Oil Recovery projects pre-payout and 20% of Enhance Oil Recovery operating income post-payout and a freehold production tax of 0% pre-payout and 8% post-payout on operating income from Enhance Oil Recovery projects; and

- *Royalty/Tax Regime for High Water-Cut Oil Wells* designed to extend the product lives and improve the recovery rates of high water-cut oil wells and granting "third tier oil" royalty/tax rates with a Saskatchewan Resource Credit of 2.5% for oil produced prior to April 2013 and 2.25% for oil produced on or after April 1, 2013 to incremental high water-cut oil production resulting from qualifying investments made to rejuvenate eligible oil wells and/or associated facilities.

On June 22, 2011, the Government of Saskatchewan released the Upstream Petroleum Industry Associated Gas Conservation Standards, which are designed to reduce emissions resulting from the flaring and venting of associated gas. The standards were jointly developed with industry and the implementation of such standards commenced on July 1, 2012 for new wells and facilities licensed on or after such date. The new standards will apply to existing licensed wells and facilities on July 1, 2015.

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.

Each of the provinces of Alberta and Saskatchewan 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 license.

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 licenses. For leases and licenses issued subsequent to January 1, 2009, shallow rights reversion will be applied at the conclusion of the primary term of the lease or license.

Environmental Regulation

The oil and natural gas industry is currently subject to regulation pursuant to a variety of provincial and federal environmental legislation, 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. 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 such legislation can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability and the imposition of material fines and penalties.

Federal

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

Alberta

The regulatory landscape in Alberta has undergone a transformation from multiple regulatory bodies to a single regulator for upstream oil and gas, oil sands and coal development activity. On June 17, 2013, the Alberta Energy Regulator assumed the functions and responsibilities of the former Energy Resources Conservation Board, including those found under the *Oil and Gas Conservation Act*. On November 30, 2013, the Alberta Energy Regulator assumed the energy related functions and responsibilities of Alberta Environment and Sustainable Resource Development in respect of the disposition and management of public lands under the *Public Lands Act*. On March 29, 2014, the Alberta Energy Regulator is expected to assume the energy related functions and responsibilities of Alberta Environment and Sustainable Resource Development in the areas of environment and water under the *Environmental Protection and Enhancement Act* and the *Water Act*, respectively. The Alberta Energy Regulator'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 the transformation to a single regulator is the creation of 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.

In December 2008, the Government of Alberta released a new land use policy for surface land in Alberta, the Alberta Land Use Framework. The Alberta Land Use Framework 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* provides the legislative authority for the Government of Alberta to implement the policies contained in the Alberta Land Use Framework. Regional plans established under the *Alberta Land Stewardship Act* 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 *Alberta Land Stewardship Act* 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 *Alberta Land Stewardship Act* also contemplates the amendment or extinguishment of previously issued statutory consents such as regulatory permits, licenses, 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 *Alberta Land Stewardship Act* 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 which came into force on September 1, 2012. The Lower Athabasca Regional Plan is the first of seven regional plans developed under the Alberta Land Use Framework. The Lower Athabasca Regional Plan 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 oilsands area, which contains approximately 82% of the province's oilsands resources and much of the Cold Lake oilsands area.

The Lower Athabasca Regional Plan 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, oilsands companies' tenure has been (or will be) cancelled in conservation areas and no new oilsands 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.

The next regional plan to take effect is the South Saskatchewan Regional Plan which covers approximately 83,764 square kilometres and includes 45% of the provincial population. The South Saskatchewan Regional Plan was released in draft form in 2013 and is expected to come into force on April 1, 2014.

With the implementation of the new Alberta regulatory structure under the Alberta Energy Regulator, Alberta Environment and Sustainable Resource Development will remain responsible for development and implementation of regional plans. However, the Alberta Energy Regulator will take on some responsibility for implementing regional plans in respect of energy related activities.

British Columbia

In British Columbia, the *Oil and Gas Activities Act* impacts conventional oil and gas producers, shale gas producers and other operators of oil and gas facilities in the province. Under the *Oil and Gas Activities Act*, the British Columbia Oil and Gas Commission has broad powers, particularly with respect to compliance and enforcement and the setting of technical safety and operational standards for oil and gas activities. The *Environmental Protection and Management Regulation* establishes the government's environmental objectives for water, riparian habitats, wildlife and wildlife habitat, old-growth forests and cultural heritage resources. The *Oil and Gas Activities Act* requires the commission to consider these environmental objectives in deciding whether or not to authorize an oil and gas activity. In addition, although not an exclusively environmental statute, the *Petroleum and Natural Gas Act* requires proponents to obtain various approvals before undertaking exploration or production work, such as geophysical licences, geophysical exploration project approvals, permits for the exclusive right to do geological work and geophysical exploration work, and well, test hole and water-source well authorizations. Such approvals are given subject to environmental considerations and licences and project approvals can be suspended or cancelled for failure to comply with this legislation or its regulations.

Saskatchewan

In May 2011, Saskatchewan passed changes to *The Oil and Gas Conservation Act*, the act governing the regulation of resource development operations in the province. Although the associated Bill received Royal Assent on May 18, 2011, it was not proclaimed into force until April 1, 2012, in conjunction with the release of *The Oil and Gas Conservation Regulations, 2012* and *The Petroleum Registry and Electronic Documents Regulations*. The aim of the amendments to the *Oil and Gas Conservation Act*, and the associated regulations, is to provide resource companies investing in Saskatchewan's energy and resource industries with the best support services and business and regulatory systems available. With the enactment of the *The Petroleum Registry and Electronic Documents Regulations* and the *Oil and Gas Conservation Regulations, 2012*, Saskatchewan has implemented a number of operational aspects, including the increased demand for record-keeping, increased testing requirements for injection wells and increased investigation and enforcement powers; and, procedural aspects including those related to Saskatchewan's participation as partner in the Petroleum Registry of Alberta.

Liability Management Rating Programs

Alberta

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

Effective May 1, 2013, the Alberta Energy Regulator implemented important changes to the Licensee Liability Rating Program that resulted in a significant increase in the number of oil and gas companies in Alberta that are required to post security. Some of the important changes include:

- a 25% increase to the prescribed average reclamation cost for each individual well or facility (which will increase a licensee's deemed liabilities);

- a $7,000 increase to facility abandonment cost parameters for each well equivalent (which will increase a licensee's deemed liabilities);

- a decrease in the industry average netback from a five-year to a three-year average (which will affect the calculation of a licensee's deemed assets, as the reduction from five to three years means the average will be more sensitive to price changes); and

- a change to the present value and salvage factor, increasing to 1.0 for all active facilities from the current 0.75 for active wells and 0.50 for active facilities (which will increase a licensee's deemed liabilities).

These changes will be implemented over a three-year period. The first phase was implemented in May of 2013, the second phase will be implemented in May of 2014 and the final phase will be implemented in May of 2015. The changes to the Licensee Liability Rating Program stem from concern that the previous regime significantly underestimated the environmental liabilities of licensees.

Saskatchewan

In Saskatchewan, the Ministry of Economy implements its own Licensee Liability Rating Program. The Saskatchewan Licensee Liability Rating Program is designed to assess and manage the financial risk that a licensee's well and facility abandonment and reclamation liabilities pose to an orphan fund established under the *The Oil and Gas Conservation Act*. The Saskatchewan orphan fund is responsible for carrying out the abandonment and reclamation of wells and facilities contained within the Licensee Liability Rating Program when a licensee or working interest partner is defunct or missing. The Saskatchewan Licensee Liability Rating Program requires a licensee whose deemed liabilities exceed its deemed assets to post a security deposit. The ratio of deemed liabilities to deemed assets is assessed once each month for all licensees of oil, gas and service wells and upstream oil and gas facilities.

Climate Change Regulation

Federal

The Government of Canada is a signatory to the *United Nations Framework Convention on Climate Change* and a participant to the Copenhagen Accord (a non-binding agreement created by the *United Nations Framework Convention on Climate Change* which represents a broad political consensus and reinforces commitments to reducing greenhouse gas emissions). On January 29, 2010, Canada inscribed in the Copenhagen Accord its 2020 economy-wide target of a 17% reduction of greenhouse gas emissions from 2005 levels. This target is aligned with the United States target. In a report dated October 2013, the Government stated that this target represents a significant challenge in light of strong economic growth (Canada's economy is projected to be approximately 31% larger in 2020 compared to 2005 levels).

On April 26, 2007, the Government of Canada released "Turning the Corner: An Action Plan to Reduce Greenhouse Gases and Air Pollution" which set forth a plan for regulations to address both greenhouse gas 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 outlines emissions intensity-based targets, for application to regulated sectors on a facility-specific, 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. The federal government indicates that it is taking a sector-by-sector regulatory approach to reducing greenhouse gas emissions and is working on regulations for other sectors. Representatives of the Government of Canada have indicated that the proposals contained in the updated action plan will be modified to ensure consistency with the direction ultimately taken by the United States with respect to greenhouse gas emissions regulation. In June 2012, the second US-Canada

Clean Energy Dialogue Action Plan was released. The plan renewed efforts to enhance bilateral collaboration on the development of clean energy technologies to reduce greenhouse gas emissions.

Alberta

As part of Alberta's 2008 Climate Change Strategy, the province committed to taking action on three themes: (a) conserving and using energy efficiently (reducing greenhouse gas emissions); (b) greening energy production; and (c) implementing carbon and capture storage.

As part of its efforts to reduce greenhouse gas emissions, Alberta introduced legislation to address greenhouse gas 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 *Climate Change and Emissions Management Act* is based on an emissions intensity approach and aims for a 50% reduction from 1990 emissions relative to GDP by 2020. The accompanying regulations include the *Specified Gas Emitters Regulation,* which imposes greenhouse gas limits, and the *Specified Gas Reporting Regulation*, which imposes greenhouse gas emissions reporting requirements. Alberta facilities emitting more than 100,000 tonnes of greenhouse gases a year are subject to compliance with the *Climate Change and Emissions Management Act*. Alberta is the first jurisdiction in North America to impose regulations requiring large facilities in various sectors to reduce their greenhouse gas emissions.

The *Specified Gas Emitters Regulation*, effective July 1, 2007, applies to facilities emitting more than 100,000 tonnes of greenhouse gases in 2003 or any subsequent year, and requires reductions in greenhouse gas emissions intensity (e.g. the quantity of greenhouse gas emissions per unit of production) from emissions intensity baselines established in accordance with the regulation. The regulation distinguishes between "Established Facilities" and "New Facilities". Established Facilities are defined as facilities that completed their first year of commercial operation prior to January 1, 2000 or that have completed eight or more years of commercial operation. Established Facilities are required to reduce their emissions intensity by 12% of their baseline emissions intensity for 2008 and subsequent years. Generally, the baseline for an Established Facility reflects the average of emissions intensity in 2003, 2004 and 2005. New Facilities are defined as facilities that completed their first year of commercial operation on December 31, 2000, or a subsequent year, and have completed less than eight years of commercial operation, or are designated as New Facilities in accordance with the regulation. New Facilities are required to reduce their emissions intensity by 2% from 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 and 10% of their baseline in the eighth year. The *Climate Change and Emissions Management Act* does not contain any provision for continuous annual improvements in emissions intensity reductions beyond those stated above.

The *Climate Change and Emissions Management Act* provides that regulated emitters can meet their emissions intensity targets by contributing to the Climate Change and Emissions Management Fund at a rate of $15 per tonne of CO_2 equivalent. The funds contributed by industry to the Climate Change and Emissions Management Fund will be used to drive innovation and test and implement new technologies for greening energy production. Emissions credits can also be purchased from regulated emitters that have reduced their emissions below the 100,000 tonne threshold or non-regulated emitters that have generated emissions offsets through activities that result in emissions reductions in accordance with established protocols published by the Government of Alberta.

Alberta is also the first jurisdiction in North America to direct dedicated funding to implement carbon capture and storage technology across industrial sectors. Alberta will invest $2 billion into demonstration 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.

Saskatchewan

On May 11, 2009, the Government of Saskatchewan announced *The Management and Reduction of Greenhouse Gases Act* to regulate greenhouse gas emissions in the province. The act received Royal Assent on May 20, 2010 and will come into force on proclamation. The act establishes a framework for achieving the provincial target of a 20% reduction in greenhouse gas emissions from 2006 levels by 2020. The act and related regulations have yet to be proclaimed in force.

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, nor should be taken as a complete summary or description of all the risks associated with our business and the oil and natural gas business generally.

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 or discovered by us. Our ability to market our oil and natural gas may depend upon our ability to acquire space 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 our reserves are from pipelines, railway lines, processing and storage facilities, operational problems affecting pipelines, railway lines and facilities as well as 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 conditions, in the United States, Canada and Europe, the actions of OPEC, governmental regulation, political stability in the Middle East, Northern Africa and elsewhere, the foreign supply 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.

North American crude oil price differentials are expected to continue to be volatile throughout 2013, which will have an impact on Canadian producers. The supply of Canadian crude oil with demand from the refinery complex and access to those markets through various transportation outlets is currently finely balanced, and therefore very sensitive to pipeline and refinery outages, which contributes to this volatility. There are a number of refinery expansion and pipeline de-bottlenecking projects underway, and there continues to be growth in the ability of Canadian producers to access new markets by moving crude production on railways. Completion of these projects has the potential to, over time, mitigate the current volatility in oil price differentials. There can be no assurance that any or all of these projects will be completed on a timely basis.

A material decline in 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 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 acquisition, 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, 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.

In addition, bank borrowings available to us may, in part, be determined by our borrowing base. A sustained material decline in prices from historical average prices could reduce our borrowing base, therefore reducing the bank credit available to us which could require that a portion, or all, of our bank debt be repaid.

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 natural 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 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 participations 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 assure 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, and shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other 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.

Reserve Estimates

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and natural gas liquids reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth in this document are estimates only. Generally, estimates of economically recoverable oil and natural gas reserves and the future net cash flows from such estimates 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 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 and such variations could be material.

The estimation of proved reserves that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves rather than actual production history. Recovery factors and drainage areas were 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 cash flows derived from our 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 the activities we intend to undertake in future years. The reserves and estimated cash flows 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 therefore does not reflect changes in our reserves since that date.

Uncertainties Associated with Estimating Resource Volumes

There are numerous uncertainties inherent in estimating quantities of Discovered Petroleum Initially-In-Place, Contingent Resources and Economic Contingent Resources and the before-tax net present value of Economic Contingent Resources, including many factors beyond the Corporation's control. The Discovered Petroleum Initially-In-Place and the Economic Contingent Resources estimates disclosed under "*General Development of Our Business – History and Development – Wapiti Montney Play Resource Evaluation*" have been independently evaluated by GLJ. These estimates include a number of factors and assumptions made as of the date on which the evaluation is made such as geological and engineering estimates which have inherent uncertainties, the effects of regulation by governmental agencies, initial production rates, production decline rates, ultimate recovery of reserves and Contingent Resources, timing and amount of capital expenditures, marketability of production, current and forecast prices of crude oil and natural gas, the Corporation's ability to transport its product to various markets, operating costs, abandonment and salvage values and royalties and other government levies that may be imposed over the producing life of the reserves and Contingent Resources. Many of these assumptions are subject to change and may not, over time, prove to be accurate. Further, there is no certainty that any portion of these resources will ultimately be developed or produced or that resources currently classified as ECR will be classified as Reserves, either because it may not be commercially viable to do so or for other reasons.

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 over-runs 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 and hydraulic fracturing, or our ability to dispose of water used or removed from strata at a reasonable cost and in accordance with applicable environmental regulations;
- the supply of and demand for oil and natural gas;
- the availability of alternative fuel sources;
- 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 it produces effectively.

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);
- 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. 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. 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.

Refinancing Risk and Debt Service Charges

At present, no principal payments are required under our Credit Facility until April 29, 2015. In the event that our Credit Facility is not extended before April 29, 2015, our Credit Facility will go from a revolving facility to a term facility and the indebtedness will be repayable at the end of the term. There is also a risk that our Credit Facility will not be renewed for the same amount or on the same terms. In addition, the amount authorized under our Credit

Facility is dependent on the borrowing base determined by our lenders. We are required to comply with covenants under our Credit Facility 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 the failure of us to comply with such covenants. A failure to comply with covenants could result in the default under our Credit Facility, which could result in us being required to repay amounts owing thereunder. Even if we are able to obtain new financing, it may not be on commercially reasonable terms or terms that are acceptable to us. If we are unable to repay amounts owing under our Credit Facility, the lenders under our Credit Facility could proceed to foreclose or otherwise realize upon the collateral granted to them to secure the indebtedness. 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. A material decline in 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.

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. There is risk that if the economy and banking industry experienced unexpected and/or prolonged deterioration, our access to additional financing may be affected.

Because of global economic 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.

Gathering and Processing Facilities, Pipeline Systems and Rail

We deliver our products through gathering and processing facilities and pipeline systems some of which we do not own and 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, and pipeline systems and railway lines. The lack of availability of capacity in any of the gathering and processing facilities and pipeline systems and railway lines, and in particular the processing facilities, 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. Although pipeline expansions are ongoing, the lack of firm pipeline capacity continues to affect the oil and natural gas industry and limit the ability to produce and market oil and natural gas production. In addition, the pro-rationing of capacity on inter-provincial pipeline systems continues to affect the ability to export oil and natural gas. Furthermore, 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 and it is projected to continue in this upward trend. Any significant change in market factors or other conditions affecting these infrastructure systems and facilities, as well as any delays in constructing new infrastructure systems and facilities could harm our business and, in turn, our financial condition, results of operations and cash flows.

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 affect our ability to process our production and deliver the same for sale.

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.

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 will require regulatory permits, licenses, registrations, approvals and authorizations from various governmental authorities. There can be no assurance that we will be able to obtain all of the permits, licenses, registrations, approvals and authorizations that may be required to conduct operations that we may wish to undertake. In addition to regulatory requirements pertaining to the production, marketing and sale of oil and natural gas mentioned above, our business and financial condition could be influenced by federal legislation affecting, in particular, foreign investment, through legislation such as the *Competition Act* (Canada) and the *Investment Canada Act* (Canada).

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 becomes defunct. 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 of the ratio of the Corporation' deemed assets to deemed liabilities or changes to the requirements of liability management programs may result in significant increases to the security that must be posted. See: "*Industry Conditions*".

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 the legal basis of an aboriginal land claim and aboriginal rights is a matter of considerable legal complexity and the impact of the assertion of such a claim, or the possible effect of a settlement of such claim upon us cannot be predicted without any degree of certainty at this time. In addition, no assurance can be given that any recognition of aboriginal rights or claims whether by way of a negotiated settlement or by judicial pronouncement (or through the grant of an injunction prohibiting exploration or development pending resolution of any such claim) would not delay or even prevent our exploration and development activities. 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.

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 those of 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. There may be liabilities associated with an acquisition that we fail to discover. Management continually assesses the value and contribution of services provided 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, if disposed of, may realize less than their carrying value on our financial statements.

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.

Continuing production from a property, and to some extent the marketing of production therefrom, largely depend upon the ability of the operator of the property or related facilities and the uninterrupted access to pipelines. Operating costs on most properties have increased over recent years. To the extent the operator fails to perform these functions properly or pipeline access is restricted, revenues will be reduced. Payments from production generally flow through the operator and there is a risk of delay and additional expense in receiving such revenues if the operator becomes insolvent. Our return on assets operated by others therefore depends upon a number of factors that may be outside of our control, including 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.

Global Economic Events

Market events and conditions, including disruptions in the international credit markets and other financial systems and the American and European sovereign debt levels, may cause significant volatility to commodity prices and a decline in funds from operations. Global economic events and conditions may cause a loss of confidence in the broader global credit and financial markets and create a climate of greater volatility, less liquidity, wider credit spreads, a lack of price transparency, increased credit losses and tighter credit conditions. Market events in the future may affect our ability to obtain equity or debt financing on acceptable terms and may make it more difficult to operate effectively.

Market Price of our Common Shares

The trading price of securities of oil and natural gas issuers is subject to substantial volatility often based on factors related and unrelated to the financial performance or prospects of the issuers involved. 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.

Competition

The petroleum industry is competitive in all of its phases. We compete with numerous other entities in the search for, and the acquisition of, oil and natural gas properties and in the 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, methods, and reliability of delivery and storage.

Royalty Regimes

There can be no assurance that the federal government and the provincial governments of the western provinces will not adopt a new or modify the royalty regime 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.

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 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.

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 the spill, releases or emission of various substances produced in association with certain oil and gas industry operations.

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 laws 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.

Climate Change

Our exploration and production facilities and other operations and activities emit greenhouse gases and which may require us to comply with greenhouse gas 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 *United Nations Framework Convention on Climate Change* (the "**UNFCCC**") and 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 will seek a 17% reduction in greenhouse gas emissions from 2005 levels by 2020. These greenhouse gas emission reduction targets are not binding, however. Although it is not the case today, some of our significant facilities may ultimately be subject to future regional, provincial and/or federal climate change regulations to manage greenhouse gas emissions. 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. Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not possible to predict the impact on us and our operations and financial condition.

Variations in Foreign Exchange Rates and Interest Rates

World oil and natural gas prices are quoted in United States dollars. The Canadian/U.S. 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, Canadian/United States exchange rates could affect the future value of our reserves as determined by independent evaluators.

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 could negatively impact the market price of our Common Shares.

Issuance of Debt

From time to time, we may enter into transactions to acquire assets or shares of other organizations. 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 equity and/or 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;
- 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 dollars in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to the United States dollar. However, if the Canadian dollar declines in value compared to the United States dollar, 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) in the particular areas where such activities will be conducted.

Demand for such limited equipment or access restrictions may affect the availability of such equipment 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 an unforeseen 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 legislative changes which affect our title to the oil and natural gas properties we control that could impair our activities on them and result in a reduction of the revenue received by us.

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.

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, related to personal injuries, property damage, property tax, land rights, the environment and contract disputes. The outcome of 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.

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 and other 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.

Cost of New Technologies

The oil industry is characterized by rapid and significant technological advancements and introductions of new products and services utilizing new technologies. Other oil 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. 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, our business, financial condition and results of operations could also be materially adversely affected.

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 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.

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. In addition, 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. 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 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.

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 of 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 we 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 person insurance in effect. The contributions of the existing management team to the immediate and near term operations of NuVista 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.

Dividends

We do not currently pay any dividends on our outstanding Common Shares. Payment of dividends in the future will be dependent on, among other things, our cash flow, results of operations and financial condition, the need for funds to finance ongoing operations and other considerations, as our Board of Directors considers relevant.

Intellectual Property Litigation

Due to the rapid development of oil and gas technology, 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 in which it is alleged that we have infringed the intellectual property rights of others or commence lawsuits against others who we believe are infringing upon our intellectual property rights. Our involvement in intellectual property litigation could result in significant expense, adversely affecting the development of our assets or intellectual property or diverting the efforts of our technical and management personnel, whether or not such litigation is resolved in our favour. In the event of an adverse outcome as a defendant in any such litigation, we may, among other things, be required to: (a) pay substantial damages; cease the development, use, sale or importation of processes that infringe upon other patented intellectual property; (b) expend significant resources to develop or acquire non-infringing intellectual property; (c) discontinue processes incorporating infringing technology; or (d) obtain licences to the infringing intellectual property. However, we may not be successful in such development or acquisition or such licences may not be available on reasonable terms. Any such development, acquisition or licence could require the expenditure of substantial time and other/ resources and 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 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.

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

Investors are cautioned not to place undue reliance on 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.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

There are no legal proceedings that we are or were a party to, or that any of our property is or was the subject of, during our most recently completed financial year, that were or are material to us, and there are no such material legal proceedings that we are currently aware of that are contemplated.

There were no: (i) penalties or sanctions imposed against us by a court relating to securities legislation or by a security regulatory authority during the most recently completed financial year; (ii) 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; or (iii) settlement agreements we entered into before a court relating to securities legislation or with a securities regulatory authority during our most recently completed financial year.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

There are no material interests, direct or indirect, of our directors and senior officers, or any holder of our Common Shares who beneficially owns, or controls or directs, directly or indirectly, more than 10% of our outstanding Common Shares, or any known associate or affiliate of such persons, in any transaction completed within the last three years or in any proposed transaction during the current financial year which have materially affected or are reasonably expected to materially affect us, other than as disclosed herein.

AUDITORS

KPMG LLP, Suite 2700, Bow Valley Square II, 205 – 5^{th} Avenue S.W., Calgary, Alberta, T2P 4B9, is our auditor.

TRANSFER AGENT AND REGISTRAR

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

MATERIAL CONTRACTS

The only material contract entered into by us within the most recently completed financial year and which is presently material other than in the ordinary course of business, is the credit agreement in respect of our Credit Facility. A copy of this agreement is available on SEDAR at *www.sedar.com*.

INTERESTS OF EXPERTS

There is no person or company whose profession or business gives authority to a statement made by such person or company and who is named as having prepared or certified a report, valuation, statement or opinion described or included in a filing, or referred to in a filing, made under National Instrument 51-102 by us during, or related to, our most recently completed financial year other than GLJ, our independent engineering evaluator and KPMG LLP, our independent auditors.

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

None of the designated professionals of 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 statement, report or valuation prepared by it, at any time thereafter or to be received by them.

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 Grant A. Zawalsky, one of our directors, is the managing partner of Burnet, Duckworth & Palmer LLP, the law firm which renders legal services to us.

ADDITIONAL INFORMATION

Additional information relating to us can be found on SEDAR at *www.sedar.com* and on our website at *www.nuvistaenergy.com*. 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 Shareholder meeting to be held on May 13, 2014. Additional financial information is contained in our consolidated financial statements for the year ended December 31, 2013 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:

NuVista Energy Ltd.
Suite 3500, 700 – 2nd Street S.W.
Calgary, Alberta, T2P 2W2
Tel: (403) 538-8500
Fax: (403) 538-8505

APPENDIX A

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

Management of NuVista Energy Ltd. ("**NuVista**") is responsible for the preparation and disclosure of information with respect to NuVista's oil and natural gas activities in accordance with securities regulatory requirements. This information includes reserves data which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2013, estimated using forecast prices and costs.

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

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

(a) reviewed NuVista'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 NuVista'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

(a) the content and filing with securities regulatory authorities of Form 51-101F2 containing reserves data and other oil and gas information;

(b) the filing of Form 51-101F2 which is the report of the independent qualified reserves evaluator on the reserves data; and

(c) 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) "*Ronald J. Eckhardt*"
Ronald J. Eckhardt
Director and Chairman of the Reserves Committee

(signed) "*Jonathan A. Wright*"
Jonathan A. Wright
President and Chief Executive Officer

(signed) "*Keith MacPhail*"
Keith MacPhail
Chairman

(signed) "*Mike Lawford*"
Mike Lawford
Vice President, Development

March 6, 2014

APPENDIX B

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

To the Board of Directors of NuVista Energy Ltd. (the "**Company**"):

1. We have evaluated the Company's reserves data as at December 31, 2013. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2013, 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.

   We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "**COGE Handbook**") prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

3. 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.

4. The following table sets forth the estimated 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 by us for the year ended December 31, 2013, and identifies the respective portions thereof that we have evaluated and reported on to the Company's Board of Directors:

			Net Present Value of Future Net Revenue (before income taxes, 10% discount rate – $000s)			
Independent Qualified Reserves Evaluator	**Description and Preparation Date of Evaluation Report**	**Location of Reserves (County or Foreign Geographic Area)**	**Audited**	**Evaluated**	**Reviewed**	**Total**
GLJ Petroleum Consultants	Corporate Summary February 10, 2014	Canada	-	1,322,722	-	1,322,722

5. 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. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.

6. We have no responsibility to update our reports for events and circumstances occurring after their respective preparation dates.

7. 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:

GLJ Petroleum Consultants Ltd., Calgary, Alberta, Canada, February 12, 2014.

"ORIGINALLY SIGNED BY"

Myron J. Hladyshevsky, P. Eng.
Vice-President

APPENDIX C

NUVISTA ENERGY LTD.

MANDATE OF THE AUDIT COMMITTEE

Role and Objective

The Audit Committee (the "**Committee**") is a committee of the Board of Directors (the "**Board of Directors**") of NuVista Energy Ltd. ("**NuVista**") to whom the Board of Directors has delegated responsibility for oversight of the nature and scope of the annual audit, management's reporting on internal accounting standards and practices, financial information and accounting systems and procedures, financial reporting and statements and recommending, for Board of Directors approval, the audited financial statements and other mandatory disclosure releases containing financial information. The objectives of the Committee, with respect to NuVista and its subsidiaries, partnership and other controlled entities are as follows:

- To assist the directors in meeting their responsibilities (especially for accountability) in respect of the preparation and disclosure of the financial statements of NuVista and related matters;
- To provide better communication between directors and external auditors;
- To enhance the external auditor's independence;
- To increase the credibility and objectivity of financial reports; and
- To strengthen the role of the outside directors by facilitating in depth discussions between directors on the Committee, management and external auditors.

Membership of Committee

- The Committee shall be comprised of at least three directors, all of whom are "independent" (as such term is used in Multilateral Instrument 52-110 — Audit Committees ("MI 52-110").
- The Board of Directors shall have the power to appoint the Committee Chair and other members of the Committee.
- All of the members of the Committee shall be "financially literate". The Board of Directors has adopted the definition for "financial literacy" used in MI 52-110.

Meetings

- At all meetings of the Committee every question shall be decided by a majority of the votes cast. In case of an equality of votes, the Committee Chair shall not be entitled to a second or casting vote.
- A quorum for meetings of the Committee shall be a majority of its members, and the rules for calling, holding, conducting and adjourning meetings of the Committee shall be the same as those governing the Board of Directors.
- Meetings of the Committee should be scheduled to take place at least four times per year. Minutes of all meetings of the Committee shall be taken. The CEO and CFO shall attend meetings of the Committee, unless otherwise excused from all or part of any such meeting by the Committee Chair.
- The Committee shall forthwith report the results of meetings and reviews undertaken and any associated recommendations to the Board of Directors.

- The Committee shall 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.

Mandate and Responsibilities of Committee

- It is the responsibility of the Committee to oversee the work of the external auditors, including resolution of disagreements between management and the external auditors regarding financial reporting.

- It is the responsibility of the Committee to monitor, on behalf of the Board of Directors, NuVista's internal control systems, including:

  - identifying, monitoring and mitigating business risks; and

  - ensuring compliance with legal, ethical and regulatory requirements including the certification process.

- It is a primary responsibility of the Committee to review the annual financial statements of NuVista prior to their submission to the Board of Directors for approval. The process should include but not be limited to:

  - 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;

  - reviewing significant accruals, reserves or other estimates such as the ceiling test calculation;

  - reviewing accounting treatment of unusual or non-recurring transactions;

  - ascertaining compliance with covenants under loan agreements;

  - reviewing the adequacy of the asset retirement obligation in the financial statements;

  - reviewing disclosure requirements for commitments and contingencies;

  - reviewing adjustments raised by the external auditors, whether or not included in the financial statements;

  - reviewing unresolved differences between management and the external auditors;

  - reviewing non-recurring transactions;

  - reviewing related party transactions; and

  - obtaining explanations of significant variances with comparative reporting periods.

- The Committee is to review the financial statements, prospectuses, management discussion and analysis (MD&A), annual information forms (AIF) and all public disclosure containing audited or unaudited financial information before release and prior to Board of Directors approval. The Committee must be satisfied that adequate procedures are in place for the review of NuVista's disclosure of all other financial information and shall periodically access the accuracy of those procedures.

- With respect to the appointment of external auditors by the Board of Directors, the Committee shall:

  - recommend to the Board of Directors the appointment of the external auditors;

  - recommend to the Board of Directors the terms of engagement of the external auditor, including the compensation of the auditors and a confirmation that the external auditors shall report directly to the Committee;

  - when there is to be a change in auditors, review the issues related to the change and the information to be included in the required notice to securities regulators of such change; and

  - review and approve any non-audit services to be provided by the external auditors' firm and consider the impact on the independence of the auditors.

- The Committee shall review with external auditors (and internal auditor if one is appointed by NuVista) their assessment of the internal controls of NuVista, their written reports containing recommendations for improvement, and management's response and follow-up to any identified weaknesses. The Committee shall also review annually with the external auditors their plan for their audit and, upon completion of the audit, their reports upon the financial statements of NuVista and its subsidiaries.

- The Committee must pre–approve all non–audit services to be provided to NuVista or its subsidiaries by the external auditors. 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 comply with such other procedures as may be established by the Committee from time to time.

- The Committee shall review financial risk management policies and procedures of NuVista (i.e. hedging, litigation and insurance).

- The Committee shall establish a procedure for:

  - the receipt, retention and treatment of complaints received by NuVista regarding accounting, internal accounting controls or auditing matters; and

  - the confidential, anonymous submission by employees of NuVista of concerns regarding questionable accounting or auditing matters.

- The Committee shall review and approve NuVista's hiring policies regarding employees and former employees of the present and former external auditors of NuVista.

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

- The Committee shall meet periodically with the external auditors, independent of management. The issues for consideration should include, but are not limited to:

  - obtaining feedback on competencies, skill sets and performance of key members of the financial reporting team;

  - enquiring as to significant differences from prior year period audits or reviews;

  - enquiring as to transactions accounted for in an acceptable manner but on a basis which in the opinion of the external auditor, was not the preferable accounting treatment;

  - enquiring as to any differences between management and the external auditor;

  - enquiring as to material differences in accounting policies, disclosures or presentation from prior periods;

  - enquiring as to deficiencies in internal controls identified in the course of the performance of the procedures by the external auditors; and

  - enquiring as to any other matters or observations that the external auditors would like to bring to the attention of the Committee.

- The Committee may retain persons having special expertise and/or obtain independent professional advice to assist in filling their responsibilities at the expense of NuVista without any further approval of the Board of Directors.

Approved by the Board of Directors: March 6, 2008