NUVISTA ENERGY LTD

2011 ANNUAL INFORMATION FORM

MARCH 28, 2012

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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 Report means the report of GLJ evaluating as of December 31, 2011, our crude oil, natural gas and natural gas liquids reserves dated February 22, 2012.

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.

ABBREVIATIONS

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

Other

AECO	the natural gas storage facility located at Suffield, Alberta, connected to TransCanada's Alberta System
API	American Petroleum Institute
°API	an indication of the specific gravity of crude oil measured on the API gravity scale
BOE or Boe	barrel or barrels of oil equivalent, using the conversion factor of six Mcf of natural gas being equivalent to one barrel of oil
Boe/d	barrels of oil equivalent per day
$Cdn	Canadian dollars
m^3	cubic metres
Mboe	thousand barrels of oil equivalent
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	28.174
cubic metres	cubic feet	35.494
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 2012 capital program, strategy and focus, the allocation of our 2012 capital program, anticipated cash flow, average production volumes and our future drilling 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; "*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 and natural gas;
- commodity prices; and
- expected royalty rates and the anticipated benefits of royalty incentive programs.

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

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

- volatility of commodity prices;
- liabilities inherent in oil and natural gas operations;
- imprecision of reserve estimates;

- risks associated with refinancing our Credit Facility;
- competition from other industry participants;
- 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;
- 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 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

The terms "Boe" and "Mcfe" may be misleading, particularly if used in isolation. A Boe conversion ratio of six thousand cubic feet per barrel (6 Mcf: 1 Bbl) of natural gas to barrels of oil equivalence and a Mcfe conversion ratio of 1 barrel per six thousand cubic feet (1 Bbl: 6 Mcf) of barrels of oil to natural gas equivalence 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-IFRS 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 as presented, does not have any standardized meaning prescribed by international financial reporting standards 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, per the statement of cash flows, net earnings (loss) or other measures of financial performance calculated in accordance with international financial reporting standards. 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, 2011, 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 international financial reporting standards. 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 international financial reporting standards 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*", "*General Description 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 1400, 350 – 7th Avenue S.W., Calgary, Alberta, T2P 3N9.

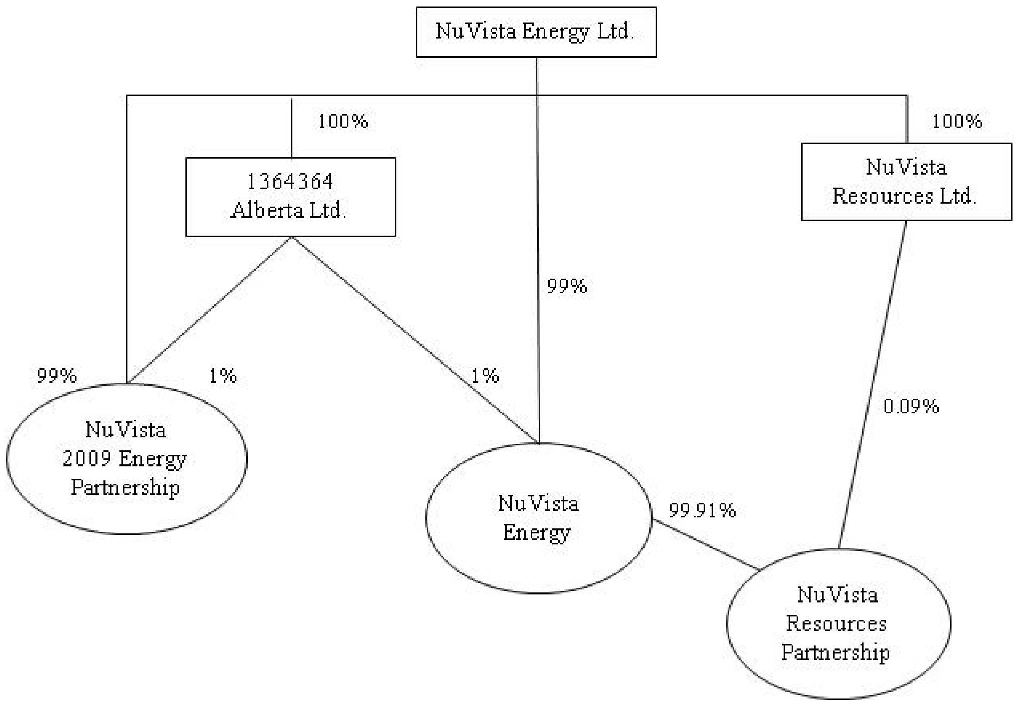
Inter-Corporate Relationships

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	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 on July 2, 2003, we have grown our business through a combination of exploration, development and optimization of our assets as well as the completion of a number of strategic acquisitions in western Canada.

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

On January 29, 2009, we completed the acquisition of 1,600 Boe/d of production, primarily in our Ferrier/Sunchild, Wapiti and Northwest Saskatchewan operating areas for approximately $55 million which was funded by cash flow from operations and bank debt. Total proved plus probable reserves acquired, based on management's internal estimates effective as of December 31, 2008, were 4.5 million Boe.

On June 15, 2009, we entered into an agreement to acquire certain properties located in the Martin Creek area of northeast British Columbia and in northwest Alberta for cash consideration of approximately $174 million. We closed this acquisition on July 27, 2009. The purchase price for the acquisition was funded through a combination of bank debt and the net proceeds from a public offering of 7,500,000 subscription receipts at a price of $11.00 per subscription receipt for gross proceeds of $82.5 million and a private placement of 1,500,000 subscription receipts at a price of $11.00 per subscription receipt for gross proceeds of $16.5 million. Upon completion of the acquisition, each subscription receipt was exchanged for one of our Common Shares for no additional consideration or further action. At the time of closing, the properties acquired were producing approximately 5,900 Boe/d with an 82% natural gas weighting. The majority of the liquids production was light oil production from Keg River pools in northwest Alberta. Approximately 96% of the production was operated with an average working interest of 77%. Included in the acquisition was approximately 140,000 net acres of undeveloped land with an average working interest of 71% with over 30 identified drilling opportunities.

Concurrent with the closing of the Martin Creek acquisition, our Credit Facility was increased from $450 million to $510 million.

On March 8, 2010, our Board of Directors declared a quarterly dividend of $0.05 per Common Share. The first dividend payment was on April 15, 2010, payable in cash to Shareholders of record on March 31, 2010. On June 9, 2010 we announced the adoption and implementation of a dividend reinvestment plan pursuant to which eligible Shareholders could receive dividends as a cash payment or can reinvest the dividend to purchase Common Shares through the dividend reinvestment plan.

In November of 2010, our lenders completed the semi-annual review of the borrowing base under our Credit Facility and the borrowing base remained at $510 million.

On November 23, 2010, Alex G. Verge, our former President & Chief Executive Officer, resigned at the request of our Board of Directors and Robert F. Froese was appointed as our Interim President & Chief Executive Officer. Our Board of Directors also formed an Interim Board Executive Committee consisting of Keith A. MacPhail, Clayton H. Woitas and Ronald G. Poelzer to assist our management and to conduct an executive search for a President and Chief Executive Officer.

On February 2, 2011, we entered into a series of transactions with the Bonavista Energy Corporation to separate our joint ownership of certain crude oil and natural gas assets held through NuVista Energy and NuVista Resources Partnership. Under these transactions: (a) we and the Bonavista Energy Corporation retained our respective pro-rata share of all crude oil properties; (b) we and the Bonavista Energy Corporation retained our pro-rata share of certain natural gas properties; and (c) we and the 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 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 and 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 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.

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

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.

In May of 2011, our lenders completed the semi-annual review of the borrowing base under our Credit Facility which resulted in a reduction of our facility to $470 million.

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 Vice President, Development.

NuVista completed the semi-annual review of the borrowing base of our Credit Facility in November, 2011 with our lenders, which resulted in a reduction of our facility to $440 million.

Recent Developments

Our Board of Directors has approved a 2012 first half capital budget range of $70 million to $80 million, approximately equal to our anticipated cash flow and the proceeds from minor property dispositions. The objective of this capital program is to conduct an active drilling program prior to spring break-up to further evaluate the economics of our W6 Wapiti Montney and W5 liquids-rich plays and to continue heavy oil development drilling. Average production for the first half of 2012 is forecast at 24,500 Boe/d to 25,500 Boe/d. We have an inventory of quality drilling opportunities and are continuing to remain flexible to accelerate our capital program if natural gas prices improve or we are able to complete selected non-core asset dispositions. Our natural gas drilling focus remains on strategic advancement of repeatable liquids-rich plays that have significant long term value and strong economics.

GENERAL DESCRIPTION OF OUR BUSINESS

Stated Business Objectives and Strategy

With the outlook for continued low natural gas prices over the near term, we are carefully evaluating our business to ensure a sustainable model without jeopardizing our financial flexibility or longer term growth opportunities in the our operating areas. Our near term focus remains on delivering immediate results in a disciplined manner while advancing plays that have strong economics in the current natural gas price environment, and significant upside potential. Despite maintaining discipline with a prudent capital program in this environment, we have been able to maintain production volumes relatively flat. Our current business plan involves the focused development of our highest return oil and liquids-rich natural gas projects to deliver near term operating and financial results. In addition, we are continuing to selectively evaluate existing and new resource plays targeting oil and liquids-rich natural gas within our core regions to provide for sustainable future growth.

We apply our technical and operating expertise within our core regions with a disciplined approach based on seven principles:

- focus on operating areas, establish technical expertise in these areas;
- operate our production;
- hold a high working interest;
- attract and retain a talented team;
- maintain a low cost structure;
- control our business plan and be opportunity driven; and
- maintain financial flexibility.

We have created a team based organization in which operational and technical excellence and idea generation are encouraged. Each of our operating areas has a multi-disciplined team that is self-motivated and empowered to develop their ideas. They are all rewarded with an ownership stake in us, closely aligning their interests with those of our Shareholders. Together, they concentrate their efforts in our operating areas, where we can achieve a dominant land position, operate and control infrastructure, and therefore manage costs, as well as discourage encroachment by competitors. By focusing in an operating area, our team become experts in identifying opportunities. 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 an intermediate company with a focus on longer-life assets containing growth opportunities primarily in the Deep Basin area of central Alberta. Our production has grown from 3,500 Boe/d in 2003 to approximately 24,500 Boe/d today.

Cyclical and Seasonal Impact of Industry

Our operational results and financial condition is 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 2011, 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 2011 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 29, 2012. 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, 2011, we employed 142 full-time employees, including 115 office and 27 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 22, 2012. The statement is effective as of December 31, 2011 and the preparation date of the statement is February 22, 2012. 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, 2011, as contained in the GLJ 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 Report has been prepared in accordance with the standards contained in the Canadian Oil and Gas Evaluation 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, 2011 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 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 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, 2011
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	2,739	2,265	4,968	4,546	210,377	186,627	5,870	4,290
Developed Non-Producing	155	124	276	227	34,209	30,238	1,276	996
Undeveloped	1,674	1,410	1,138	1,084	52,199	48,196	1,904	1,538
TOTAL PROVED	4,568	3,799	6,382	5,858	296,785	265,062	9,049	6,823
PROBABLE	2,857	2,223	2,566	2,324	173,434	155,490	5,868	4,371
TOTAL PROVED PLUS PROBABLE	7,425	6,022	8,948	8,182	470,220	420,552	14,917	11,194

	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	1,116,348	867,813	713,671	609,205	533,836	16.91	2.82
Developed Non-Producing	166,318	109,305	81,166	64,458	53,321	12.71	2.12
Undeveloped	264,529	163,230	106,585	71,657	48,599	8.83	1.47
TOTAL PROVED	1,547,195	1,140,348	901,422	745,320	635,757	14.86	2.48
PROBABLE	1,053,698	591,456	382,596	269,127	199,806	10.98	1.83
TOTAL PROVED PLUS PROBABLE	2,600,893	1,731,804	1,284,019	1,014,447	835,563	13.45	2.24

Note:

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

RESERVES CATEGORY	NET PRESENT VALUES OF FUTURE NET REVENUE AFTER INCOME TAXES DISCOUNTED AT (%/year) 0 ($000s)	5 ($000s)	10 ($000s)	15 ($000s)	20 ($000s)
PROVED:					
Developed Producing	1,042,705	817,344	677,362	582,077	512,954
Developed Non-Producing	126,392	81,706	60,176	47,555	39,208
Undeveloped	197,736	116,528	70,948	42,919	24,567
TOTAL PROVED	1,366,833	1,015,578	808,486	672,551	576,730
PROBABLE	788,557	437,030	277,952	191,582	138,988
TOTAL PROVED PLUS PROBABLE	2,155,389	1,452,608	1,086,438	864,133	715,718

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
AS OF DECEMBER 31, 2011
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	3,388,511	462,219	1,076,928	251,525	50,643	1,547,195	180,363	1,366,833
Total Proved plus Probable	5,702,974	799,839	1,767,169	473,643	61,430	2,600,893	445,503	2,155,389

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, 2011
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)	126,065	25.91	4.32
	Heavy Oil (including solution gas and other by-products)	196,981	33.92	5.65
	Natural Gas (including by-products but excluding natural gas from oil wells)	578,375	11.57	1.93
	Total	901,422	14.86	2.48
Proved plus Probable	Light and Medium Crude Oil (including solution gas and other by-products)	181,442	24.15	4.03
	Heavy Oil (including solution gas and other by-products)	258,485	32.17	5.36
	Natural Gas (including by-products but excluding natural gas from oil wells)	844,092	10.56	1.76
	Total	1,284,019	13.45	2.24

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

5. "**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.

6. "**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.

7. "**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.

8. "**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.

9. "**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).

10. Numbers may not add due to rounding.

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

12. 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 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									
2012	97.00	97.96	72.37	90.12	3.49	58.78	76.41	2.0	0.980
2013	100.00	101.02	73.60	92.94	4.13	60.61	78.80	2.0	0.980
2014	100.00	101.02	74.51	91.93	4.59	60.61	78.80	2.0	0.980
2015	100.00	101.02	74.51	91.93	5.05	60.61	78.80	2.0	0.980
2016	100.00	101.02	74.51	91.93	5.51	60.61	78.80	2.0	0.980
2017	100.00	101.02	74.51	91.93	5.97	60.61	78.80	2.0	0.980
2018	101.35	102.40	75.54	93.18	6.21	61.44	79.87	2.0	0.980
2019	103.38	104.47	77.09	95.07	6.33	62.68	81.49	2.0	0.980
2020	105.45	106.58	78.67	96.99	6.46	63.95	83.13	2.0	0.980
2021	107.56	108.73	80.28	98.95	6.58	65.24	84.81	2.0	0.980
2022+	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	2.0	0.980

Notes:
(1) As at January 1, 2012.
(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, 2011, excluding financial derivative commodity contracts were $3.90/Mcf for natural gas, $94.58/Bbl for light and medium oil, $72.87/Bbl for heavy oil and $64.31/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, 2010	5,756	2,963	8,719	6,290	2,553	8,843
Discoveries	-	-	-	-	-	-
Extensions	115	35	150	804	447	1,251
Infill Drilling	-	-	-	522	102	624
Improved Recovery	-	-	-	-	-	-
Technical Revisions	(356)	(15)	(371)	339	(354)	(15)
Acquisitions	-	-	-	155	75	230
Dispositions	(326)	(92)	(418)	(461)	(276)	(736)
Economic Factors	(52)	(34)	(86)	55	18	73
Production	(569)	-	(569)	(1,322)	-	(1,322)
December 31, 2011	4,568	2,857	7,425	6,382	2,566	8,948

	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, 2010	318,158	169,676	487,834	8,735	5,218	13,953
Discoveries	-	-	-	-	-	-
Extensions	24,403	12,293	36,696	1,283	888	2,171
Infill Drilling	540	2,311	2,851	16	46	62
Improved Recovery	-	-	-	-	-	-
Technical Revisions	7,852	(8,967)	(1,115)	462	(242)	220
Acquisitions	10,889	4,286	15,175	29	6	35
Dispositions	(12,305)	(6,451)	(18,756)	(158)	(44)	(202)
Economic Factors	(14,996)	286	(14,710)	(243)	(5)	(248)
Production	(37,756)	-	(37,756)	(1,075)	-	(1,075)
December 31, 2011	296,785	173,434	470,220	9,049	5,868	14,917

Additional Information Relating to Reserves Data

Undeveloped Reserves

Undeveloped reserves are attributed by GLJ in accordance with standards and procedures contained in the Canadian Oil and Gas Evaluation 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 95% of the proved undeveloped reserves in the GLJ 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	-	-	-	83	2,979	4,121	45	49
2009	303	312	666	752	22,846	28,403	608	665
2010	2,232	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

Of our total proved plus probable reserves, 13.4 MMboe or 12% are proved undeveloped reserves. These well locations are allocated reserves because they are within the defined distances to proved reserve accumulations. There are five play types that account for 8.1 MMboe or 61% of the proved undeveloped reserves. These play types are: West Central Saskatchewan Birdbear (1.0 MMboe, 7%), Pembina Cardium (1.0 MMboe, 8%), Wapiti Montney (3.1 MMboe, 23%), Wapiti Cardium (0.8 MMboe, 6%) and Kaybob Montney (2.2 MMboe, 17%). Capital expenditures of $64 million in 2012 and $79 million in 2013 will be invested in developing our 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	181	181	25	95	10,972	14,193	233	281
2009	530	711	300	397	21,699	37,746	640	955
2010	1,668	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

Of our total proved plus probable reserves, 21.0 MMboe or 19% are probable undeveloped reserves. These well locations are allocated reserves because they are within the defined distances to proved reserve accumulations. There are five play types that account for 11.1 MMboe or 53% of the proved undeveloped reserves. These play types are: West Central Saskatchewan Birdbear (0.6 MMboe, 3%), Alder Flats Spirit River (1.6 MMboe, 8%), Wapiti Montney (6.6 MMboe, 31%), Wapiti Cardium (0.9 MMboe, 4%) and Kaybob Montney (1.5 MMboe, 7%). Capital expenditures of $38 million in 2012 and $55 million in 2013 will be invested developing our 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)
2012	64,408	102,339
2013	79,364	134,746
2014	68,549	99,464
2015	29,901	90,840
2016	4,081	34,216
2017	253	722
2018	574	631
2019	57	595
2020	410	747
2021	1,116	1,109
2022	-	60
2023	105	804
Remaining	2,707	7,370
Total (Undiscounted)	251,525	473,643

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 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, 2011. Information in respect of current production is average production, net to our working interest, except where otherwise indicated.

Alberta Deep Basin Core Region

Wapiti

Wapiti, our largest operating area is located south of Grande Prairie, Alberta, approximately 520 kilometres northwest of Calgary. The Wapiti operating area falls largely within the deep basin gas window and is characterized as having multiple stacked prospective Cretaceous–Jurassic gas bearing formations that lend themselves both to vertical and horizontal drilling and multi-stage fracturing technology. Our Wapiti operating area lies within the ERCB Development Entity #2 which allows four wells per pool per section further expanding our already large development drilling portfolio. The Wapiti area has a land base of approximately 186,000 net acres with an average working interest of 65%. Natural gas production in the Wapiti area is processed at third party operated facilities where NuVista owns a working interest, primarily the Devon South Wapiti 16-36-67-9W6 (3.7%) and Devon Elmworth Deep Cut 4-8-69-8W6 (2.2%). These large plants provide both favourable liquid recoveries and low operating costs for our production. This operating area is expected to play an important role in our future growth.

We hold rights in approximately 96,500 net acres of land with an approximate working interest of 92% that are prospective for the Triassic Montney formation. This formation is typified by high rate liquids-rich natural gas. These rights are held in two large contiguous land blocks identified by NuVista as the North and South Blocks. The North block and South blocks have approximately 93 (net) sections and 58 (net) sections of undeveloped land respectively. In 2011, we commenced a five well program and participated in the construction of a compressor and dehydration station with throughput capacity of up to 20 MMcf/day. As of December 31, 2011, we had drilled and completed two wells of the program resulting in one gas well and with one well evaluating due to on-going completion issues.

In 2011, Nuvista also participated in one (0.5 net) Wapiti Falher well. The Falher formation is a cretaceous target that is seeing increasing development with the use of horizontal multi-stage fracturing, NuVista will continue to selectively develop wells in the Falher in the future.

Our 2011 average production rate was approximately 4,450 Boe/d (17.9 MMcf/d of natural gas and 1,465 of oil and liquids). In 2011, we drilled seven (4.6 net) wells in the area yielding five (2.6 net) natural gas and two (2.0 net) oil wells.

Pembina

Our Pembina operating area is located approximately 230 kilometres north of Calgary, Alberta. Our properties in this operating area include Pembina and Alder Flats. This area is characterized by mature production with gas and light oil development opportunities. We have a 100% interest in a 25 MMcf/d gas plant and access to many third party plants. This area contains 117,000 net acres of land with an average working interest of 64%. In 2011, we drilled 12 (9.0 net) wells resulting in nine (6.8 net) gas wells and three (2.3 net) oil wells. Of particular note, in the Alder Flats area, we drilled five (3.5 net) wells targeting the Spirit River A formation with promising initial results.

Our 2011 average production rate was approximately 3,860 Boe/d (15.8 MMcf/d of natural gas and 1,230 Bbls/d of oil and liquids).

Ferrier/Sunchild

Our Ferrier/Sunchild operating area is approximately 200 kilometres northwest of Calgary, Alberta, and includes both our Ferrier and Sunchild properties. Natural gas production in the Ferrier/Sunchild area is processed at third party facilities, primarily the Keyera Nordegg and the Keyera Strachan gas plants. These large plants provide both favourable liquid recoveries and reasonable operating costs for our production. This operating area has a land base of approximately 27,000 net acres with an average working interest of 62%.

Our production in this area comes from liquids-rich natural gas wells. The production is mature and possesses some of our lowest overall corporate declines. Our 2011 average production rate was approximately 2,920 Boe/d (14.1 MMcf/d of natural gas and 580 Bbls/d of oil and liquids).

We drilled one (1.0 net) gas well in the Ferrier/Sunchild area in 2011.

Kaybob/Waskahigan

Our Kaybob/Waskahigan operating area is located approximately 100 kilometres southeast of Grande Prairie, Alberta. This operating area has a land base of approximately 32,500 net acres with an average working interest of 77%. Our 2011 average production rate was approximately 2,560 Boe/d (13.0 MMcf/d of natural gas and 385 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, NuVista has a 100% owned facility with throughput capacity of up to 20 MMcf/d.

In 2011, we drilled two (0.8 net) horizontal gas wells which were drilled and completed using multi-stage fracturing techniques.

Eastern Alberta and Saskatchewan Core Region

West Central Saskatchewan

Our west central Saskatchewan operating area is located east of the Alberta border approximately 400 kilometres northeast of Calgary. This operating area was established in June 2006 when we acquired natural gas properties in west central and northwestern Saskatchewan. This area has multi-zone production from both Cretaceous and Devonian heavy oil and Cretaceous natural gas horizons.

Heavy oil prospects in the Birdbear formation were our primary focus for drilling in 2011. In 2011, we drilled 27 (19.8 net) wells yielding 27 oil wells. The 2011 drilling program focused on development and extension drilling at primarily at Hallam, Hallam South and Zoller Lake.

In 2011, our average production rate was approximately 1,270 Boe/d (1,270 Bbls/d of oil). We operate nearly all production in this operating area. This operating area contains 35,000 net acres of land with an average working interest of 79%.

Provost

Our Provost operating area is located west of the Saskatchewan border approximately 350 kilometres northeast of Calgary, Alberta. Our 2011 average production rate in the Provost area was 2,100 Boe/d consisting of approximately 1,860 Bbls/d of oil and liquids and 1.4 MMcf/d of natural gas. This operating area contains 54,000 net acres of land with an average working interest of 61%.

The northern portion of the Provost area has multi-zone potential and contains both Mannville medium-heavy oil and natural gas targets. The southern portion of this area contains ten prospective natural gas horizons at drill depths of less than 1,100 metres.

In 2011, we drilled six (5.9 net) wells yielding six oil wells.

Oyen

Our Oyen operating area is located west of the Saskatchewan border approximately 175 kilometres east of Calgary, Alberta. This operating area produces primarily natural gas from more than ten different Cretaceous age horizons and our control of infrastructure provides a strategic advantage and a barrier to entry for our competitors. Our original operating area continues to provide new discoveries and trends that permit numerous follow-up locations.

Our 2011 average production rate in the Oyen operating area was 1,920 Boe/d (10.6 MMcf/d of natural gas and 153 Bbls/d of oil). Our operations in the area include six main processing facilities and a number of field compressors connected through an extensive network of gathering lines. Our dominant position in Oyen ensures a high degree of flexibility in operating the production and controlling the pace of development with the area.

This operating area contains 447,000 net acres of land with an average working interest of 85%. Our extensive 2D and 3D seismic database enhances the prospectivity of our lands in the area.

In 2011, we drilled one (1.0 net) well seeking oil that resulted in one dry hole.

We are not planning on any drilling activity in this region during 2012.

Northwest Saskatchewan

Our northwest Saskatchewan operating area is located 100 kilometres east of Cold Lake near the Alberta-Saskatchewan border. This area is natural gas prone and is characterized by larger, more mature pools with lower production decline rates.

Our 2011 average production rate was approximately 2,100 Boe/d (10.7 MMcf/d of natural gas and 300 Bbls/d of oil). We operate nearly all the production in this area and our facilities process over 95% of our production. Our operations in the area include nine main processing facilities connected through an extensive network of large diameter gathering lines.

We have 311,000 net acres of land with an average working interest of 67%.

This area contains a minimum of four prospective natural gas horizons at drill depths of less than 800 metres and is prospective for heavy oil in the southern portion. We did not drill any wells in this area in 2011.

Northwest Alberta and British Columbia Core Region

Martin Creek, Black and Conroy, British Columbia

Our Martin Creek, Black and Conroy properties are located approximately 100 kilometres northwest of Fort St. John, British Columbia. The property is operated with an average 76% overall working interest. 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. This operating area contains 126,000 net acres with an average working interest of 74%.

Our 2011 average production rate was approximately 1,980 Boe/d (10.7 MMcf/d of natural gas and 200 Bbls/d of oil and liquids). We own a 60% to 100% working interest in key facilities, including five compressor stations, one gas plant with 24 MMcf/d current throughput and over 290 kilometres of pipelines, which gives us a dominant infrastructure position in this portion of British Columbia.

We are not planning on any drilling activity in this region during 2012.

Northwestern Alberta

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. Regionally, Keg River oil wells are characterized by production from prolific carbonate pinnacle reefs. Bluesky sandstone reservoirs tend to provide lower deliverability, but longer-life natural gas production. 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 area contains 214,000 net acres with an average working interest of 79%.

Our 2011 production averaged 2,030 Boe/d (8.6 MMcf/d of natural gas and 610 Bbls/d of oil and liquids) from this area.

No drilling is planned in this area for the 2011/2012 winter season.

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, 2011.

	Oil Wells				**Natural Gas Wells**			
	Producing		**Non-Producing**		**Producing**		**Non-Producing**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Alberta	465	324.1	230	156.1	1,103	698.1	1,029	761.1
British Columbia	2	1.6	-	-	94	71.7	84	62.8
Saskatchewan	104	70.3	19	11.5	343	250.6	379	268.2
Total	571	396.0	249	167.6	1,540	1,020.4	1,492	1,092.1

Developed and Undeveloped Lands

The following table sets out our developed and undeveloped land holdings as at December 31, 2011.

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Alberta	810,210	533,320	643,278	547,253	1,453,488	1,080,573
British Columbia	85,919	64,854	82,547	60,649	168,466	125,503
Saskatchewan	301,988	200,335	209,089	145,862	511,077	346,197
Total	1,198,117	798,509	934,914	753,764	2,133,031	1,552,273

Rights to explore, develop and exploit 249,938 net acres of these undeveloped land holdings could expire by December 31, 2012 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, 2011 see Note 16 to our consolidated financial statements for the year ended December 31, 2011.

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 60% of our net after royalty production for terms not exceeding two years. 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. Our sales portfolio also includes sales to traditional aggregators. The integration and application of these strategies resulted in an average realized price (excluding financial derivative commodity contracts) of $3.90/Mcf for the year ended December 31, 2011.

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 markets and look for opportunities to enter into price risk management contracts for up to 60% of net after royalty production. In 2011, our average realized oil price (excluding financial derivative commodity contracts) was $79.41/Bbl and our average realized price for natural gas liquids was $64.31/Bbl.

For additional details on our price risk management program see in Note 16 to our consolidated financial statements for the year ended December 31, 2011.

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, 2011, we had 2,676 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, 2011	267,300	56,400
Anticipated to be paid in 2012	1,100	900
Anticipated to be paid in 2013	1,700	1,300
Anticipated to be paid in 2014	2,000	1,300

The future net revenues disclosed in this Annual Information Form based on the GLJ Report do not contain an allowance for abandonment and reclamation costs for surface leases, facilities and pipelines. The GLJ Report only deducted $50.6 million (undiscounted) and $20.8 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 2012 cash flow and capital expenditures, we do not expect to be cash taxable in 2012. Projecting taxability beyond 2012 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, 2011:

Expenditure	**Year Ended December 31, 2011[5] ($000s)**
Property acquisition costs – Unproved properties [1] [2]	2,811
Property acquisition costs – Proved properties [2]	4,459
Exploration costs [3]	17,176
Development costs [4]	136,888
Other	496
Total	161,830

Notes:

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

(2) Net of dispositions.

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

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

(5) Does not include $42.4 million in proceeds from minor property sales.

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, 2011.

	Development		Exploratory	
	Gross	Net	Gross	Net
Natural Gas	15	9.2	2	2.0
Oil	36	28.4	2	1.5
Dry	-	-	1	1.0
Total	51	37.6	5	4.5

In 2012, we expect to drill approximately 25 to 30 wells with a focus on oil and liquids-rich resource plays. 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:

	2011		2010		Three Year Average	
($/Boe)	Proved	Proved plus Probable	Proved	Proved plus Probable	Proved	Proved plus Probable
Finding, development and acquisition costs [1]	28.95	29.93	22.15	18.51	18.56	16.37
Finding, development [1]	31.35	28.77	22.68	19.06	23.08	20.69
Acquisition costs	(43.17)	(24.58)	15.48	10.85	11.82	9.55

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.

Excluding revisions, the proved plus probable finding and development costs including future development capital was $20.65/Boe. Significant momentum is building in our W6 Montney and W5 Spirit River/Notikewin plays which are expected to result in material increases to proved and proved plus probable reserves bookings, however, year end cut-off phasing has pushed much of this benefit to 2012. In the Wapiti Montney alone, we have only five proved drilling locations and eight probable drilling locations booked to date.

Production Estimates

The following table sets out the volumes of our working interest production estimated for the year ended December 31, 2012, 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	1,308	3,538	104,727	3,170	25,470
Total Proved plus Probable	1,382	4,064	113,467	3,454	27,810

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 2011				Year Ended
	Mar. 31	**June 30**	**Sept. 30**	**Dec. 31**	**Dec. 31, 2011**
Average Daily Production [1]					
Light and Medium Oil (Bbls/d)	1,230	2,194	1,256	1,593	1,568
Heavy Oil (Bbls/d)	3,861	2,988	3,787	3,913	3,638
Natural Gas (MMcf/d)	107.4	103.8	104.6	101.3	104.3
NGLs (Bbls/d)	3,094	3,008	2,885	2,912	2,974
Combined (Boe/d)	26,078	25,488	25,360	25,306	25,556
Average Net Production Prices Received					
Light and Medium Oil ($/Bbl)	66.11	85.69	88.51	76.27	78.03
Heavy Oil ($/Bbl)	65.54	75.32	67.98	82.82	72.87
Natural Gas ($/Mcf)	4.02	3.92	3.91	3.63	3.87
NGLs ($/Bbl)	58.66	66.39	63.53	68.82	64.31
Combined ($/Boe)	36.33	39.98	37.40	40.03	38.43
Royalties Paid					
Light and Medium Oil ($/Bbl)	22.50	21.56	14.73	18.85	19.67
Heavy Oil ($/Bbl)	5.14	7.16	11.95	1.95	6.48
Natural Gas ($/Mcf)	0.32	0.23	(0.13)	(0.22)	0.05
NGLs ($/Bbl)	18.14	21.47	19.98	18.97	19.64
Combined ($/Boe)	5.29	6.17	4.27	2.79	4.63
Production Costs [2][3]					
Light and Medium Oil ($/Bbl)	18.31	13.58	16.73	14.23	15.30
Heavy Oil ($/Bbl)	15.22	15.18	12.68	14.48	14.34
Natural Gas ($/Mcf)	1.76	1.78	1.61	1.69	1.70
NGLs ($/Bbl)	10.56	10.68	9.66	10.13	10.22
Combined ($/Boe)	11.51	11.45	10.45	11.06	11.12
Transportation					
Light and Medium Oil ($/Bbl)	1.70	2.66	15.12	8.76	6.55
Heavy Oil ($/Bbl)	1.17	1.25	1.11	1.37	1.23
Natural Gas ($/Mcf)	0.14	0.13	0.13	0.13	0.13
NGLs ($/Bbl)	0.01	0.02	0.02	0.04	0.02
Combined ($/Boe)	0.83	0.92	1.45	1.30	1.12
Netback Received [4]					
Light and Medium Oil ($/Bbl)	23.60	47.89	31.86	34.42	53.06
Heavy Oil ($/Bbl)	44.01	37.18	42.24	65.02	50.82
Natural Gas ($/Mcf)	1.80	1.78	2.30	2.03	1.99
NGLs ($/Bbl)	29.95	34.22	33.87	39.68	34.43
Combined ($/Boe)	18.71	21.44	21.23	24.88	21.56

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, transportation and losses/gains on foreign exchange contracts from revenues.

The following table indicates our average daily production (including production from our major areas) for the year ended December 31, 2011:

	Light and Medium Oil (Bbls/d)	Heavy Oil (Bbls/d)	Natural Gas Liquids (Bbls/d)	Natural Gas (Mcf/d)	BOE (Boe/d)
Wapiti	141	-	1,324	17,925	4,452
Pembina	690	-	541	15,763	3,859
Kaybob/Waskahigan	64	-	321	13,017	2,555
Ferrier	30	-	551	14,083	2,928
Provost	-	1,859	3	1,398	2,095
British Columbia	61	-	137	10,703	1,982
Northwest Saskatchewan	-	298	-	10,713	2,084
Oyen	-	144	9	10,584	1,917
Northwest Alberta	572	-	38	8,554	2,036
Central Saskatchewan	-	1,277	-	-	1,277
Other	9	61	50	1,510	371
Total	1,567	3,639	2,974	104,250	25,556

DIVIDENDS

In 2010 we established a dividend policy of paying quarterly cash dividends to Shareholders, and our initial quarterly dividend of $0.05 per Common Share was paid on April 15, 2010 to Shareholders of record on March 31, 2010. 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. The following table sets forth the per Common Share amount of quarterly dividends declared by us in 2010. We did not declare any dividends in 2011.

The following table sets forth the per Common Share amount of quarterly dividends declared by us in 2010:

Date Declared	**Dividend per Common Share**	**Payment Date**
March 8, 2010	$0.05	April 15, 2010
May 13, 2010	$0.05	July 15, 2010
August 12, 2010	$0.05	September 15, 2010
November 10, 2010	$0.05	January 17, 2011
Total	$0.20	

DESCRIPTION OF OUR CAPITAL STRUCTURE

Credit Facility

We have a $440 million extendible revolving term Credit Facility available 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. 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. Under the term period, no principal payments would be required until April 2013.

During the revolving period, a determination of the maximum borrowing amount occurs semi-annually at approximately October 31. As part of the 2011 semi-annual review process, we requested and were granted a reduction in our borrowing base to $440 million. The annual renewal date of our Credit Facility is April 28, 2012. Although we have no reason to believe that we will be unable to extend our Credit Facility after April 28, 2012, 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**
2011			
January	9.54	8.56	10,170,975
February	10.45	9.31	7,887,783
March	10.17	8.57	5,713,932
April	10.04	9.26	3,728,242
May	9.72	8.67	3,302,205
June	9.61	8.59	3,828,800
July	10.50	8.95	4,704,595
August	10.24	7.65	4,528,744
September	8.40	5.57	3,454,538
October	6.67	5.22	6,269,007
November	6.27	4.35	7,611,028
December	5.54	3.96	6,884,775
2012			
January	5.90	4.13	6,643,604
February	4.34	3.71	4,457,164
March (1 – 20)	4.46	3.73	2,907,966

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 Chairman and Chief Executive Officer 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).
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 President and Vice Chairman of Bonavista Energy Corporation.
Clayton H. Woitas (2)(4)(5) Calgary, Alberta	Director	July 2003	Chairman, President and Chief Executive Officer of Range Royalty Management Ltd., general partner of Range Royalty Limited Partnership (an oil and gas royalty limited partnership) since July 2006; prior thereto President, Chief Executive Officer and a Director of Profico Energy Management Ltd. (a private oil and gas company) from February 2000 to June 2006.
Jonathan A. Wright 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 Malisia.
Grant A. Zawalsky (2)(4) Calgary, Alberta	Director	May 2003	Partner of Burnet, Duckworth & Palmer LLP (barristers and solicitors).
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. Prior thereto, he was the Controller at Petrofund Energy Trust and Ultima Energy Trust.
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. Prior thereto, he was Marketing Manager at TAQA North Ltd. (formerly, Northrock Resources Ltd.).
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 operating areas of NuVista.

Name and Municipality of Residence	Position with NuVista	Director or Officer Since	Principal Occupation
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. Mr. McDavid joined us as Production Manager in January 2005.
Joshua T. Truba Calgary, Alberta	Vice President, Land	January 2009	Our Vice President, Land since January 2009. Mr. Truba joined NuVista in February 2005 as Area Landman, he was promoted to Land Manager in May 2008.
Wayne M. Olmstead Calgary, Alberta	Vice President, Human Resources and Office Administration	January 2011	Our Vice President, Human Resources and Office Administration since January 2011. Prior thereto, Mr. Olmstead was our Manager of Human Resources and Office Administration since July 2008. Prior thereto he was Regional Manager (N.A.) of Human Resources at Brodero Shaw. Prior thereto he was Director of Human Resources at Value Creation Inc./BA Energy Ltd. Prior thereto, Mr. Olmstead served as Corporate Manager at Flint Energy Services Ltd.

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 interim board executive committee which was established to assist our management and to conduct an executive search for a President and Chief Executive Officer.
(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 20, 2012 our directors and officers, as a group, beneficially owned, or directed or controlled, directly or indirectly, approximately 5.2 million Common Shares or approximately 5.2% 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 counsellors based in Toronto, Ontario, a position he has held since August, 1999. Mr. Comber was the President of Newtonhouse Investment Management Ltd., investment counsellors 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.

Mr. Comber is also a director of Sure Energy Inc.

Pentti O. Karkkainen: *KERN Partners Ltd.*

Mr. Karkkainen has 27 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 26 years experience in the oil and gas industry and is currently Executive Vice President & Vice Chairman of Bonavista Energy Corporation. Prior to joining Bonavista Energy Corporation in 1997, Mr. Poelzer held various financial, merger and acquisition and strategic planning roles with Poco Petroleums Ltd. leading to his appointment as Vice President, Business Development. Prior thereto, Mr. Poelzer was in public 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 since 1985.

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 $365,000 in 2011 and $312,500 in 2010. Audit fees in 2011 and 2010 contained costs of $75,000 each related to the conversion to IFRS based financial statements.

Audit-Related Fees

The aggregate fees billed in each of the last two fiscal years for assurance and related services by our external auditor that were $55,000 in 2011 and $NIL in 2010.

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 $22,135 in 2011 and $128,265 in 2010.

All Other Fees

Our auditors did not provide any other products or services not reported above in 2011 and 2010.

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 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 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. Oil prices are primarily based on worldwide supply and demand. The specific price depends in part on oil quality, prices of competing fuels, distance to market, value of refined products, the supply/demand balance and contractual terms of sale. Oil exporters are also entitled to enter into export contracts with terms not exceeding one year in the case of light crude oil and two years in the case of heavy crude oil, provided that an order approving such export has been obtained from the National Energy Board of Canada (the "**NEB**"). Any oil export to be made pursuant to a contract of longer duration (to a maximum of 25 years) requires an exporter to obtain an export licence from the NEB.

Natural Gas

The price of the vast majority of natural gas produced in western Canada is now determined through highly liquid market hubs such as the Alberta "NIT" (Nova Inventory Transfer) hub rather than through direct negotiation between buyers and sellers. 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 NEB.

The governments of Alberta, British Columbia and Saskatchewan also regulate the volume of natural gas that may be removed from those provinces for consumption elsewhere based on such factors as reserve availability, transportation arrangements and market considerations.

The North American Free Trade Agreement

The North American Free Trade Agreement ("NAFTA") among the governments of Canada, the United States and Mexico became effective 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.

Royalties and Incentives

General

In addition to federal regulation, each province has legislation and regulations which 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, from time to time, carved out of the working interest owner's interest 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. Effective January 1, 2011, the maximum royalty payable under the royalty regime was set at 40%. The royalty curve for conventional oil announced on May 27, 2010 amends the price component of the conventional oil royalty formula to moderate the increase in the royalty rate at prices higher than \$535/m^3 compared to the previous royalty curve.

Royalty rates for natural gas under the royalty regime are similarly determined using a single sliding rate formula incorporating separate variables to account for production rates and market prices. Effective January 1, 2011, the maximum royalty payable under the royalty regime was set at 36%. The royalty curve for natural gas announced on May 27, 2010 amends the price component of the natural gas royalty formula to moderate the increase in the royalty rate at prices higher than $5.25/GJ compared to the previous royalty curve.

Oil sands projects are also subject to the 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 and 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, concurrently 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 current royalty regime.

Producers of oil and natural gas from freehold lands in Alberta are required to pay annual freehold production taxes. The level of the freehold production tax is based on the volume of monthly production and a specified rate of tax for both oil and gas.

The Innovative Energy Technologies Program (the "**IETP**"), which is currently in place, 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 IETP provides royalty adjustments to specific pilot and demonstration projects that utilize new or innovative technologies to increase recovery from existing reserves.

The Government of Alberta currently has in place two royalty programs, both of which commenced in 2008 and are intended to encourage the development of deeper, higher cost oil and gas reserves. A five-year program for conventional oil exploration wells over 2,000 metres provides qualifying wells with up to a $1 million or 12 months of royalty relief, whichever comes first, and a five-year program for natural gas wells deeper than 2,500 metres provides a sliding scale royalty credit based on depth of up to $3,750 per metre. On May 27, 2010, the natural gas deep drilling program was amended, retroactive to May 1, 2010, by reducing the minimum qualifying depth to 2,000 metres, removing a supplemental benefit of $875,000 for wells exceeding 4,000 metres that are spudded subsequent to that date, and including wells drilled into pools drilled prior to 1985, among other changes.

On November 19, 2008, the Government of Alberta announced the introduction of a five-year program of transitional royalty rates with the intent of promoting new drilling. The five-year transition option is designed to provide lower royalties at certain price levels in the initial years of a well's life when production rates are expected to be the highest. Under this program, companies drilling new natural gas or conventional deep oil wells (between 1,000 and 3,500 m) are given a one-time option, on a well-by-well basis, to adopt either the new transitional royalty rates or those outlined in the royalty regime. These options expired on February 15, 2011 and on January 1, 2014, all producers operating under the transitional royalty rates will automatically become subject to the royalty regime. The revised royalty curves for conventional oil and natural gas will not be applied to production from wells operating under the transitional royalty rates.

On March 3, 2009, the Government of Alberta announced a three-point incentive program in order to stimulate new and continued economic activity in Alberta. One aspect of the program was a drilling royalty credit program which provided up to a $200 per metre royalty credit for new wells. The drilling credit program applied to wells that were drilled between April 1, 2009 and March 31, 2010 and has not been extended for wells drilled after March 31, 2010. Another aspect of the program was a new well royalty program which provided for a maximum 5% royalty rate for eligible new wells for the first twelve (12) productive months or until the regulated "volume cap" was reached. The *New Well Royalty Regulation*, providing for the permanent implementation of this incentive program, was approved by an Order-in-Council on March 17, 2011.

In addition to the foregoing, the Government of Alberta has implemented certain initiatives intended to accelerate technological development and facilitate the development of unconventional resources (the "**Emerging Resource and Technologies Initiative**"). 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 at that time 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, currently at a rate of $3.50 per hectare, 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 based on the determination of whether the oil is produced from a pool discovered before October 31, 1975 ("old oil"), between October 31, 1975 and June 1, 1998 ("new oil"), or after June 1, 1998 ("third-tier oil"). 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 as an incentive for the production and marketing of natural gas which might otherwise have been flared.

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. For natural gas, the freehold production tax 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.

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

- *Summer Royalty Credit Program* providing a royalty credit of 10% of drilling and completion costs up to $100,000 for wells drilled between April 1 and November 30 of each year, intended to increase summer drilling activity, employment and business opportunities in northeastern British Columbia;

- *Deep Royalty Credit Program* providing a royalty credit equal to approximately 23% of 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 2,300 metres;

- *Deep Re-Entry Royalty Credit Program* providing royalty credits for deep re-entry wells with a true vertical depth greater than 2,300 metres and a re-entry date subsequent to December 1, 2003;

- *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 with a spud date after November 30, 2003;

- *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 royalty reductions for low productivity natural gas wells with average monthly production under 25,000 m^3 during the first 12 production months and average daily production less than 23 m^3 for every metre of marginal well depth;

- *Ultra-Marginal Royalty Reduction Program* providing additional royalty reductions for low productivity shallow natural gas wells with a true vertical depth of less than 2,500 metres in the case of vertical wells, and a total vertical depth of less than 2,300 metres in the case of a horizontal well, average monthly production under 60,000 m^3 during the first 12 production months and average daily production less than 11.5 m^3 (development wells) or 17 m^3 (exploratory wildcat wells) for every 100 metres of marginal well depth; 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 (the "**Infrastructure Royalty Credit Program**") which provides royalty credits for up to 50% of the cost of certain approved road construction or pipeline infrastructure projects intended to improve, or make possible, the access to new and underdeveloped oil and gas areas. In 2009, 2010 and 2011, the Government of British Columbia awarded $120 million in royalty credits to oil and gas companies under the Infrastructure Royalty Credit Program.

On August 6, 2009, the Government of British Columbia announced an oil and gas stimulus package designed to attract investment in and create economic benefits for British Columbia. The stimulus package includes four royalty initiatives related primarily to natural gas drilling and infrastructure development. British Columbia's existing Deep Royalty Credit Program was permanently amended for wells spudded after August 31, 2009 by increasing the royalty deduction on deep drilling for natural gas by 15% and extending the program to include horizontal wells drilled to depths of between 1,900 and 2,300 metres. An additional $50 million was also allocated to be distributed through the Infrastructure Royalty Credit Program to stimulate investment in oilfield-related road and pipeline construction.

Saskatchewan

In Saskatchewan, the amount payable as Crown royalty or 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 classified as "heavy oil", "southwest designated oil" or "non-heavy oil other than southwest designated oil". The conventional royalty and production tax classifications ("fourth tier oil", "third tier oil", "new oil" and "old oil") depend on the finished drilling date of a well and are applied to each of the three crude oil types slightly differently. Heavy oil is classified as third tier oil (having a finished drilling date on or after January 1, 1994 and before October 1, 2004), fourth tier oil (having a finished drilling date on or after October 1, 2002) or new oil (not classified as either third tier oil or fourth tier oil). Southwest designated oil uses the same definitions of third and fourth tier oil but 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 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, whereas old oil is defined as conventional oil not classified as third or fourth tier oil or new oil.

Base prices are used to establish lower limits in the price-sensitive royalty structure for conventional 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 Crown royalty or freehold production tax in respect of natural gas production is determined by a sliding scale based on the actual price received, the quantity produced in a given month, the type of natural gas, and the vintage of the natural gas. Like conventional oil, natural gas may be classified as "non-associated gas" or "associated gas" and royalty rates are determined according to the finished drilling date of the respective well. As an incentive for the production and marketing of natural gas which may have been flared, the royalty rate on natural gas produced in association with oil is less than on non-associated natural gas. 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 more than 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* replacing the existing *Freehold Oil and Gas Production Tax Act* with the intention to facilitate more efficient payment of freehold production taxes by industry. No regulations have been passed with respect to the calculation of freehold production taxes under the new legislation, although several regulations remain in force under the previous legislation.

As with conventional oil production, base prices 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 $50 per thousand m^3 for third and fourth tier gas and $35 per thousand m^3 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 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 and freehold tax rates 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);

- *Royalty/Tax Incentive Volumes for Exploratory Gas Wells Drilled on or after October 1, 2002* providing reduced Crown royalty and freehold tax rates 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 and freehold tax rates 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 or within certain formations);

- *Royalty/Tax Incentive Volumes for Horizontal Gas Wells drilled on or after June 1, 2010 and before April 1, 2013* providing reduced Crown royalty and freehold tax rates on incentive volumes of 25,000,000 m^3 for horizontal gas wells;

- *Royalty/Tax Regime for Incremental Oil Produced from New or Expanded Waterflood Projects Implemented on or after October 1, 2002* treating incremental production from waterflood projects as fourth tier oil for the purposes of royalty calculation;

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

- *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 enhanced oil recovery projects pre-payout and 20% post-payout and a freehold production tax of 0% on operating income from enhanced oil recovery projects pre-payout and 8% post-payout; and

- *Royalty/Tax Regime for High Water-Cut Oil Wells* granting "third tier oil" royalty/tax rates to incremental high water-cut oil production resulting from qualifying investments made to rejuvenate eligible oil wells and/or associated facilities.

In 1975, the Government of Saskatchewan introduced a Royalty Tax Rebate ("**RTR**") as a response to the Government of Canada disallowing crown royalties and similar taxes as a deductible business expense for income tax purposes. As of January 1, 2007, the remaining balance of any unused RTR will be limited in its carry forward to seven years since the Government of Canada's initiative to reintroduce the full deduction of provincial resource royalties from federal and provincial taxable income. Saskatchewan's RTR will be wound down as a result of the Government of Canada's plan to reintroduce full deductibility of provincial resource royalties for corporate income tax purposes.

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

Land Tenure

Crude oil and natural gas located in the western provinces is owned predominantly by the respective provincial governments. 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. Oil and natural gas located in such provinces can also be privately owned 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, British Columbia 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. On March 29, 2007, British Columbia's policy of deep rights reversion was expanded for new leases to provide for the reversion of both shallow and deep formations that cannot be shown to be capable of production at the end of their primary term.

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. Holders of leases or licences that have been continued indefinitely prior to January 1, 2009 will receive a notice regarding the reversion of the shallow rights, which will be implemented three years from the date of the notice. Leases and licences that were granted prior to January 1, 2009 but continued after that date are not subject to shallow rights reversion until they reach the end of their primary term and are continued (at which time deep rights reversion will be applied); thereafter, the holders of such agreements will be served with shallow rights reversion notices based on vintage and location similar to leases and licences that were already continued as of January 1, 2009. The order in which these agreements will receive reversion notices will depend on their vintage and location, and the Government of Alberta had anticipated that the receipt of reversion notices for older leases and licenses would commence in April 2011. However, on April 14, 2011, the Government of Alberta announced it was deferring serving shallow rights reversion notices and will revisit the decision in spring 2012.

Environmental Regulation

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation, all of which is subject to governmental review and revision from time to time. Such legislation provides for restrictions and prohibitions on the 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 requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. 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 for pollution damage, and the imposition of material fines and penalties.

In December, 2008, the Government of Alberta released a new land use policy for surface land in Alberta, the Alberta Land Use Framework (the "**ALUF**"). The ALUF sets out an approach to manage public and private land use and natural resource development in a manner that is consistent with the long-term economic, environmental and social goals of the province. It calls for the development of 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.

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

On August 29, 2011 the Government of Alberta released a revised draft of the Lower Athabasca Regional Plan (the "**Revised LARP**") updating its prior draft of April 5, 2011 (the "**Draft LARP**"). The Revised LARP, while establishing several conservation areas of the Athabasca region, has changed the boundaries of certain conservation areas outlined in the Draft LARP with the result that fewer oil sands leases appear to be impacted. Consistent with the Draft LARP, as the intention of the Revised LARP is to manage the areas to minimize or prevent new land disturbance, activities associated with oil sands development are considered incompatible with the intent to manage such conservation areas. However, references to the cancellation of existing tenures have been removed from the Revised LARP and the Revised LARP now contemplates that the conservation areas will be created pursuant to existing legislation rather than the previously contemplated regulations. Existing conventional petroleum and natural gas rights will not be affected, although the Revised LARP raises some question as to whether new conventional leases and licenses will be granted in the conservation areas in the future. The planning process is also underway for a regional plan for the South Saskatchewan Region.

Climate Change Regulation

Federal

In December 2002, the Government of Canada ratified the Kyoto Protocol ("**Kyoto Protocol**"), which requires a reduction in greenhouse gas ("**GHG**") emissions by signatory countries between 2008 and 2012. The Kyoto Protocol officially came into force on February 16, 2005 although on December 12, 2011 Canada formally withdrew from the Kyoto Protocol.

On April 26, 2007, the Government of Canada released "Turning the Corner: An Action Plan to Reduce Greenhouse Gases and Air Pollution" (the "**Action Plan**") which set forth a plan for regulations to address both GHGs and air pollution. An update to the Action Plan, "Turning the Corner: Regulatory Framework for Industrial Greenhouse Gas Emissions" was released on March 10, 2008 (the "**Updated Action Plan**"). The Updated Action Plan outlines emissions intensity-based targets which will be applied to regulated sectors on either a facility-specific, sector-wide or company-by-company basis. Facility-specific targets apply to the upstream oil and gas, oil sands, petroleum refining and natural gas pipelines sectors. Unless a minimum regulatory threshold applies, all facilities within a regulated sector will be subject to the emissions intensity targets.

The Updated Action Plan makes a distinction between "Existing Facilities" and "New Facilities". For Existing Facilities, the Updated Action Plan requires an emissions intensity reduction of 18% below 2006 levels by 2010 followed by a continuous annual emissions intensity improvement of 2%. "New Facilities" are defined as facilities beginning operations in 2004 and include both greenfield facilities and major facility expansions that (i) result in a 25% or greater increase in a facility's physical capacity, or (ii) involve significant changes to the processes of the facility. New Facilities will be given a 3-year grace period during which no emissions intensity reductions will be required. Targets requiring an annual 2% emissions intensity reduction will begin to apply in the fourth year of commercial operation of a New Facility. Further, emissions intensity targets for New Facilities will be based on a cleaner fuel standard to encourage continuous emissions intensity reductions over time. The method of applying this cleaner fuel standard has not yet been determined. In addition, the Updated Action Plan indicates that targets for the adoption of carbon capture and storage ("**CCS**") technologies will be developed for oil sands in-situ facilities, upgraders and coal-fired power generators that begin operations in 2012 or later. These targets will become operational in 2018, although the exact nature of the targets has not yet been determined.

Given the large number of small facilities within the upstream oil and gas and natural gas pipeline sectors, facilities within these sectors will only be subject to emissions intensity targets if they meet certain minimum emissions thresholds. That threshold will be (i) 50,000 tonnes of CO_2 equivalents per facility per year for natural gas pipelines; (ii) 3,000 tonnes of CO_2 equivalents per facility per year for the upstream oil and gas facility; and (iii) 10,000 boe/d/company. These regulatory thresholds are significantly lower than the regulatory threshold in force in Alberta, discussed below. In all other sectors governed by the Updated Action Plan, all facilities will be subject to regulation.

Four separate compliance mechanisms are provided for in the Updated Action Plan in respect of the above targets:

(a) Regulated entities will be able to use Technology Fund contributions to meet their emissions intensity targets. The contribution rate for Technology Fund contributions will increase over time, beginning at $15 per tonne of CO_2 equivalent for the 2010 to 2012 period, rising to $20 in 2013, and thereafter increasing at the nominal rate of GDP growth. Maximum contribution limits will also decline from 70% in 2010 to 0% in 2018. Monies raised through contributions to the Technology Fund will be used to invest in technology to reduce GHG emissions. Alternatively, regulated entities may be able to receive credits for investing in large-scale and transformative projects at the same contribution rate and under similar requirements as described above.

(b) The offset system is intended to encourage emissions reductions from activities outside of the regulated sphere, allowing non-regulated entities to participate in and benefit from emissions reduction activities. In order to generate offset credits, project proponents must propose and receive approval for emissions reduction activities that will be verified before offset credits will be issued to the project proponent. Those credits can then be sold to regulated entities for use in compliance or non-regulated purchasers that wish to either purchase the offset credits for cancellation or banking for future use or sale.

(c) Under the Updated Action Plan, regulated entities were able to purchase credits created through the Clean Development Mechanism of the Kyoto Protocol which facilitates investment by developed nations in emissions-reduction projects in developing countries. The purchase of such Emissions Reduction Credits will be restricted to 10% of each firm's regulatory obligation, with the added restriction that credits generated through forest sink projects will not be available for use in complying with the Canadian regulations. However, with the recent withdrawal from the Kyoto Protocol, the future use of this mechanism may not occur.

(d) Finally, a one-time credit of up to 15 million tonnes worth of emissions credits will be awarded to regulated entities for emissions reduction activities undertaken between 1992 and 2006. These credits will be both tradable and bankable.

From December 7 to 18, 2009, government leaders and representatives met in Copenhagen, Denmark and agreed to the Copenhagen Accord, which reinforces the commitment to reducing GHG emissions contained in the Kyoto Protocol and promises funding to help developing countries mitigate and adapt to climate change. Another meeting of government leaders and representatives in 2010 resulted in the Cancun Agreements wherein developed countries committed to additional measures to help developing countries deal with climate change. Neither the Copenhagen Accord nor the Cancun Agreements establish binding GHG emissions reduction targets. In response to the Copenhagen Accord, the Government of Canada indicated that it will seek to achieve a 17% reduction in GHG emissions from 2005 levels by 2020.

Although draft regulations for the implementation of the Updated Action Plan were intended to become binding on January 1, 2010, only draft regulations pertaining to carbon dioxide emissions from coal-fired generation of electricity have been proposed to date. Further, 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 GHG emissions regulation. As a result, it is unclear to what extent, if any; the proposals contained in the Updated Action Plan will be implemented.

The United States Environmental Protection Agency (the "**EPA**") has indicated its intention to impose GHG emissions standards for fossil fuel-fired power plants by specifying that it will issue final regulations by May 26, 2012, and with respect to refineries, specifying that it will issue proposed regulations by December 10, 2011 and finalized regulations by November 10, 2012. The EPA did not meet the December 10, 2011 deadline and it is unclear whether the EPA will also miss the finalized regulations deadline.

Alberta

Alberta enacted the *Climate Change and Emissions Management Act* (the "**CCEMA**") on December 4, 2003, amending it through the *Climate Change and Emissions Management Amendment Act* which received royal assent on November 4, 2008. The CCEMA is based on an emissions intensity approach similar to the Updated Action Plan and aims for a 50% reduction from 1990 emissions relative to GDP by 2020.

Alberta facilities emitting more than 100,000 tonnes of GHGs a year are subject to compliance with the CCEMA. Similar to the Updated Action Plan, the CCEMA and the associated *Specified Gas Emitters Regulation* make a distinction 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 to 88% of their baseline for 2008 and subsequent years, with their baseline being established by the average of the ratio of the total annual emissions to production for the years 2003 to 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 *Specified Gas Emitters Regulation*. New Facilities are required to reduce their emissions intensity by 2% from baseline in the fourth year of commercial operation, 4% of baseline in the fifth year, 6% of baseline in the sixth year, 8% of baseline in the seventh year, and 10% of baseline in the eighth year. Unlike the Updated Action Plan, the CCEMA does not contain any provision for continuous annual improvements in emissions intensity reductions beyond those stated above.

The CCEMA contains compliance mechanisms that are similar to the Updated Action Plan. Regulated emitters can meet their emissions intensity targets by contributing to the Climate Change and Emissions Management Fund (the "**Fund**") at a rate of $15 per tonne of CO_2 equivalent. Unlike the Updated Action Plan, CCEMA contains no provisions for an increase to this contribution rate. Emissions credits can 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.

On December 2, 2010, the Government of Alberta passed the *Carbon Capture and Storage Statutes Amendment Act, 2010*, which 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.

We do not operate any facilities in Alberta that emit greater than 100,000 tonnes of GHG per year but do have a 2.2% working interest in a third party operated Wapiti gas plant that emitted greater than 100,000 tonnes of CO_2 equivalent in prior years. We will continue to carefully monitor the emission requirements in Alberta and will strive to ensure all facilities, which we have interest in, comply with the emission targets outlined. For those facilities that may exceed the targets, we expect to trade for and or purchase emission credits as economically available. Currently, any potential costs under this option would not be material to us.

British Columbia

In February, 2008, British Columbia announced a revenue-neutral carbon tax that took effect July 1, 2008. The tax is consumption-based and applied at the time of retail sale or consumption of virtually all fossil fuels purchased or used in British Columbia. The current tax level is $25 per tonne of CO_2 equivalent. It is scheduled to increase to $30 per tonne of CO_2 equivalent on July 31, 2012. In order to make the tax revenue-neutral, British Columbia has implemented tax credits and reductions in order to offset the tax revenues that the Government of British Columbia would otherwise receive from the tax.

On April 3, 2008, British Columbia introduced the *Greenhouse Gas Reduction (Cap and Trade) Act* (the "**Cap and Trade Act**") which received royal assent on May 29, 2008 and partially came into force by regulation of the Lieutenant Governor in Council. Unlike the emissions intensity approach taken by the federal government and the Government of Alberta, the Cap and Trade Act establishes an absolute cap on GHG emissions. Although more specific details of British Columbia's cap and trade plan have not yet been finalized, on January 1, 2010, new reporting regulations came into force requiring all British Columbia facilities emitting over 10,000 tonnes of CO_2 equivalents per year to begin reporting their emissions. Facilities reporting emissions greater than 25,000 tonnes of CO_2 equivalents per year are required to have their emissions reports verified by a third party. Regulations pertaining to proposed offsets and emissions trading are currently in the consultation stage.

We operate two facilitates in British Columbia that individually emit greater than 10,000 tonnes CO_2 equivalents per year and therefore each of these facilities must be registered with the province and report their emissions. In addition, our total emissions from all operations in British Columbia in 2009 exceeded the 25,000 tonnes CO_2 equivalents per year and therefore we must have our emissions verified by a third party. For 2010, we reported a total of 65,499 tonnes of CO_2 equivalents from all of our operations in British Columbia. We will carefully monitor the emissions reporting requirements in British Columbia and we plan to participate in the cap and trade plan as economically available. Currently, any potential costs under the cap and trade program would not be material to us. Our 2010 EHG Emissions Report was subject to a "reasonable assurance" audit carried out by a verification body accredited in accordance with ISO 14065. A positive verification statement was received by the auditor.

Saskatchewan

On May 11, 2009, the Government of Saskatchewan announced *The Management and Reduction of Greenhouse Gases Act* (the "**MRGGA**") to regulate GHG emissions in the province. The MRGGA received Royal Assent on May 20, 2010 and will come into force on proclamation. Regulations under the MRGGA have also yet to be proclaimed, but draft versions indicate that Saskatchewan will adopt the goal of a 20% reduction in GHG emissions from 2006 levels by 2020 and permit the use of pre-certified investment credits, early action credits and emissions offsets in compliance, similar to both the federal and Alberta climate change initiatives. It remains unclear whether the scheme implemented by the MRGGA will be based on emissions intensity or an absolute cap on emissions.

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.

Prices, Markets and Marketing

The marketability and price of oil and natural gas that may be acquired or discovered by us is and will continue to be affected by numerous factors beyond our control. 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. We may also be affected by deliverability uncertainties related to the proximity of our reserves to pipelines and processing and storage facilities and operational problems affecting such pipelines and facilities as well as extensive government regulation relating to price, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and many other aspects of the oil and natural gas business.

The prices of oil and natural gas prices may be volatile and subject to fluctuation. Any material decline in prices could result in a reduction of our net production revenue and may be less than our costs of production. The economics of producing from some wells may change as a result of lower prices, which could result in reduced production of oil or gas and a reduction in the volumes of our reserves. We might also elect not to produce from certain wells at lower prices. All of these factors could result in a material decrease in our expected net production revenue and a reduction in our oil and gas acquisition, development and exploration activities. Prices for oil and gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and gas, market uncertainty and a variety of additional factors beyond our control. These factors include economic conditions, in the United States and Canada, the actions of OPEC, governmental regulation, political stability in the Middle East and elsewhere, the foreign supply of oil and gas, risks of supply disruption, the price of foreign imports and the availability of alternative fuel sources. Any substantial and extended decline in the price of oil and 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 as a result of market uncertainties over the supply and the demand of these commodities due to the current state of the world economies, OPEC actions, excess North American natural gas supply and sanctions imposed on certain oil producing nations by other countries and the ongoing credit and liquidity concerns. Volatile oil and gas prices make it difficult to estimate the value of producing properties for acquisition and often cause disruption in the market for oil and 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, any existing reserves we may have at any particular time, and the production therefrom will decline over time as such existing reserves are exploited. A future increase in our reserves will depend not only on our ability to explore and develop any properties we may have from time to time, but also on our ability to select and acquire suitable producing properties or prospects. No assurance can be given that we will be able to continue to locate satisfactory properties for acquisition or participation therein. Moreover, if such acquisitions or participations are identified, our management may determine that current markets, terms of acquisition and participation or pricing conditions make such acquisitions or participations uneconomic. There is no assurance that further commercial quantities of oil and natural gas will be discovered or acquired by us.

Future oil and natural gas exploration may involve unprofitable efforts, not only from dry wells, but also 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 or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, 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, production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely 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 fire, explosion, blowouts, cratering, sour gas releases, spills or other environmental hazards, each of which could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment or personal injury. 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. In accordance with 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, the nature of certain risks is such that liabilities 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 future cash flow information set forth herein are estimates only. In general, estimates of economically recoverable oil and natural gas reserves and the future net cash flows therefrom 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 gas, royalty rates, 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 thereof and such variations could be material.

Estimates 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 and 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 gas reserves will vary from the estimates contained in the reserve evaluation, and such variations could be material. The reserve evaluation is based in part on the assumed success of activities we intend to undertake in future years. The reserves and estimated cash flows to be derived therefrom 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 has not been updated and thus does not reflect changes in our reserves since that date.

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 our 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 within 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;
- changes in regulations;
- 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 not be able to effectively market the oil and natural gas that we produce.

Refinancing Risk and Increased Debt Service Charges

The amount authorized under our Credit Facility is dependent on the borrowing base determined by our lenders. We are also required to comply with covenants under the Credit Facility and in the event that we do not comply therewith our access to capital could be restricted or repayment could be required. The failure of us to comply with such covenants, which may be affected by events beyond our control, 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, the lenders under the 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, from time to time, impose operating and financial restrictions on us that could include restrictions on, incurring of additional indebtedness, 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 borrowing base is determined and re-determined by our lenders based on our reserves, commodity prices, applicable discount rate and other factors as determined by the our lenders. A material decline in commodity prices could reduce our borrowing base, therefore reducing the funds available to us under the Credit Facility which could result in a portion, or all, of our bank indebtedness be required to be repaid.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

We make acquisitions and dispositions of businesses and assets in the ordinary course of business. Achieving the benefits of acquisitions depends in part on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner as well as our ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with ours. The integration of acquired businesses may require substantial management effort, time and resources and may divert management's focus from other strategic opportunities and operational matters.

There may be liabilities associated with an acquisition that we fail to discover or are unable to quantify in our due diligence and we may not be indemnified for some or all of these liabilities.

Management continually assesses the value and contribution of services provided and assets required to provide such services. In this regard, non-core assets are 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, could be expected to realize less than their carrying value on our financial statements.

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, tax burden due to new 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.

Additional Funding Requirements

Our cash flow 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. As a result of the global economic volatility, we, along with many other oil and natural gas entities, 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 its 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 or 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 materially and adversely affected 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.

Operational Dependence

We do not operate all of our properties and facilities. Therefore, our results of operations may be adversely affected by pipeline interruptions and apportionments and the actions or inactions of third party operators, any of which could cause delays and additional expenses in receiving our revenues, which could in turn adversely affect our business, financial condition, results of operations and prospects.

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.

Gathering and Processing Facilities and Pipeline Systems

We deliver our products through gathering, processing and pipeline systems some of which we do not own. 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, processing and pipeline systems. The lack of availability of capacity in any of the gathering, processing and pipeline systems, 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. 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 materially adversely affect our ability to process our production and to deliver the same for sale.

Global Financial Crisis

Recent market events and conditions, including disruptions in the international credit markets and other financial systems and the American and European sovereign debt levels have caused significant volatility in commodity prices. These conditions have caused a decrease in confidence in the global credit and financial markets and have created a climate of greater volatility, less liquidity, widening of credit spreads, a lack of price transparency, increased credit losses and tighter credit conditions. Notwithstanding various actions by governments, concerns about the general condition of the capital markets, financial instruments, banks, investment banks, insurers and other financial institutions caused the broader credit markets to further deteriorate and stock markets to decline substantially. This volatility may in the future affect our ability to obtain equity or debt financing on acceptable terms.

Market Price of Common Shares

The trading price of securities of oil and natural gas issuers is subject to substantial volatility. This volatility is often based on factors both related and unrelated to the financial performance or prospects of the issuers involved. The market price of the Common Shares could be subject to significant fluctuations in response to variations in our operating results, financial condition, liquidity and other internal factors. Factors that could affect the market price of the Common Shares that are unrelated to our performance include domestic and global commodity prices and market perceptions of the attractiveness of particular industries. The price at which the Common Shares will trade cannot be accurately predicted.

Hydraulic Fracturing

Hydraulic fracturing involves the injection of water, sand and small amounts of additives under pressure into rock formations to stimulate hydrocarbon (oil and natural gas) production. The use of hydraulic fracturing is being used to produce 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 or 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.

Competition

The petroleum industry is competitive in all its phases. We compete with numerous other organizations 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 and methods and reliability of delivery and storage. Competition may also be presented by alternate fuel sources.

Regulatory

Oil and natural gas operations (exploration, production, pricing, marketing and transportation) are subject to extensive controls and regulations imposed by various levels of government, which may be amended from time to time. See "*Industry Conditions*". Governments may regulate or intervene with respect to exploration and production activities, prices, taxes, royalties and the exportation of oil and natural gas. Such regulations may be changed from time to time in response to economic or political conditions. The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for natural gas and crude oil 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 gas operations, we will require licenses from various governmental authorities. There can be no assurance that we will be able to obtain all of the licenses and permits that may be required to conduct operations that we may wish to undertake.

Environmental

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and natural gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such 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 regulations, 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 require us to comply with greenhouse gas emissions legislation in Alberta and British Columbia or that may be enacted in other provinces. We may also be required comply with the regulatory scheme for greenhouse gas emissions ultimately adopted by the federal government, which regulations are expected to be consistent with the regulatory scheme for greenhouse gas emissions adopted by the United States. The direct or indirect costs of these regulations may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. The future implementation or modification of greenhouse gases regulations, whether to meet the limits regulated by the Copenhagen Accord or as otherwise determined, could have a material impact on the nature of oil and natural gas operations, including ours. 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 the Corporation and its operations and financial condition. See "*Industry Conditions – Climate Change Regulation*".

Variations in Foreign Exchange Rates and Interest Rates

World oil and gas prices are quoted in United States dollars and the price received by Canadian producers is therefore affected by the Canadian/U.S. dollar exchange rate, which will fluctuate over time. In recent years, the Canadian dollar has increased materially in value against the United States dollar. Material increases in the value of the Canadian dollar negatively impacts our production revenues. Future Canadian/United States exchange rates could accordingly impact the future value of our reserves as determined by our 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, which 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 the 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 its 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 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 to defeat our claim which may have a material adverse effect on our business, financial condition, results of operations and prospects. There may be valid challenges to title, or proposed legislative changes which affect title, to the oil and natural gas properties we control that, if successful or made into law, could impair our activities on them and result in a reduction of the revenue received by us.

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, such 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.

Geo-Political Risks

The marketability and price of oil and natural gas that may be acquired or discovered by us is and will continue to be affected by political events throughout the world that cause disruptions in the supply of oil. Conflicts, or conversely peaceful developments, arising in the Middle East, North Africa and other areas of the world, have a significant impact on the price of oil and natural gas. Any particular event could result in a material decline in prices and therefore result in a reduction of our net production revenue.

In addition, our oil and natural gas properties, wells and facilities could be subject to 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.

Aboriginal Claims

Aboriginal peoples have claimed aboriginal title and rights to portions of western Canada and have also made claims that certain developments, including oil and gas exploration development, may have been proceeding without the Crown carrying out appropriate consultations in the course of allowing such developments to proceed.

Seasonality

The level of activity in the Canadian oil and 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. Also, certain oil and 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.

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 are also directors of other oil and gas companies and as such may, in certain circumstances, have a conflict of interest requiring them to abstain from certain decisions. Conflicts, if any, will be subject to the procedures and remedies of 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 our immediate and near term operations are likely to be of central importance. In addition, the competition for qualified personnel in the oil and natural gas industry is intense and there can be no assurance that we will be able to continue to attract and retain all personnel necessary for the development and operation of our business. Investors must rely upon the ability, expertise, judgment, discretion, integrity and good faith of our management.

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 – 5th 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 the auditors of the Company and have confirmed that they are independent with respect to the Company within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of Alberta.

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 a partner at Burnet, Duckworth & Palmer LLP, which law firm renders legal services to us.

ADDITIONAL INFORMATION

Additional information relating to us can be found on 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 and special shareholders meeting to be held on May 10, 2012. Additional financial information is contained in our consolidated financial statements for the year ended December 31, 2011 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, 2011, 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) "*Keith A. MacPhail*"
Keith A. MacPhail
Chairman

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

(signed) "*Clayton H. Woitas*"
Clayton H. Woitas
Director and Chairman of the Reserves Committee

(signed) "*Pentti O. Karkkainen*"
Pentti O. Karkkainen
Director and Member of the Reserves Committee

March 2, 2012

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, 2011. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2011, 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, 2011, and identifies the respective portions thereof that we have evaluated and reported on to the Company's Board of Directors:

Independent Qualified Reserves Evaluator	Description and Preparation Date of Evaluation Report	Location of Reserves (County or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate – $000s)			
			Audited	**Evaluated**	**Reviewed**	**Total**
GLJ Petroleum Consultants	Corporate Summary February 22, 2012	Canada	-	1,284,019	-	1,284,019

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 23, 2012.

"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