2008 Annual Information Form

March 30, 2009

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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.

Bonavista means Bonavista Petroleum Ltd.

Bonavista Group means collectively Bonavista, Bonavista Oil & Gas Ltd. and Bonavista Partnership.

Bonavista Trust means Bonavista Energy Trust.

Bonavista Partnership means Bonavista Petroleum, a general partnership.

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

NuVista 2009 Partnership means NuVista 2009 Energy Partnership, a general partnership.

NuVista Partnership means NuVista Energy, a general partnership.

NuVista Resources means NuVista Resources Ltd.

NuVista Resources Partnership means NuVista Resources, a general partnership.

Rider means Rider Resources Ltd.

Shareholders means holders of our Common Shares.

Independent Engineering

COGE Handbook means Canadian Oil and Gas Evaluation Handbook.

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

GLJ Report means the report prepared by GLJ dated March 3, 2009 evaluating the crude oil, natural gas, natural gas liquids and sulphur reserves attributable to all of our oil and natural gas assets as at December 31, 2008.

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.

Performance Shares means our Class B performance shares, as presently constituted.

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, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101. 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 principals in Canada ("**GAAP**"). 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

Bbl	barrel
Bbls	barrels
Bbls/d	barrels per day
Mbbls	thousand barrels
MMbbls	million barrels
Mstb	thousand stock tank barrels of oil
NGLs	natural gas liquids

Natural Gas

Mcf	thousand cubic feet
MMcf	million cubic feet
Bcf	billion cubic feet
Mcf/d	thousand cubic feet per day
MMcf/d	million cubic feet per day
MMbtu	million British Thermal Units
GJ	Gigajoule

Other

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

CONVERSIONS

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

To Convert From	To	Multiply By
Mcf	cubic metres	28.174
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 herein, contains forward-looking information and statements. These 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 information and statements. Such statements and information 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. 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 information and statements are based on the estimates and opinions of our management at the time the statements were made. In addition, forward-looking information and 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 information and statements are based will occur.

In particular, this Annual Information Form and the documents incorporated by reference, contain forward-looking statements pertaining to the following:

- the performance characteristics of our oil and natural gas properties;
- expectation of future production rates, volumes and product mixes;
- our oil and gas reserve and resource volumes and reserve life indices;
- projected costs and plans and objectives;
- our future development and drilling plans and opportunities;
- projections of market prices and trading liquidity;
- our expenditure capital program, the timing of expenditures and the sources of funding;
- our access to credit facilities, ability to raise capital and financial flexibility;
- targeted debt levels;
- future payment of dividends, if any;
- our ability to fund the development costs of our reserves;
- interest and other funding costs;
- proposed acquisitions or dispositions,
- supply and demand for oil and natural gas;
- capital and income taxes;
- commodity prices and commodity price risk management activity;
- projected funds from operations and earnings and the components thereof;
- expected royalty rates and the anticipated benefits of royalty incentive programs; and
- future income tax treatment and tax pools.

Forward-looking information and 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 information and 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 information and statements contained herein include the following:

- volatility of commodity prices;

- liabilities inherent in oil and natural gas operations;
- imprecision of reserve and resource estimates;
- 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*".

The reader is further cautioned that the preparation of financial statements in accordance with Canadian GAAP 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. Information and statements relating to "reserves" or "resources" are deemed to be forward-looking information and statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves and resources described exist in the quantities predicted or estimated, and that the reserves can be profitably produced in the future. **The information contained in this Annual Information Form, including the documents incorporated by reference herein, identifies additional factors that could affect our operating results and performance. We urge you to carefully consider those factors.**

The forward-looking information and statements contained herein are expressly qualified in their entirety by this cautionary statement. The forward-looking information and 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 information and statements to reflect new information, subsequent events or otherwise unless required by applicable securities laws.

BARREL OF OIL EQUIVALENCY

The term "Boe" or barrels of oil equivalent 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 is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

NON-GAAP MEASURES

Within this Annual Information Form, references are made to terms commonly used in the oil and natural gas industry. Management uses funds from operations to analyze operating performance and leverage. Funds from operations as presented does not have any standardized meaning prescribed by Canadian GAAP and therefore it may not be comparable with the calculation of similar measures for other entities. Funds from operations as presented is not intended to represent operating cash flow or operating profits for the period nor should it be viewed as an alternative to cash flow from operating activities, net income or other measures of financial performance calculated in accordance with Canadian GAAP.

For more information, see our "*Management's Discussion and Analysis*" for the year ended December 31, 2008, which includes a reconciliation of "funds from operations" to cash provided by operating activities, which has been filed on SEDAR at www.sedar.com.

NUVISTA ENERGY LTD.

General

We are an intermediate oil and natural gas company engaged in the exploration for, and the acquisition, development and production of oil and natural gas reserves in the Provinces of Alberta and Saskatchewan.

We were incorporated under the *Business Corporations* Act (Alberta) (the "**ABCA**") as 1040491 Alberta Ltd. on April 7, 2003. On May 20, 2003, we changed our name to "NuVista Energy Ltd.". 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 and thereafter amalgamated with Roberts Bay Resources Ltd., another of our wholly-owned subsidiaries.

We were originally formed as part of a plan of arrangement involving Bonavista, which resulted in the shareholders of Bonavista receiving one of our Common Shares for each common share of Bonavista held. Pursuant to this plan of arrangement, we acquired approximately 10% of the oil and natural gas properties of Bonavista, with the balance of the properties of Bonavista being acquired by Bonavista Trust.

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 Partnership	75.78% (1)(2)	General Partnership	Alberta
NuVista Resources Partnership	75.78% (3)	General Partnership	Alberta
NuVista Resources	100%	Corporation	Alberta
NuVista 2009 Partnership	100%	General Partnership	Alberta
1364364 Alberta Ltd.	100%	Corporation	Alberta

Notes:

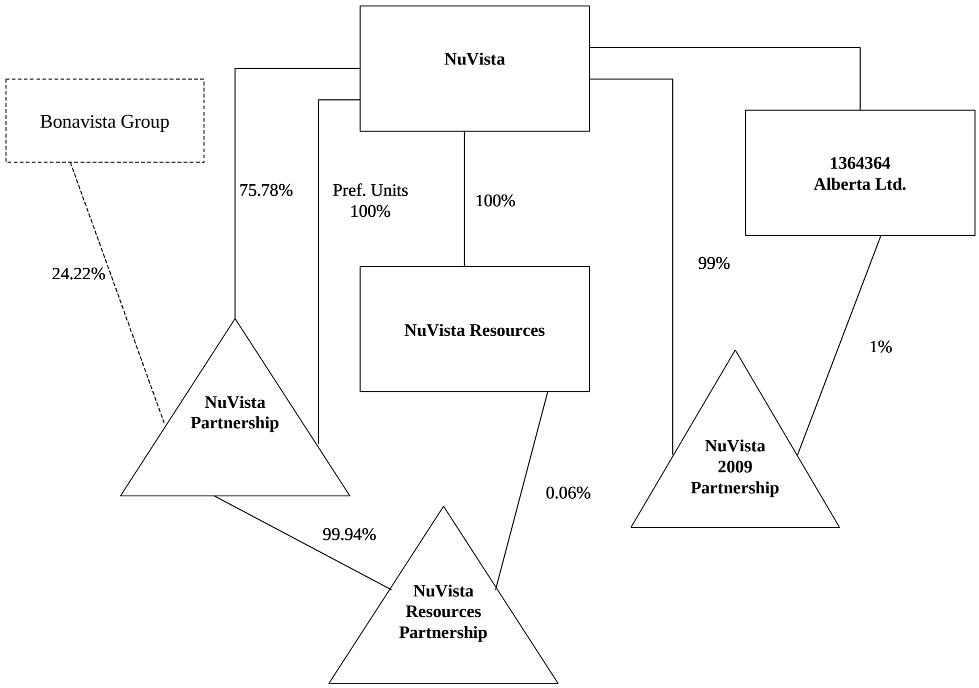
(1) As part of a plan of arrangement completed on July 2, 2003, all of Bonavista's eastern Alberta developed assets were conveyed to NuVista Partnership. We are the managing partner of the NuVista Partnership and the other partner is the Bonavista Group.

(2) As at December 31, 2008 and the date hereof, our general partnership interest in NuVista Partnership was 75.78%. The Bonavista Group holds the remaining 24.22%. We also own 100% of the non-voting preferred units. The preferred units in NuVista Partnership relate to certain producing assets contributed by us. The preferred units are allocated 100% of the economic and financial results of the assets contributed to NuVista Partnership.

(3) As at December 31, 2008 and the date hereof, NuVista Resources Partnership was owned 99.94% by NuVista Partnership and 0.06% by NuVista Resources.

Our Organizational Structure

The following diagram describes the inter-corporate relationships among us and our material subsidiaries 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 pursuant to which we acquired certain assets of Bonavista and our Common Shares were distributed to the former holders of common shares of Bonavista. Since the completion of the plan of arrangement on July 2, 2003, we have grown our business through a combination of exploration, development and exploitation of our assets as well as the completion of a number of strategic acquisitions in western Canada.

On June 1, 2006, we completed the acquisition of certain natural gas properties in west central and northwest Saskatchewan. The acquisition was completed through a series of transactions, for a net acquisition cost, paid in cash, of approximately $82 million. With this acquisition we established a new core area in west central Saskatchewan and increased our dominance in our northwest Saskatchewan core area. The acquisition included natural gas production of approximately 13.3 MMcf/d (2,200 Boe/d). The assets acquired also included approximately 106,000 net acres of undeveloped lands. The acquisition was funded with bank debt.

On April 2, 2007, we completed the acquisition of certain natural gas properties located in our Kaybob/Waskahigan core area. The acquisition cost, payable in cash, for these assets was approximately $34 million. Production from the acquired properties was approximately 800 Boe/d, with an 85% natural gas weighting.

On April 20, 2007 we completed an equity issue of 2,750,000 Common Shares on a bought deal basis at a price of $14.50 per share. The net proceeds of the offering were used to fund our ongoing capital program and for general corporate purposes.

On January 8, 2008, we closed the acquisition of certain oil properties located primarily in our Provost core area, in close proximity to our existing Chauvin properties. The acquisition cost, payable in cash, for these assets was approximately $24.5 million. At the time of purchase, production from the acquired properties was approximately 650 Bbls/d of 23 degree API oil.

On March 4, 2008, we completed a plan of arrangement (the "**Rider Arrangement**") pursuant to which we acquired Rider on the basis of 0.3540 of a Common Share for each common share of Rider resulting in the issuance of approximately 19.8 million Common Shares. As a result of the Rider Arrangement, we acquired four new core areas in liquids rich natural gas prone regions of Alberta, characterized by high netbacks and long reserve life production and a high impact deep gas drilling inventory to our exploration and development program.

Pursuant to the Rider Arrangement, we acquired approximately 11,500 Boe/d of production (approximately 77% natural gas) and approximately 33 million Boe of proved plus probable reserves (calculated as at December 31, 2007 and based upon our management's pro forma estimates). We also acquired over 155,000 net acres of undeveloped land with an average working interest of approximately 77% and with 75 identified drilling locations. In connection with the Rider Arrangement, Mr. Craig W. Stewart, the former President and Chief Executive Officer of Rider, joined the Board of Directors.

In connection with the Rider Arrangement, we also completed a private placement with the Ontario Teachers' Pension Plan ("**OTPP**") pursuant to which OTPP subscribed for 6.0 million of our units ("**Units**") at a price of $14.00 per Unit for proceeds of $84.0 million. Each Unit was comprised of one Common Share and one-half of one common share purchase warrant ("**Warrant**"). Each full Warrant entitled the holder to purchase one Common Share for an exercise price of $15.50 on or before March 4, 2009, subject to the usual adjustment provisions. None of the Warrants were exercised prior to their expiry on March 4, 2009. The proceeds of the private placement were used to reduce our aggregate outstanding indebtedness following completion of the Rider Arrangement.

Recent Developments

Property Acquisition

On January 29, 2009, we completed the acquisition of 1,600 boe/d of production, primarily in our Ferrier/Sunchild, Wapiti and Northwest Saskatchewan core 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. These reserves are not included in the Reserves Data contained in this Annual Information Form.

Credit Facility

We have a credit facility from a syndicate of primarily Canadian banks with a maximum borrowing amount of $450 million. The credit facility is 364 day revolving facility subject to a request for an extension of the revolving period for a further 364 days and an annual review by the lenders, at which time a lender can provide an extension of the revolving period or request conversion to a one year term loan. Under the term period, no principal payments would be required until March 4, 2010.

As a result of the completion of the Rider Arrangement, and the concurrent amendment of our credit facility, the 364 day revolving period of our credit facility ended on March 3, 2009. Our lenders and us have agreed to an extension of the revolving period of the credit facility from March 3, 2009 until April 30, 2009 in order to return us to our historical annual review date. As part of this extension, the credit facility borrowing rates were amended to current market rates and all other terms of the credit facility remained unchanged. NuVista's bank syndicate is in the process of completing their annual review of NuVista's year end reserves and financial information. See "*Risk Factors – Refinancing Risk and Increased Debt Service Charges*".

Capital Program

We anticipate that funds from operations will provide the flexibility to fund our planned 2009 capital program. In this period of lower commodity prices and challenging economic environment, we will place increased emphasis on maintaining our financial flexibility. We plan to closely monitor our 2009 business plan and adjust capital programs in the context of commodity prices and access to bank and equity capital. At this time we are targeting first half and annual capital expenditures to approximate funds from operations. With the closing of the property acquisition on January 29, 2009, our current borrowings under our credit facility are approximately $390 million. It is our intent to have a reduced drilling program for the remainder of the first half of 2009, which in turn will reduce net debt to the targeted level of approximately $350 million.

Significant Acquisitions

The completion of the Rider Arrangement on March 4, 2008 constituted a significant acquisition under Part 8 of National Instrument 51-102. We filed a business acquisition report for the Rider Arrangement on SEDAR on May 16, 2008.

GENERAL DESCRIPTION OF OUR BUSINESS

Stated Business Objectives and Strategy

Our business plan is to create sustainable and profitable per share growth in the oil and natural gas industry in western Canada. We have an acquire and develop business model that currently includes operations in eight core areas. We pursue strategic acquisitions that will result in a new core area or synergistic acquisitions that complement our properties in existing core areas. Once a property has been acquired we pursue optimization and ongoing development and exploration opportunities. Our asset base provides the flexibility to pursue shallow natural gas, deep natural gas and heavy oil targets, both through exploration and development activities and acquisitions.

We apply our technical and operating expertise within our core areas with a disciplined approach. The seven principles we remain focused on are:

- focus on core 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 pursue strategic acquisition opportunities that would permit us to form a new core area in which to lever our expertise. Every opportunity, however, must be carefully evaluated to ensure it complements our defined business strategy. Ideally, each potential acquisition must offer us the opportunity to acquire undeveloped land and seismic, as well as a high working interest ownership and operatorship, in an area where infrastructure is underutilized and further optimization and development opportunities exist.

We are also looking for synergistic acquisitions in our existing core areas. These types of acquisitions enable us to solidify our position in areas where we have technical expertise and reinforce barriers to competition that could affect the profitability of our projects.

We have created a team based organization in which operational and technical excellence and idea generation are encouraged. Each of our core 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 core 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 a core 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 know that financial flexibility can enable a company to capitalize on the inevitable acquisition opportunities that occur at the bottom of the commodity price cycle. We are well positioned to capture these opportunities, if and when they arise.

Cyclical and Seasonal Impact of Industry

Our operational results and financial condition will be dependent on the prices received 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.

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.

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 2009 by the renegotiation or termination of contracts or subcontracts. See also "*General Development of Our Business – Recent Developments – Credit Facility*".

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.

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

Human Resources

We entered into the Technical Services Agreement with Bonavista concurrently with the completion of the plan of arrangement under which we commenced business. Pursuant to this agreement Bonavista personnel provided services in respect of the management, development, exploitation and operation of our assets. Bonavista also provided various administrative services, as well as access to geological and technical data relating to our assets.

Effective January 1, 2007, the terms of the Technical Services Agreement were amended to reflect the reduced level of services provided by Bonavista. On August 31, 2007, the Technical Services Agreement was terminated and replaced with a services agreement that reflected the remaining ongoing services that would be provided by Bonavista. The services provided under the new services agreement consisted primarily of provision of office space, oil and natural gas marketing services, reception services and some information technology services. The services were charged to us based on an assessment of market rates. On November 1, 2008, this services agreement was terminated and Bonavista no longer provides any ongoing services to us. For the year ending December 31, 2008, we paid Bonavista $1.1 million in fees relating to general and administrative services provided by Bonavista pursuant to the services agreement. In 2008, we charged Bonavista management fees for jointly owned partnerships totalling $1.4 million.

At December 31, 2008, we employed 116 full-time employees, including 95 office and 21 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 March 3, 2009. The statement is effective as of December 31, 2008 and the preparation date of the statement is February 10, 2009. The Report Of Management And Directors On 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, 2008 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 COGE Handbook and the reserve definitions contained in NI 51-101. 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 and Saskatchewan.

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, 2008
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	3,320	2,854	4,059	3,821	183,285	149,139	4,458	3,035
Developed Non-Producing	201	167	490	438	33,114	25,640	1,120	766
Undeveloped	-	-	573	524	13,156	10,072	227	150
TOTAL PROVED	3,521	3,021	5,121	4,783	229,554	184,851	5,805	3,951
PROBABLE	1,519	1,265	2,079	1,878	110,099	86,486	2,851	1,923
TOTAL PROVED PLUS PROBABLE	5,040	4,286	7,200	6,661	339,653	271,337	8,656	5,874

	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)	($/Mcf)
PROVED:							
Developed Producing	1,328,444	1,025,874	844,380	723,041	635,883	24.43	4.07
Developed Non-Producing	218,054	154,506	120,744	99,606	84,966	21.40	3.57
Undeveloped	82,174	61,129	47,289	37,475	30,182	20.10	3.35
TOTAL PROVED	1,628,672	1,241,509	1,012,444	860,123	751,032	23.79	3.96
PROBABLE	852,312	497,976	338,220	249,608	194,009	17.36	2.89
TOTAL PROVED PLUS PROBABLE	2,480,983	1,739,485	1,350,664	1,109,731	945,041	21.77	3.63

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

	NET PRESENT VALUES OF FUTURE NET REVENUE AFTER INCOME TAXES DISCOUNTED AT (%/year)				
RESERVES CATEGORY	0% ($000s)	5% ($000s)	10% ($000s)	15% ($000s)	20% ($000s)
PROVED:					
Developed Producing	1,158,865	896,391	739,279	634,180	558,577
Developed Non-Producing	161,538	113,149	87,619	71,633	60,594
Undeveloped	60,684	44,112	33,207	25,485	19,762
TOTAL PROVED	1,381,087	1,053,652	860,104	731,298	638,934
PROBABLE	634,951	367,977	247,457	180,549	138,568
TOTAL PROVED PLUS PROBABLE	2,016,038	1,421,629	1,107,561	911,847	777,502

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
AS OF DECEMBER 31, 2008
FORECAST PRICES AND COSTS

RESERVES CATEGORY	REVENUE ($000s)	ROYALTIES ($000s)	OPERATING COSTS ($000s)	DEVELOPMENT COSTS ($000s)	WELL ABANDONMENT COSTS ($000s)	FUTURE NET REVENUE BEFORE INCOME TAXES ($000s)	INCOME TAXES ($000s)	FUTURE NET REVENUE AFTER INCOME TAXES ($000s)
Total Proved	3,039,811	571,635	750,983	49,569	38,952	1,628,672	247,585	1,381,087
Total Proved plus Probable	4,706,620	910,401	1,148,149	120,676	46,410	2,480,983	464,945	2,016,038

Notes:

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

(2) Royalties include Crown, freehold and ORR's and mineral tax.

FUTURE NET REVENUE
BY PRODUCTION GROUP
AS OF DECEMBER 31, 2008
FORECAST PRICES AND COSTS

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) ($000s)	UNIT VALUE (1)	
			($/Boe)	($/Mcf)
Proved	Light and Medium Crude Oil (including solution gas and other by-products)	95,624	26.57	4.43
	Heavy Oil (including solution gas and other by-products) (2)	133,309	28.03	4.67
	Natural Gas (including by-products but excluding natural gas from oil wells)	783,512	22.90	3.82
	Total	1,012,444	23.79	3.96
Proved plus Probable	Light and Medium Crude Oil (including solution gas and other by-products)	123,972	24.00	4.00
	Heavy Oil (including solution gas and other by-products) (2)	177,485	27.05	4.51
	Natural Gas (including by-products but excluding natural gas from oil wells)	1,049,208	20.85	3.48
	Total	1,350,664	21.77	3.63

Notes:

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

(2) This crude oil averages approximately 18° API and is therefore classified as heavy oil under NI 51-101.

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 NuVista is 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 statement assume primarily increases in wellhead selling prices and take into account inflation with respect to future operating and capital costs. Crude oil and natural gas benchmark reference pricing, inflation and exchange rates utilized in the 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									
2008	99.48	103.44	75.54	93.74	8.16	57.82	76.91	2.0	0.943
2009	57.50	68.61	43.10	59.00	7.58	43.22	52.14	2.0	0.825
2010	68.00	78.94	49.76	68.68	7.94	49.73	61.57	2.0	0.850
2011	74.00	83.54	54.35	73.52	8.34	52.63	65.16	2.0	0.875
2012	85.00	90.92	59.23	80.01	8.70	57.28	70.92	2.0	0.925
2013	92.01	95.91	62.54	84.40	8.95	60.42	74.81	2.0	0.950
2014	93.85	97.84	63.82	86.10	9.14	61.64	76.32	2.0	0.950
2015	95.73	99.82	65.13	87.84	9.34	62.89	77.86	2.0	0.950
2016	97.64	101.83	66.46	89.61	9.54	64.15	79.43	2.0	0.950
2017	99.59	103.89	67.83	91.42	9.75	65.45	81.03	2.0	0.950
2018	101.59	105.99	69.22	93.27	9.95	66.77	82.67	2.0	0.950
2019	103.62	108.11	70.60	95.14	10.15	68.11	84.32	2.0	0.950
2020	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	2.0	0.950

Notes:
(1) As at January 1, 2008.
(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, 2008, including price risk management activities were $8.39/Mcf for natural gas, $75.89/Bbl for light and medium oil, $78.85/Bbl for heavy oil and $70.09/Bbl for NGLs. All price risk management activities are reflected in the realized light and medium oil price.

Reserves Reconciliation

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

	LIGHT AND MEDIUM OIL			HEAVY OIL		
	Gross Proved (Mbbls)	Gross Probable (Mbbls)	Gross Proved Plus Probable (Mbbls)	Gross Proved (Mbbls)	Gross Probable (Mbbls)	Gross Proved Plus Probable (Mbbls)
December 31, 2007	735	308	1,043	5,230	1,864	7,093
Discoveries	-	-	-	-	-	-
Extensions	103	401	504	822	255	1,077
Infill Drilling	-	-	-	367	105	472
Improved Recovery	3	3	5	-	-	-
Technical Revisions	615	213	828	(218)	(147)	(365)
Acquisitions	2,600	594	3194	7	2	8
Dispositions	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-
Production	(534)	-	(534)	(1,085)	-	1,085
December 31, 2008	3,522	1,519	5,040	5,121	2,079	7,200

	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, 2007	127,075	53,862	18,0936	876	453	1,329
Discoveries	-	-	-	-	-	-
Extensions	26,440	26,659	53,099	896	824	1,720
Infill Drilling	535	281	816	-	-	-
Improved Recovery	2,102	(213)	1,889	83	6	89
Technical Revisions	1,416	(8,790)	(7,373)	119	(94)	25
Acquisitions	110,532	38,300	148,832	4,701	1,662	6,363
Dispositions	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-
Production	(38,546)	-	(38,546)	(870)	-	(870)
December 31, 2008	229,555	110,099	339,653	5,805	2,851	8,656

Additional Information Relating to Reserves Data

Undeveloped Reserves

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

In some cases, it will take longer than two years to develop these reserves. We plan to develop approximately 95% of the proved undeveloped reserves in the GLJ Report over the next two years and the significant majority of the proved 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 the most recent three financial years and, in the aggregate, before that time.

Year	Light and Medium Oil (Mbbls)		Heavy Oil (Mbbls)		Natural Gas (MMcf)		NGLs (Mbbls)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
Prior	-	-	-	-	1,256	1,256	1	1
2006	-	-	77	77	1,077	3,382	2	2
2007	-	-	471	547	5,304	7,683	75	81
2008	-	-	409	573	6,047	13,156	160	227

GLJ has assigned 3.0 MMboe of proved undeveloped reserves in the GLJ Report under forecast prices and costs, together with $31.5 million of associated undiscounted future capital expenditures to be spent in the first two forecast years. The majority of our proved undeveloped reserves evaluated in the GLJ Report are attributable to the Fir, Hallum and Kirkwall properties.

Probable Undeveloped Reserves

The following table discloses, for each product type, the volumes of probable undeveloped reserves that were first attributed in each of the 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	-	-	168	168	1,186	1,186	5	5
2006	-	-	31	206	1,075	4,242	25	35
2007	70	70	368	463	8,773	10,796	105	154
2008	210	210	304	429	21,952	28,655	611	690

GLJ has assigned 6.1 MMboe of probable undeveloped reserves in the GLJ Report under forecast prices and costs, and $60.0 million in undiscounted future capital attributed to all probable undeveloped reserves scheduled for the first five years.

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.

Year	FORECAST PRICES AND COSTS Proved Reserves ($000s)	Proved Plus Probable Reserves ($000s)
2009	40,493	70,833
2010	6,679	40,422
2011	67	181
2012	315	1,058
2013	234	250
Remaining	1,780	7,933
Total (Undiscounted)	49,569	120,676

We expect to fund the development costs of our reserves through a combination of internally generated cash flow and debt.

There can be no guarantee that funds will be available or that our Board of Directors will allocate funding to develop all of the reserves attributed in the GLJ Report. Failure to develop those reserves could have a negative impact on our future cash flow.

The 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, 2008. Information in respect of current production is average production, net to us, except where otherwise indicated.

Wapiti

Wapiti, our largest core area is located south of Grande Prairie, Alberta, approximately 520 kilometres northwest of Calgary. This core area will play an important role in our future growth.

When Rider acquired Wapiti from a senior oil and gas company in May of 2007, the property was producing 2,800 Boe/d, primarily consisting of non-operated shallow decline Cadomin gas. One and one-half years later at the end of 2008, Wapiti was producing 4,700 Boe/d, with the increase in production resulting from the drilling of higher working interest operated wells in the eastern portion of the property. Current production in this core area is approximately 5,500 Boe/d.

Over the past year we have invested a significant amount of capital in the area resulting in an increase in undeveloped land from 45,000 net acres to 125,000 net acres. In addition to an annually renewable inventory of approximately 20 high working interest, multi zone drilling prospects, we have significant interests in three high gas-in-place resource prospects, with significant development potential. The Cadomin, the most mature of these plays is not operated by us, but may ultimately lead to over 100 development infill locations at a working interest of approximately 40%. Both of the other high gas-in-place resource plays are operated by us. Our first four wells in the Dunvegan play were tied-in during February 2009, adding 1,200 net Boe/d of production. If production tests on thicker sands in the lower Dunvegan are successful, this play may yield a combination of over 100 horizontal and vertical development wells over the next five years.

Although further into the future, we have procured approximately 160 sections of contiguous Montney acreage with an average working interest of 90%.

Pembina

The Pembina core area is located approximately 230 kilometres north of Calgary, Alberta. Our properties in this core area include Pembina, Pembina Units (including Pembina Keystone Cardium Unit No. 2), Buck Creek and Alsike. This area is characterized by mature production with gas and light oil development opportunities. We have a 62% interest in a 5 MMcf/d operated sour gas plant and a 100% interest in a 25 MMcf/d gas plant.

This area contains 61,000 acres of undeveloped land with an average working interest of 80%.

Our 2008 average production rate was approximately 3,978 Boe/d (17.5 MMcf/d of natural gas and 1,061 Bbls/d of oil and liquids). The 2008 exit production rate was approximately 4,076 Boe/d.

In 2008, we drilled or re-entered 9 (5.7 net) wells and achieved an average success rate of 100%, yielding 6 natural gas wells and 3 oil wells.

Ferrier/Sunchild

The Ferrier/Sunchild core area is approximately 200 kilometres northwest of Calgary, Alberta, and includes both the 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 low operating costs for our production.

This core area has an undeveloped land base of approximately 21,000 acres with an average working interest of 77%.

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. We recently acquired overlapping land and production interests in this area. The acquisition which closed on January 29, 2009, added approximately 800 Boe/d of low decline production to this core area.

Our 2008 average production rate was approximately 2,729 Boe/d (13.1 MMcf/d of natural gas and 552 Bbls/d of oil and liquids). The 2008 exit production rate was approximately 3,170 Boe/d.

In 2008, we drilled or re-entered 3 (2.2 net) wells, yielding 3 natural gas wells.

Kaybob/Waskahigan

The Kaybob/Waskahigan core area is located approximately 100 kilometres southeast of Grande Prairie, Alberta.

This core area has an undeveloped land base of approximately 43,000 acres with an average working interest of 87%.

Our 2008 average production rate was approximately 1,329 Boe/d (7.1 MMcf/d of natural gas and 147 Bbls/d of oil and liquids). The 2008 exit production rate was approximately 1,315 Boe/d. Production from the Kaybob/Waskahigan core area is characterized by 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.

Our Fir property has been offset to the northeast and southwest by successful Montney horizontal gas wells. We are evaluating our acreage to see if similar opportunities exist on our land.

In 2008, we drilled 2 (1.3 net) gas wells and have developed an inventory of future drilling opportunities.

Provost

Our Provost core area is located west of the Saskatchewan border approximately 250 kilometres northeast of Calgary, Alberta. In 2003, pursuant to the plan of arrangement with Bonavista, we obtained one minor oil property in this area.

We have increased our operations in this core area through exploration and development activities as well as by acquiring additional producing properties and undeveloped land.

Our 2008 average production rate in the Provost area was 4,549 Boe/d consisting of approximately 3,229 Bbls/d of oil and 7.9 MMcf/d of natural gas. Our 2008 exit production rate was approximately 4,116 Boe/d. This core area contains 101,100 acres of undeveloped land with an average working interest of 88%.

The northern portion of the Provost area has multi-zone potential and contains both medium-heavy oil and natural gas targets. In 2008, our focus was the delineation of a pool extension at our Auburndale property based on 3D seismic and infill drilling at Chauvin. The southern portion of this area contains ten prospective natural gas horizons at drill depths of less than 1,100 metres.

In 2008, we pursued both oil and natural gas exploration and development opportunities in this core area with good success. We drilled or re-entered 18 (16.3 net) wells and achieved an average success rate of 83%, resulting in 12 oil wells, 3 natural gas wells and 3 dry holes.

On January 8, 2008, we acquired oil properties located in the Provost core area, in close proximity to our Chauvin property. At the time of the acquisition, production averaged approximately 650 Bbls/d of 23° API oil. During 2008, we optimized production from these properties, increasing production to over 800 Bbls/d.

Oyen

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

Our 2008 average production rate in the Oyen core area was 3,558 Boe/d (20.5 MMcf/d of natural gas and 146 Bbls/d of oil) and our 2008 exit production rate was approximately 3,485 Boe/d. 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 core area contains 224,000 acres of undeveloped land with an average working interest of 85%. The Oyen core area also contains over 263,000 acres of land that is considered to be developed but is included in the area that received downspacing approval from the Alberta Government in 2006. Our extensive 2D and 3D seismic database enhances the prospectivity of both our developed and undeveloped lands in the area.

In 2008, we had a very successful drilling program in our Oyen core area and identified several trends with follow-up locations. We drilled or re-entered 34 (28.3 net) wells and achieved an average success rate of 94%, resulting in 31 natural gas wells, 1 oil well, and 2 dry holes.

For 2009, new wells in Oyen will receive substantial economic benefits from the royalty incentive programs announced by the Government of Alberta on March 3, 2009, where 1,000 metre wells costing between $225,000 and $250,000 to drill are expected to receive approximately a $200,000 drilling credit which can be applied against our 2009 crown royalties. See "*Industry Conditions*".

Northwest Saskatchewan

Our northwest Saskatchewan core area is located 100 kilometres east of Cold Lake near the Alberta-Saskatchewan border. The region was established as a core area in August 2005, when we acquired natural gas properties in northwest Saskatchewan for approximately $150 million. In June 2006, we acquired additional properties contiguous to our existing operations thereby increasing our dominance in the area. This area is natural gas prone and characterized by larger, more mature pools with lower production decline rates. Parts of this core area are restricted to winter access and therefore we typically conduct an active first quarter drilling program in this area. In the southern part of this core area, we are currently evaluating several heavy oil prospects where access tends to be available year round. Our 2008 average production rate was approximately 3,200 Boe/d (18.1 MMcf/d of natural gas and 181 Bbls/d of oil) and our 2008 exit production rate was approximately 3,226 Boe/d. We operate nearly all the production in this area and our facilities process over 95% of our production. Our operations in the area include seven main processing facilities connected through an extensive network of large diameter gathering lines.

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. The Onion Lake oil pool was the focus of our development drilling program in 2008.

We have 125,000 acres of undeveloped land with an average working interest of 63%. We have acquired over 4,500 kilometres of 2D seismic, most of which is proprietary. In 2008, we drilled 15 (11.6 net) wells and achieved an average success rate of 100%, resulting in 4 natural gas wells, and 11 oil wells.

West Central Saskatchewan

Our west central Saskatchewan core area is located east of the Alberta border approximately 400 kilometres northeast of Calgary. The region was established as a core area in June 2006 when we acquired natural gas properties in west central and northwestern Saskatchewan. This core area has multi-zone production from both natural gas and heavy oil horizons. In 2008, our daily average production was approximately 1,355 Boe/d (5.1 MMcf/d of natural gas and 491 Bbls/d of oil). The 2008 exit production rate was approximately 1,412 Boe/d. We operate nearly all production in this core area. Our operations in the area include six natural gas processing facilities and a number of field compressors connected through an extensive network of gathering lines. This core area contains 56,000 acres of undeveloped land with an average working interest of 78%.

In 2008, we drilled or re-entered 17 (11.9 net) wells yielding 10 oil wells and seven dry holes. The 2008 drilling program focused on development and extension drilling at Reflex Lake, Yonkers and the first phase of a horizontal infill drilling program at Hallum. The four Hallum horizontal wells were producing at rate of approximately 360 Bbls/d (gross) at year end with additional infill phases planned. We have has over 15 additional horizontal locations identified in Hallum, each of which is forecasted to produce in excess of 100,000 Bbls of oil, pay a 2% royalty and produce oil at low operating costs.

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, 2008.

	OIL WELLS				**NATURAL GAS WELLS**			
	Producing		**Non-Producing**		**Producing**		**Non-Producing**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Alberta	797	461.3	285	175.1	628	407.0	679	452.3
Saskatchewan	79	50.3	46	24.5	368	252.9	372	250.6
Total	876	511.6	331	199.6	996	659.9	1,051	702.9

Of these non-producing wells, 63 (40.6 net) natural gas wells were capable of production and had reserves assigned to them. 52 (34.9 net) of these non-producing natural gas wells were placed on production as of date of this Annual Information Form.

Properties With No Attributed Reserves

The following table sets out our developed and undeveloped land holdings as at December 31, 2008.

	DEVELOPED ACRES		UNDEVELOPED ACRES		TOTAL ACRES	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Alberta	670,405	392,826	690,320	579,371	1,360,725	972,197
Saskatchewan	245,576	168,280	278,474	189,049	524,050	357,329
Total	915,981	561,106	968,794	768,420	1,884,775	1,329,526

Rights to explore, develop and exploit 193,107 net acres of these undeveloped land holdings could expire by December 31, 2009 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, 2008 see Notes 13 and 16 to our consolidated financial statements for the year ended December 31, 2008 which are incorporated herein by reference.

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, 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 of Cdn $8.39/Mcf for the year ended December 31, 2008.

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 2008, our average realized oil price was Cdn $77.00/Bbl and our average realized price for natural gas liquids was Cdn $70.09/Bbl.

Additional details on our price risk management program are shown in Notes 13 and 16 of our consolidated financial statements for the year ended December 31, 2008 which are incorporated herein by reference.

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, and 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, 2008 we had 2,074 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 8% ($000s)
Total liability as at December 31, 2008	187,900	34,800
Anticipated to be paid in 2009	1,600	1,500
Anticipated to be paid in 2010	1,600	1,500
Anticipated to be paid in 2011	1,700	1,600

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 $39.0 million (undiscounted) and $16.3 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. We do not expect to pay any material amounts with respect to abandonment and reclamation costs in the next three financial years.

Tax Horizon

Based on the current tax regime, we may be cash taxable in 2009 with actual cash taxability primarily dependent on commodity prices, anticipated capital expenditures and any changes to our corporate structure.

Costs Incurred

The following table summarizes the costs incurred related to our activities for the year ended December 31, 2008.

Expenditure	Year Ended December 31, 2008 ($000s)
Property acquisition costs – Unproved properties (1) (2)	37,014
Property acquisition costs – Proved properties (2)	32,533
Exploration costs (3)	36,144
Development costs (4)	93,170
Other	1,876
Total	200,737

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.

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, 2008.

	Development		**Exploratory**	
	Gross	**Net**	**Gross**	**Net**
Natural Gas	41	24.8	24	20.9
Heavy Oil	36	29.8	1	1.0
Dry	7	4.3	6	5.2
Total	84	58.9	31	27.1

In 2009, we expect to drill approximately 42 natural gas wells in Alberta. In Saskatchewan, we expect to drill 11 oil wells.

Finding and Development Costs

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

	2008		**2007**		**Three Year Average**	
($/Boe)	**Proved**	**Proved plus Probable**	**Proved**	**Proved plus Probable**	**Proved**	**Proved plus Probable**
Finding, development and acquisition cost (1)	24.29	18.51	20.78	17.22	24.20	18.54
Finding, development (1)	24.37	19.48	21.26	18.52	23.39	18.80
Acquisition costs	24.26	18.16	19.66	14.35	24.70	18.37

Notes:
(1) Including changes in future development capital expenditures.
(2) The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development capital expenditures generally will not reflect total finding and development costs related to reserves additions for that year.

Production Estimates

The following table sets out the volumes of our working interest production estimated for the year ended December 31, 2009, which is reflected in the estimate of future net revenue disclosed in the forecast price tables contained above under the subheading "*Disclosure of Reserves Data* ".

	Light and Medium Oil (Bbls/d)	**Heavy Oil (Bbls/d)**	**Natural Gas (Mcf/d)**	**Natural Gas Liquids (Bbls/d)**	**BOE (Boe/d)**
Total Proved	1,545	2,785	111,992	3,019	26,014
Total Proved plus Probable	1,720	3,032	124,370	3,462	29,013

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 2008				Year Ended
	Mar. 31	**June 30**	**Sept. 30**	**Dec. 31**	**Dec. 31, 2008**
Average Daily Production (1)					
Heavy Oil (Bbls/d)	3,985	4,714	4,554	4,663	4,472
Gas (MMcf/d)	85.5	113.0	111.4	109.8	104.9
NGLs (Bbls/d)	1,105	2,609	2,942	2,760	2,357
Combined (Boe/d)	19,339	26,153	26,065	25,689	24,320
Average Net Production Prices Received					
Heavy Oil ($/Bbl)	76.69	91.82	92.06	47.44	77.00
Gas ($/Mcf)	7.83	9.44	8.35	7.80	8.34
NGLs ($/Bbl)	77.74	81.88	81.95	43.41	70.09
Combined ($/Boe)	54.85	65.52	61.05	46.55	57.16
Royalties Paid					
Heavy Oil ($/Bbl)	10.61	16.24	17.47	9.12	13.45
Gas ($/Mcf)	2.24	2.12	2.24	1.39	1.98
NGLs ($/Bbl)	9.57	30.03	24.95	14.88	21.59
Combined ($/Boe)	12.63	15.10	15.45	9.17	13.13
Production Costs (2)(3)					
Heavy Oil ($/Bbl)	11.18	13.76	14.70	16.95	14.16
Gas ($/Mcf)	1.14	1.16	1.20	1.21	1.18
NGLs ($/Bbl)	6.84	6.96	7.20	7.26	7.08
Combined ($/Boe)	7.62	8.19	8.50	8.98	8.37
Transportation					
Heavy Oil ($/Bbl)	1.38	1.86	1.87	1.57	1.68
Gas ($/Mcf)	0.12	0.15	0.13	0.11	0.13
NGLs ($/Bbl)	–	0.02	–	–	–
Combined ($/Boe)	0.82	0.96	0.87	0.76	0.86
Netback Received (4)					
Heavy Oil ($/Bbl)	53.60	59.96	58.02	19.80	47.71
Gas ($/Mcf)	4.33	6.01	4.78	5.09	5.05
NGLs ($/Bbl)	61.33	44.87	49.80	21.27	41.42
Combined ($/Boe)	33.78	41.27	36.23	27.64	34.80

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 commodity and 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, 2008.

	Heavy Oil [1] (Bbls/d)	Natural Gas Liquids (Bbls/d)	Natural Gas (MMcf/d)	BOE (Boe/d)
Central Saskatchewan	489	–	5.0	1,324
Ferrier	16	532	12.9	2,702
Kaybob/Waskahigan	4	142	7.0	1,315
Oyen	131	13	20.3	3,520
Provost	3,153	23	7.8	4,482
Pembina	427	619	17.3	3,931
Northwest Saskatchewan	181	–	17.9	3,168
Wapiti	5	1,012	15.6	3,611
Other	66	16	1.1	267
Total	4,472	2,357	104.9	24,320

Note:

(1) This crude oil averages less than 24° API and is therefore classified as heavy oil under NI 51-101. Also includes light and medium crude oil production which is not material (less than 10%).

For the year ended December 31, 2008, approximately 62% of our gross revenue was derived from natural gas, 26% from crude oil, virtually all heavy oil (24° API or less) and 12% from natural gas liquids. Our production for the year ended December 31, 2008 was approximately 72% natural gas, 18% crude oil, virtually all heavy oil (24° API or less) and 10% natural gas liquids.

DESCRIPTION OF OUR CAPITAL STRUCTURE

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 with Bonavista 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 (the "**NuVista Closing Price**") less $2.00, if positive, divided by the NuVista 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**
2008			
January	15.06	12.88	5,001,713
February	16.50	14.39	3,534,554
March	16.75	14.46	7,259,659
April	18.24	15.02	6,893,475
May	20.23	16.24	6,883,810
June	20.16	16.99	8,770,988
July	17.69	13.52	12,913,192
August	15.50	13.21	9,530,167
September	14.81	11.58	11,097,671
October	12.80	9.33	8,546,538
November	11.92	6.25	5,389,065
December	8.85	6.54	10,966,659
2009			
January	9.43	6.68	3,609,681
February	7.95	5.11	4,815,623
March (1 – 17)	6.09	4.90	6,725,442

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)(6) Calgary, Alberta	Chairman and Director	May 2003	Our Chairman and Chairman and Chief Executive Officer of Bonavista.
W. Peter Comber (1)(3)(4) Toronto, Ontario	Director	May 2004	Managing Director of Barrantagh Investment Management Inc. (an investment counselling firm).
Pentti O. Karkkainen (1)(2)(3)(5) Calgary, Alberta	Director	July 2003	General Partner, KERN Partners Ltd. (a private equity firm and partnership).
Ronald J. Poelzer (6) Calgary, Alberta	Director	May 2003	Executive Vice President and Vice Chairman of Bonavista.
Craig W. Stewart (2)(3) Calgary, Alberta	Director	March 2008	Chairman, President and Chief Executive Officer of RMP Energy Ltd. since September 2008. Prior thereto, Mr. Stewart was the President and Chief Executive Officer of Rider from February 2003 to March 2008. Mr. Stewart was the President and Chief Executive Officer of Meota Resources Corp. between January 2000 and October 2002 and prior thereto, Mr. Stewart was President and Chief Executive Officer of Poco Petroleums Ltd. for seven years.

Name and Municipality of Residence	Position with NuVista	Director or Officer Since	Principal Occupation
Alex G. Verge Calgary, Alberta	President, Chief Executive Officer and Director	July 2003	Our President and Chief Executive Officer since July 2003 and prior thereto Vice President, Engineering of Bonavista.
Clayton H. Woitas (1)(2)(4) 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.
Grant A. Zawalsky (3)(4) Calgary, Alberta	Director	May 2003	Partner of Burnet, Duckworth & Palmer LLP (barristers and solicitors).
Glenn A. Hamilton (6) Calgary, Alberta	Corporate Secretary	July 2003	Our Corporate Secretary since July 2006 and Senior Vice President and Chief Financial Officer of Bonavista since June 1, 2008. Prior thereto Vice President, Finance of Bonavista. Our Vice President and Chief Financial Officer from July 2003 and until May 2006.
Robert F. Froese Calgary, Alberta	Vice President, Finance and Chief Financial Officer	May 2006	Our Vice President, Finance and Chief Financial Officer since May 2006. Prior thereto, Mr. Froese was our Vice President Finance commencing March 2006. Prior thereto, he was Treasurer at Suncor Energy Inc.
Steven J. Dalman Calgary, Alberta	Vice President, Business Development	January 2006	Our Vice President, Business Development since January 2008. Prior thereto, Mr. Dalman was our Vice President Engineering since January 2006. Mr. Dalman joined us as Manager, Engineering in January 2005. Prior thereto, he was a Senior Exploitation Engineer at Bonavista.
Dan McKinnon Calgary, Alberta	Vice President, Engineering	January 2008	Our Vice President, Engineering since January 2008. Prior thereto, Mr. McKinnon was a senior exploitation engineer with us commencing in January 2005 and then our Manager, Business Planning since July 2007. Prior thereto, Mr. McKinnon was a senior exploitation engineer with Bonavista between August 2003 and January 2005, Exploitation Manager of Midnight Oil & Gas Ltd. (a public oil and gas company) between April 2003 and August 2003 and Manager of Engineering of Capture Energy Ltd. (a public oil and gas company) between August 2001 and April 2003.
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. Prior thereto, he was a Production Engineer at Bonavista.

Name and Municipality of Residence	Position with NuVista	Director or Officer Since	Principal Occupation
Kevin J. Christie Calgary, Alberta	Vice President, Exploration	June 2008	Our Vice President, Exploration since June 2008. Prior thereto, Mr. Christie was Vice President Exploration at TAQA North Ltd. (formerly Northrock Resources Ltd.) since July, 1999. Mr. Christie has over 33 years of experience in the oil and gas industry.
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, was promoted to Land Manager in May 2008. Prior thereto, Mr. Truba was employed by Addison Energy Inc. as Area Landman.

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) Our Lead Director.
(6) Member of our non-board executive committee.

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

As at March 17, 2009 our directors and officers, as a group, beneficially owned, or directed or controlled, directly or indirectly, 8,683,125 Common Shares or approximately 11.0% 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. Stewart who was a former Director of Calibre Energy Inc., which sought protection under the *Companies' Creditors Arrangement Act* (Canada) in February, 1999. In September, 1999 a cease trade order was issued against such company for failure to file financial statements. Mr. Stewart resigned as the director of the company on October 12, 1999. In addition, Mr. MacPhail 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 members will be provided to us.

The ABCA 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 ABCA. To the extent that conflicts of interests arise, such conflicts will be resolved in accordance with the provisions of the ABCA.

Our partners in NuVista Partnership may have interests in oil and natural gas properties or carry on other business of any nature, including interests and business that compete with ours, and pursuant to the partnership agreement governing NuVista Partnership, no partner is required to account to NuVista Partnership for profits earned from the holding of such interests and/or the carrying on of such business. In the event that the interests of a partner are in conflict with those of NuVista Partnership, the partner shall make decisions acting in good faith and shall advise NuVista Partnership of any material conflict; provided, however, that all decisions involving or affecting NuVista Partnership assets will be made in NuVista Partnership's best interest. In addition, each partner will have the right to contract or otherwise deal with or for the sale or lease of property, the provision of management, administrative or executive services and other services, and to receive payments and fees from NuVista Partnership in connection therewith as the manager shall determine to be in NuVista Partnership's best interest, provided that such payments or fees are no greater than the payments or fees that would be paid to persons with whom NuVista Partnership deals with at arm's length (as that term is defined in and construed under the *Income Tax Act* (Canada)).

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. Woitas, each of whom are independent and financially literate. We have adopted the definition of "independence" as set out in Section 1.4 of Multilateral Instrument 52-110 *Audit Committees* ("**MI 52-110**"). 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. Since August 1999, Mr. Comber has been managing director of Barrantagh Investment Management Inc., investment counselors based in Toronto, Ontario. Mr. Comber was the President of Newtonhouse Investment Management Ltd., investment counselors located in Toronto, Ontario from May 1993 to August 1999. Between June 1989 and December 1991, Mr. Comber was Senior Vice President, Thommark Capital Corporation, an investment holding company, and principal officer of Thommark Capital Funding Corporation, merchant bank. Prior to 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. and Exshaw Oil Corporation.

***Pentti O. Karkkainen:** KERN Partners Ltd.*

Mr. Karkkainen has 23 years of investment management, energy sector research and investment banking experience, as well as four year of industry experience with Gulf Canada Resources. Mr. Karkkainen is a founding and a General Partner of KERN Partners Ltd. – a Calgary based energy sector private equity firm that was established 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 Energy Ltd., Gibraltar Exploration Ltd., Dolomite Exploration and Peloton Exploration Inc..

***Clayton H. Woitas:** Range Royalty Management Ltd.*

Mr. Woitas has 35 years experience in the oil and gas industry and is currently President and CEO of Range Royalty Management Ltd., general partner of Range Royalty Limited Partnership (an oil and gas royalty limited partnership). Mr. Woitas was President and CEO of Profico Energy Management Ltd. (a private oil and gas company) from February 2000 to June 2006. Prior thereto, Mr. Woitas was President and CEO of Renaissance Energy Ltd.

Mr. Woitas is also a director of AspenAir Corp., EnCana Corporation, EnerMark Inc. (the administrator of Enerplus Resources Fund), Flagstone Energy Inc., Chairman and a director of Spur Resources Ltd.

Mr. Woitas holds a Bachelor of Science degree in Civil Engineering from the University of Alberta and is a member of the Association of Professional Engineers, Geologists & Geophysicists of Alberta.

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 $145,000 in 2008 and $115,000 in 2007.

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 are reasonably related to the performance of the audit or review of our financial statements that are not reported under "*Audit Fees*" above were $56,000 in 2008 and $44,500 in 2007. Fees billed for prospectus review in each of the last two fiscal years were $95,000 in 2008 and $50,000 in 2007.

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 $18,750 in 2008 and $6,735 in 2007.

All Other Fees

The aggregate fees billed in each of the last two fiscal years for products and services provided by our auditors, other than services reported, above were $7,500 in 2008 in connection with a business acquisition report relating to an acquisition and $nil in 2007.

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 Sections 2.4, 3.2, 3.4 or 3.5 of MI 52-110, or an exemption from MI 52-110, in whole or in part, granted under Part 8 thereof. In addition, at no time since the commencement of our most recently completed financial year have we relied upon the exemptions in Subsection 3.3(2) or Section 3.6 of MI 52-110. Furthermore, at no time since the commencement of our most recently completed financial year have we relied upon Section 3.8 of MI 52-110.

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.

DIVIDEND POLICY

We have not paid any dividends to date on our outstanding Common Shares. Our Board of Directors will determine the timing, payment and amount of dividends, if any, that may be paid by us from time to time based upon, among other things, our cash flow, results of operations and financial condition, the need for funds to finance ongoing operations and other business considerations as our Board of Directors considers relevant.

Our credit facility provides that we shall not without the prior approval of our banker, not to be unreasonably withheld, reduce or distribute capital or pay dividends or redeem or repurchase common or preferred shares, unless such dividends, redemptions, and repurchases do not impair our capacity to fulfil our obligations with respect to the credit facilities including the repayment of the loan.

INDUSTRY CONDITIONS

The oil and natural gas industry is subject to extensive controls and regulations governing its operations (including land tenure, exploration, development, production, refining, transportation, and marketing) imposed by legislation enacted by various levels of government and with respect to pricing and taxation of oil and natural gas by 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 controls or regulations will affect our operations in a manner materially different than they would affect other oil and gas companies of similar size. All current legislation is a matter of public record and we are unable to predict what additional legislation or amendments may be enacted. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the oil and gas industry.

Pricing and Marketing - Oil and Natural Gas

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 the markets, the value of refined products, the supply/demand balance, and other contractual terms. 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 and the issuance of such licence requires a public hearing and the approval of the Governor in Council.

The price of natural gas is determined by 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 a larger quantity requires an exporter to obtain an export licence from the NEB and the issuance of such licence requires a public hearing and the approval of the Governor in Council.

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.

Pipeline Capacity

Although pipeline expansions are ongoing, the lack of firm pipeline capacity continues to affect the oil and natural gas industry and limit the ability to produce and to market natural gas production. In addition, the pro-rationing of capacity on the inter-provincial pipeline systems also continues to affect the ability to export oil and natural gas.

The North American Free Trade Agreement

The North American Free Trade Agreement ("**NAFTA**") among the governments of Canada, United States of America, and Mexico became effective on January 1, 1994. NAFTA carries forward most of the material energy terms that are contained in the Canada United States Free Trade Agreement. 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 domestic use (based upon 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 voluntary measures which only restrict the volume of exports; and (iii) disrupt normal channels of supply. All three countries are prohibited from imposing minimum or maximum export or import price requirements, provided, in the case of export price requirements, any prohibition in any circumstances in which any other form of quantitative restriction is prohibited, and in the case of import-price requirements, such requirements do not apply with respect to enforcement of countervailing and anti-dumping orders and undertakings.

NAFTA contemplates the reduction of Mexican restrictive trade practices in the energy sector by 2010 and prohibits discriminatory border restrictions and export taxes. NAFTA also contemplates clearer disciplines on regulators to ensure fair implementation of any regulatory changes and to minimize disruption of contractual arrangements and avoid undue interference with pricing, marketing and distribution arrangements, which is important for Canadian natural gas exports.

Provincial Royalties and Incentives

General

In addition to federal regulation, each province has legislation and regulations which govern land tenure, royalties, production rates, environmental protection, and other matters. The royalty regime is a significant factor in the profitability of 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. Crown royalties are determined by governmental regulation and are generally calculated as a percentage of the value of the 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, and tax credits, and are generally introduced when commodity prices are low. The programs are designed to encourage exploration and development activity by improving earnings and cash flow within the industry. Royalty holidays and reductions would reduce the amount of Crown royalties paid by oil and gas producers to the provincial governments and would increase the net income and funds from operations of such producers. However, the trend in recent years has been for provincial governments to eliminate, amend or allow such incentive programs to expire without renewal, and consequently few such incentive programs are currently operative.

The Canadian federal corporate income tax rate levied on taxable income is 19.5% effective January 1, 2008 for active business income including resource income. With the elimination of the corporate surtax effective January 1, 2008 and other rate reductions introduced in the October 2007 Economic Statement and Notice of Ways and Means Motion, 2006 Federal Budget, the federal corporate income tax rate will decrease to 15% in four additional steps: 19% on January 1, 2009, 18% on January 1, 2010, 16.5% on January 1, 2011 and 15% on January 1, 2012.

Alberta

In Alberta, companies are granted the right to explore, produce and develop petroleum and natural gas resources in exchange for royalties, bonus bid payments and rents. On October 25, 2007, the Government of Alberta released a report entitled "The New Royalty Framework" (the "**NRF**") containing the Government's proposals for Alberta's new royalty regime, which was followed by the *Mines and Minerals (New Royalty Framework) Amendment Act*, 2008, which was given Royal Assent on December 2, 2008. The NRF and the applicable new legislation became effective on January 1, 2009. Prior to the NRF, the amount of royalties that were payable was influenced by the oil production, density of the oil, and the vintage of the oil. Originally, the vintage classified oil was "new oil" and "old oil" depending on when the oil pools were discovered. If the pool was discovered prior to March 31, 1974 it was considered "old oil", if it was discovered after March 31, 1974 and before September 1, 1992, it was considered "new oil". The Alberta Government introduced in 1992 a Third Tier Royalty with a base rate of 10% and a rate cap of 25% for oil pools discovered after September 1, 1992. The new oil royalty reserved to the Crown had a base rate of 10% and a rate cap of 30%. The old oil royalty reserved to the Crown had a base rate of 10% and a rate cap of 35%. The NRF eliminates this classification and establishes new royalty rates for conventional oil, natural gas and oil sands. The new royalty rates for conventional oil are set by a single sliding rate formula which is applied monthly and increases the old royalty from 30% to 35% applied to the old and new tiers, to up to 50% and with rate caps once the price of conventional oil reaches $120 per barrel. The sliding rate formula includes in its calculation the price of oil and well production.

With respect to natural gas, and similar to the conventional oil framework, the royalties outlined in the NRF are set by a single sliding rate formula ranging from 5% to 50% with a rate cap once the price of natural gas reaches $16.59/GJ. Prior to the NRF, the royalty reserved to the Crown in respect of natural gas production, subject to various incentives, was between 15% and 30%, in the case of new natural gas, and between 15% and 35%, in the case of old natural gas, depending upon a prescribed or corporate average reference price. In response to the drop in commodity prices experienced during the second half of 2008, the Government of Alberta announced on November 19, 2008, the introduction of a five year program of transitional royalty rates with the intent of promoting new drilling. Under this new program companies drilling new natural gas or conventional oil deep wells (between 1,000 and 3,500 metres) will be given a one-time option, on a well by well basis, to adopt either the new transitional royalty rates or those outlined in the NRF. In order to qualify for this program wells must be drilled during the period starting on November 19, 2008 and ending on December 31, 2013. Following this period all new wells drilled will automatically be subject to the NRF.

Oil sands projects are now subject to the NRF, and regulated, among others, by the *Oil Sands Royalty Regulation, 2009 Oil Sands Allowed Costs (Ministerial) Regulation* and the *Bitumen Valuation Methodology (Ministerial) Regulation*, *2009*, all approved by the Government of Alberta on December 10, 2008. The rates applicable to oil sands are between 1% and 9% and are calculated depending on the price of oil. The royalty payable is 1% when oil is priced below or at $55 per barrel and it increases for every dollar over and above that price, to a maximum of 9% when oil is priced at $120 or higher. The after payout net royalty starts at 25% and increases for every dollar when oil is priced above $55 up to 40% when oil is priced at $120 or higher.

On April 10, 2008, the Government of Alberta introduced two new royalty programs that will encourage the development of deep oil and gas reserves, and these are: (a) a five-year oil program for exploration wells over 2,000 metres that will provide royalty adjustments to offset higher drilling costs and provide a greater incentive for producers to continue to pursue new, deeper oil plays (these oil wells will qualify for up to a $1 million or 12 months of royalty offsets, whichever comes first); and (b) a five-year natural gas deep drilling program that will replace the existing program in order to encourage continued deep gas exploration for wells deeper than 2,500 metres (the program will create a sliding scale of royalty credit according to depth, of up to $3,750 per metre). These new programs are to be implemented along with the NRF.

Regulations made pursuant to the *Mines and Minerals Act* (Alberta) provided various incentives for exploring and developing oil reserves in Alberta. However, the Alberta Government announced in August of 2006 that four royalty programs were to be amended, a new program was to be introduced and the Alberta Royalty Tax Credit Program was to be eliminated, effective January 1, 2007. The programs affected by this announcement were: (i) Deep Gas Royalty Holiday; (ii) Low Productivity Well Royalty Reduction; (iii) Reactivated Well Royalty Exemption; and (iv) Horizontal Re-Entry Royalty Reduction. The program introduced was the Innovative Energy Technologies Program (the "**IETP**") which has a stated objective of promoting the producers' investment in research, technology and innovation for the purposes of improving environmental performance while creating commercial value. The IETP provides royalty reductions which are presumed to reduce financial risk. Alberta Energy decides which projects qualify and the level of support that will be provided. The deadline for the IETP's final round of applications was September 20, 2008. The successful applicants for the first two rounds have been announced, and those for the third round selection are scheduled to be announced in the first half of 2009. The technical information gathered from this program is to be made public once a two-year confidentiality period expires.

The NRF includes a policy of "shallow rights reversion". The Government of Alberta started to implement this policy on January 1, 2009, and its intent is to maximize the development of currently undeveloped resources that is consistent with the Government of Alberta's objective of maximizing recovery of known gas resources, while increasing royalty revenues. The policy's stated objective is for the mineral rights to shallow gas geological formations that are not being developed to revert back to the Government and be made available for resale, and in the event of non-productive shallow wells, to sever the rights from shallow zones and encourage increased production from up-hole zones. The shallow rights reversion policy affects all petroleum and natural gas agreements; however, the timing of the reversion will differ depending on whether the leases and licenses were acquired prior to January 1, 2009 or subsequent to January 1, 2009. Leases granted after January 1, 2009 will be subject to shallow rights reversion at the expiry of the primary term, and in the event of a licence the policy will apply at the expiry of the intermediate term. 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. The lease or licence holder can make a request to extend this period. The order in which these agreements will receive the reversion notice will depend on the vintage of their term, with the older leases and licenses receiving a reversion notice first. Leases or licences that were granted prior January 1, 2009 but have not yet been continued will have a grace period until they are continued under section 15 of the *P&G Tenure Regulation* and be subject to deeper rights reversion prior to receiving a shallow rights reversion notice.

On March 3, 2009, the Government of Alberta announced a three-point incentive program to stimulate new and continued economic activity in Alberta which included a drilling royalty credit for new conventional oil and natural gas wells and a new well royalty incentive program. Under the drilling royalty credit program a $200 per meter royalty credit will be available on new conventional oil and natural gas wells drilled between April 1, 2009 and March 31, 2010, subject to certain maximum amounts. The maximum credits available will be determined by the company's production level in 2008 and its drilling activity between April 1, 2009 and March 31, 2010. Based on the Corporation's 2008 production it will be entitled to a maximum credit of 40% of royalties payable in the period April 1, 2009 and March 31, 2010. The new well incentive program will apply to wells beginning production of conventional oil and natural gas between April 1, 2009 and March 31, 2010 and provides for a maximum 5% royalty rate for the first 12 months of production, up to a maximum of 50,000 barrels or 500 Mmcf of natural gas.

British Columbia

Producers of oil and natural gas in British Columbia are required to pay annual rental payments with respect to the Crown leases and royalties and freehold production taxes in respect of oil and gas produced from Crown and freehold lands. The amount payable as a royalty in respect of oil depends on the type of oil, the value of the oil, the quantity of oil produced in a month, and the vintage of the oil. Generally, 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 rates are calculated in three stages, which take into account the vintage of the oil, if the oil produced has already been sold and any royalty exempt value applicable (exempt wells). Oil produced from newly discovered pools may be exempt from the payment of a royalty for the first 36 months of production or 11,450m^3 produced, whichever comes first; and the royalties for third-tier oil are the lowest reflecting the higher costs of exploration and extraction that the producers would incur. The royalty payable on natural gas is determined by a sliding scale based on a reference price, which is the greater of the price obtained by the producer, and a prescribed minimum price. However, when the reference price is below the select price (a parameter used in the royalty rate formula), the royalty rate is fixed. As an incentive for the production and marketing of natural gas, which may have been flared, natural gas produced in association with oil has a lower royalty then the royalty payable on non-conservation gas.

On May 30, 2003, the Ministry of Energy and Mines for British Columbia announced an Oil and Gas Development Strategy for the Heartlands ("**Strategy**"). The Strategy is a comprehensive program to address road infrastructure, targeted royalties and regulatory reduction, and British Columbia service sector opportunities. In addition, the Strategy will result in economic and employment opportunities for communities in British Columbia's heartlands.

Some of the financial incentives in the Strategy include:

- Royalty credits towards the construction, upgrading, and maintenance of road infrastructure in support of resource exploration and development. Funding will be contingent upon an equal contribution from industry. This program has evolved over past years as a result of the Province's stated objective to increase competitiveness, and on March 2, 2009 the Government of British Columbia announced the 2009 Infrastructure Royalty Credit Program ("**Program**") which allocates $120 million in royalty credits for oil and gas companies. The Program provides access to royalty credits to oil and gas companies with respect to certain approved road construction or pipeline infrastructure projects intended to improve, or make possible, the access to new and underdeveloped oil and gas areas. Companies must apply to the Ministry of

Energy and Mines for British Columbia prior to 2:00 p.m. on April 30, 2009 to be considered for approval under the program.

- Changes to provincial royalties: new royalty rates for low productivity natural gas to enhance marginally economic resources plays, royalty credits for deep gas exploration to locate new sources of natural gas, and royalty credits for summer drilling to expand the drilling season.

The British Columbia Energy Plan announced on February 27, 2007 outlines the requirements for the development of goals for conservation, energy efficiency and clean energy. In addition, its stated goal is to promote competitiveness through the implementation of a Net Profit Royalty Program ("**NPRP**") among others, and facilitate the development of the oil and gas industry. The NPRP's objective is to share the capital risk of successful developments. Pursuant to the Net Profit Royalty Regulation, the holder of a lease can apply to pay monthly net profit royalties on production of oil and for natural gas wells within a proposed project. The amount paid is calculated on the producer's interest in the project, and it ranges from 2% to 5% of the gross revenue and 15% to 35% of the net revenues received. In addition, it depends at which stage the well is, which may be either pre-payout, after-payout or already producing marketable gas.

The Government of British Columbia has introduced a few more royalty programs, in addition to the ones previously mentioned, including a royalty program for deep discovery wells, royalty programs with a stated goal of attracting investment to less productive shallow gas wells (Ultra-Marginal Royalty Program), and the implementation of royalty credits to assist the development of the coalbed gas reserves found in the Province of British Columbia.

Saskatchewan

In Saskatchewan, the amount payable as a royalty in respect of oil depends on the vintage of the oil, the type of oil, the quantity of oil produced in a month, and the value of the oil. For Crown royalty and freehold production tax purposes, crude oil is considered "heavy oil", "southwest designated oil", or "non-heavy oil other than southwest designated oil". The conventional royalty and production tax classifications ("fourth tier oil" introduced October 1, 2002, "third tier oil", "new oil" and "old oil") of oil production are applicable to each of the three crude oil types. The Crown royalty and freehold production tax structure for crude oil is price sensitive and varies between the base royalty rates of 5% for all "fourth tier oil" to 20% for "old oil". Marginal royalty rates are 30% for all "fourth tier oil" to 45% for "old oil".

The amount payable as a royalty in respect of natural gas is determined by a sliding scale based on a reference price (which is the greater of the amount obtained by the producer and a prescribed minimum price), the quantity produced in a given month, the type of natural gas, and the vintage of the natural gas. 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. The royalty and production tax classifications of gas production are "fourth tier gas" introduced October 1, 2002, "third tier gas", "new gas", and "old gas". The Crown royalty and freehold production tax for gas is price sensitive and varies between the base royalty rate of 5% for "fourth tier gas" and 20% for "old gas". The marginal royalty rates are between 30% for "fourth tier gas" and 45% for "old gas".

On October 1, 2002, the following changes were made to the royalty and tax regime in Saskatchewan:

- A new Crown royalty and freehold production tax regime applicable to associated natural gas (gas produced from oil wells) that is gathered for use or sale and is produced from: (a) oil wells with a finished drilling date on or after October 1, 2002, and (b) 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 cubic metres of gas for every cubic metre of oil. The royalty/tax will be payable on associated natural gas produced from an oil well that exceeds approximately 65,000 cubic metres in a month. The associated natural gas royalty/tax regime will apply to gas produced from oil wells affected by concurrent production approvals after October 1, 2002 if the oil wells meet (a) or (b) above.

- A modified system of incentive volumes and maximum royalty/tax rates applicable to the initial production from oil wells and gas wells with a finished drilling date on or after October 1, 2002, was introduced. The incentive volumes are applicable to various well types and are subject to a maximum royalty rate of 2.5% and a freehold production tax rate of zero per cent.

- The elimination of the re-entry and short section horizontal oil well royalty/tax categories. All horizontal oil wells with a finished drilling date on or after October 1, 2002, will receive the "fourth tier" royalty/ tax rates and new incentive volumes.

- A horizontal oil well, with a finished drilling date on or after October 1, 2002, that is a non-deep oil well qualifies for a 6,000 cubic metre incentive volume.

- A horizontal oil well, with a finished drilling date on or after October 1, 2002, that is a deep oil well qualifies for a 16,000 cubic metre incentive volume.

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 if Canada's plan to reintroduce full deductibility of provincial resource royalties for corporate income tax purposes.

On June 19, 2007, the Government of Saskatchewan introduced the Orphan Well and Facility Liability Management Program pursuant to the amendment of the Oil and Gas Conservation *Act* and the *Oil and Gas Conservation Regulations*, 1985. The program includes a security deposit, which has two purposes: (i) preventing any person with insufficient financial capability from acquiring oil and gas wells or facilities; and (ii) in the case of a bankrupt company, the funds cover the decommissioning and reclaiming of orphan properties. An additional change introduced is the mandatory licensing of all upstream oil and gas facilities in Saskatchewan.

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 from two years, 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.

Environmental Regulation

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation. 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. 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.

Environmental legislation in Alberta has been consolidated into the *Environmental Protection and Enhancement Act* (Alberta) (the "**EPEA**"), which came into force on September 1, 1993, and the *Oil and Gas Conservation Act* (Alberta) (the "**OGCA**"). The EPEA and OGCA impose stricter environmental standards, require more stringent compliance, reporting and monitoring obligations, and significantly increased penalties. In 2006, the Alberta Government enacted regulations pursuant to the EPEA to specifically target sulphur oxide and nitrous oxide emissions from industrial operations including the oil and gas industry. In addition, the reduction emission guidelines outlined in the *Climate Change and Emissions Management Amendment Act* came into effect on July 1, 2007 ("**CCEMAA**"). Under this legislation, Alberta facilities emitting more than 100,000 tonnes of greenhouse gases a year must reduce their emissions intensity by 12%. Industries have three options to choose from in order to meet the reduction requirements outlined in this legislation, and these are: (i) by making improvement to operations that result in reductions; (ii) by purchasing emission credits from other sectors or facilities that have emissions below the 100,000 tonne threshold and are voluntarily reducing their emission; or (iii) by contributing to the Climate Change and Emissions Management Fund (the "**Fund**"). Industries can either choose one of these options or a combination thereof. Pursuant to CCEMAA and the *Specified Gas Emitters Regulation*, companies were obliged to reduce their emission intensity by 12% by March 31, 2008. Alberta industries have achieved 2.6 million tonnes of actual reduction, due to changes in operations and investing on verified offset projects. In addition, certain companies contributed $40 million to the Fund. It is reasonably likely that the trend towards stricter standards in environmental legislation and regulation will continue.

On January 24, 2008, the Alberta Government announced a new climate change action plan that will cut Alberta's projected 400 million tonnes of emissions in half by 2050. This plan is based on three areas: (i) carbon capture and storage, which will be mandatory for *in situ* oil sand facilities that use heavy fuels for steam generation; (ii) energy conservation and efficiency; and (iii) greening production through increased investment in clean energy technology, including supporting research on new oil sands extraction processes, as well as the funding of projects that reduce the cost of separating carbon dioxide from other emissions supporting carbon capture and storage. In addition to this action plan, the Provincial Energy Strategy unveiled on December 11, 2008 is expected to, among other things, support the upgrading, refining and petrochemical clusters existing in the Province, market Alberta's energy internationally, review the emission targets and carbon charges applied to large facilities, and promote the innovation of energy technology by encouraging investment in research and development.

British Columbia's *Environmental Assessment Act* became effective June 30, 1995. This legislation rolls the previous processes for the review of major energy projects into a single environmental assessment process with public participation in the environmental review process. On February 27, 2007 the Government of British Columbia unveiled the Energy Plan outlining its strategy towards the environment and which includes targeting for zero net greenhouse gas emissions, promoting new investments in innovation, and becoming the world's leader in sustainable environmental management. For this purpose, on December 18, 2007 proposals were sought for applications to the Innovative Clean Energy Fund, in order to attract new technologies that will help solve energy and environmental issues. With regards to the oil and natural gas industry the objective is to achieve clean energy through conservation and energy efficient practices, whilst competitiveness is advocated in order to attract investment for the development of the oil and natural gas sector. Among the changes to be implemented are: (i) a new of Net Profit Royalty Program; (ii) the creation of a Petroleum Registry; (iii) the establishment of an infrastructure royalty program (combining roads and pipelines); (iv) the elimination of routine flaring at producing wells; (v) the creation of policies and measures for the reduction of emissions; (vi) the development of unconventional resources such as tight gas and coalbed gas; and (vii) new the Oil and Gas Technology Transfer Incentive Program that encourages the research, development and use of innovative technologies to increase recoveries from existing reserves and promotes responsible development of new oil and gas reserves. Furthering these initiatives, the Government of British Columbia introduced on July 1, 2008, revenue-neutral carbon tax legislation that is applied to all fossil fuels used in the Province of British Columbia. The tax would be phased in, and the initial rate would be based on CO2e of $10 per tonne for the first six months of 2009 and $15 per tonne for the last six months of 2009, following $5 per tonne increases on July of every year until 2012. Tax credits and reductions will be used in order to offset the tax revenues that the Government of British Columbia would receive otherwise. On April 3, 2008, the Government of British Columbia introduced the *Greenhouse Gas Reduction (Cap and Trade) Act* which will allow participation in the Western Climate Initiative cap and trade systems being developed. The system establishes a limit on emissions, and allows regulated emitters to buy/sell emission allowances or offset emits. The emitter is obliged to obtain emission allowances (compliance units) equal to the amount of greenhouse gases emitted within a certain period of time, and that are supposed to be surrendered to the Government of British Columbia as compliance proof.

In December 2002, the Government of Canada ratified the Kyoto Protocol ("**Kyoto Protocol**"). The Kyoto Protocol calls for Canada to reduce its greenhouse gas emissions to 6% below 1990 "business-as-usual" levels between 2008 and 2012. Given revised estimates of Canada's normal emissions levels, this target translates into an approximately 40% gross reduction in Canada's current emissions. It is questionable, based on the Updated Action Plan announced by the Federal Government (see below), that the Kyoto Protocol target of 6% below 1990 emission levels will be enforced in Canada. Bill C-288, which is intended to ensure that Canada meets its global climate change obligations under the Kyoto Protocol, was passed by the House of Commons on February 14, 2007. On April 26, 2007, the Federal Government released its Action Plan to Reduce Greenhouse Gases and Air Pollution (the "**Action Plan**") also known as ecoACTION which includes the regulatory framework for air emissions. This Action Plan covers not only large industry, but regulates the fuel efficiency of vehicles and the strengthening of energy standards for a number of energy using products.

The Government of Canada and the Province of Alberta released on January 31, 2008 the final report of the Canada-Alberta ecoENERGY Carbon Capture and Storage Task Force, which recommends among others: (i) incorporating carbon capture and storage into Canada's clean air regulations; (ii) allocating new funding into projects through competitive process; and (iii) targeting research to lower the cost of technology.

In order to strengthen the Action Plan, on March 10, 2008, the Government of Canada released "Turning the Corner – Taking Action to Fight Climate Change" (the "**Updated Action Plan**") which provides some additional guidance with respect to the Government's plan to reduce greenhouse gas emissions by 20% by 2020 and by 60% to 70% by 2050.

The Updated Action Plan is primarily directed towards industrial emissions from certain specified industries including the oil sands, oil and gas and refining. The Updated Action Plan is intended to create a carbon emissions trading market, including an offset system, to provide incentive to reduce greenhouse gas emission and establish a market price for carbon. There are mandatory reductions of 18% from the 2006 baseline starting in 2010 and an additional 2% in subsequent years for existing facilities. This target will be applied to regulated sectors on a facility-specific, sector-wide or corporate basis; in the case of oil sands production, petroleum refining, natural gas pipelines and upstream oil and gas the target will be considered facility-specific (sectors in which the facilities are complex and diverse, or where emissions are affected by factors beyond the control of the facility operator). Emissions from new facilities, which are those built between 2004 and 2011, will be based on a cleaner fuel standard to encourage continuous emissions intensity reductions over time, and will be granted a 3-year grace period during which no emissions intensity targets will apply. Targets will begin to apply on the fourth year of commercial operation and the baseline will be the third year's emissions intensity, with a 2% continuous annual emission intensity improvement required. The definition of new facility also includes greenfield facilities, major expansions constituting more than a 25% increase in a facility's physical capacity, as well as transformations to a facility that involve significant changes to its processes. For upstream oil and gas and natural gas pipelines, it will be applied using a sector-specific approach. For the oil sands, its application will be process-specific, oil sands plants built in 2012 and later, those which use heavier hydrocarbons, up-graders and *in-situ* production will have mandatory standards in 2018 that will be based on carbon capture and storage.

In the following regulated sectors, the Updated Action Plan will apply only to facilities exceeding a minimum annual emissions threshold: (i) 50,000 tonnes of CO_2 equivalent per year for natural gas pipelines; (ii) 3,000 tonnes of CO_2 equivalent per upstream oil and gas facility; and (iii) 10,000 boe/d/company. These proposed thresholds are significantly stricter than the current Alberta regulatory threshold of 100,000 tonnes of CO_2 equivalent per year per facility.

Four separate compliance mechanisms are provided in respect of the above targets: Technology Fund contributions, offset credits, clean development credits and credits for early action. The most significant of these compliance mechanisms, at least initially, will be the Technology Fund and for which regulated entities will be able to contribute in order to comply with emissions intensity reductions. The contribution rate will increase over time, beginning at $15 per tonne for the 2010-12 period, rising to $20 per tonne in 2013, and thereafter increasing at the nominal rate of GDP growth. Contribution limits will correspondingly 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 greenhouse gas 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 mentioned above.

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 cancel the offset credits or bank them for future use or sale.

Under the Updated Action Plan, regulated entities will also be able to purchase credits created through the Clean Development Mechanism of the Kyoto Protocol. 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.

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**.**

Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not currently possible to predict either the nature of those requirements or the impact on the Corporation and its operations and financial condition at this time.

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.

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. 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, operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs. In addition, 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 hazards such as fire, explosion, blowouts, cratering, sour gas releases and spills, each of which could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment or personal injury. In particular, we may explore for and produce sour natural gas in certain areas. An unintentional leak of sour natural gas could result in personal injury, loss of life or damage to property and may necessitate an evacuation of populated areas, all of which could result in liability to us. In accordance with industry practice, we are not fully insured against all of these risks, nor are all such risks insurable. Although we maintain liability insurance in an amount that we consider consistent with industry practice, the nature of these risks is such that liabilities could exceed policy limits, in which event we could incur significant costs. 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.

Global Financial Crisis

Recent market events and conditions, including disruptions in the international credit markets and other financial systems and the deterioration of global economic conditions, have caused significant volatility to commodity prices. These conditions worsened in 2008 and are continuing in 2009, causing a loss of confidence in the broader U.S. and global credit and financial markets and resulting in the collapse of, and government intervention in, major banks, financial institutions and insurers and creating 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. These factors have negatively impacted company valuations and will impact the performance of the global economy going forward.

Petroleum prices are expected to remain volatile for the near future as a result of market uncertainties over the supply and demand of these commodities due to the current state of the world economies, OPEC actions and the ongoing global credit and liquidity concerns.

Refinancing Risk and Increased Debt Service Charges

We have a credit facility from a syndicate of primarily Canadian banks with a maximum borrowing amount of $450 million. The credit facility is 364 day revolving facility subject to a request for an extension of the revolving period for a further 364 days and an annual review by the lenders, at which time a lender can provide an extension of the revolving period or request conversion to a one year term loan. Under the term period, no principal payments would be required until March 4, 2010.

As a result of closing the Rider Arrangement on March 4, 2008 and the concurrent amendment of our credit facility, the 364 day revolving period of our credit facility ended on March 3, 2009. We and the bank syndicate agreed to an extension of the revolving period from March 3, 2009 until April 30, 2009 in order to return us to our historical annual review date. As part of this extension, the credit facility borrowing rates were amended to current market rates and all other terms of the credit facility remained unchanged. Our bank syndicate is in the process of completing their annual review of our year end reserves and financial information.

In normal circumstances, borrowers such as us rely on the fact that the banks will honour their contractual commitments to fund draws as required. In today's economic environmental there is a risk that our lender may not honour draws requested by us and thereby effect our ability to maintain our capital expenditure program. Although we have no reason to believe that we will be unable to extend our credit facility after April 30, 2009, if not renewed, the facility will be available on a non-revolving basis for a period of 364 days thereafter, at which time the facility would be due and payable. There is also a risk that the credit facility will not be renewed for the same amount or on the same terms. Variations in interest rates and scheduled principal repayments could result in significant changes in the amount required to be applied to debt service. Furthermore, any of these events could affect our ability to fund ongoing operations.

We are required to comply with covenants under the credit facility. In the event that we do not comply with covenants under the credit facility, our access to capital could be restricted or repayment could be required on an accelerated basis by our lender. The lender has security over substantially all of our assets. If we become unable to pay our debt service charges or otherwise commit an event of default such as breach of our financial covenants, the lender may foreclose on or sell our working interests in our properties.

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 its 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. 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 our 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.

Petroleum 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 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.

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 business may require substantial management effort, time and resources and may divert management's focus from other strategic opportunities and operational matters. 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 our non-core assets, if disposed of, could be expected to realize less than their carrying value on our financial statements.

Operational Dependence

Other companies operate some of the assets in which we have an interest. As a result, we will have limited ability to exercise influence over the operation of those assets or their associated costs, which could adversely affect our financial performance. Our return on assets operated by others 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.

Project Risks

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

- the availability of processing capacity;
- the availability and proximity of pipeline capacity;
- the availability of storage capacity;
- the 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.

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 price, 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, any 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.

Kyoto Protocol

Canada is a signatory to the United Nations Framework Convention on Climate Change and has ratified the Kyoto Protocol established thereunder to set legally binding targets to reduce nationwide emissions of carbon dioxide, methane, nitrous oxide and other so-called "greenhouse gases". Our exploration and production facilities and other operations and activities emit greenhouse gases which will require us to comply with the new regulatory framework announced on March 10, 2008 by the Federal Government which is intended to force large industries to reduce emissions of greenhouse gases, in addition to the proposed *Clean Air Act* (Canada) of 2006 and Alberta's recently enacted *Climate Change and Emissions Management Act* and *Specified Gas Emitters Regulation*. The direct or indirect costs of these regulations may have a material adverse effect on our business, financial condition, results of operations and prospects. See "*Industry Conditions – Environmental Regulation*".

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. There has been much public debate with respect to Canada's ability to meet these targets and the Government's strategy or alternative strategies with respect to climate change and the control of greenhouse gases. Implementation of strategies for reducing greenhouse gases whether to meet the limits required by the Kyoto Protocol or as otherwise determined, could have a material impact on the nature of oil and natural gas operations. Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not possible to predict the impact on us and our operations and financial condition. See "*Industry Conditions – Environmental 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 effected 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 although the Canadian dollar has recently decreased from such levels. Material increases in the value of the Canadian dollar negatively impact our production revenues. Future Canadian/United States exchange rates could accordingly impact the future value of our reserves as determined by independent evaluators.

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

An increase in interest rates could result in a significant increase in the amount we pay to service debt, which could negatively impact the market price of the Common Shares.

Substantial Capital Requirements

We anticipate making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. If our revenues or reserves decline, we may not have access to the capital necessary to undertake or complete future drilling programs. In addition, uncertain levels of near term industry activity coupled with the present global credit crisis exposes us to additional access to capital risk. 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. The inability to access sufficient capital for our operations could have a material adverse effect on our financial condition, results of operations and prospects.

Additional Funding Requirements

Our cash flow from our reserves may not be sufficient to fund our ongoing activities at all times. From time to time, we may require additional financing in order to carry out our oil and gas acquisition, exploration and development activities. Failure to obtain such financing on a timely basis could cause us to forfeit our interest in certain properties, miss certain acquisition opportunities and reduce or terminate our operations. If our revenues from our reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect our ability to expend the necessary capital to replace our reserves or to maintain our production. If our cash flow from operations is not sufficient to satisfy our capital expenditure requirements, there can be no assurance that additional debt or equity financing will be available to meet these requirements or, if available, on terms acceptable to us. Continued uncertainty in domestic and international credit markets could materially affect our ability to access sufficient capital for our capital expenditures and acquisitions, and as a result, may have a material adverse effect on our ability to execute our business strategy and on our business, financial condition, results of operations and prospects.

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.

Commodity Price Risk Management

From time to time we may enter into agreements to receive fixed prices on our oil and natural gas production to offset the risk of revenue losses if commodity prices decline; however, if commodity prices increase beyond the levels set in such agreements, we will not benefit from such increases and we may nevertheless be obligated to pay royalties on such higher prices, even though not received by it, after giving effect to such agreements. Similarly, from time to time we may enter into agreements to fix the exchange rate of Canadian to United States dollars in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to the United States dollar; however, if the Canadian dollar declines in value compared to the United States dollar, we will not benefit from the fluctuating exchange rate.

Availability of Drilling Equipment and Access

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

Title to Assets

Although title reviews may be conducted prior to the purchase of oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise to defeat our claim which may have a material adverse effect on our business, financial condition, results of operations and prospects.

Reserve Estimates

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and natural gas liquids reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth 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.

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, 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 will 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 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 it 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.

Dividends

We have not paid any dividends on our outstanding shares. Payment of dividends in the future will be dependent on, among other things, the cash flow, results of operations and financial condition, the need for funds to finance ongoing operations and other considerations as the board of directors considers relevant.

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. An action has been commenced on behalf of the Sunchild First Nation ("**Sunchild**") against the Provincial Crown, various provincial ministries, the Energy Resources Conservation Board and numerous respondent oil and gas companies. Although we have not been named in the action, we have interests in the area in question. Sunchild First Nation seeks judicial review of various Crown and Energy Resources Conservation Board decisions issued since June 30, 2008 in relation to what is claimed to be their traditional land, and which appears to include a significant portion of the foothills area of Alberta, on the basis that the Crown failed to properly consult and accommodate Sunchild First Nation, in the context of issuing licences to the oil and gas companies, forestry and coal companies within Sunchild First Nation's reserve and claimed foothills traditional lands area since the end of June, 2008. While the proceedings could result in a change in the consultative and decision-making processes with respect to the granting of Crown rights and other licences in respect of the area or some portion of it, it is too early to assess the likelihood of such a possibility or its impact on our future operations in this area.

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 or officers 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 ABCA. See "*Directors and Officers – Conflicts of Interest*".

Reliance on Key Personnel

Our success depends in large measure on certain key personnel. The loss of the services of such key personnel may have a material adverse effect on our business, financial condition, results of operations and prospects. We do not have any key person insurance in effect. The contributions of the existing management team to the immediate and near term operations 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 the management.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

There are no legal proceedings that we are or was 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 within the last fiscal year and in any proposed transaction which has materially affected or is 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 $450 million credit facility with a syndicate of Canadian chartered banks, which agreement is described in Note 12 to our consolidated financial statements for the year ended December 31, 2008, which note is incorporated by reference herein. 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.

We used KPMG LLP for external audit and tax advisory services for the fiscal year ended December 31, 2008. KPMG LLP has advised us that they are independent with respect to us 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 is contained in our proxy materials relating to our annual and special shareholders meeting held on May 8, 2008 and will be contained in our proxy materials relating to our annual shareholders meeting to be held on May 5, 2009. Additional financial information is contained in our consolidated financial statements for the year ended December 31, 2008 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, 2008, 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. However, any variation should be consistent with the fact that reserves are categorized according to the probability of their recovery.

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

(signed) "*Alex G. Verge*"
Alex G. Verge
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 5, 2009

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, 2008. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2008, 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, 2008, 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 10, 2009	Canada	-	$1,350,664	-	$1,350,664

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.

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. However, any variation should be consistent with the fact that reserves are categorized according to the probability of their recovery.

Executed as to our report referred to above:

GLJ Petroleum Consultants Ltd., Calgary, Alberta, Canada, March 3, 2009

"(signed)"

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 NuVista Energy Ltd. ("**NuVista**") to whom the Board 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 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 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 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.
- 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.

- 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, 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 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 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, the Committee shall:

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

  - recommend to the Board 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.

Approved by the Board: March 6, 2008