PACIFIC RODERA ENERGY INC.

ANNUAL INFORMATION FORM

FOR THE YEAR ENDED

DECEMBER 31, 2007

March 28, 2008

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ABBREVIATIONS

Oil and Natural Gas Liquids		Natural Gas	
Bbl	barrel	Mcf	thousand cubic feet
Boe	barrels of oil equivalent	MMcf	million cubic feet
Mbbls	thousand barrels	Mcf/d	thousand cubic feet per day
MMbbls	million barrels	Mmcf/d	million cubic feet per day
Mstb	1,000 stock tank barrels	Mmbtu	million British Thermal Units
Bbls/d	barrels per day	Bcf	billion cubic feet
Boe/d	barrels of oil equivalent per day	GJ	gigajoule
NGLs	natural gas liquids	M	Thousand
STB	standard stock tank barrels	Mm	Million

Other

AECO	EnCana Corp.'s natural gas storage facility located at Suffield, Alberta.
API	American Petroleum Institute
^{o}API	an indication of the specific gravity of crude oil measured on the API gravity scale.
ARTC	Alberta Royalty Tax Credit
BOE	barrel of oil equivalent of natural gas and crude oil on the basis of 1 BOE for 6 Mcf of natural gas (this conversion factor is an industry accepted norm and is not based on either energy content or current prices)
BOE/d	barrel of oil equivalent per day
m^3	cubic metres
MBOE	1,000 barrels of oil equivalent
$000s	thousands of dollars
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade

Measurements expressed in Boe's may be misleading, particularly if used in isolation. A Boe conversion ratio of 6 mcf:1 Bbl is based on an approximate energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

CONVERSIONS

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 oil	6.290
feet	metres	0.305
metres	feet	3.281
miles	kilometres	1.609
kilometres	miles	0.621
acres (Alberta)	hectares	0.400
hectares (Alberta)	acres	2.500

CERTAIN DEFINITIONS

In this Annual Information Form, the following words and phrases have the following meanings, unless the context otherwise requires:

"**ABCA**" means *Business Corporations Act* (Alberta);

"**Board of Directors**" means the board of directors of the Company;

"**COGE Handbook**" means the Canadian Oil and Gas Evaluation Handbook prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum;

"**Common Shares**" means the common shares in the capital of the Company;

"**Company**" or "**Pacific Rodera**" means Pacific Rodera Energy Inc., the corporation continued into Alberta under the ABCA;

"**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.

"**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, geo-chemical, 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.

"**GLJ**" means GLJ Petroleum Consultants Ltd.;

"**GLJ Report**" means the report of GLJ dated February 8, 2008 with a preparation date of January 31, 2008 evaluating the crude oil, natural gas liquids and natural gas reserves of the Company as at December 31, 2007;

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

"**Preferred Shares**" means the preferred shares in the capital of the Company; and

"**TSXV**" means the TSX Venture Exchange Inc.

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 stated, information in this Annual Information Form is as at the end of the Company's most recently completed financial period, being December 31, 2007.

Unless otherwise stated, all dollar amounts herein are in Canadian dollars.

FORWARD-LOOKING STATEMENTS

Certain of the statements contained herein including, without limitation, financial and business prospects and financial outlook, reserve and production estimates, drilling and re-completion plans, timing of drilling, re-completion and tie-in of wells, productive capacity of wells and productive capacity of wells and capital expenditures and the timing thereof may be forward-looking statements. Words such as "may", "will", "should", "could", "anticipate", "believe", "expect", "intend", "plan", "potential", "continue" and similar expressions may be used to identify these forward-looking statements. These statements reflect management's current beliefs and are based on information currently available to management. Forward-looking statements involve significant risk and uncertainties. A number of factors could cause actual results to differ materially from the results discussed in the forward-looking statements including, but not limited to, risks associated with oil and gas exploration, development, exploitation, production, marketing and transportation, loss of markets, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other producers, inability to retain drilling rigs and other services, the successful completion of acquisitions and dispositions, incorrect assessment of the value of acquisitions, failure to realize the anticipated benefits of acquisitions or dispositions, delays resulting from or inability to obtain required regulatory approvals, joint venture arrangements and ability to access sufficient capital from internal and external sources and the risk factors outlined under "Risk Factors" and elsewhere herein. The recovery and reserve estimates of Pacific Rodera's reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. As a consequence, actual exhaustive results may differ materially from those anticipated in the forward-looking statements. Readers are cautioned that the foregoing list of factors is not exhausted. Risks relating to our joint venture arrangements include, but are not limited to the acquisition of surface rights, entering into definitive agreements on matters relating to the joint venture and risks of disputes arising in connection with such joint ventures. Additional information on these and other factors that could effect Pacific Rodera's operations and financial results are included in documents on file with Canadian securities regulatory authorities and may be accessed through the SEDAR website (www.sedar.com). Although the forward-looking statements contained herein are based upon what management believes to be reasonable assumptions, management cannot assure that actual results will be consistent with these forward-looking statements. Investors should not place undue reliance on forward-looking statements. These forward-looking statements are made as of the date hereof and the Company assumes no obligation to update or review them to reflect new events or circumstances except as required by applicable securities laws.

Forward-looking statements and other information contained herein concerning the oil and gas industry and the Company's general expectations concerning this industry is based on estimates prepared by management using data from publicly available industry sources as well as from reserve reports, market research and industry analysis and on assumptions based on data and knowledge of this industry which the Company believes to be reasonable. However, this data is inherently imprecise, although generally indicative of relative market positions, market shares and performance characteristics. While the Company is not aware of any misstatements regarding any industry data presented herein, the industry involves risks and uncertainties and is subject to change based on various factors.

BACKGROUND

Pacific Rodera is an Alberta based publicly traded junior oil and gas company engaged in the exploration, development and production of oil and natural gas in Western Canada.

Pacific Rodera's address is 650, 700 - 2nd Street SW, Calgary, Alberta T2P 2W1 and its registered office is located at Suite 1400, 350 – 7th Avenue S.W., Calgary, Alberta T2P 3N9.

Pacific Rodera is a reporting issuer in the Provinces of British Columbia and Alberta and its Common Shares trade on the TSXV under the symbol "PRD".

Pacific Rodera currently has no subsidiaries.

DESCRIPTION OF THE BUSINESS AND GROWTH STRATEGIES

General

The Company's focus is to create a culture (i) that seeks rewards from exploration success, (ii) that is cost conscious and (iii) where the management and employees are at risk to the outcome of the Company so that they are aligned as closely as possible to the shareholders. In this regard, the Company intends to encourage the maintenance of high levels of employee ownership of the Company. The management team has invested a significant portion of its net worth in the Company. To date, directors and officers of the Company have invested approximately $12 million in Pacific Rodera in the past 16 months and hold, directly or indirectly, approximately 25% of the common shares. See "Recent Developments". Management of the Company has extensive experience in oil and gas exploration and development in Western Canada. See "Directors and Officers".

Growth Strategy

Pacific Rodera has approximately 97,400 net undeveloped acres of land with core areas of operation currently focused in Central Alberta, Northeastern British Columbia and the Northwest Territories. Pacific Rodera intends to look for acquisition candidates in the 500 to 5,000 BOE range with significant exploitation, exploration and development upside and development dollars already expended for infrastructure. Pacific Rodera can then leverage its assets with its capital. Management believes that many public and private oil and gas companies are not currently well capitalized, and that it is apparent access to capital will be very difficult for most companies in the near to mid-term. The Company's business plan is to seek acquisitions and farm-ins that represent large working interests as operators in a limited number of core areas with large contiguous land positions. The Company expects to attract companies and partners who are of like mind to build a mid-size exploration and development company.

GENERAL DEVELOPMENT OF THE BUSINESS

Historical Overview

The Company was formed by the amalgamation in British Columbia of Pacific Royal Ventures Ltd. ("**Pacific**") and Rodera Diamond Corp. ("**Rodera**"), pursuant to an Amalgamation Agreement dated effective as of March 1, 1999, under the name "Pacific Rodera Ventures Inc." Each of the amalgamating companies were involved in the acquisition, exploration and development of resource properties. The common shares of Pacific and Rodera were exchanged for common shares of the Company on the basis of five Pacific common shares for each common share of the Company and eight Rodera common shares for each common share of the Company. On June 21, 2004, Pacific Rodera Ventures Inc. changed its name to Pacific Rodera Energy Inc.

The Company is a natural resource exploration company, primarily engaged in the acquisition, exploration and development of petroleum and natural gas in Western Canada. The Company's principal oil and gas property interests arise from a joint venture formed pursuant to a letter agreement dated April 30, 1997 and a subsequent formal joint venture agreement dated October 21, 1997 among Pacific, Rodera and International Frontier Resources Corp., a Calgary based exploration company. As a result of the amalgamation, the Company continued with the rights and obligations of Pacific and Rodera under the joint venture agreement. Pursuant to the joint venture agreement, the Company may earn working interests ranging from 6.625% to 12.5% in International Frontier Resources' interest in various oil and gas prospects located in the Northwest Territories.

The Company also holds various working interests in oil and gas properties located in northeastern British Columbia and interests in oil and gas prospects located in Central Alberta.

2005 – 2007

Investments by Michael Greenwood

On December 5, 2006 and January 8, 2007, the Company completed non brokered private placements of 11,600,000 units of the Company to Mr. Michael Greenwood and his associates at a price of $0.32 per unit, for gross proceeds of $3,712,000. 11,000,000 of the units consisted of 11,000,000 Common Shares issued on a "flow-through basis" and 5,500,000 common share purchase warrants. 600,000 of the units consisted of 600,000 Common Shares and 300,000 common share purchase warrants. Each warrant entitles the holder to purchase an additional Common Share at an exercise price of $0.40 for a period of two years from the date of issue.

Pursuant to these private placements, Mr. Greenwood became a "control person" of the Company with an approximate equity interest of 19.9% and was granted the right to participate in future financings of the Company to maintain his approximate 19.9% equity interest. The TSXV required Pacific Rodera to seek shareholder approval for these private placements, which approval was obtained at the Company's annual and special meeting of shareholders on April 25, 2007. Effective January 8, 2007, Mr. Greenwood was appointed a Director, Chairman and Chief Executive Officer of Pacific Rodera.

Private Placements of 45,000,000 Units

On March 2, 2007, the Company closed a private placement of 42,620,082 units at a price of $0.60 per unit for gross proceeds of $25,572,049 led by Canaccord Capital Corporation on a best efforts agency basis. Each unit consisted of one Common Share and one half of one non-transferable common share purchase warrant. Each whole warrant entitles the holder upon exercise, to purchase an additional common share at a price of $0.70 per share. The warrants expire two years from the closing date unless (i) during the period commencing on the date that is four months following the closing date and ending on the second anniversary of the closing date, the daily volume weighted average trading price of the Common Shares on the TSXV exceeds $1.00 for each day of a period of 20 consecutive trading days, and (ii) the Company gives the holders of the warrants written notice of such occurrence within 30 days of such occurrence, in which case the warrants will expire on the 30th day following the giving of such notice. In connection with the March 2, 2007 private placement of units, Canaccord was issued an option, exercisable within 30 days following closing, to offer for sale up to an additional 3,333,000 units on the same terms. On March 14, 2007, Canaccord exercised its over allotment option pursuant to which the Company issued 2,379,918 units at a price of $0.60 per unit for gross proceeds of $1,427,951.

Amendments to the Articles of the Company

On April 25, 2007 at the Company's annual and special meeting, shareholders of Pacific Rodera approved amendments to the Company's articles of continuance to (a) change the maximum number of Common Shares that the Company is authorized to issue from 200,000,000 Common Shares to an unlimited number of Common Shares; (b) create a new class of shares in the capital of the Company designated as "Preferred Shares", issuable in series; and (c) change the rights, privileges, restrictions and conditions attached to the Common Shares. These articles of amendment were filed on April 25, 2007. Additionally, shareholders of the Company approved the private placements to Mr. Greenwood, as described above, and approved a new stock option plan for the Company.

New Management Appointments

On September 5, 2007, the Company announced that it appointed Mr. Mark Hornett as President, Chief Operating Officer and a member of the Board of Directors; Mr. Roger Harman as Chief Financial Officer; Mr.

Andrew Arthur as Vice President, Exploration; Mr. Douglas J. Crawford as Vice President, Production; and Mr. David J.L. Williams Senior Vice President, Corporate Development and Investor Relations.

On October 3, 2007, Messrs. Hornett, Harman, Arthur and Crawford or their associates subscribed for an aggregate of 3,400,000 units of the Company at a price of $0.50 per unit for gross proceeds of $1.7 million. Each unit consisted of one flow through common share and one half of one non transferable common share purchase warrant. Each whole warrant entitles the holder upon exercise, to purchase an additional Common Share at a price of $0.70 per share. The warrants expire March 2, 2009 unless (i) during the period commencing on the date that is four months following the closing date and ending on the second anniversary of the closing date, the daily volume weighted average trading price of the Common Shares on the TSXV exceeds $1.00 for each day of a period of twenty consecutive trading days, and (ii) the Company gives the holders of the warrants written notice of such occurrence within thirty days of such occurrence, in which case the warrants will expire on the 30th day following the giving of such notice.

On March 20, 2008, the Company announced the appointment of John Nesbitt as Vice President, Land effective April 1, 2008.

Increased Working Interest in North West Territories

On October 5, 2007 Pacific Rodera increased its working interest in the NWT Exploration Licence 423 to 10 per cent and its ownership in the NWT Exploration Licence 397 to 10.87 per cent. A second significant discovery licence has been received for EL 397 respecting the Summit Creek B-44 well which tested at rates of approximately 20 million cubic feet per day of natural gas and in excess of 6,000 barrels per day of light oil and condensate.

Joint Venture Agreement and Land Acquisitions for Central Alberta

In December 2007, Pacific Rodera entered into a joint venture agreement to develop lands in Central Alberta. Pursuant to this agreement, Pacific Rodera will be the operator of a multi-well drilling program on a 50/50 basis. To date, Pacific Rodera has purchased 3,004 acres on a gross basis at Crown land sales to support these drilling locations.

Other Recent Developments

First Nations Memorandum of Agreement

In February 2008. Pacific Rodera entered into a memorandum of agreement ("**MOA**") with several First Nation bands in Saskatchewan relating to the acquisition, exploration and development of prospective lands located in Saskatchewan. Pursuant to the First Nations MOA, these bands are requesting the Saskatchewan government to impose an 18-month moratorium on the sale of the Crown-owned mineral rights associated with approximately 88,000 acres of land located within the Bakken play area of SE Saskatchewan. Under the MOA, the First Nations bands have granted Pacific Rodera the right to explore and develop all oil and gas reserves located on the lands in which the First Nations acquire rights. One of the requirements for the First Nations to acquire the subsurface rights is that they first acquire the surface rights from the present land owners. Because of this requirement, Pacific Rodera expects the actual land acquired will be materially less then the 88,000 acres. The First Nations bands have agreed that they will continue to negotiate exclusively with Pacific Rodera on the acquisition, exploration and development of these lands.

Sale of Trutch Working Interest

On March 20, 2008, Pacific Rodera announced that it has agreed to sell its 8% working interest in its Trutch property for $2.2 million cash subject to customary price adjustments. The production attributed to Pacific Rodera's working interest in these properties represents approximately 45 boes of production per day. The sale of such a low working interest is consistent with Pacific Rodera’s objective of being focused in high working interest, operated properties. Completion of the sale is subject to the approval of the TSX Venture Exchange and consent of the purchaser's lenders which is expected to be received.

Significant Acquisitions

There were no significant acquisitions completed by the Company during the 12 month period ended November 30, 2007 or the one month period ended December 31, 2007, being the two most recently completed financial years of the Company.

DISCLOSURE OF RESERVES DATA

The statement of reserves data and other oil and gas information set forth below is dated March 28, 2008 (the "**Statement**"). The effective date of the Statement is December 31, 2007 and the preparation date of the Statement is January 31, 2008.

The reserve disclosure presented below conforms to the requirements of National Instrument 51-101 — Standards of Disclosure for Oil and Gas Activities ("**NI 51-101**"). Additional information not required by NI 51-101 has been presented to provide continuity which Pacific Rodera's management believes is important to readers of this information.

Principal Properties

A summary description of the principal oil and natural gas properties of Pacific Rodera is set out below.

Reported production reflects the Company's net working interest production share. Unless otherwise specified, gross and net acres and well count information are as at December 31, 2007.

As at December 31, 2007, the Company focused its oil and gas field operations in Alberta, British Columbia and the Northwest Territories.

Trutch, British Columbia

The Trutch properties are located onshore approximately 200 kilometres northeast of Fort St. John, British Columbia. Pacific Rodera has an average working interest of 8% in 19,500 (1,550 net) acres of land in this area. There are 11 (1 net) producing natural gas wells which commenced production in May 2006 and 6 (0.4 net) non producing natural gas wells that are currently being evaluated.

During the year ended December 31, 2007 3 (0.27 net) wells were drilled in this area. As well, Pacific Rodera and the other members of the consortium completed the construction of the production infrastructure facilities and a permanent access road to the properties.

On March 20, 2008, Pacific Rodera announced that it has agreed to sell its 8% working interest in its Trutch property. See *General Development of the Business – Other Recent Developments – Sale of Trutch Working Interest* for further details.

Central MacKenzie Valley, Northwest Territories

The Central MacKenzie Valley properties are located onshore approximately 100 kilometres southwest of Norman Wells, Northwest Territories. Pacific Rodera has an average working interest of 10.9% in 864,000 (94,500 net) acres of land in this area. The Company has no producing wells in this area.

Alberta

The Company's Alberta properties are located in central Alberta. Pacific Rodera has an average working interest of 50% in 3,004 (1,502 net) acres of land in this area. The Company has no producing wells in this area.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

Introduction

On March 20, 2008, Pacific Rodera announced that it has agreed to sell its 8% working interest in its Trutch property. See *General Development of the Business – Other Recent Developments – Sale of Trutch Working Interest* for further details. Readers are cautioned that the figures below relating to Pacific Rodera's reserves, the net present value of future net revenue attributable to such reserves and certain other information will change considerably if the Company completes this sale as planned.

Disclosure of Reserves Data

The tables below summarize Pacific Rodera's reserves and the net present value of future net revenue attributable to such reserves as evaluated by GLJ Petroleum Consultants Ltd. ("**GLJ**") based on forecast price and cost estimates. In accordance with NI 51-101, GLJ submitted a report dated February 8, 2008 with a preparation date of January 31, 2008 (the "**GLJ Report**") evaluating Pacific Rodera's reserves with an effective date of December 31, 2007. The information below is prepared in accordance with standards contained in the Canadian Oil and Gas Evaluation Handbook (the "**COGE Handbook**") and the reserves definitions contained in NI 51-101 and the COGE Handbook. The following tables summarize the data contained in the GLJ Report and as a result may contain slightly different numbers than such report due to rounding. Also due to rounding, certain columns may not add exactly.

The net present value of future net revenue attributable to Pacific Rodera's reserves is stated without provision for interest costs and general and administrative costs, but after providing for estimated royalties, production costs, development costs, other income, future capital expenditures, and well abandonment costs for only those wells assigned reserves by GLJ. It should not be assumed that the undiscounted or discounted net present value of future net revenue attributable to Pacific Rodera's reserves estimated by GLJ represent the fair market value of those reserves. Other assumptions and qualifications relating to costs, prices for future production and other matters are summarized herein. Actual reserves may be greater than or less than the estimates provided herein.

The GLJ Report is based on certain factual data supplied by Pacific Rodera and GLJ's opinion of reasonable practice in the industry. GLJ accepted this data as presented and neither title searches nor field inspections were conducted by GLJ.

Reserves Data – Forecast Prices and Costs

Reserves – Forecast Prices and Costs

	Gross Reserves			Net Reserves		
	Natural Gas	Natural Liquids	Oil Equivalent	Natural Gas	Natural Gas Liquids	Oil Equivalent
	Mmcf	Mbbls	Mbbl	Mmcf	Mbbls	Mbbl
Proved						
Producing	540	9	99	496	8	91
Developed Non-Producing	49	1	9	48	1	9
Undeveloped	107	2	20	101	2	18
Total Proved	696	12	128	645	10	118
Total Probable	334	6	62	311	5	57
Total Proved plus Probable	1030	18	190	956	15	174

Note:

(1) Columns may not add due to rounding.

Net Present Value of Future Net Revenue – Forecast Prices and Costs

	Before Future Income Tax Expenses and Discounted at:				
	0%	5%	10%	15%	20%
	(M$)	(M$)	(M$)	(M$)	(M$)
Proved					
Producing	2,216	1,868	1,621	1,437	1,296
Developed Non-Producing	160	119	90	67	50
Undeveloped	338	259	200	156	121
Total Proved	2,713	2,246	1,911	1,660	1,467
Total Probable	1,253	887	659	507	400
Total Proved plus Probable	3,966	3,133	2,569	2,167	1,868

Note:

(1) Columns may not add due to rounding.

	After Future Income Tax Expenses and Discounted at:				
	0%	5%	10%	15%	20%
	(M$)	(M$)	(M$)	(M$)	(M$)
Proved					
Producing	2216	1868	1621	1437	1296
Developed Non-Producing	160	119	90	67	50
Undeveloped	338	259	200	156	121
Total Proved	2713	2246	1911	1660	1467
Total Probable	1253	887	659	507	400
Total Proved plus Probable	3966	3133	2569	2167	1868

Note:

(1) Columns may not add due to rounding.

Additional Information Concerning Future Net Revenue – Forecast Prices and Costs

	Revenue	Royalties	Operating Costs	Development Costs	Abandonment Costs	Future Net Revenue Before Income Taxes	Future Income Tax Expenses	Net Revenue After Future Income Taxes
	(M$)	(M$)	(M$)	(M$)	(M$)	(M$)	(M$)	(M$)
Total Proved	6322	532	2723	294	59	2713	0	2713
Total Proved plus Probable	9550	795	4182	528	78	3966	0	3966

Future Net Revenue by Production Group – Forecast Case

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) (M$)	UNIT VALUE ($/Mcf)
Proved Reserves	Natural Gas (including by-products but excluding solution gas and by-products from oil wells)	1,911	$2.71/Mcf
	TOTAL	1,911	$16.23/boe
Proved Plus Probable Reserves	Natural Gas (including by-products but excluding solution gas and by-products from oil wells)	2,569	$2.45/Mcf
	TOTAL	2,569	$14.73/boe

Pricing Assumptions – Forecast Prices and Costs

GLJ employed the following inflation rate, exchange rate and pricing assumptions as of December 31, 2007 in estimating the Company's reserves data using forecast prices and costs.

Summary of Pricing and Inflation Rate Assumptions as of December 31, 2007 - Forecast Prices and Costs

Natural Gas Liquids
Price Forecast
Effective January 1, 2008

			Alberta Natural Gas Liquids (Then Current Dollars)			
Year	Inflation %	Bank of Canada Average Noon Exchange Rate $US/$Cdn	Spec Ethane $Cdn/Bbl	Edmonton Propane $Cdn/Bbl	Edmonton Butane $Cdn/Bbl	Edmonton Pentanes Plus $Cdn/Bbl
2008 Q1	2.0	1.000	22.73	58.30	72.88	92.92
2008 Q2	2.0	1.000	22.73	58.30	72.88	92.92
2008 Q3	2.0	1.000	21.01	58.30	72.88	92.92
2008 Q4	2.0	1.000	24.46	58.30	72.88	92.92
2008	2.0	1.000	22.73	58.30	72.88	92.92
2009	2.0	1.000	25.49	55.74	69.68	88.84
2010	2.0	1.000	25.66	53.18	66.48	84.76
2011	2.0	1.000	25.66	51.90	64.88	82.72
2012	2.0	1.000	25.66	51.90	64.88	82.72
2013	2.0	1.000	25.66	51.90	64.88	82.72
2014	2.0	1.000	26.35	51.90	64.88	82.72
2015	2.0	1.000	26.94	51.90	64.88	82.72
2016	2.0	1.000	27.52	51.91	64.89	82.74
2017	2.0	1.000	28.11	52.97	66.21	84.42
2018+	2.0	1.000	ESCALATE AT 2 % PER YEAR			

Historical futures contract price is an average of the daily settlement price of the near month contract over the calendar month.

Natural Gas and Sulphur
Price Forecast
Effective January 1, 2008

Year	NYMEX Futures Contract Last 3 day Price Constant 2008 $US/mmbtu	NYMEX Futures Contract Last 3 day Price Then Current $US/mmbtu	Midwest Price @ Chicago Then Current $US/mmbtu	AECO/N IT Spot Then Current $US/mmbtu	Sumas Sport $US/mmbtu	British Columbia Westcoast Station 2 $/mmbtu	British Columbia Spot Plant Gate $/mmbtu	Sulphur FOB Vancouver $US/LT	Alberta Sulphur Plant Gate $Cdn/LT
2008 Q1	7.50	7.50	7.40	6.75	6.90	6.55	6.35	120.00	77.00
2008 Q2	7.50	7.50	7.40	6.75	6.90	6.55	6.35	120.00	77.00
2008 Q3	7.00	7.00	6.90	6.25	6.40	6.05	5.86	120.00	77.00
2008 Q4	8.00	8.00	7.90	7.25	7.40	7.05	6.85	120.00	77.00
2008	7.50	7.50	7.40	6.75	6.90	6.55	6.35	120.00	77.00
2009	8.09	8.25	8.20	7.55	7.70	7.35	7.15	90.00	47.00
2010	7.93	8.25	8.25	7.60	7.70	7.40	7.20	70.00	27.00
2011	7.77	8.25	8.35	7.60	7.70	7.40	7.20	70.00	27.00
2012	7.62	8.25	8.35	7.60	7.70	7.40	7.20	70.00	27.00
2013	7.47	8.25	8.35	7.60	7.70	7.40	7.20	70.00	27.00
2014	7.50	8.45	8.55	7.80	7.90	7.60	7.40	71.40	28.40
2015	7.50	8.62	8.72	7.97	8.07	7.77	7.57	72.83	29.83
2016	7.50	8.79	8.89	8.14	8.24	7.94	7.73	74.28	31.28
2017	7.50	8.96	9.06	8.31	8.41	8.11	7.90	75.77	32.77
2018	7.50	9.14	9.24	8.48	8.58	8.27	8.06	77.29	33.43
2019+	7.50	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr

Reconciliation of Changes in Reserves and Future Net Revenue

Reserves Reconciliation by Principal Product Type - Forecast Prices and Costs

The following table sets forth a reconciliation of the Company's gross reserves as at December 31, 2007 derived from the GLJ Report using forecast prices and cost estimates, reconciled to the gross reserves of the Company as at November 30, 2006 based on forecast prices and cost estimates.

	Natural Gas (Mmcf)	Natural Gas Liquids (Mbbl)	Oil Equivalent (Mboe)
Gross Proved			
Opening balances – November 30, 2006	658	12	122
Extensions	197	4	36
Improved recovery	0	0	0
Technical revisions	0	-1	0
Discoveries	0	0	0
Acquisitions	0	0	0
Dispositions	0	0	0
Economic factors	0	0	0
Production	-160	-3	-30
Closing balances –December 31, 2007	696	12	128
Gross Probable			
Opening balances – November 30, 2006	396	9	75
Extensions	128	2	24
Improved recovery	0	0	0
Technical revisions	-189	-5	-37
Discoveries	0	0	0
Acquisitions	0	0	0
Dispositions	0	0	0
Economic factors	0	0	0
Production	0	0	0
Closing balances – December 31, 2007	334	6	62
Gross Proved plus Probable			
Opening balances – November 30, 2006	1054	21	197
Extensions	325	6	60
Improved recovery	0	0	0
Technical revisions	-189	-5	-37
Discoveries	0	0	0
Acquisitions	0	0	0
Dispositions	0	0	0
Economic factors	0	0	0
Production	-160	-3	-30
Closing balances – December 31, 2007	1030	19	190

Note:

(1) Columns may not add due to rounding.

Additional Information Relating to Reserves Data

Undeveloped Reserves

The following discussion generally describes the basis on which Pacific Rodera attributes proved and probable undeveloped reserves and its anticipated plans for developing those undeveloped reserves.

Proved Undeveloped Reserves

Proved undeveloped reserves are generally those reserves related to wells that have been tested and not yet tied in, wells drilled near the end of the fiscal year or wells further away from gathering systems. In addition, such reserves may relate to planned infill drilling locations. The majority of these reserves are planned to be on-stream within a two year timeframe.

The following tables set forth the proved undeveloped reserves, each by product type, attributed to Pacific Rodera's assets for the years ended November 30 2005, November 30, 2006 and December 31, 2007 and, in the aggregate, before that time based on forecast prices and costs.

Product Type	Units	Prior	2005	2006	2007	Total
	Company Gross Reserves First Attributed By Year					
Proved Undeveloped						
Natural Gas	MMcf	0	0	53	54	107
Natural Gas Liquids	Mbbl	0	0	1	1	2
Total: Oil Equivalent	Mbbl	0	0	10	10	20

Probable Undeveloped Reserves

Probable undeveloped reserves are generally those reserves tested or indicated by analogy to be productive, infill drilling locations and lands contiguous to production. The majority of these reserves are planned to be on-stream within a two year timeframe.

The following tables set forth the probable undeveloped reserves, each by product type, attributed to Pacific Rodera's assets for the years ended November 30 2005, November 30, 2006 and December 31, 2007 and, in the aggregate, before that time based on forecast prices and costs.

Product Type	Units	Prior	2005	2006	2007	Total
	Company Gross Reserves First Attributed By Year					
Probable Undeveloped						
Natural Gas	MMcf	0	0	70	73	143
Natural Gas Liquids	Mbbl	0	0	2	1	3
Total: Oil Equivalent	Mbbl	0	0	14	13	27

Significant Factors or Uncertainties Affecting Reserves Data

The process of estimating reserves is complex. It requires significant judgments and decisions based on available geological, geophysical, engineering, and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change. The reserve estimates contained herein are based on current production forecasts, prices and economic conditions. The Company's reserves are evaluated by GLJ Petroleum Consultants Ltd., independent engineers.

As circumstances change and additional data become available, reserve estimates also change. Estimates made are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, commodity prices, economic conditions and governmental restrictions.

Although every reasonable effort is made to ensure that reserve estimates are accurate, reserve estimation is an inferential science. As a result, the subjective decisions, new geological or production information and a changing environment may impact these estimates. Revisions to reserve estimates can arise from changes in year-end oil and gas prices, and reservoir performance. Such revisions can be either positive or negative.

Future Development Costs

The table below sets out the development costs deducted in the estimation of future net revenue attributable to proved reserves (using both constant prices and costs and forecast prices and costs) and proved plus probable reserves (using forecast prices and costs only).

	Forecast Prices and Costs	
	Total Proved Reserves	Total Proved Plus Probable Reserves
	(M$)	(M$)
2008	191	425
2009	103	103
2010	0	0
2011	0	0
2012	0	0
2013	0	0
Remaining Years	0	0
Total Undiscounted	294	528
Total Discounted 10% per year	271	495

Pacific Rodera's primary source of liquidity to fund its estimated capital expenditure program and other future development costs, as outlined in the above table, is derived from the Company's internally generated cash flow from operations and new equity issues if made available on favourable terms.

Wells

The following table sets forth the number and status of the oil and natural gas wells in which Pacific Rodera has a working interest as at December 31, 2007.

	Natural Gas			
	Producing		Non-Producing(3)	
	Gross(1)	Net(2)	Gross(1)	Net(2)
British Columbia	11	1	6	0.40
Northwest Territories	0	0	4	0.27
TOTAL	11	1	10	0.67

Notes:

(1) "Gross" wells means the number of wells in which Pacific Rodera has a working interest.
(2) "Net" wells means the aggregate number of wells obtained by multiplying each gross well by Pacific Rodera's percentage working interest therein.
(3) Non-producing includes wells shut-in for economic reasons, wells not capable of production and wells used for disposal of water.

Properties with No Attributed Reserves

The following table summarizes the gross and net acres of the unproved properties, effective December 31, 2007, in which Pacific Rodera has an interest and also the number of net acres for which Pacific Rodera's rights to explore, develop or explore will, absent further action, expire within one year.

	Gross Acres	Net Acres	Net Acres Expiring Within One Year
British Columbia	18,000	1,446	546
Alberta	3,004	1,502	0
Northwest Territories	864,049	94,549	0
TOTAL	885,053	97,497	546

Forward Contracts

Pacific Rodera is not subject to any forward contracts, hedges or collars.

Additional Information Concerning Abandonment Costs

We use our internal historical costs to estimate our abandonment costs when available. The costs are estimated on an area by area basis. The industry's historical costs are used when available. If representative comparisons are not readily available, an estimate is prepared based on the various regulatory abandonment requirements. We currently have 1 net well for which we expect to incur abandonment costs.

The total abandonment cost in respect of proved reserves using forecast prices is $59 thousand (undiscounted) and $20 thousand (discounted at 10%). 100% of such amounts were deducted as abandonment costs in estimating our future net revenue as disclosed above.

The following table sets forth the abandonment costs deducted in the estimation of our future net revenue:

Forecast Prices and Costs (Total Proved) ($000s)

Year	Abandonment Costs (Undiscounted)
2008	0
2009	3
2010	0
Thereafter	56
Total Undiscounted	59
Total Discounted @ 10%	20

Tax Horizon

Pacific Rodera estimates that it will not be required to pay corporate income taxes until at least 2009.

Costs Incurred

The following table summarizes Pacific Rodera's capital expenditures for the 12 month period ended November 30, 2007.

	Property Acquisition Costs			
	Proved properties ($000s)	Unproved Properties ($000s)	Exploration Costs ($000s)	Development ($000s)
Total (M$)	0	425	3,088	1,297

The following table summarizes Pacific Rodera's capital expenditures for the one month period ended December 31, 2007.

	Property Acquisition Costs			
	Proved properties ($000s)	Unproved Properties ($000s)	Exploration Costs ($000s)	Development ($000s)
Total (M$)	0	0	594	0

Exploration and Development Activities

The following table sets forth the gross and net exploratory and development wells associated with our assets in which Pacific Rodera participated during the 13 month period ended December 31, 2007.

	Exploratory Wells		Development Wells	
	Gross[1]	Net[2]	Gross[1]	Net[2]
Light and Medium Oil	0	0	0	0
Natural Gas	0	0	3	0.27
Service	0	0	0	0
Dry and Abandoned	0	0	0	0
Total	0	0	3	0.27

Notes:

(1) "Gross" drilled wells means the number of wells in which Pacific Rodera has a working interest.

(2) "Net" drilled wells means the aggregate number of wells obtained by multiplying each gross well by Pacific Rodera's percentage working interest therein.

Production Forecasts

The following table sets out the volume of Pacific Rodera's working interest production, before royalties, estimated in the GLJ Report for 2007, which is reflected in the estimate of future net revenue disclosed in the tables contained under "Reserves Data - Forecast Prices and Costs".

	Natural Gas (Mcf/d)	Natural Gas Liquids (Bbls/d)	Oil Equivalent (Boe/d)
2008 Total Proved	281	5	52
2008 Total Proved Plus Probable	314	6	58

Production History

The following table discloses Pacific Rodera's share of average daily production volume, prior to royalties, and the prices received, royalties paid, production and transportation costs incurred and netbacks on a per unit of volume basis for each product type, for the periods indicated below.

	One Month Period Ended	Quarter Ended			
	Dec 07	Nov 07	Aug 07	May 07	Feb 07
Average Daily Production:					
Natural Gas (mcf/d)	297.60	329.40	397.90	479.60	431.50
NGLs (Bbls/d)	4.70	6.30	8.20	9.30	5.80
Oil equivalent combined (Boe/d)	54.30	61.20	74.50	89.20	77.70
Average Price Received:					
Natural Gas ($/mcf)	6.79	5.94	5.71	7.45	7.65
NGLs ($/Bbl)	81.66	74.40	59.61	55.51	69.10
Oil equivalent combined (Boe/d)	44.31	39.35	37.06	45.81	47.65
Royalties – combined ($/Boe)	6.68	3.33	5.40	7.01	7.80
Production Costs – combined ($/Boe)	16.76	24.67	16.03	10.16	19.05
Netback Received - combined ($/Boe only)	20.87	11.35	14.74	29.32	20.87

DIVIDEND POLICY

Pacific Rodera has not paid any dividends on the outstanding Common Shares. The Board of Directors will determine the actual timing, payment and amount of dividends, if any, that may be paid by Pacific Rodera from time to time based upon, among other things, the cash flow, results of operations and financial conditions of Pacific Rodera, the needs for funds to finance ongoing operations and other business considerations as the Board of Directors considers relevant.

DESCRIPTION OF CAPITAL STRUCTURE

The authorized capital of Pacific Rodera consists of an unlimited number of Common Shares and an unlimited number of Preferred Shares issuable in series. As at March 20, 2008, there were 109,391,058 Common Shares of the Company issued and outstanding. No Preferred Shares are presently issued and outstanding. There are 30,125,000 warrants outstanding.

The following is a summary of the rights, privileges, restrictions and conditions attaching to the Common Shares and Preferred Shares of Pacific Rodera:

Common Shares

Holders of Common Shares are entitled to one vote per share at meetings of shareholders of Pacific Rodera, to receive dividends if, as and when declared by the Board of Directors and to receive pro rata the remaining property and assets of Pacific Rodera upon its dissolution, liquidation or winding-up, subject to the rights of shares having priority over the Common Shares.

Preferred Shares

Subject to filing of articles of amendment, each series of Preferred Shares shall consist of such number of shares and having such rights, privileges, restrictions and conditions as may be determined by the Board of Directors prior to the issuance thereof. With respect to the payment of dividends and distribution of assets in the event of liquidation, dissolution or winding-up of Pacific Rodera, whether voluntary or involuntary, holders of Preferred Shares are entitled to preference over the Common Shares and any other shares ranking junior to the Preferred Shares from time to time and may also be given such other preferences over the Common Shares and any other shares ranking junior to the Preferred Shares as may be determined at the time of creation of such series.

MARKET FOR SECURITIES

The Common Shares are currently listed and posted for trading on the TSXV and trade under the symbol "PRD". The Common Shares began trading on the Vancouver Stock Exchange, a predecessor of the TSXV, on March 1, 1999. The following sets forth the price range and trading volume of the Common Shares on the TSXV (as reported by the TSXV) for the periods indicated:

	Price Range		
	High ($/share)	**Low ($/share)**	**Volume (000s)**
2007			
January	0.65	0.46	4,491,100
February	0.68	0.58	4,704,600
March	0.80	0.55	3,076,800
April	0.78	0.61	2,608,700
May	0.67	0.56	2,120,100
June	0.59	0.50	1,093,000
July	0.56	0.48	2,454,600
August	0.53	0.38	2,889,300
September	0.59	0.45	2,610,400
October	0.70	0.52	5,149,900
November	0.68	0.46	2,606,309
December	0.59	0.44	3,126,390
2008			
January	0.69	0.58	6,290,600
February	0.80	0.68	5,587,100
March 1-20	0.75	0.56	2,872,016

DIRECTORS AND OFFICERS

The names and provinces of residence, positions with the Company, and principal occupation of the directors and officers of the Company are set out below:

Name and Province of Residence	Position with Pacific Rodera	Date Appointed	Principal Occupation during past five years
Michael G. Greenwood Alberta	Chairman and Chief Executive Officer	January 9, 2007	Chairman and Chief Executive Officer of the Company since January 9, 2007; formerly President, Chief Operating Officer and director of Canaccord Capital Company from 1997 to 2006 and its predecessor company from 1994 to 1997; formerly President and Chief Operating Officer and director of Canaccord Capital Inc. from 1997 to 2006.
Mark Hornett Alberta	President, Chief Operating Officer and Director	September 5, 2007	President and Chief Operating Officer of the Company since Sept 5, 2007; formerly Operations Manager of Mission Oil & Gas Inc. from 2005 to 2007. Operations Manager of Burlington Resources Ltd. from 1993 to 2005
David J.L. Williams Alberta	Senior Vice President, Corporate Development and Investor Relations and Director	January 1, 2005	Senior Vice President of Corporate Development and Investor Relations of the Company since Sept 5, 2007; formerly President of the Company from January 1, 2005 to September 5, 2007; Chief Executive Officer of the Company from January 1, 2005 to January 8, 2007; President of TWE Enterprises Ltd. since March 1983.
Roger Harman Alberta	Chief Financial Officer	September 5, 2007	Chief Financial Officer of the Company since Sept 5, 2007; Chief Financial Officer of Canadian Superior Energy since August 2006, prior to that Manager Revenue and Marketing, Canadian Superior Energy June 2003 – August 2006, and Manager Production Revenue Accounting, Altagas Services, April 2001 – June 2003
Andrew Arthur Alberta	Vice President, Exploration	September 5, 2007	Vice President, Exploration of the Company since Sept 5, 2007; formerly Senior Geologist with Mission Oil & Gas Inc. from July 2005 to 2006; formerly Senior Geologist with Blue Mountain Energy from January 2004 to July 2005; formerly Senior Geologist with Bow Valley Energy from October 2001 to December 2003
Douglas J. Crawford Alberta	Vice President, Production	September 5, 2007	Vice President, Production for the Company since Sept 5, 2007; formerly Vice President, Production with Mission Oil & Gas Inc. from April 2005 to February 2007; former senior Engineering Advisor for Burlington Canada Resources Ltd. from April 2002 to March 2005

Name and Province of Residence	Position with Pacific Rodera	Date Appointed	Principal Occupation during past five years
John Nesbitt Alberta	Vice President, Land	Effective April 1, 2008	Land Consultant of the Company since February 1, 2008 and Vice President, Land effective April 1, 2008; formerly Vice President, Land with Capitol Energy Resources Ltd. from January 2004 to June 2006; formerly Senior Landman with Talisman Energy from October 1987 to December 2003.
Grant Fagerheim(2) Alberta	Director	December, 2005	President and Chief Executive Officer of Kereco Energy Ltd. since January 2005; formerly President and Chief Executive Officer of Ketch Resources Ltd. from October 2002 to January 2005, and President and Chief Executive Officer of Ketch Energy Ltd. from April 2000 to October 2002.
A. Gordon Stollery(2) Alberta	Director	December, 2006	Chairman and Chief Executive Officer of Highpine Oil and Gas Limited since March 1998; formerly Chairman of Northstar Energy Company from 1997 to 1998 and President and Chief Executive Officer of Morrison Petroleums Ltd. from 1980 to 1997.
C. Geoffrey Hampson(1)(3) British Columbia	Director	May, 2000	President of Hampson Equities since 1983; President of Fibrox Technologies Ltd. since July 1993; formerly President and Chief Executive Officer of Peer1.net from September 2000 to December 2005.
William B. Shupe(1)(3) Saskatchewan	Director	January, 2005	President of Shupe & Company Inc. since 1996; President of W. Shupe & Company Investment Advisory Services Inc. since July 2003; formerly Chairman of Centurion Investment Advisors Inc. from January 2002 to April 2003.
John Greenwood(1)(2)(3) Alberta	Director	April, 2007	President and Chief Executive Officer of Wood Composite Technologies Inc. since September 2002; Regional Manager of Canadian Imperial Bank of Commerce until 2000.

Notes:

(1) Member of the Audit Committee.
(2) Member of the Reserves Committee.
(3) Member of the Corporate Governance Committee.

Michael G. Greenwood – Chairman and Chief Executive Officer

Mr. M. Greenwood has over 20 years experience in corporate and government finance. Mr. M. Greenwood has held senior investment banking positions with a number of national investment dealers and has covered a broad base of major Canadian corporations actively participating in the Canadian capital markets and merger and acquisition activity. Mr. M. Greenwood has acted in the capacities of financial advisor, underwriter or valuator for the federal government and provincial governments, as well as many Canadian corporations. He is the Chair and a director of the Canadian Investor Protection Fund and was a past director and member of the Executive Committee of the Investment Dealers Association. Mr. M. Greenwood has a Bachelor of Science degree from Dalhousie

University, an MBA from the University of Calgary and is a Chartered Business Valuator. Mr. Greenwood was formerly President, Chief Operating Officer and director of Canaccord Capital Company from 1997 to 2006 and its predecessor company from 1994 to 1997, and President and Chief Operating Officer and director of Canaccord Capital Inc. from 1997 to 2006.

Mark Hornett – President, Chief Operating Officer and Director

Mr. Hornett has over 30 years of operational experience in the Canadian and international oil and gas industry. Prior to joining Pacific Rodera, Mr. Hornett held the position of Operations Manager at Mission Oil & Gas Inc. where he directed all drilling and completion activities. Prior to Mission, Mr. Hornett held senior positions of increasing technical and managerial responsibility for Burlington Resources Ltd. Mr. Hornett has extensive experience both in Canada and internationally.

David J.L. Williams – Senior Vice President, Corporate Development and Investor Relations and Director

Mr. Williams served the Company as its full time President and Chief Executive Officer from January 1, 2005 until January 8, 2007 and served as its President from January 8, 2007 to September 5, 2007. Currently, Mr. Williams serves as the Company's Senior Vice President, Corporate Development and Investor Relations. Prior thereto, Mr. Williams was Vice President/Land Manager of the Company from December 2001 until January 1, 2005. Mr. Williams is also President of TWE Enterprises Ltd., a marketing and consulting company from March 1983 to present.

Roger Harman – Chief Financial Officer

Mr. Harman is a Certified Management Accountant with over 30 years of financial and accounting experience in the Canadian oil and gas industry. Mr. Harman's background includes, Chief Financial Officer of Canadian Superior Energy Inc. prior to that Manager, Revenues and Marketing at Canadian Superior and prior to Canadian Superior, Mr. Harman was Manager, Production and Revenue Accounting for AltaGas Services Inc. Prior to AltaGas, Mr. Harman held numerous finance, accounting and marketing positions within the oil and gas Industry. Mr. Harman has experience in all facets of accounting finance and marketing.

Andrew Arthur – Vice President, Exploration

Mr. Arthur obtained his Bachelor of Science (Honours) in Geology from the University of British Columbia in 1985 and his Masters of Science in Geology from the University of British Columbia in 1987. Mr. Arthur has over 20 years of diverse geological experience in the Canadian and international oil and gas industry. Prior to joining Pacific Rodera, Mr. Arthur was a Senior Geologist with Mission Oil & Gas Inc. where he was responsible for the Worsley core area in the Peace River Arch area and a member of the development team responsible for exploiting the Bakken Resource play in South-eastern Saskatchewan. Prior to Mission, Mr. Arthur was a Senior Geologist with companies varying in size and location.

Douglas J. Crawford – Vice President, Production

Mr. Crawford obtained his Bachelor of Science in Chemical Engineering from the University of Calgary in 1982. Mr. Crawford has over 25 years of engineering and operational experience in the Canadian oil and gas industry. Prior to joining Pacific Rodera, Mr. Crawford held the position of Vice President, Production at Mission Oil & Gas Inc. Prior to joining Mission, Mr. Crawford held various positions at Burlington Canada Resources Ltd. of increasing technical and managerial authority.

John Nesbitt, P. Land – Vice President, Land

Mr. Nesbitt has over 27 years of experience in all facets of land in the oil and gas business in Canada including successful negotiations within the oil and gas community as well as extensive experience with surface, First Nations and governmental negations. Prior to joining Pacific Rodera, Mr Nesbitt was Vice President, Land at Capitol Energy Resources Ltd., a successful junior company that sold to a major trust in 2007, and was Senior Landman at Talisman Energy Inc. from 1987 to 2003.

Grant Fagerheim – Director

Mr. Fagerheim has over 24 years of diverse experience in both the upstream and downstream areas of the oil and gas business and is currently the President, Chief Executive Officer and Director of Kereco Energy Ltd. Prior to the establishment of Kereco he was President, CEO and Director of Ketch Energy Ltd. and Ketch Resources Ltd. He has also held senior positions at Northrock and Sceptre Resources Ltd. In addition to his role at Kereco, Mr. Fagerheim also currently serves on the Boards of Directors for Escavar Energy Inc., Invico Capital Corp. and IROC Systems Corp. Other past and current professional affiliations include the Calgary Foundation - Investment Committee member, the Canadian Association of Petroleum Landmen – Director, the Canadian Association of Petroleum Producers – Governor, Young Presidents Organization – Member. Mr. Fagerheim currently serves as Chairman of the Edge School for Athletes, is an Owner and Director of the National Sports Development facility and Director of the Canadian Hockey Foundation.

A. Gordon Stollery – Director

Mr. Stollery is chairman and chief executive officer of Highpine Oil & Gas Ltd., a Calgary-based oil and gas company. Prior to his position with Highpine Oil & Gas Ltd., he was chairman of Northstar Energy Corp., and was the president and chief executive officer of Morrison Petroleums Ltd. from 1980 to 1997. He is also the owner of the Angus Glen Golf Club in Toronto, home of the 2007 Canadian Open. Mr. Stollery was awarded the Oilweek Producer of the Year in 1993, and the Pinnacle Award for Entrepreneurship in Alberta for 1992-1993, and has twice been the recipient of The Wall Street Week Gold Award. He holds a Master of Science (Geology) degree from the University of Toronto and a Bachelor of Science in Engineering (Civil and Geological) from Princeton University.

C. Geoffrey Hampson – Director

Mr. Hampson has been involved as President and Chief Executive Officer of many start up and operating companies over the last thirty years. He is currently the Chairman of the Board and CEO of Communicate.com, Inc., an eCommerce company listed on the OTC BB exchange. He was the founder and Chief Executive Officer of Novocon International Inc., a manufacturer of specialty fibre for composite re-enforcement until it was sold to Synthetic Industries in 1997. Mr. Hampson was also Chief Executive Officer of Peir 1 Network Enterprises Inc., an internet and infrastructure company based in Vancouver listed on the TSX V. In addition, Mr. Hampson is President and Chief Executive Officer of Fibrox Technologies Ltd., a manufacturer of specialty mineral fiber products, a director of Carat Exploration Inc., a junior mining exploration company listed on the TSX Venture Exchange with properties in Canada and in Chile and various other entities in both Canada and the United States.

William B. Shupe – Director

Mr. Shupe is President and chief investment advisor of W. Shupe & Company, a Regina based investment advisory firm. W. Shupe & Company, together with its predecessor firm, Shupe & Company Inc., have been providing investment and corporate finance advisory services to businesses, governments and individuals since 1996. Prior to establishing Shupe & Company in 1996, Mr. Shupe was President and Chief Executive Officer and Crown Life Investment Management Inc. and prior to that, was Vice President, Corporate Finance of Pemberton Houston Willoby Inc. Mr. Shupe also serves as Executive-in-Residence and Lecturer in Finance of the Faculty of Business Administration of the University of Regina. He is also an advisory board member of the GrowthWorks Canadian Funds and a director of Observatory Credit Markets Fund Limited. Mr. Shupe is a Chartered Financial Analyst (CFA) and is a Sloan fellow and Masters graduate of London Business School. He also holds a law degree from the University of Saskatchewan; he is a member of the CFA institute and Law Society of Saskatchewan (non-practicing) and is a registered portfolio manager with the Saskatchewan Financial Services Commission.

John Greenwood – Director

Mr. J. Greenwood is President, CEO and Director of Wood Composite Technologies. Prior to his position with Wood Composite Technologies, Mr. Greenwood was employed by the Canadian Imperial Bank of Commerce for over twenty-three years in a variety of roles. Mr. Greenwood's experience with Canadian Imperial Bank of Commerce includes sales leadership, commercial and corporate credit, compliance and customer service with exposure to a wide variety of industries.

The term of office of each director expires at the next annual meeting of shareholders of the Company.

As at March 20, 2008, the directors and officers of Pacific Rodera, as a group, beneficially owned, directly or indirectly approximately 26,796,295 Common Shares or approximately 25% of the issued and outstanding Common Shares.

Corporate Cease Trade Orders or Bankruptcies

No director, officer or promoter of the Company has, within the last ten years, been a director, officer or promoter of any reporting issuer that, while such person was acting in that capacity, was the subject of a cease trade or similar order or an order that denied the company access to any statutory exemption for a period of more than 30 consecutive days or was declared a bankrupt or made a voluntary assignment in bankruptcy, made a proposal under any legislation relating to bankruptcy or been 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 that person.

Penalties or Sanctions

No director, officer or promoter of the Company, within the last 10 years, has been subject to any penalties or sanctions imposed by a court or securities regulatory authority relating to trading in securities, promotion or management of a publicly-traded issuer or theft or fraud.

Personal Bankruptcies

No director, officer or promoter of the Company, or a shareholder holding sufficient securities of the Company to affect materially the control of the Company, or a personal holding company of any such persons, has, within the 10 years preceding the date of this Annual Information Form, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or being 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 individual.

Conflicts of Interest

There are potential conflicts of interest to which the directors and officers of the Company will be subject in connection with the operations of the Company. In particular, certain of the directors and officers of the Company are involved in managerial and/or director positions with other oil and gas companies whose operations may, from time to time, be in direct competition with those of the Company or with entities which may, from time to time, provide financing to, or make equity investments in, competitors of the Company. See "Directors and Officers". Conflicts, if any, will be subject to the procedures and remedies available under the ABCA. The ABCA provides that in the event that a director has an interest in a contract or proposed contract or agreement, the director shall disclose his interest in such contract or agreement and shall refrain from voting on any matter in respect of such contract or agreement unless otherwise provided by the ABCA.

AUDIT COMMITTEE INFORMATION

Audit Committee Mandate and Terms of References

The Mandate and Terms of Reference of the Audit Committee of the board of directors is attached hereto as Schedule "C".

Composition of the Audit Committee

The following table sets forth the names of each current member of the Audit Committee, whether such member is independent, whether such member is financially literate and the relevant education and experience of such member:

Name	Independent	Financially Literate	Relevant Education and Experience
C. Geoffrey Hampson	Yes	Yes	Mr. Hampson has run numerous successful companies in the capacity of President and Chief Executive Officer over the past thirty years. He has considerable financial experience proven through the running of these organizations as well in his capacity as a director of numerous public and privately-held companies.
William B. Shupe	Yes	Yes	Mr. Shupe is a Chartered Financial Analyst (CFA), a Sloan fellow and Masters graduate of London Business School and holds a law degree from the University of Saskatchewan. Mr. Shupe is President and Chief Investment Advisor of an investment advisory firm and serves as Executive-in-Residence and Lecturer in Finance of the Faculty of Business Administration, University of Regina.
John Greenwood	No	Yes	Mr. J. Greenwood has over twenty three years experience in the banking industry as well as running a successful public company as President, Chief Executive Officer and Director.

Pre-Approval of Policies and Procedures

As of the date hereof the Audit Committee has not adopted specific policies or procedures in respect of the provision of non-audit services to the Company.

External Auditor Service Fees

Audit Fees

The aggregate fees billed by our external auditor in each of the last three fiscal years for audit services were $91,677.00 in 2006, $45,000 for the 12 month period ended November 30, 2007 and $15,000 for the one month period ended December 31, 2007.

Audit – Related Fees

The aggregate fees billed in each of the last two fiscal years for assurance and related services by the Company's external auditor that are reasonably related to the performance of the audit or review of the Company's financial statements that are not reported under "Audit Fees" above were $4,350.00 in 2006, nil for the 12 month period ended November 30, 2007 and nil for the one month period ended December 31, 2007.

Tax Fees

The aggregate fees billed in each of the last two fiscal years for professional services rendered by the Company's external auditor for tax compliance, tax advice and tax planning were $12,327.00 in 2006, $5,000 for the 12 month period ended November 30, 2007 and $2,500 for the one month period ended December 31, 2007.

All Other Fees

The aggregate fees billed in each of the last two fiscal years for products and services provided by the Company's auditors other than services reported above were nil in 2006, nil for the 12 month period ended November 30, 2007 and nil for the one month period ended December 31, 2007.

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 the operations of Pacific Rodera 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 Pacific Rodera is 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 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 twp years or for a term of two to 20 years (in quantities of not more than 30,000 m3/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 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, 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 negotiations between the mineral 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 22.1% effective January 1, 2007 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 five steps: 19.5% on January 1, 2008, 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. Currently, the amount of royalties that are payable is influenced by the oil production, density of the oil, and the vintage of the oil. Originally, the vintage classified oil in "new oil" and "old oil" depending on when the oil pools were discovered. If the pool was discovered prior to March 31, 1974 it is considered "old oil", if discovered after March 31, 1974 and before September 1, 1992, it is 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 has a base rate of 10% and a rate cap of 30%. The old oil royalty reserved to the Crown has a base rate of 10% and a rate cap of 35%.

The royalty reserved to the Crown in respect of natural gas production, subject to various incentives, is 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. Natural gas produced from qualifying intervals in eligible gas wells spudded or deepened to a depth below 2,500 metres is also subject to a royalty exemption, the amount of which depends on the depth of the well.

Oil sands projects are subject to a specific regulation made effective July 1, 1997, and expiring June 30, 2007, which, among other things, determines the Crown's share of crude and processed oil sands products.

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 ("**ARTC**") was to be eliminated, effective January 1, 2007. The programs affected by this announcement are: (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 being introduced is the Innovative Energy Technologies Program (the "**IETP**") which is intended to promote 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 will be the one to decide which projects qualify and the level of support that will be provided. The deadline for the IETP's third round of applications was May 31, 2007. The successful applicants have not yet been announced and it appears, based on the previous two rounds, that the selection process can take at least 8 months. The technical information gathered from this program is to be made public once a two-year confidentiality period expires.

On October 25, 2007, the Alberta government released a report entitled "The New Royalty Framework" (the "**NRF**") containing the government's proposals for Alberta's new royalty regime that is scheduled to be effective on January 1, 2009. The proposed NRF includes new royalty formulas for conventional oil and natural gas that will operate on sliding scales that are determined by commodity prices and well productivity; in addition to the policy of "shallow rights reversion". The Alberta government is intending to implement this policy in order to maximize the development of currently undeveloped resources which is consistent with the government's objective of maximizing recovery of known gas resources, while increasing royalty revenues. The policy's 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. It appears that leaseholders will get a grace period before the shallower zones are reverted to the Crown, which is still to be determined. Substantial legislative, regulatory and systems updates will be introduced before changes become fully effective in January 2009. See "Risk Factors – New Alberta Royalty Regime".

British Columbia

Producers of oil and natural gas in the Province of 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 the Province of 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 of up to $30 million annually 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.

- 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.

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", or "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 thousand 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 federal government 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 five years since the federal government had the initiative to reintroduce the full deduction of provincial resource royalties from federal and provincial taxable income.

In June 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 the individual with insufficient financial capability from acquiring oil and gas wells or facilities; and (ii) in the case of a bankrupt company, the funds cover for the decommissioning and reclaiming of orphan property. An additional change introduced is the mandatory licensing of all upstream oil and gas facilities in Saskatchewan.

Northwest Territories

The royalty regime is a significant factor in the profitability of oil and natural gas production. Royalties payable on production from lands other than Crown lands, such as lands held privately in fee simple or lands held by First Nations groups, are determined by negotiations between the mineral owner and the lessee. Crown royalties are determined by government regulation and are generally calculated as a percentage of the value of the gross production, and the rate of royalties payable generally depends in part on well productivity, geographical location, production and marketing costs and the type or quality of the petroleum product produced. Additionally, other royalties and royalty-like interests are occasionally 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 or net carried interests.

Federal land in the Northwest Territories is categorized as “frontier lands” under the *Canada Petroleum Resources Act* (Canada) (the "**CPRA**"). Pursuant to the CPRA, royalties on petroleum and natural gas production from frontier lands are reserved for Canada's federal government. There are no royalties payable directly to the government of the Northwest Territories.

The calculation of federal Crown royalties on frontier lands is governed by the *Frontier Lands Petroleum Royalty Regulations* (Canada). Under these regulations, royalties are payable to the federal Crown once production from project lands has commenced (which is the time at which the petroleum products become marketable). Royalties are not payable during the pre-production period when activities such as exploration, testing, and drilling are being conducted.

Prior to payout, (payout means the point where the cumulative adjusted gross revenues of the interest holder in relation to the project exceeds the adjusted cumulative cost base of the interest holder in relation to the project) royalties are payable on a graduated monthly basis. For the first 18 months after production has commenced, 1% of gross revenues are payable to the Crown; for the 19th to the 36th month after the commencement of production, 2%. for the 37th to 54th month after production has commenced, 3% of gross revenues are payable to the Crown; for the 55th to the 72nd month after production has commenced, 4% of gross revenues are payable to the Crown; and from the 73rd month after production commences until payout has been achieved, 5% of gross revenues are payable to the Crown. The capital remaining in the payout account receives a capital cost allowance of the long-term Government of Canada bond rate plus 10% added annually to the account.

Once payout has been achieved, royalties to the Crown continue to be paid on a monthly basis. The post-payout Crown royalty payable will be the greater of thirty percent of net revenues or five percent of gross revenues of the project.

Royalties payable to the First Nations organizations under the Spinout Assets lands covered by the concession agreements are similar to those payable to the Crown.

Land Tenure and Production Rights Processes

Provinces

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.

Federal Crown Lands

Crude oil and natural gas located in the Northwest Territories is owned predominantly by the Government of Canada. The federal government grants rights to explore for and produce oil and natural gas pursuant to licences issued for varying terms and on varying conditions as set forth in federal legislation and by the parties themselves. Such conditions may include, but are not limited to, obligations to drill wells or produce petroleum substances.

Oil and natural gas rights in lands owned by the federal government within the Northwest Territories are initially obtained by way of an exploration licence ("**EL**"). EL's are issued through a bid process and generally incorporate the terms and conditions set out in the bid. EL's may be issued for non-renewable terms of up to and including 9 years, subject to extensions where the drilling of a well is in progress. Where the holder of an EL makes a significant discovery, as determined by the NEB, they may apply for and be issued a "declaration of significant discovery" from the NEB. Upon the issuance of the declaration of significant discovery, the holder of the EL may apply for and be issued a significant discovery license (an "**SDL**"), which will remain in effect for so long as the declaration of significant discovery continues. The area covered by an SDL may vary in accordance with amendments to the declaration of significant discovery. Both ELs and SDLs provide the holder with the right to explore for and the exclusive right to drill and test for petroleum, the exclusive right to develop the lands in order to produce petroleum and the exclusive right to obtain a production licence for the lands once a declaration of commercial discovery has been made by the NEB.

Where a declaration of commercial discovery has been made by the NEB, the holder of the EL or SDL may then apply for and shall be issued a production licence ("**PL**"). PLs are issued for a term of 25 years, subject to the continuance of the certificate of commercial discovery, and are automatically extended for such time thereafter as commercial production continues. PLs provide the same rights as ELs and SDLs along with the exclusive right to produce petroleum and title to the petroleum so produced. Where commercial production has not commenced on any portion of the commercial discovery area, an order may be issued requiring production from such portion or else forfeiture of that portion from the commercial discovery area. The area covered by the PL may vary in accordance with amendments to the commercial discovery area.

Concession Agreement Lands

Oil and natural gas located in the Northwest Territories can also be privately owned and rights to explore for and produce such oil and natural gas are granted by leases and concession agreements on such terms and conditions as may be negotiated between the parties themselves.

Pursuant to agreements made between First Nations and the Government of Canada, First Nations have been granted title to certain lands in the Northwest Territories, in fee simple, including mines and minerals within, upon or under such lands. Pacific Rodera has acquired from First Nations an interest in eight (8) freehold leases for certain lands located in the Northwest Territories. Pacific Rodera's working interests in these lands range from 6.625 percent to 12.5 percent.

In order to obtain the right to explore and produce minerals within these lands, corporations enter into oil and gas concession agreements with the owner (or its designated organization) of the lands.

Generally, such concession agreements function similar to oil and gas leases, whereby the lessor, as the legal owner, grants the lessee certain rights to explore for and produce oil and gas, subject to the specific terms of the concession agreement.

Typically, upon entering into the concession agreement, the lessee is granted the right to explore and produce oil and gas from the land, for an initial term, followed by potential renewable terms. All lease terms are subject to various drilling and payment obligations, which if not satisfied by the lessee, may result in, without limitation, the termination of certain rights, the surrendering of specific portions of the leased land, payment penalties and/or termination of the agreement.

The grant to the lessee is also subject to the payment of royalties to the lessor based on production from the leased lands or revenues from production from the leased lands. Typically, the royalty procedure and calculation is comparable to the Crown royalty calculation, stated below. More specifically, the royalty rates vary (most often escalate) with the length of time a well or production unit has been producing. After a well or production unit has been producing for a specified period of time, or in some instances at the time a well “pays out”, the royalty will most often become fixed at a certain percentage. Furthermore, it is common for the lessor to have a right to acquire a working interest in the leased lands, or a right to convert the royalty interest to a working interest in the leased lands.

In addition, the lessee is often contractually obligated to consult with the lessor and associated First Nations representatives and to commit to community support incentives such as first consideration for employment, training and business opportunities; support and utilization of local business; development of employment opportunity procedures and development training plans etc.

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 the Province of 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. 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. Industries can either choose one of these options or a combination thereof. Pacific Rodera will be committed to meeting its responsibilities to protect the environment wherever it operates and anticipates making increased expenditures of both a capital and an expense nature as a result of the increasingly stringent laws relating to the protection of the environment, and will be taking such steps as required to ensure compliance with the EPEA and similar legislation in other jurisdictions in which it operates. Pacific Rodera believes that it is in material compliance with applicable environmental laws and regulations. Pacific Rodera also believes that it is reasonably likely that the trend towards stricter standards in environmental legislation and regulation will continue.

In January 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 CO_2 from other emissions supporting carbon capture and storage.

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.

In the Northwest Territories, environmental compliance is governed by the *Environmental Protection Act* (Northwest Territories), the *Environmental Rights Act* (Northwest Territories), the *Canadian Environmental Assessment Act* (Canada), the *Canadian Environmental Protection Act*, 1999 (Canada) and the *Canada Oil and Gas Operations Act* (Canada), all of which impose certain environmental responsibilities on oil and natural gas operators and working interest holders in the Northwest Territories and impose penalties for violations.

On February 27, 2007 the Government of British Columbia unveiled the Energy Plan outlining the Province's 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 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 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, on February 19, 2008 the provincial Government announced that starting on July 1, 2008, provided the legislation is approved; a revenue-neutral carbon tax will be applied to all fossil fuels used in the Province. The tax would be phased in, and the initial rate would be based on CO_{2e} 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 would receive otherwise.

In December, 2002, the Government of Canada ratified the Kyoto Protocol ("**Protocol**"). The 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 target of 6% below 1990 emission levels will be enforced in Canada. Bill C288, 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 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 oils 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 CO2 equivalent per year for natural gas pipelines; (ii) 3,000 tonnes of CO2 equivalent per upstream oil and gas facilities; and (iii) 10,000 boe/d/company. These proposed thresholds are significantly stricter than the current Alberta regulatory threshold of 100,000 tonnes of CO2 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 Mt 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 Company 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 the Company's 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. The long-term commercial success of Pacific Rodera depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, Pacific Rodera's existing reserves and the production therefrom will decline over time as such existing reserves are exploited. A future increase in Pacific Rodera's reserves will depend not only on its ability to explore and develop any properties it may have from time to time, but also on its ability to select and acquire suitable producing properties or prospects. No assurance can be given that Pacific Rodera will be able to continue to locate satisfactory properties for acquisition or participation. Moreover, if such acquisitions or participations are identified, management of Pacific Rodera 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 Pacific Rodera.

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, Pacific Rodera 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 Pacific Rodera. In accordance with industry practice, Pacific Rodera is not fully insured against all of these risks, nor are all such risks insurable. Although Pacific Rodera maintains liability insurance in an amount that it considers consistent with industry practice, the nature of these risks is such that liabilities could exceed policy limits, in which event Pacific Rodera could incur significant costs that could have a material adverse effect upon its financial condition. 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 could have a material adverse effect on Pacific Rodera.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

The Company makes 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 the Company's ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of the Company. 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 the Company can focus its efforts and resources more efficiently. Depending on the state of the market for such non-core assets, certain non-core assets of the Company, if disposed of, could be expected to realize less than their carrying value on the financial statements of the Company.

Operational Dependence

Other companies operate some of the assets in which Pacific Rodera has an interest. As a result, Pacific Rodera has limited ability to exercise influence over the operation of those assets or their associated costs, which could adversely affect Pacific Rodera's financial performance. Pacific Rodera's return on assets operated by others will therefore depend upon a number of factors that may be outside of Pacific Rodera's 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

Pacific Rodera will manage a variety of small and large projects in the conduct of its business. Project delays may delay expected revenues from operations. Significant project cost over-runs could make a project uneconomic.

Pacific Rodera's ability to execute projects and market oil and natural gas will depend upon numerous factors beyond Pacific Rodera's 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, Pacific Rodera 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 it produces.

Absence of Infrastructure to Transport the Company's Gas Production

Due to the location of certain of the Company's assets in the Northwest Territories, there is no infrastructure currently available to transport natural gas from the Company's existing and future wells to market. While the Mackenzie Valley pipeline and related gathering system, which would enable the Company to transport its natural gas to market either with or without additional infrastructure being built by the Company, has been proposed and is currently the subject of regulatory hearings, there is no guarantee that it will be completed on a timely basis or at all. The Company's ability to market its natural gas, and therefore receive payment for its production, depends upon Pacific Rodera's ability to transport its natural gas to market. If the Company is unable to transport its natural gas to market within a reasonable time, the value of its assets, and therefore of the Common Shares, will be materially affected.

Production Transportation Plans

Pacific Rodera intends to discuss the transportation of its natural gas via the Mackenzie Valley pipeline and related gathering system, if approved and constructed, with TransCanada Pipelines Limited. Pacific Rodera will need to construct additional facilities in respect of certain of its properties in order to utilize the Mackenzie Valley pipeline and related gathering system, if approved and constructed.

If the construction of the Mackenzie Valley pipeline and related gathering system is deferred, delayed or not approved, the Company will examine its available options to transport its natural gas to market, including the support by the Company for the construction by others of alternate pipeline and gathering systems.

Seasonal Factors

Oil and natural gas development activities, including seismic and drilling programs in the central Mackenzie Valley and Mackenzie Delta are restricted to those months of the year when the ground is frozen. Seasonal weather variations, including freeze-up and break-up, will affect access.

Competition

The petroleum industry is competitive in all its phases. Pacific Rodera competes 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. Pacific Rodera's competitors will include oil and natural gas companies that have substantially greater financial resources, staff and facilities than Pacific Rodera. Pacific Rodera's ability to increase its reserves in the future will depend not only on its ability to explore and develop its present properties, but also on its 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, 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 Pacific Rodera's costs, any of which may have a material adverse effect on Pacific Rodera's business, financial condition and results of operations. In order to conduct oil and gas operations, Pacific Rodera requires licenses from various governmental authorities. There can be no assurance that Pacific Rodera will be able to obtain all of the licenses and permits that may be required to conduct operations that it may wish to undertake.

New Alberta Royalty Regime

On October 25, 2007, the Alberta government released a report entitled "The New Royalty Framework" (the "**NRF**") containing the government's proposals for Alberta's new royalty regime which is scheduled to be effective on January 1, 2009. Given that the NRF has only recently been announced, it is not possible at this time to determine the full impact of the NRF on Pacific Rodera's financial condition and operations.

Pacific Rodera cannot provide any assurance that the NRF will be implemented in the form proposed. If changes are made to the NRF before it is implemented by the Alberta government, such changes could result in the implementation of a new royalty regime that impacts Pacific Rodera in a materially different manner, and that is more adverse to Pacific Rodera, than the NRF as currently proposed.

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". Pacific Rodera's exploration and production facilities and other operations and activities emit greenhouse gases and will subject Pacific Rodera 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 government of Canada's proposed *Clean Air* Act of 2006 and Alberta's recently enacted *Climate Change and Emissions Management Act.* The direct or indirect costs of these regulations may adversely affect the expected business of Pacific Rodera. 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 Pacific Rodera to incur costs to remedy such discharge. Although Pacific Rodera believes that it is 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 adversely affect Pacific Rodera's financial condition, results of operations or 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, including those of the Company. Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not possible to predict the impact on the Company and its operations and financial condition. See "Industry Conditions – Environmental Regulation".

Prices, Markets and Marketing

The marketability and price of oil and natural gas that may be acquired or discovered by Pacific Rodera is and will continue to be affected by numerous factors beyond its control. Pacific Rodera's ability to market its oil and natural gas depends upon its ability to acquire space on pipelines that deliver natural gas to commercial markets. Pacific Rodera is also affected by deliverability uncertainties related to the proximity of its 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 may be volatile and subject to fluctuation. Any material decline in prices could result in a reduction of Pacific Rodera's 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 Pacific Rodera's reserves. Pacific Rodera might also elect not to produce from certain wells at lower prices. All of these factors could result in a material decrease in Pacific Rodera's net production revenue and a reduction in its 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 the control of the Company. These factors include economic conditions, in the United States and Canada, the actions of the Organization of Petroleum Exporting Countries, governmental regulation, political stability in the Middle East and elsewhere, the foreign supply of oil and gas, risks of supply disruption, the price of foreign imports and the availability of alternative fuel sources. Any substantial and extended decline in the price of oil and gas would have an adverse effect on the Company's carrying value of its proved reserves, borrowing capacity, revenues, profitability and cash flows from operations.

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 Pacific Rodera will be in part determined by Pacific Rodera's borrowing base. A sustained material decline in prices from historical average prices could reduce Pacific Rodera's expected borrowing base, therefore reducing the bank credit available to Pacific Rodera which could require that a portion, or all, of Pacific Rodera's bank debt be repaid and a liquidation of assets.

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. Such material increases in the value of the Canadian dollar may negatively impact Pacific Rodera's operating entities production revenues. Further material increases in the value of the Canadian dollar would exacerbate this potential negative impact. This increase in the exchange rate for the Canadian dollar and future Canadian/United States exchange rates could accordingly impact the future value of Pacific Rodera's reserves as determined by independent evaluators.

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

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

Substantial Capital Requirements

Pacific Rodera anticipates making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. If Pacific Rodera's revenues or reserves decline, it may not have access to the capital necessary to undertake or complete future drilling programs. There can be no assurance that debt or equity financing, or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to Pacific Rodera. The inability of Pacific Rodera to access sufficient capital for its operations could have a material adverse effect on Pacific Rodera's financial condition, results of operations and prospects.

Additional Funding Requirements

Pacific Rodera's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times. From time to time, Pacific Rodera may require additional financing in order to carry out its oil and gas acquisition, exploration and development activities. Failure to obtain such financing on a timely basis could cause Pacific Rodera to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If Pacific Rodera's revenues from its reserves decrease as a result of lower oil and natural gas prices or otherwise, Pacific Rodera's ability to expend the necessary capital to replace its reserves or to maintain its production will be impaired. If Pacific Rodera's cash flow from operations is not sufficient to satisfy its 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 favourable terms.

Issuance of Debt

From time to time Pacific Rodera 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 Pacific Rodera's debt levels above industry standards for oil and natural gas companies of similar size. Depending on future exploration and development plans, Pacific Rodera may require additional equity and/or debt financing that may not be available or, if available, may not be available on favourable terms. Neither Pacific Rodera's articles nor its by-laws limit the amount of indebtedness that Pacific Rodera may incur. The level of Pacific Rodera's indebtedness from time to time, could impair Pacific Rodera's ability to obtain additional financing on a timely basis to take advantage of business opportunities that may arise.

Hedging

From time to time Pacific Rodera may enter into agreements to receive fixed prices on its oil and natural gas production to offset the risk of revenue losses if commodity prices decline; however, if commodity prices increase beyond the levels set in such agreements, Pacific Rodera will not benefit from such increases and Pacific Rodera 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 Pacific Rodera 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, Pacific Rodera 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 Pacific

Rodera and may delay exploration and development activities. To the extent Pacific Rodera is not the operator of its oil and gas properties, Pacific Rodera will be dependent on such operators for the timing of activities related to such properties and will be largely unable to direct or control the activities of the operators.

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 Pacific Rodera's claim which could result in a reduction of the revenue received by Pacific Rodera.

Reserve Estimates

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and NGL reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth in this document are estimates only. 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. All such estimates are to some degree speculative, and classifications of reserves are only attempts to define the degree of speculation involved. 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. Pacific Rodera's actual production, revenues, taxes and development and operating expenditures with respect to its 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, Pacific Rodera's 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 Pacific Rodera's oil and gas reserves will vary from the estimates contained in the GLJ Report, and such variations could be material. The GLJ Report is based in part on the assumed success of activities Pacific Rodera intends to undertake in future years. The reserves and estimated cash flows set out in the GLJ Report 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 Pacific Rodera's reserves since that date.

Insurance

Pacific Rodera's involvement in the exploration for and development of oil and natural gas properties may result in Pacific Rodera becoming subject to liability for pollution, blow outs, property damage, personal injury or other hazards. Although Pacific Rodera will 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, Pacific Rodera 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 Pacific Rodera. The occurrence of a significant event that Pacific Rodera is not fully insured against, or the insolvency of the insurer of such event, could have a material adverse effect on Pacific Rodera.

Geo-Political Risks

The marketability and price of oil and natural gas that may be acquired or discovered by Pacific Rodera 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 Pacific Rodera's net production revenue.

In addition, Pacific Rodera's oil and natural gas properties, wells and facilities could be subject to a terrorist attack. If any of Pacific Rodera's properties, wells or facilities are the subject of terrorist attack it could have a material adverse effect on Pacific Rodera. Pacific Rodera will not have insurance to protect against the risk from terrorism.

Dividends

Any decision to pay dividends on the shares of Pacific Rodera will be made by the Board of Directors on the basis of Pacific Rodera's earnings, financial requirements and other conditions existing at such future time. See "Dividend Record and Policy".

Conflicts of Interest

Certain directors of Pacific Rodera are also directors of other oil and gas companies and as such may, in certain circumstances, have a conflict of interest requiring them to abstain from certain decisions. Conflicts, if any, will be subject to the procedures and remedies of the ABCA. See "Directors and Officers – Conflicts of Interest".

Dilution

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

Management of Growth

Pacific Rodera may be subject to growth-related risks including capacity constraints and pressure on its internal systems and controls. The ability of Pacific Rodera to manage growth effectively will require it to continue to implement and improve its operational and financial systems and to expand, train and manage its employee base. The inability of Pacific Rodera to deal with this growth could have a material adverse impact on its business, operations and prospects.

Expiration of Licenses and Leases

Pacific Rodera's properties are held in the form of licences and leases and working interests in licences and leases. If Pacific Rodera 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 Pacific Rodera's licences or leases or the working interests relating to a licence or lease may have a material adverse effect on Pacific Rodera's results of operations and business.

Aboriginal Claims

Aboriginal peoples have claimed aboriginal title and rights to portions of Western Canada. Pacific Rodera is not aware that any claims have been made in respect of its property and assets; however, if a claim arose and was successful this could have an adverse effect on Pacific Rodera and its operations.

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 and corresponding declines in the demand for the goods and services of Pacific Rodera.

Third Party Credit Risk

Pacific Rodera may be exposed to third party credit risk through its contractual arrangements with its current or future joint venture partners, marketers of its petroleum and natural gas production and other parties. In the event such entities fail to meet their contractual obligations to Pacific Rodera, such failures could have a material adverse effect on Pacific Rodera and its cash flow from operations. In addition, poor credit conditions in the industry and of joint venture partners may impact a joint venture partner's willingness to participate in Pacific Rodera's ongoing capital program, potentially delaying the program and the results of such program until Pacific Rodera finds a suitable alternative partner.

Reliance on Key Personnel

Pacific Rodera's success depends in large measure on certain key personnel. The loss of the services of such key personnel could have a material adverse affect on Pacific Rodera. Pacific Rodera does not have any key person insurance in effect for management. The contributions of the existing management team to the immediate and near term operations of Pacific Rodera 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 Pacific Rodera will be able to continue to attract and retain all personnel necessary for the development and operation of its business. Investors must rely upon the ability, expertise, judgment, discretion, integrity and good faith of the management of Pacific Rodera.

AUDITORS, TRANSFER AGENT AND REGISTRAR

The auditors of the Company are Ernst & Young LLP, Chartered Accountants, Pacific Centre, 700 West Georgia Street, P.O. Box 10101, Vancouver, British Columbia, V7Y 1C7.

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

LEGAL PROCEEDINGS

To the knowledge of the Company, there are no legal proceedings material to the Company to which the Company or its subsidiaries is a party or of which any of their respective properties is the subject matter nor are there any such proceedings known to the Company to be contemplated.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Other than as disclosed in the section of this Annual Information Form entitled "*General Development of the Business – Historical Overview - - Recent Developments*", there were no material interests, direct or indirect, of directors or executive officers of the Company, any shareholder who beneficially owns, directly or indirectly, or exercises control or direction over more than 10% of the outstanding Common Shares of the Company, or any known associate or affiliate of such persons in any transactions in the last three years or during the current financial year which has materially affected, or would materially affect, the Company or its subsidiaries.

MATERIAL CONTRACTS

Except as described in this Annual Information Form and contracts entered into in the ordinary course of business, the Company has not entered into any material contracts since commencement of its operations which are still in effect.

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 statement, report or valuation described or included in a filing, or referred to in a filing, made under NI 51-102 – *Continuous Disclosure Obligation* by the Company during, or related to, the Company's most recently completed financial year other than GLJ, the Company's independent engineering evaluator. As at the date hereof, to the knowledge of management of the Company, none of the aforementioned persons or companies, or principals thereof, had any registered or beneficial interests, direct or indirect, in any securities or other property of the Company 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.

Ernst & Young LLP, our auditors, are independent in accordance with the Rules of Professional Conduct of the Institute of Chartered Accountants of British Columbia.

ADDITIONAL INFORMATION

Additional information relating to the Company can be found on SEDAR at www.sedar.com. Additional information, including directors' and officers' remuneration and indebtedness, principal holders of the Company's securities and securities authorized for issuance under equity compensation plans will be contained in the Company's information circular and proxy statement for the Company's annual meeting of shareholders. Additional financial information is contained in the Company's consolidated financial statements and the related management's discussion and analysis for the year ended November 30, 2007. It is expected that the Company's consolidated financial statements and the related management's discussion and analysis for the year ended December 31, 2007 will be filed on or before April 29, 2008.

SCHEDULE "A"

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

Management of Pacific Rodera Energy Inc. (the "**Company**") are responsible for the preparation and disclosure of information with respect to the Company's oil and 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, 2007, estimated using forecast prices and costs.

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

The Reserves Committee of the board of directors of the Company has:

(a) reviewed the Company'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, to inquire whether there had been disputes between the previous independent qualified reserves evaluator; and

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

The Reserves Committee of the board of directors has reviewed the Company's procedures for assembling and reporting other information associated with oil and 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 51-101F1 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 judgements regarding future events, actual results will vary and the variations may be material. However, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

DATED as of this 28th day of March, 2008.

(signed) "*Michael Greenwood*"
Michael Greenwood
Chief Executive Officer and a Director

(signed) "*Mark Hornett*"
Mark Hornett
President and Chief Operating Officer and a Director

signed "*Grant B. Fagerheim*"
Grant B. Fagerheim
Director and a Member of the Reserves Committee

(signed) "*A. Gordon Stollery*"
A. Gordon Stollery
Director and a Member of the Reserves Committee

SCHEDULE "B"

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

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

1. We have evaluated the Company's reserves data as at December 31, 2007. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2007, 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, 2007, and identifies the respective portions thereof that we have evaluated and reported on to the Company's board of directors:

Independent Qualified Reserves Evaluator or Auditor	Description and Preparation Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate)			
			Audited	Evaluated (M$)	Reviewed	Total (M$
GLJ Petroleum Consultants Ltd.	January 31, 2008	Canada	-	$2,569	-	$2,569
Totals						

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

6. We have no responsibility to update our reports referred to in paragraph 4 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 variations 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, February 8, 2008

Per: (signed) *"Terry L. Aarsby"*
Terry L. Aarsby, P. Eng.
VP Corporate Evaluations

SCHEDULE "C"

PACIFIC RODERA ENERGY LTD.

AUDIT COMMITTEE MANDATE

Introduction

Pacific Rodera Energy Inc. (the "**Corporation**") is an Alberta based junior oil and gas exploration and development company. The Board of Directors of the Corporation (the "**Board**") has the responsibility for the overall stewardship of the conduct of the business of the Corporation and its subsidiaries and the activities of management of the Corporation, which is responsible for the day-to-day conduct of the business.

Purpose

The overall purpose of the Audit Committee (the "**Committee**") is to ensure that the Corporation's management has designed and implemented an effective system of internal financial controls and disclosure controls and procedures, to review and report on the integrity of the consolidated financial statements of the Corporation, to review the Corporation's compliance with regulatory and statutory requirements as they relate to financial statements, taxation matters and disclosure of material facts and to review the Corporation's externally disclosed oil and gas reserves estimates including reviewing the qualifications of, and procedures used by, the independent engineering firm responsible for evaluating the Corporation's reserves.

Composition, Procedures And Organization

1. The Committee shall consist of at least three members of the Board of Directors (the "**Board**"), a majority of whom shall be "independent", as that term is defined in Sections 1.4 and 1.5 of Multilateral Instrument 52-110, Audit Committees (provided that, if the Common Shares of the Corporation are listed and posted on the Toronto Stock Exchange, then all of the members of the Audit Committee shall be "independent").

2. All of the members of the Committee shall be "financially literate" (i.e. able to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of those of the Corporation and that can be reasonably expected to be raised by the Corporation's financial statements).

3. The Committee composition, including the qualifications of its members, shall comply with the applicable requirements of stock exchanges on which the Corporation lists its securities and of securities regulatory authorities, as such requirements may be amended from time to time.

4. The Board shall appoint the members of the Committee. The Board may at any time remove or replace any member of the Committee and may fill any vacancy in the Committee.

5. Unless the Board shall have appointed a chair of the Committee, the members of the Committee shall elect a chair from among their members.

6. The quorum for meetings shall be a majority of the members of the Committee, present in person or by telephone or other telecommunication device that permits all persons participating in the meeting to speak and to hear each other.

7. The Committee shall have access to such officers and employees of the Corporation and to the Corporation's external auditors, and to such information respecting the Corporation, as it considers necessary or advisable in order to perform its duties and responsibilities.

8. Meetings of the Committee shall be conducted as follows:

(a) the Committee shall meet at least four times annually at such times and at such locations as may be requested by the chair of the Committee. The external auditors or any member of the Committee may request a meeting of the Committee;

(b) the external auditors shall receive notice of and have the right to attend all meetings of the Committee; and

(c) the following management representatives shall be invited to attend all meetings, except executive sessions and private sessions with the external auditors:

Chief Executive Officer
President
Chief Financial Officer
Chief Operating Officer
Controller

Other management representatives shall be invited to attend as necessary.

9. The external auditors shall report directly to the Committee and the external auditors and internal auditors (if any) shall have a direct line of communication to the Committee through its chair and may bypass management if deemed necessary. The Committee, through its chair, may contact directly any employee of the Corporation as it deems necessary, and any employee may bring before the Committee any matter involving questionable, illegal or improper financial practices or transactions.

10. The Committee may retain, at the Corporation's expense, special legal, accounting or other consultants or experts it deems necessary in the performance of its duties and may set and pay the compensation for any advisor engaged. The Committee will notify the Chairman of the Board whenever independent consultants are engaged.

Handling of Complaints

The Committee shall maintain procedures for the receipt, retention and treatment of complaints received by the Corporation regarding accounting, internal accounting controls or auditing matters, and the confidential, anonymous submission by employees of the Corporation of concerns regarding questionable accounting or auditing matters (a "**whistleblower policy**").

Annual Review

The Committee shall review and assess the adequacy of its mandate annually, report to the Board of Directors thereon and recommend any proposed changes to the Board of Directors for approval. The Committee shall also perform an annual evaluation of the performance of the Committee and shall report the results of the evaluation to the Chairman of the Board of the Corporation's Board of Directors.

Roles And Responsibilities

The overall duties and responsibilities of the Committee shall be as follows:

(a) to assist the Board in the discharge of its responsibilities relating to the Corporation's accounting principles, reporting practices and internal controls and its approval of the Corporation's annual and quarterly consolidated financial statements and management's discussion and analysis;

(b) to establish and maintain a direct line of communication with the Corporation's internal (if any) and external auditors and assess their performance;

(c) to assist the Board in the discharge of its responsibilities relating to oversight of the Corporation's internal, financial and disclosure controls and procedures;

(d) to periodically review the audit and non-audit services pre-approval policy and recommend to the Board any changes which the Committee deems appropriate;

(e) to periodically consider whether there is a need to outsource internal audit functions or create an internal audit department;

(f) to assist the Board in the discharge of its responsibilities relating to the evaluation and disclosure of its oil and gas reserves and oil and gas activities and the approval and filing of all necessary statements and reports related thereto;

(g) to receive and review complaints received pursuant to the Corporation's Whistleblower Policy and oversee and provide direction on the investigation and resolution of such concerns and to periodically review the said policy and recommend to the Board changes which the Committee may deem appropriate;

(h) to report regularly to the Board on the fulfilment of its duties and responsibilities;

(i) to identify and monitor the management of the principal risks that could impact the financial reporting of the Corporation;

(j) to ensure that it satisfies those responsibilities set out in Part 2 of MI 52-110 and provisions contained within the Companion Policy to 52-110; and

(k) review and approve the Corporation's hiring policies regarding partners, employees and former partners and employees of the present and former external auditors of the Corporation.

The duties and responsibilities of the Committee as they relate to the external auditors shall be as follows:

(l) to be directly responsible for overseeing the work of the external auditors engaged for the purpose of preparing or issuing an auditor's report or performing other audit, review or attest services for the Corporation, including the resolution of disagreements between management and the external auditors regarding financial reporting;

(m) to recommend to the Board a firm of external auditors to be nominated for appointment by the shareholders of the Corporation, and to monitor and verify the independence of such external auditors;

(n) to review and approve the fee, scope and timing of the audit and other audit related and non-audit services rendered by the external auditors;

(o) review the audit plan of the external auditors prior to the commencement of the audit;

(p) to review with the external auditors, upon completion of their audit:

   (i) contents of their report;

   (ii) scope and quality of the audit work performed;

   (iii) adequacy of the Corporation's financial and auditing personnel;

   (iv) co-operation received from the Corporation's personnel during the audit;

   (v) internal resources used;

   (vi) significant transactions outside of the normal business of the Corporation;

   (vii) significant proposed adjustments and recommendations for improving internal accounting controls, accounting principles or management systems; and

(viii) the non-audit services provided by the external auditors, as pre-approved pursuant to the audit and non-audit services pre-approval policy;

(q) to discuss with the external auditors the quality and not just the acceptability of the Corporation's accounting principles;

(r) to review any unresolved issues between management and the external auditors that could affect the financial reporting or internal controls of the Corporation;

(s) to implement structures and procedures to ensure that the Committee meets the external auditors on a regular basis in the absence of management; and

(t) to receive a written statement not less than annually from the external auditor describing in detail all relationships between the auditor and the Corporation that may impact the objectivity and independence of the auditor. The Committee shall review annually with the Board of Directors the independence of the external auditors and either confirms to the Board of Directors that the external auditors are independent or recommend that the Board of Directors take appropriate action to satisfy itself of the external auditor's independence.

The duties and responsibilities of the Committee as they relate to the internal control procedures of the Corporation are to:

(u) review the appropriateness and effectiveness of the Corporation's policies and business practices which impact on the financial integrity of the Corporation, including those relating to insurance, accounting, information services and systems and financial controls, management reporting and risk management;

(v) review compliance under the Corporation's Code of Business Conduct Policy with those matters addressed in the policy which affect the financial integrity of the Corporation and to periodically review this policy and recommend to the Board changes which the Committee may deem appropriate; and

(w) periodically review the Corporation's financial and auditing procedures and the extent to which recommendations made by the internal accounting staff or by the external auditors have been implemented.

The Committee is also charged with the responsibility to:

(x) review and recommend to the Board for its approval, the Corporation's annual financial statements, management's discussion and analysis, annual information form and annual earnings press releases before the Corporation publicly discloses this information;

(y) review and approve the Corporation's interim financial statements, interim management's discussion and analysis including the impact of unusual items and changes in accounting principles and estimates and report to the Board with respect thereto and interim earnings press releases before the Corporation publicly discloses this information;

(z) review and approve the financial sections of:

(i) the annual report to shareholders;

(ii) the annual information form;

(iii) prospectuses;

(iv) other public reports requiring approval by the Board; and

(v) press releases related thereto,

and report to the Board with respect thereto;

(aa) review regulatory filings and decisions as they relate to the Corporation's consolidated financial statements;

(bb) review the appropriateness of the policies and procedures used in the preparation of the Corporation's consolidated financial statements and other required disclosure documents, and consider recommendations for any material change to such policies;

(cc) review and report on the integrity of the Corporation's consolidated financial statements;

(dd) review the minutes of any audit committee meeting of any subsidiary of the Corporation;

(ee) review with management, the external auditors and, if necessary, with legal counsel, any litigation, claim or other contingency, including tax assessments that could have a material effect upon the financial position or operating results of the Corporation and the manner in which such matters have been disclosed in the consolidated financial statements;

(ff) review the Corporation's compliance with regulatory and statutory requirements as they relate to financial statements, tax matters and disclosure of material facts;

(gg) develop a calendar of activities to be undertaken by the Committee for each ensuing year related to the Committee's duties and responsibilities as set forth in this Charter and to submit the calendar in the appropriate format to the Board of Directors within a reasonable period of time following each annual general meeting of shareholders;

(hh) ensure all material public documents relating to the financial performance, financial position or analysis thereon are reviewed by the Committee or another appropriate committee, as designated by the Board of Directors. In certain cases which involve severe timing considerations, the Committee may designate the responsibility for review to any two members of the Committee. The Committee shall review and monitor practices and procedures adopted by the Corporation to assure compliance with applicable listing requirements, laws, regulations and other rules, and where appropriate, make recommendations or reports thereon to the Board of Directors;

(ii) The Committee shall review significant changes in the accounting principles to be observed in the preparation of the accounts of the Corporation and its subsidiaries, or in their application, and in financial disclosure presentation; and

(jj) The Committee shall prepare or review such reports as may be required by any applicable securities regulatory authority to be included in the Corporation's information circular – proxy statement or any other disclosure document of the Corporation.

Accountability

The Committee shall report its activities and proceedings to the Board by distributing the minutes of its meetings or by oral or written report at the next Board meeting.

Standards of Liability

Nothing contained in this mandate is intended to expand applicable standards of liability under statutory, regulatory, common law or any other legal requirements for the Board or members of the Committee. The purposes and responsibilities outlined in this mandate are meant to serve as guidelines rather than inflexible rules and the Committee may adopt such additional procedures and standards as it deems necessary from time to time to fulfill its responsibilities.

Annual Review And Assessment

The Committee shall conduct an annual review and assessment of its performance, including compliance with this Charter and its role, duties and responsibilities, and submit such report to the Board of Directors.