ANNUAL INFORMATION FORM

FOR THE YEAR ENDED

DECEMBER 31, 2010

March 15, 2011

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APPENDICES

CONVENTIONS

A reference in this Annual Information Form to "**Perpetual**" or the "**Corporation**" means Perpetual Energy Inc. Certain other terms used but not defined herein are defined in National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities* ("**NI 51-101**") and in the Canadian Oil and Gas Evaluation Handbook Volume I (the "**COGE Handbook**"). Unless otherwise specified, information in this Annual Information Form is as at the end of the Corporation's most recently completed financial year, being December 31, 2010. All dollar amounts herein are in Canadian dollars, unless otherwise stated. Words importing the singular also include the plural, and *vice versa*, and words importing one gender include all genders.

ABBREVIATIONS

Natural Gas		**Oil and Liquids**	
Mcf	thousand cubic feet	Bbl	barrels
MMcf	million cubic feet	Mbbl	thousand barrels
Mcfe	thousand cubic feet equivalent	Bpd	barrels per day
Bcf	billion cubic feet	m^3	cubic metres
Bcfe	billion cubic feet equivalent	BOE	barrel of oil equivalent of natural gas on the basis of 1 Bbl for 6 Mcf of natural gas
Mcf/d	thousand cubic feet per day	MBOE	thousand barrels of oil equivalent
MMcf/d	million cubic feet per day	MMBOE	million barrels of oil equivalent
Mcfe/d	thousand cubic feet equivalent per day	BOE/d	barrels of oil equivalent per day
m^3	cubic metres		
MMbtu	million British Thermal Units		
GJ	gigajoule		

Approximately 95% of the Corporation's annual production volumes and 94% of the its proved and probable reserves are related to natural gas and, as such, the Corporation reports production and reserves in Mcf equivalent (Mcfe). Mcfe may be misleading, particularly if used in isolation. In accordance with NI 51-101, an Mcfe conversion ratio for oil of 1 Bbl: 6 Mcf has been used, which, like BOE, is based on an energy equivalency conversion method primarily applicable at the burner tip and does not necessarily represent a value equivalency at the wellhead.

CONVERSION

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

To Convert From	**To**	**Multiply By**
Mcf	cubic metres	28.174
cubic metres	cubic feet	35.494
bbls	cubic metres	0.159
cubic metres	bbls	6.293
feet	metres	0.305
metres	feet	3.281
miles	kilometres	1.609
kilometres	miles	0.621
acres	hectares	0.405
hectares	acres	2.471
gigajoules	MMbtu	0.950

SPECIAL NOTE REGARDING FORWARD-LOOKING INFORMATION AND STATEMENTS

Certain statements contained in this Annual Information Form constitute forward-looking information and statements within the meaning of applicable securities laws. This information and these statements relate to future events or to Perpetual's future performance. All statements other than statements of historical fact may be forward-looking statements. The use of any of the words "anticipate", "continue", "estimate", "expect", "may", "will", "project", "should", "believe", "outlook", "guidance", "objective", "plans", "intends", "targeting", "could", "potential", "outlook", "strategy" and any similar expressions are intended to identify forward-looking information and statements.

In particular, but without limiting the foregoing, this Annual Information Form contains forward-looking information and statements pertaining to the following:

- the quantity and recoverability of the Corporation's reserves;
- the timing and amount of future production;
- future prices as well as supply and demand for natural gas and oil;
- the existence, operations and strategy of the commodity price risk management program;
- the approximate amount of forward sales and hedging to be employed, and the value of financial forward natural gas contracts;
- funds flow sensitivities to commodity price, production, foreign exchange and interest rate changes;
- operating, G&A, and other expenses;
- cash dividends, and the funding and tax treatment thereof;
- expected use of proceeds of the Notes;
- amount of future abandonment and reclamation costs, asset retirement and environmental obligations;
- the use of exploration and development activity, prudent asset management, and acquisitions to sustain, replace or add to reserves and production or expand the Corporation's asset base;
- the Corporation's acquisition strategy and the existence of acquisition opportunities, the criteria to be considered in connection therewith and the benefits to be derived therefrom;
- the Corporation's ability to benefit from the combination of growth opportunities and the ability to grow through the capital markets;
- expected book value and related tax value of the Corporation's assets and prospect inventory and estimates of net asset value;
- ability to fund dividends and exploration and development;
- expectations regarding the Corporation's access to capital to fund its acquisition, exploration and development activities;
- the transition to IFRS and its impact on the Corporation's financial results;
- expected realization of gas over bitumen royalty adjustments;
- future income tax and its effect on funds flow and dividends;
- intentions with respect to preservation of tax pools of and taxes payable by the Corporation;
- funding of and anticipated results from capital expenditure programs;
- renewal of and borrowing costs associated with the credit facility;
- future debt levels, financial capacity, liquidity and capital resources;
- future contractual commitments;
- drilling, completion, facilities and construction plans;
- the impact of Canadian federal and provincial governmental regulation on the Corporation relative to other issuers;
- Crown royalty rates;
- the Corporation's treatment under governmental regulatory regimes;
- business strategies and plans of management, including future changes in the structure of business operations;
- the anticipated dividend payment and amount thereof contemplated to be paid; and
- the reliance on third parties in the industry to develop and expand the Corporation's assets and operations.

The forward-looking information and statements contained in this Annual Information Form reflect several material factors and expectations and assumptions of the Corporation including, without limitation, that Perpetual will conduct its operations in a manner consistent with its expectations and, where applicable, consistent with past practice; the general continuance of current or, where applicable, assumed industry conditions; the continuance of existing, and in certain circumstances, the implementation of proposed tax, royalty and regulatory regimes; the ability of Perpetual to obtain equipment, services, and supplies in a timely manner to carry out its activities; the accuracy of the estimates of Perpetual's reserve and resource volumes; the timely receipt of required regulatory approvals; certain commodity price and other cost assumptions; the timing and costs of storage facility and pipeline construction and expansion and the ability to secure adequate product transportation; the continued availability of adequate debt and/or equity financing and funds flow to fund the Corporation's capital and operating requirements as needed; and the extent of Perpetual's liabilities.

Perpetual believes the material factors, expectations and assumptions reflected in the forward-looking information and statements are reasonable but no assurance can be given that these factors, expectations and assumptions will prove to be correct. The forward-looking information and statements included in this Annual Information Form are not guarantees of future performance and should not be unduly relied upon. Such information and statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information or statements including, without limitation:

- volatility in market prices for oil and natural gas products;
- supply and demand regarding Perpetual's products;
- risks inherent in Perpetual's operations, such as production declines, unexpected results, geological, technical, or drilling and process problems;
- unanticipated operating events that can reduce production or cause production to be shut-in or delayed;
- changes in exploration or development plans by Perpetual or by third party operators of Perpetual's properties;
- reliance on industry partners;
- uncertainties or inaccuracies associated with estimating reserves volumes;
- competition for, among other things; capital, acquisitions of reserves, undeveloped lands, skilled personnel, equipment for drilling, completions, facilities and pipeline construction and maintenance; increased costs;
- incorrect assessments of the value of acquisitions;
- increased debt levels or debt service requirements;
- industry conditions including fluctuations in the price of natural gas and related commodities;
- royalties payable in respect of Perpetual's production;
- governmental regulation of the oil and gas industry, including environmental regulation;
- fluctuation in foreign exchange or interest rates;
- the need to obtain required approvals from regulatory authorities;
- changes in laws applicable to the Corporation, royalty rates, or other regulatory matters;
- general economic conditions in Canada, the United States and globally;
- stock market volatility and market valuations;
- limited, unfavourable, or a lack of access to capital markets; and
- certain other risks detailed from time to time in Perpetual's public disclosure documents including, without limitation, those risks and contingencies described above and under "Risk Factors" in this Annual Information Form and under "Risk Factors" in the Corporation's management's discussion and analysis for the year ended December 31, 2010, which will be available on the Corporation's website at www.perpetualenergyinc.com as well as at www.sedar.com and at www.sec.gov. The foregoing list of risk factors should not be considered exhaustive.

The forward-looking information and statements contained in this Annual Information Form speak only as of the date of this Annual Information Form, and none of the Corporation or its subsidiaries assumes any obligation to publicly update or revise them to reflect new events or circumstances, unless expressly required to do so by applicable securities laws.

CORPORATE STRUCTURE

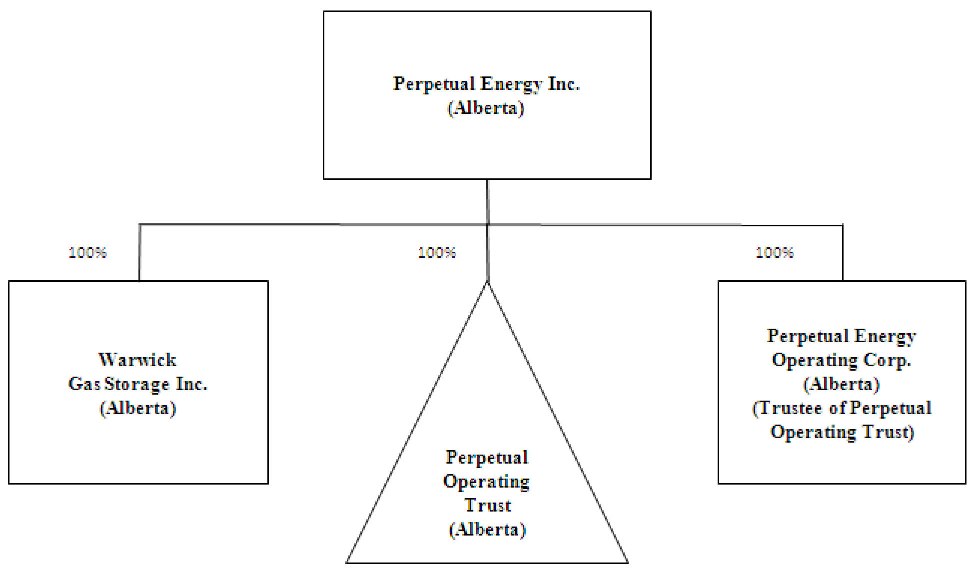
Name, address and incorporation

Perpetual was incorporated under the *Business Corporations Act* (Alberta) (the "**ABCA**") under the name "Perpetual Energy Inc." on April 26, 2010. Perpetual amalgamated with its wholly-owned subsidiaries 1143046 Alberta Ltd., POT Acquisition Company Ltd., Profound Energy Inc. and Starboard Gas (W3) Ltd. on June 30, 2010 and continued as Perpetual Energy Inc.

Perpetual's head office and registered office is located at Suite 3200, 605 – 5th Avenue S.W., Calgary, Alberta T2P 3H5.

Intercorporate relationships

The following diagram illustrates the intercorporate relationship between Perpetual and its material subsidiaries, the percentage of votes attached to all voting securities of the subsidiaries beneficially owned, or controlled or directed, directly or indirectly, by Perpetual and the jurisdiction of incorporation or formation of the subsidiaries.



GENERAL DEVELOPMENT OF THE BUSINESS

Three Year History

The general development of Perpetual's business over the last three completed financial years that include events, such as acquisitions or dispositions, or conditions that have had an influence on that development, are described below.

In November 2010, the Corporation sold natural gas assets for gross proceeds of $40.0 million. The disposed assets had proved plus probable natural gas reserves of 33.4 Bcf. Production of these assets had previously been shut-in by an order from the Energy Resources Conservation Board ("**ERCB**") in an effort to protect potential future bitumen production from comingling with natural gas reserves. As such, the economic benefit to Perpetual was derived from the royalty deductions management could realize from the shut-in production. Under the terms of the transaction, Perpetual retained the right to the royalty deductions. See "*Risk Factors – Gas Over Bitumen Matters*".

On November 8, 2010, Perpetual reduced its dividend from $0.05/share per month to $0.03/share per month in order to provide Perpetual with additional capital to direct towards economic new venture development opportunities in the Cardium and Wilrich, the continued evaluation of other new ventures in the Montney play at Elmworth, Alberta, the Viking and Colorado shale plays and the further delineation and development of its liquids-rich gas and light and heavy oil and bitumen resource prospects.

On June 30, 2010, Perpetual completed a plan of arrangement pursuant to which former unitholders of Paramount Energy Trust (the "**Trust**") received common shares ("**Common Shares**") in consideration for the cancellation of their trust units on a one-for-one basis, the Trust was dissolved and Perpetual assumed all of the existing liabilities of the Trust, including the Trust's outstanding convertible debentures which are now convertible debentures of the Corporation.

In May 2010, Perpetual began injection in its gas storage operation which was built using one of its depleted gas reservoirs. The facility is located near three major pipelines in the Warwick area east of Edmonton.

On April 1, 2010, the Trust acquired oil and natural gas assets in the Edson area of west central Alberta for approximately $126 million (the "**Edson Acquisition**"). The assets acquired pursuant to the Edson Acquisition consisted of 10.1 MMcfe/d of natural gas and liquids production (80% natural gas) as well as extensive gathering and processing infrastructure and 13,393 net acres of undeveloped prospective lands in a desirable multi-zone part of the Alberta deep basin.

As part of the Edson Acquisition, Perpetual agreed to farm-in on 37 gross (31 net) sections of undeveloped Cardium rights in the area of which 22 net sections are believed to be prospective for light oil. The farm-in included a two well horizontal drilling and completion commitment, each earning 50 percent of the vendor's net interest in four sections followed by a rolling option to earn the additional lands on the same basis. The Edson Acquisition was funded through a combination of bank debt, the early termination of gas price hedging contracts and an issue of 12.1 million subscription receipts at a price of $4.75 per subscription receipt for total proceeds of $57.5 million, which were subsequently converted into 12.1 million trust units of the Trust.

On August 13, 2009, pursuant to a takeover offer, the conversion of previously issued special warrants, open market purchases and a second stage transaction, the Trust acquired all of the outstanding common shares of Profound Energy Inc. ("**Profound**"). Cash consideration paid for Profound consisted of $6.9 million for the special warrants, $3.1 million for the open market share purchases and $14.2 million for the tendered shares, and $3.3 million of acquisition costs for a total of $27.5 million. In addition, the Trust issued 10 million trust units of the Trust to Profound shareholders valued at $32.2 million. Through the acquisition of Profound, Perpetual established production in west central Alberta, and secured deep basin resource-style play opportunities and exposure to development of the Pembina area tight Cardium oil play.

Significant Acquisitions

Perpetual did not complete any significant acquisitions during its most recently completed financial year for which disclosure is required under Part 8 of National Instrument 51-102 – *Continuous Disclosure Obligations*.

Recent Developments

On March 15, 2011, the Corporation issued $150 million aggregate principal amount of 8.75% senior unsecured notes due March 15, 2018 (the "**Notes**"). It is anticipated that the net proceeds from the issuance of the Notes will be used for the repayment of bank indebtedness and the Corporation's outstanding 6.50% Convertible Debentures.

DESCRIPTION OF THE BUSINESS

General

Perpetual is engaged in finding, exploiting, producing and marketing oil and gas based energy. Perpetual's business primarily consists of three operations: (i) operations associated with the drilling and extraction of natural gas and heavy oil from mature producing regions in eastern Alberta where the Corporation has an established gathering, processing and transportation infrastructure; (ii) the Corporation's natural gas resource growth opportunities in the deep basin in west central Alberta and the Viking/Colorado shale in east central Alberta, and bitumen opportunities in northeast Alberta; and (iii) the Corporation's gas storage facility at Warwick, Alberta.

Business Plan

Perpetual's business plan pursues an entrepreneurial approach to value creation and is focused on sustainability of production and funds flow from its base shallow gas assets and growth through new ventures. In recent years, the Corporation has consciously moved to reposition its asset base to enhance and diversify its prospect inventory, adding an element of higher impact, growth oriented, resource-style opportunities to its asset portfolio. New ventures include exploration, exploitation and development of oil and liquids rich resource plays, heavy oil exploration and development and bitumen resource definition and extraction in northeast Alberta. These opportunities include Cardium development at Pembina, Wilrich development at Edson, Montney exploration at Elmworth, Viking and Colorado shale in east central Alberta, and heavy oil/bitumen plays in northeast Alberta. Other new ventures include development of commercial gas storage synergistic with its base shallow gas assets. Currently new ventures are geographically focused in Alberta, with oil and liquids rich gas resource new ventures concentrated in the Alberta deep basin and heavy oil exploration and development synergistic with its base gas assets in eastern Alberta. Geographic diversity into other regions in North America is within the scope of Perpetual's business plan.

Further option value is imbedded in Perpetual's assets as well in such areas as gas over bitumen technical solutions potentially returning shut-in gas to production, Perpetual's bitumen resource base in northeast Alberta, tight oil and gas exploration, CO_2 sequestration and storage and coalbed methane assets in eastern Alberta.

The Corporation seeks to add value through sustainability of its base shallow gas assets, maximizing funds flow and optimizing exploitation of these base producing assets, pursuing low exposure, concentric exploration of its undeveloped shallow gas land base and making accretive acquisitions to complement and enhance the value of the shallow gas opportunity inventory.

Further value creation is targeted through growth from new ventures. Development and further expansion of Perpetual's resource-style liquids-rich gas reserves in west central Alberta, development of tight oil resources and further exploration to expand the tight oil opportunity base, exploration and development of heavy oil, expansion of the working gas capacity of its gas storage business and prudent acquisitions of additional lands and assets driven by these core competencies.

OTHER BUSINESS INFORMATION

Specialized Skill and Knowledge

Perpetual employs individuals with various professional skills in the course of pursuing its business plan. These professional skills include, but are not limited to, geology, geophysics, engineering, financial and business skills, which are widely available in the industry. Drawing on significant experience in the oil and gas business, Perpetual believes its management team has a demonstrated track record of bringing together all of the key components to a successful exploration and production company: strong technical and leadership skills; expertise in planning and financial controls; ability to execute on business development opportunities; capital markets expertise; and an entrepreneurial spirit that allows Perpetual to effectively identify, evaluate and execute on value added initiatives.

Competitive Conditions

The oil and natural gas industry is very competitive. The Canadian Association of Petroleum Producers estimates that there are over 1,000 exploration and production companies in Canada. Perpetual controls less than one percent of the business in western Canada, but where it is active, Perpetual believes it has a strong competitive position.

Companies operating in the petroleum industry must manage risks which are beyond the direct control of company personnel. Among these risks are those associated with exploration, environmental damage, commodity prices, foreign exchange rates and interest rates.

The oil and natural gas industry is intensely competitive and Perpetual competes with a substantial number of other entities, many of which have greater technical or financial resources. With the maturing nature of the Western Canadian Sedimentary Basin, the access to new prospects is becoming more competitive and complex.

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

Cycles

Our operational results and financial condition will be dependent on commodity prices, specifically the prices of oil and natural gas. Commodity prices have fluctuated widely during recent years and are determined by supply and demand factors including weather and general economic conditions as well as conditions in other oil and natural gas producing regions. The exploration for and the development of oil and natural gas reserves is dependent on access to areas where drilling is to be conducted. Seasonal weather variation, including "freeze-up" and "break-up", affect access in certain circumstances. See "Risk Factors – Seasonality".

Environmental Protection

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

Employees

At December 31, 2010, Perpetual had 154 permanent employees and 21 consultants located at its Calgary office, and 106 permanent employees and seven contract operators in various field locations. Perpetual currently has 153 permanent employees and 20 consultants located at its Calgary office, and 103 permanent employees and seven contract operators in various field locations.

Reorganizations

Other than disclosed under "General Development of the Business", Perpetual has not completed any material reorganization within the three most recently completed financial years or completed during the current financial year. No material reorganization is currently proposed for the current financial year. See "General Development of the Business".

Environmental, Health and Safety Policies

The Corporation supports environmental protection and employee health and safety by integrating the essential principles and practices through its environmental management systems and employee occupational health and safety programs. The Corporation promotes safety and environmental awareness and protection through the implementation and communication of the Corporation's environmental management and employee occupational health and safety programs policies and procedures. Committees focused on environment, health and safety ("**EH&S**") issues are established in the Corporation's operations which are designed to allow for employee participation and development of EH&S policies and programs which target accountability for EH&S by all employees. Practices for continuous improvement of EH&S performance include providing employees with job orientation, training, instruction and supervision to build knowledge, skill and accountability in conducting their activities in an environmentally responsible and safe manner.

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

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

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

Date of Statement

The statement of reserves data and other oil and gas information set forth below is dated March 10, 2011 and effective as at December 31, 2010.

Disclosure of Reserves Data

The reserves data set forth below is based upon the simple arithmetical summation by Perpetual of the figures contained in: (i) the report of McDaniel & Associates Consultants Ltd. ("**McDaniel**") dated effective December 31, 2010, with a preparation date of February 7, 2011 (the "**Primary Reserve Report**") evaluating substantially all of Perpetual's crude oil, natural gas liquid ("**NGL**") and natural gas reserves except for Perpetual's Elmworth Montney property located in the Alberta Deep Basin; and (ii) the report of GLJ Petroleum Consultants Ltd. ("**GLJ**") dated effective December 31, 2010, with a preparation date of February 24, 2011 (the "**Supplemental Reserve Report**") evaluating all of Perpetual's crude oil, NGL and natural gas reserves of Perpetual's Elmworth Montney property.

McDaniel evaluated in the Primary Reserve Report approximately 91% of the assigned total proved plus probable reserves and 94% of the total proved plus probable future net revenue discounted at 10%. GLJ evaluated in the Supplemental Reserve Report approximately 7% of the assigned total proved plus probable reserves and 4% of the total proved plus probable future net revenue discounted at 10%.

Each of McDaniel and GLJ prepared their respective reserve reports using their own technical assumptions and interpretations, methodologies and pricing and cost assumptions. Accordingly, the simple arithmetic summation of the Primary Reserve Report and the Supplemental Reserve Report presented below would vary from the reserve information that would be derived from a consolidated reserves report prepared by McDaniel. Also due to rounding, certain columns may not add.

The Primary Reserve Report and Supplemental Reserve Report have each been prepared in accordance with the standards contained in the COGE Handbook and the reserve definitions contained in Form 51-101F1 of National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities* ("**NI 51-101**") and the COGE Handbook. Additional information not required by NI 51-101 has been presented to provide continuity and additional information which Perpetual believes is important to readers of this annual information form. McDaniel and GLJ were engaged to provide evaluations of proved and proved plus probable reserves and no attempt was made to evaluate possible reserves.

All of the Corporation's reserves are in Canada and, more specifically, in the province of Alberta.

The applicable Reports on Reserves Data by Independent Qualified Reserves Evaluators in Form 51-101F2 and the Report of Management and Directors on Oil and Gas Disclosure in Form 51-101F3 are attached as Appendices A through C to this annual information form.

There are numerous uncertainties inherent in estimating quantities of crude 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 annual information form 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 natural gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially from actual results. For those reasons, estimates of the economically recoverable crude oil, NGL 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. The Corporation'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.

The information relating to the Corporation's crude oil, NGL and natural gas reserves contains forward-looking statements relating to future net revenues, forecast capital expenditures, future development plans and costs related thereto, forecast operating costs, anticipated production and abandonment costs. See "*Forward-Looking Statements*" and "*Risk Factors – Reserves Estimates*".

It should not be assumed that the estimates of future net revenues presented in the tables below represent the fair market value of the reserves. There is no assurance that the forecast prices and costs assumptions will be attained and variances could be material. Actual natural gas reserves may be greater than or less than the estimates provided in this Statement of Reserves and Other Oil and Gas Information.

SUMMARY OF RESERVES
TOTAL RESERVES
as at December 31, 2010
FORECAST PRICES AND COSTS

	Light and Medium Crude Oil		Heavy Oil		Natural Gas		Natural Gas Liquids		Natural Gas Equivalent	
RESERVES CATEGORIES	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (MMcf)**	**Net (MMcf)**	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (MMcfe)**	**Net (MMcfe)**
Proved Producing	599	507	333	317	185,670	165,452	1,396	938	199,639	176,021
Proved Non Producing	0	0	0	0	20,785	18,874	141	104	21,632	19,496
Proved Undeveloped	92	80	128	123	22,990	21,257	513	411	27,389	24,943
Total Proved	691	587	461	440	229,445	205,584	2,051	1,452	248,661	220,459
Total Probable	244	189	348	312	224,742	198,724	1,415	1,021	236,782	207,855
Proved and Probable	935	776	809	752	454,187	404,308	3,466	2,473	485,444	428,314

NET PRESENT VALUE OF FUTURE NET REVENUE
BEFORE TAX
as at December 31, 2010
FORECAST PRICES AND COSTS ($millions)

	Before Income Taxes Discounted at (%) ($)					Unit Value Before Income Tax Discounted At 10%/Year ($/Mcfe)
RESERVES CATAGORIES	**0%**	**5%**	**10%**	**15%**	**20%**	
Proved Producing	785	630	532	464	413	2.67
Proved Non Producing	100	44	26	19	15	1.22
Proved Undeveloped	57	36	23	15	9	0.85

RESERVES CATAGORIES	Before Income Taxes Discounted at (%) ($)					Unit Value Before Income Tax Discounted At 10%/Year ($/Mcfe)
	0%	5%	10%	15%	20%	
Total Proved	942	710	582	498	437	2.34
Total Probable	759	491	346	258	199	1.46
Proved and Probable	1,700	1,201	928	756	636	1.91

NET PRESENT VALUE OF FUTURE NET REVENUE AFTER TAX as at December 31, 2010 FORECAST PRICES AND COSTS ($millions)

RESERVES CATAGORIES	After Income Taxes Discounted at (%)					Unit Value After Income Tax Discounted At 10%/Year ($/Mcfe)
	0%	5%	10%	15%	20%	
Proved Producing	776	624	528	461	411	2.64
Proved Non Producing	80	35	21	15	12	0.96
Proved Undeveloped	43	26	15	8	4	0.56
Total Proved	899	685	564	484	426	2.27
Total Probable	570	364	255	188	144	1.08
Proved and Probable	1,469	1,049	818	672	571	1.69

FUTURE NET REVENUE TOTAL RESERVES (UNDISCOUNTED) as at December 31, 2010 FORECAST PRICES AND COSTS ($ millions)

Reserves Category	Revenue	Royalties	Gas over Bitumen Royalty Adjustments	Operating Costs	Development Costs	Abandonment and Reclamation Costs	Future Net Revenue After Costs Before Income Taxes	Income Taxes	Future Net Revenue after Income Taxes
Proved Reserves	$1,681	($197)	$111	($527)	($75)	($50)	$942	($43)	$899
Proved and Probable Reserves	$3,458	($404)	$111	($1,100)	($280)	($84)	$1,700	($232)	$1,468

FUTURE NET REVENUE TOTAL RESERVES by production type as at December 31, 2010

RESERVES CATEGORY	Production Group	Future Net Revenue Before Income Taxes (discounted at 10%/year) ($millions)	Unit Value ($/Mcfe) ($/bbl)
Proved Reserves	Natural Gas and NGL (including by products but excluding solution gas from wells)	$543	$2.25
Proved Reserves	Light and Medium Crude Oil (including solution gas and other by products)	25	35.59
Proved Reserves	Heavy Oil (including solution gas and other by products)	14	30.48
Proved Reserves – Total		$582	$2.34
Proved and Probable Reserves	Natural Gas and NGL (including by products but excluding solution gas from	$873	$1.84

RESERVES CATEGORY	Production Group	Future Net Revenue Before Income Taxes (discounted at 10%/year) ($millions)	Unit Value ($/Mcfe) ($/bbl)
	wells)		
Proved and Probable Reserves	Light and Medium Crude Oil (including solution gas and other by products)	32	34.30
Proved and Probable Reserves	Heavy Oil (including solution gas and other by products)	23	29.00
Proved and Probable Reserves – Total		$928	$1.91

Forecast Prices and Costs

Pricing Assumptions (Forecast Prices and Costs)

SUMMARY OF PRICING ASSUMPTIONS
AS AT DECEMBER 31, 2010
FORECAST PRICES AND COSTS FOR
THE PRIMARY RESERVE REPORT

Year	West Texas Intermediate Crude Oil ($US/bbl)	Edmonton Light Crude Oil ($Cdn/bbl)	Natural Gas at AECO ($Cdn/GJ)	Foreign Exchange ($US/$Cdn)(1)
2011	85.00	84.20	4.03	0.975
2012	87.70	88.40	4.65	0.975
2013	90.50	91.80	5.12	0.975
2014	93.40	94.80	5.59	0.975
2015	96.30	97.70	6.02	0.975
2016	99.40	100.90	6.40	0.975
2017	101.40	102.90	6.73	0.975
2018	103.40	104.90	7.02	0.975
2019	105.40	107.00	7.21	0.975
2020	107.60	109.20	7.35	0.975
2021	109.70	111.30	7.44	0.975
2022	111.90	113.60	7.63	0.975
2023	114.10	115.80	7.78	0.975
2024	116.40	118.10	7.96	0.975
Thereafter	2%	2%	2%	0.975

SUMMARY OF PRICING ASSUMPTIONS
AS AT DECEMBER 31, 2010
FORECAST PRICES AND COSTS FOR
THE SUPPLEMENTAL RESERVE REPORT

Year	West Texas Intermediate Crude Oil ($US/Bbl)	Edmonton Light Crude Oil ($Cdn/Bbl)	Natural Gas at AECO ($Cdn/MMBtu)	Foreign Exchange ($US/$Cdn)(1)
2011	88.00	86.22	4.16	0.98
2012	89.00	89.29	4.74	0.98
2013	90.00	90.92	5.31	0.98
2014	92.00	92.96	5.77	0.98
2015	95.17	96.19	6.22	0.98
2016	97.55	98.62	6.53	0.98
2017	100.26	101.39	6.76	0.98
2018	102.74	103.92	6.90	0.98
2019	105.45	106.68	7.06	0.98
2020	107.56	108.84	7.21	0.98

Year	West Texas Intermediate Crude Oil ($US/Bbl)	Edmonton Light Crude Oil ($Cdn/Bbl)	Natural Gas at AECO ($Cdn/MMBtu)	Foreign Exchange ($US/$Cdn)(1)
Thereafter	2%	2%	2%	0.98

Note:

(1) Exchange rates used to generate the benchmark reference prices in this table.

For comparison purposes, the Corporation realized a weighted average gas price for the year ended December 31, 2010 of $4.17/Mcfe, including $2.93/Mcfe of realized hedging gains for natural gas. The weighted average AECO daily gas price for the same 12 month period was $4.00/Mcf.

Reconciliations of Changes in Reserves and Future Net Revenue

RECONCILIATION OF GROSS RESERVES
TOTAL RESERVES(1)
FORECAST PRICES AND COSTS

	Gross Proved				Gross Probable				Gross Proved + Probable			
FACTORS	Oil Mbbl	Gas MMcf	Liquids Mbbl	Gas Equiva-lent MMcfe	Oil Mbbl	Gas MMcf	Liquids Mbbl	Gas Equiva-lent MMcfe	Oil Mbbl	Gas MMcf	Liquids Mbbl	Gas Equivalent MMcfe
December 31, 2009(2)	1,123	229,330	1,107	242,709	515	219,840	607	226,574	1,638	449,170	1,714	469,283
Improved Recoveries, Extensions and Discoveries(3)	692	33,627	858	42,932	327	27,307	764	33,849	1,019	60,935	1,622	76,781
Technical Revisions	(49)	32,491	(248)	30,707	(77)	(2,802)	(164)	(4,248)	(127)	29,689	(412)	26,459
Acquisitions	168	24,488	778	30,168	50	10,672	356	13,113	219	35,159	1,135	43,281
Dispositions	(586)	(14,683)	(121)	(18,925)	(213)	(32,381)	(91)	(34,209)	(800)	(47,064)	(212)	(53,134)
Production	(183)	(52,313)	(255)	(54,942)	0	0	0	0	(183)	(52,313)	(255)	(55,704)
Economic Factors	(13)	(23,495)	(69)	(23,987)	(9)	2,106	(58)	1,704	(23)	(21,390)	(126)	(22,283)
December 31, 2010	1,152	229,445	2,051	248,661	592	224,742	1,415	236,783	1,744	454,187	3,466	485,444

(1) Includes reserves from zones not affected by gas over bitumen issue and reserves shut-in pursuant to AEUB decisions and orders. See "*Risk Factors – Gas Over Bitumen Matters*".

(2) The opening balance on December 31, 2009 includes all of Perpetual's reserves, including reserves that were shut-in or identified for shut-in as a result of the gas over bitumen issue. At December 31, 2009 and 2010 all reserves shut-in as a result of the gas over bitumen issue were categorized as probable reserves.

(3) The Corporation includes all reserve additions resulting from capital expenditures in Extensions, Improved Recoveries and Discoveries.

Additional Information Relating to Reserves Data

Undeveloped Reserves

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

	Light and Medium Oil (Mbbl)		Heavy Oil (Mbbl)		Natural Gas (MMcf)		NGLs (Mbbl)	
Year	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
Prior thereto	137	137	-	-	45,770	45,770	-	-

Year	Light and Medium Oil (Mbbl) First Attributed	Light and Medium Oil (Mbbl) Cumulative at Year End	Heavy Oil (Mbbl) First Attributed	Heavy Oil (Mbbl) Cumulative at Year End	Natural Gas (MMcf) First Attributed	Natural Gas (MMcf) Cumulative at Year End	NGLs (Mbbl) First Attributed	NGLs (Mbbl) Cumulative at Year End
2008	-	20	-	-	159	39,018	-	-
2009	78	78	-	-	6,509	31,018	306	306
2010	92	92	128	128	12,215	22,990	514	514

The Corporation has a large inventory of proved undeveloped reserves. Poor gas prices in 2010 deferred activity on these reserves. These reserves are booked as per the COGE handbook to company land immediately adjacent to existing producing wells. The Corporation plans to develop these reserves over the next four to five years as part of larger drilling programs. The Corporation uses many factors to determine its annual budgets and all projects, booked and unbooked, compete based on these factors with funds balanced to maximize returns from capital investments as well as drive strategic initiatives.

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

Year	Light and Medium Oil (Mbbl) First Attributed	Light and Medium Oil (Mbbl) Cumulative at Year End	Heavy Oil (Mbbl) First Attributed	Heavy Oil (Mbbl) Cumulative at Year End	Natural Gas (MMcf) First Attributed	Natural Gas (MMcf) Cumulative at Year End	NGLs (Mbbl) First Attributed	NGLs (Mbbl) Cumulative at Year End
Prior thereto	35	34	-	-	94,027	94,027	-	-
2008	-	90	-	-	9,246	100,109	-	-
2009	29	54	-	-	10,082	86,074	269	269
2010	46	46	86	86	14,373	101,690	486	600

The Corporation has a large inventory of proved and probable undeveloped reserves primarily on its Viking resource play in east central Alberta. New wells typically experience rapid production declines within the first 12 months of production and therefore a significant percent of the well's revenue is generated very early in its productive life. Poor gas prices in 2009 deferred activity on these reserves. These reserves are booked as per the COGE handbook to company lands. The Corporation plans to develop these reserves over the next eight to nine years as part of larger drilling programs. As stated above, the Corporation uses many factors to determine its annual budgets and all projects, booked and unbooked, compete based on these factors for a limited pool of capital funds.

Significant Factors or Uncertainties

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 reserves estimates contained herein are based on current production forecasts, prices and economic conditions.

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, 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, geophysical 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 following table sets forth development costs deducted in the estimation of Perpetual's future net revenue attributable to the reserve categories noted below.

FUTURE DEVELOPMENT COSTS
FORECAST PRICES AND COSTS ($millions)

Year	**Proved Reserves**		**Proved And Probable Reserves**	
	0%	10%	0%	10%
2011	44.0	42.0	54.2	51.7
2012	20.1	17.4	42.5	36.9
2013	10.3	8.1	32.5	25.6
2014	0.1	0.1	26.9	19.3
2015	0	0	23	15
Thereafter	0.5	0.2	100.6	50.2
Total	75.0	67.8	279.8	198.7

The Corporation expects to fund future development costs from internally-generated funds flow, debt or equity financing through the capital markets or the Corporation's Premium Distribution™ and Distribution Reinvestment Plan and the Corporation does not expect such costs to make development of any properties uneconomic.

The Reserve Reports estimate that future capital costs of $279.8 million will be required over the life of the Corporation's proved and probable reserves for the drilling, completion, equipping and tie-in of 19 conventional wells and up to 862 unconventional wells, 837 targeting the Cretaceous Viking formation, two targeting the Wilrich, 12 targeting the Montney formation, 11 targeting other west central zones and recompletion of up to 95 conventional wells and 144 resource wells included in Perpetual's proved and probable reserves. As the Corporation's technical staff continue to analyze and evaluate the asset base and expand the facilities and pipeline infrastructure, development of the Corporation's undeveloped reserves will be undertaken over the next several years. In addition to opportunities on Perpetual's asset base recognized in the Primary Reserve Report, many of Perpetual's current assets include significant incremental exploration, exploitation and development opportunities. The Corporation has identified in its prospect inventory additional drilling recompletion and facility-related opportunities beyond those included in the Primary Reserve Report. See "*Statement of Reserves Data and Other Oil and Gas Information - Other Oil and Gas Information – Prospect Inventory*".

Other Oil and Gas Information

Oil and Gas Properties

The following is a description of the Corporation's important oil and natural gas properties as at December 31, 2010. Production stated is the Corporation's working and royalty interest share of production volumes and, unless otherwise stated, is average production for 2010. Reserve amounts stated include Corporation Gross Reserves plus royalty interest reserves as at December 31, 2010 based on forecast costs and prices as evaluated in the Primary Reserve Report. See "*Disclosure of Reserves Data*". The estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties due to the effects of aggregation. Unless otherwise specified, gross acres, net acres and well count information are as at December 31, 2010.

Northern District

Athabasca

Calling Lake

The Calling Lake area is located in northeast Alberta approximately 230 kilometres north of Edmonton and comprises 94,317 net acres (46.1% undeveloped) with an average 62.4% working interest in 108 gross (67.4 net) producing natural gas wells. The average daily production for 2010 from the Calling Lake area was 6.1 MMcf/d of natural gas. The Primary Reserve Report evaluate the Corporation's total proved reserves at 6.8 Bcf and probable reserves at 3.0 Bcf for the Calling Lake area. Current production in Calling Lake is processed through a combination of operated and third party facilities.

Darwin

The Darwin area is located in northeast Alberta approximately 100 kilometres northeast of Peace River and comprises 123,611 net acres (87.0% undeveloped) including an average 73.0% working interest in 20 gross (14.6 net) producing natural gas wells. The average daily production for 2010 from the Darwin area was 2.0 MMcf/d of natural gas. The Primary Reserve Report evaluated the Corporation's total proved reserves at 2.4 Bcf and probable reserves at 1.1 Bcf for the Darwin area. Current production in Darwin is processed through a non-operated plant where the Corporation has a working interest.

Marten Hills

The Marten Hills area is located in northeast Alberta approximately 220 kilometres north of Edmonton and comprises 164,539 net acres (56.4% undeveloped) of which 68,682 gross (68,619 net) undeveloped acres are oil sands leases, including an average 74.8% working interest in 95 gross (71.1 net) producing natural gas wells. The average daily production for 2010 from the Marten Hills area was 4.2 MMcf/d of natural gas. The Primary Reserve Report evaluated the Corporation's total proved reserves at 9.2 Bcfe of natural gas and probable reserves at 3.1 Bcfe of natural gas. Production in the Marten Hills area is processed through a combination of third party and operated facilities.

Mitsue

The Mitsue area is located in northeast Alberta approximately 130 kilometres north of Edmonton and comprises 16,812 net acres (33.5% undeveloped) including an average 73.4% working interest in 34 gross (25.0 net) producing oil and natural gas wells. The average daily production for 2010 from the Mitsue area was 2.3 MMcfe/d of natural gas, oil and liquids. The Primary Reserve Report evaluated the Corporation's total proved reserves at 2.8 Bcfe of natural gas and probable reserves at 0.8 Bcfe of natural gas for the Mitsue area. The majority of the production in the Mitsue area is processed through a 100% Corporation owned facility with a small amount going into a third party facility. On February 23, 2011, the Mitsue property was sold for net proceeds of $9.0 million.

Panny

The Panny area is located in northeast Alberta and comprises 164,400 net acres (81.7% undeveloped) of which 97,920 gross (97,920 net) undeveloped acres are oil sands leases, with an average 100% working interest in 37 gross (37.0 net) producing natural gas wells. The average daily production for 2010 from the Panny area was 4.0 MMcf/d of natural gas. The Primary Reserve Report evaluated the Corporation's total proved reserves at 6.0 Bcfe and probable reserves at1.6 Bcfe for the Panny area. Current production in Panny is processed through a 100% Corporation owned gas processing facility.

Peter Lake

The Peter Lake area is located in northeast Alberta and comprises 32,191 net acres (39.8% undeveloped) with an average 93.0% working interest in 31 gross (28.8 net) producing natural gas wells. The average daily production for 2010 from the Peter Lake area was 3.4 MMcf/d of natural gas. The Primary Reserve Report evaluated the Corporation's total proved reserves at 3.1 Bcf and probable reserves at 1.5 Bcf for the Peter Lake area. Currently a majority of the production in Peter Lake is processed through two 100% Corporation owned and operated gas processing facilities, while a small amount goes through a 100% Corporation owned booster compressor and is then processed through a third party facility.

Wabasca

The Wabasca area is located in northeast Alberta approximately 170 kilometres north of Edmonton. The area comprises 98,813 net acres (60.8% undeveloped) of which 18,560 gross (18,560 net) undeveloped acres are oil sands leases, with an average 98.0% working interest in 64 gross (62.8 net) producing natural gas wells. The average daily production for 2010 from the Wabasca area was 9.5 MMcf/d of natural gas. The Primary Reserve Report evaluated Perpetual's total proved reserves at 14.3 Bcf and probable reserves at 5.1 Bcf for the Wabasca area. Current production in Wabasca is processed through a third party facility and operated compressor stations.

Athabasca Other

The other assets in the Athabasca area in northeast Alberta comprise 250,683 net acres (56.5% undeveloped) of which 28,800 gross (28,800 net) undeveloped acres are oil sands leases in the Duncan area, including an average 70.4% working interest in 81 gross (57.0 net) producing natural gas wells. The average daily production for 2010 from these assets was approximately 7.5 MMcf/d of natural gas. The Primary Reserve Report evaluated Perpetual's total proved reserves at 7.7 Bcf and probable reserves at 3.9 Bcf of natural gas for the Athabasca Other area. Production from these properties is processed through a combination of non-operated plants where the Corporation has a working interest and third party plants.

Northeast

Craigend

The Craigend area is in northeast Alberta approximately 120 kilometres northeast of Edmonton. The Craigend area comprises 127,474 net acres (43.9% undeveloped) with an average 84.5% working interest in 87 gross (73.5 net) producing natural gas wells. The average daily production for 2010 from the Craigend area was approximately 5.1 MMcf/d of natural gas. The Primary Reserve Report evaluated Perpetual's total proved reserves at 7.2 Bcf and probable reserves at 2.3 Bcf for the Craigend area. Production from the Craigend area is processed through a 100% owned and operated gas plant.

Ells

The Ells area is located in northeast Alberta approximately 70 kilometres northwest of Fort McMurray, and comprises 40,480 net acres (72.3% undeveloped) of which 15,360 gross (15,360 net) undeveloped acres are oil sands leases, as well as a 100% working interest in 24 gross (24.0 net) producing natural gas wells. The average daily production for 2010 from the Ells area was approximately 1.7 MMcf/d of natural gas. The Primary Reserve Report evaluated Perpetual's total proved reserves at 1.8 Bcf and probable reserves at 0.6 Bcf of natural gas for the Ells Property. The Ells area includes related facilities including a 100% Corporation owned and operated gas plant and a booster compressor station.

Kettle/ Chard /Quigley

The Chard/Kettle/Quigley area is in northeast Alberta approximately 80 kilometres south of Fort McMurray. The area comprises 131,368 net acres (51.3% undeveloped) including an average 92.4% working interest in 72 gross (66.6 net) producing natural gas wells. The average daily production for 2010 from the Chard area, including Kettle and Quigley, was approximately 3.0 MMcf/d of natural gas. The Primary Reserve Report evaluated Perpetual's total proved reserves at 3.9 Bcf and probable reserves at 1.6 Bcf of natural gas for the Chard/Kettle/Quigley area. In addition, the Corporation has 0.7 Bcf of probable reserves shut-in as a result of the gas over bitumen issue in this area. A majority of the production from the area is processed through a 100% Corporation owned gas plant at Kettle River. Two booster compressors reduce gathering system pressures to optimize production.

Leismer, Corner

The Corner/Leismer area is in northeast Alberta approximately 90 kilometres southwest of Fort McMurray. The area comprises 315,355 net acres (53.6% undeveloped) including a 98.6% working interest in 98 gross (96.6 net) producing natural gas wells. The average daily production for 2010 from the Corner/Leismer area was approximately 6.0 MMcf/d of natural gas. The Primary Reserve Report evaluated Perpetual's total proved reserves at 6.8 Bcf and probable reserves at 2.5 Bcf of natural gas for the Corner/Leismer area. In addition, the Corporation has 17.3 Bcf of probable reserves shut-in as a result of the gas over bitumen issue in this area. Production from the Corner/Leismer area is processed through five 100% Corporation owned field booster compressors and one gas plant 32.5% owned by the Corporation.

Liege/Legend

The Liege/ Legend area is in northeast Alberta approximately 120 kilometres west of Fort McMurray. The area comprises 134,008 net acres (76.9% undeveloped) of which 83,200 gross (83,200 net) undeveloped acres are oil sands leases, including an average 78.3% working interest in 18 gross (14.1 net) producing natural gas wells. The average daily production for 2010 from the Liege Area, including South, North, East Liege and Legend, was approximately 2.3 MMcf/d of natural gas. The Primary Reserve Report evaluated our total proved reserves at 0.1 Bcf and probable reserves at 0.0 Bcf of natural gas for the Liege area. In addition, we have 0.9 Bcf of probable reserves shut-in as a result of the gas over bitumen issue in this area. Production from the Liege area is processed through the South Liege gas plant owned 80.5% Company owned. The North Liege production flows through a 98% Company owned booster compressor to a third party plant for processing.

Saleski

The Saleski area is in northeast Alberta approximately 110 kilometres west of Fort McMurray. The area comprises 125,997 net acres (72.5% undeveloped) of which 1,280 gross (256 net) undeveloped acres are oil sands leases, including an average 80.5% working interest in 43 gross (34.6 net) producing natural gas wells. The average daily production for 2010 from the Saleski area was approximately 4.3 MMcf/d of natural gas. The Primary Reserve Report evaluated Perpetual's total proved reserves at 13.6 Bcf and probable reserves at 4.0 Bcf of natural gas for the Saleski area. Production at Saleski is processed through one gas plant owned 58.6% and operated by the Corporation.

Teepee Creek

The Teepee Creek area is in northeast Alberta approximately 175 kilometres west of Fort McMurray. The area comprises 21,680 net acres (27.3% undeveloped) including an average 92.9% working interest in 35 gross (32.5 net) producing natural gas wells. The average daily production for 2010 from the Teepee Creek area was 1.8 MMcf/d. The Primary Reserve Report evaluated Perpetual's total proved reserves at 2.5 Bcf and probable reserves at 0.4 Bcf of natural gas for the Teepee Creek area. Production from the Teepee Creek area is processed through a 100% the Corporation owned and operated gas plant.

Thornbury

The Thornbury area is in northeast Alberta approximately 75 kilometres southwest of Fort McMurray. The area comprises 53,540 net acres (33.4% undeveloped) including an average 77.4% working interest in 62 gross (48.0 net) producing natural gas wells. The average daily production for 2010 from the Thornbury area was approximately 4.3 MMcf/d of natural gas. The Primary Reserve Report evaluated Perpetual's total proved reserves at 5.6 Bcf and probable reserves at 2.0 Bcf of natural gas for the Thornbury area. In addition, the Corporation has 0.3 Bcf of probable reserves shut-in as a result of the gas over bitumen issue in this area. Production from the Thornbury area is processed through four gas plants and a field booster compressor owned by a third party.

Woodenhouse

The Woodenhouse area is located in northeast Alberta approximately 140 kilometres southwest of Fort McMurray and 300 kilometres north of Edmonton and comprises 122,054 net acres (48.5% undeveloped) of which 12,800 gross (12,800 net) undeveloped acres are oil sands leases, with an average 100.0% working interest in 61 gross (61.0 net) producing natural gas wells. The average daily production for 2010 from the Woodenhouse area was 5.1 MMcf/d of natural gas. The Primary Reserve Report evaluated Perpetual's total proved reserves at 16.7 Bcf and probable reserves at 2.7 Bcf for the Woodenhouse area. Current production in Woodenhouse is processed through a 100% the Corporation owned and operated gas plant.

Northeast Other

The other assets in the Northeast area in Alberta comprise 186,497 net acres (52.8% undeveloped) of which 3,840 gross (3,840 net) undeveloped acres are oil sands leases; including an average 57.3% working interest in 102 gross (58.4 net) producing natural gas wells. The average daily production for 2010 from these assets was approximately

5.7 MMcf/d of natural gas. The Primary Reserve Report evaluated Perpetual's total proved reserves at 5.1 Bcf and probable reserves at 2.2 Bcf of natural gas for the Northeast Other area. In addition, the Corporation has 8.8 Bcf of probable reserves shut-in as a result of the gas over bitumen issue in this area. Production from these properties is processed through a combination of non-operated plants where the Corporation has a working interest and third party plants.

Southern District

Birchwavy East

Duvernay

The Duvernay area comprises 255,694 net acres (41.3% undeveloped) including an average 88.0% working interest in 238 gross (209.4 net) producing wells. The average daily production for 2010 from the Duvernay area was 15.8 MMcf/d of natural gas. The Primary Reserve Report evaluated Perpetual's total proved reserves at 21.3 Bcf and probable reserves at 38.7 Bcf. Production in Duvernay is processed through a combination of an owned and operated plant, thru non-operated plants where the Corporation has a working interest, and third party plants.

Mannville

The Manville area comprises 124,899 net acres (21.8% undeveloped) including an average 94.8% working interest in 152 gross (144.1 net) producing wells. The average daily production for 2010 from the Manville area was 8.9 MMcf/d of natural gas and 42 bbls/d of oil and liquids. The Primary Reserve Report evaluated Perpetual's total proved reserves at 19.5 Bcfe and probable reserves at 15.8 Bcfe. Production in Manville is processed through two plants owned and operated by the Corporation.

Viking Kinsella

The Viking Kinsella area comprises 95,174 net acres (53.4% undeveloped) including an average 54.7% working interest in 83 gross (45.4 net) producing wells. The average daily production for 2010 from the Viking Kinsella area was 2.6 MMcfe/d of natural gas and 124 bbls/d oil and liquids. The Primary Reserve Report evaluated Perpetual's total proved reserves at 5.2 Bcfe and probable reserves at 5.3 Bcfe. Production in Viking Kinsella is processed through a combination of an owned and operated plant, a non-operated plant where the Corporation has a working interest, and third party plants.

Birchwavy West

Bruce

The Bruce area comprises 200,945 net acres (27.9% undeveloped) including an average 80.9% working interest in 202 gross (163.5 net) producing wells. The average daily production for 2010 from the Bruce area was 6.8 MMcfe/d of natural gas, oil and liquids. The Primary Reserve Report evaluated Perpetual's total proved reserves at 9.1 Bcfe and probable reserves at 38.4 Bcf. Production in Bruce is processed through one 91.5% owned and operated the Corporation plant and third party plants.

Killam

The Killam area comprises 61,557 net acres (60.8% undeveloped) including an average 73.6% working interest in 40 gross (29.4 net) producing wells. The average daily production for 2010 from the Killam area was 1.8 MMcf/d of natural gas. The majority of the assets in this area were acquired through the Birchwavy acquisition. The Primary Reserve Report evaluated Perpetual's total proved reserves at 1.9 Bcfe and probable reserves at 1.8 Bcf. Production in Killam is processed through a small 100% owned and operated plant and other third party plants.

Warwick

The Warwick area comprises 200,849 net acres (57.9% undeveloped) including an average 86.6% working interest in 162 gross (140.3 net) producing wells. The average daily production for 2010 from the Warwick area was 10.6 MMcf/d of natural gas. The Primary Reserve Report evaluated Perpetual's total proved reserves at 8.2 Bcf and probable reserves and probable reserves at 2.0 Bcf. In addition, the Corporation has 1.2 Bcf of proved reserves and 6.3 Bcf of probable reserves shut-in related to Warwick Gas Storage. Production in Warwick is processed through a combination of an owned and operated plant and third party plants.

Other Southern

Other non-core assets in the Southern area comprise 38,009 net acres (90.3% undeveloped) including an average 16.8% working interest in 106 gross (17.8 net) producing natural gas wells. The average daily production for 2010 from the Other Southern area was 0.7 MMcf/d of natural gas. The Primary Reserve Report evaluated Perpetual's total proved reserves at 0.8 Bcfe and probable reserves at 0.2 Bcfe. Production is processed through a combination of 100% owned facilities and several third party facilities.

West Central

Carrot Creek

The Carrot Creek area comprises 24,795 net acres (23.6% undeveloped) including an average 64.8% working interest in 45 gross (29.2 net) producing wells. The average daily production for 2010 for the Carrot Creek area was 7.2 MMcf/d of natural gas and 450 bbls/d of oil and liquids. The Primary Reserve Report evaluated Perpetual's total proved reserves at 17.5 Bcfe and probable reserves at 9.5 Bcfe. Production in Carrot Creek is processed through a non-operated plant and other third party facilities where the Corporation has working interest.

Edson

The Edson area comprises 33,811 net acres (43.5% undeveloped) including an average 94.8% working interest in 47 gross (44.6 net) producing wells. The average daily production for 2010 for the Edson area was 5.4 MMcf/d of natural gas and 291 bbls/d of oil and liquids. The Primary Reserve Report evaluated our total proved reserves at 31.4 Bcfe and probable reserves at 18.5 Bcfe. Production in Edson is processed through an owned and operated plant. Production in Edson is processed through an owned and operated compressor station with sales processed at a third party plant.

Elmworth

The Elmworth area comprises 53,776 net acres (100% undeveloped) including an average 46.6% working interest in 3.0 gross (1.4 net) producing wells. The Primary Reserve Report evaluated our total proved reserves at 14.5 Bcfe and probable reserves at 17.6 Bcfe.

Grande Prairie

The Grande Prairie area comprises 4,752 net acres (50.5% undeveloped) including an average 91.3% working interest in 4.0 gross (3.7 net) producing wells. The average daily production for 2010 for the Grande Prairie area was 3.5 MMcf/d of natural gas and 41 bbls/d of oil and liquids. The Primary Reserve Report evaluated Perpetual's total proved reserves at 3.2 Bcfe and probable reserves at 1.1 Bcfe. Production in Grande Prairie is processed through an owned and operated plant.

Pembina

The Pembina area comprises 27,801 net acres (64.4% undeveloped) including an average 70.8% working interest in 32 gross (22.7 net) producing wells. The average daily production for 2010 from the Pembina area was 1.2 MMcf/d of natural gas and 124 bbls/d of oil and liquids. The Primary Reserve Report evaluated Perpetual's total proved reserves at 4.9 Bcfe and probable reserves at 2.3 Bcfe. Production in Pembina is processed through owned and operated plants, as well as third party plants.

West Central Other

Other non-core assets in the West Central area comprise 58,912 net acres (85.1% undeveloped) acres of which 3,840 gross (3,840 net) undeveloped acres are oil sands leases; including an average 87.0% working interest in 10 gross (8.7 net) producing natural gas wells. The average daily production for 2010 from the West Central Other area was 1.4 MMcfe/d of natural gas and heavy oil. The Primary Reserve Report evaluated Perpetual's total proved reserves at 1.1 Bcfe and probable reserves at 10.4 Bcfe. Production from these areas is processed through a combination of 100% owned and operated facilities and several third party plants.

Oil and Gas Wells

The following table sets forth the number and status of wells in which the Corporation had a working interest as at December 31, 2010.

	Producing Gas Wells		Producing Oil Wells		Non Producing Gas Wells(3)(4)		Non Producing Oil Wells(3)(4)	
Property	**Gross(1)**	**Net(2)**	**Gross(1)**	**Net(2)**	**Gross(1)**	**Net(2)**	**Gross(1)**	**Net(2)**
Northern District								
Athabasca								
Calling Lake	108	67.4	-	-	56	25.2	-	-
Darwin	20	14.6	-	-	18	13.8	-	-
Marten Hills	93	69.1	2	2.0	60	49.2	1	1.0
Mitsue	25	16.6	9	8.4	8	4.0	1	0.1
Panny	36	36.0	1	1.0	8	8.0	-	-
Peter Lake	31	28.8	-	-	16	15.9	-	-
Wabasca	64	62.8	-	-	17	15.3	-	-
Athabasca Other(5)	216	132.0	-	-	137	78.6	1	0.5
Athabasca subtotal	593	427.3	12	11.4	320	210.0	3	1.6
Northeast								
Craigend	87	73.5	-	-	66	55.0	-	-
Ells	24	24.0	-	-	55	4.5	-	-
Kettle, Chard, Quigley	72	66.6	-	-	43	40.8	-	-
Leismer, Corner	98	96.6	-	-	138	134.2	-	-
Liege, Legend	18	14.1	-	-	32	29.5	-	-
Saleski	43	34.6	-	-	23	21.1	-	-
Teepee Creek	35	32.5	-	-	12	11.3	-	-
Thornbury	62	48.0	-	-	26	16.6	-	-
Woodenhouse	61	61.0	-	-	28	28.0	-	-
Northeast Other(6)	102	58.4	-	-	144	83.8	-	-
Northeast subtotal	602	509.2	-	-	517	424.9	-	-
Southern District								
Birchwavy East								
Duvernay	230	202.9	8	6.5	77	64.7	-	-
Mannville	146	139.3	6	4.8	56	56.3	4	4.0
Viking Kinsella	74	43.3	9	2.1	30	16.9	6	2.3
Birchwavy East subtotal	450	385.5	23	13.4	163	134.9	10	6.3
Birchwavy West								
Bruce	202	163.5	-	-	76	55.3	-	-
Killam	37	26.4	3	3.0	24	16.9	3	1.1
Warwick	161	139.6	1	0.7	59	48.2	-	-
Birchwavy West subtotal	400	329.6	4	3.7	159	120.4	3	1.1
Other Southern(7)	105	17.6	1	0.2	8	2.8	2	0.4

Property	Producing Gas Wells		Producing Oil Wells		Non Producing Gas Wells(3)(4)		Non Producing Oil Wells(3)(4)	
	Gross(1)	Net(2)	Gross(1)	Net(2)	Gross(1)	Net(2)	Gross(1)	Net(2)
West Central District								
Carrot Creek	34	21.5	11	7.7	12	7.9	1	0.7
Edson	43	41.4	4	3.1	18	13.5	-	-
Elmworth	-	-	-	-	3	1.4	-	-
Grande Prairie	4	3.7	-	-	-	-	1	1.0
Pembina	17	11.1	15	11.6	10	7.4	7	5.4
West Central Other(8)	6	5.4	4	3.3	8	7.0	1	1.0
West Central subtotal	104	83.1	34	25.7	51	37.1	10	8.1
Warwick Gas Storage	10	10.0	-	-	1	1.0	-	-
TOTAL	2,264	1,762.2	74	54.3	1,216	929.6	28	17.4

Notes:

(1) "**Gross**" refers to the number of wells, respectively, in which a working interest is held by the Corporation. In addition the Corporation held royalty interests 322 producing wells at December 31, 2010.
(2) "**Net**" refers to the aggregate of the numbers obtained by multiplying each gross well by the percentage working interest therein.
(3) "**Non-Producing**" refers to wells which are not currently producing either due to lack of facilities, markets or regulatory approval. This includes 111 gross (93.6 net) wells shut-in as a result of gas over bitumen regulatory rulings.
(4) Allowance for the abandonment costs associated with the well bores was made in the Primary Reserve Report. There are 50 wells that are classified as service wells not included in the gross/net well count.
(5) **Athabasca Other** includes Duncan, Edwand, Figure Lake, Portage, Ryan, Steele, Stry and Westlock.
(6) **Northeast Other** includes Birch Tar, Bohn Lake, Clyde, Hospital Creek Legend, Liege, Jean Lake, Pony, Surmont and Winefred.
(7) **Other Southern** includes Craigmyle, Medicine Hat, Sedalia and Sarcee.
(8) **West Central Other** includes Cabin Creek, Karr/Gold Creek and Peace River Arch.

Acreage Information

The following table sets out Perpetual's developed and undeveloped land holdings as at December 31, 2010. The Corporation does not have any material work commitments on any of Perpetual's properties.

Property	Developed Acres		Undeveloped Acres	
	Gross(1)	Net(2)	Gross(1)	Net(2)
Northern District				
Athabasca				
Calling Lake	100,160	50,871	72,000	43,446
Darwin	24,160	16,010	112,800	107,601
Marten Hills	96,402	71,049	28,281	24,232
Marten Hills Oil Sands Leases	640	640	68,682	68,619
Mitsue	17,762	11,179	8,000	5,632
Panny	30,944	30,080	37,184	36,400
Panny Oil Sands Leases	-	-	97,920	97,920
Peter Lake	23,235	19,372	15,138	12,819
Wabasca	40,354	38,466	44,665	41,567
Wabasca Oil Sands Leases	640	320	18,560	18,560
Athabasca Other(5)	252,797	108,941	151,348	112,942
Athabasca Other Oil Sands Leases	-	-	28,800	28,800
Athabasca subtotal	587,094	346,928	683,378	598,538
Northeast Alberta				
Craigend	89,105	71,507	71,277	55,966
Ells	12,160	11,200	16,640	13,920
Ells Oil Sands Leases	-	-	15,360	15,360
Kettle, Chard, Quigley	69,760	63,916	71,040	67,452
Liege, Legend	40,960	30,972	79,200	53,116

Property	Developed Acres Gross[(1)]	Developed Acres Net[(2)]	Undeveloped Acres Gross[(1)]	Undeveloped Acres Net[(2)]
Liege, Legend Oil Sands Leases	-	-	83,200	83,200
Leismer, Corner	151,930	146,325	182,150	169,030
Saleski	39,840	34,590	107,680	91,151
Saleski Oil Sands Leases	-	-	1,280	256
Teepee Creek	18,560	15,760	6,400	5,920
Thornbury	47,360	35,684	21,120	17,856
Woodenhouse	63,015	62,829	46,425	46,425
Woodenhouse Oil Sands Leases	-	-	12,800	12,800
Northeast Other[(6)]	164,444	87,936	211,287	97,721
Northeast Other Oil Sands Leases	-	-	3,840	3,840
Northeast subtotal	699,134	560,720	929,699	731,014
Southern District				
Birchwavy East				
Duvernay	195,771	150,159	110,708	105,535
Mannville	108,855	97,683	29,055	27,216
Viking Kinsella	106,659	44,383	60,752	50,792
Birchwavy East subtotal	411,286	292,225	200,514	183,542
Birchwavy West				
Bruce	210,752	144,971	58,657	55,974
Killam	50,795	24,151	52,757	37,405
Warwick	154,744	84,639	126,072	116,210
Birchwavy West subtotal	416,291	253,761	237,486	209,590
Other Southern[(7)]	29,002	3,703	37,689	34,306
West Central				
Carrot Creek	32,526	18,934	10,400	5,862
Edson	38,240	19,098	17,920	14,713
Elmworth	-	-	59,200	53,776
Grande Prairie	2,720	2,352	3,040	2,400
Pembina	16,800	9,894	23,040	17,907
West Central Other[(8)]	13,760	8,752	56,155	46,320
West Central Other Oil Sands Leases	-	-	3,840	3,840
West Central subtotal	104,046	59,029	173,595	144,818
TOTAL	2,246,853	1,516,366	2,265,562	1,876,409

Notes:

(1) "**Gross**" means the total number of acres in which the Corporation has an interest in respect of Perpetual's current assets.

(2) "**Net**" means the aggregate of the numbers obtained by multiplying each gross acre by the actual percentage interest therein.

(3) During 2011, 16,909 net acres are set to expire. A total of 165,526 net acres expired in 2010. The Corporation intends to assess all expiring lands and, where appropriate, seek continuation through mapping, development activity or, in the case of higher risk areas, farm outs, where third parties provide exploration funding in exchange for an earned working interest.

(4) "**Undeveloped Acres**" refers to land where there are not any existing wells within the rights associated with those lands

(5) **Athabasca Other** includes Caribou, Duncan, Edwand, Figure Lake, Fox Creek, Hercules, Portage, Ryan, Steele and Stry.

(6) **Northeast Other** includes Birch Tar, Bohn Lake, Clyde, Legend, Liege, Jean Lake, Pony, Surmont and Winefred.

(7) **Other Southern** includes Caroline, Craigmyle, Del Bonita, Medicine Hat, Red Jacket, Rouleau, Sarcee, Waskahigan,

(8) **West Central Other** includes Cabin Creek, Edson, Elmworth, Garrington, Jenner, Karr/Gold Creek, Peace River Arch and Willesden Green.

Production Estimates

The following table sets out the volume of Perpetual's production estimated by McDaniel on a proved and probable basis for the year ended December 31, 2011, which is reflected in the estimate of future net revenue disclosed in the tables.

2011 McDaniel Forecast Production	Natural Gas (MMcf/d)	Crude Oil (Mbbl/d)	Natural Gas Liquids (Mbbl/d)
Proved	140.4	0.6	0.6
Probable	11.3	0.0	0.1
Total Proved and Probable	151.7	0.6	0.7

Production History

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

	2010 Quarter Ended			
	Dec 31	Sept 30	June 30	Mar 31
Average Daily Production Volume				
Natural Gas (MMcfe/d)	145.1	151.0	165.2	149.2
Average Realized Price ($/Mcfe)	8.33	6.18	5.54	9.78
Royalties Paid ($/Mcfe)	(0.20)	(0.25)	(0.46)	(0.59)
Operating Costs ($/Mcfe)	(1.56)	(1.79)	(1.45)	(2.20)
Transportation Costs ($/Mcfe)	(0.21)	(0.21)	(0.20)	(0.22)
Netback ($/Mcfe)	6.36	4.27	3.48	7.12

The following table indicates Perpetual's average daily production from each of the Corporation's core areas for the year ended December 31, 2010:

Property	Production (MMcfe/d)
Northern District	
Athabasca	
Calling Lake	6.1
Darwin	2.0
Marten Hills	4.2
Mitsue	2.3
Panny	4.0
Peter Lake	3.4
Wabasca	9.5
Athabasca Other	7.5
Athabasca subtotal	39.1
Northeast Alberta	
Cold Lake/ Cold Lake Sonoma	1.6
Craigend	5.1
Ells	1.7
Kettle, Chard, Quigley	3.0
Leismer, Corner	6.0
Liege, Legend	7.0
Saleski	4.3
Teepee Creek	1.8
Thornbury	4.3

Property	Production (MMcfe/d)
Woodenhouse	5.1
Northeast Other	5.7
Northeast subtotal	41.2
Southern District	
Birchwavy East	
Duvernay	15.8
Mannville	9.1
Viking Kinsella	3.4
Birchwavy East subtotal	28.3
Birchwavy West	
Bruce	6.8
Killam	1.8
Warwick	10.6
Birchwavy West subtotal	19.2
Other Southern	0.7
West Central Region	
Carrot Creek	9.9
Edson	7.2
Grande Prairie	3.7
Pembina	1.9
West Central Other	1.4
West Central subtotal	24.1
TOTAL	**152.6**

Prospect Inventory

The Corporation has identified numerous exploitation, development and low exposure exploration opportunities which are not recorded in the Primary Reserve Report as these opportunities do not meet the criteria to be booked as proved or probable reserves under NI 51-101. These prospects are at various degrees of technical refinement and risk and will be pursued during 2011 and beyond through drilling, completion and tie-in activities or evaluated further with additional seismic. These will be pursued as they are technically refined and as economic factors such as commodity prices, proximity to infrastructure, operating costs, and gas production rates permit. The spending of additional capital beyond the estimates contained in the Primary Reserve Report is expected to increase value to the holders of Common Shares ("**Shareholders**") through the addition of production and reserves from new pools or acceleration of production in existing pools to decrease gas production rate declines with a corresponding increase in recoverable reserves, and a reduction in the number of years fixed costs are incurred. Facility optimization projects target production and reserves additions through improved recovery and by reducing operating costs to extend the economic life of producing assets with a corresponding increase in recoverable reserves.

Conventional Shallow Gas Opportunities

While the Primary Reserve Report includes costs and reserves for the drilling of only 19 conventional natural gas wells, the Corporation is pursuing the drilling of over five gross wells as part of Perpetual's inventory 2011 capital expenditure budget. Further, the Corporation's evaluation of its prospect inventory has identified more than 482 additional conventional drilling opportunities on the company lands targeting cretaceous Mannville and Devonian shallow gas including pool extensions, down spacing for new pools on developed lands and low exposure exploration on undeveloped lands. Additional drilling prospects are at varying levels of technical analysis and economic evaluation. In addition, potential exists for incremental gas production through recompletion of uphole zones in existing wells and optimization of facilities. Over 1,036 workovers and secondary zone completions have been identified that are not identified in the Primary Reserve Report. The Corporation's inventory of conventional drilling opportunities is continually replenished with the direction of a portion of the Corporation's annual capital expenditure budget to Crown and freehold land purchases.

Unconventional Viking and Colorado Shale

The Corporation has developed an inventory of unconventional Viking formation tight gas opportunities including 973 drilling and recompletion targets included in the Primary Reserve Report well counts. The Corporation has also identified in excess of 1,013 future drilling locations targeting the Viking formation and Colorado shale that were not included in the Primary Reserve Report. These will be pursued in orderly development with recompletions following the depletion of the underlying Mannville reservoirs and multi-well drilling programs initiated as economic and technical conditions dictate.

Bitumen Land Bank

The Corporation has positioned itself with 334,282 gross (307,594 net) acres of undeveloped oil sands leases throughout many of its shallow gas operating areas in northeast Alberta including Clyde, Duncan, Ells, Legend, Liege, Marten Hills, Panny, Peace River Arch, Ryan, Saleski, Wabasca/Hoole, and Woodenhouse. The bitumen resource potential on these leases will likely be developed over the long term using a variety of recovery techniques ranging from cold production to in-situ techniques such as SAGD technology. In 2011, Perpetual is drilling up to 10 wells to evaluate various oil sands leases.

West Central Alberta Exploration

The Corporation has accumulated 173,595 gross (144,818 net) acres of undeveloped land in West Central Alberta. The primary target is a high impact resource style tight gas and oil plays. Exploration activities on these lands are planned throughout the next several years. If economically and technically successful the lands will warrant significant capital for future development activities. The Corporation has increased its focus on growth opportunities in 2010, with plans in place to exploit several of its opportunities in the Montney formation at Elmworth, the Cardium formation at Carrot Creek and Pembina. In the Elmworth area, the Corporation and its partners are preparing to drill three horizontal (1.4 net) Montney gas wells drilled to date.

The Supplemental Reserve Report recognizes 14.5 Bcfe (2.4 MMBOE) of proven and 32.1 Bcfe (5.3 MMBOE) of proved and probable reserves to Perpetual's interest. Using the GLJ January 1, 2011 price forecast, the net present value of the reserves discounted at eight percent is estimated at $14.7 million for proved reserves and $43.6 million for total proved and probable reserves net to Perpetual, including recovery of future development capital ("**FDC**"). These reserves had previously been classified by McDaniel as contingent resources pending the definition of a development plan which was not available at the time their report was completed. Through an information swap with other nearby producers, the operator has since gathered the necessary data to build an economic development plan for the area. Perpetual has reviewed the development plan, and is in agreement with the assignment of reserves at this time. Based on the development plan, GLJ has assigned 20 to 25 bbls per MMcf of associated NGL reserves to the Montney at Elmworth. Liquids recovery could be enhanced through a development plan that incorporated improved deep cut liquids recovery as test results indicate free condensate in the order of 20 to 25 bbls per MMcf and other entrained NGL's of an additional 20 to 40 bbls per MMcf which could potentially be recoverable depending on the liquids recovery process. GLJ estimates FDC required to convert the non-producing and undeveloped reserves to producing reserves at $45.1 million.

An independent contingent resource assessment report was prepared by McDaniel for 35 gross sections of Perpetual's Montney acreage in the Elmworth area which on a preliminary basis estimates gross original gas in place on company interest lands of 809.4 Bcf plus associated natural gas liquids ("**NGLs**"). Assuming a range in recovery factors from 20-50%, gross recoverable sales gas is estimated from a low of 137.6 Bcf with 4.9 MMbbls of NGLs (166.7 Bcfe, 27.8 MMBOE) to a high of 344.0 Bcf with 20.2 MMbbls NGLs (465.4 Bcfe, 77.6 MMBOE), with McDaniel's best estimate at 35 percent recovery factor translating to 240.8 Bcf with 11.3 MMbbls NGLs (308.8 Bcfe, 51.5 MMBOE). On a working interest basis, the best estimate recoverable contingent resource is estimated at 145.0 Bcfe (24.2 MMBOE). Perpetual has an additional 34 gross sections in the Elmworth area which have not yet been evaluated through drilling in the Montney formation and therefore have no contingent resource or reserves assigned as yet.

Capital Expenditures

The following tables summarize capital expenditures related to Perpetual's activities for the year ended December 31, 2010:

	($millions)
Exploration and development expenditures	$101.6
Crown and freehold land purchases	13.8
Gas Storage	57.6
Acquisitions	142.6
Dispositions	(91.2)
Other	0.7
Total	$225.1

Exploration and development expenditures for 2010 include approximately $4.0 million in exploration costs which have been expensed directly on the Corporation's statement of earnings. Exploration costs include seismic expenditures and dry hole costs and are considered by the Corporation to be more closely related to investing activities than operating activities; as a result they are included with capital expenditures.

Exploration and Development Activities

The following table sets forth the gross and net exploratory and development wells in which the Corporation participated during the year ended December 31, 2010:

	Gross	**Net**
Exploratory Wells		
Light and Medium Oil	3	2.1
Natural Gas	20	18.1
Service	0	0.0
Dry	1	1.0
Total	24	21.2
Success Rate (%)	96%	95%
Development Wells		
Light and Medium Oil	10	8.5
Natural Gas	30	28.2
Service	5	6.0
Dry	1	1.0
Total	46	43.7
Success Rate (%)	98%	98%

Additional Information Concerning Abandonment and Reclamation Costs

The Corporation prepares an annual estimate of the Corporation's total future asset retirement obligation, based on net ownership interest in all wells and facilities, including wells with no reserves attributed including costs to abandon the wells, facilities and pipelines and reclaim the sites and the estimating timing of the costs to be incurred in future periods. Pursuant to this evaluation, the estimated undiscounted total value of the Corporation's future asset retirement obligations is $315 million as at December 31, 2010. As at December 31, 2010, the undiscounted net salvage value of the Corporation's gas plants, compressors and facilities was estimated at $148 million. The Primary Reserve Report includes an undiscounted amount of $83 million with respect to expected future well abandonment costs related specifically to proved and probable reserves and such amount is included in the values captioned "Proved and Probable" in the summary tables of Net Present Value of Future Revenue (See "*Disclosure of Reserves Data*"). Of the total future well abandonment costs included in the Primary Reserve Report an undiscounted amount of $56 million relates to the Corporation's developed reserves. The following table presents the estimated future asset retirement obligations and estimated net salvage values at various discount rates:

($millions, net to the Corporation)	Undiscounted	5%	8%	Discounted at 10%
Well abandonment costs for developed reserves included in Primary Reserve Report	$56	$35	$28	$24
Well abandonment costs for undeveloped reserves included in Primary Reserve Report	$28	$14	$10	$7
Well abandonment costs for total proved and probable reserves included in Primary Reserve Report	$84	$49	$37	$31
Estimate of other abandonment and reclamation costs not included in Primary Reserve Report	$231	$136	$103	$86
Total estimated future abandonment and reclamation costs	$315	$186	$140	$117
Salvage value	($148)	($88)	($66)	($55)
Abandonment and reclamation costs, net of salvage	$167	$98	$74	$62
Well abandonment costs for developed reserves included in Primary Reserve Report(1)	($56)	($35)	($28)	($24)
Estimate of additional future abandonment and reclamation costs, net of salvage (1)	$110	$63	$46	$38

Note:

(1) Future abandonment and reclamation costs not included in the Primary Reserve Report, net of salvage value.

Marketing and Transportation

The Corporation proactively manages its marketing portfolio in order to maximize the price the Corporation obtains for its production. Perpetual's internal team of gas marketing professionals is responsible for hands-on management of its physical oil and gas sales and hedging, including transportation and storage arrangements. Continuous market surveillance and analysis leads Perpetual to employ various hedging tools and pricing arrangements to, among other things:

- Protect the level of funds flow, monthly dividends and manage the balance sheet;
- Enhance or protect the economics of an acquisition or capital program by capturing pricing either at the same level or higher than the original evaluation; and
- Capitalize on perceived market anomalies.

Aside from the physical forward sales contracts at AECO fixed prices outlined below, the Corporation currently has no material future contracts to buy, sell, exchange or transport natural gas from Perpetual's assets. According to January estimates, Perpetual currently sells approximately 90% of Perpetual's gas production at AECO-based market prices. The remaining 10% is directed to natural gas aggregator pools.

As part of the Corporation's risk management strategy, Perpetual has also sold forward financial call options to counterparties to purchase natural gas from the Corporation at strike prices in excess of current forward prices. Call option contracts outstanding as of March 7, 2011 are as follows.

Type of Contract	Volumes at AECO (GJ/d)	% of 2011 Budgeted Production(2)	Strike Price (1) ($/GJ)	Futures Market(3) ($/GJ)	Term
Sold call	30,000	16	6.00	3.22	April – October 2011

Notes:

(1) Weighted average prices are calculated by netting the volumes of the lowest-priced financial and physical sold/bought contracts together and measuring the net volume at the weighted average "sold" price for the remaining financial and physical contracts.

(2) Calculated using 185,000 GJ/d and includes actual and gas over bitumen deemed projected production volumes and voluntary production shut-ins.
(3) Futures market reflects AECO/NYMEX forward market prices as at March 7, 2011.

From time to time the Corporation will enter into financial and forward physical gas sales arrangements to fix the basis differential between the NYMEX and AECO trading hubs. As of March 7, 2011, the Corporation had no outstanding net position in basis differential contracts.

INDUSTRY CONDITIONS

Companies operating in the oil and natural gas industry are subject to extensive regulation and control of operations (including land tenure, exploration, development, production, refining, transportation, and marketing) as a result of legislation enacted by various levels of government and with respect to the pricing and taxation of oil and natural gas through agreements among the governments of Canada, Alberta and British Columbia, all of which should be carefully considered by investors in the oil and natural gas industry. It is not expected that any of these regulations or controls will affect the Corporation's operations in a manner materially different than they will affect other oil and natural gas companies of similar size. All current legislation is a matter of public record and the Corporation 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 natural gas industry.

Pricing and Marketing

Crude Oil

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

Natural Gas

The price of the vast majority of natural gas produced in western Canada is now determined through highly liquid market hubs such as the Alberta "NIT" (Nova Inventory Transfer) hub rather than through direct negotiation between buyers and sellers. Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet certain other criteria prescribed by the NEB and the Government of Canada. Natural gas (other than propane, butane and ethane) exports for a term of less than two years or for a term of two to 20 years (in quantities of not more than 30,000 m^3/day) must be made pursuant to an NEB order. Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 25 years) or for a larger quantity requires an exporter to obtain an export licence from the NEB and the issuance of such a licence requires a public hearing and the approval of the Governor in Council.

The governments of Alberta and British Columbia 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

As a result of pipeline expansions over the past several years, there is ample pipeline capacity to accommodate current production levels of oil and natural gas in western Canada and pipeline capacity does not generally limit the ability to produce and market such production.

The North American Free Trade Agreement

The North American Free Trade Agreement ("**NAFTA**") among the governments of Canada, the United States and Mexico became effective on January 1, 1994. 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 the total supply of goods of the party maintaining the restriction as compared to the proportion prevailing in the most recent 36 month period; (ii) impose an export price higher than the domestic price (subject to an exception with respect to certain measures which only restrict the volume of exports); and (iii) disrupt normal channels of supply. All three signatory countries are prohibited from imposing a minimum or maximum export price requirement in any circumstance where any other form of quantitative restriction is prohibited. The signatory countries are also prohibited from imposing a minimum or maximum import price requirement except as permitted in enforcement of countervailing and anti-dumping orders and undertakings.

NAFTA prohibits discriminatory border restrictions and export taxes. NAFTA also requires energy regulators to ensure the orderly and equitable implementation of any regulatory changes and to ensure that the application of those changes will cause minimal disruption to contractual arrangements and avoid undue interference with pricing, marketing and distribution arrangements, all of which are important for Canadian oil and natural gas exports.

Royalties and Incentives

General

In addition to federal regulation, each province has legislation and regulations which govern royalties, production rates and other matters. The royalty regime in a given province is a significant factor in the profitability of crude oil, natural gas liquids, sulphur and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiation between the mineral freehold owner and the lessee, although production from such lands is subject to certain provincial taxes and royalties. Royalties from production on Crown lands are determined by governmental regulation and are generally calculated as a percentage of the value of gross production. The rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date, method of recovery and the type or quality of the petroleum product produced. Other royalties and royalty-like interests are, from time to time, carved out of the working interest owner's interest through non-public transactions. These are often referred to as overriding royalties, gross overriding royalties, net profits interests, or net carried interests.

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

Alberta

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

On October 25, 2007, the Government of Alberta released a report entitled "The New Royalty Framework" ("**NRF**") containing the Government's proposals for Alberta's new royalty regime which were subsequently implemented by the *Mines and Minerals (New Royalty Framework) Amendment Act, 2008*. The NRF took effect on January 1, 2009. On March 11, 2010, the Government of Alberta announced changes to Alberta's royalty system intended to increase Alberta's competitiveness in the upstream oil and natural gas sectors, which changes included a decrease in the maximum royalty rates for conventional oil and natural gas production effective for the January 2011 production month. Royalty curves incorporating the changes announced on March 11, 2010 were released on May 27, 2010.

With respect to conventional oil, the NRF eliminated the classification system used by the previous royalty structure which classified oil based on the date of discovery of the pool. Under the NRF, royalty rates for conventional oil are set by a single sliding rate formula which is applied monthly and incorporates separate variables to account for production rates and market prices. Royalty rates for conventional oil under the NRF ranged from 0-50%, an increase from the previous maximum rates of 30-35% depending on the vintage of the oil, and rate caps were set at $120 per barrel. Effective January 1, 2011, the maximum royalty payable under the NRF was reduced to 40%. The royalty curve for conventional oil announced on May 27, 2010 amends the price component of the conventional oil royalty formula to moderate the increase in the royalty rate at prices higher than $535/m^3 compared to the previous royalty curve.

Royalty rates for natural gas under the NRF are similarly determined using a single sliding rate formula incorporating separate variables to account for production rates and market prices. Royalty rates for natural gas under the NRF ranged from 5-50%, an increase from the previous maximum rates of 5-35%, and rate caps were set at $16.59/GJ. Effective January 1, 2011, the maximum royalty payable under the NRF was reduced to 36%. The royalty curve for natural gas announced on May 27, 2010 amends the price component of the natural gas royalty formula to moderate the increase in the royalty rate at prices higher than $5.25/GJ compared to the previous royalty curve.

Oil sands projects are also subject to the NRF. Prior to payout, the royalty is payable on gross revenues of an oil sands project. Gross revenue royalty rates range between 1-9% depending on the market price of oil: rates are 1% when the market price of oil is less than or equal to $55 per barrel and increase for every dollar of market price of oil increase to a maximum of 9% when oil is priced at $120 or higher. After payout, the royalty payable is the greater of the gross revenue royalty based on the gross revenue royalty rate of 1-9% and the net revenue royalty based on the net revenue royalty rate. Net revenue royalty rates start at 25% and increase for every dollar of market price of oil increase above $55 up to 40% when oil is priced at $120 or higher. An oil sands project reaches payout when its cumulative revenue exceeds its cumulative costs. Costs include specified allowed capital and operating costs related to the project plus a specified return allowance. As part of the implementation of the NRF, the Government of Alberta renegotiated existing contracts with certain oil sands producers that were not compatible with the NRF.

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

In April 2005, the Government of Alberta implemented the Innovative Energy Technologies Program (the "**IETP**"), which has the stated objectives of increasing recovery from oil and gas deposits, finding technical solutions to the gas over bitumen issue, improving the recovery of bitumen by in-situ and mining techniques and improving the recovery of natural gas from coal seams. The IETP is backed by a $200 million funding commitment over a five-year period beginning April 1, 2005 and provides royalty adjustments to specific pilot and demonstration projects that utilize new or innovative technologies to increase recovery from existing reserves.

On April 10, 2008, the Government of Alberta introduced two new royalty programs to be implemented along with the NRF and intended to encourage the development of deeper, higher cost oil and gas reserves. A five-year program for conventional oil exploration wells over 2,000 metres provides qualifying wells with up to a $1 million or 12 months of royalty relief, whichever comes first, and a five-year program for natural gas wells deeper than 2,500 metres provides a sliding scale royalty credit based on depth of up to $3,750 per metre. On May 27, 2010, the natural gas deep drilling program was amended, retroactive to May 1, 2010, by reducing the minimum qualifying depth to 2,000 metres, removing a supplemental benefit of $875,000 for wells exceeding 4,000 metres that are spud subsequent to that date, and including wells drilled into pools drilled prior to 1985, among other changes.

On November 19, 2008, in response to the drop in commodity prices experienced during the second half of 2008, the Government of Alberta announced the introduction of a five-year program of transitional royalty rates with the intent of promoting new drilling. The 5-year transition option is designed to provide lower royalties at certain price levels in the initial years of a well's life when production rates are expected to be the highest. Under this new program, companies drilling new natural gas or conventional deep oil wells (between 1,000 and 3,500 m) are given a one-time option, on a well-by-well basis, to adopt either the new transitional royalty rates or those outlined in the NRF. Pursuant to the changes made to Alberta's royalty structure announced on March 11, 2010, producers were only able to elect to adopt the transitional royalty rates prior to January 1, 2011 and producers that had already elected to adopt such rates as of that date were permitted to switch to Alberta's conventional royalty structure up until February 15, 2011. On January 1, 2014, all producers operating under the transitional royalty rates will automatically become subject to Alberta's conventional royalty structure. The revised royalty curves for conventional oil and natural gas will not be applied to production from wells operating under the transitional royalty rates.

On March 3, 2009, the Government of Alberta announced a three-point incentive program in order to stimulate new and continued economic activity in Alberta. The program introduced a drilling royalty credit for new conventional oil and natural gas wells and a new well royalty incentive program, both applying to conventional oil or natural gas wells drilled between April 1, 2009 and March 31, 2010. The drilling royalty credit provides up to a $200 per metre royalty credit for new wells and is primarily expected to benefit smaller producers since the maximum credit available will be determined using the company's production level in 2008 and its drilling activity between April 1, 2009 and March 31, 2010, favouring smaller producers with lower activity levels. The new well incentive program initially applied to wells that began producing conventional oil or natural gas between April 1, 2009 and March 31, 2010 and provided for a maximum 5% royalty rate for the first 12 months of production on a maximum of 50,000 barrels of oil or 500 MMcf of natural gas. In June, 2009, the Government of Alberta announced the extension of these two incentive programs for one year to March 31, 2011. On March 11, 2010, the Government of Alberta announced that the incentive program rate of 5% for the first 12 months of production would be made permanent, with the same volume limitations.

In addition to the foregoing, on May 27, 2010, in conjunction with the release of the new royalty curves, the Government of Alberta announced a number of new initiatives intended to accelerate technological development and facilitate the development of unconventional resources (the "**Emerging Resource and Technologies Initiative**"). Specifically:

- Coalbed methane wells will receive a maximum royalty rate of 5% for 36 producing months on up to 750 MMcf of production, retroactive to wells that began producing on or after May 1, 2010;

- Shale gas wells will receive a maximum royalty rate of 5% for 36 producing months with no limitation on production volume, retroactive to wells that began producing on or after May 1, 2010;

- Horizontal gas wells will receive a maximum royalty rate of 5% for 18 producing months on up to 500 MMcf of production, retroactive to wells that commenced drilling on or after May 1, 2010; and

- Horizontal oil wells and horizontal non-project oil sands wells will receive a maximum royalty rate of 5% with volume and production month limits set according to the depth of the well (including the horizontal distance), retroactive to wells that commenced drilling on or after May 1, 2010.

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

In addition to the foregoing, Alberta currently maintains a royalty reduction program for low productivity oil and oil sands wells, a royalty adjustment program for deep marginal gas wells and a royalty exemption for re-entry wells, among others.

British Columbia

Producers of oil and natural gas from Crown lands in British Columbia are required to pay annual rental payments, currently at a rate of $3.50 per hectare, and make monthly royalty payments in respect of oil and natural gas produced. The amount payable as a royalty in respect of oil depends on the type and vintage of the oil, the quantity of oil produced in a month and the value of that oil. Generally, oil is classified as either light or heavy and the vintage of oil is based on the determination of whether the oil is produced from a pool discovered before October 31, 1975 ("**old oil**"), between October 31, 1975 and June 1, 1998 ("**new oil**"), or after June 1, 1998 ("**third-tier oil**"). The royalty calculation takes into account the production of oil on a well-by-well basis, the specified royalty rate for a given vintage of oil, the average unit selling price of the oil and any applicable royalty exemptions. Royalty rates are reduced on low productivity wells, reflecting the higher unit costs of extraction, and are the lowest for third-tier oil, reflecting the higher unit costs of both exploration and extraction.

The royalty payable in respect of natural gas produced on Crown lands is determined by a sliding scale formula based on a reference price, which is the greater of the average net price obtained by the producer and a prescribed minimum price. For non-conservation gas (not produced in association with oil), the royalty rate depends on the date of acquisition of the oil and natural gas tenure rights and the spud date of the well and may also be impacted by the select price, a parameter used in the royalty rate formula to account for inflation. Royalty rates are fixed for certain classes of non-conservation gas when the reference price is below the select price. Conservation gas is subject to a lower royalty rate than non-conservation gas as an incentive for the production and marketing of natural gas which might otherwise have been flared.

Producers of oil and natural gas from freehold lands in British Columbia are required to pay monthly freehold production taxes. For oil, the level of the freehold production tax is based on the volume of monthly production. For natural gas, the freehold production tax is determined using a sliding scale formula based on the reference price similar to that applied to natural gas production on Crown land, and depends on whether the natural gas is conservation gas or non-conservation gas.

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

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

- *Deep Royalty Credit Program* providing a royalty credit equal to approximately 23% of drilling and completion costs for vertical wells with a true vertical depth greater than 2,500 metres and horizontal wells with a true vertical depth greater than 2,300 metres spud between December 1, 2003 and September 1, 2009;

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

- *Deep Discovery Royalty Credit Program* providing the lesser of a 3-year royalty holiday or 283,000,000 m^3 of royalty free gas for deep discovery wells with a true vertical depth greater than 4,000 metres whose surface locations are at least 20 kilometres away from the surface location of any well drilled into a recognized pool within the same formation with a spud date after November 30, 2003;

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

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

- *Ultra-Marginal Royalty Reduction Program* providing additional royalty breaks for low productivity shallow natural gas wells with a true vertical depth of less than 2,300 metres, average monthly production under 60,000 m^3 during the first 12 production months and average daily production less than 11.5 m^3 (development wells) or 17 m^3 (exploratory wildcat wells) for every 100 metres of marginal well depth; and

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

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

The Government of British Columbia also maintains an Infrastructure Royalty Credit Program (the "**Infrastructure Royalty Credit Program**") which provides royalty credits for up to 50% of the cost of certain approved road construction or pipeline infrastructure projects intended to improve, or make possible, the access to new and underdeveloped oil and gas areas. In both 2009 and 2010, the Government of British Columbia allocated $120 million in royalty credits for oil and gas companies under the Infrastructure Royalty Credit Program.

On August 6, 2009, the Government of British Columbia announced an oil and gas stimulus package designed to attract investment in and create economic benefits for British Columbia. The stimulus package includes four royalty initiatives related primarily to natural gas drilling and infrastructure development. Natural gas wells spudded within the 10-month period from September 1, 2009 to June 30, 2010 and brought on production by December 31, 2010 qualify for a 2% royalty rate for the first 12 months of production, beginning from the first month of production for the well (the "**Royalty Relief Program**"). British Columbia's existing Deep Royalty Credit Program was permanently amended for wells spudded after August 31, 2009 by increasing the royalty deduction on deep drilling for natural gas by 15% and extending the program to include horizontal wells drilled to depths of between 1,900 and 2,300 metres. Wells spud between September 1, 2009 and June 30, 2010 may qualify for both the Royalty Relief Program and the Deep Royalty Credit Program but will only receive the benefits of one program at a time. An additional $50 million was also allocated to be distributed through the Infrastructure Royalty Credit Program to stimulate investment in oilfield-related road and pipeline construction.

Land Tenure

Crude oil and natural gas located in the western provinces is owned predominantly by the respective provincial governments. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licences, and permits for varying terms, and on conditions set forth in provincial legislation including requirements to perform specific work or make payments. Oil and natural gas located in such provinces can also be privately owned and rights to explore for and produce such oil and natural gas are granted by lease on such terms and conditions as may be negotiated.

Each of the provinces of Alberta and British Columbia has implemented legislation providing for the reversion to the Crown of mineral rights to deep, non-productive geological formations at the conclusion of the primary term of a lease or license. On March 29, 2007, British Columbia's policy of deep rights reversion was expanded for new leases to provide for the reversion of both shallow and deep formations that cannot be shown to be capable of production at the end of their primary term.

In Alberta, the NRF includes a policy of "shallow rights reversion" which provides for the reversion to the Crown of mineral rights to shallow, non-productive geological formations for all leases and licenses. For leases and licenses issued subsequent to January 1, 2009, shallow rights reversion will be applied at the conclusion of the primary term of the lease or license. Holders of leases or licences that have been continued indefinitely prior to January 1, 2009 will receive a notice regarding the reversion of the shallow rights, which will be implemented three years from the date of the notice. The order in which these agreements will receive the reversion notice will depend on their vintage and location, with the older leases and licenses receiving reversion notices first beginning in January 2011. Leases and licences that were granted prior to January 1, 2009 but continued after that date will not be subject to shallow rights reversion until they reach the end of their primary term and are continued (at which time deep rights reversion will be applied); thereafter, the holders of such agreements will be served with shallow rights reversion notices based on vintage and location similar to leases and licences that were already continued as of January 1, 2009.

Environmental Regulation

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation, all of which is subject to governmental review and revision from time to time. Such legislation provides for restrictions and prohibitions on the release or emission of various substances produced in association with certain oil and gas industry operations, such as sulphur dioxide and nitrous oxide. In addition, such legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. Compliance with such legislation can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage, and the imposition of material fines and penalties.

In December, 2008, the Government of Alberta released a new land use policy for surface land in Alberta, the Alberta Land Use Framework (the "**ALUF**"). The ALUF sets out an approach to manage public and private land use and natural resource development in a manner that is consistent with the long-term economic, environmental and social goals of the province. It calls for the development of region-specific land use plans in order to manage the combined impacts of existing and future land use within a specific region and the incorporation of a cumulative effects management approach into such plans. The *Alberta Land Stewardship Act* (the "**ALSA**") was proclaimed in force in Alberta on October 1, 2009, providing the legislative authority for the Government of Alberta to implement the policies contained in the ALUF. Regional plans established pursuant to the ALSA are deemed to be legislative instruments equivalent to regulations and are binding on the Government of Alberta and provincial regulators, including those governing the oil and gas industry. In the event of a conflict or inconsistency between a regional plan and another regulation, regulatory instrument or statutory consent, the regional plan will prevail. Further, the ALSA requires local governments, provincial departments, agencies and administrative bodies or tribunals to review their regulatory instruments and make any appropriate changes to ensure that they comply with an adopted regional plan. The ALSA also contemplates the amendment or extinguishment of previously issued statutory consents such as regulatory permits, licenses, approvals and authorizations in order for the purpose of achieving or maintaining an objective or policy resulting from the implementation of a regional plan. Among the measures to support the goals of the regional plans contained in the ALSA are conservation easements, which can be granted for the protection, conservation and enhancement of land; and conservation directives, which are explicit declarations contained in a regional plan to set aside specified lands in order to protect, conserve, manage and enhance the environment. Although no regional plans have been established under the ALSA, the planning process is underway for the Lower Athabasca Region (which contains the majority of oil sands development) and the South Saskatchewan Region. While the potential impact of the regional plans established under the ALSA cannot yet be determined, it is clear that such regional plans may have a significant impact on land use in Alberta and may affect the oil and gas industry.

Climate Change Regulation

Federal

In December 2002, the Government of Canada ratified the Kyoto Protocol ("**Kyoto Protocol**"), which requires a reduction in greenhouse gas ("**GHG**") emissions by signatory countries between 2008 and 2012. The Kyoto Protocol officially came into force on February 16, 2005 and commits Canada to reduce its GHG emissions levels to 6% below 1990 "business-as-usual" levels by 2012.

On February 14, 2007, the House of Commons passed Bill C-288, *An Act to ensure Canada meets its global climate change obligations under the Kyoto Protocol*. The resulting *Kyoto Protocol Implementation Act* came into force on June 22, 2007. Its stated purpose is to "ensure that Canada takes effective and timely action to meet its obligations under the Kyoto Protocol and help address the problem of global climate change." It requires the federal Minister of the Environment to, among other things, produce an annual climate change plan detailing the measures to be taken to ensure Canada meets its obligations under the Kyoto Protocol. It also authorizes the establishment of regulations respecting matters such as emissions limits, monitoring, trading and enforcement.

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

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

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

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

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

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

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

The United Nations Framework Convention on Climate Change is working towards establishing a successor to the Kyoto Protocol. From December 7 to 18, 2009, a meeting between government leaders and representatives from approximately 170 countries in Copenhagen, Denmark (the "**Copenhagen Conference**") resulted in the Copenhagen Accord, which reinforces the commitment to reducing GHG emissions contained in the Kyoto Protocol and promises funding to help developing countries mitigate and adapt to climate change. From November 29 to December 10, 2010, a meeting between representatives from approximately 190 countries in Cancun, Mexico resulted in the Cancun Agreements, in which developed countries committed to additional measures to help developing countries deal with climate change. Unlike the Kyoto Protocol, however, neither the Copenhagen Accord nor the Cancun Agreements establish binding GHG emissions reduction targets.

In response to the Copenhagen Accord, the Government of Canada indicated on January 29, 2010 that it will seek to achieve a 17% reduction in GHG emissions from 2005 levels by 2020. This goal is similar to the goal expressed in previous policy documents which were discussed above.

Although draft regulations for the implementation of the Updated Action Plan were intended to be published in the fall of 2008 and become binding on January 1, 2010, no such regulations have been proposed to date. Further, representatives of the Government of Canada have indicated that the proposals contained in the Updated Action Plan will be modified to ensure consistency with the direction ultimately taken by the United States with respect to GHG emissions regulation. As a result, it is unclear to what extent, if any, the proposals contained in the Updated Action Plan will be implemented.

On December 23, 2010, the United States Environmental Protection Agency indicated its intention to impose GHG emissions standards for fossil fuel-fired power plants by July, 2011 and for refineries by December, 2011.

Alberta

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

Alberta facilities emitting more than 100,000 tonnes of GHGs a year are subject to compliance with the CCEMA. Similar to the Updated Action Plan, the CCEMA and the associated *Specified Gas Emitters Regulation* make a distinction between "Established Facilities" and "New Facilities". Established Facilities are defined as facilities that completed their first year of commercial operation prior to January 1, 2000 or that have completed eight or more years of commercial operation. Established Facilities are required to reduce their emissions intensity to 88% of their baseline for 2008 and subsequent years, with their baseline being established by the average of the ratio of the total annual emissions to production for the years 2003 to 2005. New Facilities are defined as facilities that completed their first year of commercial operation on December 31, 2000, or a subsequent year, and have completed less than eight years of commercial operation, or are designated as New Facilities in accordance with the *Specified Gas Emitters Regulation*. New Facilities are required to reduce their emissions intensity by 2% from baseline in the fourth year of commercial operation, 4% of baseline in the fifth year, 6% of baseline in the sixth year, 8% of baseline in the seventh year, and 10% of baseline in the eighth year. Unlike the Updated Action Plan, the CCEMA does not contain any provision for continuous annual improvements in emissions intensity reductions beyond those stated above.

The CCEMA contains compliance mechanisms that are similar to the Updated Action Plan. Regulated emitters can meet their emissions intensity targets by contributing to the Climate Change and Emissions Management Fund (the "**Fund**") at a rate of $15 per tonne of CO_2 equivalent. Unlike the Updated Action Plan, CCEMA contains no provisions for an increase to this contribution rate. Emissions credits can be purchased from regulated emitters that have reduced their emissions below the 100,000 tonne threshold or non-regulated emitters that have generated emissions offsets through activities that result in emissions reductions in accordance with established protocols published by the Government of Alberta. Unlike the Updated Action Plan, the CCEMA does not contemplate a linkage to external compliance mechanisms such as the Kyoto Protocol's Clean Development Mechanism.

On December 2, 2010, the Government of Alberta passed the *Carbon Capture and Storage Statutes Amendment Act, 2010*, which deemed the pore space underlying all land in Alberta to be, and to have always been, the property of the Crown and provided for the assumption of long-term liability for carbon sequestration projects by the Crown, subject to the satisfaction of certain conditions.

British Columbia

In February, 2008, British Columbia announced a revenue-neutral carbon tax that took effect July 1, 2008. The tax is consumption-based and applied at the time of retail sale or consumption of virtually all fossil fuels purchased or used in British Columbia. The initial level of the tax was set at $10 per tonne of CO_2 equivalent and rose to $15 per tonne of CO_2 equivalent on July 1, 2009 and $20 per tonne of CO_2 equivalent on July 1, 2010. It is scheduled to further increase at a rate of $5 per tonne of CO_2 equivalent on July 1 of every year until it reaches $30 per tonne of CO_2 equivalent on July 31, 2012. In order to make the tax revenue-neutral, British Columbia has implemented tax credits and reductions in order to offset the tax revenues that the Government of British Columbia would otherwise receive from the tax.

On April 3, 2008, British Columbia introduced the *Greenhouse Gas Reduction (Cap and Trade) Act* (the "**Cap and Trade Act**") which received royal assent on May 29, 2008 and will come into force by regulation of the Lieutenant Governor in Council. Unlike the emissions intensity approach taken by the federal government and the Government of Alberta, the Cap and Trade Act establishes an absolute cap on GHG emissions. It is expected that GHG emissions restrictions will be applied to facilities emitting more than 25,000 tonnes of CO_2 equivalents per year, which will be required to meet established targets through a combination of emissions allowances issued by the Government of British Columbia and the purchase of emissions offsets generated through activities that result in a reduction in GHG emissions. Although more specific details of British Columbia's cap and trade plan have not yet been finalized, on January 1, 2010, new reporting regulations came into force requiring all British Columbia facilities emitting over 10,000 tonnes of CO_2 equivalents per year to begin reporting their emissions. Facilities reporting emissions greater than 25,000 tonnes of CO_2 equivalents per year are required to have their emissions reports verified by a third party.

RISK FACTORS

Investors should carefully consider the risk factors set out below and consider all other information contained herein and in the Corporation's other public filings before making an investment decision.

Gas Over Bitumen Matters

The ERCB has established a process to identify gas production in Alberta that may pose an unacceptable risk to the stability and viability of co-located bitumen resources and has ordered the shut-in of natural gas production in northeast Alberta. These "shut-in orders" have called into question the ability to produce natural gas when the production of natural gas interferes with ultimate bitumen recovery. In particular, the ERCB, as part of its broad bitumen conservation strategy, has ordered the shut-in of natural gas production in the Wabiskaw and McMurray formations in certain parts of the Athabasca Oil Sands Area in northeast Alberta. Prior to certain asset dispositions undertaken by Perpetual, the Corporation's production used to be directly affected by such shut-in orders. The Corporation cannot ensure that additional production will not be shut-in in the future or that it will be able to negotiate adequate compensation for having to shut-in any such production. This could have a material adverse effect on the amount of cash available for dividends.

The Government of Alberta has presently prescribed a reduction in the royalty calculated for operators of gas wells which have been affected by shut-in orders. The Corporation is currently receiving these royalty reductions and there is no assurance that such reductions will continue to be received by the Corporation.

Solution Gas Ownership

A portion of the Corporation's natural gas production is from properties where third parties hold bitumen rights. Certain of these third parties have suggested that "solution gas" exists within the bitumen and that therefore this solution gas is the property of the bitumen rights holder. If this is proven to be correct, and if it is demonstrated that this solution gas has been or may continue to be produced in association with the recovery of Perpetual's conventional natural gas rights, these facts may give rise to a third party claim for compensation and impact future production and reserves. A successful claim in this regard may have a material adverse effect on our business, financial condition and operations.

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 the Corporation depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, any existing reserves the Corporation may have at any particular time, and the production therefrom will decline over time as such existing reserves are exploited. A future increase in the Corporation'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 the Corporation will be able to continue to locate satisfactory properties for acquisition or participation. Moreover, if such acquisitions or participations are identified, management of the Corporation 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 the Corporation.

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, the Corporation 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 the Corporation. In accordance with industry practice, the Corporation is not fully insured against all of these risks, nor are all such risks insurable. Although the Corporation 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 the Corporation could incur significant costs. Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including encountering unexpected formations or pressures, premature decline of reservoirs and the invasion of water into producing formations. Losses resulting from the occurrence of any of these risks may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Global Financial Crisis

Recent market events and conditions, including disruptions in the international credit markets and other financial systems and the deterioration of global economic conditions, have caused significant volatility to commodity prices. These conditions worsened in 2008 and continued in 2009, causing a loss of confidence in the broader U.S. and global credit and financial markets and resulting in the collapse of, and government intervention in, major banks, financial institutions and insurers and creating a climate of greater volatility, less liquidity, widening of credit spreads, a lack of price transparency, increased credit losses and tighter credit conditions. Notwithstanding various actions by governments, concerns about the general condition of the capital markets, financial instruments, banks, investment banks, insurers and other financial institutions caused the broader credit markets to further deteriorate and stock markets to decline substantially. Although economic conditions improved towards the latter portion of 2009 and in 2010, as anticipated, the recovery from the recession has been slow in various jurisdictions including in Europe and the United States and has been impacted by various ongoing factors including sovereign debt levels and high levels of unemployment which continue to impact commodity prices and to result in high volatility in the stock market.

Prices, Markets and Marketing

The marketability and price of oil and natural gas that may be acquired or discovered by the Corporation is and will continue to be affected by numerous factors beyond its control. The Corporation's ability to market its oil and natural gas may depend upon its ability to acquire space on pipelines that deliver natural gas to commercial markets.

The Corporation may also be 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 prices may be volatile and subject to fluctuation. Any material decline in prices could result in a reduction of the Corporation'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 the Corporation's reserves. The Corporation might also elect not to produce from certain wells at lower prices. All of these factors could result in a material decrease in the Corporation's expected 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 Corporation. These factors include economic conditions, in the United States and Canada, the actions of OPEC, governmental regulation, political stability in the Middle East and elsewhere, the foreign supply of oil and gas, risks of supply disruption, the price of foreign imports and the availability of alternative fuel sources. Any substantial and extended decline in the price of oil and gas would have an adverse effect on the Corporation's carrying value of its reserves, borrowing capacity, revenues, profitability and cash flows from operations and may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Petroleum prices are expected to remain volatile for the near future as a result of market uncertainties over the supply and the demand of these commodities due to the current state of the world economies, OPEC actions and the ongoing credit and liquidity concerns. Volatile oil and gas prices make it difficult to estimate the value of producing properties for acquisition and often cause disruption in the market for oil and gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for and project the return on acquisitions and development and exploitation projects.

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

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

The Corporation 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 Corporation's ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of the Corporation. 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 Corporation 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 Corporation, if disposed of, could be expected to realize less than their carrying value on the financial statements of the Corporation.

Operational Dependence

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

The Corporation manages 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. The Corporation's ability to execute projects and market oil and natural gas depends upon numerous factors beyond the Corporation'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, the Corporation 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.

Competition

The petroleum industry is competitive in all its phases. The Corporation 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. The Corporation's competitors include oil and natural gas companies that have substantially greater financial resources, staff and facilities than those of the Corporation. The Corporation'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, pricing, marketing and transportation) are subject to extensive controls and regulations imposed by various levels of government, which may be amended from time to time. See "Industry Conditions". Governments may regulate or intervene with respect to price, taxes, royalties and the exportation of oil and natural gas. Such regulations may be changed from time to time in response to economic or political conditions. The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for natural gas and crude oil and increase the Corporation's costs, any of which may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. In order to conduct oil and gas operations, the Corporation will require licenses from various governmental authorities. There can be no assurance that the Corporation will be able to obtain all of the licenses and permits that may be required to conduct operations that it may wish to undertake.

Environmental

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and natural gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach of applicable environmental legislation may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require the Corporation to incur costs to remedy such discharge. Although the Corporation believes that it will be in material compliance with current applicable environmental regulations, no assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Climate Change

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". 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. The Corporation's exploration and production facilities and other operations and activities emit greenhouse gases and require the Corporation to comply with greenhouse gas emissions legislation in Alberta and British Columbia or that may be enacted in other provinces. The Corporation may also be required comply with the regulatory scheme for greenhouse gas emissions ultimately adopted by the federal government, which is now expected to be modified to ensure consistency with the regulatory scheme for greenhouse gas emissions adopted by the United States. The direct or indirect costs of these regulations may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. The future implementation or modification of greenhouse gases regulations, whether to meet the limits required by the Kyoto Protocol, the Copenhagen Accord or as otherwise determined, could have a material impact on the nature of oil and natural gas operations, including those of the Corporation. Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not possible to predict the impact on the Corporation and its operations and financial condition. See "Industry Conditions – Climate Change Regulation".

Variations in Foreign Exchange Rates and Interest Rates

World oil and gas prices are quoted in United States dollars and the price received by Canadian producers is therefore affected by the Canadian/U.S. dollar exchange rate, which will fluctuate over time. In recent years, the Canadian dollar has increased materially in value against the United States dollar. Material increases in the value of the Canadian dollar negatively impact the Corporation's production revenues. Future Canadian/United States exchange rates could accordingly impact the future value of the Corporation's reserves as determined by independent evaluators.

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

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

Substantial Capital Requirements

The Corporation anticipates making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. If the Corporation's revenues or reserves decline, it may not have access to the capital necessary to undertake or complete future drilling programs. In addition, uncertain levels of near term industry activity coupled with the present global credit crisis exposes the Corporation to additional access to capital risk. There can be no assurance that debt or equity financing, or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to the Corporation. The inability of the Corporation to access sufficient capital for its operations could have a material adverse effect on the Corporation's business financial condition, results of operations and prospects.

Additional Funding Requirements

The Corporation's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times. From time to time, the Corporation 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 the Corporation to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If the Corporation's revenues from its reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect the Corporation's ability to expend the necessary capital to replace its reserves or to maintain its production. If the Corporation'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 terms acceptable to the Corporation. Continued uncertainty in domestic and international credit markets could materially affect the Corporation's ability to access sufficient capital for its capital expenditures and acquisitions, and as a result, may have a material adverse effect on the Corporation's ability to execute its business strategy and on its business, financial condition, results of operations and prospects.

Issuance of Debt

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

Hedging

From time to time the Corporation 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, the Corporation will not benefit from such increases and the Corporation 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 the Corporation 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, the Corporation 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 the Corporation and may delay exploration and development activities.

Title to Assets

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

Reserve Estimates

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and natural gas liquids reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth herein are estimates only. In general, estimates of economically recoverable oil and natural gas reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of oil and gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially from actual results. For those reasons, estimates of the economically recoverable oil and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves prepared by different engineers, or by the same engineers at different times, may vary. The Corporation'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, the Corporation'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 the Corporation's oil and gas reserves will vary from the estimates contained in the reserve evaluation, and such variations could be material. The reserve evaluation is based in part on the assumed success of activities the Corporation intends to undertake in future years. The reserves and estimated cash flows to be derived therefrom contained in the reserve evaluation will be reduced to the extent that such activities do not achieve the level of success assumed in the reserve evaluation. The reserve evaluation is effective as of a specific effective date and has not been updated and thus does not reflect changes in the Corporation's reserves since that date.

Insurance

The Corporation's involvement in the exploration for and development of oil and natural gas properties may result in the Corporation becoming subject to liability for pollution, blow outs, leaks of sour natural gas, property damage, personal injury or other hazards. Although the Corporation maintains 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, the Corporation 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 the Corporation. The occurrence of a significant event that the Corporation is not fully insured against, or the insolvency of the insurer of such event, may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Geopolitical Risks

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

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

Dilution

The Corporation may make future acquisitions or enter into financings or other transactions involving the issuance of securities of the Corporation which may be dilutive. In addition, existing shareholders of the Corporation may in the future wish to reduce their share position in the Corporation and sell some or all of their shares. The sale of a substantial number of the Common Shares in the public market, or the perception that such sales may occur, could adversely affect the prevailing market price of the Common Shares and negatively impact the Corporation's ability to raise equity capital in the future.

Management of Growth

The Corporation may be subject to growth-related risks including capacity constraints and pressure on its internal systems and controls. The ability of the Corporation 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 the Corporation to deal with this growth may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Expiration of Licences and Leases

The Corporation's properties are held in the form of licences and leases and working interests in licences and leases. If the Corporation 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 the Corporation's licences or leases or the working interests relating to a licence or lease may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Dividends

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

Aboriginal Claims

Aboriginal peoples have claimed aboriginal title and rights to portions of western Canada. The Corporation is not aware that any claims have been made in respect of its properties and assets; however, if a claim arose and was successful such claim may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

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 the Corporation.

Third Party Credit Risk

The Corporation 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 the Corporation, such failures may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. In addition, poor credit conditions in the industry and of joint venture partners may impact a joint venture partner's willingness to participate in the Corporation's ongoing capital program, potentially delaying the program and the results of such program until the Corporation finds a suitable alternative partner.

Reliance on Key Personnel

The Corporation's success depends in large measure on certain key personnel including its Chief Executive Officer and its management team. The loss of the services of such key personnel may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. The Corporation does not have any key person insurance in effect for the Corporation. The contributions of the existing management team to the immediate and near term operations of the Corporation 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 the Corporation 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 the Corporation.

Certain Forward-Looking Information May Prove Inaccurate

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

Share Price Volatility

The market price for Common Shares may be volatile and subject to wide fluctuations in response to numerous factors, many of which are beyond the Corporation's control, including the following: (i) actual or anticipated fluctuations in the Corporation's quarterly results of operations; (ii) actual or anticipated changes in oil and natural gas prices; (iii) recommendations by securities research analysts; (iv) changes in the economic performance or market valuations of other companies that investors deem comparable to the Corporation; (v) addition or departure of the Corporation's executive officers and other key personnel; (ii) sales or perceived sales of additional Common Shares; (vii) significant acquisitions or business combinations, strategic partnerships, joint ventures or capital commitments by or involving the Corporation or its competitors; and (viii) news reports relating to trends, concerns, technological or competitive developments, regulatory changes and other related issues in the Corporation's industry or target markets.

Financial markets have experienced significant price and volume fluctuations in the last several years that have particularly affected the market prices of equity securities of companies and that have, in many cases, been unrelated to the operating performance, underlying asset values or prospects of such companies. Accordingly, the market price of the Common Shares may decline even if the Corporation's operating results, underlying asset values or prospects have not changed. Additionally, these factors, as well as other related factors, may cause decreases in asset values that are deemed to be other than temporary, which may result in impairment losses. As well, certain institutional investors may base their investment decisions on consideration of the Corporation's environmental, governance and social practices and performance against such institutions' respective investment guidelines and criteria, and failure to meet such criteria may result in a limited or no investment in the Common Shares by those institutions, which could adversely affect the trading price of the Common Shares. There can be no assurance that continuing fluctuations in the price and volume of publicly traded equity securities will not occur. If such increased levels of volatility and market turmoil continue, the Corporation's operations could be adversely impacted and the trading price of the Common Shares may be adversely affected.

Conflicts of Interest

Certain directors of the Corporation 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".

Changes to Accounting Policies, including the Implementation of IFRS

International Financial Reporting Standards ("**IFRS**") replaced Canadian generally accepted accounting principles ("**Canadian GAAP**") in 2011 for Canadian publicly accountable enterprises. While IFRS uses a conceptual framework similar to Canadian GAAP, there are significant differences that must be evaluated. The implementation of IFRS may result in significant adjustments to the Corporation's financial results, which could negatively impact the Corporation's business, including increasing the risk of failing a financial covenant contained within the Credit Facilities.

Future Acquisition Activities May Have Adverse Effects

The acquisition of oil and natural gas companies and assets is subject to substantial risks, including the failure to identify material problems during due diligence, the risk of over-paying for assets and the inability to arrange financing for an acquisition as may be required or desired. Further, the integration and consolidation of acquisitions requires substantial human, financial and other resources and, ultimately, the Corporation's acquisitions may not be successfully integrated. There can be no assurances that any future acquisitions will perform as expected or that the returns from such acquisitions will support the indebtedness incurred to acquire them or the capital expenditures needed to develop them.

Internal Controls

Effective internal controls are necessary for the Corporation to provide reliable financial reports and to help prevent fraud. Although the Corporation undertakes a number of procedures in order to help ensure the reliability of its financial reports, including those imposed on it under Canadian securities laws, the Corporation cannot be certain that such measures will ensure that the Corporation will maintain adequate control over financial processes and reporting. Failure to implement required new or improved controls, or difficulties encountered in their implementation, could harm the Corporation's results of operations or cause it to fail to meet its reporting obligations. If the Corporation or its independent auditors discover a material weakness, the disclosure of that fact, even if quickly remedied, could reduce the market's confidence in the Corporation's consolidated financial statements and adversely affect the trading price of the Common Shares.

Litigation Risks

In the normal course of the Corporation's operations, it may become involved in, named as a party to, or be the subject of, various legal proceedings, including regulatory proceedings, tax proceedings and legal actions, relating to personal injuries, property damage, property taxes, land rights, the environment and contract disputes. The outcome of outstanding, pending or future proceedings cannot be predicted with certainty and may be determined adversely to the Corporation and as a result, could have a material adverse effect on the Corporation's assets, liabilities, business, financial condition and results of operations. Even if the Corporation prevails in any such legal proceeding, the proceedings could be costly and time-consuming and may divert the attention of management and key personnel from the Corporation's business operations, which could adversely affect its financial condition.

DIVIDENDS

Perpetual distributes cash to Shareholders out of the income and other amounts the Corporation receives. The credit facilities and the terms of the Notes contain provisions which restrict the ability of the Corporation to pay dividends to Shareholders in the event of the occurrence of certain events of default, and Section 43 of the ABCA also imposes certain restrictions on the ability of a corporation to pay dividends.

The historical dividends described below may not be reflective of future dividends, which will be subject to review by the board of directors of the Corporation taking into account the prevailing circumstances at the relevant time. See "Risk Factors".

The accompanying table summarizes cash dividends to Shareholders for each of the last three years:

For the Period Ended	Payment Date	Distribution per Common Share
2008		
January 31, 2008	February 15, 2008	$0.10
February 29, 2008	March 27, 2008	$0.10
March 31, 2008	April 15, 2008	$0.10
April 30, 2008	May 15, 2008	$0.10
May 31, 2008	June 16, 2008	$0.10
June 30, 2008	July 15, 2008	$0.10
July 31, 2008	August 15, 2008	$0.10
August 31, 2008	September 15, 2008	$0.10
September 30, 2008	October 15, 2008	$0.10
October 31, 2008	November 17, 2008	$0.10
November 30, 2008	December 15, 2008	$0.10
December 31, 2008	January 15, 2009	$0.10
2009		
January 31, 2009	February 17, 2009	$0.07
February 28, 2009	March 16, 2009	$0.07
March 31, 2009	April 15, 2009	$0.05
April 30, 2009	May 15, 2009	$0.05
May 31, 2009	June 15, 2009	$0.05
June 30, 2009	July 15, 2009	$0.05
July 31, 2009	August 17, 2009	$0.05
August 31, 2009	September 15, 2009	$0.05
September 30, 2009	October 15, 2009	$0.05
October 31, 2009	November 16, 2009	$0.05
November 30, 2009	December 15, 2009	$0.05
December 31, 2009	January 15, 2010	$0.05
2010		
January 31, 2010	February 16, 2008	$0.05
February 28, 2010	March 15, 2008	$0.05
March 31, 2010	April 15, 2008	$0.05
April 30, 2010	May 17, 2008	$0.05
May 31, 2010	June 15, 2008	$0.05
June 30, 2010	July 15, 2008	$0.05
July 31, 2010	August 16, 2008	$0.05
August 31, 2010	September 15, 2008	$0.05
September 30, 2010	October 15, 2008	$0.05
October 31, 2010	November 15, 2008	$0.05
November 30, 2010	December 15, 2008	$0.03
December 31, 2010	January 17, 2009	$0.03
2011		
January 31, 2011	February 15, 2011	$0.03
February 28, 2011	March 15, 2011	$0.03

MARKET FOR SECURITIES

Trading Price and Volume

The outstanding Common Shares, 6.50% Convertible Debentures, 7.00% Convertible Debentures and 7.25% Convertible Debentures are listed and posted for trading on the TSX under the trading symbols "PMT", "PMT.DB.C", "PMT.DB.E" and "PMT.DB.D", respectively. The 7.00% Convertible Debentures commenced trading on May 26, 2010. Prior to July 6, 2010 the Common Shares traded as Trust Units under the symbol "PMT.UN", and the Debentures traded as securities convertible into Trust Units.

The following tables set forth the closing price range and trading volume of each of these securities as reported by the TSX for the periods indicated:

Common Shares

	Price Range		
	High ($)	**Low ($)**	**Volume**
2010			
February	5.19	4.81	6,405,897
March	5.10	4.68	11,656,280
April	5.23	4.66	9,997,057
May	5.15	4.61	10,387,463
June	5.47	4.78	11,895,618
July	5.25	4.94	9,964,791
August	5.19	4.78	8,227,577
September	5.04	4.73	7,995,192
October	4.83	4.02	13,725,040
November	4.50	3.78	17,579,319
December	4.19	3.80	12,940,849
2011			
January	4.12	3.85	9,120,217
February	4.33	3.89	7,592,478
March (1 to 14)	4.38	3.89	5,355,954

6.50% Convertible Debentures

	Price Range		
	High ($)	**Low ($)**	**Volume**
2010			
February	102.00	100.11	2,333,000
March	102.99	100.00	683,000
April	101.50	99.75	7,254,000
May	101.50	99.00	1,793,000
June	102.00	100.02	2,846,500
July	102.75	101.75	1,001,000
August	102.50	101.60	1,011,000
September	102.40	101.25	1,051,500
October	101.75	100.00	1,070,000
November	101.75	100.12	845,000
December	101.44	100.77	564,000
2011			
January	102.49	100.90	524,000
February	103.00	101.50	551,000
March (1 to 14)	102.25	101.50	206,000

7.00% Convertible Debentures

	Price Range		
	High ($)	**Low ($)**	**Volume**
2010			
May 26 – 31	101.00	100.25	3,966,000
June	150.10	100.06	5,276,000
July	107.00	103.30	2,078,000
August	104.75	103.20	981,000
September	104.15	103.21	1,245,000
October	103.99	99.30	1,400,000
November	101.75	99.30	1,784,500
December	101.19	99.70	1,636,000
2011			
January	103.00	100.00	1,889,000
February	103.75	101.39	1,136,500

	Price Range		
	High ($)	Low ($)	Volume
March (1 to 14)	102.25	101.85	532,000

7.25% Convertible Debentures

	Price Range		
	High ($)	Low ($)	Volume
2010			
February	104.00	103.75	1,414,000
March	105.99	101.56	2,827,000
April	104.50	101.75	1,018,000
May	102.50	100.00	1,308,000
June	108.00	100.35	2,334,000
July	105.00	103.60	503,000
August	105.00	103.50	1,147,000
September	104.66	104.00	929,000
October	105.50	100.00	826,000
November	102.00	100.50	971,000
December	102.00	101.30	1,000,000
2011			
January	104.00	101.51	633,000
February	104.05	101.30	647,000
March (1 to 14)	103.00	101.75	1,376,000

Prior Sales

Other than Share Options and Restricted Rights to acquire Common Shares and the Notes, there is no class of securities of Perpetual that is outstanding and not listed or quoted on a marketplace.

Set forth below are the exercise prices at which Share Options and Restricted Rights were issued during the most recently completed financial year by Perpetual, the number of Share Options and Restricted Rights issued at such exercise prices and the date on which the securities were issued.

Date of Grant	Number of Share Options Granted	Exercise Price
March 19, 2010	20,000	$4.90
August 19, 2010	3,479,250	$5.03
November 29, 2010	154,000	$3.92
December 23, 2010	862,200	$3.90

Date of Grant	Number of Restricted Rights Granted	Exercise Price
May 28, 2010	106,067	$0.01

DESCRIPTION OF CAPITAL STRUCTURE

The authorized share capital of Perpetual consists of an unlimited number of Common Shares and an unlimited number of preferred shares. As at the date hereof, there is one Common Share and no preferred shares issued and outstanding. Each Common Share entitles the holder thereof to receive notice of and to attend all meetings of shareholders of Perpetual and to one vote per share at such meetings (other than meetings of another class of shares of Perpetual). The Common Shares entitle the holders thereof to receive dividends as and when declared by the board of directors of Perpetual on the Common Shares as a class, subject to prior satisfaction of all preferential rights to dividends attached to all shares of other classes of shares of Perpetual ranking in priority to the Common Shares in respect of dividends. Holders of Common Shares will be entitled in the event of any liquidation, dissolution or winding-up of Perpetual, whether voluntary or involuntary, or any other distribution of the assets of Perpetual among its shareholders for the purposes of winding-up its affairs, and subject to prior satisfaction of all preferential rights to return of capital on dissolution attached to all shares of other classes of shares of Perpetual ranking in priority to the Common Shares in respect of return of capital on dissolution, to share rateably, together with the holders of shares of any other class of shares of Perpetual ranking equally with the Common Shares in respect of return of capital, in such assets of Perpetual as are available for distribution.

The preferred shares may be issuable in one or more series, each series to consist of such number of shares as may, before the issuance thereof, be determined by the board of directors of Perpetual. The board of directors may from time to time fix, before issuance, the designation, rights, privileges, restrictions and conditions attaching to each series of preferred shares including, without limiting the generality of the foregoing, the amount, if any, specified as being payable preferentially to such series on a distribution, the extent, if any, of further participation on a distribution, voting rights, if any, and dividend rights (including whether such dividends be preferential, or cumulative or non-cumulative), if any.

The holders of each series of preferred shares are entitled to receive any dividends declared by the board of directors of Perpetual in priority to the Common Shares and to be paid rateably with holders of each other series of preferred shares, and are entitled to participate in any distribution of the assets of Perpetual upon the liquidation, dissolution, bankruptcy or winding-up of Perpetual or other distribution of its assets among its shareholders for the purpose of winding-up its affairs in priority to the holders of the Common Shares and to share rateably in the distribution with holders of each other series of preferred shares.

Constraints

There are currently no constraints imposed on the ownership of securities of the Corporation to ensure that Perpetual has a required level of Canadian ownership.

Ratings

The following information relating to our credit ratings is provided as it relates to our financing costs and liquidity. Credit ratings affect our ability to obtain short-term and long-term financing and the cost of such financing. A negative change in our ratings outlook or any downgrade in our current credit ratings by our ratings agencies could adversely affect our cost of borrowing and/or access to sources of liquidity and capital. We believe that our credit ratings will allow us to continue to have access to the capital markets, as and when needed, at a reasonable cost of funds.

Other than as set forth below, Perpetual has not asked for and received a stability rating, or to the knowledge of Perpetual, has received any other kind of rating, including, a provisional rating, from one or more approved rating organizations for securities of Perpetual that are outstanding and which continue in effect.

The Notes have been assigned ratings of B- by Standard and Poor's Rating Services, a division of McGraw-Hill Companies (Canada) Corporation ("**S&P**") and B3/LGD3-46% by Moody's Investors Service, Inc. ("**Moody's**").

S&P and Moody's provide credit ratings of debt securities for commercial entities. A credit rating generally provides an indication of the risk that the borrower will not fulfill its full obligations in a timely manner with respect to both interest and principal commitments.

S&P's credit ratings are on a long-term debt rating scale that ranges from AAA to D, which represents the range from highest to lowest quality of such securities rated. S&P has assigned Perpetual a corporate credit rating of B, stable outlook, and a credit rating of B- on the Notes. An obligation rated "B" is more vulnerable to non-payment than those rated BB, but the obligor currently has the capacity to meet its financial commitments on the obligation. Adverse business, financial, or economic conditions will likely impair the obligor's capacity or willingness to meet its financial commitment on the obligation. The ratings from AA to CCC may be modified by the addition of a plus (+) or a minus (-) sign to show relative standing within the major rating categories. In addition, S&P may add a rating outlook of "positive", "negative" or "stable" which assesses the potential direction of a long-term credit rating over the intermediate term (typically six months to two years).

Moody's credit ratings are on a long-term debt rating scale that ranges from AAA to C, which represents the range from highest to lowest quality of such securities rated. Moody's has assigned Perpetual a corporate family credit rating of B3, negative outlook, and a credit rating of B3/LGD3-46%, negative outlook on the Notes. According to the Moody's rating system, securities rated "B" are considered speculative and are subject to high credit risk. Moody's appends numerical modifiers 1, 2 and 3 to each generic rating classification from AA through C. The modifier 1 indicates that the security ranks in the higher end of its generic rating category, the modifier 2 indicates a mid-range ranking and the modifier 3 indicates a ranking in the lower end of its generic rating category. In addition, Moody's may add a rating outlook of "positive", "negative" or "stable", which assess the likely direction of an issuer's rating over the medium term.

Credit ratings are intended to provide investors with an independent measure of credit quality of an issue of securities. Credit ratings are not recommendations to purchase, hold or sell securities and do not address the market price or suitability of a specific security for a particular investor. There is no assurance that any rating will remain in effect for any given period of time or that any rating will not be revised or withdrawn entirely by a rating agency in the future if, in its judgment, circumstances so warrant. A rating can be revised, suspended or withdrawn at any time by the rating agency. Potential investors should consult the rating agency should they require more information with respect to the interpretation and implications of the foregoing ratings. A revision or withdrawal of a credit rating could have a material adverse effect on the pricing and liquidity of the Notes in the secondary market.

ESCROWED SECURITIES AND SECURITIES SUBJECT TO CONTRACTUAL RESTRICTION ON TRANSFER

To the knowledge of the Corporation, none of Perpetual's securities are held in escrow or subject to a contractual restriction on transfer.

DIRECTORS AND OFFICERS

Name, Occupation and Security Holding

The names, province or state, and country of residence, positions and offices held with the Corporation, and principal occupation of the directors and executive officers of the Corporation are set out below and, in the case of directors, the period each has served as a director of the Corporation.

Name and Province and Country of Residence	Position held with the Company and Period Served as a Director	Principal Occupations During the Past Five Years
Clayton H. Riddell Alberta, Canada	Chairman of the Board and Director since June 28, 2002	Mr. Riddell has been the Chairman of the Board and Chief Executive Officer of Paramount since 1978. Until June 2002 he was also the President. He is currently Chairman of the Board of the Company and prior thereto was the Chairman and Chief Executive Officer of the Company (and formerly Paramount Energy Operating Corp. ("**PEOC**")). He graduated from the University of Manitoba with a Bachelor of Science (Honours) Degree in Geology and is currently a member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta, the Canadian Association of Petroleum Producers, the Canadian Society of Petroleum Geologists, and the American Association of Petroleum Geologists.

Name and Province and Country of Residence	Position held with the Company and Period Served as a Director	Principal Occupations During the Past Five Years
Susan L. Riddell Rose(4) Alberta, Canada	President, Chief Executive Officer and Director since June 28, 2002	Ms. Riddell Rose has been the President and Chief Executive Officer of the Company (and formerly PEOC) since May 9, 2005. Prior to that time, Ms. Riddell Rose was the President and Chief Operating Officer of PEOC since June 28, 2002. Prior to her current occupation, Ms. Riddell Rose was employed by Paramount, culminating in the position of Corporate Operating Officer. She has also been a director of Paramount since 2000. Ms. Riddell Rose also sits on the Board of Directors of Newalta Corporation.
Karen A. Genoway(2)(3)(5)(7) Alberta, Canada	Director since June 28, 2002	Ms. Genoway is a professional landman with over 28 years experience in the oil and natural gas industry. Currently, she is the Vice President, Land with Rimfire Energy Inc., a private company. From February 2001 she was Vice President of Request Management Inc., manager of Request Income Trust until its acquisition by Pulse Data Inc. in January 2002. Ms. Genoway was with Enerplus Resources Fund where she held the positions of Senior Vice President (1997 to 2000), Vice President Land (1989 to 1997) and Land Manager (1987 to 1989). Ms. Genoway is a graduate of the ICD Corporate Governance College, Directors Education Program, February 2006 and received her accreditation from the Institute of Corporate Directors, Institute-Certified Director, ICD.D, April 2006.
Randall E. Johnson(1)(3)(5)(7) Alberta, Canada	Director since June 20, 2006	Mr. Johnson has been an independent businessman since 2005. Prior to that he was Managing Director of the Bank of Montreal's Corporate Banking group from 1996 to 2005, having been with the Bank of Montreal since 1984. Mr. Johnson has served on the Board of Directors of Atlas Energy Ltd. (May 2005 to December 2006) and Dual Exploration Inc. (June 2005 to November 2006). Since January 2007 Mr. Johnson has also been a director of Magellan Resources Ltd., a privately held oil and gas company.
Robert A. Maitland(1)(3)(5)(7) Alberta, Canada	Director since February 7, 2008	Mr. Maitland is a Chartered Accountant with over 30 years of senior business experience, primarily in the oil and gas industry. Mr. Maitland was most recently the Vice President Finance and Chief Financial Officer of Fairquest Energy Ltd. (June 2005 to June 2007) and Fairborne Energy Ltd. (May 2002 to May 2005). He has also been the Vice President and Chief Financial Officer for Canadian Midstream Services Ltd. (April 1999 to May 2001), Summit Resources Ltd., Omega Hydrocarbons Ltd., Shiningbank Energy Income Fund, Post Energy Ltd. and Pan East Petroleum Corp. He presently serves on the board of directors of Developmental Disabilities Resources Centre and several other private companies.

Name and Province and Country of Residence	Position held with the Company and Period Served as a Director	Principal Occupations During the Past Five Years
Geoffrey C. Merritt(1)(2)(4)(7) Alberta, Canada	Director since June 17, 2010	Geoff Merritt has over 30 years of experience in the upstream oil and gas sector. He was the founder and Chief Executive Officer of Masters Energy Inc., a public exploration and production company, incorporated in 2003 and acquired by Zargon Oil & Gas Ltd. in April 2009. From 1998 to 2003, Mr. Merritt was the President and CEO of Sunfire Energy, a public exploration and production company. Prior to 1998, Geoff was the Vice President and General Manager of the oil and gas division of Pembina Corporation. Mr. Merritt is on the board of Zargon Oil and Gas Ltd. Mr. Merritt received a B.Sc. in Chemical Engineering from the University of Alberta in 1978 and is a graduate of the Harvard Business School.
Donald J. Nelson(2)(4)(7) Alberta, Canada	Director since June 28, 2002	Mr. Nelson is President of Fairway Resources Inc., an oil and gas consulting firm. Prior to his current occupation, Mr. Nelson held the consecutive positions of Vice President, Operations and President and Director with Summit Resources Limited from July 1996 to June 2002. He is an active member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta and of the Society of Petroleum Engineers.
Howard R. Ward(3)(4)(5)(7) Alberta, Canada	Director since June 28, 2002	Mr. Ward has been a partner with International Energy Counsel LLP, a law firm, since December 2002. Prior thereto, Mr. Ward was counsel with the law firm McCarthy Tétrault LLP from June 2002 to December 2002. Prior to that, he was counsel with Donahue and Partners LLP and, for more than 22 years, partner with Burstall Ward (now Burstall Winger LLP), Barristers and Solicitors. He has been a member of the Law Society of Alberta since 1975. He also has served as a director of the following publicly traded entities: Blue Sky Resources Ltd. (July 1999 to July 2000); Cabre Exploration Ltd. (June 1981 to December 2000); Jet Energy Corp. (August 1995 to November 1999); and Tuscany Resources Ltd. (October 1997 to October 2001).
Jeffrey R. Green Alberta, Canada	Vice President, Production Operations and Administration	Vice President, Production Operations of the Company (and formerly PEOC) since January 30, 2009. Prior to his current position Mr. Green was Manager, Acquisitions & Divestitures of PEOC from April 1, 2007 to January 30, 2009. Prior to that he held position as was Exploitation Manager and Production Manager at Anadarko Canada Corporation.

Name and Province and Country of Residence	Position held with the Company and Period Served as a Director	Principal Occupations During the Past Five Years
Gary C. Jackson Alberta, Canada	Vice President, Land and Acquisitions	Vice President, Land, Legal and Acquisitions of the Company (and formerly PEOC) since June 28, 2002. Prior to his current occupation, Mr. Jackson was Vice President, Land of Summit Resources Limited from May 2000 to June 28, 2002. Prior to that, he was Manager of Acquisitions and Divestitures, Joint Venture Mid-Stream Services at Petro-Canada Oil & Gas.
Kevin J. Marjoram Alberta, Canada	Vice President, Warwick Gas Storage Operations	Vice President, Warwick Gas Storage (and formerly Vice President, Engineering Execution at PEOC) since November 1, 2008. Prior to his current position Mr. Marjoram was Vice President Engineering and Operations of PEOC from June 28, 2002 to October 31, 2008. Prior to that, Mr. Marjoram was Engineering Manager, Northeast Alberta West Side for Paramount from July 2000 to June 2002. Prior to that, he held positions in an operations managerial capacity for Spire Energy Ltd. and Northrock Resources Ltd.
Marcello M. Rapini Alberta, Canada	Vice President, Marketing	Vice President, Marketing of Perpetual (and formerly PEOC) since December 7, 2006. Prior to his current occupation, Mr. Rapini worked for PEOC from December 15, 2005 as Manager, Marketing. From November 2004 to November 2005 Mr. Rapini was Senior Trader with Eagle Energy Marketing Canada. From 2003 to 2004 he worked as a Senior Trader and Vice President Trading with Sempra Energy Trading, and from 1996 to 2002 was Senior Trader with Mirant Energy Marketing Ltd.
Cameron R. Sebastian Alberta, Canada	Vice President, Finance and Chief Financial Officer	Vice President, Finance and Chief Financial Officer of the Company (and formerly PEOC) since June 28, 2002. Prior to his current occupation, Mr. Sebastian was Vice President, Finance of Summit Resources Limited from June 2000 to June 2002. Prior to that, he was Vice President, Finance of Pursuit Resources Corp.
J.C. Strong Alberta, Canada	Corporate Secretary and Corporate Counsel	Corporate Secretary and Corporate Counsel of Perpetual (and formerly PEOC) since May 7, 2009, Acting Corporate Secretary and Corporate Counsel of the Company (and formerly PEOC) from September 2006 forward. Mr. Strong practiced with the law firm of Gunn & Prithipaul from June 1996 until January 2002, and thereafter worked as a sole practitioner up until joining Alaris Income Growth Fund as counsel in December 2005.

Name and Province and Country of Residence	Position held with the Company and Period Served as a Director	Principal Occupations During the Past Five Years
R. William Thornton Alberta, Canada	Vice President, Heavy Oil	Vice President, Heavy Oil of Perpetual since July 5, 2010. Mr. Thornton previously served as President and Chief Executive Officer of Megawest Energy Corp. (formerly Brockton Capital Corp.) from January 2009 to June 30, 2010. Previously, he served as President of Megawest Energy since February 8, 2008 and as Chief Operating Officer from January 1, 2007 to January 23, 2009. Prior thereto, he held the position of General Manager – Petroleum Engineering at Western OilSands from November 2004 to December 2006.
Roderick P. Warters Alberta, Canada	Vice President, Geoscience and New Ventures	Vice President, Geoscience and New Ventures of Perpetual (and formerly PEOC) since September 4, 2007. Mr. Warters joined Petro-Canada in 1996 as their Chief Geophysicist and later held the position of Northern Exploration Manager. In 2001 he joined Burlington Resources as the Vice President of Exploration for Canada, and after their merger in 2006 he assumed the position of Senior Vice President of Exploration for ConocoPhillips Canada. Mr. Warters has held a number of technical and management positions in other organizations including Amerada Hess and Dome Petroleum.

Notes:

(1) Member of the Audit Committee.
(2) Member of the Reserves Committee.
(3) Member of the Corporate Governance Committee.
(4) Member of the Environmental, Health and Safety Committee.
(5) Member of the Compensation Committee.
(6) The terms of office of all directors of the Company will expire on the date of the next annual Shareholders' meeting.
(7) Ms. Genoway, Mr. Johnson, Mr. Maitland, Mr. Nelson, Mr. Merritt and Mr. Ward are independent, non-employee directors.

The directors and officers of Perpetual, as a group, beneficially own or control or direct, directly or indirectly an aggregate of 33,968,545 voting securities as of March 1, 2011 representing approximately 23% of the outstanding Common Shares.

Cease Trade Orders, Bankruptcies, Penalties or Sanctions

Cease Trade Orders

To the knowledge of the Corporation, except as described below, no director or executive officer of the Corporation (nor any personal holding company of any of such persons) is, as of the date of this Annual Information Form, or was within 10 years before the date of this Annual Information Form, a director, chief executive officer or chief financial officer of any company (including the Corporation), that: (a) was subject to a cease trade order (including a management cease trade order), an order similar to a cease trade order or an order that denied the relevant company access to any exemption under securities legislation, in each case that was in effect for a period of more than 30 consecutive days (collectively, an "**Order**"), that was issued while the director or executive officer was acting in the capacity as director, chief executive officer or chief financial officer; or (b) was subject to an Order that was issued after the director or executive officer ceased to be a director, chief executive officer or chief financial officer and which resulted from an event that occurred while that person was acting in the capacity as director, chief executive officer or chief financial officer.

Mr. Clayton Riddell is a director and executive officer of Paramount Resources Ltd. ("**Paramount**"). From 1992 to 2008, Paramount was the general partner of T.T.Y. Paramount Partnership No. 5 ("**TTY**"), a limited partnership, which was an unlisted reporting issuer in certain provinces of Canada. TTY was established in 1980 to conduct oil and gas exploration and development but had not carried on active operations since 1984 and had only nominal assets. A cease trade order against TTY was issued by the Autorité des marches financiers in 1999 for failing to file the June 30, 1998 interim financial statements in Québec. The cease trade order was revoked on April 9, 2008. TTY was dissolved on July 21, 2008.

From 1997 to 2003, Mr. Maitland was a director of Military International Ltd. which was cease traded for failure to file financial statements, which cease trade order is still in effect.

Bankruptcies

To the knowledge of the Corporation, no director or executive officer of the Corporation (nor any personal holding company of any of such persons), or shareholder holding a sufficient number of securities of the Corporation to affect materially the control of the Corporation: (a) is, as of the date of this Annual Information Form, or has been within the 10 years before the date of this Annual Information Form, a director or executive officer of any company (including the Corporation) that, while that person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets; or (b) has, within the 10 years before the date of this Annual Information Form, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of the director, executive officer or shareholder.

Penalties or Sanctions

To the knowledge of the Corporation, no director or executive officer of the Corporation (nor any personal holding company of any of such persons), or shareholder holding a sufficient number of securities of the Corporation to affect materially the control of the Corporation, has been subject to: (a) any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority; or (b) any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

Conflicts of Interest

Certain officers and directors of the Corporation are also officers and/or directors of other entities engaged in the oil and gas business generally. As a result, situations may arise where the interest of such directors and officers conflict with their interests as directors and officers of other companies. The resolution of such conflicts is governed by applicable corporate laws, which require that directors act honestly, in good faith and with a view to the best interests of the Corporation. Conflicts, if any, will be handled in a manner consistent with the procedures and remedies set forth in 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 Charter

The mandate and responsibilities of Perpetual's audit committee (the "**Audit Committee**") are set out in the Audit Committee Charter which is part of the Corporation's Corporate Governance Directors' Manual. The Audit Committee Charter is set out in Appendix "E" to this annual information form, which Appendix is incorporated in this annual information form by reference.

Audit Committee

The Audit Committee reviews and recommends to the Board the approval of the annual and interim financial statements, the associated management's discussion and analysis and related financial disclosure to the public and regulatory authorities. It is responsible for the engagement of Perpetual's external auditors, upon approval by Shareholders, including fees paid for the annual audit and interim financial reviews, and pre-approves non-audit services. The Audit Committee communicates directly with the auditors and reviews programs and policies regarding the effectiveness of internal controls over the Corporation's accounting and financial reporting systems. It also reviews insurance coverage and directors' and officers' liability insurance. The Audit Committee must liaise with the Reserves Committee on matters relating to reserves valuations which impact Perpetual's financial statements.

Composition of the Audit Committee

The Audit Committee consists of three members: Robert A. Maitland, Geoffrey C. Merritt and Randall E. Johnson. Mr. Maitland is Chair of the Audit Committee. Each of the members of the Audit Committee is independent and financially literate in accordance with the meanings set out in National Instrument 52 110 Audit Committees.

Relevant Education and Experience

Robert A. Maitland

Mr. Maitland is a Chartered Accountant. He has completed the Institute of Corporate Directors - Director Education Program and has received his accreditation as Institute-Certified Director, ICD.D. He has over 30 years of senior business experience, primarily in the oil and gas industry and has been the Vice President and Chief Financial Officer of Summit Resources Ltd., Omega Hydrocarbons Ltd., Shiningbank Energy Income Fund, Post Energy Ltd., Pan East Petroleum Corp., Fairborne Energy Ltd. and Fairquest Energy Ltd. He presently serves on the board of directors of GASFRAC Energy Services Inc. (a publicly traded oil and gas service company) and the Developmental Disabilities Resources Centre and several other private companies.

Randall E. Johnson

Mr. Johnson graduated with a Bachelor of Science degree in Mathematics (1980) and a Masters of Business Administration degree (1982) from Brigham Young University in Provo, Utah. His 22 year career in Corporate Banking commenced with CIBC in 1982 in Calgary. In 1984, he moved to Bank of Montreal's Corporate Banking group where worked as an Associate from 1984 to 1987, Account Manager from 1987 to 1990, Director from 1990 to 1996, and then as Managing Director from 1996 to 2005. After retiring from Bank of Montreal in January 2005, Mr. Johnson joined the Board of Directors of three publicly traded oil and gas companies: Atlas Energy Ltd. (May 2005 to December 2006), Dual Exploration Inc. (June 2005 to November 2006), and Perpetual (June 2006 to present). During 2005 and 2006, Mr. Johnson was a part-time faculty member of the Bissett School of Business at Mount Royal University.

Geoffrey C. Merritt

Geoff Merritt has over 30 years of experience in the upstream oil and gas sector. He was the founder and Chief Executive Officer of Masters Energy Inc., a public exploration and production company, incorporated in 2003 and acquired by Zargon Oil & Gas Ltd. in April 2009. From 1998 to 2003, Mr. Merritt was the President and CEO of Sunfire Energy, a public exploration and production company. Prior to 1998, Geoff was the Vice President and General Manager of the oil and gas division of Pembina Corporation. Mr. Merritt is on the board of Zargon Oil and Gas Ltd. Mr. Merritt received a B.Sc. in Chemical Engineering from the University of Alberta in 1978 and is a graduate of the Harvard Business School.

Pre Approval of Policies and Procedures

Perpetual has adopted policies and procedures with respect to the pre-approval of audit and permitted non-audit services to be provided by KPMG LLP. The Audit Committee establishes a budget for the provision of a specified list of audit and permitted non-audit services that the audit committee believes to be typical, recurring or otherwise likely to be provided by KPMG LLP. The budget generally covers the period between the adoption of the budget and the next meeting of the Audit Committee, but at the option of the Audit Committee it may cover a longer or shorter period. The list of services is sufficiently detailed as to the particular services to be provided to ensure that (i) the Audit Committee knows precisely what services it is being asked to pre-approve and (ii) it is not necessary for any member of management to make a judgment as to whether a proposed service fits within the pre-approved services.

The Audit Committee must pre-approve the provision of permitted services by KPMG LLP which are not otherwise pre-approved by the Audit Committee, including the fees and terms of the proposed services. Prohibited services may not be pre-approved by the Audit Committee.

External Auditor Service Fees

Audit Fees

The aggregate fees billed by Perpetual's external auditor in each of the last two fiscal years for audit services were $965,500 in 2010 and $636,315 in 2009, which includes fees related to offering documents, IFRS conversion work (in 2010) and the Corporation's year-end audit and quarterly reviews.

Audit-Related Fees

The aggregate fees billed in each of the last two fiscal years for assurance related services by Perpetual's external auditor that are reasonably related to the performance of the audit or review of the financial statements that are not reported under Audit Fees above were $0 in 2010 and $83,450 in 2009. Fees for 2009 were primarily related to the takeover bid circular for the Profound acquisition, and Perpetual also incurred fees for the filing of the Corporation's form 40-F in the United States.

Tax Fees

The aggregate fees billed in each of the last two fiscal years for professional services rendered by Perpetual's external auditor for tax compliance, tax advice and tax planning were $9,705 in 2010 and $38,124 in 2009.

These services relate to the determination and reporting of taxability of security dividends for each of Canada and the United States, the preparation and filing of Canadian trust and corporate income tax returns, and services with respect to discussions on tax compliance in various foreign jurisdictions.

All Other Fees

The aggregate fees billed in the 2010 fiscal year by Perpetual’s external auditor for services other than those services reported above were $126,000, and were related to valuation services and French translation; for the 2009 fiscal year those fees totalled $22,000 and were related to the Corporation's transition to International Financial Reporting Standards.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

Legal Proceedings

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

Regulatory Actions

There are no:

(a) penalties or sanctions imposed against Perpetual by a court relating to securities legislation or by a securities regulatory authority during Perpetual's financial year;

(b) other penalties or sanctions imposed by a court or regulatory body against Perpetual that would likely be considered important to a reasonable investor in making an investment decision; and

(c) settlement agreements Perpetual entered into before a court relating to securities legislation or with a securities regulatory authority during Perpetual's financial year.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

There is no material interest, direct or indirect, of any: (a) director or executive officer of Perpetual; (b) person or company that beneficially owns, or controls or directs, directly or indirectly, more than 10% of any class or series of Perpetual's voting securities; and (c) associate or affiliate of any of the persons or companies referred to in (a) or (b) above in any transaction within the three most recently completed financial years or during the current financial year that has materially affected or is reasonably expected to materially affect Perpetual.

TRANSFER AGENT AND REGISTRAR

Computershare Trust Company of Canada at its offices in Calgary, Alberta and Toronto, Ontario acts as the transfer agent and registrar for the Common Shares and the Convertible Debentures.

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business, the Corporation has not entered into any material contracts within the most recently completed financial year, or before the most recently completed financial year which are still in effect.

INTEREST OF EXPERTS

Names of Experts

The only persons or companies who are named as having prepared or certified a report, valuation, statement or opinion described or included in a filing, or referred to in a filing, made under National Instrument 51-102 by the Corporation during, or relating to, the Corporation's most recently completed financial year, and whose profession or business gives authority to the report, valuation, statement or opinion made by the person or company, are KPMG LLP, the Corporation's independent auditors, McDaniel and GLJ, the Corporation's independent reserve evaluators. McDaniel and GLJ are together referred to as the "Evaluators".

Interests of Experts

To the Corporation's knowledge, no registered or beneficial interests, direct or indirect, in any securities or other property of the Corporation or of one of the Corporation's associates or affiliates (i) were held by any of the Evaluators or by the "designated professionals" (as defined in Form 51-102F2) of the Evaluators, when the Evaluators prepared their respective reports, valuations, statements or opinions referred to herein as having been prepared by such Evaluators, (ii) were received by any of the Evaluators or the designated professionals of the Evaluators after such Evaluator prepared the report, valuation, statement or opinion in question, or (iii) is to be received by any of the Evaluators or the designated professionals of the Evaluators.

None of the Evaluators nor any director, officer or employee of any of the Evaluators is or is expected to be elected, appointed or employed as a director, officer or employee of the Corporation or of any associate or affiliate of the Corporation.

KPMG LLP are the auditors of the Company and have confirmed that they are independent with respect to the Company within the meaning of the Rules of Professional Conduct of Institute of Chartered Accountants of Alberta and within the meaning of the U.S. Securities Act of 1933 and the applicable rules and regulations thereunder adopted by the Securities and Exchange Commission and the Public Company Accounting Oversight Board (United States).

ADDITIONAL INFORMATION

Additional information relating to the Corporation may be found on SEDAR at www.sedar.com.

Additional information, including directors' and officers' remuneration and indebtedness, principal holders of the Corporation's securities and securities authorized for issuance under equity compensation plans is contained in the Corporation's information circular for the Corporation's most recent annual meeting of securityholders that involved the election of directors.

Additional financial information is contained in the Corporation's financial statements and the related management's discussion and analysis for the Corporation's most recently completed financial year.

APPENDIX A

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

Management of Perpetual Energy Inc. (the "**Corporation**") are responsible for the preparation and disclosure of information with respect to the Corporation'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, 2010, estimated using forecast prices and costs.

McDaniel & Associates Consultants Ltd. and GLJ Petroleum Consultants Ltd., each an independent qualified reserves evaluator has evaluated the Corporation's reserves data. The reports of the independent qualified reserves evaluator are presented below.

The Reserves Committee of the board of directors of the Corporation has

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

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

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

The Reserves Committee of the board of directors has reviewed the Corporation'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 approved

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

(e) the filing of Form 51-102F2 which is the reports of the independent qualified reserves evaluators on the reserves data; and

(f) the content and filing of this report.

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

DATED as of this 10th day of March, 2011.

"*Susan L. Riddell Rose*"	"*Cameron R. Sebastian*"
Susan L. Riddell Rose President and Chief Executive Officer	Cameron R. Sebastian Vice President, Finance and Chief Financial Officer
"*Robert A. Maitland*"	"*Donald J. Nelson*"
Robert A. Maitland Director	Donald J. Nelson Director

APPENDIX B

REPORT ON RESERVES DATA BY MCDANIEL & ASSOCIATES CONSULTANTS LTD. IN ACCORDANCE WITH FORM 51-101F2
–
MCDANIEL & ASSOCIATES CONSULTANTS LTD.

To the board of directors of Perpetual Energy Inc. (the "**Corporation**"):

1. We have evaluated the Corporation's reserves data as at December 31, 2010. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2010, estimated using forecast prices and costs.

2. The reserves data are the responsibility of the Corporation'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 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 Corporation evaluated by us for the year ended December 31, 2010, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Corporation's board of directors:

Independent Qualified Reserves Evaluator	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	Reviewed	Total
			M$	M$	M$	M$
McDaniel & Associates Consultants Ltd.	February 7, 2011	Canada	-	875,960	15,726	891,686

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.

EXECUTED as to our report referred to above.

McDaniel & Associates Consultants Ltd., Calgary, Alberta, Canada, February 7, 2011.

"P. A. Welch"

P. A. Welch, P. Eng.
President & Managing Director

APPENDIX C

REPORT ON RESERVES DATA BY GLJ PETROLEUM CONSULTANTS LTD.
IN ACCORDANCE WITH FORM 51-101F2

To the board of directors of Perpetual Energy Inc. (the "**Corporation**"):

1. We have evaluated the Corporation's reserves data as at December 31, 2010. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2010, estimated using forecast prices and costs.

2. The reserves data are the responsibility of the Corporation'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 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 Corporation evaluated by us for the year ended December 31, 2010, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Corporation's board of directors:

Independent Qualified Reserves Evaluator	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**	**Reviewed**	**Total**
			M$	**M$**	**M$**	**M$**
GLJ Petroleum Consultants	January 15, 2011	Canada	-	36,430	-	36,430

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.

EXECUTED as to our report referred to above.

GLJ Petroleum Consultants Ltd., Calgary, Alberta, Canada, February 24, 2011.

"Jodi L. Anhorn"

Jodi L. Anhorn, M. Sc., P. Eng.
Vice-President

APPENDIX D

AUDIT COMMITTEE CHARTER

The Audit Committee is responsible for:

- reviewing and, if appropriate, recommending to the Board the approval of the annual and interim financial statements, the associated MD&A and related financial disclosure;
- annually reviewing the Audit Committee mandate and recommending any changes to the Corporate Governance Committee;
- supplying for the purposes of this Manual, in consultation with Corporate Counsel, a list of the laws, rules and regulations that pertain to the operation of the Committee;
- engaging external Auditors as approved by Perpetual's Shareholders;
- pre-approving non-audit permitted services including the fees and other terms related to the non-audit permitted services;
- communicating directly with the Auditors who will report directly to the Audit Committee;
- reviewing programs and policies regarding the maintenance and effectiveness of disclosure controls and internal controls over the Corporation's accounting and financial reporting systems;
- reviewing insurance coverage and Directors' and Officers' liability insurance; and,
- liaising with the reserves committee ("**Reserves Committee**") on matters relating to reserves valuations which impact the financial statements of Perpetual.

Purpose

The Audit Committee's purpose is to provide assistance to the Board in fulfilling its legal, regulatory and fiduciary obligations with respect to: financial accounting, internal control processes, continuous public disclosure, the independent audit function, non-audit services provided by Independent Auditors and such other related matters as may be delegated by the Board of Directors.

Composition, Procedures and Organization

1. The Audit Committee will be comprised of three or more Directors as determined from time to time by resolution of the Board.

2. Each member of the Audit Committee must be independent (defined on page 3-4) and as such must be free from any material relationship that may interfere with the exercise of his or her independent judgment as a member of the Audit Committee.

3. Consistent with the appointment of other Board committees, the members of the Audit Committee will be appointed by the Board at the first meeting of the Board following each AGM or at such other time as may be determined by the Board.

4. The Committee will designate the Chairman of the Audit Committee by majority vote. The presence in person or by telephone of a majority of the Audit Committee's members constitutes a quorum for any meeting.

5. All actions of the Audit Committee will require a vote of the majority of its members present at a meeting of such committee at which a quorum is present.

6. All members of the Audit Committee must be financially literate at the time of their appointment or have become financially literate within a reasonable period of time after such appointment. MI 52-110 sets out that an individual is "financially literate" if he or she has the ability 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 the issues that can reasonably be expected to be raised by Perpetual's financial statements.

7. The Board shall designate at least one Audit Committee member as the financial expert, and the member so designated must have accounting or related financial management expertise, as such qualification may be determined in the business judgment of the Board in accordance with the requirements of applicable regulatory bodies.

Accountability and Reporting

The Audit Committee is accountable to the Board. The Audit Committee must provide the Board with a summary of all meetings and its recommendations together with a copy of the minutes of each such meeting. If applicable, the Chairman will provide oral reports as requested.

All information reviewed and discussed by the Audit Committee at any meeting must be retained and made available for examination by the Board. The Audit Committee will review its mandate annually, and will forward to the Corporate Governance Committee any recommended alterations to that mandate.

Meetings

The Committee will meet with such frequency and at such intervals as it determines is necessary to carry out its duties and responsibilities.

The Audit Committee will meet to review the interim and year-end financial statements and MD&A; related financial public disclosure and regulatory filings including the annual information form, management information circular; other continuous disclosure documentation ("**Continuous Disclosure Documents**") as described in MI 52-101 (which is incorporated herein by reference); the Auditor's Report with respect to annual attestation of Internal Controls over Financial Reporting ("**ICOFR**"), and to report to the Board on same. In conjunction with the review of the year-end financial statements and MD&A, the Audit Committee will consider the annual independent evaluation of the oil and gas reserves of Perpetual. In addition to these scheduled quarterly meetings as contained in "Planning Documents For Board and Committees" (Section 4 of the Manual), the Audit Committee may meet on other occasions with the Auditors in order to be advised of current practices in the industry and to discuss and review other matters including the annual work plans, processes and procedures. The Audit Committee must meet at least quarterly with the Auditors in the absence of Perpetual's Officers and employees to discuss any matters that the Committee or a committee member believes should be discussed privately.

The Chairman of the Audit Committee will appoint a Director, Officer or employee of Perpetual to act as secretary for the purposes of recording the minutes of each meeting.

Responsibilities

The Audit Committee must:

- review and approve the Audit Committee Mandate annually;
- review and recommend to the Board the appointment, termination and retention of, and the compensation to be paid to, the Auditors;
- evaluate the performance of the Auditors;
- review and consider the Auditors' integrated audit plan and annual engagement letter including the proposed fees and the proposed work plan;
- consider and make recommendations to the Board or otherwise pre-approve, all non-audit services provided by the Auditors to Perpetual or its subsidiaries;
- oversee the work and the performance of the Auditors, review the independence of the Auditors and report to the Board on these matters;
- review the annual and quarterly financial statements, MD&A and financial press releases, annual information form, Management Information Circular and other related Continuous Disclosure Documents as appropriate, prior to their public disclosure;
- oversee management's establishment and maintenance of ICOFR to provide reasonable assurance with regard to reliability of financial reporting;

- review the Auditors' report on the annual audited financial statements and related assessment of ICOFR and the Auditor's review letters on interim financial statements;
- provide oral or written reports to the Board when necessary;
- resolve disagreements between management and the Auditors regarding financial reporting;
- receive periodic certificates and reports from management with respect to compliance with financial, regulatory, taxation and continuous disclosure requirements, and satisfy itself (a) that adequate procedures are in place to ensure timely and full public disclosure of Continuous Disclosure Documents; and, (b) that a system of internal controls over financial reporting has been implemented and is being maintained, in accordance with both the Disclosure Policy and the Management Responsibility For Internal Control Policy; and additionally, must consider whether any identified deficiencies in internal controls are significant or are material weaknesses;
- meet with the Auditors, without management being present, at each time the interim and financial statements are being considered, to ensure that no management restrictions have been placed on the scope of the Auditors' work and to discuss the working relationship between the Auditors and management and other matters that the Audit Committee or the Auditors may wish to raise;
- review and monitor the implementation and adequacy of disclosure policies;
- review insurance coverage including Directors' and Officers' liability insurance;
- be notified in writing within three business days of any embezzlement, litigation or regulatory investigation which, in the opinion of the Corporation's management, is objectively significant. Confirmation of receipt of such notification by each member of the Audit Committee will additionally be required. Any embezzlement, litigation or regulatory investigation not reported as outlined above will be reported quarterly to the Board of Directors at the March, May, August, and November meetings immediately following the discovery of such occurrence;
- review and monitor the implementation and adequacy of hedging policies and controls, with reference to the Corporation's Hedging and Risk Management Policy, which is attached to this Manual in Section 7;
- review compliance with applicable laws, regulations and policies;
- be advised of and review the results of any internal audits of Perpetual and report on same to the Board;
- establish a Whistle blower Policy with procedures for:

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

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

- ensure that Perpetual management regularly advises employees of the existence of a Whistleblower Process;
- receive regular reports respecting complaints made under the Whistleblower Process;
- inform the Auditors of whether the Audit Committee has knowledge of any actual, suspected or alleged fraud affecting Perpetual, including complaints regarding financial reporting and confidential submissions by employees;
- review and validate Perpetual management's annual review of fraud risk assessment;
- review and approve Perpetual's hiring policies regarding partners, employees and former partners and employees of the present and former Auditor of the issuer; and
- monitor the selection and application of proper accounting principles and practices and to review the status of all relevant financial and related fiduciary aspects of Perpetual.