ZARGON

ENERGY TRUST

2009 ANNUAL INFORMATION FORM

March 15, 2010

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GLOSSARY OF TERMS

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

Entities

Board of Directors means the board of directors of Zargon Oil & Gas.

Churchill means Churchill Energy Inc.

ExchangeCo means Zargon ExchangeCo Inc.

Masters means Masters Energy Inc.

Newpact means Newpact Energy Corp.

Rival means Rival Energy Ltd.

SEC means the United States Securities and Exchange Commission

Trustee means Valiant Trust Company, our trustee.

Unitholders means holders of our Trust Units.

Zargon, **we**, **us, our** or **Trust** means Zargon Energy Trust and all its controlled entities on a consolidated basis.

Zargon Oil & Gas means Zargon Oil & Gas Ltd.

Zargon Partnership means Zargon Oil & Gas Partnership.

Independent Engineering

COGE Handbook means the Canadian Oil and Gas Evaluation Handbook.

CSA 51-324 means Staff Notice 51-324 – *Glossary to NI 51-101 Standards of Disclosure For Oil And Gas Activities* of the Canadian Securities Administrators.

McDaniel means McDaniel & Associates Consultants Ltd., independent petroleum consultants of Calgary, Alberta.

McDaniel Report means the report prepared by McDaniel dated February 23, 2010 evaluating the crude oil, natural gas and natural gas liquids reserves attributable to certain of our oil and natural gas assets at December 31, 2009.

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

Securities

Credit Agreement means the Credit Agreement dated September 30, 2005 including the second amendment dated July 30, 2007; the third amendment dated December 19, 2007; the fourth amendment dated July 28, 2008; and the fifth amendment dated July 27, 2009.

Exchangeable Shares means exchangeable shares of Zargon Oil & Gas which are exchangeable for Trust Units.

Exchange Ratio means the ratio at which Exchangeable Shares may be converted to Trust Units.

Notes means the unsecured subordinated promissory notes issued by Zargon Oil & Gas now held by us.

Note Indenture means the note indenture relating to the issuance of the Notes.

NPI means the net profit interest in the petroleum substances owned by the Zargon Oil & Gas and held by the Trust.

Special Voting Right means the special voting right issued by the Trust entitling holders of Exchangeable Shares to voting rights at meetings of Unitholders.

Trust Indenture means the amended and restated trust indenture between Valiant Trust Company and Zargon Oil & Gas made as of July 14, 2004.

Trust Unit means a unit issued by us, each unit representing an equal undivided beneficial interest in our assets.

ABBREVIATIONS

Oil and Natural Gas Liquids		Natural Gas	
bbl	barrel	gj	gigajoule
bbl/d	barrels per day	Mcf	thousand cubic feet
Mbbl	thousand barrels	MMcf	million cubic feet
MMbbl	million barrels	bcf	billion cubic feet
NGLs	natural gas liquids	Mcf/d	thousand cubic feet per day
Mmboe	million barrels of oil equivalent	MMcf/d	million cubic feet per day
Mboe	thousand barrels of oil equivalent	m^3	cubic metres
boe/d	barrels of oil equivalent per day	MMbtu	million British Thermal Units

Other

BOE or boe	means barrel of oil equivalent.
WTI	West Texas Intermediate.
°API	the measure of the density or gravity of liquid petroleum products derived from a specific gravity.
psi	pounds per square inch.
m	metres

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	6.289
feet	metres	0.305
metres	feet	3.281
miles	kilometres	1.609
kilometres	miles	0.621
acres	hectares	0.405
hectares	acres	2.471
gigajoules	MMbtu	0.950
MMbtu	gigajoules	1.0526

We have adopted the standard of 6 mcf:1 bbl when converting natural gas to oil and 1 bbl:6 mcf when converting oil to natural gas. **Boe's may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf:1 Boe is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.**

All dollar amounts set forth in this Annual Information Form are in Canadian dollars, except where otherwise indicated.

NOTICE TO READER

Special Note Regarding Forward-Looking Statements

Certain statements contained in this Annual Information Form, and in certain documents incorporated by reference into this Annual Information Form, constitute forward-looking statements. These statements relate to future events or our future performance. All statements other than statements of historical fact may be forward-looking statements. Such statements are generally identified by the use of words such as "anticipate", "continue", "estimate", "expect", "forecast", "may", "will", "project", "should", "plan", "intend", "believe", and similar expressions (including the negatives thereof). In addition, there are forward-looking statements in this Annual Information Form under the headings: "*Zargon Energy Trust – Federal Tax Changes for Income Trusts and Corporations*" as to our anticipated conversion to a corporation and related tax matters; "*Description of Our Business – Disclosures of Reserve Data and Other Oil and Gas Information*" as to our reserves and future net revenues from our reserves, pricing and inflation rates, future development costs; the development of our proved undeveloped reserves and probable undeveloped reserves; "*Description of Our Business – Other Oil and Gas Information*" as to our future development activities, hedging policies, reclamation and abandonment obligations, tax horizon, exploration and development activities and production estimates. By their nature, forward-looking statements are subject to numerous risks and uncertainties, some of which are beyond our control, including such as those relating to results of operations and financial condition, general economic conditions, industry conditions, changes in regulatory and taxation regimes, volatility of commodity prices, escalation of operating and capital costs, currency fluctuations, the availability of services, imprecision of reserve estimates, geological, technical, drilling and processing problems, environmental risks, weather, the lack of availability of qualified personnel or management, stock market volatility, the ability to access sufficient capital from internal and external sources and competition from other industry participants for, among other things, capital, services, acquisitions of reserves, undeveloped lands and skilled personnel. Forward looking statements are provided to allow investors to have a greater understanding of our business.

You are cautioned that the assumptions, including among other things, future oil and natural gas prices; future capital expenditures levels; future production levels; future exchange rates; the cost of developing and expanding our assets; our ability to obtain equipment in a timely manner to carry out development activities; our ability to market our oil and natural gas successfully to current and new customers; the impact of increasing competition; our ability to obtain financing on acceptable terms; and our ability to add production and reserves through our development and acquisition activities use in the preparation of such information, although considered reasonable at the time of preparation, may prove to be imprecise and, as such, undue reliance should not be placed on forward-looking statements. Our actual results, performance, or achievement could differ materially from those expressed in, or implied by, these forward-looking statements. We can give no assurance that any of the events anticipated will transpire or occur, or if any of them do, what benefits we will derive from them. The forward-looking information contained in this document is expressly qualified by this cautionary statement. Our policy for updating forward-looking statements is that Zargon disclaims, expect as required by law, any intention or obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

We believe the expectations reflected in these forward-looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and such forward-looking statements included in, or incorporated by reference into, this Annual Information Form should not be unduly relied upon. These statements speak only as of the date of this Annual Information Form or as of the date specified in the documents incorporated by reference into this Annual Information Form, as the case may be.

In addition to the forward-looking statements identified above, this Annual Information Form, and the documents incorporated by reference, contains forward-looking statements pertaining to the following:

- the performance characteristics of our oil and natural gas properties;
- oil and natural gas production levels;

- seismic and exploration costs;
- projections of market prices and costs and the related sensitivities of distributions;
- supply and demand for oil and natural gas;
- expectations regarding the ability to raise capital and to continually add to reserves through acquisitions and development;
- treatment under governmental regulatory regimes and tax laws;
- our distribution policy and payment of distributions; and
- capital expenditures programs.

Actual results could differ materially from those anticipated in these forward-looking statements as a result of numerous known and unknown risks and uncertainties and other factors, many of which are beyond our control. Such factors include, but are not limited to:

- declines in oil and natural gas prices;
- variations in interest rates and foreign exchange rates;
- uncertainties relating to the weakened global economy and consequential restricted access to capital, stock market volatility, market valuations and increased borrowing costs;
- refinancing risk for existing debt and debt service costs;
- access to external sources of capital; borrowings and equity sales;
- risks associated with our hedging activities;
- third party credit risk;
- risks associated with the exploitation of our properties and our ability to acquire reserves;
- government regulation and control and changes in governmental legislation;
- changes in income tax laws, royalty rates and other incentive programs;
- uncertainties associated with estimating oil and natural gas reserves;
- risks associated with our conversion to a corporate structure;
- risks associated with acquiring, developing and exploring for natural gas and other aspects of our operations;
- risks associated with the marketability of oil and natural gas;
- changes in climate change laws and other environmental regulations;
- risks associated with the exploitation of our properties and our ability to acquire reserves;
- the failure to realize anticipated benefits of acquisitions and dispositions or to manage growth;
- competition in the oil and gas industry;
- depletion of our reserves
- risks associated with large projects or expansion of our activities;
- the activities of our operating activities and key personnel;
- risks associated with securing and maintaining our properties;
- seasonality;
- risks associated with the timing of payment of distributions
- risks associated with residency restrictions in the ownership of our Trust Units;

- our permitted investments; and
- risks associated with our structure and ownership of Trust Units; risks for United States and other non-resident unitholders.

Statements relating to "reserves" or "resources" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the resources and reserves described can be profitably produced in the future. Readers are cautioned that the foregoing lists of factors are not exhaustive. The forward-looking statements contained in this Annual Information Form, and the documents incorporated by reference herein, are expressly qualified by this cautionary statement. We do not undertake any obligation to publicly update or revise any forward-looking statements except as required by applicable law.

Access to Documents

Any document referred to in this Annual Information Form and described as being filed on SEDAR at *www.sedar.com* (including those documents referred to as being incorporated by reference in this Annual Information Form) may be obtained free of charge from us at Suite 700, 333 – 5th Avenue S.W., Calgary, Alberta, T2P 3B6.

ZARGON ENERGY TRUST

General

We are an open-end investment trust created on June 17, 2004 under the laws of the Province of Alberta pursuant to the Trust Indenture. Valiant Trust Company has been appointed as our trustee under the Trust Indenture. The beneficiaries of the Trust are holders of the Trust Units. Our principal and head office is located at Suite 700, 333 – 5th Avenue S.W., Calgary, Alberta, T2P 3B6.

We commenced operations on July 15, 2004 as a result of the completion of a Plan of Arrangement under the *Business Corporations Act* (Alberta). Pursuant to this Plan of Arrangement, holders of common shares of Zargon Oil & Gas received either Trust Units or Exchangeable Shares for their common shares.

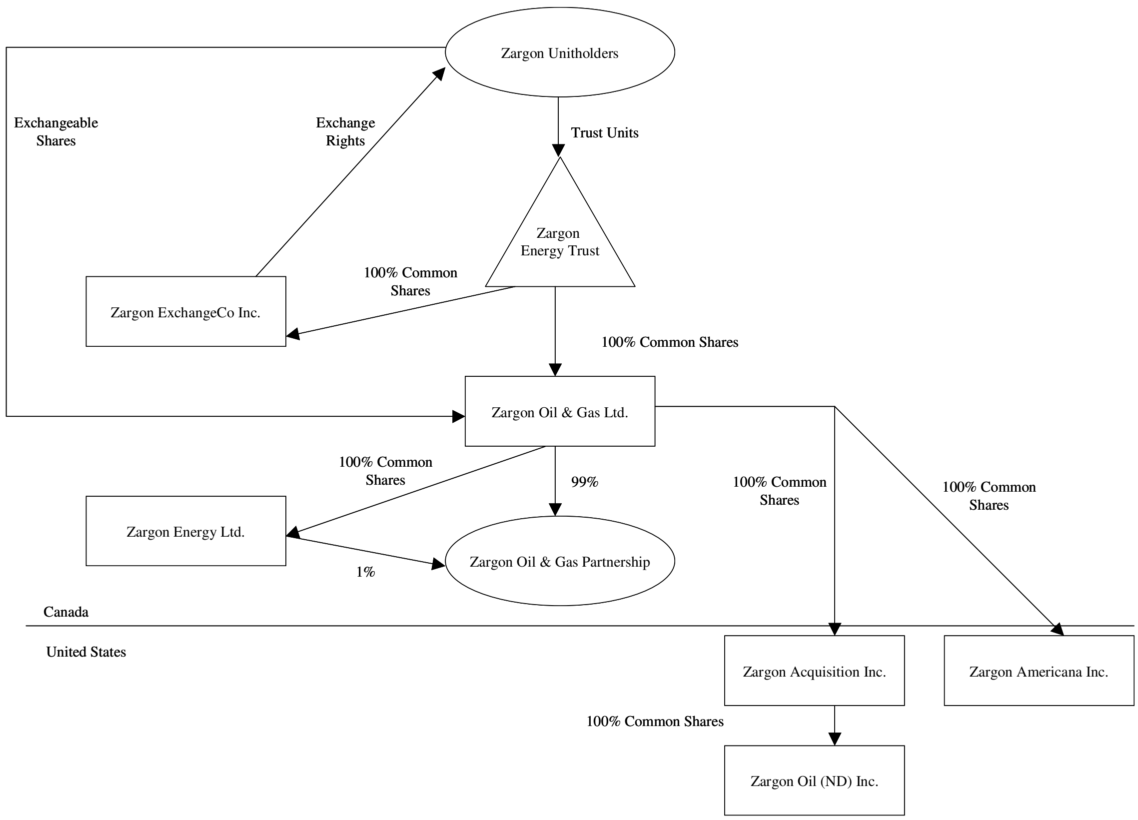
Inter-Corporate Relationships

The following are the names and percentages of voting securities that we own and the jurisdiction of incorporation, continuance or formation of our subsidiaries and partnerships either, direct and indirect, as at the date hereof.

	Percentage of voting securities (directly or indirectly)	Nature of Entity	Jurisdiction of Incorporation/ Formation
Zargon Oil & Gas Ltd.	100%	Corporation	Alberta
Zargon ExchangeCo Inc.	100%	Corporation	Alberta
Zargon Energy Ltd.	100%	Corporation	Alberta
Zargon Acquisition Corp. (inactive)	100%	Corporation	Alberta
Zargon Oil & Gas Partnership	100%	General Partnership	Alberta
Zargon Acquisition Inc.	100%	Corporation	Wyoming
Zargon Oil (ND) Inc.	100%	Corporation	Delaware
Zargon Americana Inc.	100%	Corporation	Montana

Our Organization Structure

The following diagram describes the inter-corporate relationships between us and our material subsidiaries and partnership.



Notes:

(1) Unitholders own 100 percent of our equity.
(2) Zargon Oil & Gas had a total of 1,783,696 Exchangeable Shares issued and outstanding as at December 31, 2009, which were exchangeable for 2,920,071 Trust Units.
(3) Cash distributions are made on a monthly basis to Unitholders based upon our funds flow from operations. Our primary sources of cash flow are payments from Zargon Oil & Gas pursuant to the NPI and interest on the principal amount of the Notes and other intercorporate notes. In addition to such amounts, prepayments in respect of principal on the Notes and other intercorporate notes may be made from time to time by Zargon Oil & Gas before the maturity of such notes.

Federal Tax Changes for Income Trusts and Corporations

On June 22, 2007, the federal legislation (Bill C-52) implemented a tax on publicly traded income trusts and limited partnerships (the "**SIFT Rules**") received Royal Assent. The SIFT Rules are not expected to affect us until 2011 provided we do not exceed the normal growth guidelines announced by the Department of Finance. We can increase our equity by approximately $486 million before 2011 without exceeding the normal growth guidelines. We do not anticipate that the normal growth guidelines will impair our ability to annually replace or grow reserves in 2010.

Under the SIFT Rules, the SIFT tax rate will be the federal general corporate income tax rate and the applicable provincial corporate rate. The federal general corporate income tax rate will be 16.5 percent in 2011 and 15 percent after 2011 and the provincial component will be 10 percent.

The tax legislation for the conversion of publicly traded income trusts into taxable Canadian corporations on a tax deferred basis received Royal Assent on March 12, 2009.

Management and our Board of Directors continue to work on the plan for converting us to a corporation on or before January 1, 2011. After the conversion, the corporation would expect to allocate its cash flow among funding a portion of capital expenditures, periodic debt repayments and cash payments to shareholders in the form of dividends. Current taxes payable by us after converting to a corporation will be subject to normal corporate tax rates. Taxable income as a corporation will vary depending on total income and expenses and vary with changes to commodity prices, costs, claims for both accumulated tax pools and tax pools associated with current year expenditures. As we have approximately $293 million of income tax pools, it is expected that taxable income will be reduced or potentially eliminated for the initial period post conversion.

Returns to shareholders after conversion to a corporation will be impacted by the reduction of cash flow required to pay current income taxes, if any. Over the longer term, we would expect Canadian investors who hold their Trust Units in a taxable account to be relatively indifferent on an after tax basis as to whether we are structured as a corporation or as a trust in 2011. However, Canadian tax deferred investors (those holding their trust units in a tax deferred vehicle such as a registered retirement savings plan, registered retirement income fund or pension plan) and foreign investors will realize a lower after tax return on distributions in taxable years after 2011 due to the introduction of the SIFT Tax should we stay as a trust, and their inability to claim the dividend tax credit if we convert to a corporation.

If a conversion from the trust structure to a corporation is approved by our Unitholders, the income tax payable will vary and each Unitholder should consult their own tax advisor for details on the direct impact to themselves.

GENERAL DEVELOPMENT OF THE BUSINESS

History and Development

On July 15, 2004, Zargon Oil & Gas completed a Plan of Arrangement whereby holders of common shares of Zargon Oil & Gas received either Trust Units or Exchangeable Shares for their common shares.

On January 23, 2008, we completed a Plan of Arrangement whereby we indirectly acquired all of the shares of Rival in consideration of the issuance of 0.57 million Trust Units, $16.4 million in cash and the assumption of approximately $17.2 million of debt. At closing, Rival's production was approximately 1,020 boe/d, which consisted of 650 bbl/d of crude oil and 2.22 MMcf/d of natural gas. Approximately 63 percent of Rival's production was from the operated Bellshill Lake oil property, which is located within our Alberta Plains core area, just south of Jarrow, our largest producing property. This acquisition brought oil development drilling opportunities at Bellshill Lake, seismically defined oil exploration opportunities at the Bellshill Lake and Morinville, Alberta properties, natural gas exploration locations at Robsart, Saskatchewan, and high volume lift oil exploitation projects at Bellshill Lake.

On May 16, 2008, we acquired all of the outstanding shares of Newpact for consideration of $9.54 million consisting of the issuance of 0.43 million Trust Units valued at $22.04 per unit and acquisition costs of $0.15 million. At closing, Newpact's production was approximately 350 boe/d, primarily from two Alberta properties, which consisted of 100 bbl/d of crude oil and 1.50 MMcf/d of natural gas. Approximately 48 percent of Newpact's production was from the operated St. Anne oil and natural gas property which is located northwest of Edmonton and 25 percent of production was from the Ghost Pine natural gas property, which primarily consists of shallow decline coal bed methane production, and is located northeast of Calgary.

On February 27, 2009, we entered into an arrangement agreement with Masters pursuant to which we agreed to acquire all of the issued and outstanding common shares of Masters pursuant to a plan of arrangement on the basis of, at the election of each Masters shareholder, cash or Trust Units or a combination thereof, subject to proration. The acquisition was completed on April 29, 2009, for a total consideration of approximately 1.475 million Trust Units, $5.70 million in cash and the assumption of approximately $13.29 million of net debt (including adjustments and transactions costs) for a total transaction value of approximately $40.03 million. The acquisition provided us with approximately 1,230 boe/d of production, consisting of 630 bbl/d of oil and 3.60 MMcf/d of natural gas of which approximately 55 percent was from the operated Little Bow oil property in Southern Alberta. The acquisition also provided us with an Alkaline Surfactant Polymer tertiary oil recovery opportunity at the Little Bow property and more than 100 thousand net acres of undeveloped Alberta land.

On June 5, 2009, we completed a public offering of 2.365 million Trust Units on a bought deal basis (including 215,000 Trust Units issued pursuant to the exercise in full of the over-allotment option granted to the underwriters) at a price of $15.00 per Trust Unit for total gross proceeds of approximately $35.48 million ($33.44 million net of issue costs).

On July 27, 2009, we amended and renewed our Credit Agreement to maintain our borrowing base to $180 million.

On July 28, 2009, we entered into an arrangement agreement with Churchill pursuant to which we agreed to acquire all of the issued and outstanding common shares of Churchill pursuant to a plan of arrangement on the basis of, at the election of each Churchill shareholder, cash or Trust Units or a combination thereof, subject to a maximum of $4.60 million in cash. The plan of arrangement was completed on September 23, 2009 for a total consideration of approximately 0.555 million Trust Units, $0.11 million in cash and the assumption of approximately $6.85 million of net debt (including adjustments and transactions costs) for a total transaction value of approximately $16.31 million. The Churchill Acquisition provided us with approximately 400 boe/d of production, consisting of 195 bbl/d of oil and 1.23 MMcf/d of natural gas in southern and west central Alberta and approximately 61 thousand net acres of undeveloped land.

Significant Acquisitions

We have not completed any significant acquisition during our most recently completed financial year for which disclosure is required under Part 8 of National Instrument 51-102 – *Continuous Disclosure Obligations*.

DESCRIPTION OF OUR BUSINESS

Overview

Our principal undertaking is to issue Trust Units and to acquire and hold securities of subsidiaries, trusts and partnerships, net profits interests, royalties, notes and other interests. Our direct and indirect subsidiaries and partnerships carry on the business of acquiring, developing, exploring, exploiting and holding interests in petroleum and natural gas properties and assets related thereto. At December 31, 2009, we had 63 employees. Cash flow from the properties is flowed from Zargon Oil & Gas to us by way of interest payments and principal repayments on notes and payments from Zargon Oil & Gas to us pursuant to the NPI.

The Board of Directors may declare cash distributions payable to the Unitholders and allocate all or any of our income to the Unitholders. It is currently anticipated that the only income we will receive will be from Zargon Oil & Gas by way of interest and principal repayments received on the principal amount of notes and payments pursuant to the NPI. We make monthly cash distributions to Unitholders from this income after expenses and any cash redemptions of Trust Units.

Cash distributions are made on or about the 15th day of each month to Unitholders of record on or about the last calendar day of the immediately preceding month.

Zargon Oil & Gas

Zargon Oil & Gas is a corporation amalgamated and subsisting pursuant to the laws of Alberta. Zargon Oil & Gas is actively engaged in the business of oil and natural gas exploitation, development, acquisition and production in Canada.

The Trust is the sole common shareholder of Zargon Oil & Gas. The Exchangeable Shares are owned by the public.

The head and registered office of Zargon Oil & Gas is located at Suite 700, 333 – 5th Avenue S.W., Calgary, Alberta, T2P 3B6.

Notes

The Notes were issued by Zargon Oil & Gas to us under the Note Indenture in connection with the Plan of Arrangement. The Notes are unsecured and bear interest at a rate of 10 percent per annum. Although Zargon Oil & Gas is permitted to make payments against the principal amount of the Notes outstanding from time to time without notice or bonus, Zargon Oil & Gas is not required to make any payment in respect of principal until July 15, 2034, subject to extension in the limited circumstances provided in the Note Indenture.

In contemplation of the possibility that Notes may be distributed to Unitholders upon the redemption of their Trust Units, the Note Indenture provides that, if persons other than us own Notes having an aggregate principal amount in excess of $10,000,000, either we or such holders shall be entitled, among other things, to require Valiant Trust Company to exercise the powers and remedies available under the Note Indenture upon an event of default and, with the Trust, such holders may provide consents, waivers or directions relating generally to the variance of the Note Indenture and the rights of noteholders. The Note Indenture allows us flexibility to delay payments of interest or principal otherwise due to us while payment is made to other noteholders, and to allow other noteholders to be paid out before us. Any delayed payments will be due 5 days after demand.

NPI

We are a party to a net profits interest agreement with Zargon Oil & Gas pursuant to which we have the right to receive the NPI on petroleum and natural gas rights held by Zargon Oil & Gas from time to time. Pursuant to the terms of the agreement, we are entitled to a payment from Zargon Oil & Gas for each month equal to the amount by which 99 percent of the gross proceeds from the sale of production attributable to the property interests of Zargon Oil & Gas for such month exceed 99 percent of certain deductible costs for such period. Zargon Oil & Gas is entitled to set off amounts reimbursable to it against NPI payments payable by Zargon Oil & Gas. The term of the agreement is for so long as there are petroleum and natural gas rights to which the NPI applies.

Disclosure of Reserves Data and Other Oil and Natural Gas Information

The statement of reserves data and other oil and gas information set forth below is dated February 23, 2010. The effective date of the statement is December 31, 2009 and the preparation date of the statement is February 23, 2010. Readers should also refer to the Report of Management and Directors on Oil and Gas Disclosure attached hereto as Appendix A and the Report on Reserves Data by McDaniel attached hereto as Appendix B.

The reserves data set forth below is based upon an evaluation by McDaniel with an effective date of December 31, 2009 contained in the McDaniel Report. The reserves data summarizes our crude oil, natural gas liquids and natural gas reserves and the net present values of future net revenue for these reserves using forecast prices and costs. The McDaniel Report has been prepared in accordance with the standards contained in the COGE Handbook and the reserve definitions contained in CSA 51-324. We engaged McDaniel to provide an evaluation of proved and proved plus probable reserves and no attempt was made to evaluate possible reserves.

Our reserves are in Canada in the provinces of Alberta, Saskatchewan, Manitoba and British Columbia, and in the United States in North Dakota.

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. The recovery and reserve estimates of our crude oil, natural gas liquids and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas and natural gas liquid reserves may be greater than or less than the estimates provided herein. Readers should review the definitions and information contained in "*Definitions and Notes to Reserves Data Tables*" below in conjunction with the following tables and notes. For more information as to the risks involved, see "*Risk Factors – Risk Relating to Our Business and Operations*".

Reserves Data (Forecast Prices and Costs)

SUMMARY OF OIL AND GAS RESERVES
AND NET PRESENT VALUES OF FUTURE NET REVENUE
as of December 31, 2009
FORECAST PRICES AND COSTS

CANADA

RESERVES CATEGORY	LIGHT AND MEDIUM OIL Gross (Mbbl)	LIGHT AND MEDIUM OIL Net (Mbbl)	HEAVY OIL Gross (Mbbl)	HEAVY OIL Net (Mbbl)	NATURAL GAS Gross (MMcf)	NATURAL GAS Net (MMcf)	NATURAL GAS LIQUIDS Gross (Mbbl)	NATURAL GAS LIQUIDS Net (Mbbl)
Proved								
Developed Producing	8,139	7,102	2,834	2,454	42,659	36,829	111	70
Developed Non-Producing	101	92	62	55	5,264	4,226	17	11
Undeveloped	84	71	45	38	317	297	-	-
Total Proved	**8,324**	**7,265**	**2,941**	**2,547**	**48,239**	**41,352**	**128**	**82**
Probable	**3,409**	**2,872**	**1,122**	**919**	**24,780**	**20,681**	**74**	**45**
Total Proved Plus Probable	**11,733**	**10,138**	**4,063**	**3,466**	**73,019**	**62,034**	**201**	**127**

NET PRESENT VALUES OF FUTURE NET REVENUE
BEFORE INCOME TAXES DISCOUNTED AT (%/year)

RESERVES CATEGORY	0% ($000s)	5% ($000s)	10% ($000s)	15% ($000s)	20% ($000s)
Proved					
Developed Producing	584,462	450,041	369,244	315,860	277,928
Developed Non-Producing	21,985	17,331	14,072	11,708	9,938
Undeveloped	5,190	2,953	1,869	1,251	856
Total Proved	**611,636**	**470,325**	**385,185**	**328,819**	**288,722**
Probable	**327,383**	**197,851**	**138,057**	**104,599**	**83,372**
Total Proved Plus Probable	**939,019**	**668,176**	**523,241**	**433,418**	**372,093**

NET PRESENT VALUES OF FUTURE NET REVENUE
AFTER INCOME TAXES DISCOUNTED AT (%/year)

RESERVES CATEGORY	0% ($000s)	5% ($000s)	10% ($000s)	15% ($000s)	20% ($000s)
Proved					
Developed Producing	524,412	413,188	344,646	298,483	265,148
Developed Non-Producing	17,315	13,781	11,302	9,500	8,145
Undeveloped	3,622	2,008	1,224	775	489
Total Proved	**545,349**	**428,976**	**357,172**	**308,758**	**273,782**
Probable	**244,928**	**150,095**	**105,892**	**81,068**	**65,267**
Total Proved Plus Probable	**790,277**	**579,071**	**463,064**	**389,826**	**339,050**

BY PRODUCTION GROUP
as of December 31, 2009
FORECAST PRICES AND COSTS

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) ($000s)	UNIT VALUE [1] ($/bbl) ($/Mcf)
Proved	Light and Medium Crude Oil (including solution gas and other by-products)	205,990	28.60
	Heavy Oil (including solution gas and other by-products)	74,447	29.23
	Natural Gas (including by-products but excluding natural gas from oil wells)	104,748	2.84
	Total	**385,185**	
Proved plus Probable	Light and Medium Crude Oil (including solution gas and other by-products)	274,170	27.30
	Heavy Oil (including solution gas and other by-products)	95,757	27.63
	Natural Gas (including by-products but excluding natural gas from oil wells)	153,314	2.77
	Total	**523,241**	

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

SUMMARY OF OIL AND GAS RESERVES
AND NET PRESENT VALUES OF FUTURE NET REVENUE
as of December 31, 2009
FORECAST PRICES AND COSTS

UNITED STATES

	LIGHT AND MEDIUM OIL		HEAVY OIL		NATURAL GAS		NATURAL GAS LIQUIDS	
RESERVES CATEGORY	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)	Gross (MMcf)	Net (MMcf)	Gross (Mbbl)	Net (Mbbl)
Proved								
Developed Producing	3,197	2,369	-	-	-	-	-	-
Developed Non-Producing	-	-	-	-	-	-	-	-
Undeveloped	98	73	-	-	-	-	-	-
Total Proved	**3,294**	**2,442**	-	-	-	-	-	-
Probable	**776**	**575**	-	-	-	-	-	-
Total Proved Plus Probable	**4,070**	**3,017**	-	-	-	-	-	-

RESERVES CATEGORY	NET PRESENT VALUES OF FUTURE NET REVENUE BEFORE INCOME TAXES DISCOUNTED AT (%/year) 0% ($000s)	5% ($000s)	10% ($000s)	15% ($000s)	20% ($000s)
Proved					
Developed Producing	116,295	76,882	56,668	45,100	37,697
Developed Non-Producing	-	-	-	-	-
Undeveloped	2,308	1,814	1,427	1,122	878
Total Proved	**118,603**	**78,696**	**58,096**	**46,222**	**38,575**
Probable	**45,927**	**19,607**	**11,068**	**7,368**	**5,407**
Total Proved Plus Probable	**164,530**	**98,303**	**69,164**	**53,589**	**43,982**

RESERVES CATEGORY	NET PRESENT VALUES OF FUTURE NET REVENUE AFTER INCOME TAXES DISCOUNTED AT (%/year) 0% ($000s)	5% ($000s)	10% ($000s)	15% ($000s)	20% ($000s)
Proved					
Developed Producing	66,217	45,425	33,775	27,041	22,724
Developed Non-Producing	-	-	-	-	-
Undeveloped	1,342	1,056	830	652	510
Total Proved	**67,559**	**46,481**	**34,606**	**27,693**	**23,234**
Probable	**26,718**	**11,406**	**6,438**	**4,284**	**3,143**
Total Proved Plus Probable	**94,277**	**57,887**	**41,043**	**31,977**	**26,376**

BY PRODUCTION GROUP
as of December 31, 2009
FORECAST PRICES AND COSTS

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) ($000s)	UNIT VALUE ($/bbl) [(1)] ($/Mcf)
Proved	Light and Medium Crude Oil (including solution gas and other by-products)	58,096	23.79
	Heavy Oil (including solution gas and other by-products)	-	-
	Natural Gas (including by-products but excluding natural gas from oil wells)	-	-
	Total	**58,096**	
Proved plus Probable	Light and Medium Crude Oil (including solution gas and other by-products)	69,164	22.92
	Heavy Oil (including solution gas and other by-products)	-	-
	Natural Gas (including by-products but excluding natural gas from oil wells)	-	-
	Total	**69,164**	

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

SUMMARY OF OIL AND GAS RESERVES
AND NET PRESENT VALUES OF FUTURE NET REVENUE
as of December 31, 2009
FORECAST PRICES AND COSTS

AGGREGATE

RESERVES CATEGORY	LIGHT AND MEDIUM OIL		HEAVY OIL		NATURAL GAS		NATURAL GAS LIQUIDS	
	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)	Gross (MMcf)	Net (MMcf)	Gross (Mbbl)	Net (Mbbl)
Proved								
Developed Producing	11,336	9,471	2,835	2,454	42,659	36,829	111	70
Developed Non-Producing	101	92	62	55	5,264	4,226	17	11
Undeveloped	181	144	45	38	317	297	-	-
Total Proved	**11,618**	**9,708**	**2,941**	**2,547**	**48,239**	**41,352**	**128**	**82**
Probable	**4,185**	**3,447**	**1,122**	**919**	**24,780**	**20,681**	**74**	**45**
Total Proved Plus Probable	**15,803**	**13,155**	**4,063**	**3,466**	**73,019**	**62,034**	**201**	**127**

RESERVES CATEGORY	NET PRESENT VALUES OF FUTURE NET REVENUE BEFORE INCOME TAXES DISCOUNTED AT (%/year) 0% ($000s)	5% ($000s)	10% ($000s)	15% ($000s)	20% ($000s)
Proved					
Developed Producing	700,757	526,923	425,912	360,960	315,625
Developed Non-Producing	21,985	17,331	14,072	11,708	9,938
Undeveloped	7,497	4,767	3,296	2,373	1,734
Total Proved	**730,239**	**549,021**	**443,280**	**375,040**	**327,297**
Probable	**373,310**	**217,458**	**149,125**	**111,967**	**88,779**
Total Proved Plus Probable	**1,103,548**	**766,479**	**592,405**	**487,007**	**416,075**

RESERVES CATEGORY	NET PRESENT VALUES OF FUTURE NET REVENUE AFTER INCOME TAXES DISCOUNTED AT (%/year) 0% ($000s)	5% ($000s)	10% ($000s)	15% ($000s)	20% ($000s)
Proved					
Developed Producing	590,629	458,613	378,422	325,524	287,872
Developed Non-Producing	17,315	13,781	11,302	9,499	8,145
Undeveloped	4,964	3,064	2,054	1,428	998
Total Proved	**612,908**	**475,457**	**391,778**	**336,452**	**297,016**
Probable	**271,646**	**161,501**	**112,329**	**85,351**	**68,410**
Total Proved Plus Probable	**884,554**	**636,958**	**504,107**	**421,803**	**365,426**

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
as of December 31, 2009
FORECAST PRICES AND COSTS

($ thousand) RESERVES CATEGORY	REVENUE	ROYALTIES	OPERATING COSTS	DEVELOPMENT COSTS	ABANDONMENT AND RECLAMATION COSTS	FUTURE NET REVENUE BEFORE INCOME TAXES	INCOME TAXES	FUTURE NET REVENUE AFTER INCOME TAXES
Proved Reserves								
Canada	1,362,360	199,055	500,105	5,387	46,176	611,637	66,288	545,349
United States	324,872	84,244	111,925	2,417	7,684	118,602	51,043	67,559
Total	1,687,232	283,299	612,030	7,804	53,860	730,239	117,331	612,908
Proved Plus Probable Reserves								
Canada	2,047,881	315,943	720,331	21,924	50,665	939,018	148,742	790,276
United States	416,459	108,005	133,605	2,417	7,902	164,530	70,252	94,278
Total	2,464,340	423,948	853,936	24,341	58,567	1,103,548	218,994	884,554

BY PRODUCTION GROUP
as of December 31, 2009
FORECAST PRICES AND COSTS

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) ($000s)	UNIT VALUE [1] ($/bbl) ($/Mcf)
Proved	Light and Medium Crude Oil (including solution gas and other by-products)	264,086	27.38
	Heavy Oil (including solution gas and other by-products)	74,447	29.23
	Natural Gas (including by-products but excluding natural gas from oil wells)	104,748	2.84
	Total	**443,280**	
Proved plus Probable	Light and Medium Crude Oil (including solution gas and other by-products)	343,334	26.29
	Heavy Oil (including solution gas and other by-products)	95,757	27.63
	Natural Gas (including by-products but excluding natural gas from oil wells)	153,314	2.77
	Total	**592,405**	

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

Definitions and Notes to Reserves Data Tables:

1. Columns may not add due to rounding.

2. The crude oil, natural gas liquids and natural gas reserve estimates presented in the McDaniel Report are based on the definitions and guidelines contained in the COGE Handbook and CSA 51-324. A summary of those definitions are set forth below.

   Reserve Categories

   Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on:

   - analysis of drilling, geological, geophysical and engineering data;
   - the use of established technology; and
   - specified economic conditions.

   Reserves are classified according to the degree of certainty associated with the estimates.

   Proved reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

Probable reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

Other criteria that must also be met for the categorization of reserves are provided in the COGE Handbook.

Each of the reserve categories (proved and probable) may be divided into the following developed and undeveloped categories:

Developed reserves are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for example, when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.

Developed producing reserves are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainly.

Developed non-producing reserves are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.

Undeveloped reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable) to which they are assigned.

In multi-well pools it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to subdivide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities and completion intervals in the pool and their respective development and production status.

Levels of Certainty for Reported Reserves

The qualitative certainty levels referred to in the definitions above are applicable to individual reserve entities (which refers to the lowest level at which reserves calculations are performed) and to reported reserves (which refers to the highest level sum of individual entity estimates for which reserves are presented). Reported reserves should target the following levels of certainty under a specific set of economic conditions:

- at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves; and
- at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves.

A qualitative measure of the certainty levels pertaining to estimates prepared for the various reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, the majority of reserves estimates will be prepared using deterministic methods that do not provide a mathematically derived quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

Forecast Prices and Costs

The forecast cost and price assumptions assume increases in wellhead selling prices and take into account inflation with respect to future operating and capital costs. Crude oil and natural gas benchmark reference pricing, as at December 31, 2009, inflation and exchange rates utilized in the McDaniel Report were as follows:

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
as of December 31, 2009
FORECAST PRICES AND COSTS

Year	WTI Cushing Oklahoma ($US/bbl)	Edmonton Par Price 40° API ($Cdn/bbl)	Bow River Hardisty API ($Cdn/bbl)	Alberta Heavy 12° API ($Cdn/bbl)	Cromer Medium 29.3° API ($Cdn/bbl)	Natural Gas AECO Price ($Cdn/MMBTU)	Natural Gas Liquids FOB Field Gate ($Cdn/bbl)	Inflation Rate[1] %/year	Exchange Rate[2] ($US/$Cdn)
Forecast									
2010	80.00	83.20	72.30	68.10	76.50	6.05	60.30	2.0	0.95
2011	83.60	87.00	73.80	67.60	79.10	6.75	63.50	2.0	0.95
2012	87.40	91.00	74.40	68.00	81.80	7.15	66.50	2.0	0.95
2013	91.30	95.00	75.80	68.10	85.40	7.45	69.40	2.0	0.95
2014	95.30	99.20	79.20	71.10	89.20	7.80	72.50	2.0	0.95
2015	99.40	103.50	82.60	74.20	93.10	8.15	75.60	2.0	0.95
2016	101.40	105.60	84.30	75.70	94.90	8.40	77.20	2.0	0.95
2017	103.40	107.70	85.90	77.20	96.80	8.55	78.70	2.0	0.95
2018	105.40	109.80	87.60	78.70	98.70	8.70	80.30	2.0	0.95
2019	107.60	112.10	89.40	80.40	100.70	8.90	82.00	2.0	0.95
2020	109.70	114.30	91.20	81.90	102.70	9.05	83.60	2.0	0.95
2021	111.90	116.50	93.00	83.60	104.80	9.25	85.20	2.0	0.95
2022	114.10	118.80	94.80	85.20	106.80	9.45	86.90	2.0	0.95
2023	116.40	121.20	96.70	86.90	109.00	9.65	88.70	2.0	0.95
2024	118.80	123.70	98.70	88.70	111.20	9.85	90.50	2.0	0.95
Thereafter:	Escalate at 2.0%/year	Escalate at 2.0%/year	Escalate at 2.0%/year	Escalate at 2.0%/year	Escalate at 2.0%/year	Escalate at 2.0%/year	Escalate at 2.0%/year	2.0	0.95

Notes:
(1) Inflation rates for forecasting prices and costs.
(2) Exchange rates used to generate the benchmark reference prices in this table.

Weighted average historical prices realized by us (before the impact of financial risk management contracts) for the year ended December 31, 2009, were $4.32/Mcf for natural gas and $59.89/bbl for oil and natural gas liquids.

Future Development Costs

The following table sets forth development costs deducted in the estimation of our future net revenue attributable to the reserve categories noted below:

CANADA

	Forecast Prices and Costs	
Year ($ thousand)	Proved Reserves	Proved Plus Probable Reserves
2010	2,947	11,535
2011	1,803	9,002
2012	133	371
2013	116	412
2014	66	66
Thereafter	322	538
Total Undiscounted	5,387	21,924
Total Discounted at 10%	4,766	19,660

UNITED STATES

Year ($ thousand)	Forecast Prices and Costs Proved Reserves	Proved Plus Probable Reserves
2010	1,196	1,196
2011	1,221	1,221
2012	-	-
2013	-	-
2014	-	-
Thereafter	-	-
Total Undiscounted	2,417	2,417
Total Discounted at 10%	2,198	2,198

AGGREGATE

Year ($ thousand)	Forecast Prices and Costs Proved Reserves	Proved Plus Probable Reserves
2010	4,143	12,732
2011	3,024	10,222
2012	133	371
2013	116	412
2014	66	66
Thereafter	322	538
Total Undiscounted	7,804	24,341
Total Discounted at 10%	6,965	21,858

Notes:

(1) We expect to fund the development costs of our reserves through a combination of internally generated cash flow, debt and sale of Trust Units.

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

(3) The interest or other costs of external funding are not included in the reserves and future net revenue estimates. This would reduce reserves and future net revenue to some degree depending upon the funding sources utilized. We do not anticipate that interest or other funding costs would make development of any property uneconomic.

(4) Estimated future abandonment and reclamation costs related to a property have been taken into account by McDaniel in determining reserves that should be attributed to a property. Reasonable estimated future well abandonment costs were deducted in determining the aggregate future net revenue. No allowance was made, however, for reclamation of well sites or the abandonment and reclamation of any facilities.

(5) The forecast price and cost assumptions assume the continuance of current laws and regulations.

(6) The extent and character of all factual data supplied to McDaniel were accepted by McDaniel as represented. No field inspection was conducted.

Reconciliations of Changes in Reserves

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

CANADA

	LIGHT AND MEDIUM OIL AND NATURAL GAS LIQUIDS			HEAVY OIL			ASSOCIATED AND NON-ASSOCIATED GAS		
FACTORS	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)
December 31, 2008	8,424	3,244	11,668	1,124	716	1,840	48,473	23,012	71,485
Extensions & Improved Recovery	555	228	783	117	53	170	1,747	1,217	2,964
Technical Revisions	512	(400)	112	253	(238)	15	3,148	(3,371)	(223)
Discoveries	-	144	144	-	-	-	450	633	1,083
Acquisitions	200	266	466	1,789	591	2,380	4,935	3,289	8,224
Dispositions	-	-	-	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-	-	-	-
Production	(1,239)	-	(1,239)	(342)	-	(342)	(10,514)	-	(10,514)
December 31, 2009	8,452	3,482	11,934	2,941	1,122	4,063	48,239	24,780	73,019

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

UNITED STATES

	LIGHT AND MEDIUM OIL AND NATURAL GAS LIQUIDS			HEAVY OIL			ASSOCIATED AND NON-ASSOCIATED GAS		
FACTORS	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)
December 31, 2008	3,429	870	4,299	-	-	-	-	-	-
Extensions & Improved Recovery	-	-	-	-	-	-	-	-	-
Technical Revisions	130	(94)	36	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-	-	-	-
Production	(265)	-	(265)	-	-	-	-	-	-
December 31, 2009	3,294	776	4,070	-	-	-	-	-	-

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

AGGREGATE

	LIGHT AND MEDIUM OIL AND NATURAL GAS LIQUIDS			HEAVY OIL			ASSOCIATED AND NON-ASSOCIATED GAS		
FACTORS	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)
December 31, 2008	11,852	4,115	15,967	1,124	716	1,840	48,473	23,012	71,485
Extensions & Improved Recovery	555	228	783	117	53	170	1,747	1,217	2,964
Technical Revisions	643	(494)	148	253	(238)	15	3,148	(3,371)	(223)
Discoveries	-	144	144	-	-	-	450	633	1,083
Acquisitions	200	266	466	1,789	591	2,380	4,935	3,289	8,224
Dispositions	-	-	-	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-	-	-	-
Production	(1,504)	-	(1,504)	(342)	-	(342)	(10,514)	-	(10,514)
December 31, 2009	11,746	4,259	16,004	2,941	1,122	4,063	48,239	24,780	73,019

Additional Information Relating to Reserves Data

Undeveloped Reserves

Undeveloped reserves are attributed by McDaniel in accordance with standards and procedures contained in the COGE Handbook. Proved undeveloped reserves are those reserves that can be estimated with a high degree of certainty and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. Probable undeveloped reserves are those reserves that are less certain to be recovered than proved reserves and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. In Zargon's practice, proved undeveloped reserves tend to be those reserves related to wells that have been tested and not yet tied-in, wells drilled near the end of the fiscal year or wells further away from our gathering systems. In addition, such reserves may relate to planned infill drilling locations. Probable undeveloped reserves may be reserves tested or indicated by analogy to be productive, infill drilling location and lands contiguous to production. In either case, the majority of undeveloped reserves are planned to be on stream within a two-year timeframe. Undeveloped proved and probable reserves represent only about four percent of our proved and probable reserves.

There are a number of factors that could result in delayed or cancelled development, including the following: (i) changing economic conditions (due to pricing, operating and capital expenditure fluctuations); (ii) changing technical conditions (including production anomalies, such as water breakthrough or accelerated depletion); (iii) multi-zone developments (for instance, a prospective formation completion may be delayed until the initial completion is no longer economic); (iv) a larger development program may need to be spread out over several years to optimize capital allocation and facility utilization; and (v) surface access issues (including those relating to land owners, weather conditions and regulatory approvals). For more information, see "*Risk Factors – Risks Relating to Our Business and Operations*".

Significant Factors or Uncertainties Affecting Reserves Data

Our evaluated oil and gas properties have no material extraordinary risks or uncertainties beyond those which are inherent in an oil and gas producing company as described under the heading "*Management's Discussion and Analysis*" in our Annual Report. See also "*Risk Factors – Risks Relating to Our Business and Operations*" below.

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. Our reserves are evaluated by McDaniel, an independent engineering firm.

As circumstances change and additional data becomes 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 of the subjective decisions implied, new geological or production information and a changing environment may impact these estimates. Revisions to reserve estimates can arise from changes in year end oil and gas prices, and reservoir performance. Such revisions can be either positive or negative.

Other Oil and Gas Information

Oil and Gas Properties

The following is a description of our principal oil and natural gas properties on production or under development as at December 31, 2009. The term "net", when used to describe our share of production, means the total of our working interest share before deduction of royalties owned by others. Unless otherwise specified, gross and net acres and well count information are as at December 31, 2009. **Estimates of reserves 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.

Our major properties are concentrated within the following four core regions in Alberta, British Columbia, Saskatchewan and Manitoba in Canada and in North Dakota in the United States. Each region offers a large undeveloped land base, a vast seismic database, and significant ownership and operatorship in production facilities.

West Central Alberta

Our West Central Alberta core area is comprised of two producing regions located directly west of the city of Edmonton and on the Peace River Arch. This core area is characterized by a large undeveloped land base of 250 thousand net acres. In 2009, the area accounted for approximately 41 percent of our natural gas production and eight percent of oil production.

Some of our properties in West Central Alberta have substantial natural gas exploitation potential. In particular, the western acreage in the Peace River Arch has significant gas-charged Montney, Doig and Bluesky sandstones, which may be exploitable through new horizontal well fracture technology. Additionally, the core area's large undeveloped land base and somewhat disparate natural gas properties can be rationalized through trades, acquisitions and sales into a more focused asset.

Although oil production volumes are relatively small, West Central Alberta includes five oil properties, generally located west of Edmonton, which have significant oil-in-place and exploitation potential. Consistent with many of our other assets, these properties hold smaller accumulations of oil-in-place that our exploitation programs target for increased recovery factors.

In 2009, we spent $8.68 million of field-related capital in the West Central Alberta core area, which represented 93 percent of the $9.31 million of property cash flow generated by this area. We drilled 4.1 net wells which resulted in 2.8 net natural gas wells and 1.3 net oil wells.

This core area's field capital programs were augmented by $11.87 million of capital pertaining to the Masters and Churchill corporate acquisitions, taking the total capital program to $20.55 million or 221 percent of the core area's cash flow. As a result, we increased West Central Alberta production by 21 percent to 2,345 boe/d, and proved and probable reserves by 16 percent to 6.20 Mmboe. In particular, Doig exploitation gas wells at the Kakut property on the Peace River Arch provided large gains in reserves and production.

Alberta Plains

The Alberta Plains core area is located in the east central and southeastern regions of Alberta and is characterized by relatively shallow wells and all-season surface access. This core area brings a large undeveloped land base of 229 thousand net acres. In 2009, Alberta Plains accounted for 58 percent of our natural gas production and 37 percent of oil production.

Historically, the area has provided significant natural gas operating cash flows from the Jarrow and Hamilton Lake properties. In the past, our large Jarrow and Hamilton Lake undeveloped land inventories provided the feedstock that we successfully explored to maintain production volumes. These same undeveloped lands and partially drained producing reservoirs are now the feedstock for our natural gas exploitation initiatives.

Over the last two years, we have completed four smaller corporate acquisitions, which added exploitation properties at Bellshill Lake, Grand Forks and Little Bow. These new properties, along with our Taber property, offer a significant oil-in-place target for our oil exploitation initiatives.

In 2009, we spent $18.29 million of field-related capital in the Alberta Plains core area, which represented 51 percent of the $35.69 million of property cash flow generated by this area. With these expenditures, we drilled 12.0 net wells which resulted in 7.0 net natural gas wells and 5.0 net oil wells.

This core area's field capital programs were augmented by $45.31 million of capital pertaining to the Masters and Churchill corporate acquisitions, taking the total capital program to $63.60 million, or 178 percent of the core area's cash flow. With this expanded oil-focused capital program, we increased the core area's oil production to 1,852 boe/d, a 48 and 229 percent gain over the 2008 and 2007 production volumes, respectively. Similarly, the area's proved and probable oil reserves increased by 49 and 161 percent over 2008 and 2007, respectively, to reach the year end reserves of 6.06 Mmboe. In particular, the Masters and Churchill corporate acquisitions and the Taber horizontal drilling program provided large gains in reserves and production.

Williston Basin

The Williston Basin core area is characterized by a stable oil production base and significant long term oil exploitation opportunities. The Williston Basin properties are located within relatively close proximity in southeast Saskatchewan, southwest Manitoba and three northern counties of North Dakota. The properties produce light and medium-gravity oil from carbonate reservoirs at depths up to 1,600 metres. In 2009, the Williston Basin contributed 55 percent of our oil and liquids production and accounted for 62 percent of our proved and probable oil and liquids reserves.

The majority of our Williston Basin producing reservoirs are characterized by low to moderate permeability and large volumes of remaining oil-in-place. Through exploitation projects, we seek to increase oil recovery factors through a combination of exploitation techniques, including: pressure maintenance by water injection, 3D seismic, unstimulated horizontal wells and fracture-stimulated horizontal wells to unlock additional oil reserves. In general, all of our waterflood initiatives are long term projects that lead to facility modifications and revised injector patterns, which then enable the drilling of very profitable drainage horizontal locations in future years.

In 2009, we spent $19.48 million of field-related capital in the Williston Basin core area, which represented 54 percent of the $35.83 million of property cash flow generated by this area. With these expenditures, we drilled 9.6 net oil wells with 100 percent success, of which 8.6 net wells were horizontal locations. With this capital program, we maintained production at 2,897 boe/d and replaced proved and probable reserves of 12.89 Mboe. In particular, we posted significant gains oil production and reserves with the drilling of 7.6 net horizontal wells at the Steelman Frobisher ridge property.

Oil and Gas Wells

The following table sets forth the number and status of wells in which we had a working interest as at December 31, 2009.

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Canada								
Alberta	396	254.0	193	95.3	528	334.2	330	206.8
Saskatchewan	340	231.9	46	35.4	102	50.4	39	18.9
Manitoba	57	56.7	10	10.0	-	-	-	-
United States								
North Dakota	92	90.0	7	6.9	-	-	-	-
Total	885	632.6	256	147.6	630	384.6	369	225.7

Properties with no Attributable Reserves

The following table sets out our developed and undeveloped land holdings as at December 31, 2009.

	Undeveloped Acres	
(thousand net acres)	Gross	Net
Alberta	594	426
British Columbia	3	2
Saskatchewan	143	105
Manitoba	3	3
United States	4	4
Total	748	540

With respect to our undeveloped land inventory and farm-in agreements, we have a commitment to one industry participant to re-complete one well in the Jarrow area of our Alberta Plains core area by June 1, 2010 at an estimated cost of $0.10 million.

Rights to explore, develop and exploit 65,758 net acres of our undeveloped land holdings are scheduled to expire by December 31, 2010.

Forward Contracts

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

For details of our material commitments to sell natural gas and crude oil that were outstanding at December 31, 2009 see note 12 to our 2009 annual audited consolidated financial statements, which is incorporated herein by reference.

Additional Information Concerning Abandonment and Reclamation Costs

As at December 31, 2009, we had 1,390.5 net wells capable of production for which we expect to incur abandonment and reclamation costs.

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

Period	Abandonment and Reclamation Costs Escalated at 2% Undiscounted ($000s)	Abandonment and Reclamation Costs Escalated at 2% Discounted at 10% ($000s)
Total liability as at December 31, 2009	58,567	13,916
Anticipated to be paid in 2010	97	92
Anticipated to be paid in 2011	687	595
Anticipated to be paid in 2012	1,349	1,063

We have estimated the net present value of our total asset retirement obligations to be $35.47 million as at December 31, 2009 based on a total future liability of $164.58 million. The future net revenues disclosed in this Annual Information Form based on the McDaniel Report do not contain an allowance for abandonment and reclamation costs for batteries and salvage values are deducted, which are not allowed under Canadian generally accepted accounting principles. The McDaniel Report deducted $58.57 million (undiscounted) and $13.92 million (10 percent discount using forecast prices and costs for proved and probable reserves) for abandonment and reclamation costs in estimating the future net revenue disclosed in this Annual Information Form.

We do not expect to pay any material amounts with respect to abandonment and reclamation costs in the next two financial years.

Tax Horizon

As a result of our tax efficient structure, annual taxable income is currently transferred from our operating entities to us and from us to Unitholders. This is primarily accomplished through the deduction by the NPI on underlying oil and gas properties and the deduction of interest on the Notes.

We did not pay Canadian income taxes in 2009. See "*Risk Factors*". During 2009, we incurred current income taxes in the United States of $2.21 million, compared to $3.08 million in 2008. On a year-over-year comparison, current income taxes have decreased due to a reduction in 2009 taxable income in the United States related to lower revenue attributed to relatively lower oil prices in 2009.

Costs Incurred

The following tables summarize capital expenditures related to our activities for the year ended December 31, 2009:

($ million)	**Canada**	**United States**	**Total**
Property Acquisition Costs:			
Proved Properties [(1)]	1.04	-	1.04
Unproved Properties	5.40	0.20	5.60
Corporate Acquisitions	56.34	-	56.34
Development Costs [(2)]	35.20	0.32	35.52
Exploration Costs [(3)]	5.33	-	5.33
Total	103.31	0.52	103.83

Notes:

(1) Acquisitions are net of disposition of properties.
(2) Development and facilities expenditures.
(3) Cost of land acquired, geological and geophysical capital expenditures and drilling costs for 2009 exploration wells drilled.

Exploration and Development Activities

The following table sets forth the gross and net exploratory and development wells in which we participated during the year ended December 31, 2009. We did not participate in any exploratory and development wells in the United States during the year ended December 31, 2009.

Canada	**Exploratory Wells**		**Development Wells**	
	Gross	**Net**	**Gross**	**Net**
Oil	-	-	17.0	15.9
Natural Gas	4.0	2.3	8.0	7.5
Service	-	-	-	-
Dry	-	-	-	-
Total	4.0	2.3	25.0	23.4

In 2010, we are budgeted to invest approximately $58 million in our core areas. The entire amount is dedicated to exploration, exploitation, development and optimization of our existing assets. This amount does not include any capital for acquisitions, which will be pursued on an opportunistic basis.

Our most important current exploration and development activities for 2010 include the following:

West Central Alberta

- Advance oil exploitation initiatives in the Carrot Creek Cardium, Highvale Banff, Brazeau Nisku, St. Anne Banff and Spirit River Gething projects. Although not large in scope, each of these projects provides the opportunity to deliver very strong returns, production and reserves through the implementation of waterfloods or further horizontal well exploitation.
- Exploit the Doig, Montney and Bluesky natural gas-bearing horizons at the Spirit River, Kakut, Webster and Rycroft horizons on the Peace River Arch area.
- Maximize natural gas production volumes at existing properties with production optimizations, recompletions and workovers. Rationalize disparate natural gas assets through trades, acquisitions and sales.
- Evaluate and maximize the value of the large undeveloped land base acquired in previous exploration initiatives and from four recent corporate acquisitions. Use farm-outs, sales and trades to derive value.

Alberta Plains

- Exploit primary recovery oil projects at Taber South, Bellshill Lake, Provost and Hamilton Lake. In particular, continue to develop the Taber South Mannville A pool with horizontal wells and improve reservoir vertical sweep efficiency at Bellshill Lake with vertical wells.
- Exploit secondary recovery oil projects at Taber South, Grand Forks and Hamilton Lake. In particular, rebalance and improve water injection schemes at the Grand Forks Glauconite E pool, the Taber South Mannville D and Glauconite C pools and the Hamilton Lake Viking pool. Subsequent to pool delineation, we plan to design and implement a secondary recovery scheme for the Taber South Mannville A pool.
- Finalize the Little Bow ASP tertiary recovery reservoir studies, project design and detailed cost estimates. Provided project authorization is justified, we will submit regulatory applications and prepare to award the facility construction contracts.
- Conclude the necessary completions, reservoir studies and pilot test expenditures required to evaluate the regional Viking and mid-Mannville channel gas-in-place opportunities at Jarrow and Hamilton Lake.
- Incorporate 3D seismic and material balance analyses to exploit our Jarrow Mannville gas-in-place opportunities.
- Maximize natural gas production volumes at existing properties with production optimizations, recompletions and workovers.

Williston Basin

- Exploit primary recovery oil projects at the Steelman, Manor, Fertile, Elswick, Cromer (Saskatchewan), Virden, Daly (Manitoba) and Mackobee Coulee (North Dakota) properties. In particular, we will continue to use unstimulated horizontal wells to develop the Steelman Frobisher ridges, the Manor Tilston/Alida structural highs, the Elswick Midale ridges and the Virden Lodgepole pool extensions.
- The Torquay (Bakken) formation at the Fertile and Cromer properties will be exploited with fracture stimulated horizontal wells.
- A large 3D survey will be undertaken at Mackobee Coulee to set up next year's horizontal drilling program.
- Design and initiate secondary (waterflood) recovery schemes in the Midale and Frobisher formations at Steelman and Elswick, Saskatchewan.
- Modify and enhance secondary (waterflood) recovery schemes in the Midale, Frobisher and Tilston formations at Steelman, Pinto, Elswick, Ralph, Frys and Carnduff.
- Conclude multi-disciplined reservoir studies to rebalance injections and maximize recoveries from the large Haas and Truro, North Dakota pools.

Production Estimates

The following table sets out the volume of our gross production estimated in the McDaniel Report for the year ended December 31, 2010, which is reflected in the estimate of future net revenue disclosed in the tables contained under "*Disclosure of Reserves Data And Other Oil And Natural Gas Information*".

	Light and Medium Oil	**Natural Gas**	**Natural Gas Liquids**	**BOE**
	(bbl/d)	(Mcf/d)	(bbl/d)	(boe/d)
Total Proved	1,803	10,393	27	9,751
Total Probable	184	892	2	917
Total Proved Plus Probable	1,987	11,285	29	10,668

Production History and Prices Received

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

CANADA

	Quarter Ended			
	2009			
	Dec. 31	**Sept. 30**	**June 30**	**Mar. 31**
Average Daily Production:				
Gas (Mcf/d)	30,604	28,234	28,439	29,917
Light and Medium Crude Oil (bbl/d) (2)	3,556	5,598	3,191	3,226
Heavy Oil (bbl/d)	1,244	1,081	843	566
Combined (boe/d)	9,901	9,385	8,773	8,444
Average Price Received: (1)				
Gas ($/Mcf)	4.57	3.91	4.20	6.33
Light and Medium Crude Oil ($/bbl) (2)	70.67	66.28	60.65	44.41
Heavy Oil ($/bbl)	64.30	60.48	58.76	41.23
Combined ($/boe)	53.52	50.63	49.28	47.72
Royalties Paid:				
Gas ($/Mcf)	0.32	0.33	0.30	0.87
Light and Medium Crude Oil ($/bbl) (2)	14.45	13.88	11.64	8.12
Heavy Oil ($/bbl)	13.47	13.18	9.84	6.38
Combined ($/boe)	7.87	7.84	6.16	6.42
Production Costs:				
Gas ($/Mcf)	2.44	2.11	2.07	1.92
Light and Medium Crude Oil ($/bbl) (2)	11.98	14.98	15.34	16.98
Heavy Oil ($/bbl)	11.83	12.34	10.96	15.33
Combined ($/boe)	13.32	13.52	13.36	13.86
Netback Received: (3)				
Gas ($/Mcf)	1.81	1.47	1.83	3.54
Light and Medium Crude Oil ($/bbl) (2)	44.24	37.42	33.67	19.31
Heavy Oil ($/bbl)	39.00	34.96	37.96	19.52
Combined ($/boe)	32.33	29.27	29.76	27.44

Notes:

(1) Average price received is calculated after the impact of realized risk management gains/losses.
(2) Includes an immaterial amount of NGLs.
(3) Netbacks are calculated by subtracting royalties and operating costs from revenues after realized risk management gains/losses.

UNITED STATES

	Quarter Ended			
	2009			
	Dec. 31	Sept. 30	June 30	Mar. 31
Average Daily Production:				
Gas (Mcf/d)	-	-	-	-
Light and Medium Crude Oil (bbl/d) [2]	685	703	747	768
Heavy Oil (bbl/d)	-	-	-	-
Combined (boe/d)	685	703	747	768
Average Price Received: [1]				
Gas ($/Mcf)	-	-	-	-
Light and Medium Crude Oil ($/bbl) [2]	67.61	62.91	57.97	48.26
Heavy Oil ($/bbl)	-	-	-	-
Combined ($/boe)	67.61	62.91	57.97	48.26
Royalties Paid:				
Gas ($/Mcf)	-	-	-	-
Light and Medium Crude Oil ($/bbl) [2]	17.21	12.37	15.61	10.24
Heavy Oil ($/bbl)	-	-	-	-
Combined ($/boe)	17.21	12.37	15.61	10.24
Production Costs:				
Gas ($/Mcf)	-	-	-	-
Light and Medium Crude Oil ($/bbl) [2]	9.81	8.87	9.73	10.31
Heavy Oil ($/bbl)	-	-	-	-
Combined ($/boe)	9.81	8.87	9.73	10.31
Netback Received: [3]				
Gas ($/Mcf)	-	-	-	-
Light and Medium Crude Oil ($/bbl) [2]	40.59	41.67	32.63	27.71
Heavy Oil ($/bbl)	-	-	-	-
Combined ($/boe)	40.59	41.67	32.63	27.71

Notes:

(1) Average price received is calculated after the impact of realized risk management gains/losses.

(2) Netbacks are calculated by subtracting royalties and operating costs from revenues after realized risk management gains/losses.

AGGREGATE

	Quarter Ended 2009			
	Dec. 31	**Sept. 30**	**June 30**	**Mar. 31**
Average Daily Production:				
Gas (Mcf/d)	30,604	28,234	28,439	27,917
Light and Medium Crude Oil (bbl/d) (2)	4,241	4,301	3,938	3,994
Heavy Oil (bbl/d)	1,244	1,081	843	566
Combined (boe/d)	10,586	10,088	9,520	9,213
Average Price Received: (1)				
Gas ($/Mcf)	4.57	3.91	4.20	6.33
Light and Medium Crude Oil ($/bbl) (2)	70.22	65.78	60.20	43.22
Heavy Oil ($/bbl)	64.30	60.48	58.76	41.23
Combined ($/boe)	54.43	51.48	49.97	47.77
Royalties Paid:				
Gas ($/Mcf)	0.32	0.33	0.30	0.87
Light and Medium Crude Oil ($/bbl) (2)	14.90	13.63	12.39	8.53
Heavy Oil ($/bbl)	13.47	13.18	9.84	6.38
Combined ($/boe)	8.50	8.15	6.92	6.74
Production Costs:				
Gas ($/Mcf)	2.44	2.11	2.07	1.92
Light and Medium Crude Oil ($/bbl) (2)	11.63	13.98	14.28	15.70
Heavy Oil ($/bbl)	11.83	12.34	10.96	15.33
Combined ($/boe)	13.09	13.18	13.08	13.56
Netback Received: (3)				
Gas ($/Mcf)	1.81	1.47	1.83	3.54
Light and Medium Crude Oil ($/bbl) (2)	43.69	38.17	33.53	18.99
Heavy Oil ($/bbl)	39.00	34.96	37.96	19.52
Combined ($/boe)	32.84	30.15	29.97	27.47

Notes:

(1) Average price received is calculated after the impact of realized risk management gains/losses.
(2) Includes an immaterial amount of NGLs.
(3) Netbacks are calculated by subtracting royalties and operating costs from revenues after realized risk management gains/losses.

The following table indicates our average daily production from our core areas for the year ended December 31, 2009:

	Natural Gas	**Light and Medium Crude Oil**	**Heavy Oil**	**NGLs**	**BOE**
	(Mcf/d)	**(bbl/d)**	**(bbl/d)**	**(bbl/d)**	**(boe/d)**
West Central Alberta	11,696	272	79	45	2,345
Alberta Plains	16,564	960	857	34	4,614
Williston Basin	535	2,807	-	1	2,897
Total	28,795	4,039	956	80	9,856

Marketing Arrangements

Natural Gas

Most of our natural gas production was sold by spot sale contracts and Alberta Index prices were received. In order to control and manage credit risk and ensure competitive bids, we engage with a number of reputable counterparties for our natural gas transactions. The integration and application of these strategies resulted in an average realized price (after realized risk management gains/losses) of $4.32 Cdn per Mcf in 2009 compared to $8.12 Cdn per Mcf in 2008.

Oil and Natural Gas Liquids

We sell our oil and natural gas liquids production to a variety of customers. This allows us to benefit from specific regional advantages while maintaining pricing and delivery flexibility. In general, we market our oil production with various purchasers under one month renewable contracts and receive posted reference prices with adjustments for quality and transportation. In 2009, our average realized oil and liquids price (after realized risk management gains/losses) was $59.89 Cdn per bbl compared to $89.65 Cdn per bbl in 2008.

Risk Management Activities

Our commodity risk management policy, which is approved by the Board of Directors, allows the use of forward sales, costless collars and other instruments in either US or Canadian dollars for up to a 24 month term and for up to 30 percent of the combined oil and natural gas working interest production volumes. The policy also allows the use of forward purchases, costless collars and other instruments for up to a 24 month term for up to 50 percent of estimated electricity consumption volumes. Because our risk management strategy is protective in nature and is designed to guard us against extreme effects on funds flow from sudden falls in prices and revenues, upward price spikes tend to produce overall losses.

For 2009, the total realized risk management gain was $27.69 million; compared to a loss of $15.72 million in 2008 and a gain of $4.26 million in 2007. Of the 2009 gain, $4.34 million (equivalent to an increase of $0.41 per thousand cubic feet) is related to a gain from natural gas financial risk management transactions, $23.36 million (equivalent to an increase of $12.65 per barrel) related to gains from oil financial risk management transactions (foreign exchange contracts are considered in conjunction with the oil contracts) and $0.01 million is related to a loss from electricity risk management transactions. Oil swaps and collars are settled against the NYMEX WTI pricing index, whereas natural gas swaps, collars and puts are settled against the AECO monthly pricing index. Electricity swaps are settled against the AESO pricing index. In 2009, NYMEX WTI crude oil prices rose throughout the first half of the year, before holding relatively steady for the remainder of the year. AECO natural gas prices continued to trend lower throughout the first eight months, finding its low for the August months before beginning to trend upwards. These lower prices, relative to the respective risk management contracts, resulted in overall year-to-date realized risk management gains for 2009.

We consider financial risk management contracts to be effective on an economic basis but we have decided not to designate these contracts as hedges for accounting purposes, and, accordingly, for these contracts, an unrealized gain or loss is recorded based on the fair value (mark-to-market) of the contracts at year end. The 2009 net unrealized risk management loss totalled $36.39 million which, compares to a $44.38 million net unrealized risk management gain in 2008 (2007 – $16.80 million loss). Specifically, the 2009 net unrealized risk management losses resulted from financial oil contract losses ($34.70 million), financial natural gas contract losses ($2.87 million) and financial electricity contract losses ($0.13 million) and were offset by financial foreign exchange contract gains ($1.31 million). These unrealized risk management gains or losses are generated by the change over the reporting period in the mark-to-market valuation of our future financial contracts. Gains or losses on fixed price physical contracts are included in petroleum and natural gas revenue when settled in the statements of earnings and comprehensive income and no mark-to-market valuation is recorded on these contracts.

Acquisitions and Dispositions

During 2009, we completed several property transactions including the acquisition and disposition of oil and natural gas properties. In aggregate, we made $57.38 million of net property acquisitions and corporate acquisitions in the year.

Environmental Policies

We have an environmental policy in place as part of our commitment to protecting the environment while conducting our operations. Our environmental policy states that:

- Operating in an environmentally responsible manner is key to insuring our continued growth and the industry.
- Sound environmental management is an integral component of a good business plan. Environmental stewardship reduces costs and corporate liability. It enhances shareholder value, boosts employee moral and enhances our image in the eyes of regulators and the public.
- Managing our environmental responsibilities is a team effort requiring the commitment of management, employees and contractors.
- Preventing environmental damage is cheaper than repairing damage.
- An effective environmental program helps operations staff to understand and comply with environmental laws and regulations and to minimize the costs and liabilities associated with environmental damage. It helps meet the concerns of investors, analysts, bankers, partners and the public that environmental issues are being managed properly and will provide a due-diligence defence in the event of an environmental incident.

Our management also monitors developments related to the climate change and other environmental laws and regulations.

We are not currently impacted by proposed environmental laws and regulations relating to the control of greenhouse gases (see "*Industry Conditions – Climate Change Regulation*") as none of our facilities qualify and currently, no facility production qualifies under the criteria described in the Updated Action Plan. We will continue to monitor the regulatory developments and any impact that they may have on our future compliance costs.

SHARE CAPITAL OF ZARGON OIL & GAS

Common Shares

Zargon Oil & Gas has authorized for issuance an unlimited number of common shares, all of which are owned by us. The voting of such shares is delegated to the Board of Directors under the Trust Indenture other than: (i) any sale, lease or other disposition of, or any interest in, all or substantially all of the assets of Zargon Oil & Gas, except in conjunction with an internal reorganization of the direct or indirect assets of Zargon Oil & Gas as a result of which either Zargon Oil & Gas or we have the same, or substantially similar, interest, whether direct or indirect, in the assets as the interest, whether direct or indirect, that it had prior to the reorganization; (ii) any statutory amalgamation of Zargon Oil & Gas with any other corporation or any amalgamation, merger or other transaction, as the case may be, of Zargon Oil & Gas with any other entity, except in conjunction with an internal reorganization as referred to in paragraph (i) above; (iii) any statutory arrangement involving Zargon Oil & Gas, except in conjunction with an internal reorganization as referred to in paragraph (i) above; (iv) any amendment to the articles of Zargon Oil & Gas to increase or decrease the minimum or maximum number of directors; or (v) any material amendment to the articles of Zargon Oil & Gas to change the authorized share capital or amend the rights, privileges, restrictions and conditions attaching to any class of Zargon Oil & Gas's shares in a manner that may be prejudicial to us, which must be approved by the Unitholders by special resolution at a meeting of Unitholders called for that purpose.

The holders of common shares are entitled to receive notice of and to attend all meetings of the shareholders of Zargon Oil & Gas and to one vote at such meetings. The holders of common shares will be, at the discretion of the Board of Directors, subject to applicable legal restrictions and to certain preferences of holders of Exchangeable Shares, entitled to receive any dividends declared by the Board of Directors on the common shares to the exclusion of the holders of Exchangeable Shares, provided that no dividends shall be paid on the common shares unless all declared dividends on the outstanding Exchangeable Shares have been paid in full. The holders of common shares will be entitled to share equally in any distribution of the assets of Zargon Oil & Gas upon the liquidation, dissolution, bankruptcy or winding-up of Zargon Oil & Gas or other distribution of its assets among its shareholders for the purpose of winding-up its affairs. Such participation is subject to the rights, privileges, restrictions and conditions attaching to the Exchangeable Shares and any other shares having priority over the common shares.

Exchangeable Shares

Zargon Oil & Gas is authorized to issue an unlimited number of Exchangeable Shares of which, as of December 31, 2009, 1,783,696 were outstanding. The Exchangeable Shares rank prior to the common shares of Zargon Oil & Gas and any other shares ranking junior to the Exchangeable Shares with respect to the payment of dividends and the distribution of assets in the event of the liquidation, dissolution or winding-up of Zargon Oil & Gas. The Exchangeable Share provisions have been filed on SEDAR at *www.sedar.com*.

Valiant Trust Company acts as the transfer agent for the Exchangeable Shares.

Each Exchangeable Share has economic rights (including the right to have the Exchange Ratio adjusted to account for distributions paid to Unitholders) and voting attributes (through the benefit of the Special Voting Rights granted to the Trustee) equivalent to those of the Trust Units into which they are exchangeable from time to time. As at December 31, 2009, the Exchange Ratio was 1.63709 and will be increased on each distribution payment date by an amount, rounded to the nearest five decimal places, equal to a fraction having as its numerator the distribution, expressed as an amount per Trust Unit, paid on that date multiplied by the Exchange Ratio immediately prior to the record date for such distribution and having as its denominator the current market price of the Trust Units (five day weighted average trading price) on the first business day following the record date for the distribution. In addition, holders of Exchangeable Shares have the right to receive Trust Units at any time in exchange for their Exchangeable Shares, on the basis of the Exchange Ratio in effect at the time of the exchange. Fractional Trust Units will not be delivered on any exchange of Exchangeable Shares. In the event that the Exchange Ratio in effect at the time of an exchange would otherwise entitle a holder of Exchangeable Shares to a fractional Trust Unit, the number of Trust Units to be delivered will be rounded to the nearest whole number of Trust Units. Holders of Exchangeable Shares will not receive cash distributions from us or Zargon Oil & Gas, rather, the Exchange Ratio will be adjusted to account for distributions paid to Unitholders.

Ranking

The Exchangeable Shares rank rateably with shares of any other series of exchangeable shares of Zargon Oil & Gas and prior to any common shares of Zargon Oil & Gas and any other shares ranking junior to the Exchangeable Shares with respect to the payment of dividends, if any, that have been declared and the distribution of assets in the event of the liquidation, dissolution or winding-up of Zargon Oil & Gas.

Dividends

Holders of Exchangeable Shares will be entitled to receive cash dividends if, as and when declared by the Board of Directors. Zargon Oil & Gas anticipates that it may from time to time declare dividends on the Exchangeable Shares up to but not exceeding any cash distributions on the Trust Units into which such Exchangeable Shares are exchangeable. In the event that any such dividends are paid, the Exchange Ratio will be correspondingly reduced to reflect such dividends.

Certain Restrictions

Zargon Oil & Gas will not, without obtaining the approval of the holders of the Exchangeable Shares as set forth below under the subheading "*Amendment and Approval*":

(a) pay any dividend on the common shares or any other shares ranking junior to the common shares, other than stock dividends payable in common shares or any other shares ranking junior to the Exchangeable Shares;

(b) redeem, purchase or make any capital distribution in respect of the common shares of Zargon Oil & Gas or any other shares ranking junior to the Exchangeable Shares;

(c) redeem or purchase any other shares of Zargon Oil & Gas ranking equally with the Exchangeable Shares with respect to the payment of dividends or on any liquidation distribution; or

(d) issue any shares, other than Exchangeable Shares or common shares, which rank superior to the Exchangeable Shares with respect to the payment of dividends or on any liquidation distribution.

The above restrictions shall not apply if all declared dividends on the outstanding Exchangeable Shares have been paid in full.

Liquidation or Insolvency of Zargon Oil & Gas

In the event of the liquidation, dissolution or winding-up of Zargon Oil & Gas or any other proposed distribution of the assets of Zargon Oil & Gas among its shareholders for the purpose of winding up its affairs, a holder of Exchangeable Shares, subject to applicable law, will be entitled to receive from Zargon Oil & Gas, in respect of each such Exchangeable Share, that number of Trust Units equal to the Exchange Ratio as at the effective date of such event.

Upon the occurrence of such an event, we and ExchangeCo will each have the overriding right to purchase all, but not less than all, of the Exchangeable Shares then outstanding (other than Exchangeable Shares which are held by us or any subsidiaries) at a purchase price per Exchangeable Share to be satisfied by the issuance or delivery, as the case may be, of that number of Trust Units equal to the Exchange Ratio at such time and, upon the exercise of this right, the holders thereof will be obligated to sell such Exchangeable Shares to us or ExchangeCo, as applicable. This right may be exercised by either us or ExchangeCo.

Automatic Exchange Right on our Liquidation

The voting and exchange trust agreement provides that in the event of a "trust liquidation event", as described below, we or ExchangeCo will be deemed to have purchased all outstanding Exchangeable Shares and each holder of Exchangeable Shares will be deemed to have sold their Exchangeable Shares immediately prior to such trust liquidation event at a purchase price per Exchangeable Share to be satisfied by the issuance or delivery, as the case may be, of that number of Trust Units equal to the Exchange Ratio at such time. "Trust liquidation event" means:

- any determination by us to institute our voluntary liquidation, dissolution or winding-up proceedings or to effect any other distribution of our assets among the Unitholders for the purpose of winding up our affairs; or

- the earlier of, our receiving notice of or us otherwise becoming aware of, any threatened or instituted claim, suit, petition or other proceedings with respect to our involuntary liquidation, dissolution or winding up or to effect any other distribution of our assets among the Unitholders for the purpose of winding up our affairs in each case where we have failed to contest, in good faith, such proceeding within 30 days of becoming aware thereof.

Retraction of Exchangeable Shares by Holders and Retraction Call Right

Subject to the Retraction Call Right granted to us and ExchangeCo, described below, a holder of Exchangeable Shares will be entitled at any time to require Zargon Oil & Gas to redeem any or all of the Exchangeable Shares held by such holder for a retraction price (the "**Retraction Price**") per Exchangeable Share equal to the value of that number of Trust Units equal to the Exchange Ratio as at the date of redemption (the "**Retraction Date**"), to be satisfied by the delivery of such number of Trust Units. Fractional Trust Units will not be delivered. Any amount payable on account of the Retraction Price that includes a fractional Trust Unit will be rounded to the nearest whole number of Trust Units. Holders of the Exchangeable Shares may request redemption by presenting to Zargon Oil & Gas or the transfer agent for the Exchangeable Shares a certificate or certificates representing the number of Exchangeable Shares the holder desires to have redeemed, together with a duly executed retraction request and such other documents as may be reasonably required to effect the redemption of the Exchangeable Shares. Subject to the extension as described below, the redemption will become effective on the Retraction Date, which will be three business days after the date on which Zargon Oil & Gas or the transfer agent receives the retraction notice.

When a holder requests Zargon Oil & Gas to redeem the Exchangeable Shares, we and ExchangeCo will have an overriding right (the "**Retraction Call Right**") to purchase, on the Retraction Date, all, but not less than all, of the Exchangeable Shares that the holder has requested Zargon Oil & Gas to redeem at a purchase price per Exchangeable Share equal to the Retraction Price, to be satisfied by the delivery of that number of Trust Units equal to the Exchange Ratio at such time. At the time of a Retraction Request by a holder of Exchangeable Shares, Zargon Oil & Gas will immediately notify us and ExchangeCo. We or ExchangeCo must then advise Zargon Oil & Gas within two business days as to whether the Retraction Call Right will be exercised. A holder may revoke his or her Retraction Request at any time prior to the close of business on the last business day immediately preceding the Retraction Date, in which case the holder's Exchangeable Shares will neither be purchased by us or ExchangeCo nor be redeemed by Zargon Oil & Gas. If the holder does not revoke his or her Retraction Request, the Exchangeable Shares that the holder has requested Zargon Oil & Gas to redeem will, on the Retraction Date, be purchased by us or ExchangeCo or redeemed by Zargon Oil & Gas, as the case may be, in each case at a purchase price per Exchangeable Share equal to the Retraction Price. In addition, a holder of Exchangeable Shares may elect to instruct the Trustee to exercise the optional exchange right (the "**Optional Exchange Right**") to require us or ExchangeCo to acquire such holder's Exchangeable Shares in circumstances where neither we nor ExchangeCo have exercised the Retraction Call Right.

The Retraction Call Right may be exercised by either us or ExchangeCo. If, as a result of solvency provisions of applicable law, Zargon Oil & Gas is not permitted to redeem all Exchangeable Shares tendered by a retracting holder, Zargon Oil & Gas will redeem only those Exchangeable Shares tendered by the holder as would not be contrary to such provisions of applicable law. The holder of any Exchangeable Shares not redeemed by Zargon Oil & Gas will be deemed to have required us to purchase such unretracted Exchangeable Shares in exchange for Trust Units on the Retraction Date pursuant to the Optional Exchange Right.

Redemption of Exchangeable Shares

Subject to applicable law and the Redemption Call Right granted to us, ExchangeCo and Zargon Oil & Gas:

(a) will on July 15, 2014, subject to extension of such date by the Board of Directors (the "**Automatic Redemption Date**"), redeem all, but not less than all, of the then outstanding Exchangeable Shares for a redemption price per Exchangeable Share equal to the value of that number of Trust Units equal to the Exchange Ratio as at the last Business Day prior to that Redemption Date (as that term is defined below) (the "**Redemption Price**"), to be satisfied by the delivery of such number of Trust Units;

(b) may, on the July 15, 2009 (the "**Optional Redemption Date**"), redeem all, but not less than all, of the outstanding Exchangeable Shares for the Redemption Price per Exchangeable Share at the last Business Day prior to that Redemption Date (as that term is defined below), to be satisfied by the delivery of Trust Units;

(c) may, on any date that is within the first 90 days of any calendar year, redeem up to that number of Exchangeable Shares equal to 20 percent of the number of Exchangeable Shares that were outstanding on July 15, 2004 for the Redemption Price per Exchangeable Share at the last Business Day prior to that Redemption Date (as that term is defined below), to be satisfied by the delivery of Trust Units; and

(d) may, at any time when the aggregate number of issued and outstanding Exchangeable Shares is less than 350,000 (other than Exchangeable Shares held by us and our subsidiaries and as such shares may be adjusted from time to time) (the "**De Minimus Redemption Date**" and, collectively with the Automatic Redemption Date, optional Redemption Date and Annual Redemption Date, a "**Redemption Date**"), redeem all, but not less than all, of the then outstanding Exchangeable Shares for the Redemption Price per Exchangeable Share (unless contested in good faith by us).

Zargon Oil & Gas will, at least 90 days prior to any Redemption Date, provide the registered holders of the Exchangeable Shares with written notice of the prospective redemption of the Exchangeable Shares by Zargon Oil & Gas.

We and ExchangeCo have the right (the "**Redemption Call Right**"), notwithstanding a proposed redemption of the Exchangeable Shares by Zargon Oil & Gas on the applicable Redemption Date, pursuant to the terms of the Exchangeable Shares, to purchase on any Redemption Date all, but not less than all, of the Exchangeable Shares then outstanding (other than Exchangeable Shares held by us or our subsidiaries) in exchange for the Redemption Price per Exchangeable Share and, upon the exercise of the Redemption Call Right, the holders of all of the then outstanding Exchangeable Shares will be obliged to sell all such shares to us or ExchangeCo, as applicable. If either we or ExchangeCo exercise the Redemption Call Right, then Zargon Oil & Gas's right to redeem the Exchangeable Shares on the applicable Redemption Date will terminate. The Redemption Call Right may be exercised by either us or ExchangeCo.

Voting Rights

Except as required by applicable law, the holders of the Exchangeable Shares are not entitled, as such, to receive notice of or attend any meeting of the shareholders of Zargon Oil & Gas or to vote at any such meeting. Holders of Exchangeable Shares will have the notice and voting rights respecting meetings that are provided in the voting and exchange trust agreement.

Amendment and Approval

The rights, privileges, restrictions and conditions attaching to the Exchangeable Shares may be changed only with the approval of the holders thereof. Any such approval or any other approval or consent to be given by the holders of the Exchangeable Shares will be sufficiently given if given in accordance with applicable law and subject to a minimum requirement that such approval or consent be evidenced by a resolution passed by not less than two-thirds of the votes cast thereon (other than shares beneficially owned by us, or any of our entities and other affiliates) at a meeting of the holders of the Exchangeable Shares duly called and held at which holders of at least 10 percent of the then outstanding Exchangeable Shares are present in person or represented by proxy. In the event that no such quorum is present at such meeting within one half hour after the time appointed therefore, then the meeting will be adjourned to such place and time (not less than ten days later) as may be determined at the original meeting and the holders of Exchangeable Shares present in person or represented by proxy at the adjourned meeting will constitute a quorum thereat and may transact the business for which the meeting was originally called. At the adjourned meeting, a resolution passed by the affirmative vote of not less than two-thirds of the votes cast thereon (other than shares beneficially owned by us or any of our subsidiaries and other affiliates) will constitute the approval or consent of the holders of the Exchangeable Shares.

Actions by Us under the Support Agreement and the Voting and Exchange Trust Agreement

In accordance with the terms of the Exchangeable Shares, Zargon Oil & Gas has agreed to take all such actions and do all such things as are necessary or advisable to perform and comply with its obligations under, and to ensure the performance and compliance by us and ExchangeCo with its obligations under, the support agreement and the voting and exchange trust agreement.

Support Agreement and Voting and Exchange Trust Agreement

The support agreement and the voting and exchange trust agreement have been filed on SEDAR at *www.sedar.com*.

INFORMATION RELATING TO US

Trust Units

An unlimited number of Trust Units may be created and issued pursuant to the Trust Indenture. The Trust Units represent equal undivided beneficial interests in us. All Trust Units share equally in all distributions made by us and all Trust Units carry equal voting rights at meetings of Unitholders. No Unitholder will be liable to pay any further calls or assessments in respect of the Trust Units. No conversion, retraction, redemption or pre-emptive rights attach to the Trust Units except as described below under "*Trust Indenture – Right of Redemption*".

Special Voting Units

The Trust Indenture also provides for the issuance of special voting units and which are entitled to such number of votes at meetings of Unitholders equal to the number of Trust Units reserved for issuance that such special voting units represent, such number of votes and any other rights or limitations prescribed by the Board of Directors when the Board of Directors authorizes issuing such special voting units. The Trust Units and the special voting units vote together as a single class on all matters. In the event of any of our liquidation, dissolution or winding-up, the holders of special voting units will not be entitled to receive any of our assets available for distribution to its holders of Trust Units. The holders of special voting units will not be entitled to receive dividends or other distributions from us.

A single special voting unit was issued to Valiant Trust Company as trustee under a voting and exchange trust agreement for the benefit of holders of the Exchangeable Shares issued in connection with the plan of arrangement completed in July, 2004. This special voting unit is entitled to a number of votes, exercisable at any meeting at which Unitholders are entitled to vote, equal to the number of Trust Units (rounded down to the nearest whole number), into which the Exchangeable Shares are then exchangeable multiplied by the number of votes to which the holder of one Trust Unit is then entitled. Valiant Trust Company is required to vote the special voting units in the manner that holders of Exchangeable Shares instruct, and to abstain from voting on the Exchangeable Shares for which Valiant Trust Company does not receive instructions.

Trust Indenture

The Trust Indenture, among other things, provides for the calling of meetings of Unitholders, the conduct of business thereof, notice provisions, the appointment and removal of the Trustee and the form of Trust Unit certificates. The Trust Indenture may be amended from time to time. Substantive amendments to the Trust Indenture, including early termination of the Trust and the sale or transfer of our property as an entirety or substantially as an entirety requires approval by special resolution of the Unitholders. Any approval or consent of Unitholders in relation to any matter required by any regulatory body will require a majority of, or such other level of approval of Unitholders as may be stipulated by such regulatory authority, including as to the exclusion of interested or other Unitholders in the calculation of such level of approval. See "*Information Relating to Us – Trust Indenture – Meetings and Voting*" below.

The following is a summary of certain provisions of the Trust Indenture. For a complete description of such indenture, reference should be made to the Trust Indenture, a copy of which has been filed on SEDAR at *www.sedar.com*.

Trustee

Valiant Trust Company is our trustee and also acts as the transfer agent for the Trust Units. The Trustee is responsible for, among other things, accepting subscriptions for Trust Units and issuing Trust Units pursuant thereto and maintaining our books and records and providing timely reports to holders of Trust Units. The Trust Indenture provides that the Trustee shall exercise its powers and carry out its functions thereunder as Trustee honestly, in good faith, and in our best interests and in the best interest of the Unitholders and, in connection therewith, shall exercise that degree of care, diligence and skill that a reasonably prudent trustee would exercise in comparable circumstances.

The initial term of the Trustee's appointment is until the third annual meeting of Unitholders. The Unitholders shall, at the third annual meeting of the Unitholders, re-appoint or appoint a successor to the Trustee for an additional three year term, and thereafter, the Unitholders are required to reappoint or appoint a successor to the Trustee at the annual meeting of Unitholders three years following the reappointment or appointment of the successor to the Trustee. The Trustee may also be removed by special resolution of the Unitholders. Such resignation or removal becomes effective upon the acceptance or appointment of a successor trustee.

Zargon Oil & Gas presently administers us on behalf of the Trustee. Zargon Oil & Gas, on behalf of the Trustee, keeps such books and records as are necessary for the proper recording of our business transactions.

The Trust Indenture provides that the Trustee shall be under no liability for any action or failure to act unless such liabilities arise out of the Trustee's gross negligence, wilful default or fraud. The Trustee, where it has met its standard of care, shall be indemnified out of our assets for any taxes or other government charges imposed upon the Trustee in consequence of its performance of its duties but shall have no additional recourse against Unitholders. In addition, the Trust Indenture contains other customary provisions limiting the liability of the Trustee.

Future Offerings

The Trust Indenture provides that Trust Units, including rights, warrants and other securities to purchase, to convert into or to exchange into Trust Units, may be created, issued, sold and delivered on such terms and conditions and at such times as the Trustee, upon the recommendation of the Board of Directors may determine. The Trust Indenture also provides that Zargon Oil & Gas may authorize the creation and issuance of debentures, notes and other evidences of indebtedness by us which debentures, notes or other evidences of indebtedness may be created and issued from time to time on such terms and conditions to such persons and for such consideration as Zargon Oil & Gas may determine.

Distributions and Allocations of Trust Income

The Trust Indenture provides that distributable cash of the Trust shall be calculated for each period between distribution record dates, which are currently calendar months, provided that December 31 shall be always be a distribution record date. The Trustee, may upon the recommendation of Zargon Oil & Gas, declare payable and distribute all or part of the distributable cash to the Unitholders of record on the last day of each such calendar month. The Trust Indenture further provides that all net income, net realizable taxable gains and other income shall be distributed such that the Trust has no tax liability in any year. This income is allocated to Unitholders for tax purposes. In addition, the Trust Indenture provides that such distributable income may be paid in whole or in part by cash or in Trust Units. The Trust Indenture also provides for the consolidation of the Trust Units in the discretion of the Board of Directors to the pre-distribution number of Trust Units after any pro-rata distribution of additional Trust Units to all Unitholders.

The distribution by the Trust of such distributable income is enforceable by Unitholders on the payment date determined by the Trustee.

For more information, see "*Risk Factors – Risks Relating to Our Business and Operations*".

Meetings and Voting

Annual meetings of the Unitholders will be held annually. Special meetings of Unitholders may be called at any time by the Trustee and shall be called by the Trustee upon the written request of Unitholders holding in aggregate not less than 20 percent of the Trust Units. Notice of all meetings of Unitholders shall be given to Unitholders at least 21 days prior to the meeting.

Unitholders will be entitled, at each annual meeting, to appoint our auditors and to elect all the members of the Board of Directors.

Our Management

The Board of Directors has generally been delegated all of our significant management decisions. In particular, the Trustee has delegated to Zargon Oil & Gas responsibility for any and all matters relating to the following: (i) an offering; (ii) ensuring compliance with all applicable laws, including in relation to an offering; (iii) all matters relating to the content of any offering documents, the accuracy of the disclosure contained therein, and the certification thereof; (iv) all matters concerning the terms of, and amendment from time to time of our material contracts; (v) all matters concerning any underwriting or agency agreement providing for the sale of Trust Units or rights to Trust Units; (vi) all matters relating to the redemption of Trust Units; (vii) all matters relating to the voting rights on any investments in the trust fund or any subsequent investments; (viii) all matters relating to the specific powers and authorities as set forth in the Trust Indenture.

Zargon Oil & Gas has accepted all such delegation and has agreed that, in respect of such matters, it shall carry out its functions honestly, in good faith and in our best interests and the best interests of the Unitholders and, in connection therewith, shall exercise that degree of care, diligence and skill that a reasonable person would exercise in comparable circumstances.

Limitation on Non-Resident Ownership

In order that we maintain our status as a "mutual fund trust" under the Income Tax Act (Canada), certain provisions of the *Income Tax Act* (Canada) require that we not be established nor maintained primarily for the benefit of non-residents of Canada. Accordingly, in order to comply with such provisions, the Trust Indenture contains restrictions on the ownership of Trust Units by Unitholders who are non-residents of Canada. In this regard, we shall, among other things, take all necessary steps to monitor the ownership of the Trust Units to carry out such intentions. If at any time we become aware that the beneficial owners of 50 percent or more of the Trust Units then outstanding are or may be non-residents of Canada or that such a situation is imminent, we shall take such action as may be necessary to carry out the forgoing intentions.

Right of Redemption

Trust Units are redeemable at any time on demand by the holders thereof upon delivery to us of the certificate or certificates representing such Trust Units, accompanied by a duly completed and properly executed notice requiring redemption. Upon receipt of the notice to redeem Trust Units by us, the holder thereof shall only be entitled to receive a price per Trust Unit (the "**Market Redemption Price**") equal to the lesser of: (i) 90 percent of the "market price" of the Trust Units on the principal market on which the Trust Units are quoted for trading during the 10 trading day period commencing immediately after the date on which the Trust Units are tendered to us for redemption; and (ii) the closing market price on the principal market on which the Trust Units are quoted for trading on the date that the Trust Units are so tendered for redemption.

For the purposes of this calculation, "market price" will be an amount equal to the simple average of the closing price of the Trust Units for each of the trading days on which there was a closing price; provided that, if the applicable exchange or market does not provide a closing price but only provides the highest and lowest prices of the Trust Units traded on a particular day, the market price shall be an amount equal to the simple average of the average of the highest and lowest prices for each of the trading days on which there was a trade; and provided further that if there was trading on the applicable exchange or market for fewer than five of the 10 trading days, the market price shall be the simple average of the following prices established for each of the 10 trading days: (i) the average of the last bid and last ask prices for each day on which there was no trading; (ii) the closing price of the Trust Units for each day that there was trading if the exchange or market provides a closing price; and (iii) the average of the highest and lowest prices of the Trust Units for each day that there was trading, if the market provides only the highest and lowest prices of Trust Units traded on a particular day. The closing market price shall be: (i) an amount equal to the closing price of the Trust Units if there was a trade on the date; (ii) an amount equal to the average of the highest and lowest prices of the Trust Units if there was trading and the exchange or other market provides only the highest and lowest prices of Trust Units traded on a particular day; and (iii) the average of the last bid and last ask prices if there was no trading on the date.

The aggregate Market Redemption Price payable by us in respect of any Trust Units surrendered for redemption during any calendar month shall be satisfied by way of a cash payment on the last day of the following month. The entitlement of Unitholders to receive cash upon the redemption of their Trust Units is subject to the limitation that the total amount payable by us in respect of such Trust Units and all other Trust Units tendered for redemption in the same calendar quarter shall not exceed $100,000; provided that we may, in our sole discretion, waive such limitation in respect of any calendar quarter. If this limitation is not so waived, the Market Redemption Price payable by us in respect of Trust Units tendered for redemption in such calendar month shall be paid on the last day of the following month as follows: (i) firstly, by us distributing Notes having an aggregate principal amount equal to the aggregate Market Redemption Price of the Trust Units tendered for redemption; and (ii) secondly, to the extent that we do not hold Notes having a sufficient principal amount outstanding to effect such payment, by us issuing our own promissory notes to the Unitholders who exercised the right of redemption having an aggregate principal amount equal to any such shortfall, which promissory notes (herein referred to as "**Redemption Notes**") shall have terms and conditions substantially identical to those of the Notes.

If at the time Trust Units are tendered for redemption by a Trust Unitholder, the outstanding Trust Units are not listed for trading on the Toronto Stock Exchange and are not traded or quoted on any other stock exchange or market, which Zargon Oil & Gas considers, in its sole discretion, provides representative fair market value price for the Trust Units or trading of the outstanding Trust Units is suspended or halted on any stock exchange on which the Trust Units are listed for trading or, if not so listed, on any market on which the Trust Units are quoted for trading, on the date such Trust Units are tendered for redemption or for more than five trading days during the 10 trading day period, commencing immediately after the date such Trust Units were tendered for redemption then such Trust Unitholder shall, instead of the Market Redemption Price, be entitled to receive a price per Trust Unit (the "**Appraised Redemption Price**") equal to 90 percent of the fair market value thereof as determined by Zargon Oil & Gas as at the date on which such Trust Units were tendered for redemption. The aggregate Appraised Redemption Price payable by us in respect of Trust Units tendered for redemption in any calendar month shall be paid on the last day of the third following month by, at our option: (i) a cash payment; or (ii) a distribution of Notes and/or Redemption Notes as described above.

It is anticipated that this redemption right will not be the primary mechanism for holders of Trust Units to dispose of their Trust Units. Notes or Redemption Notes, which may be distributed *in specie* to Unitholders in connection with a redemption, will not be listed on any stock exchange and no market is expected to develop for such Notes or Redemption Notes. Notes or Redemption Notes may not be qualified investments for trusts governed by registered retirement savings plans, registered retirement income funds, deferred profit sharing plans or registered education savings plans.

Termination of the Trust

The Unitholders may vote to terminate the Trust at any meeting of the Unitholders, subject to the following: (a) a vote may only be held if requested in writing by the holders of not less than 20 percent of the Trust Units; (b) a quorum of 50 percent of the issued and outstanding Trust Units is present in person or by proxy; and (c) the termination must be approved by special resolution of the Unitholders.

Unless the Trust is earlier terminated or extended by vote of the Unitholders, the Trustee shall commence to wind-up the affairs of the Trust on December 31, 2099. In the event that the Trust is wound-up, the Trustee will liquidate all our assets, pay, retire, discharge or make provision for some or all of our obligations and then distribute the remaining proceeds of sale to Unitholders.

Reporting to Unitholders

Our financial statements will be audited annually by an independent recognized firm of chartered accountants. Our audited financial statements, together with the report of such chartered accountants, will be mailed by the Trustee to Unitholders and the unaudited interim financial statements will be mailed to Unitholders within the periods prescribed by securities legislation. Our year end is December 31. We are also subject to the continuous disclosure obligations under all applicable securities legislation.

Unitholders are entitled to inspect, during normal business hours, at the offices of the Trustee, and, upon payment of reasonable reproduction costs, to receive photocopies of the Trust Indenture and a listing of the registered holders of Trust Units.

CORPORATE GOVERNANCE

General

In general, Zargon Oil & Gas has been delegated responsibility for substantially all of the management decisions of the Trust. The Unitholders are entitled to elect all of the Board of Directors pursuant to the terms of the Trust Indenture.

Trust Indenture

Pursuant to the Trust Indenture, Unitholders are entitled to direct the manner in which we will vote our common shares in Zargon Oil & Gas at all meetings in respect of matters, relating to the election of the directors of Zargon Oil & Gas, approving our financial statements and appointing auditors of Zargon Oil & Gas who shall be the same as our auditors. Prior to us voting our common shares in Zargon Oil & Gas, in respect of such matters, each Unitholder is entitled to vote in respect of the matter on the basis of one vote per Trust Unit held, and we are required to vote our common shares in Zargon Oil & Gas in accordance with the result of the vote of Unitholders.

Decision Making

The Board of Directors has a mandate to supervise the management of our business and affairs of Zargon Oil & Gas and our other direct or indirect subsidiaries, trusts and partnerships and to act with a view to our best interests. The Board of Directors' mandate includes: (i) an offering of securities by us; (ii) ensuring compliance with all applicable laws, including in relation to an offering of our securities; (iii) all matters relating to the content of any documents relating to an offering of our securities; the accuracy of the disclosure contained therein, and the certification thereof; (iv) all matters concerning the terms of, and amendment from time to time of, our material contracts; (v) all matters concerning any subscription agreement or underwriting or agency agreement providing for the sale or issue of Trust Units or securities convertible for or exchangeable into Trust Units or rights to acquire Trust Units; (vi) all matters relating to the redemption of Trust Units; (vii) all matters relating to the voting rights on any of our investments; (viii) all matters relating to the specific powers and authorities as set forth in the Trust Indenture (ix) the adoption of a Unitholder rights plan and other miscellaneous matters relating to the maximization of Unitholder value; and (x) all matters relating to amending Zargon Oil & Gas articles to create a class or classes of exchangeable shares. The Board of Directors holds regularly scheduled meetings at least quarterly to review the business and affairs of our subsidiaries, partnerships and trusts and make any necessary decisions relating thereto.

The Trust Indenture gives to the Board of Directors the authority to exercise the rights, powers and privileges for all matters relating to the maximization of Unitholder value in the context of an offer including any Unitholder rights protection plan, any defensive action to an offer, any directors circular in response to an offer, any regulatory or court proceeding relating to an offer and any related or ancillary matter.

Additional information in respect of corporate governance matters is contained in our information circular which is filed on SEDAR at *www.sedar.com*.

Distributions and Distribution Policy

Cash distributions are made on the 15th day (or if such date is not a business day, on the next business day) following the end of each calendar month to Unitholders of record on the last business day of each such calendar month or such other date as determined from time to time by the Trustee.

Distributions are normally announced on a monthly basis in the context of prevailing and anticipated commodity prices. During periods of volatile commodity prices, we may vary the distribution rate monthly.

Pursuant to the provisions of the Trust Indenture all income earned by us in a fiscal year, not previously distributed in that fiscal year, must be distributed to Unitholders of record on December 31. This excess income, if any, will be allocated to Unitholders of record at December 31 but the right to receive this income, if the amount is not determined and declared payable at December 31, will trade with the Trust Units until determined and declared payable in accordance with the rules of the Toronto Stock Exchange. To the extent that a Unitholder trades Trust

Units in this period they will be allocated such income but will dispose of their right to receive such distribution. See "*Risk Factors – Risks Relating to Our Business and Operations*".

Directors and Officers

The name, municipality of residence, principal occupation for the prior five years and position, of each of the directors and officers of Zargon Oil & Gas are as follows:

Directors

Name and Municipality of Residence	Director Since	Principal Occupation
Craig H. Hansen Calgary, Alberta	1992	President & Chief Executive Officer Zargon Oil & Gas
K. James Harrison (2) (3) Oakville, Ontario	1995	President, K.J. Harrison & Partners Inc., a private client investment management firm in Toronto, Ontario Chairman of the Board of Directors Zargon Oil & Gas
Kyle D. Kitagawa (1) (4) Calgary, Alberta	2001	Managing Director, North River Capital Corp., a private corporation
Margaret A. McKenzie (1) (3) Calgary, Alberta	2007	Chief Financial Officer, Range Royalty Management Ltd. (general partner of Range Royalty Limited Partnership, a private royalty partnership)
Geoffrey C. Merritt (4) Calgary, Alberta	2009	Independent Businessman since April, 2009; prior thereto, President & Chief Executive Officer and a director of Masters Energy Inc. since 2003
Jim Peplinski (2) (4) Calgary, Alberta	1997	Executive Chairman, Humberview Group of Companies which owns Jim Peplinski's Leasemaster, automotive dealerships and various real estate investments. He is also the VP Business Development, Calgary Flames Hockey Club
J. Graham Weir (1) (4) Calgary, Alberta	2004	Chairman of Graymont Limited, a producer of chemical lime and limestone in Canada, Mexico and the United States
Grant A. Zawalsky (2) (3) Calgary, Alberta	2000	Partner, Burnet, Duckworth & Palmer LLP (barristers and solicitors)

Notes:

(1) Member of audit committee.
(2) Member of compensation committee.
(3) Member of governance and nominating committee.
(4) Member of the reserves committee.
(5) Zargon Oil & Gas does not have an executive committee.
(6) Directors hold office until the next annual meeting of unitholders or until their successors are duly elected or appointed.

Officers

Name and Municipality of Residence	Office
Craig H. Hansen Calgary, Alberta	President & Chief Executive Officer
Brent C. Heagy Calgary, Alberta	Executive Vice President & Chief Financial Officer
Henry J. Baird Calgary, Alberta	Vice President, Reservoir Engineering
Jason B. Dranchuk Calgary, Alberta	Vice President, Finance and Controller
Tracy L. Howard Calgary, Alberta	Corporate Secretary
Brian G. Kergan Calgary, Alberta	Vice President, Corporate Development and Alberta Plains South
Mark I. Lake Calgary, Alberta	Vice President, Geosciences and West Central Alberta
Daniel A. Roulston Calgary, Alberta	Vice President, Engineering and Williston Basin
Lorne D. Schwetz Calgary, Alberta	Vice President, Land
Kevin C.Y. Lee Calgary, Alberta	Vice President, Alberta Plains North
Al D. Thorsen Calgary, Alberta	Vice President, Operations

As at March 15, 2010, the directors and officers of Zargon Oil & Gas, as a group, beneficially owned, controlled or directed, directly or indirectly, 1,005,385 Trust Units or approximately 4.3 percent of the issued and outstanding Trust Units and 540,434 Exchangeable Shares or approximately 30.6 percent of the issued and outstanding Exchangeable Shares resulting in an approximate total ownership of 7.3 percent.

Corporate Cease Trade Orders, Bankruptcies or Penalties or Sanctions

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

Except as otherwise disclosed herein, no director or executive officer of Zargon Oil & Gas (nor any personal holding company of any of such persons), or shareholder holding a sufficient number of securities of Zargon to affect materially the control of Zargon is, as of the date of this Annual Information Form, or has been, within the ten years before the date of this Annual Information Form, a director or executive officer of any company (including Zargon Oil & Gas) that, while that person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets, other than Mr. Zawalsky who was a director of Efficient Energy Resources Ltd. (a private electrical generation company), which agreed to the voluntary appointment of a receiver in 2005. In addition, no director or executive officer of Zargon Oil & Gas (nor any personal holding company of any such persons), or shareholder holding a sufficient number of our securities to materially affect the control of us has, within the ten years before the date of this Annual Information Form, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of the director, executive officer or shareholder.

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

Conflicts of Interest

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

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

AUDIT COMMITTEE INFORMATION

Audit Committee Mandate and Terms of Reference

The Mandate of the Audit Committee of Zargon Oil & Gas is attached hereto as Schedule "C". The members of the Audit Committee are Kyle D. Kitagawa, Margaret A. McKenzie and J. Graham Weir.

Composition of the Audit Committee

The members of the Audit Committee are independent (in accordance with National Instrument 52-110) and are financially literate.

Relevant Education and Experience

Name	Relevant Education and Experience
Kyle D. Kitagawa *(Audit Committee Chairman)*	Mr. Kitagawa brings over 20 years experience in commodity trading, equity investing, and structured finance in energy and energy intensive industries. Prior to April 2003, he held senior executive positions in a global energy trading and capital corporation. Mr. Kitagawa is the managing director of North River Capital Corp. In addition, Mr. Kitagawa serves as Chairman of Canadian Energy Services L.P. and Coral Hill Energy Ltd. and is a Director of ProspEx Resources Ltd. Prior directorships included Advanced Mobile Power Systems, LLC, Esprit Exploration Ltd., Ferus Trust, Independent Energy Ltd., Invasion Energy Inc., Livingston Energy Ltd., Papier Masson Ltee. and Wave Energy Ltd.

Name	Relevant Education and Experience
	Mr. Kitagawa holds a Master of Business Administration degree from Queen's University, a Bachelor of Commerce from the University of Calgary and is a Chartered Accountant.
Margaret A. McKenzie	Ms. McKenzie is the Chief Financial Officer, Range Royalty Management Ltd. (general partner of Range Royalty Limited Partnership, a private royalty partnership) and Spur Resources Ltd. (a private oil and natural gas exploration and development company). She was previously Vice President Finance and Chief Financial Officer of Profico Energy Management Ltd. (a private oil and gas company) and Manager, Treasury and Administration with Renaissance Energy Ltd. (a public oil and gas company). Ms. McKenzie holds a Bachelor of Commerce with Distinction degree from the University of Saskatchewan and has been a member of the Institute of Chartered Accountants of Alberta since 1985. Ms. McKenzie is on the board of directors of Bonavista Energy Trust (a public energy trust) and Endurance Energy Ltd. (a private oil and natural gas exploration and development company).
J. Graham Weir	Mr. Weir is an independent businessman. From September 1990 to December 2000, he was Vice President and Director of Corporate Finance for Goepel McDermid Inc. (an investment bank), where he initiated and completed acquisition, financing, financial advisory, merger and valuation assignments for mid-market public and private companies generally headquartered in Calgary and active in the oil and gas producer and service sectors. Mr. Weir chairs the boards of Graymont Limited and Pulse Seismic Inc. and serves as a director of other companies including: Coral Hill Energy Ltd., Flagstone Energy Inc., Grupo Calidra, S.A. de C.V. and Joss Windpower Inc. Mr. Weir graduated from Trent University in 1974 with a Bachelors Degree in Mathematics and the University of Manitoba in 1977 with a Masters Degree in Actuarial Mathematics. Mr. Weir received the designation Chartered Business Valuator in 1994 and completed a Masters Degree in Mathematical Finance at the University of Oxford in 2005.

Pre-Approval Policies and Procedures

The Audit Committee must pre-approve all non-audit services to be provided to us or our subsidiaries by the external auditors. The Audit Committee may delegate to one or more members the authority to pre-approve non-audit services, provided that the member reports to the Audit Committee at the next scheduled meeting and that such pre-approval and the member comply with such other procedures as may be established by the Audit Committee from time to time.

External Auditor Service Fees

Audit Fees

The aggregate fees billed by our external auditor, including expenses, in each of the last two fiscal years for audit services were $269,830 in 2009 and $200,700 in 2008.

International Financial Reporting Standards Fees

The aggregate fees billed in each of the last two fiscal years for assurance related services by our external auditor, including expenses, that are reasonably related to the performance of the audit or review of our financial statements, that are not reported under "Audit Fees" above were $31,499 in 2009 and $22,300 in 2008. The 2009 fees specifically relate to the International Financial Reporting Standards diagnostic work performed by our auditors.

Tax Fees

The aggregate fees billed in each of the last two fiscal years for professional services rendered by our external auditor, including expenses for tax compliance, tax advice and tax planning were $301,355 in 2009 and $269,647 in 2008.

All Other Fees

The aggregate fees billed in each of the last two fiscal years for products and services provided by our auditors other than services reported above were $81,953 in 2009 and $26,203 in 2008.

DISTRIBUTIONS TO UNITHOLDERS

Since our formation, monthly cash distributions were declared in the following amounts:

For the Month Ended	Distributions per Unit	Payment Date
August 31, 2004	$0.14	September 15, 2004
September 30, 2004	$0.14	October 15, 2004
October 31, 2004	$0.14	November 15, 2004
November 30, 2004	$0.14	December 15, 2004
December 31, 2004	$0.14	January 17, 2005
Total	$0.70	

For the Month Ended	Distributions per Unit	Payment Date
January 31, 2005	$0.14	February 15, 2005
February 28, 2005	$0.14	March 15, 2005
March 31, 2005	$0.14	April 15, 2005
April 30, 2005	$0.14	May 16, 2005
May 31, 2005	$0.14	June 15, 2005
June 30, 2005	$0.14	July 15, 2005
July 31, 2005	$0.14	August 15, 2005
August 31, 2005	$0.16	September 15, 2005
September 30, 2005	$0.16	October 17, 2005
October 31, 2005	$0.16	November 15, 2005
November 30, 2005	$0.18	December 15, 2005
December 31, 2005	$0.68	January 16, 2006
Total	$2.32	

For the Month Ended	Distributions per Unit	Payment Date
January 31, 2006	$0.18	February 15, 2006
February 28, 2006	$0.18	March 15, 2006
March 31, 2006	$0.18	April 17, 2006
April 30, 2006	$0.18	May 15, 2006
May 31, 2006	$0.18	June 15, 2006
June 30, 2006	$0.18	July 17, 2006
July 31, 2006	$0.18	August 15, 2006
August 31, 2006	$0.18	September 15, 2006
September 30, 2006	$0.18	October 16, 2006
October 31, 2006	$0.18	November 15, 2006
November 30, 2006	$0.18	December 15, 2006
December 31, 2006	$0.18	January 15, 2007
Total	$2.16	

For the Month Ended	Distributions per Unit	Payment Date
January 31, 2007	$0.18	February 15, 2007
February 28, 2007	$0.18	March 15, 2007
March 31, 2007	$0.18	April 17, 2007
April 30, 2007	$0.18	May 15, 2007
May 31, 2007	$0.18	June 15, 2007
June 30, 2007	$0.18	July 17, 2007
July 31, 2007	$0.18	August 15, 2007
August 31, 2007	$0.18	September 15, 2007
September 30, 2007	$0.18	October 16, 2007
October 31, 2007	$0.18	November 15, 2007
November 30, 2007	$0.18	December 15, 2007
December 31, 2007	$0.18	January 15, 2008
Total	$2.16	

For the Month Ended	Distributions per Unit	Payment Date
January 31, 2008	$0.18	February 15, 2008
February 28, 2008	$0.18	March 17, 2008
March 31, 2008	$0.18	April 15, 2008
April 30, 2008	$0.18	May 15, 2008
May 31, 2008	$0.18	June 16, 2008
June 30, 2008	$0.18	July 15, 2008
July 31, 2008	$0.18	August 15, 2008
August 31, 2008	$0.18	September 15, 2008
September 30, 2008	$0.18	October 15, 2008
October 31, 2008	$0.18	November 17, 2008
November 30, 2008	$0.18	December 15, 2008
December 31, 2008	$0.18	January 15, 2009
Total	$2.16	

For the Month Ended	Distributions per Unit	Payment Date
January 31, 2009	$0.18	February 16, 2009
February 28, 2009	$0.18	March 16, 2009
March 31, 2009	$0.18	April 15, 2009
April 30, 2009	$0.18	May 15, 2009
May 31, 2009	$0.18	June 15, 2009
June 30, 2009	$0.18	July 15, 2009
July 31, 2009	$0.18	August 17, 2009
August 31, 2009	$0.18	September 15, 2009
September 30, 2009	$0.18	October 15, 2009
October 31, 2009	$0.18	November 16, 2009
November 30, 2009	$0.18	December 15, 2009
December 31, 2009	$0.18	January 15, 2010
Total	$2.16	

For Canadian income tax purposes, cash distributions paid to Unitholders were 100 percent taxable as other income. See "*Corporate Governance – Distributions and Distribution Policy*".

In certain circumstances, distributions may be restricted by our borrowing agreements. Distributions may be only declared and paid to Unitholders if: (i) no default or event of default shall have occurred or shall occur as a result of making any such distributions; (ii) no borrowing base shortfall shall have occurred that is continuing; and (iii) such distributions are not in excess of the amounts specified in the Trust Indenture, unless such distributions have been publicly disclosed prior to such default, event of default or borrowing base shortfall.

MARKET FOR SECURITIES

The Trust Units and Exchangeable Shares are listed and traded on the Toronto Stock Exchange. The trading symbol for the Trust Units is ZAR.UN and for the Exchangeable Shares is ZOG.B.

The following sets forth trading information for Trust Units in 2009 and 2010 up to March 15, 2010.

Period	High	Low	Volume
2009			
January	17.97	14.57	882,903
February	16.40	13.25	727,486
March	16.77	13.05	708,094
April	16.26	14.80	554,841
May	16.58	15.03	1,753,017
June	16.56	15.25	1,573,635
July	18.69	15.20	964,661
August	19.20	17.01	925,119
September	19.24	17.00	713,220
October	18.68	17.28	1,480,955
November	18.87	17.51	852,109
December	19.33	18.20	901,062
2010			
January	20.20	18.90	1,439,228
February	20.90	19.29	1,044,846
March (1 to 15)	20.00	19.79	494,205

The following sets forth trading information for Exchangeable Shares in 2009 and 2010 up to March 15, 2010.

Period	High	Low	Volume
2009			
January	-	-	70
February	-	-	-
March	24.00	24.00	100
April	-	-	-
May	-	-	-
June	26.25	20.50	1,102
July	27.47	27.47	1,200
August	27.25	27.00	300
September	29.00	29.00	200
October	-	-	-
November	-	-	-
December	30.00	29.59	4,551
2010			
January	32.50	29.95	600
February	33.00	33.00	15,500
March (1 to 15)	-	-	-

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, British Columbia, Saskatchewan and Manitoba, all of which should be carefully considered by investors in the oil and gas industry. It is not expected that any of these regulations or controls will affect our operations in a manner materially different than they will affect other oil and natural gas companies of similar size. All current legislation is a matter of public record and we are unable to predict what additional legislation or amendments may be enacted. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the oil and gas industry.

Pricing and Marketing

Oil

The producers of oil are entitled to negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. Oil prices are primarily based on worldwide supply and demand. The specific price depends in part on oil quality, prices of competing fuels, distance to market, 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 the liquid market established at the Alberta "NIT" 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, British Columbia and Saskatchewan also regulate the volume of natural gas that may be removed from those provinces for consumption elsewhere based on such factors as reserve availability, transportation arrangements, and market considerations. As yet, Manitoba does not have natural gas production in commercial quantities and does not therefore impose such export restrictions.

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, or NAFTA as it is often referred to, 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 domestic use (based upon the proportion prevailing in the most recent 36 month period); (ii) impose an export price higher than the domestic price (subject to an exception with respect to certain voluntary measures which only restrict the volume of exports); and (iii) disrupt normal channels of supply. All three signatory countries are prohibited from imposing minimum or maximum export or import price requirements, provided, in the case of export price requirements, that any prohibition in any circumstances in which any other form of quantitative restriction is applied is prohibited, and in the case of import-price requirements, that such requirements do not apply with respect to enforcement of countervailing and anti-dumping orders and undertakings.

NAFTA contemplates the reduction of Mexican restrictive trade practices in the energy sector by 2010 and prohibits discriminatory border restrictions and export taxes. NAFTA also contemplates clearer disciplines on regulators to ensure fair implementation of any regulatory changes, minimize disruption of 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; specifically, the maximum royalty rates for conventional oil and natural gas production will be decreased effective for the January 2011 production month and certain temporary incentive programs currently in place will be made permanent. Further details with respect to the changes to Alberta's royalty system are expected to be provided in the coming months.

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 range from 0-50%, an increase from the previous maximum rates of 30-35% depending on the vintage of the oil, and rate caps are set at $120 per barrel. Effective January 1, 2011, the maximum royalty payable under the NRF will be reduced to 40%.

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 range from 5-50%, an increase from the previous maximum rates of 5-35%, and rate caps are set at $17.75/GJ. Effective January 1, 2011, the maximum royalty payable under the NRF will be reduced to 36%.

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.

In August 2006, the Government of Alberta introduced the Innovative Energy Technologies Program (the "**IETP**"), which has a stated objective of promoting producers' investment in research, technology and innovation for the purposes of improving environmental performance while creating commercial value. 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 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 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 oil deep 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 will only be able to elect to adopt the transitional royalty rates prior to January 1, 2011 and producers that have already elected to adopt the transitional royalty rates as of that date will be permitted to switch to Alberta's conventional royalty structure. On December 31, 2013, all producers operating under the transitional royalty rates will automatically become subject to Alberta's conventional royalty structure.

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, 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.

As at the beginning of 2009, British Columbia maintained 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;

- *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 breaks 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;

- *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 event on either Crown or freehold land and completed in a new pool discovery 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.

On March 2, 2009, the Government of British Columbia announced the 2009 Infrastructure Royalty Credit Program which allocates $120 million in royalty credits for oil and gas companies. The 2009 Infrastructure Royalty Credit Program 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. The Government of British Columbia has recently announced the same level of funding for the 2010 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. 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 stimulus package 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.

Saskatchewan

In Saskatchewan, the amount payable as a royalty in respect of oil depends on the type and vintage of oil, the quantity of oil produced in a month, the value of the oil produced and specified adjustment factors determined monthly by the provincial government. For Crown royalty and freehold production tax purposes, conventional oil is classified as "heavy oil", "southwest designated oil" or "non-heavy oil other than southwest designated oil". The conventional royalty and production tax classifications ("fourth tier oil", "third tier oil", "new oil" and "old oil") depend on the finished drilling date of a well and are applied to each of the three crude oil types slightly differently. Heavy oil is classified as third tier oil (having a finished drilling date on or after January 1, 1994 and before October 1, 2004), fourth tier oil (having a finished drilling date on or after October 1, 2002) or new oil (not classified as either third tier oil or fourth tier oil). Southwest designated oil uses the same definitions of third and fourth tier oil but new oil is defined as conventional oil produced from a horizontal well having a finished drilling date on or after February 9, 1998 and before October 1, 2002. For non-heavy oil other than southwest designated oil, the same classification is used but new oil is defined as conventional oil produced from a vertical well completed after 1973 and having a finished drilling date prior to 1994, whereas old oil is defined as conventional oil not classified as third or fourth tier oil or new oil.

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

The amount payable as a royalty in respect of natural gas production is determined by a sliding scale based on a reference price (which is the greater of the amount obtained by the producer and a prescribed minimum price), the quantity produced in a given month, the type of natural gas, and the vintage of the natural gas. Like conventional oil, natural gas is classified as "non-associated gas" or "associated gas" and royalty rates are determined according to the finished drilling date of the respective well. As an incentive for the production and marketing of natural gas which may have been flared, the royalty rate on natural gas produced in association with oil is less than on non-associated natural gas. Non-associated gas is classified as new gas (having a finished drilling date before February 9, 1998 with a first production date on or after October 1, 1976), third tier gas (having a finished drilling date on or after February 9, 1998 and before October 1, 2002), fourth tier gas (having a finished drilling date on or after October 1, 2002) and old gas (not classified as either third tier, fourth tier or new gas). A similar classification is used for associated gas except that the classification of old gas is not used, the definition of fourth tier gas also includes production from oil wells with a finished drilling date prior to October 1, 2002, where the individual oil well has a gas-oil production ratio in any month of more than 3,500 m^3 of gas for every m^3 of oil, and new gas is defined as oil produced from a well with a finished drilling date before February 9, 1998 that received special approval, prior to October 1, 2002, to produce oil and gas concurrently without gas-oil ratio penalties.

As with conventional oil production, base prices are used to establish lower limits in the price-sensitive royalty structure for natural gas. Where average field-gate prices are below the established base prices of $50 per thousand m^3 for third and fourth tier gas and $35 per thousand m^3 for new gas and old gas, base royalty rates are applied. Base royalty rates are 5% for all fourth tier gas, 15% for third tier or new gas, and 20% for old gas. Where average well-head prices are above base prices, marginal royalty rates are applied to the proportion of production that is above the base gas price. Marginal royalty rates are 30% for all fourth tier gas, 35% for third tier and new gas, and 45% for old gas.

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

- *Royalty/Tax Incentive Volumes for Vertical Oil Wells Drilled on or after October 1, 2002* providing reduced Crown royalty and freehold tax rates on incentive volumes of 8,000 m^3 for deep development vertical oil wells, 4,000 m^3 for non-deep exploratory vertical oil wells and 16,000 m^3 for deep exploratory vertical oil wells (more than 1,700 metres or within certain formations);

- *Royalty/Tax Incentive Volumes for Exploratory Gas Wells Drilled on or after October 1, 2002* providing reduced Crown royalty and freehold tax rates on incentive volumes of 25,000,000 m^3 for qualifying exploratory gas wells;

- *Royalty/Tax Incentive Volumes for Horizontal Oil Wells Drilled on or after October 1, 2002* providing reduced Crown royalty and freehold tax rates on incentive volumes of 6,000 m^3 for non-deep horizontal oil wells and 16,000 m^3 for deep horizontal oil wells (more than 1,700 metres or within certain formations);

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

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

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

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

Manitoba

In Manitoba, the royalty amount payable on oil produced from Crown lands depends on the classification of the oil produced as "old oil" (produced from a well drilled prior to April 1, 1974 that does not qualify as new oil or third tier oil), "new oil" (oil that is not third tier oil and is produced from a well drilled on or after April 1, 1974 an prior to April 1, 1999, from an abandoned well re-entered during that period, from an old oil well as a result of an enhanced recovery project implemented during that period, or from a horizontal well), "third tier oil" (oil produced from a vertical well drilled after April 1, 1999, an abandoned well re-entered after that date, an inactive vertical well activated after that date, a marginal well that has undergone a major workover, or from an old oil well or a new oil well as a result of an enhanced recovery project implemented after that date), or "holiday oil" (oil that is exempt from any royalty or tax payable). Royalty rates are calculated on a sliding scale and based on the monthly oil production from a spacing unit, or oil production allocated to a unit tract under a unit agreement or unit order from the Minister. For horizontal wells, the royalty on oil produced from Crown lands is calculated based on the amount of oil production allocated to a spacing unit in accordance with the applicable regulations.

Royalties payable on natural gas production from Crown lands are equal to 12.5% of the volume of natural gas sold.

Producers of oil and natural gas from freehold lands in British Columbia are required to pay monthly freehold production taxes. The freehold production tax payable on oil is calculated on a sliding scale based on the monthly production volume and the classification of oil as old oil, new oil, third tier oil and holiday oil. Producers of natural gas from freehold lands in Manitoba are required to pay a monthly freehold production tax equal to 1.2% of the volume sold. There is no freehold production tax payable on gas consumed as lease fuel.

The Government of Manitoba maintains a Drilling Incentive Program (the "**Program**") with the intent of promoting investment in the sustainable development of petroleum resources. The Program provides the licensee of newly drilled wells, or qualifying wells where a major workover has been completed, with a "holiday oil volume" pursuant to which no Crown royalties or freehold production taxes are payable until the holiday oil volume has been produced. Under the Program, wells drilled for purposes of injection (or wells converted to injection prior to producing predetermined volumes of oil) in an approved enhanced oil recovery project earn a one-year holiday for portions of the project area.

The Program consists of the following components:

- *New Well Incentive* provides licensees of newly drilled, non-horizontal wells drilled prior to January 1, 2014 with a holiday oil volume of 10,000 m^3;

- *Deep Drilling Incentive* provides licensees who drill a well to a total depth sufficient to penetrate the Devonian Duperow formation with a holiday oil volume of 20,000 m^3, and licensees who drill a well deeper than the Devonian Three Forks formation can make a one-time assignment of up to 10,000 m^3 of holiday oil volume earned through previous drilling or major workovers to such well's holiday oil volume;

- *Horizontal Well Initiative* provides licensees of horizontal wells drilled prior to January 1, 2014 with a holiday oil volume of 10,000 m^3, and a horizontal leg drilled from an existing horizontal well on or after January 1, 2009 and prior to January 1, 2014 will earn an additional holiday royalty volume of 3,000 m^3;

- *Marginal Well Major Workover Incentive* provides licensees of marginal wells where a major workover is completed prior to January 1, 2014 with a holiday oil volume of 500 m^3, with a marginal oil well defined as an abandoned well or a well that was either not operated over the previous 12 months or produced oil at an average rate of less than 1 m^3 per operating day;

- *Injection Well Incentive* provides a one year exemption from the payment of Crown royalties or freehold production taxes on production allocated to a unit tract in which a well is drilled or converted to water injection;

Further, holiday oil volumes earned by a newly drilled well or a marginal well that has undergone a major workover can be transferred to a Holiday Oil Volume Account ("**Account**") at the request of the licensee, the purpose of which is to optimize the value of holiday oil volumes earned by providing a company with the flexibility of allocating holiday oil volumes earned among new wells.

Land Tenure

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

Each of the provinces of Alberta, British Columbia, Saskatchewan and Manitoba 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.

In Alberta, the NRF includes a policy of "shallow rights reversion" which provides, for the first time in western Canada, 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. 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 which 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* 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 Alberta Land Use Framework. Regional plans established pursuant to this act 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, this act requires local governments, provincial departments, agencies and administrative bodies or tribunals to review their regulatory instruments and make any appropriate changes to ensure that they comply with an adopted regional plan. The *Alberta Land Stewardship Act* also contemplates the amendment or extinguishment of previously issued statutory consents such as regulatory permits, licenses, 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 act are conservation easements, which can be granted for the protection, conservation and enhancement of land; and conservation directives, which are explicit declarations contained in a regional plan to set aside specified lands in order to protect, conserve, manage and enhance the environment. Although no regional plans have been established under the act, 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 *Alberta Land Stewardship Act* 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, which requires a reduction in greenhouse gas 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 greenhouse gas emissions levels to 6% below 1990 "business-as-usual" levels by 2012.

In anticipation of the expiry of the Kyoto Protocol in 2012, government leaders and representatives from approximately 170 countries met in Copenhagen Conference from December 6 to 18, 2009 to attempt to negotiate a successor to the Kyoto Protocol. The primary result of the Copenhagen Conference was the Copenhagen Accord, which represents a broad political consensus rather than a binding international treaty like the Kyoto Protocol and has not been endorsed by all participating countries. The Copenhagen Accord 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. Although certain countries, including Canada, have committed to reducing their emissions individually or jointly by at least 80% by 2050, the Copenhagen Accord does not establish binding GHG emissions reduction targets. The Copenhagen Accord calls for a review and implementation of its stated goals by 2016.

In response to the Copenhagen Accord, the Government of Canada has recently indicated that it will seek to achieve a 17% reduction in greenhouse gas emissions from 2005 levels by 2020. This goal is similar to the goal expressed in previous policy documents which are discussed below.

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" which set forth a plan for regulations to address both greenhouse gases 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. 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 the Government of Canada have recently indicated that the proposals contained in the updated action plan will be modified to ensure consistency with the direction ultimately taken by the United States with respect to greenhouse gas emissions regulation. The approach of the Unites States is expected to include an absolute cap on emissions combined with allowances to be used for compliance that may be partially auctioned off to regulated entities. It is also unclear whether the approach adopted by the United States will provide for the payment into a technology fund as a compliance mechanism, as is currently permitted in Alberta and by the updated action plan. As a result, many provisions of the updated action plan, described below, are expected to be significantly modified.

The stated goal of the updated action plan, as currently drafted, is to reduce greenhouse gas emissions to 20% below 2006 levels by 2020 and 60-70% by 2050. As noted above, the goal has now been modified by the Government of Canada. 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 applied 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 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 govern 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: Technology Fund contributions, offset credits, clean development credits and credits for early action. 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 tonnes per CO_2 equivalent for the 2010-12 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 greenhouse gas emissions. Alternatively, regulated entities may be able to receive credits for investing in large-scale and transformative projects at the same contribution rate and under similar requirements as 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.

Alberta

Alberta enacted the *Climate Change and Emissions Management Act* on July 1, 2007, amending it through the *Climate Change and Emissions Management Amendment Act* which received royal asset on November 4, 2008. This act 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 greenhouse gases a year are subject to comply with the *Climate Change and Emissions Management Act*. Similarly to the updated action plan, this act and the associated *Specified Gas Emitters Regulation* make a distinction between "Existing Facilities" and "New Facilities". Existing Facilities are defined as facilities that completed their first year of commercial operation prior to January 1, 2008 or that have completed 8 or more years of commercial operation. Existing Facilities were required to reduce their emissions intensity by March 31, 2008 by 12% from a baseline established by their average emissions intensity between 2003 and 2005. New Facilities are defined as facilities that completed their first year of commercial operation subsequent to December 31, 2008, have completed less than 8 years of commercial operation, or are designated as New Facilities in accordance with the *Specified Gas Emitters Regulation*. New Facilities are also required to reduce their emissions intensity by 12% but this target is based on the emissions intensity of the facility in its third year of commercial operation and does not apply during the first 3 years of operation of the New Facility. Unlike the updated action plan, this act does not contain any provision for continuous annual improvements beyond the 12% emissions intensity required.

The *Climate Change and Emissions Management Act* contains similar compliance mechanisms as the updated action plan. Regulated emitters can meet their emissions intensity targets by contributing to the Climate Change and Emissions Management Fund at a rate of $15 per tonne of CO_2 equivalent. Unlike the updated action plan, this act 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, this act does not contemplate a linkage to external compliance mechanisms such as the Kyoto Protocol's Clean Development Mechanism.

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. 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* 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 greenhouse gas emissions. It is expected that greenhouse gas 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 greenhouse gas 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.

Saskatchewan

On May 11, 2009, the Government of Saskatchewan announced *The Management and Reduction of Greenhouse Gases Act* to regulate greenhouse gas emissions in the province. Although this act has only passed first reading in the Saskatchewan legislature and the specific details of the legislation have not yet been determined, it is expected that it will adopt the goal of a 20% reduction in greenhouse gas emissions by 2020 and permit the use of technology fund contributions and emissions offsets in compliance, similar to both the federal and Alberta climate change initiatives. It remains unclear whether the scheme implemented will be based on emissions intensity or an absolute cap on emissions.

Manitoba

The Government of Manitoba has recently indicated its intention to commence public consultations with respect to the development of a cap and trade system to reduce greenhouse gas emissions. No legislation with respect to climate change is currently in effect.

RISK FACTORS

The following is a summary of certain risk factors relating to us and our business which prospective investors should carefully consider before deciding whether to purchase Trust Units or Exchangeable Shares. Residents of the United States and other non-residents of Canada should have additional regard to the risk factors under the heading "*Risk Factors Applicable to Residents of the United States and Other Non-Residents of Canada*".

The information set forth below contains "forward-looking statements", which are qualified by the information contained in the section of this Annual Information Form entitled "*Notice to Reader – Special Note Regarding Forward-Looking Statements*".

Risks Relating to Our Business and Operations

Declines in oil and natural gas prices will adversely affect our financial condition

Our operational results and financial condition and therefore the amounts we pay to Unitholders as distributions, will be dependent on the prices received for our oil and natural gas production. Oil and natural gas prices have exhibited extreme volatility over the past few years. Declines in oil and natural gas prices may result in declines in, or elimination of distributions. Oil and natural gas prices are determined by economic factors and in the case of oil prices, political factors and a variety of additional factors beyond our control. These factors include economic conditions, in the United States and Canada and worldwide, the actions of the Organization of Petroleum Exporting Countries, governmental regulation, political stability in the Middle East and elsewhere, ongoing credit and liquidity concerns, internal capacity to produce natural gas in the United States from shale deposits, the foreign supply of oil and natural 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 natural gas would have an adverse effect on the carrying value of our proved and probable reserves, net asset value, borrowing capacity, revenues, profitability and funds flow from operating activities and ultimately on our financial condition and therefore on the amounts to be distributed to our Unitholders. Volatile oil and natural gas prices make it difficult to estimate the value of producing properties for acquisitions and often cause disruption in the market for oil and natural gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for and project the return on acquisitions and development and exploitation projects.

Variations in interest rates and foreign exchange rates could affect our ability to service our debt

There is a risk that the interest rates will increase given the current historical low level of interest rates. An increase in interest rates could result in a significant increase in the amount we pay to service debt and affect our ability to fund ongoing operations resulting in a decrease in distributions to Unitholders, and could impact the market price of the Trust Units.

World oil 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 that may fluctuate over time. A material increase in the value of the Canadian dollar negatively impacts our production revenue and our ability to maintain future distributions. Future Canadian/United States exchange rates could also impact the future value of our reserves as determined by our independent evaluator.

The global economy has not fully recovered and unforeseen events may negatively impact our financial condition

Market events and conditions, including disruptions in the international credit markets and other financial systems and the deterioration of global economic conditions, caused significant volatility to commodity prices over the last few years. These conditions worsened in 2008 and continued in early 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 continue to improve in 2010, these factors have negatively affected company and trust valuations and continue to impact the performance of the global economy going forward.

Our bank credit facilities will need to be renewed prior to June 29, 2010 and failure to renew, in whole or in part, or higher interest charges will adversely affect our financial condition

We currently have $180 million of syndicated committed credit facilities provided by a syndicate of three banks. The facilities are fully revolving for a 364-day period with the provision for an annual extension at the option of the lenders and upon notice from us. The next renewal date is June 29, 2010. Should the facilities not be renewed, they convert to one year non-revolving term facilities at the end of the revolving 364-day period. There is a risk that the Credit Facilities will not be renewed for the same amount or on the same terms which could affect our ability to fund ongoing operations.

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

Amounts paid in respect of interest and principal on debt may reduce distributions. Variations in interest rates and scheduled principal repayments could result in significant changes in the amount required to be applied to debt service before payment of distributions. Certain covenants in the agreements with our lenders may also limit distributions. Although we believe our credit facilities will be sufficient for our immediate requirements, there can be no assurance that the amount will be adequate for our future financial obligations including our future capital expenditure program, or that we will be able to obtain additional funds.

From time to time we may enter into transactions which may be financed in whole or in part with debt. The level of our indebtedness from time to time could impair our ability to obtain additional financing on a timely basis to take advantage of business opportunities that may arise.

We have been historically reliant on external sources of capital, borrowings and equity sales, and if unavailable, our financial condition will be adversely affected

As future capital expenditures will be financed out of funds flow from operating activities, borrowings and possible future equity sales, our ability to do so is dependent on, among other factors, the overall state of capital markets and investor appetite for investments in the energy industry and our securities in particular.

From time to time we may enter into transactions to acquire assets or the shares of other organizations. These transactions may be financed in whole or in part with debt, which may increase our debt levels above industry standards for oil and natural gas companies of similar size. Depending on future exploration and development plans, we may require additional equity and/or debt financing that may not be available or, if available, may not be available on favourable terms. Neither the Trust Indenture nor the constating documents of our controlled entities limit the amount of indebtedness that we may incur. The level of our indebtedness from time to time, could impair our ability to obtain additional financing on a timely basis to take advantage of business opportunities that may arise.

Alternatively, we may issue additional Trust Units from treasury at prices which may result in a decline in production per Trust Unit and reserves per Trust Unit or may wish to borrow to finance significant acquisitions or development projects to accomplish our long term objectives on less than optimal terms or in excess of our optional capital structure.

In the normal course of making capital investments to maintain and expand our oil and gas reserves additional Trust Units are issued from treasury which may result in a decline in production per Trust Unit and reserves per Trust Unit. Additionally, from time to time we issue Trust Units from treasury in order to reduce debt and maintain a more optimal capital structure.

To the extent that external sources of capital become limited or unavailable or available on onerous terms, our ability to make capital investments and maintain or expand existing assets and reserves may be impaired, and our assets, liabilities, business, financial condition, results of operations and distributions may be materially and adversely affected as a result.

We believe that estimated funds flow from operating activities, together with our existing credit facilities, will be sufficient to substantially finance our current operations, distributions to Unitholders and planned capital expenditures for the ensuing year. The timing of most of our capital expenditures is discretionary and there are no material long-term capital expenditure commitments. The level of distributions is also discretionary, and we have the ability to modify distribution levels should funds flow from operating activities be negatively impacted by a reduction in commodity prices or other factors. However, if funds flow from operating activities is lower than expected or capital costs for these projects exceed current estimates, or if we incur major unanticipated expenses related to development or maintenance of our existing properties, we may be required to seek additional capital to maintain our capital expenditures at planned levels. Failure to obtain any financing necessary for our capital expenditure plans may result in a delay in development or production on our properties or a decrease in distributions.

Our hedging activities may negatively impact our income and our financial condition

We may manage the risk associated with changes in commodity prices by entering into oil or natural gas price hedges. If we hedge our commodity price exposure, we may forego some of the benefits we would otherwise experience if commodity prices were to increase. As at December 31, 2009, our income statement reflected $36.39 million of unrealized losses resulting from hedges to protect our commodity risk exposure. For more information in relation to our commodity hedging program, see "*Statement of Reserves Data and Other Oil and Natural Gas Information – Other Oil and Gas Information – Forward Contracts*". We may initiate certain hedges to attempt to mitigate the risk of the Canadian dollar appreciating against the U.S. dollar. The increase in the exchange rate for the Canadian dollar and future Canadian/United States exchange rates will impact future distributions and the future value of our reserves as determined by independent evaluators. These hedging activities could expose us to losses and to credit risk associated with counterparties with which we contract.

Failure of third parties to meet their contractual obligations to us may have a material adverse affect on our financial condition

We are exposed to third party credit risk through our contractual arrangements with our current or future joint venture partners, third party operators, marketers of our petroleum and natural gas production, hedge counterparties and other parties. We manage this credit risk by entering into sales contracts with only creditworthy entities and reviewing our exposure to individual entities on a regular basis. However, in the event such entities fail to meet their contractual obligations to us, such failures may have a material adverse effect on our business, financial condition, results of operations and prospects In addition, poor credit conditions in the industry and of joint venture partners may impact a joint venture partner's willingness to participate in our ongoing capital program, potentially delaying the program and the results of such program until we find a suitable alternative partner.

Our ability to maintain distributions is dependent on a number of factors including volatility of prices for oil and gas, interest rates, sources of capital, changes in legislation and those set forth below

Our ability to add to our oil and natural gas reserves is highly dependent on our success in exploiting existing properties and acquiring additional reserves. Our long-term commercial success depends on our ability to find, acquire, develop and commercially produce petroleum and natural gas reserves. 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. New wells we drill or participate in may not become productive and we may not recover all or any portion of our investment in wells we drill or participate in. The cost of drilling, completing and operating a well is often uncertain, and cost factors can adversely affect the economics of a project.

Higher operating costs for our underlying properties will directly decrease the amount of cash flow received by us and, therefore, may reduce distributions to our Unitholders. Labour costs, electricity, gas processing, well servicing and chemicals are a few of our operating costs that are susceptible to material fluctuation. There is no assurance that further commercial quantities of petroleum and natural gas will be discovered or acquired by us.

The level of production from our existing properties may decline at rates greater than anticipated due to unforeseen circumstances, many of which are beyond our control. A significant decline in production could result in materially lower revenues and cash flow and, therefore, could reduce the amount available for distribution to our Unitholders.

We currently distribute a significant proportion of our funds flow from operating activities to Unitholders rather than reinvesting it in reserves additions. Our ability to make the necessary capital investments to maintain or expand our oil and natural gas reserves is dependent on external sources of capital and maintenance of our funds flow from operating activities. To the extent that we use funds flow from operating activities to finance capital expenditures or property acquisitions, the level of funds flow from operating activities available for distribution to Unitholders will be reduced.

There is no assurance we will be successful in developing additional reserves or acquiring additional reserves on terms that meet our investment objectives. Without these reserves additions, our reserves will deplete and as a consequence, either production from, or the average reserves life of, our properties will decline, which will result in a reduction in the value of Trust Units and in a reduction in funds flow from operating activities available for distributions to Unitholders.

Our business is heavily regulated and such regulation increases our costs and may adversely affect our financial condition

Oil and natural gas operations (including land tenure, exploration, development, production, refining, pricing, transportation and marketing) are subject to extensive controls and regulations imposed by various levels of government, which may be amended from time to time. Governments may regulate or intervene with respect to prices, taxes, royalties and the exportation of oil and natural gas. Regulation increases our costs. In order to conduct oil and gas operations, we require licenses from various governmental authorities. There can be no assurance that we will be able to obtain all of the licenses and permits that may be required to conduct operations that we may wish to undertake. See "*Industry Conditions*."

Income tax laws, or other laws or government incentive programs or regulations relating to our industry may in the future be changed or interpreted in a manner that adversely affects us and our Unitholders

We expect to continue to qualify as a mutual fund trust for purposes of the Income Tax Act (Canada) . We may not, however, always be able to satisfy any future requirements for the maintenance of mutual fund trust status.

Should our status as a mutual fund trust be lost or successfully challenged by a relevant tax authority, certain adverse consequences may arise for us and our Unitholders. Some of the significant consequences of losing mutual fund trust status are as follows:

- We would be taxed on certain types of income distributed to Unitholders, including income generated by the NPI held by us. Payment of this tax may have adverse consequences for some Unitholders, particularly Unitholders that are not residents of Canada and residents of Canada that are otherwise exempt from Canadian income tax.

- We would cease to be eligible for the capital gains refund mechanism available under Canadian tax laws.

- Trust Units held by Unitholders that are not residents of Canada would become taxable Canadian property. These non-resident holders would be subject to Canadian income tax on any gains realized on a disposition of Trust Units held by them.

- Trust Units could cease to be a qualified investment for registered retirement savings plans ("**RRSPs**"), registered education savings plans ("**RESPs**"), deferred profit sharing plans ("DPSPs"), registered disability savings plans ("**RDSPs**"), tax free savings accounts ("**TFSAs**") and registered retirement income funds ("**RRIFs**"). Where, at the end of a month, a RRSP, DPSP, RESP or RRIF holds Trust Units that cease to be a qualified investment, the plan must, in respect of that month, pay a tax equal to 1% of the fair market value of the Trust Units at the time such Trust Units were acquired by the plan. Trusts governed by RRSPs, RDSPs, TFSAs or RRIFs which hold Trust Units that are not qualified investments will be subject to tax on the income attributable to the Trust Units while they are not qualified investments, including the full capital gains, if any, realized on the disposition of such Trust Units. Where a trust governed by a RRSP or a RRIF acquires Trust Units that are not qualified investments, the value of the investment is included in the income of the annuitant for the year of the acquisition. Trusts governed by RESPs which hold Trust Units that are not qualified investments can have their registration revoked by the Canada Revenue Agency. The holder of a RDSP or TFSA which holds Trust Units that are not qualified investments will be subject to tax equal to 50% of the fair market value of the Trust Units.

In addition, we may take certain measures in the future to the extent we believe necessary to ensure that we maintain our status as a mutual fund trust. These measures could be adverse to certain holders of Trust Units, particularly "non-residents" of Canada as defined in the Income Tax Act (Canada). See "*Information Relating to Us – Trust Indenture – Limitations on Non-Resident Ownership*".

Tax authorities having jurisdiction over us or Unitholders may disagree with how we calculate our income for tax purposes or could change administrative practices to our detriment or the detriment of Unitholders.

The oil and natural gas industry is subject to extensive controls and regulations governing its operations (including land tenure, exploration, development, production, refining, transportation, and marketing) imposed by legislation enacted by various levels of government and with respect to pricing and taxation of oil and natural gas by agreements among the governments of Canada, Alberta, British Columbia, Saskatchewan and Manitoba, all of which should be carefully considered by investors in the oil and gas industry. All of such controls, regulations and legislation are subject to revocation, amendment or administrative change, some of which have historically been material and in some cases materially adverse and there can be no assurance that there will not be further revocation, amendment or administrative change which will be materially adverse to our assets, reserves, financial condition or results of operations or prospects and our ability to maintain distributions.

There are numerous uncertainties inherent in estimating quantities of recoverable oil and natural gas reserves, including many factors beyond our control

In general, estimates of economically recoverable oil and natural gas reserves and resources and the future net revenues 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. All such estimates are based on professional judgment and classifications of reserves, which, by their nature have a high degree of subjectivity. For those reasons, estimates of the economically recoverable oil and natural gas reserves or estimates of resources 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 reserves and recovery information contained in the McDaniel Report is only an estimate and the actual production and ultimate reserves from the properties may be greater or less than the estimates prepared by McDaniel and such variations could be material. The McDaniel Report has been prepared using certain commodity price assumptions which are described in the notes to the reserves tables. If we realize lower prices for crude oil, natural gas liquids and natural gas and they are substituted for the price assumptions utilized in the McDaniel Report, the present value of estimated future net revenues for our reserves and our net asset value would be reduced and the reduction could be significant. The estimates in the McDaniel Report are based in part on the timing and success of activities we intend to undertake in future years. The reserves and estimated cash flows to be derived therefrom contained in the McDaniel Report will be reduced, in future years, to the extent that such activities do not achieve the level of success assumed in the McDaniel Report.

Estimates of proved undeveloped reserves are sometimes 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.

We are in the process of converting to a corporate structure which may result in adverse consequences to our financial condition

New federal legislation passed in June 2007, will apply a tax ("SIFT tax") at the trust level on distributions of certain income from trusts, such as us, at rates of tax comparable to the combined federal and provincial corporate tax and will treat such distributions as dividends to the Unitholders effective January 1, 2011. The SIFT tax results in adverse tax consequences to us and certain Unitholders (including most particularly Unitholders that are tax deferred or non-residents of Canada) and may impact our distributions.

The SIFT tax will substantially eliminate the competitive advantage that we and other Canadian energy trusts enjoyed relative to their corporate peers in raising capital in a tax-efficient manner, and will make the Trust Units less attractive as an acquisition currency. As a result, it may become more difficult for us to compete effectively for acquisition opportunities. There can be no assurance that we will be able to reorganize our legal and tax structure to substantially mitigate the expected impact of the SIFT tax.

No assurance can be provided that the SIFT tax will not apply to us prior to January 1, 2011, or that the legislation will not be further changed in a manner which adversely affects us and our Unitholders.

Acquiring, developing and exploring for oil and natural gas involves many risks, which even a combination of experience, knowledge and careful evaluation may not be able to overcome

These risks include, but are not limited to, encountering unexpected formations or pressures, premature declines of reservoirs, blow-outs, craterings, equipment failures and other accidents, sour gas releases and spills, uncontrollable flows of oil, natural gas or well fluids, the invasion of water into producing formations, adverse weather conditions, pollution, other environmental risks, fires, spills and delays in payments between parties caused by operation or economic matters which could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment, personal injuries, loss of life and other hazards, all of which could result in liability. These risks will increase as the Trust undertakes more exploratory activity. Although we maintain insurance in accordance with customary industry practice, we are not fully insured against all of these risks nor are all such risks insurable. In certain circumstances, we may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or other reasons. In addition, the nature of these risks is such that liabilities could exceed policy limits, in which event we could incur significant costs that could have a material adverse effect upon our financial condition..

Exploration and development risks arise due to the uncertain results of searching for and producing oil and natural gas using imperfect scientific methods. These risks are mitigated by using highly skilled staff, focusing exploration efforts in areas in which we have existing knowledge and expertise or access to such expertise, using up-to-date technology to enhance methods, and controlling costs to maximize returns.

Continuing production from a property, and to some extent the marketing of production therefrom, are largely dependent upon the ability of the operator of the property. Other companies operate some of the properties in which we have an interest and as a result our returns on assets operated by others depends upon a number of factors outside our control. To the extent the operator fails to perform these functions properly, operating income may be reduced. In addition, payments from production generally flow through the operator and there is a risk of delay and additional expense in receiving such revenues if the operator becomes insolvent. Our return on assets operated by others will therefore depend upon a number of factors that may be outside of our control, including the timing and amount of capital expenditures, the operator's expertise and financial resources, the approval of other participants, the selection of technology and risk management practices.

In addition to the usual delays in payment by purchasers of oil and natural gas to the operators of the properties, and by the operator to our operating entities, payments between any of such parties may also be delayed by restrictions imposed by lenders, delays in the sale or delivery of products, delays in the connection of wells to a gathering system, blowouts or other accidents, recovery by the operator of expenses incurred in the operation of properties or the establishment by the operator of reserves for such expenses.

Losses resulting from the occurrence of any of these risks may have a material adverse effect on our business, financial condition, results of operations and prospects and our ability to maintain distributions.

The marketability of oil and natural gas that may be acquired or discovered by us will be affected by numerous factors beyond our control

These factors include demand for oil and natural gas, market fluctuations, the proximity and capacity of oil and natural gas pipelines and processing equipment and government regulations, including regulations relating to environmental protection, royalties, allowable production, pricing, importing and exporting of oil and natural gas and political events throughout the world that cause disruptions in the supply of oil. Any particular event could result in a material decline in prices and therefore result in a reduction of our net production revenue. In addition, our oil and natural gas properties, wells and facilities could be subject to a terrorist attack. If any of our properties, wells or facilities are the subject of terrorist attack it could have a material adverse effect on our financial condition. We do not have insurance to protect against the risk from terrorism.

Climate change laws and related environment regulation may impose restrictions or impose costs on our business which may adversely affect our financial condition and our ability to maintain distributions

Nearly all aspects of our operations 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 or 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. A breach of such legislation may result in the imposition of fines or issuance of clean up orders in respect of us or our properties, some of which may be material. We may also be exposed to civil liability for environmental matters or for the conduct of third parties, including private parties commencing actions and new theories of liability, regardless of negligence or fault. Furthermore, management believes the political climate appears to favour new programs for environmental laws and regulation, particularly in relation to the reduction of emissions or emissions intensity, and there is no assurance that any such programs, laws or regulations, if proposed and enacted, will not contain emission reduction targets which we cannot meet, and financial penalties or charges could be incurred as a result of the failure to meet such targets. For more information on the evolution and status of climate change and related environmental legislation, see "*Industry Conditions – Climate Change Regulation*".

There has been much public debate with respect to the Government's strategy or alternative strategies with respect to climate change and the control of greenhouse gases. Implementation of strategies by either the provinces in which we operate our business or by the Government of Canada, and whether to meet international agreed limits, or as otherwise determined, for reducing greenhouse gases could have a material impact on the nature of oil and natural gas operations, including ours. Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not possible to predict either the nature of those requirements or the impact on us and our operations and financial condition. Although we provide for the necessary amounts in our annual capital budget to fund our currently estimated environmental and reclamation obligations, there can be no assurance that we will be able to satisfy our actual future environmental and reclamation obligations from such funds.

Although we believe that we are in material compliance with current applicable environmental regulations, no assurance can be given that environmental laws will not result in a curtailment of production, a reduction of product demand, a material increase in the costs of production, development or exploration activities or otherwise adversely affect our business, financial condition, results of operations or prospects. Future changes in other environmental legislation could occur and result in stricter standards and enforcement, larger fines and liability, and increased capital expenditures and operating costs, which could have a material adverse effect on our financial condition or results of operations and prospects. See "*Industry Conditions – Climate Change Regulation*".

We may not be able to realize the anticipated benefits of acquisitions and dispositions or to manage growth

We make acquisitions and dispositions of businesses and assets in the ordinary course of our business. Achieving the benefits of acquisitions depends in part on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner as well as our ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with our operations. 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. There is no assurance that we will be able to continue to complete acquisitions or dispositions of oil and natural gas properties which realize all the synergistic benefits.

We periodically dispose of non-core assets so that management can focus its efforts and resources more efficiently. Depending on the state of the market for such non-core assets, certain of our non-core assets, if disposed of, could be expected to realize less than their carrying value on our financial statements.

The price we pay for the purchase of any material properties is based on engineering and economic estimates of the reserves made by independent engineers modified to reflect our technical and economic views. These assessments include a number of material factors and assumptions. Many of these factors are subject to change and are beyond our control. Consequently, the reserves acquired may be less than expected, which could adversely impact cash flow from operating activities and distributions to Unitholders. See "General Development of the Business".

We may be subject to growth-related risks including capacity constraints and pressure on our internal systems and controls. Our ability to manage growth effectively will require us to continue to implement and improve our operational and financial systems and to expand, train and manage our employee base. Our inability to deal with this growth could have a material adverse effect on our business, financial condition, results of operations and prospects.

There is strong competition relating to all aspects of the oil and gas industry

There are numerous trusts and other companies in the oil and gas industry, who are competing with us for the acquisitions of properties with longer life reserves, properties with exploitation and development opportunities and undeveloped land. As a result of such competition, it may be more difficult for us to acquire reserves on beneficial terms. Many of these other oil and gas companies have significantly greater financial and other resources than we do.

We compete with other oil and gas entities to hire and retain skilled personnel necessary for running our daily operations including planning, realizing on available technical advances and the execution of our annual capital development program. The inability to hire and retain skilled personnel could adversely impact certain of our operational and financial results.

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

Our oil and natural gas reserves are a depleting resource and decline as such reserves are produced

Distributions of distributable income in respect of properties, absent commodity price increases or cost effective acquisition and development activities, will decline over time in a manner consistent with declining production from typical oil, natural gas and natural gas liquids reserves. Our future oil and natural gas reserves and production, and therefore our funds from operating activities, will be highly dependent on our success in exploiting our reserves base and acquiring additional reserves. Without reserves additions through acquisition or development activities, our reserves and production may decline over time as reserves are produced.

We also distribute a significant proportion of our cash flow from operations to Unitholders rather than reinvesting it in reserves additions. Accordingly, if external sources of capital, including the issuance of additional Trust Units, become limited or unavailable on commercially reasonable terms, our ability to make the necessary capital investments to maintain or expand our oil and natural gas reserves may be impaired. To the extent that we use cash flow from operations to finance capital expenditures or property acquisitions, the level of cash flow from operations available for distribution to Unitholders will be reduced. There can be no assurance that we will be successful in developing or acquiring additional reserves on terms that meet our investment objectives.

We may participate in larger projects and may have more concentrated risk in certain areas of our operations

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

- the availability of processing capacity;
- the availability and proximity of pipeline capacity;
- the availability of storage capacity;
- the supply of and demand for oil and natural gas;
- the availability of alternative fuel sources;
- the effects of inclement weather;
- the availability of drilling and related equipment;
- unexpected cost increases;
- accidental events;
- changes in regulations;
- the availability and productivity of skilled labour; and
- the regulation of the oil and natural gas industry by various levels of government and governmental agencies.

Because of these factors, we could be unable to execute projects on time, on budget or at all, and may not be able to effectively market the oil and natural gas that we produce.

We only operate in western Canada and the United States and expansion outside of these areas may increase our risk exposure

Our operations and expertise are currently primarily focused on conventional oil and gas production and development in the Western Canadian Sedimentary Basin and the United States. In the future, we may acquire oil and gas properties outside of these geographic areas. In addition, the terms of the Trust Indenture do not limit us to oil and gas production and development, and we could acquire other energy related assets, such as oil and natural gas processing plants or pipelines, or an interest in an oil sands project. Expansion of our activities into new areas may present new additional risks or alternatively, significantly increase the exposure to one or more of the present risk factors which may adversely affect our future operational and financial conditions.

Our success depends in large measure on the efforts of our key personnel

The loss of key personnel of our operating entities could delay the completion of certain projects or otherwise have a material adverse effect on us. Unitholders will be dependent on our management in respect of the administration and management of all matters relating to our properties, the NPI and Trust Units and the safekeeping of our primary workspace and computer systems. As of December 31, 2009, we operated approximately 85 percent of the total daily production of our properties. Investors who are not willing to rely on our management should not invest in Trust Units.

Securing and maintaining title to our properties is subject to certain risks

Our properties are held in the form of licenses and leases and working interests in licenses and leases. If we or the holder of the license or lease fails to meet the specific requirement of a license or lease, the license or lease may terminate or expire. There can be no assurance that any of the obligations required to maintain each license or lease will be met. The termination or expiration of a license or lease or the working interest relating to a license or lease may have a material adverse affect on our results of operations and business. In addition title to the properties can become subject to dispute and defeat our claim to title over certain of our properties.

Aboriginal peoples have claimed aboriginal title and rights to portions of western Canada and have also made claims that certain developments, including oil and gas exploration development, may have been proceeding without the Crown carrying out appropriate consultations in the course of allowing such developments to proceed. We are not aware that any material claims have been made in respect of our properties and assets; however, if a claim arose and was successful this could have an adverse effect on us and our operations.

We are affected by seasonality

The level of activity in the Canadian oil and natural gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Also, certain oil and natural gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity and corresponding declines in the demand for crude oil and natural gas.

Our Board of Directors has discretion in the payment of distributions and may not choose to maintain distributions in certain circumstances

The Trust Indenture provides that all of our distributable income at the end of any calendar month including December 31 shall be declared payable and distributed to Unitholders of record on the last day of each such calendar month. The distribution by us of such distributable income is enforceable by such Unitholders of record. However, if this amount is not determined and declared payable in accordance with the rules of the Toronto Stock Exchange, the right to receive this income will trade with the Trust Units. The Trust Indenture provides that this distributable income is allocated to Unitholders for tax purposes and to the extent a Unitholder trades Trust Units in this period, they will be allocated such income but will have disposed of their right to receive such distribution.

In addition, the Trust Indenture provides that such distributable income may be paid in Trust Units. The Trust Indenture also provides for the consolidation of the Trust Units in the discretion of our Board of Directors to the pre-distribution number of Trust Units after any pro-rata distribution of additional Trust Units to all Unitholders. Accordingly, the Trust Indenture allows for the payment of distributions in a form other than cash and Unitholders may have taxable income and cash taxes payable.

We have the authority to impose restrictions on the issuance of Trust Units to, or the transfer by any Unitholder, of Trust Units to a non-resident

We intend to comply with the requirements under the Income Tax Act (Canada) for "unit trusts" and "mutual fund trusts" at all relevant times such that we maintain our status of a unit trust and a mutual fund trust for purposes of the Income Tax Act (Canada). In this regard, we may, from time to time, among other things, take all necessary steps to monitor our activities and ownership of the Trust Units. If at any time we become aware that our activities and ownership of the Trust Units by non-residents (non-residents of Canada and partnerships) may threaten our status under the Income Tax Act (Canada) as a "unit trust" or "mutual fund trust", we are authorized to take such action as may be necessary in our opinion to maintain our status as a unit trust and a mutual fund trust, including the imposition of restrictions on the issuance by the Trust, or the transfer by any Unitholder, of Trust Units to a non resident. See "*Information Relating to Us – Trust Indenture – Limitations on Non-Resident Ownership* ".

Our permitted investments may be risky

An investment in the Trust should be made with the understanding that the value of any of our investments may fluctuate in accordance with changes in the financial condition of such investments, the value of similar securities, and other factors. For example, the prices of Canadian government securities, bankers' acceptances and commercial paper react to economic developments and changes in interest rates. Commercial paper is also subject to issuer credit risk. Investments in energy-related income trusts, companies and partnerships will be subject to the general risks of investing in equity securities. These include the risk that the financial condition of issuers may become impaired, or that the energy sector may suffer a market downturn. Securities markets in general are affected by a variety of factors, including governmental, environmental and regulatory policies, inflation and interest rates, economic cycles, and global, regional and national events. The value of Trust Units could be affected by adverse changes in the market values of such investments.

Risks Relating to Our Structure and Ownership of Trust Units

Distributions do not represent a "yield" and are not comparable to debt instruments and rights of redemption have limited liquidity

Trust Units will have no value when reserves from our properties can no longer be economically produced and, as a result, distributions do not represent a "yield" in the traditional sense and are not comparable to bonds or other fixed yield securities, where investors are entitled to a full return of the principal amount of debt on maturity in addition to a return on investment through interest payments. Distributions represent a blend of return of Unitholders initial investment and a return on Unitholders initial investment.

Unitholders have a limited right to require a repurchase of their Trust Units, which is referred to as a redemption right. It is anticipated that the redemption right will not be the primary mechanism for Unitholders to liquidate their investment. The right to receive cash in connection with a redemption is subject to material limitations. Any securities which may be distributed *in specie* to Unitholders in connection with a redemption may not be listed on any stock exchange and a market may not develop for such securities and such securities may be illiquid. In addition, there may be resale restrictions imposed by law upon the recipients of the securities pursuant to the redemption right. See “*Trust Indenture – Right of Redemption*”.

The Trust Units do not represent a traditional investment in the oil and natural gas sector and should not be viewed by investors as shares in Zargon Oil & Gas

The Trust Units represent a fractional interest in us. Corporate law does not govern the Trust and the rights of Unitholders. As holders of Trust Units, Unitholders will not have the statutory rights normally associated with ownership of shares of a corporation including, for example, the right to bring oppression or derivative actions. The rights of Unitholders are specifically set forth in the Trust Indenture. In addition, trusts are not defined as recognized entities within the definitions of legislation such as the *Bankruptcy and Insolvency Act* (Canada), the *Companies' Creditors Arrangement Act* (Canada) and in some cases the *Winding Up and Restructuring Act* (Canada). As a result, in the event of an insolvency or restructuring, a Unitholder's position as such may be quite different than that of a shareholder of a corporation. Our sole assets will be the NPI and other investments in securities. The price per Trust Unit is a function of anticipated distributable income, the properties acquired by us and our ability to effect long-term growth in our value. The market price of the Trust Units will be sensitive to a variety of market conditions including, but not limited to, interest rates and our ability to acquire suitable oil and natural gas properties. Changes in market conditions may adversely affect the trading price of the Trust Units.

The Trust Units are not "deposits" within the meaning of the *Canada Deposit Insurance Corporation Act* (Canada) and are not insured under the provisions of that Act or any other legislation. Furthermore, we are not a trust company and, accordingly, are not registered under any trust and loan company legislation as we do not carry on or intend to carry on the business of a trust company.

The Trust Units are also unlike conventional debt instruments in that there is no principal amount owing to Unitholders. The Trust Units will have minimal value when reserves from our properties can no longer be economically produced or marketed. Unitholders will only be able to obtain a return of the capital they invested during the period when reserves may be economically recovered and sold. Accordingly, the distributions received over the life of the investment may not be equal to or greater than the initial capital investment.

Unitholder limited liability is subject to contractual and statutory assurances which may have some enforcement risks

The Trust Indenture provides that no Unitholder will be subject to any liability in connection with us or our obligations and affairs and, in the event that a court determines Unitholders are subject to any such liabilities, the liabilities will be enforceable only against, and will be satisfied only out of our assets. Pursuant to the Trust Indenture, we will indemnify and hold harmless each Unitholder from any costs, damages, liabilities, expenses, charges and losses suffered by a Unitholder resulting from or arising out of such Unitholder not having such limited liability.

The Trust Indenture provides that all written instruments signed by or on behalf of the Trust must contain a provision to the effect that such obligation will not be binding upon Unitholders personally. The principal investment of the Trust is the NPI which contains such provisions. Personal liability may also arise in respect of claims against us that do not arise under contracts, including claims in tort, claims for taxes and possibly certain other statutory liabilities. The possibility of any personal liability of this nature arising is considered unlikely. The *Income Trusts Liability Act* (Alberta) came into force on July 1, 2004. The legislation provides that a Unitholder will not be, as a beneficiary, liable for any act, default, obligation or liability of the trustee that arises after the legislation came into force.

Our operations will be conducted, upon the advice of counsel, in such a way and in such jurisdictions as to avoid as far as possible any material risk of liability on Unitholders for claims against us.

Certain Risks for United States and other non-resident Unitholders

There is the limited liability of residents in the United States to enforce civil remedies

We are a trust organized under the laws of Alberta, Canada and our principal place of business in Canada. Most of our directors and officers and the representatives of the experts who provide services to us (such as our auditors and our independent reserve engineers), and all or a substantial portion of our assets and the assets of such persons are located outside the United States. As a result, it may be difficult for investors in the United States to effect service of process within the United States upon such directors, officers and representatives of experts who are not residents of the United States or to enforce against them judgements of the United States courts based upon civil liability under the United States federal securities laws or the securities laws of any state within the United States. There is doubt as to the enforceability in Canada against us or any of our directors, officers or representatives of experts who are not residents of the United States, in original actions or in actions for enforcement of judgements of United States courts of liabilities based solely upon the United States federal securities laws or securities laws of any state within the United States.

There are differences in reporting practices in Canada and the United States

We report our production and reserve quantities in accordance with Canadian practices and specifically in accordance with NI 51-101. These practices are different from the practices used to report production and to estimate reserves in reports and other materials filed with the SEC by companies in the United States.

We incorporate additional information with respect to production and reserves which is either not generally included or prohibited under rules of the SEC and practices in the United States. We follow the Canadian practice of reporting gross production and reserve volumes (before deduction of crown and other royalties); however, we also follow the United States practice of separately reporting reserve volumes on a net basis (after the deduction of royalties and similar payments). We also follow the Canadian practice of using forecast prices and costs when we estimate our reserves whereas the SEC requires that prices and costs be held constant at levels in effect at the date of the reserve report.

We included in this Annual Information Form estimates of proved and proved plus probable reserves. Probable reserves are higher risk and are generally believed to be less likely to be accurately estimated or recovered than proved reserves. The SEC generally prohibits the inclusion of estimates of probable reserves in filings made with it. This prohibition does not apply to us because we are a Canadian foreign private issuer.

As a consequence of the foregoing, our reserve estimates and production volumes in this Annual Information Form may not be comparable to those made by companies utilizing United States reporting and disclosure standards.

There is additional taxation applicable to non-residents

The Income Tax Act (Canada) and the tax treaties between Canada and other countries may impose additional withholding or other taxes on the distributions or other property paid by us to Unitholders who are non-residents of Canada, and these taxes may change from time to time. Since January 1, 2005, a 15 percent Canadian withholding tax is applied to the return of capital portion of distributions made to non-resident Unitholders.

Additionally, the reduced "Qualified Dividend" rate of 15 percent tax applied to our distributions under current U.S. tax laws is scheduled to expire at the end of 2010 and there is no assurance that this reduced tax rate will be renewed by the U.S. government at such time.

Furthermore, it is anticipated that the implementation of the SIFT tax may have tax consequences for non-residents of Canada that are more adverse than the tax consequences to other classes of Unitholders.

There is a foreign exchange risk for non-resident Unitholders

Our distributions are declared in Canadian dollars and converted to foreign denominated currencies at the spot exchange rate at the time of payment. As a consequence, investors are subject to foreign exchange risk. To the extent that the Canadian dollar strengthens with respect to their currency, the amount of the distribution will be reduced when converted to their home currency.

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business, the only material contracts entered into by us within the most recently completed financial year, or before the most recently completed financial year but are still material and are still in effect, are the following:

(a) the Trust Indenture;

(b) the Exchangeable Share provisions and the related support agreement and the voting and exchange trust agreement;

(c) the note indenture creating the Notes; and

(d) the credit agreement dated September 30, 2005 and amendments related thereto among Zargon Oil & Gas and certain lenders in respect of Zargon's $180 million syndicated credit facilities, which agreement is described in Note 6 to our consolidated financial statements for the year ended December 31, 2009, which note is incorporated by reference herein.

Copies of each of these documents have been filed on SEDAR at *www.sedar*.com.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

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

There were no: (i) penalties or sanctions imposed against us by a court relating to securities legislation or by a securities regulatory authority during our most recently completed financial year; (ii) other penalties or sanctions imposed by a court or regulatory body against us that would likely be considered important to a reasonable investor in making an investment decision; or (iii) settlement agreements we entered into with a court relating to securities legislation or with a securities regulatory authority during our most recently completed financial year.

TRANSFER AGENT AND REGISTRAR

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

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

There were no material interests, direct or indirect, of directors and senior officers of Zargon Oil & Gas, any holder of Trust Units or Exchangeable Shares who beneficially owns, or controls or directs, directly or indirectly, more than 10 percent of the outstanding Trust Units or Exchangeable Shares, or any known associate or affiliate of such persons, in any transaction within the last three fiscal years or during the current fiscal year which has materially affected or would materially affect us.

INTERESTS OF EXPERTS

There is no person or company whose profession or business gives authority to a statement made by such person or company and who is named as having prepared or certified a report, valuation, statement or opinion described or included in a filing, or referred to in a filing, made under National Instrument 51-102 by us during, or related to, our most recently completed financial year other than McDaniel, our independent engineering evaluator, and Ernst & Young LLP, our auditors. None of the principals of McDaniel had any registered or beneficial interests, direct or indirect, in any of our securities or other property or of our associates or affiliates either at the time they prepared the report, valuation, statement or opinion prepared by it, at any time thereafter or to be received by them. Ernst & Young LLP is independent in accordance with the Rules of Professional Conduct as outlined by the Institute of Chartered Accountants of Alberta.

In addition, none of the aforementioned persons or companies, nor any director, officer or employee of any of the aforementioned persons or companies, is or is expected to be elected, appointed or employed as a director, officer or employee of Zargon Oil & Gas or of any of our associate or affiliate entities**,** except for Grant A. Zawalsky, a director of Zargon Oil & Gas, is a partner at Burnet, Duckworth & Palmer LLP, which is a law firm that renders legal services to us.

ADDITIONAL INFORMATION

Additional information relating to us can be found on SEDAR at *www.sedar.com* and on our website at *www.zargon.ca.* Additional information, including directors' and officers' remuneration and indebtedness, principal holders of our securities and securities issued and authorized for issuance under our equity compensation plans are contained in our information circular – proxy statement dated March 10, 2010 relating to our annual and special unitholders meeting to be held on April 28, 2010. Additional financial information is contained in our consolidated financial statements for the year ended December 31, 2009 and the related management's discussion and analysis.

For additional copies of the Annual Information Form and the materials listed in the preceding paragraphs please contact:

Zargon Energy Trust
c/o Zargon Oil & Gas
700, 333 – 5th Avenue S.W.
Calgary, Alberta, T2P 3B6
Tel: (403) 264-9992
Fax: (403) 265-3026

APPENDIX A

REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE

(Form 51-101F3)

Management of Zargon Oil & Gas on behalf of Zargon Energy Trust (collectively "**Zargon**") is responsible for the preparation and disclosure of information with respect to Zargon'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, 2009, estimated using forecast prices and costs.

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

The Reserves Committee of the board of directors of Zargon has

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

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

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

The Reserves Committee of the board of directors has reviewed Zargon's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The board of directors has, on the recommendation of the Reserves Committee, approved

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

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

(c) the content and filing of this report.

Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material. However, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

(signed) C.H. Hansen
President and Chief Executive Officer

(signed) B.G. Kergan
Vice President, Corporate Development and Alberta Plains South

(signed) J.G. Weir
Director and Chairman of the Reserves Committee

(signed) J. Peplinski
Director and Member of the Reserves Committee

(signed) K.D. Kitagawa
Director and Member of the Reserves Committee

(signed) G.C. Merritt
Director and Member of the Reserves Committee

February 23, 2010

APPENDIX B

REPORT ON RESERVES DATA BY MCDANIEL

(Form 51-101F2)

To the board of directors of Zargon Oil & Gas on behalf of Zargon Energy Trust (collectively "**Zargon**"):

1. We have evaluated Zargon's reserves data as at December 31, 2009. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2009, estimated using forecast prices and costs.

2. The reserves data are the responsibility of Zargon's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

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

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of Zargon evaluated by us for the year ended December 31, 2009, and identifies the respective portions thereof that we have evaluated and reported on to Zargon's board of directors:

Independent Qualified Reserves Evaluator or Auditor	Description and Preparation Date of Evaluation Report	Location of Reserves	Net Present Value of Future Net Revenue (thousands before income taxes, 10% discount rate)			
			Audited	Evaluated	Reviewed	Total
McDaniel & Associates Consultants Ltd.	February 23, 2010	Canada	$nil	$523,241	$nil	$523,241
		United States	$nil	$69,164	$nil	$69,164

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 report referred to in paragraph 4 for events and circumstances occurring after their respective preparation date.

7. Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material. However, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

Executed as to our report referred to above:

(signed) McDaniel & Associates Consultants Ltd.
Calgary, Alberta
February 23, 2010

APPENDIX C

MANDATE & TERMS OF REFERENCE OF THE AUDIT COMMITTEE

Role and Objective

The Audit Committee (the "Committee") is a committee of the Board of Directors (the “Board”) of Zargon Oil & Gas Ltd. ("Zargon" or the “Corporation”) to which the Board has delegated its responsibility for oversight of the nature and scope of the annual audit, management's reporting on internal accounting standards and practices, financial information and accounting systems and procedures, financial reporting and statements and recommending, for board of director approval, the audited financial statements and other mandatory disclosure releases containing financial information, and review of the annual reserves. The objectives of the Committee are as follows:

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

Membership of Committee

1. The Committee shall be comprised of at least three (3) directors of Zargon, none of whom are members of management of Zargon and all of whom are "independent" (as such term is used in Multilateral Instrument 52-110 — Audit Committees ("MI 52-110").
2. The Board shall have the power to appoint the Committee Chairman.
3. All of the members of the Committee shall be "financially literate". The Board has adopted the definition for "financial literacy" used in MI 52-110.

Meetings

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

5. The Committee shall meet with the external auditor at least once per year (in connection with the preparation of the year end financial statements) and at such other times as the external auditor and the audit Committee consider appropriate.

Mandate and Responsibilities of Committee

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

2. It is the responsibility of the Committee to satisfy itself on behalf of the board with respect to Zargon's Internal Control Systems:

   - identifying, monitoring and mitigating business risks; and
   - ensuring compliance with legal, ethical and regulatory requirements.

3. It is a primary responsibility of the Committee to review the annual financial statements of Zargon prior to their submission to the board of directors for approval. The process should include but not be limited to:

   - reviewing changes in accounting principles, or in their application, which may have a material impact on the current or future years' financial statements;
   - reviewing significant accruals, reserves or other estimates such as the ceiling test calculation;
   - reviewing accounting treatment of unusual or non-recurring transactions;
   - ascertaining compliance with covenants under loan agreements;
   - reviewing disclosure requirements for commitments and contingencies;
   - reviewing adjustments raised by the external auditors, whether or not included in the financial statements;
   - reviewing unresolved differences between management and the external auditors; and
   - obtain explanations of significant variances with comparative reporting periods.

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

5. With respect to the appointment of external auditors by the board, the Committee shall:

   - recommend to the board the appointment of the external auditors;
   - recommend to the board the terms of engagement of the external auditor, including the compensation of the auditors and a confirmation that the external auditors shall report directly to the Committee;
   - when there is to be a change in auditors, review the issues related to the change and the information to be included in the required notice to securities regulators of such change; and

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

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

7. The Committee must pre–approve all non–audit services to be provided to Zargon or its subsidiaries by the external auditors. The Committee may delegate to one or more members the authority to pre–approve non–audit services, provided that the member report to the Committee at the next scheduled meeting such pre–approval and the member comply with such other procedures as may be established by the Committee from time to time.

8. The Committee shall review on an annual basis the reserves as evaluated by the external reserve evaluators. As part of this review, the Audit Committee shall be represented by at least one member at a reserve committee face-to-face meeting with management and the reserve evaluators.

9. The Committee shall review risk management policies and procedures of Zargon (i.e. hedging, litigation and insurance).

10. The Committee shall establish a procedure for:

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

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

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

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

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