ZARGON ENERGY TRUST

2007 Annual Information Form

March 19, 2008

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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 Ltd.

ExchangeCo means Zargon ExchangeCo Inc.

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 Partnership means Zargon Oil & Gas Partnership.

Independent Engineering

COGE Handbook means the Canadian Oil and Gas Evaluation Handbook.

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

McDaniel Report means the report prepared by McDaniel dated February 28, 2008 evaluating the crude oil, natural gas and natural gas liquids reserves attributable to certain of our oil and natural gas assets at December 31, 2007.

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 and the Amendment thereto dated July 30, 2007.

Exchangeable Shares means exchangeable shares of Zargon Oil & Gas Ltd. 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 Ltd. 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 Ltd. 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 Ltd. 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, using the conversion factor of 6 Mcf of natural gas being equivalent to one barrel of oil. Boes may be misleading, particularly if used in isolation. **A boe conversion ratio of 6 Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.**
WTI	means West Texas Intermediate.
°API	means the measure of the density or gravity of liquid petroleum products derived from a specific gravity.
psi	means pounds per square inch.

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

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

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. Forward-looking statements are often, but not always, identified by the use of words such as "seek", "anticipate", "budget", "plan", "continue", "estimate", "expect", "forecast", "may", "will", "project", "predict", "potential", "targeting", "intend", "could", "might", "should", "believe" and other similar expressions. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. We believe the expectations reflected in those 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 particular, this Annual Information Form, and the documents incorporated by reference, contain forward-looking statements pertaining to the following:

- the performance characteristics of our oil and natural gas properties;
- oil and natural gas production levels;
- the size of our oil and natural gas reserves;
- 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; and
- capital expenditures programs.

The actual results could differ materially from those anticipated in these forward-looking statements as a result of the risk factors set forth below and elsewhere in this Annual Information Form:

- volatility in market prices for oil and natural gas;
- liabilities inherent in oil and natural gas operations;
- uncertainties associated with estimating oil and natural gas reserves;
- competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel;
- incorrect assessments of the value of acquisitions;
- geological, technical, drilling and processing problems;
- changes in income tax laws or changes in tax laws and incentive programs relating to the oil and gas industry and income trusts; and
- the other factors discussed under "*Risk Factors*".

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.

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 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 Ltd. received either Trust Units or Exchangeable Shares for their common shares.

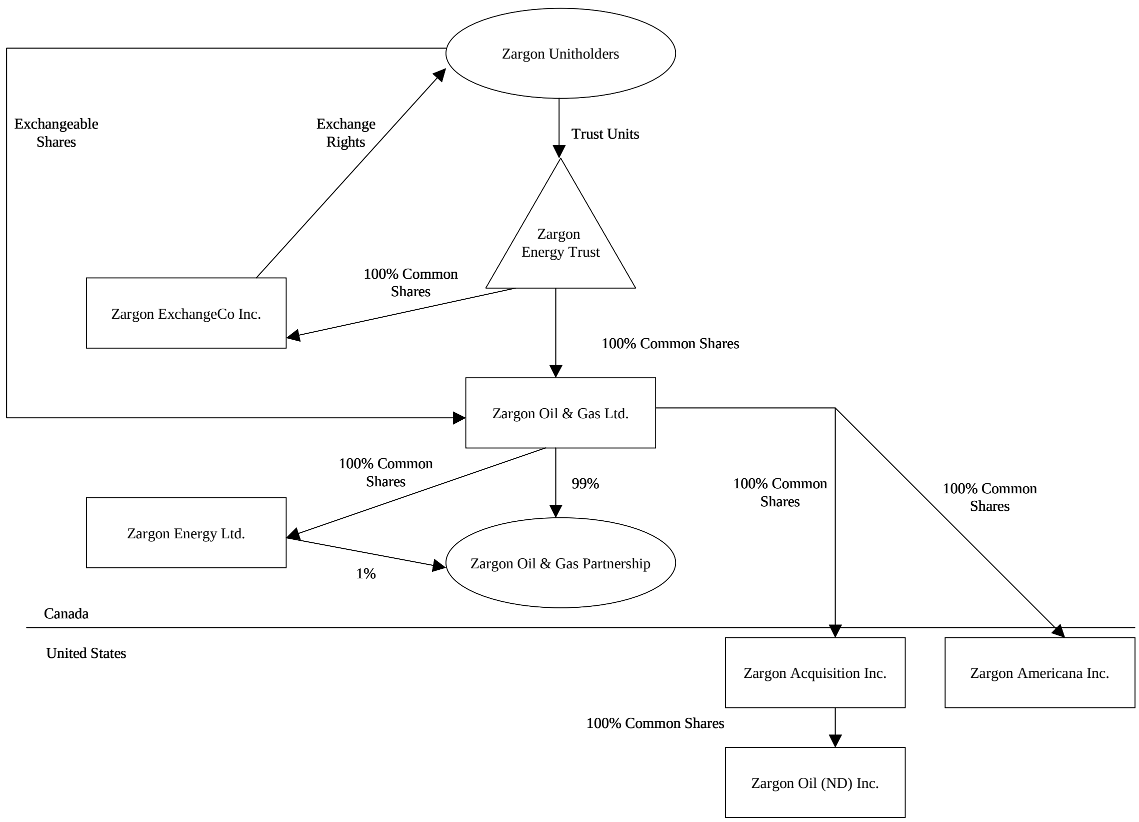
Inter-Corporate Relationships

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 Ltd. had a total of 2,070,952 Exchangeable Shares issued and outstanding as at December 31, 2007, which were exchangeable for 2,684,182 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 Ltd. 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 Ltd. before the maturity of such notes.

GENERAL DEVELOPMENT OF THE BUSINESS

History and Development

On July 15, 2004, Zargon Oil & Gas Ltd. completed a Plan of Arrangement whereby holders of common shares of Zargon Oil & Gas Ltd. 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 Energy Ltd. in consideration of the issuance of 0.57 million Trust Units, $16.4 million in cash and assumed 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 Zargon's Alberta Plains core area, just south of Jarrow, Zargon's largest producing property. The Rival 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. In support of this acquisition, Zargon hedged 500 bbl/d of oil production for calendar 2008 and 2009 at an average price of US$87.01 per barrel. The acquisition of Rival Energy Ltd. was not a "significant acquisition" as defined by National Instrument 51-102 – Continuous Disclosure Obligations.

Federal Tax Changes for Income Trusts and Corporations

On October 31, 2006, the Finance Minister announced the federal government's plan regarding taxation of income trusts and certain other flow-through entities ("**SIFTs**"). Currently, distributions paid to unitholders, other than returns of capital, are claimed as a deduction by income trusts in arriving at taxable income whereby tax is eliminated at the trust level and is paid by the unitholders.

The income trust tax legislation relating to SIFTs (the "**SIFT Rules**"), which received Royal assent on June 22, 2007, will result in a two-tiered tax structure whereby distributions from an income trust would first be subject to income taxes commencing in 2011 (or earlier, if any such income trust exceeds the normal growth guidelines announced by the Minister on December 15, 2006), and then unitholders would be subject to tax on the distribution as if it were a taxable dividend paid by a taxable Canadian corporation.

On October 30, 2007, the Finance Minister announced, as part of the 2007 Economic Statement, changes to the tax system including reduction of the corporate income tax rate to 15 percent by 2012. Legislation enacting the measures, announced in the Economic Statement, received Royal assent on December 14, 2007. The reduction in the general corporate tax rate will also be reflected in a lower tax rate on trust distributions.

Currently, the SIFT Rules provide that the SIFT tax rate will be the federal general corporate income tax rate (which is anticipated to be 16.5 percent in 2011 and 15% in 2012) plus the provincial SIFT tax factor (which is set at a fixed rate of 13 percent).

On February 26, 2008, the Minister of Finance announced (the "**Provincial SIFT Tax Proposal**") that instead of basing the provincial component of the SIFT tax on a flat rate of 13 percent, the provincial component will instead be based on the general provincial corporate income tax rate in each province in which the SIFT has a permanent establishment. Under the Provincial SIFT Tax Proposal, we would likely be considered to have a permanent establishment in Alberta, where the provincial tax rate in 2011 is expected to be 10 percent. There can be no assurance, however, that the Provincial SIFT Tax Proposal will be enacted as proposed.

On December 20, 2007, the Finance Minister announced technical amendments to provide some clarification to the SIFT Rules. As part of the announcement, the Minister indicated the federal government intends to provide, in 2008, legislation to permit income trusts to convert to taxable Canadian corporations without any undue tax consequences to the investors or the income trusts.

Our Board of Directors and management continue to review the impact of the SIFT Rules on our business strategy and the merits of converting to a corporation on or before January 1, 2011. We expect future technical interpretations and details will further clarify the legislation. At the present time, we believe that if structural or other similar changes are not made, the after-tax distribution amount in 2011 to taxable Canadian investors will remain approximately the same; however, the after-tax distribution will decline for both tax-deferred Canadian investors (RRSPs, RRIFs, pension plans, etc.) and foreign investors.

For more information, see "*Risk Factors – Risks to Our Revenues – Federal Tax Changes for Income Trusts and Corporations*" and "*Risk Factors – Risks Associated with Government Regulation – Changes in Legislation*".

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, 2007, we had 52 employees. Cash flow from the properties is flowed from Zargon Oil & Gas Ltd. to us by way of interest payments and principal repayments on notes and payments from Zargon Oil & Gas Ltd. to us under a net profits interest agreement.

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 Ltd. 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 Ltd.

Zargon Oil & Gas Ltd. is a corporation amalgamated and subsisting pursuant to the laws of Alberta. Zargon Oil & Gas Ltd. 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 Ltd. The Exchangeable Shares are owned by the public.

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

Notes

The Notes were issued by Zargon Oil & Gas Ltd. 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 Ltd. is permitted to make payments against the principal amount of the Note outstanding from time to time without notice or bonus, Zargon Oil & Gas Ltd. 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 the Trust (the "**Non-Trust Holders**") own Notes having an aggregate principal amount in excess of $10,000,000, either we or the Non-Trust Holders shall be entitled, among other things, to require the Valiant Trust Company to exercise the powers and remedies available under the Note Indenture upon an event of default and, with the Trust, the Non-Fund 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 it 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 Ltd. pursuant to which we have the right to receive the NPI on petroleum and natural gas rights held by Zargon Oil & Gas Ltd. from time to time. Pursuant to the terms of the agreement, we are entitled to a payment from Zargon Oil & Gas Ltd. 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 Ltd. for such month exceed 99 percent of certain deductible costs for such period. Zargon Oil & Gas Ltd. is entitled to set off amounts reimbursable to it against NPI payments payable by Zargon Oil & Gas Ltd. 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 (the "**Statement**") is dated February 28, 2008. The effective date of the Statement is December 31, 2007 and the preparation date of the Statement is February 28, 2008. 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.

Disclosure of Reserves Data

The reserves data set forth below (the "**Reserves Data**") is based upon an evaluation by McDaniel with an effective date of December 31, 2007 contained in the McDaniel Report. The Reserves Data summarizes our crude oil, natural gas liquids and natural gas reserves of the Trust 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 NI 51-101. 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 and Manitoba, and in the United States in North Dakota.

Disclosure provided herein in respect of barrels of oil equivalent ("**boe**") may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf is equal to 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Due to uncertainties and lack of sufficient details with which to determine royalties for some product types under the proposed Alberta new royalty regime (the "NRF"), the reserves data set forth below has been prepared using the existing royalties. See "*Industry Conditions – Provincial Royalties and Incentives – Alberta*" and "*Risk Factors – Risks to Our Revenues – New Alberta Royalty Regime*". However, a high and low sensitivity calculation with respect to the potential impact of the NRF is provided in the notes to certain of the reserves data tables set forth below.

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 – Operational Risks – Reserves Estimates*" and "*Risk Factors – Risks to Our Revenues – Volatility of Oil and Natural Gas Prices*".

Reserves Data (Forecast Prices and Costs)

SUMMARY OF OIL AND GAS RESERVES
AND NET PRESENT VALUES OF FUTURE NET REVENUE
as of December 31, 2007
FORECAST PRICES AND COSTS

CANADA

RESERVES CATEGORY	LIGHT AND MEDIUM OIL Gross (Mbbl)	Net (Mbbl)	NATURAL GAS Gross (MMcf)	Net (MMcf)	NATURAL GAS LIQUIDS Gross (Mbbl)	Net (Mbbl)
Proved						
Developed Producing	7,544	6,554	36,778	31,159	65	47
Developed Non-Producing	18	17	6,757	5,326	5	3
Undeveloped	228	203	306	296	-	-
Total Proved	7,790	6,774	43,841	36,781	70	50
Probable	3,248	2,809	23,511	19,560	29	22
Total Proved Plus Probable	11,038	9,583	67,352	56,341	99	72

RESERVES CATEGORY	NET PRESENT VALUES OF FUTURE NET REVENUE BEFORE INCOME TAXES DISCOUNTED AT (%/year) (1)(2) 0% ($000s)	5% ($000s)	10% ($000s)	15% ($000s)	20% ($000s)
Proved					
Developed Producing	390,422	320,078	273,219	240,218	215,722
Developed Non-Producing	25,022	20,797	17,715	15,398	13,608
Undeveloped	7,340	4,936	3,553	2,648	2,006
Total Proved	422,784	345,811	294,487	258,264	231,336
Probable	224,293	142,748	101,240	77,088	61,517
Total Proved Plus Probable	647,077	488,559	395,727	335,352	292,853

Notes:

(1) Management has estimated that the impact of the NRF is to decrease the net present values of future net revenue (before income taxes) by less than one percent using a 10% discount rate and using the McDaniel forecast prices set forth in this Annual Information Form. See "*Industry Conditions*" and "*Risk Factors – Risks to Our Revenues – The New Alberta Royalty Regime*".

(2) The methodology used to calculate the new royalties for the net present value of future net revenue amounts set forth in Note (1) was based on the following criteria: (i) in the case of heavy oil, a heavy oil par price was used for the high case and for the low case the light oil par price was used; (ii) since Zargon does not have a substantial volume of solution gas, application of the new conventional gas royalty formula on solution gas production will not be material to its overall net percent value so no changes were made; and (iii) in the case of deep gas, McDaniel assumed that the deep gas royalty adjustment applies to all existing and future wells in the high case and for the low case McDaniel assumed that the deep gas royalty adjustment only applies to wells drilled after 2008.

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	383,255	316,660	271,497	239,309	215,222
Developed Non-Producing	21,864	18,845	16,482	14,603	13,086
Undeveloped	5,756	3,984	2,951	2,253	1,739
Total Proved	410,875	339,489	290,930	256,165	230,047
Probable	173,494	113,839	82,985	64,772	52,825
Total Proved Plus Probable	584,369	453,328	373,915	320,937	282,872

BY PRODUCTION GROUP
as of December 31, 2007
FORECAST PRICES AND COSTS

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) (1)(2) ($000s)	UNIT VALUE (3) ($/bbl) ($/Mcf)
Proved	Light and Medium Crude Oil (including solution gas and other by-products)	166,869	$24.45/bbl
	Natural Gas (including by-products but excluding natural gas from oil wells)	127,618	$3.47/Mcf
	Total	**294,487**	
Proved plus Probable	Light and Medium Crude Oil (including solution gas and other by-products)	213,362	$22.10/bbl
	Natural Gas (including by-products but excluding natural gas from oil wells)	182,365	$3.24/Mcf
	Total	**395,727**	

Notes:

(1) Management has estimated that the impact of the NRF is to decrease the net present values of future net revenue (before income taxes) by less than one percent using a 10% discount rate and using the McDaniel forecast prices set forth in this Annual Information Form. See "*Industry Conditions*" and "*Risk Factors – Risks to Our Revenues – The New Alberta Royalty Regime*".

(2) The methodology used to calculate the new royalties for the net present value of future net revenue amounts set forth in Note (1) was based on the following criteria: (i) in the case of heavy oil, a heavy oil par price was used for the high case and for the low case the light oil par price was used; (ii) since Zargon does not have a substantial volume of solution gas, application of the new conventional gas royalty formula on solution gas production will not be material to its overall net percent value so no changes were made; and (iii) in the case of deep gas, McDaniel assumed that the deep gas royalty adjustment applies to all existing and future wells in the high case and for the low case McDaniel assumed that the deep gas royalty adjustment only applies to wells drilled after 2008.

(3) 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, 2007
FORECAST PRICES AND COSTS

UNITED STATES

RESERVES CATEGORY	LIGHT AND MEDIUM OIL Gross (Mbbl)	LIGHT AND MEDIUM OIL Net (Mbbl)	NATURAL GAS Gross (MMcf)	NATURAL GAS Net (MMcf)	NATURAL GAS LIQUIDS Gross (Mbbl)	NATURAL GAS LIQUIDS Net (Mbbl)
Proved						
Developed Producing	3,428	2,540	-	-	-	-
Developed Non-Producing	49	37	-	-	-	-
Undeveloped	98	73	-	-	-	-
Total Proved	3,575	2,650	-	-	-	-
Probable	971	720	-	-	-	-
Total Proved Plus Probable	4,546	3,370	-	-	-	-

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	95,584	73,284	58,933	49,793	43,503
Developed Non-Producing	1,956	1,811	1,685	1,576	1,481
Undeveloped	1,681	1,351	1,081	858	674
Total Proved	99,221	76,446	61,699	52,227	45,658
Probable	39,222	19,929	12,712	9,197	7,171
Total Proved Plus Probable	138,443	96,375	74,411	61,424	52,829

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	54,970	44,109	35,850	30,512	26,827
Developed Non-Producing	1,138	1,045	966	899	840
Undeveloped	978	798	651	531	433
Total Proved	57,086	45,952	37,467	31,942	28,100
Probable	22,837	11,608	7,405	5,355	4,174
Total Proved Plus Probable	79,923	57,560	44,872	37,297	32,274

BY PRODUCTION GROUP
as of December 31, 2007
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)	61,699	$23.28/bbl
	Natural Gas (including by-products but excluding natural gas from oil wells)	-	-
	Total	**61,699**	
Proved plus Probable	Light and Medium Crude Oil (including solution gas and other by-products)	74,411	$22.08/bbl
	Natural Gas (including by-products but excluding natural gas from oil wells)	-	-
	Total	**74,411**	

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, 2007
FORECAST PRICES AND COSTS

AGGREGATE

RESERVES CATEGORY	LIGHT AND MEDIUM OIL Gross (Mbbl)	LIGHT AND MEDIUM OIL Net (Mbbl)	NATURAL GAS Gross (MMcf)	NATURAL GAS Net (MMcf)	NATURAL GAS LIQUIDS Gross (Mbbl)	NATURAL GAS LIQUIDS Net (Mbbl)
Proved						
Developed Producing	10,972	9,094	36,778	31,159	65	47
Developed Non-Producing	67	54	6,757	5,326	5	3
Undeveloped	326	276	306	296	-	-
Total Proved	11,365	9,424	43,841	36,781	70	50
Probable	4,219	3,529	23,511	19,560	29	22
Total Proved Plus Probable	15,584	12,953	67,352	56,341	99	72

RESERVES CATEGORY	NET PRESENT VALUES OF FUTURE NET REVENUE BEFORE INCOME TAXES DISCOUNTED AT (%/year) (1)(2) 0% ($000s)	5% ($000s)	10% ($000s)	15% ($000s)	20% ($000s)
Proved					
Developed Producing	486,006	393,362	332,152	290,011	259,225
Developed Non-Producing	26,978	22,608	19,400	16,974	15,089
Undeveloped	9,021	6,287	4,634	3,506	2,680
Total Proved	522,005	422,257	356,186	310,491	276,994
Probable	263,515	162,677	113,952	86,285	68,688
Total Proved Plus Probable	785,520	584,934	470,138	396,776	345,682

Notes:

(1) Management has estimated that the impact of the NRF is to decrease the net present values of future net revenue (before income taxes) by less than one percent using a 10% discount rate and using the McDaniel forecast prices set forth in this Annual Information Form. See "*Industry Conditions*" and "*Risk Factors – Risks to Our Revenues – The New Alberta Royalty Regime*".

(2) The methodology used to calculate the new royalties for the net present value of future net revenue amounts set forth in Note (1) was based on the following criteria: (i) in the case of heavy oil, a heavy oil par price was used for the high case and for the low case the light oil par price was used; (ii) since Zargon does not have a substantial volume of solution gas, application of the new conventional gas royalty formula on solution gas production will not be material to its overall net percent value so no changes were made; and (iii) in the case of deep gas, McDaniel assumed that the deep gas royalty adjustment applies to all existing and future wells in the high case and for the low case McDaniel assumed that the deep gas royalty adjustment only applies to wells drilled after 2008.

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	438,225	360,769	307,347	269,821	242,049
Developed Non-Producing	23,002	19,890	17,448	15,502	13,926
Undeveloped	6,734	4,782	3,602	2,784	2,172
Total Proved	467,961	385,441	328,397	288,107	258,147
Probable	196,331	125,447	90,390	70,127	56,999
Total Proved Plus Probable	664,292	510,888	418,787	358,234	315,146

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
as of December 31, 2007
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	904,338	144,438	295,918	8,294	32,904	422,784	11,909	410,875
United States	272,569	70,662	92,605	2,542	7,539	99,221	42,135	57,086
Total	1,176,907	215,100	388,523	10,836	40,443	522,005	54,044	467,961
Proved Plus Probable Reserves								
Canada	1,360,601	216,242	438,871	21,822	36,589	647,077	62,707	584,370
United States	356,260	92,371	115,200	2,542	7,704	138,443	58,521	79,922
Total	1,716,861	308,613	554,071	24,364	44,293	785,520	121,228	664,292

BY PRODUCTION GROUP
as of December 31, 2007
FORECAST PRICES AND COSTS

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) (1)(2) ($000s)	UNIT VALUE (3) ($/bbl) ($/Mcf)
Proved	Light and Medium Crude Oil (including solution gas and other by-products)	228,568	$24.13/bbl
	Natural Gas (including by-products but excluding natural gas from oil wells)	127,618	$3.47/Mcf
	Total	**356,186**	
Proved plus Probable	Light and Medium Crude Oil (including solution gas and other by-products)	287,773	$22.09/bbl
	Natural Gas (including by-products but excluding natural gas from oil wells)	182,365	$3.24/Mcf
	Total	**470,138**	

Notes:

(1) Management has estimated that the impact of the NRF is to decrease the net present values of future net revenue (before income taxes) by less than one percent using a 10% discount rate and using the McDaniel forecast prices set forth in this Annual Information Form. See "*Industry Conditions*" and "*Risk Factors – Risks to Our Revenues – The New Alberta Royalty Regime*".

(2) The methodology used to calculate the new royalties for the net present value of future net revenue amounts set forth in Note (1) was based on the following criteria: (i) in the case of heavy oil, a heavy oil par price was used for the high case and for the low case the light oil par price was used; (ii) since Zargon does not have a substantial volume of solution gas, application of the new conventional gas royalty formula on solution gas production will not be material to its overall net percent value so no changes were made; and (iii) in the case of deep gas, McDaniel assumed that the deep gas royalty adjustment applies to all existing and future wells in the high case and for the low case McDaniel assumed that the deep gas royalty adjustment only applies to wells drilled after 2008.

(3) 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. 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 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, 2007, inflation and exchange rates utilized in the McDaniel Report were as follows:

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
as of December 31, 2007
FORECAST PRICES AND COSTS

Year	WTI Cushing Oklahoma ($US/bbl)	Edmonton Par Price 40° API ($Cdn/bbl)	Hardisty Heavy 12° API ($Cdn/bbl)	Cromer Medium 29.3° API ($Cdn/bbl)	Natural Gas AECO Price ($Cdn/gj)	Natural Gas Liquids FOB Field Gate ($Cdn/bbl)	Inflation Rate(1) %/year	Exchange Rate(2) ($US/$Cdn)
Forecast								
2008	90.00	89.00	64.70	78.20	6.45	61.60	2.0	1.00
2009	86.70	85.70	62.30	75.30	7.00	60.20	2.0	1.00
2010	83.20	82.20	59.70	72.20	7.00	58.00	2.0	1.00
2011	79.60	78.50	57.00	69.00	7.00	55.80	2.0	1.00
2012	78.50	77.40	56.20	68.00	7.10	55.20	2.0	1.00
2013	77.30	76.20	55.30	66.90	7.30	54.70	2.0	1.00
2014	78.80	77.70	56.40	68.20	7.55	55.80	2.0	1.00
2015	80.40	79.30	57.50	69.60	7.80	57.10	2.0	1.00
2016	82.00	80.80	58.70	71.00	8.00	58.20	2.0	1.00
2017	83.70	82.50	59.90	72.50	8.25	59.50	2.0	1.00
2018	85.30	84.10	61.10	73.80	8.45	60.70	2.0	1.00
2019	87.00	85.80	62.30	75.30	8.70	62.00	2.0	1.00
2020	88.80	87.50	63.60	76.90	8.95	63.30	2.0	1.00
2021	90.60	89.30	64.80	78.40	9.20	64.70	2.0	1.00
2022	92.40	91.10	66.10	80.00	9.40	66.00	2.0	1.00
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	2.0	1.00

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, 2007, were $6.40/Mcf for natural gas and $64.71/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.

	Forecast Prices and Costs	
Year ($ thousand)	Proved Reserves	Proved Plus Probable Reserves
2008	10,208	19,540
2009	65	3,850
2010	150	184
2011	62	62
2012	73	174
Thereafter	279	554
Total Undiscounted	10,837	24,364
Total Discounted at 10%	10,140	22,509

Notes:

(1) While we have reserves and production in the United States, the estimation of our future net revenue attributable to the US properties does not imply future development costs.

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

(3) 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.

(4) 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.

(5) 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.

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

(7) 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			ASSOCIATED AND NON-ASSOCIATED GAS		
FACTORS	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)
December 31, 2006	7,759	3,318	11,077	45,156	24,005	69,161
Extensions & Improved Recovery	232	187	419	299	1,914	2,213
Technical Revisions	433	(338)	95	4,865	(3,859)	1,006
Discoveries	419	112	531	4,223	1,427	5,650
Acquisitions	(1)	-	(1)	144	71	215
Dispositions	(4)	(2)	(6)	(148)	(47)	(195)
Economic Factors	-	-	-	-	-	-
Production	(978)	-	(978)	(10,698)	-	(10,698)
December 31, 2007	7,860	3,277	11,137	43,841	23,511	67,352

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

UNITED STATES

FACTORS	LIGHT AND MEDIUM OIL AND NATURAL GAS LIQUIDS Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	ASSOCIATED AND NON-ASSOCIATED GAS Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)
December 31, 2006	3,764	1,096	4,860	-	-	-
Extensions & Improved Recovery	-	-	-	-	-	-
Technical Revisions	(24)	(221)	(245)	-	-	-
Discoveries	187	93	280	-	-	-
Acquisitions	11	3	14	-	-	-
Dispositions	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-
Production	(363)	-	(363)	-	-	-
December 31, 2007	3,575	971	4,546	-	-	-

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

AGGREGATE

FACTORS	LIGHT AND MEDIUM OIL AND NATURAL GAS LIQUIDS Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	ASSOCIATED AND NON-ASSOCIATED GAS Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)
December 31, 2006	11,523	4,414	15,937	45,156	24,005	69,161
Extensions & Improved Recovery	232	187	419	299	1,914	2,213
Technical Revisions	409	(559)	(150)	4,865	(3,859)	1,006
Discoveries	606	205	811	4,223	1,427	5,650
Acquisitions	10	3	13	144	71	215
Dispositions	(4)	(2)	(6)	(148)	(47)	(195)
Economic Factors	-	-	-	-	-	-
Production	(1,341)	-	(1,341)	(10,698)	-	(10,698)
December 31, 2007	11,435	4,248	15,683	43,841	23,511	67,352

Additional Information Relating to Reserves Data

Undeveloped Reserves

Undeveloped reserves are those reserves expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable, possible) to which they are assigned. 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 locations 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 five percent of our proved and probable reserves.

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*" 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, 2007. 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, 2007.

Our major properties are concentrated within the following three core regions in Alberta, 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 located northwest of Edmonton in central Alberta and is comprised of three natural gas producing regions that provide us with a varied inventory of natural gas exploration and development opportunities. This core area currently delivers approximately 31 percent of our natural gas production and, with exploration success, can provide us the opportunity to grow our natural gas production volumes. In 2007, we spent $18.01 million of capital in the West Central Alberta core area, which represented 131 percent of the $13.70 million of property cash flow generated by this area. With these expenditures, we drilled 6.2 net wells in this core area that resulted in 4.2 net natural gas wells and 2.0 net dry holes.

Our 28 thousand net acres of undeveloped land in the Greater Highvale property is centered around the Paul First Nation land block located west of Edmonton. We own and operate natural gas production infrastructure in the area and have historically pursued seismically defined structural and stratigraphic prospects at medium depths. In 2007, we drilled 1.5 net natural gas wells and shot a 31 kilometre 2D seismic program in this area. Production for Greater Highvale averaged 2.95 million cubic feet per day of natural gas and six barrels per day of oil and liquids production in 2007. Although our total returns in the last few years for the Greater Highvale area have met expectations, the production tends to be unreliable as the wells are characterized by prolific rates that are unpredictably truncated by water influx. The variability of these production profiles is very challenging to manage within our partial distribution trust model and, consequently, we have elected to limit further capital expenditures in this area to maintenance and lease sustaining activities. In 2008, one net natural gas exploration well is planned for the Highvale area.

Over the last seven years, we have been pursuing the exploration and development of shallow under-pressured Scollard and Horseshoe Canyon natural gas sands in the Pembina area at depths up to 900 metres. We have an inventory of 54 thousand net acres of undeveloped land on this prospect. In 2007, we drilled 3.0 net natural gas wells in the Pembina area and the property provided 2.51 million cubic feet per day of natural gas and 130 barrels per day of oil and liquids production to our interest. A review of the long term results for the Pembina programs clearly demonstrates that this property has not provided a proper economic return for us. This is a disappointing observation as numerous gas bearing trends have been identified, but the related reserves and production rates have not been able to support the high costs for surface lease construction, fracture stimulations, pipelining and third party processing. Consequently, we are deferring further drilling at Pembina until a combination of improved natural gas prices, modified completion techniques and/or reduced costs are deemed to provide improved economic returns. In the meantime, we will continue with maintenance activities and selected tie-ins of 1.6 net wells that meet economic targets.

In the Peace River Arch exploration area, we are pursuing multi-zone gas exploration prospects at drilling depths ranging up to 2,100 metres. The Peace River Arch exploration strategy is more "grassroots" than in other areas as we develop prospects, post land, shoot seismic and drill high graded prospects. We have an 83 thousand net acre undeveloped land inventory that is generally characterized by year round surface access and mostly sweet natural gas multi-zone prospects. In 2007, we drilled 1.7 net wells in the Peace River Arch area that resulted in a 0.7 net natural gas well and 1.0 net abandonment. Production for the area averaged 3.48 million cubic feet per day of natural gas and 30 barrels per day of oil and liquids. During 2008, we are planning an active exploratory drilling program with 4.7 net wells scheduled in the first half of year at Progress South, Saddle Hills, Rycroft, Kakut, and Hamelin Creek. Success with this exploration program could lead to follow-up locations and an expanded budget in the second half of 2008. The target horizons include Bluesky, Gething, Charlie Lake, Montney, Doig and Debolt and have been identified by seismic and geological mapping. In the first half of the year, we will also proceed with the tie-in of 1.7 net natural gas wells that were drilled in prior years.

Alberta Plains

The Alberta Plains core area provides substantial cash flows that support trust distributions and also funds our reinvestment programs required to maintain stable production volumes and reserves. The area brings a large undeveloped land inventory and, as a result of our acquisition of Rival Energy Ltd., a substantial inventory of oil exploitation opportunities, which provides the feedstock for future gas exploration, gas development and oil exploitation programs. Our Alberta Plains area is located in the east central and south eastern regions of Alberta and is characterized by relatively shallow wells and all season surface access. This area delivered 69 percent of our total natural gas production in 2007. The Alberta Plains production volumes have been maintained at a relatively stable level since 2001 through exploration and development drilling programs on our land base. Typically, these capital programs have been funded from about 50 percent of the area's property cash flow. In 2007, the Alberta Plains area generated $34.87 million of property cash flow, of which $30.33 million or 87 percent of the property cash flow was reinvested in the area. With these expenditures, we increased the area's production volumes by five percent and maintained the area's proved and probable reserves. During 2007, the Alberta Plains capital programs provided proved and probable reserve additions at a cost of $23.80 per barrel of oil equivalent. With the early 2008 acquisition of Rival Energy Ltd., a significant oil exploitation and development opportunity at Bellshill Lake has been added to this area.

The Jarrow property continues to be our most significant producing natural gas property where we produced 16.08 million cubic feet of natural gas per day and 12 barrels of oil and liquids per day in 2007 primarily from the Mannville and Viking formations. This property is characterized by high working interests, ownership and operatorship of significant pipeline and gas processing facilities and a large inventory of prospects on a 108 thousand net acre undeveloped land inventory. At December 31, 2007, Jarrow undeveloped land inventory represented a 19 percent increase over the prior year. This increase is attributable to the freehold leasing program during the year as well as Crown acquisitions during a year of reduced industry competition for land. Reflecting the reduced competition for Crown land in the current business environment, we will look to expand our Jarrow undeveloped land inventory in 2008. During 2007, we drilled 16.1 net (19 gross) wells at Jarrow, resulting in 15.5 net natural gas wells and 0.6 net dry holes. We also shot 94 kilometres of two-dimensional ("**2D**") seismic as part of our ongoing exploration and development programs. In 2007, we focused on multi-well development programs in the Viking and Mannville reservoirs in addition to grassroots seismically based Manville exploration. In 2008, the emphasis will be focused on Mannville exploration, with the drilling of 19 net wells that are mostly located in the western and southern portions of the property.

The Hamilton Lake property produced 3.31 million cubic feet of natural gas per day and 88 barrels of oil and liquids per day in 2007 from the Mannville and Viking formations. The property's key asset is a 31 thousand net acre developed and undeveloped unit that has significant development potential in the lower permeability but extensive first Viking sand formation. The property also provides an additional 13 thousand net undeveloped acres of deeper Mannville rights. In 2007, we drilled 13.0 net (13 gross) wells at Hamilton Lake resulting in 13.0 net first Viking shallow natural gas wells. Although commercial, the returns on this Viking development program did not meet management expectations. Consequently, we are not planning any 2008 Viking development drilling at Hamilton Lake until a combination of improved natural gas prices, modified completion techniques and/or reduced costs are deemed to provide improved economic returns.

The Bellshill Lake oil property is located immediately south of Jarrow and was acquired as part of the acquisition of Rival Energy Ltd., which closed on January 23, 2008. This property will provide significant oil development drilling, exploitation drilling and production optimization opportunities from existing wells. In the fourth quarter of 2007, the Bellshill property produced approximately 549 barrels of oil and liquids per day and 0.18 million cubic feet of natural gas per day to our acquired interest. For 2008, we are planning on an eight net well drilling program along with multiple optimization and workover activities on existing wells.

Taber is a medium gravity oil property within the Alberta Plains area and is an emerging focus area for us. In 2007, this property produced 463 barrels of oil and liquids per day and 0.69 million cubic feet of natural gas per day. There were 3.0 net horizontal oil wells drilled in 2007. Building on encouraging results from 2007, we are planning two additional net horizontal wells in 2008 to further develop the potential of this area.

Williston Basin

The Williston Basin core area is characterized by a very stable oil production base that offers significant long term exploitation opportunities. The core area provides substantial cash flows that can be allocated to trust cash distributions or reinvested to provide production growth. The Williston Basin properties are located within relatively close proximity in southeast Saskatchewan, southwest Manitoba and in the northern counties of the State of North Dakota. The properties produce light and medium gravity oil from carbonate reservoirs at depths up to 1,500 metres. In 2007, the Williston Basin contributed about 80 percent of our oil and liquids production, 82 percent of our proved and probable oil and liquids reserves and provides a long proved and probable reserve life of 12.5 years. Our Williston Basin producing reservoirs are characterized by moderate permeability and a large remaining oil-in-place. By the nature of the physical characteristics of these reservoirs, the wells demonstrate relatively stable production with shallow annual production declines and, accordingly, long reserve life indices. Through exploitation projects, we attempt to find methods to increase oil recoveries from these reservoirs. Generally, we use a combination of exploitation techniques including pressure maintenance by water injection, 3D seismic and horizontal drilling to unlock additional oil reserves. Frequently, optimizing pressure support in the oil reservoir by water injection is the first step in the exploitation process. With pressure support established, we seek to characterize the reservoirs through 3D seismic analysis and interpretation, which is followed by horizontal wells designed to increase recoveries and accelerate production.

In 2007, we drilled 5.5 net horizontal wells and 3.1 net vertical wells in the Williston Basin, resulting in 8.6 net oil wells. We also shot a 12.5 kilometre 2D seismic program at Pinto, Saskatchewan. In addition to the exploitation and development drilling activities, the 2007 drilling program included 3.0 net vertical wells at Antler and Pinto that explored for Torquay and Midale targets.

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, 2007.

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Canada								
Alberta	175	102.5	55	23.7	371	253.9	152	115.0
Saskatchewan	317	212.9	40	29.9	-	-	-	-
Manitoba	57	56.7	10	10.0	-	-	-	-
United States								
North Dakota	91	89.0	7	6.9	-	-	-	-
Total	640	461.1	112	70.5	371	253.9	152	115.0

Properties with no Attributable Reserves

The following table sets out our developed and undeveloped land holdings as at December 31, 2007.

	Undeveloped Acres	
(thousand net acres)	Gross	Net
Alberta	348	293
Saskatchewan	65	61
Manitoba	2	2
United States	6	6
Total	421	362

With respect to our undeveloped land inventory and farm-in agreements, we have the following current work commitments:

- A commitment to two industry participants to drill one well in the Bellshill area of the Alberta Plains core area by June 30, 2008 at an estimated cost of $0.23 million.

- A commitment to an industry participant to drill one well in the Jarrow area of the Alberta Plains core area by August 31, 2008 at an estimated cost of $0.23 million.

We expect that rights to explore, develop and exploit 80,000 net acres of our undeveloped land holdings will expire by December 31, 2008.

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*" below.

For details of material commitments to sell natural gas and crude oil that were outstanding at December 31, 2007 see note 11 to the Financial Statements contained in our Annual Report, from which, pages are incorporated herein by reference.

Additional Information Concerning Abandonment and Reclamation Costs

As at December 31, 2007, we had 901 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 10% Undiscounted ($000s)**	**Abandonment and Reclamation Costs Escalated at 10% Discounted at 10% ($000s)**
Total liability as at December 31, 2007	44,292	9,931
Anticipated to be paid in 2008	80	76
Anticipated to be paid in 2009	334	290
Anticipated to be paid in 2010	753	593

We have estimated the net present value of our total asset retirement obligations to be $21.18 million as at December 31, 2007 based on a total future liability of $101.88 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 GAAP. The McDaniel Report deducted $44.29 million (undiscounted) and $9.93 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

We are a taxable entity under the *Income Tax Act* (Canada) and are taxable only on income that is not distributed or distributable to our Unitholders. We distribute all of our taxable income to our Unitholders and meet the requirements of the *Income Tax Act* (Canada) applicable to us.

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. Based on proposed changes announced by the federal government this may change. The effect of this new legislation is reflected in the after tax net revenue amounts disclosed in this Annual Information Form, other than the recently announced Provincial SIFT Tax Proposal. See "Zargon *Energy Trust – Federal Tax Changes for Income Trusts and Corporations*" and "*Risk to Our Revenues – Federal Tax Changes for Income Trusts and Corporations*".

We did not pay Canadian income taxes in 2007 and do not expect to pay income taxes until the earlier of January 1, 2011 or if and when we cease to be a trust. During 2007, we incurred current income taxes in the United States of $2.04 million. If high oil prices continue, there may be similar United States current income taxes payable annually that will be somewhat modified by our United States capital program activity levels.

Commencing in January 2011, (provided that we experience only "normal growth" and no "undue expansion" before then) we may be liable for tax at the federal "net corporate income tax rate" combined with the "provincial SIFT tax factor" (effectively, the federal general corporate tax rate plus 13 percent on account of provincial corporate tax or 10 percent based on the recently announced Provincial SIFT Tax Proposal) on all income payable to Unitholders, which we will not be able to deduct in computing its taxable income, as a result of being characterized as a SIFT trust. "*Risk Factors – Risks to Our Revenues – Federal Tax Changes for Income Trusts and Corporations*" and "*Risk Factors – Risks to Our Revenues – Changes in Legislation*".

Costs Incurred

The following tables summarize capital expenditures related to our activities for the year ended December 31, 2007:

($ million)	**Canada**	**United States**	**Total**
Property Acquisition Costs:			
Proved Properties [1]	1.85	0.01	1.86
Unproved Properties	7.47	0.02	7.49
Corporate Acquisitions	-	-	-
Development Costs [2]	35.43	3.08	38.51
Exploration Costs [3]	17.54	-	17.54
Total	62.29	3.11	65.40

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 2007 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, 2007:

Canada	**Exploratory Wells**		**Development Wells**	
	Gross	**Net**	**Gross**	**Net**
Oil	2.0	2.0	10.0	7.6
Natural Gas	16.0	13.7	20.0	19.0
Service	-	-	-	-
Dry	2.0	2.0	1.0	0.6
Total	20.0	17.7	31.0	27.2

United States	**Exploratory Wells**		**Development Wells**	
	Gross	**Net**	**Gross**	**Net**
Oil	-	-	2.0	2.0
Natural Gas	-	-	-	-
Service	-	-	-	-
Dry	-	-	-	-
Total	-	-	2.0	2.0

In 2008, we are budgeted to invest approximately $50 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 include the following:

- Development work with an exploration component seeking to maintain current production levels of natural gas in our Alberta Plains core area and oil exploitation of the newly acquired Bellshill properties.

- Exploitation of many of our Williston Basin properties with improved recovery techniques and reservoir re-pressurization by water injection followed in due course by geologically–driven development drilling based on 3D seismic programs.

- Exploration for natural gas in West Central Alberta, primarily in the Peace River Arch area.

Production Estimates

The following table sets out the volume of our gross production estimated in the McDaniel Report for the year ended December 31, 2008, 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	3,771	29.62	40	8,748
Total Probable	193	2.70	3	645
Total Proved Plus Probable	3,964	32.32	43	9,394

The Jarrow property in Alberta Plains accounts for 32 percent of the gross production volume estimated in the above table and is the only property that accounts for 20 percent or more of the estimated production disclosed above.

Production History and Prices Received

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

CANADA

	Quarter Ended			
	2007			
	Dec. 31	**Sept. 30**	**June 30**	**Mar. 31**
Average Daily Production:				
Gas (Mcf/d)	30,740	29,480	28,550	28,440
Light and Medium Crude Oil (bbl/d)(2)	2,721	2,650	2,701	2,716
Combined (boe/d)	7,845	7,563	7,459	7,457
Average Price Received: (1)				
Gas ($/Mcf)	6.44	5.72	7.24	7.97
Light and Medium Crude Oil ($/bbl)(2)	67.70	68.70	65.32	62.28
Combined ($/boe)	49.08	46.38	51.34	53.08
Royalties Paid:				
Gas ($/Mcf)	1.23	1.05	1.47	1.65
Light and Medium Crude Oil ($/bbl)(2)	12.93	13.45	12.44	11.80
Combined ($/boe)	9.30	8.79	10.34	10.35
Production Costs:				
Gas ($/Mcf)	1.31	1.35	1.22	1.35
Light and Medium Crude Oil ($/bbl)(2)	17.27	17.38	15.66	15.60
Combined ($/boe)	11.12	11.35	10.35	10.83
Netback Received: (3)				
Gas ($/Mcf)	3.90	3.32	4.55	4.97
Light and Medium Crude Oil ($/bbl)(2)	37.50	37.87	37.22	34.88
Combined ($/boe)	28.66	26.24	30.65	31.90

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			
	2007			
	Dec. 31	**Sept. 30**	**June 30**	**Mar. 31**
Average Daily Production:				
Gas (Mcf/d)	-	-	-	-
Light and Medium Crude Oil (bbl/d)	945	938	1,006	1,026
Combined (boe/d)	945	938	1,006	1,026
Average Price Received: (1)				
Gas ($/Mcf)	-	-	-	-
Light and Medium Crude Oil ($/bbl)	62.24	63.36	59.90	56.66
Combined ($/boe)	62.24	63.36	59.90	56.66
Royalties Paid:				
Gas ($/Mcf)	-	-	-	-
Light and Medium Crude Oil ($/bbl)	17.47	17.42	16.26	14.91
Combined ($/boe)	17.47	17.42	16.26	14.91
Production Costs:				
Gas ($/Mcf)	-	-	-	-
Light and Medium Crude Oil ($/bbl)	5.54	7.61	7.18	6.61
Combined ($/boe)	5.54	7.61	7.18	6.61
Netback Received: (2)				
Gas ($/Mcf)	-	-	-	-
Light and Medium Crude Oil ($/bbl)	39.23	38.33	36.46	35.14
Combined ($/boe)	39.23	38.33	36.46	35.14

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 2007			
	Dec. 31	**Sept. 30**	**June 30**	**Mar. 31**
Average Daily Production:				
Gas (Mcf/d)	30,740	29,480	28,550	28,440
Light and Medium Crude Oil (bbl/d)(2)	3,666	3,588	3,707	3,742
Combined (boe/d)	8,790	8,501	8,465	8,483
Average Price Received: (1)				
Gas ($/Mcf)	6.44	5.72	7.24	7.97
Light and Medium Crude Oil ($/bbl)(2)	66.30	67.31	63.84	60.74
Combined ($/boe)	56.58	54.24	59.42	53.51
Royalties Paid:				
Gas ($/Mcf)	1.23	1.05	1.47	1.65
Light and Medium Crude Oil ($/bbl)(2)	14.18	14.47	14.00	12.22
Combined ($/boe)	10.21	9.76	11.08	10.91
Production Costs:				
Gas ($/Mcf)	1.31	1.35	1.22	1.35
Light and Medium Crude Oil ($/bbl)(2)	14.25	14.83	13.36	13.14
Combined ($/boe)	10.51	10.95	9.97	10.32
Netback Received: (3)				
Gas ($/Mcf)	3.90	3.32	4.55	4.97
Light and Medium Crude Oil ($/bbl)(2)	37.87	38.01	36.48	35.38
Combined ($/boe)	35.86	33.53	38.37	32.28

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, 2007:

	Natural Gas (Mcf/d)	**Light and Medium Crude Oil (bbl/d)**	**NGLs (bbl/d)**	**BOE (boe/d)**
West Central Alberta	8,939	138	28	1,656
Alberta Plains	20,092	547	16	3,911
Williston Basin	283	2,947	-	2,993
Total	29,314	3,632	44	8,560

Marketing Arrangements

Natural Gas

We continue to maintain a risk-mitigating strategy by cultivating a diverse natural gas sales portfolio, which encompasses a variety of pricing mechanisms and term commitments. In 2007, approximately 21 percent of our natural gas production was sold under aggregator contracts pursuant to long-term contracts with Cargill Gas Marketing Ltd. (Jarrow – 14 percent) and ProGas Limited (Hamilton Lake – seven percent). The remainder of our natural gas production was sold by spot sale contracts and Alberta Index prices were received. Our risk management objectives include protecting or securing minimum prices for between 20 to 35 percent of working interest production for terms not exceeding 18 months. Our risk management methodology includes employing collars, floors or fixed price contracts. In order to control and manage credit risk and ensure competitive bids, we engage a number of reputable counterparties for our natural gas transactions. The integration and application of these strategies resulted in an average realized price (after realized risk management gains/losses) of $6.82 Cdn per Mcf in 2007 compared to $7.21 Cdn per Mcf in 2006.

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 2007, our average realized oil and liquids price (after realized risk management gains/losses) was $64.53 Cdn per bbl compared to $58.05 Cdn per bbl in 2006. Consistent with our natural gas strategy, our risk management objectives include protecting or securing minimum prices for between 20 to 35 percent of our working interest production for terms not exceeding 18 months. Our crude oil risk management strategy employs the use of costless collars and fixed pricing.

Acquisitions and Dispositions

During 2007, we completed five property transactions including the acquisition and disposition of oil and natural gas properties. In aggregate, we made $1.86 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 defense in the event of an environmental incident.

Our management also monitors developments related to the Kyoto Protocol and other environmental laws and regulations.

SHARE CAPITAL OF ZARGON OIL & GAS LTD.

Common Shares

Zargon Oil & Gas Ltd. 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 Ltd., except in conjunction with an internal reorganization of the direct or indirect assets of Zargon Oil & Gas Ltd. as a result of which either Zargon Oil & Gas Ltd. 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 Ltd. with any other corporation or any amalgamation, merger or other transaction, as the case may be, of Zargon Oil & Gas Ltd. 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 Ltd., except in conjunction with an internal reorganization as referred to in paragraph (i) above; (iv) any amendment to the articles of Zargon Oil & Gas Ltd. to increase or decrease the minimum or maximum number of directors; or (v) any material amendment to the articles of Zargon Oil & Gas Ltd. to change the authorized share capital or amend the rights, privileges, restrictions and conditions attaching to any class of Zargon Oil & Gas Ltd.'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 Ltd. 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 Ltd. upon the liquidation, dissolution, bankruptcy or winding-up of Zargon Oil & Gas Ltd. 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 Ltd. is authorized to issue an unlimited number of Exchangeable Shares of which, as of December 31, 2007, 2,070,952 were outstanding. The Exchangeable Shares rank prior to the common shares of Zargon Oil & Gas Ltd. 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 Ltd. 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, 2007, the Exchange Ratio was 1.29611 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 Ltd., 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 Ltd. and prior to any common shares of Zargon Oil & Gas Ltd. 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 Ltd.

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 Ltd. 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 Ltd. 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 Ltd. or any other shares ranking junior to the Exchangeable Shares;

(c) redeem or purchase any other shares of Zargon Oil & Gas Ltd. 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 Ltd.

In the event of the liquidation, dissolution or winding-up of Zargon Oil & Gas Ltd. or any other proposed distribution of the assets of Zargon Oil & Gas Ltd. 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 Ltd., 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 Ltd. 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 Ltd. 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 Ltd. or the transfer agent receives the retraction notice.

When a holder requests Zargon Oil & Gas Ltd. 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 Ltd. 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 Ltd. will immediately notify us and ExchangeCo. We or ExchangeCo must then advise Zargon Oil & Gas Ltd. 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 Ltd. If the holder does not revoke his or her Retraction Request, the Exchangeable Shares that the holder has requested Zargon Oil & Gas Ltd. to redeem will, on the Retraction Date, be purchased by us or ExchangeCo or redeemed by Zargon Oil & Gas Ltd., 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 Ltd. is not permitted to redeem all Exchangeable Shares tendered by a retracting holder, Zargon Oil & Gas Ltd. 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 Ltd. 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 Ltd.:

(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 redeem up to that number of Exchangeable Shares equal to 20 percent of the Exchangeable Shares outstanding on the Effective Date 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 Ltd. 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 Ltd.

We and ExchangeCo have the right (the "**Redemption Call Right**"), notwithstanding a proposed redemption of the Exchangeable Shares by Zargon Oil & Gas Ltd. on the applicable Redemption Date, pursuant to the terms of the Exchangeable Share, 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 exercises the Redemption Call Right, then Zargon Oil & Gas Ltd.'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 Ltd. 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 Ltd. 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 Exchangeable Trust Agreement

The support agreement and the voting and exchange 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 Ltd. presently administers us on behalf of the Trustee. Zargon Oil & Gas Ltd., 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 Ltd. 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 Ltd. may determine.

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 Ltd. 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 Ltd. 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 ("**non-residents**"). 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. 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 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: an amount equal to the closing price of the Trust Units if there was a trade on the date; 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 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 Ltd. 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 Ltd. 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 Ltd. 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 Ltd. at all meetings in respect of matters, relating to the election of the directors of Zargon Oil & Gas Ltd., approving our financial statements and appointing auditors of Zargon Oil & Gas Ltd. who shall be the same as our auditors. Prior to us voting our common shares in Zargon Oil & Gas Ltd., 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 Ltd. 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 Ltd. and our other direct or indirect subsidiaries and partnership 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 Ltd. 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 the Information Circular which has been 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.

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 Ltd. 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 Ltd.
K. James Harrison Oakville, Ontario	1995	President – K. J. Harrison & Partners Inc., a private client investment management firm in Toronto, Ontario Chairman of the Zargon Board
Kyle D. Kitagawa (1) (4) Calgary, Alberta	2001	Managing Director, North River Capital Corp., a private corporation
James J. Lawson (2) (3) Oakville, Ontario	2005	President and CEO, Westerkirk Capital Inc., an investment management firm
John O. McCutcheon (3) Vancouver, British Columbia	1987	Independent Businessman
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) and Spur Resources Ltd. (a private oil and natural gas exploration and development company)
Jim Peplinski (2) (4) Calgary, Alberta	1997	Executive Chairman, Humberview Group of Companies which owns Jim Peplinski's Leasemaster, nine automotive dealerships in Toronto and various real estate investments. He is also the VP Business Development, Calgary Flames Hockey Club as well as an investor and director of Wrangler West Energy Corp., a public oil and gas company
J. Graham Weir (1) (4) Calgary, Alberta	2004	Independent Businessman
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 Ltd. 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
Daniel A. Roulston Calgary, Alberta	Executive Vice President, Operations
Henry J. Baird Calgary, Alberta	Vice President, Exploitation
Jason B. Dranchuk Calgary, Alberta	Controller and Treasurer
Tracy L. Howard Calgary, Alberta	Corporate Secretary
Brian G. Kergan Calgary, Alberta	Vice President, Corporate Development and Reserves
Mark I. Lake Calgary, Alberta	Vice President, Exploration
Lorne D. Schwetz Calgary, Alberta	Vice President, Land

As at March 19, 2008, the directors and officers of Zargon Oil & Gas Ltd., as a group, beneficially owned, controlled or directed, directly or indirectly, 832,707 Trust Units or approximately 4.7 percent of the issued and outstanding Trust Units and 919,070 Exchangeable Shares or approximately 44.6 percent of the issued and outstanding Exchangeable Shares resulting in an approximate total ownership of 10.1 percent.

Corporate Cease Trade Orders, Bankruptcies or Penalties or Sanctions

No director or executive officer of Zargon Oil & Gas Ltd. (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 Ltd.), 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 Ltd. (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 Ltd.) 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 Ltd. (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 Ltd. (nor any personal holding company of any of such persons), or shareholder holding a sufficient number of our securities of Zargon 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 Ltd. No assurances can be given that opportunities identified by such board members will be provided to us or Zargon Oil & Gas Ltd.

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 Ltd. 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 is the Managing Director, North River Capital Corp., a private corporation. Mr. Kitagawa brings over 20 years experience in commodity trading, equity investing, and structured finance in both energy and energy intensive industries. Prior to April 2003, he held senior executive positions in a global energy trading and capital corporation. Mr. Kitagawa also serves on the boards of Ferus Trust and ProspEx Resources Ltd. He is currently the Chairman of Canadian Energy Services L.P., Livingston Energy Ltd. and Wave Energy Ltd. 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 is 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).
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 serves as a director of several public and private companies including: Flagstone Energy Inc., Graymont Limited, Grupo Calidra, S.A. de C.V., Pulse Data Inc. and Wave Energy Ltd. 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 $168,365 in 2007 and $150,525 in 2006.

Audit Related 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 $12,655 in 2007 and $11,150 in 2006. The increase in fees in this area was primarily due to inflation.

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 $185,327 in 2007 and $197,205 in 2006. The primary reason for the decrease was due to the timing of the tax work.

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 $17,840 in 2007 and $nil in 2006. The increase in fees in this area was primarily due to increased non-audit work regarding regulatory filings for a recent corporate acquisition.

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 Canadian income tax purposes, cash distributions paid to Unitholders in 2005, 2006 and 2007 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 2007 and 2008 up to March 19, 2008.

Period	High	Low	Volume
2007			
January	25.54	23.80	1,035,257
February	26.73	25.00	692,235
March	26.48	24.12	581,516
April	28.12	25.67	657,997
May	31.24	27.10	378,968
June	28.69	27.10	557,406
July	28.74	26.50	371,080
August	27.98	24.36	181,377
September	28.60	26.60	426,373
October	27.74	25.25	491,086
November	27.49	22.48	539,437
December	23.25	21.35	1,026,874
2008			
January	23.19	19.51	1,137,026
February	25.75	21.65	1,011,594
March (1 to 19)	23.40	21.00	922,393

The following sets forth trading information for Exchangeable Shares in 2007 and 2008 up to March 19, 2008.

Period	High	Low	Volume
2007			
January	29.75	28.78	2,886
February	31.35	30.98	5,116
March	31.00	31.00	100
April	33.91	33.00	3,800
may	36.25	34.59	2,400
June	34.99	34.25	1,400
July	35.58	34.01	1,800
August	34.00	31.70	700
September.......................	34.50	34.00	21,378
October...........................	34.01	33.50	21,512
November.......................	29.58	29.58	500
December	29.58	28.01	6,600
2008			
January	29.50	27.00	11,000
February	33.00	29.35	4,700
March (1 to 19)	-	-	-

INDUSTRY CONDITIONS

General

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

Pricing and Marketing – Oil and Natural Gas

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

The price of natural gas is determined by negotiation between buyers and sellers. Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet certain other criteria prescribed by the NEB and the Government of Canada. Natural gas exports for a term of less than 2 years or for a term of 2 to 20 years (in quantities of not more than 30,000 m^3/day) must be made pursuant to an NEB order. Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 25 years) or a larger quantity requires an exporter to obtain an export licence from the NEB and the issuance of such licence requires the approval of the Governor in Council.

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

Pipeline Capacity

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

The North American Free Trade Agreement

The North American Free Trade Agreement ("**NAFTA**"), among the governments of Canada, United States of America and Mexico, became effective on January 1, 1994. NAFTA carries forward most of the material energy terms that are contained in the Canada United States Free Trade Agreement. In the context of energy resources, Canada continues to remain free to determine whether exports of energy resources to the United States or Mexico will be allowed, provided that any export restrictions do not: (i) reduce the proportion of energy resources exported relative to domestic use (based upon the proportion prevailing in the most recent 36 month period); (ii) impose an export price higher than the domestic price subject to an exception with respect to certain voluntary measures, which only restrict the volume of exports; and (iii) disrupt normal channels of supply. All three countries are prohibited from imposing minimum or maximum export or import price requirements, provided, in the case of export price requirements, prohibition in any circumstances in which any other form of quantitative restriction is prohibited, and in the case of import price requirements, such requirements do not apply with respect to enforcement of countervailing and anti-dumping orders and undertakings.

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

Provincial Royalties and Incentives

General

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

Occasionally the governments of the western Canadian provinces create incentive programs for exploration and development. Such programs often provide for royalty rate reductions, royalty holidays, and tax credits, and are generally introduced when commodity prices are low. The programs are designed to encourage exploration and development activity by improving earnings and cash flow within the industry. Royalty holidays and reductions would reduce the amount of Crown royalties paid by oil and gas producers to the provincial governments and would increase the net income and funds from operations of such producers. However, the trend in recent years has been for provincial governments to eliminate, amend or allow such incentive programs to expire without renewal, and consequently few such incentive programs are currently operative.

The Canadian federal corporate income tax rate levied on taxable income is 22.1 percent effective January 1, 2007 for active business income including resource income. With the elimination of the corporate surtax effective January 1, 2008 and other rate reductions introduced in the October 2007 Economic Statement and Notice of Ways and Means Motion, 2006 Federal Budget, the federal corporate income tax rate will decrease to 19 percent in three steps: 20.5 percent on January 1, 2008, 20 percent on January 1, 2009 and 19 percent on January 1, 2010.

Alberta

In Alberta, companies are granted the right to explore, produce and develop petroleum and natural gas resources in exchange for royalties, bonus bid payments and rents. Currently, the amount of royalties that are payable is influenced by the oil production, density of the oil, and the vintage of the oil. Originally, the vintage classified oil as "new oil" and "old oil" depending on when the oil pools were discovered. If the pool was discovered prior to March 31, 1974 it is considered "old oil", if it was discovered after March 31, 1974 and before September 1, 1992, it is considered "new oil". The Alberta government introduced in 1992 a Third Tier Royalty with a base rate of 10% and a rate cap of 25% for oil pools discovered after September 1, 1992. The new oil royalty reserved to the Crown has a base rate of 10% and a rate cap of 30%. The old oil royalty reserved to the Crown has a base rate of 10% and a rate cap of 35%.

The royalty reserved to the Crown in respect of natural gas production, subject to various incentives, is between 15% and 30%, in the case of new natural gas, and between 15% and 35%, in the case of old natural gas, depending upon a prescribed or corporate average reference price. Natural gas produced from qualifying intervals in eligible gas wells spudded or deepened to a depth below 2,500 metres is also subject to a royalty exemption, the amount of which depends on the depth of the well.

Oil sands projects are subject to a specific regulation made effective July 1, 1997, and expiring June 30, 2009, which, among other things, determines the Crown's share of crude and processed oil sands products.

Regulations made pursuant to the *Mines and Minerals Act* (Alberta) provided various incentives for exploring and developing oil reserves in Alberta. However, the Alberta Government announced in August of 2006 that four royalty programs were to be amended, a new program was to be introduced and the Alberta Royalty Tax Credit Program ("**ARTC**") was to be eliminated, effective January 1, 2007. The programs affected by this announcement are: (i) Deep Gas Royalty Holiday; (ii) Low Productivity Well Royalty Reduction; (iii) Reactivated Well Royalty Exemption; and (iv) Horizontal Re-Entry Royalty Reduction. The program being introduced is the Innovative Energy Technologies Program (the "**IETP**") which is intended to promote the producers' investment in research, technology and innovation for the purposes of improving environmental performance while creating commercial value. The IETP provides royalty reductions which are presumed to reduce financial risk. Alberta Energy will be the one to decide which projects qualify and the level of support that will be provided. The deadline for the IETP's third round of applications was May 31, 2007. The successful applicants have not yet been announced and it appears, based on the previous two rounds, that the selection process can take at least 8 months.**]** The technical information gathered from this program is to be made public once a two-year confidentiality period expires.

On October 25, 2007, the Alberta government released a report entitled "The New Royalty Framework" containing the government's proposals for Alberta's new royalty regime that is scheduled to be effective on January 1, 2009. The proposed NRF includes new royalty formulas for conventional oil and natural gas that will operate on sliding scales that are determined by commodity prices and well productivity; in addition to the policy of "shallow rights reversion". The Alberta government is intending to implement this policy in order to maximize the development of currently undeveloped resources which is consistent with the government's objective of maximizing recovery of known gas resources, while increasing royalty revenues. The policy's objective is for the mineral rights to shallow gas geological formations that are not being developed to revert back to the government and be made available for resale. It appears that leaseholders will get a grace period before the shallower zones are reverted to the Crown, which is still to be determined. Substantial legislative, regulatory and systems updates will be introduced before changes become fully effective in January 2009. See "*Risk Factors – Risks to Our Reserves – New Alberta Royalty Regime*".

Saskatchewan

The amount payable as a royalty in respect of natural gas is determined by a sliding scale based on a reference price (which is the greater of the amount obtained by the producer and a prescribed minimum price), the quantity produced in a given month, the type of natural gas, and the vintage of the natural gas. As an incentive for the production and marketing of natural gas which may have been flared, the royalty rate on natural gas produced in association with oil is less than on non-associated natural gas. The royalty and production tax classifications of gas production are "fourth tier gas" introduced October 1, 2002, "third tier gas", "new gas", and "old gas". The Crown royalty and freehold production tax for gas is price sensitive and varies between the base royalty rate of 5 percent for "fourth tier gas" and 20 percent for "old gas". The marginal royalty rates are between 30 percent for "fourth tier gas" and 45 percent for "old gas".

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

- A new Crown royalty and freehold production tax regime applicable to associated natural gas (gas produced from oil wells) that is gathered for use or sale. The royalty/tax will be payable on associated natural gas produced from an oil well that exceeds approximately 65 thousand cubic metres in a month.

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

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

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

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

Land Tenure

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

Environmental Regulation

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

Environmental legislation in the Province of Alberta has been consolidated into the *Environmental Protection and Enhancement Act* (Alberta) (the "**EPEA**"), which came into force on September 1, 1993, and the *Oil and Gas Conservation Act* (Alberta) (the "**OGCA**"). The EPEA and OGCA impose stricter environmental standards, require more stringent compliance, reporting and monitoring obligations, and significantly increased penalties. In 2006, the Alberta Government enacted regulations pursuant to the EPEA to specifically target sulphur oxide and nitrous oxide emissions from industrial operations including the oil and gas industry. In addition, the reduction emission guidelines outlined in the *Climate Change and Emissions Management Amendment Act* came into effect on July 1, 2007. Under this legislation, Alberta facilities emitting more than 100,000 tonnes of greenhouse gases a year must reduce their emissions intensity by 12%. Industries have three options to choose from in order to meet the reduction requirements outlined in this legislation, and these are: (i) by making improvement to operations that result in reductions; (ii) by purchasing emission credits from other sectors or facilities that have emissions below the 100,000 tonne threshold and are voluntarily reducing their emission; or (iii) by contributing to the Climate Change and Emissions Management Fund. Industries can either choose one of these options or a combination thereof. We are committed to meeting our responsibilities to protect the environment wherever we operate and anticipate making increased expenditures of both a capital and an expense nature as a result of the increasingly stringent laws relating to the protection of the environment, and will take such steps as required to ensure compliance with the EPEA and similar legislation in other jurisdictions in which we operates. We believe that we are in material compliance with applicable environmental laws and regulations. We also believe that it is reasonably likely that the trend towards stricter standards in environmental legislation and regulation will continue.

In January 24, 2008, the Alberta Government announced a new climate change action plan that will cut Alberta's projected 400 million tonnes of emissions in half by 2050. This plan is based on three areas: (i) carbon capture and storage, which will be mandatory for *in situ* oil sand facilities that use heavy fuels for steam generation; (ii) energy conservation and efficiency; and (iii) greening production through increased investment in clean energy technology, including supporting research on new oil sands extraction processes, as well as the funding of projects that reduce the cost of separating CO_2 from other emissions supporting carbon capture and storage.

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

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

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

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

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

Four separate compliance mechanisms are provided in respect of the above targets: Technology Fund contributions, offset credits, clean development credits and credits for early action. The most significant of these compliance mechanisms, at least initially, will be the Technology Fund and for which regulated entities will be able to contribute in order to comply with emissions intensity reductions. The contribution rate will increase over time, beginning at $15 per tonne for the 2010-12 period, rising to $20 per tonne in 2013, and thereafter increasing at the nominal rate of GDP growth. Contribution limits will correspondingly decline from 70% in 2010 to 0% in 2018. Monies raised through contributions to the Technology Fund will be used to invest in technology to reduce greenhouse gas emissions. Alternatively, regulated entities may be able to receive credits for investing in large-scale and transformative projects at the same contribution rate and under similar requirements as mentioned above.

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

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

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

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

Trends

There are a number of trends that have been developing in the oil and gas industry during the past several years that appear to be shaping the near future of the business.

The first trend is the volatility of commodity prices. Natural gas is a commodity influenced by factors within North America. A tight supply-demand balance for natural gas causes significant elasticity in pricing, whereas higher than average storage levels tend to depress natural gas pricing. Drilling activity, weather, fuel switching and demand for electrical generation are all factors that affect the supply-demand balance. Changes to any of these or other factors create price volatility. Crude oil is influenced by the world economy, Organization of the Petroleum Exporting Countries' ability to adjust supply to world demand and weather. Crude oil prices have been kept high by political events causing disruptions in the supply of oil and concern over potential supply disruptions triggered by unrest in the Middle East and more recently have been impacted by weather and increased storage levels. Political events trigger large fluctuations in price levels.

The impact on the oil and gas industry from commodity price volatility is significant. During periods of high prices, producers generate sufficient cash flows to conduct active exploration programs without external capital. Increased commodity prices frequently translate into very busy periods for service suppliers triggering premium costs for their services. Purchasing land and properties similarly increase in price during these periods. During low commodity price periods, acquisition costs drop, as do internally generated funds to spend on exploration and development activities. With decreased demand, the prices charged by the various service suppliers also decline.

A second trend within the Canadian oil and gas industry is the fairly consistent "renewal" of private and small junior oil and gas companies starting up business. These companies often have experienced management teams from previous industry organizations that have disappeared as a part of the ongoing industry consolidation. Many are able to raise capital and recruit well qualified personnel. We will have to compete with these companies and others to attract qualified personnel.

RISK FACTORS

The following is a summary of certain risk factors relating to us which prospective investors should carefully consider before deciding whether to purchase Trust Units or Exchangeable Shares.

Risks to Our Revenues

Volatility of Oil and Natural Gas Prices

The operational results and financial condition of our operating entities and therefore the amounts paid to us, will be dependent on the prices received for oil and natural gas production. Oil and natural gas prices have fluctuated widely during recent years and are determined by economic 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, the actions of the Organization of Petroleum Exporting Countries, governmental regulation, political stability in the Middle East and elsewhere, the foreign supply of oil and 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 gas would have an adverse effect on the carrying value of our proved and probable reserves, borrowing capacity, revenues, profitability and funds flow from operations. Any movement in oil and natural gas prices could have an effect on our financial condition and therefore on the amounts to be distributed to our Unitholders. 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 will forego the benefits we would otherwise experience if commodity prices were to increase. In addition, commodity hedging activities could expose us to losses. As at December 31, 2007, our income statement reflected $16.80 million of unrealized commodity losses resulting from hedges to protect our commodity risk exposure. To the extent that we engage in risk management activities related to commodity prices, we will be subject to credit risks associated with counterparties with which we contract.

Volatile oil and gas prices make it difficult to estimate the value of producing properties for acquisition and often cause disruption in the market for oil and gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for and project the return on acquisitions and development and exploitation projects. See "*Risk Factors – Risks Associated with Acquisitions and Expansions – Purchase of Properties*" and "*Risk Factors – Operational Risks – Project Risks*".

Variations in Interest Rates and Foreign Exchange Rates

An increase in interest rates could result in a significant increase in the amount we pay to service debt, resulting in a decrease in distributions to Unitholders, as well as impact the market price of the Trust Units.

World oil prices are quoted in Unites 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 may negatively impact our net production revenue.

In addition, the exchange rate for the Canadian dollar versus the U.S. dollar has increased significantly over the last 12 months, resulting in our receipt of fewer Canadian dollars for our production which may affect future distributions. To the extent that we engage in risk management activities related to foreign exchange rates, we will be subject to credit risk associated with counterparties with which we contract. 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 our independent evaluator.

Federal Tax Changes for Income Trusts and Corporations

New 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. 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 cash distributions from the Trust.

Generally, there will be a four year transition period for an existing trust, such as us, and the tax under the new legislation will not apply until January 1, 2011. However, the new legislation provides that there are circumstances under which an existing trust may lose its transitional relief before 2011, including where the "normal growth" of a trust existing on October

31, 2006 is exceeded. "Normal growth" includes equity growth within certain "safe harbour" limits, measured by reference to a SIFT trust's market capitalization as of the end of trading on October 31, 2006 (which would include only the market value of the SIFT's issued and outstanding publicly-traded trust units, and not any convertible debt, options or other interests convertible into or exchangeable for trust units). Those safe harbour limits are 40 percent for the period from November 1, 2006 to December 31, 2007, and 20 percent each for calendar 2008, 2009 and 2010. Moreover, these limits are cumulative, so that any unused limit for a period carries over into the subsequent period. The growth limits for us are approximately $220.47 million for 2007 and an additional approximately $110.24 million for each of 2008, 2009 and 2010 with any unused amount rolling forward to the next year.

While the normal growth restrictions are such that it is unlikely they would affect our ability to raise the capital required to maintain and grow our existing operations in the ordinary course during the transition period, they could adversely affect the cost of raising capital and our ability to undertake more significant acquisitions. The SIFT tax has reduced the value of the Trust Units, which has increased the cost to us of raising capital in the public capital markets. In addition management of Zargon Oil & Gas Ltd. believes that the SIFT tax: (a) substantially eliminates the competitive advantage that we and other Canadian energy trusts enjoyed relative to our corporate peers in raising capital in a tax-efficient manner, and (b) places the Trust and other Canadian energy trusts at a competitive disadvantage relative to industry competitors, including U.S. master limited partnerships, which will continue to not be subject to entity level taxation. The new legislation also makes 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 affects us and Unitholders. See "*Risk Factors – Risks Associated with Government Regulation – Changes in Legislation*".

New Alberta Royalty Regime

On October 25, 2007, the Alberta government released a report entitled "The New Royalty Framework" containing the government's proposals for Alberta's new royalty regime which is scheduled to be effective on January 1, 2009. Given that the NRF has only recently been announced, it is not possible at this time to determine the full impact of the NRF on our financial condition and operations and in particular the extent to which the NRF will reduce our cash flow, which will in turn reduce the cash otherwise available for distribution by us to our Unitholders.

The NRF includes the following features:

- New, simplified royalty formulas for conventional oil and natural gas that will operate on sliding scales that are determined by commodity prices and well productivity. The formulas eliminate the need for conventional oil and natural gas tiers and several royalty exemption programs.

- A sliding scale will be implemented for oil sands royalty rates ranging from one to nine percent pre-payout and 25 to 40 percent post-payout depending on the price of oil.

- The province will exercise its existing right to receive "royalty-in-kind" on oil sands projects (i.e. raw bitumen delivered to the Crown-operated Alberta Petroleum Marketing Commission in lieu of cash royalties).

- The government will ensure that eligible expenditures and definitions of oil sands projects (also known as "ring fence" definition) that determine when a project has reached payout are tightly and clearly defined. Environmental "costs of doing business" will continue to be recognized as eligible expenditures.

- No grandfathering will be implemented for existing oil sands projects.

- Substantial legislative, regulatory and systems updates will be introduced before changes become fully effective in January 2009.

We cannot provide any assurance that the NRF will be implemented in the form proposed. If changes are made to the NRF before it is implemented by the Alberta government, such changes could result in the implementation of a new royalty regime that impacts us in a materially different manner, and that is more adverse to us, than the NRF as currently proposed. See "*Risk Factors – Risks Associates with Government Regulation – Changes in Legislation*".

Market Risk Management Activities

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

Marketing

The marketability and price 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.

Geo-Political Risks

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

In addition, our oil and natural gas properties, wells and facilities could be subject to a terrorist attack. If any of our properties, wells or facilities are the subject of terrorist attack it could have a material adverse effect on our financial condition. We do not have insurance to protect against the risk from terrorism.

Third Party Credit Risk

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

Delay in Cash Receipts

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.

Operational Risks

Exploration, Development and Production Risks

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. Our long-term commercial success depends on our ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, any existing reserves we may have at any particular time, and the production therefrom will decline over time as such existing reserves are exploited. A future increase in our reserves will depend not only on our ability to explore and develop any properties we may have from time to time, but also on our ability to select and acquire suitable producing properties or prospects. No assurance can be given that we will be able to continue to locate satisfactory properties for acquisition or participation. Moreover, if such acquisitions or participations are identified, our management may determine that current markets, terms of acquisition and participation or pricing conditions make such acquisitions or participations uneconomic. There is no assurance that further commercial quantities of oil and natural gas will be discovered or acquired by us.

Future oil and natural gas exploration may involve unprofitable efforts, not only from dry wells, but also from wells that are productive but do not produce sufficient petroleum substances to return a profit after drilling, operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs. In addition, drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. While diligent well supervision and effective maintenance operations can contribute to maximizing production rates over time, production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow levels to varying degrees.

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including hazards such as fire, explosion, blowouts, cratering, sour gas releases and spills, each of which could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment or personal injury. In particular, we may explore for and produce sour natural gas in certain areas. An unintentional leak of sour natural gas could result in personal injury, loss of life or damage to property and may necessitate an evacuation of populated areas, all of which could result in liability. In accordance with industry practice, we are not fully insured against all of these risks, nor are all such risks insurable. Although we maintain liability insurance in an amount that we consider consistent with industry practice, the nature of these risks is such that liabilities could exceed policy limits, in which event we could incur significant costs that could have a material adverse effect upon our financial condition. Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including encountering unexpected formations or pressures, premature decline of reservoirs and the invasion of water into producing formations. Losses resulting from the occurrence of any of these risks could have a material adverse effect on 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.

Operating Costs and Production Declines

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.

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 distributions to Unitholders.

Operational Dependence

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

Project Risks

We will manage a variety of small and large projects in the conduct of our business. Project delays may delay expected revenues from operations. Significant project cost over-runs could make a project uneconomic. Our ability to execute projects and market oil and natural gas will depend 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.

Availability of Drilling Equipment and Access

Oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment (typically leased from third parties) in the particular areas where such activities will be conducted. Demand for such limited equipment or access restrictions may affect the availability of such equipment to us and may delay exploration and development activities. To the extent we are not the operator of our oil and gas properties, we will be dependent on such operators for the timing of activities related to such properties and will be largely unable to direct or control the activities of the operators.

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.

Reserves Estimates

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and natural gas liquids reserves and resources and the future cash flows attributed to such 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 to some degree speculative, and classifications of reserves are only attempts to define the degree of speculation involved. For those reasons, estimates of the economically recoverable oil and natural gas reserves 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.

Actual production and cash flows derived from reserves will vary from the reserves estimates contained in the McDaniel Report summarized in this Annual Information Form, and such variations could be material. The estimates in the McDaniel Report is 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 reserves that may be developed and produced in the future 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.

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. 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 those reserves reports, the present value of estimated future net cash flows for our reserves would be reduced and the reduction could be significant.

Depletion of Reserves

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. We will not be reinvesting funds flow from operations to the same extent as other industry participants as one of our main objectives is to maintain long-term distributions. Accordingly, absent capital injections, our initial production levels and reserves will decline and the level of distributable income will be reduced.

Our future oil and natural gas reserves and production, and therefore our funds flow from operations, 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 will decline over time as reserves are produced.

To the extent that external sources of capital, including the issuance of additional Trust Units become limited or unavailable, our ability to make the necessary capital investments to maintain or expand our oil and natural gas reserves will be impaired. To the extent that we are required to use funds flow from operations to finance capital expenditures or property acquisitions, the level of distributable income 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.

Insurance

Our involvement in the exploration for and development of oil and natural gas properties may result in us becoming subject to liability for pollution, blow outs, property damage, personal injury or other hazards. Although prior to drilling our operating entities will obtain insurance in accordance with industry standards to address certain of these risks, such insurance has limitations on liability that may not be sufficient to cover the full extent of such liabilities. In addition, such risks may not in all circumstances be insurable or, in certain circumstances, our operating entities may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or other reasons. The payment of such uninsured liabilities would reduce the funds available to us. The occurrence of a significant event that we are not fully insured against, or the insolvency of the insurer of such event, could have a material adverse effect on our financial position, results of operations or prospects and will reduce income otherwise distributable to us.

Competition

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 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 will be more difficult to acquire reserves on beneficial terms. We also compete for reserves acquisitions and undeveloped land with a substantial number of other oil and gas companies, many of which 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 of daily operations of the Trust including the execution of the annual capital development program. The inability to hire and retain skilled personnel could adversely impact certain of our operational and financial results.

Risks Associated with Government Regulation

Environmental Concerns

The oil and natural gas industry is subject to environmental regulation pursuant to local, provincial and federal legislation. 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. Such legislation may be changed to impose higher standards and potentially more costly obligations on us. Furthermore, management believes the political climate appears to favour new programs for environmental laws and regulation, particularly in relation to the reduction of emissions, 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 or taxes based upon emissions. In particular there is uncertainty regarding the *Government of Canada's Clean Air Act of 2006*. The Clean Air Act proposes to reduce greenhouse gas emissions, however emission targets and compliance deadlines differ from those outlined in the Kyoto Protocol which was ratified by Canada. If passed, the Clean Air Act may have adverse operational and financial implications to us. See "*Industry Conditions – Environmental Regulation*". Based on our current knowledge, there can be no assurance that we will be able to satisfy our actual future environmental and reclamation obligations.

Provincial emission reduction requirements, such as those in Alberta's *Climate Change* and *Emissions Management Amendment Act*, may require the reduction of emissions or emissions intensity of our operations and facilities. The direct or indirect costs of these regulations may adversely and materially affect our business. See "*Industry Conditions – Environmental Regulation*".

Canada is a signatory to the United Nations Framework Convention on Climate Change and in December 2002 the Government of Canada ratified the Kyoto Protocol and it became legally binding on February 16, 2005. This protocol calls for Canada to reduce its greenhouse gas emissions to six per cent below 1990 levels during the period between 2008 and 2012. Our exploration and production facilities and other operations and activities emit greenhouse gases that may subject us to legislation regulating emissions of greenhouse gases. The Government of Canada has put forward a Climate Change Plan for Canada which suggests further legislation will set greenhouse gases emission reduction requirements for various industrial activities, including oil and gas exploration and production. There has been much public debate with respect to Canada's ability to meet these targets and the Government's strategy or alternative strategies with respect to climate change and the control of greenhouse gases. Implementation of strategies for reducing greenhouse gases whether to meet the limits required by the Kyoto Protocol or as otherwise determined, could have a material impact on the nature of oil and natural gas operations, including 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. See "*Risk Factors – Risks Associated with Government Regulation – Change of Legislation*".

Although we believe that we are in material compliance with current applicable environmental regulations, no assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise adversely affect our 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. See "*Industry Conditions – Environmental Regulation*".

Regulatory

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

Changes in Legislation

Income tax laws, or other laws or government incentive programs relating to the oil and gas industry, such as the treatment of mutual fund trusts and resource taxation, may in the future be changed or interpreted in a manner that adversely affects us and our Unitholders. Tax authorities having jurisdiction over us or Unitholders may disagree with how we calculate our income for tax purposes or could change administrative practises to our detriment or the detriment of Unitholders.

We intend 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 our 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 Unitholders. Some of the significant consequences of losing our 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 if we ceased to be a mutual fund trust.

- 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 would not constitute qualified investments for registered retirement savings plans ("**RRSPs**"), registered retirement income funds ("**RRIFs**"), registered education savings plans ("**RESTs**") or deferred profit sharing plans ("**DPSPs**"). If, at the end of any month, one of these exempt plans holds Trust Units that are not qualified investments, the plan must pay a tax equal to one per cent of the fair market value of the Trust Units at the time the Trust Units were acquired by the exempt plan. An RRSP or RRIF holding non-qualified Trust Units would be subject to taxation on income attributable to the Trust Units. If an RESP holds non-qualified Trust Units, it may have its registration revoked by the Canada Revenue Agency.

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).

For more information, see "*Risk Factors – Risks Associated with Government Regulation – Non-resident Ownership of Trust Units*", and "*Risk Factors – Risks to Our Revenues – Federal Tax Changes for Income Trusts and Corporations*".

Non-resident Ownership of Trust Units

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, 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*" and "*Risk Factors – Risks Associated with Government Regulation – Change of Legislation*".

Expiration of Licences and Leases

Our properties are held in the form of licences and leases and working interests in licences and leases. If we or the holder of the licence or lease fails to meet the specific requirement of a licence or lease, the licence or lease may terminate or expire. There can be no assurance that any of the obligations required to maintain each licence or lease will be met. The termination or expiration of our licences or leases or the working interests relating to a licence or lease may have a material adverse effect on our results of operations and business.

Risks Associated with Acquisitions and Expansion

Purchase of Properties

The price we pay for the purchase of 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 assumptions regarding such factors as recoverability and marketability of oil, natural gas, natural gas liquids and sulphur, future prices of oil, natural gas, natural gas liquids and sulphur and operating costs, future capital expenditures and royalties and other government levies which will be imposed over the producing life of the reserves. Many of these factors are subject to change and are beyond our control and the control of the operators of the properties. In particular, changes in the prices of and markets for petroleum, natural gas, natural gas liquids and sulphur from those anticipated at the time of making such assessments will affect the amount of future distributions and as such the value of the Trust Units. In addition, all such estimates involve a measure of geological and engineering uncertainty which could result in lower production and reserves than attributed to the properties. Actual reserves could vary materially from these estimates. Consequently, the reserves acquired may be less than expected, which could adversely impact cash flows and distributions to Unitholders.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

We make acquisitions and dispositions of businesses and assets in the ordinary course of business. Achieving the benefits of acquisitions depends in part on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner as well as our ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of 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. In this regard, non-core assets are periodically disposed of, so that we can focus our efforts and resources more efficiently. Depending on the state of the market for such non-core assets, certain of our non-core assets, if disposed of, could realize less than their carrying value on our financial statements.

Expansion of Operations

Our operations and expertise are currently focused on conventional oil and gas production and development in the Western Canadian Sedimentary Basin and in the United States. In the future, we may acquire oil and gas properties outside of these geographic areas. In addition, the Trust Indenture does not limit our activities 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 our exposure to one or more of the present risk factors which may adversely affect our future operational and financial conditions.

Title Risks

Title to Assets

Although title reviews may be conducted prior to the purchase of oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise to defeat our claim which could result in a reduction of the revenue received by us.

Aboriginal Claims

Aboriginal peoples have claimed aboriginal title and rights to portions of western Canada. 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 our operations.

Management Risks

Reliance on Key Personnel

Our success depends in large measure on certain key personnel. The loss of the services of such key personnel could have a material adverse affect on us. The contributions of the existing management team to our immediate and near term operations are likely to be of central importance. In addition, the competition for qualified personnel in the oil and natural gas industry is intense and there can be no assurance that we will be able to continue to attract and retain all personnel necessary for the development and operation of our business. Investors must rely upon the ability, expertise, judgment, discretion, integrity and good faith of our management.

Reliance on Management

Unitholders will be dependent on our management in respect of the administration and management of all matters relating to our properties and Trust Units. As of December 31, 2007, we operated approximately 94 per cent of our total daily production of our properties. Investors who are not willing to rely on our management should not invest in Trust Units.

Management of Growth

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

Conflicts of Interest

The directors or officers of Zargon Oil & Gas Ltd. may also be directors or officers of other oil and natural gas companies or otherwise involved in natural resource exploration and development and situations may arise where they are in a conflict of interest with us. Conflicts of interest, if any, which arise will be subject to and governed by procedures prescribed by the *Business Corporations Act* (Alberta) which require a director or officer of a corporation who is a party to, or is a director or an officer of, or has a material interest in any person who is a party to, a material contract or proposed material contract with us disclose his or her interest and, in the case of directors, to refrain from voting on any matter in respect of such contract unless otherwise permitted under the *Business Corporations Act* (Alberta).

Capital Risks

Substantial Capital Requirements

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

Issuance of Debt

From time to time we may enter into transactions to acquire assets or the shares of other organizations. These transactions may be financed in whole or in part with debt, which may increase our debt levels above industry standards for oil and natural gas companies of similar size. Depending on future exploration and development plans, we may require additional equity and/or debt financing that may not be available or, if available, may not be available on favourable terms. Neither 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.

Additional Financing

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. Conversely to the extent that external sources of capital, including the issuance of additional Trust Units become limited or unavailable, our ability to make the necessary capital investments to maintain or expand our oil and gas reserves will be impaired. Management believes that the SIFT Tax imposed by the Government of Canada will substantially eliminate the competitive advantage that we and other energy trusts have enjoyed relative to our industry competitors in raising capital in a tax-efficient manner. See "*Risk Factors – Risks to Our Revenues – Federal Tax Changes to Income Trusts and Corporations*". To the extent that we are required to use funds flow from operations to finance capital expenditures or property acquisitions or to pay debt service charges or to reduce debt, the level of funds flow from operations available for distribution to Unitholders will be reduced.

Debt Service

Amounts paid in respect of interest and principal on debt we have incurred will reduce income available for 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 the NPI. Certain covenants of 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 or that additional funds will be able to be obtained.

Our lenders have or will be provided with 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 bankruptcy, our lenders may foreclose on or sell our oil and natural gas assets.

Net Asset Value

The net asset value of our assets from time to time will vary dependent upon a number of factors beyond the control of management, including oil and gas prices. The trading prices of the Trust Units from time to time is also determined by a number of factors which are beyond the control of management and such trading prices may be greater or less than the net asset value of our assets.

Dilution

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

Risks Associated with Our Structure as a Trust

Return of Capital

Trust Units will have no value when reserves from the 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. See "*Information Relating to Us – Trust Indenture – Right of Redemption*." 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 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. In addition, there may be resale restrictions imposed by law upon the recipients of the securities pursuant to the redemption right.

Nature of Trust Units

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 Ltd. The Trust Units represent a fractional interest in us. Corporate law does not govern us 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 of our operating entities. 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.

Unitholder Limited Liability

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 us, 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. Our principal investment is the rNPI 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.

Maintenance of Distributions

We add to our oil and natural gas reserves primarily through a combination of low risk development, acquisitions and exploration. As a result, future oil and natural gas reserves are highly dependent on our operating entities success in exploiting existing properties, acquiring additional reserves and exploration success. We also distribute a substantial portion of our net cash flow to Unitholders rather than reinvesting it in reserve additions. Accordingly, if external sources of capital, including the issuance of additional Trust Units, become limited or unavailable on commercially reasonable terms, our operating entities ability to make the necessary capital investments to maintain or expand their oil and natural gas reserves will be impaired. To the extent that our operating entities are required to use cash flow to finance capital expenditures or property acquisitions, the level of cash flow available for distribution to Unitholders will be reduced. Additionally, we cannot guarantee that we will be successful in developing additional reserves, acquiring additional reserves or finding new reserves through exploration on terms that meet our investment objectives. Without these reserve additions, our reserves will deplete and as a consequence, either production from, or the average reserve life of, our properties will decline. Either decline may result in a reduction in the value of Trust Units and in a reduction in cash available for distributions to Unitholders.

Allocation of Trust Income

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.

Accounting Write-Downs as a Result of GAAP

Canadian Generally Accepted Accounting Principles ("**GAAP**") require that management apply certain accounting policies and make certain estimates and assumptions which affect reported amounts in our consolidated financial statements. The accounting policies may result in non-cash charges to net income and write-downs of net assets in the financial statements. Such non-cash charges and write-downs may be viewed unfavourably by the market and may result in an inability to borrow funds and/or may result in a decline in the Trust Unit price.

Under GAAP, the net amounts at which petroleum and natural gas costs on a property or project basis are carried are subject to a cost-recovery test which is based in part upon estimated future net cash flows from reserves. If net capitalized costs exceed the estimated recoverable amounts, we will have to charge the amounts of the excess to earnings. A decline in the net value of oil and natural gas properties could cause capitalized costs to exceed the cost ceiling, resulting in a charge against earnings. The net value of oil and gas properties are highly dependent upon the prices of oil and natural gas. See "*Risk Factors – Risks to Our Revenues – Volatility of Oil and Natural Gas Prices*".

GAAP requires that goodwill balances be assessed at least annually for impairment and that any permanent impairment be charged to net income. A permanent reduction in reserves, decline in commodity prices, and/or reduction in the Trust Unit price may indicate goodwill impairment. As at December 31, 2007 we had $nil goodwill recorded on our balance sheet. An impairment would result in a write-down of the goodwill value and a non-cash charge against net income. The calculation of impairment value is subject to management estimates and assumptions.

New GAAP surrounding accounting for derivatives may result in non-cash charges against net income as a result of changes in the fair market value of derivative instruments. A decrease in the fair market value of the derivative instruments as the result of fluctuations in commodity prices and foreign exchange rates may result in a write-down of net assets and a non-cash charge against net income. Such write-downs and non-cash charges may be temporary in nature if the fair market value subsequently increases.

Certain Risks for United States Unitholders

Limited Ability of Residents in the United States to Enforce Civil Remedies

We are organized under the laws of Alberta, Canada and have our principal place of business in Canada. Most of our directors and all of our officers and the representatives of the experts who provide services to us (such as our auditors and our independent reserve engineers), and a substantial portion of our assets and all or a substantial portion of 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 against 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 judgement 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.

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 Securities Exchange Commission ("**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; however, we also follow the United States practice of separately reporting these 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 and we do not estimate our reserves using prices and costs held constant at the effective date of the reserve report.

We included in this Annual Information Form estimates of proved and proved plus probable 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.

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 cash 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 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.

Foreign Exchange Risk of 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 weakens 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 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 Ltd. and certain lenders in respect of Zargon's $150 million syndicated credit facilities, which agreement is described in Note 5 to Zargon's financial statements for the year ended December 31, 2007, 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 office in Calgary, Alberta and through its co-agent, BNY Equity Trust Services, at its principal office in 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 Ltd., 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 fiscal year and in any proposed transaction 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 Accounts 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 Ltd. or of any of our associate or affiliate entities**,** except for Grant A. Zawalsky, a director of Zargon Oil & Gas Ltd., is a partner at Burnet, Duckworth & Palmer LLP, which is a law firm that renders legal services to us.

ADDITIONAL INFORMATION

Additional information including remuneration of directors and officers of Zargon Oil & Gas Ltd., principal holders of the Trust Units, Exchangeable Shares and rights to purchase Trust Units, is contained in the Information Circular which relates to the Annual Meeting of Unitholders to be held on April 23, 2008, and additional financial information is provided in our consolidated financial statements and management discussion and analysis of financial results for the year ended December 31, 2007 which have been filed on SEDAR at *www.sedar.com*.

We shall provide to any person, upon request to the Secretary of Zargon Oil & Gas Ltd. acting on our behalf:

1. when our securities are in the course of a distribution pursuant to a short form prospectus or a preliminary short form prospectus has been filed in respect of a distribution of its securities,

    (a) one copy of our Annual Information Form, together with one copy of any document, or the pertinent pages of any document, incorporated by reference in the Annual Information Form;

    (b) one copy of our consolidated financial statements for the most recently completed fiscal year together with the accompanying report of the auditor and one copy of any subsequent interim financial statements;

    (c) one copy of our information circular; and

    (d) one copy of any other documents that are incorporated by reference into the preliminary short form prospectus or the short form prospectus and are not required to be provided under (a) to (c) above; or

2. at any other time, one copy of any other documents referred to in (1)(a), (b) and (c) above, provided we may require the payment of a reasonable charge if the request is made by a person who is not a holder of our securities.

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 Ltd.
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 Ltd. 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, 2007, 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 Reserves

(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

February 28, 2008

APPENDIX B

REPORT ON RESERVES DATA BY MCDANIEL

(Form 51-101F2)

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

1. We have evaluated Zargon's reserves data as at December 31, 2007. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2007, estimated using forecast prices and costs.

2. The reserves data are the responsibility of 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, 2007, 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 28, 2008	Canada	$nil	$395,727	$nil	$395,727
		United States	$nil	$74,411	$nil	$74,411

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 28, 2008

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 of Zargon Oil & Gas Ltd. ("**Zargon**") 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 of Directors shall have the power to appoint the Committee Chairman.

3. All of the members of the Committee shall be "financially literate". The Board of Directors of Zargon 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.