ARC Energy Trust

2008 Annual Information Form

March 18, 2009

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GLOSSARY OF TERMS

In this Annual Information Form, capitalized terms shall have the meanings set forth below:

ARC, **we**, **us**, **our** or **Trust** means ARC Energy Trust and all its controlled entities as a consolidated body;

ARC Resources means ARC Resources Ltd.;

ARC Sask means ARC Oil & Gas Fund, an Alberta trust;

ARC Subco means 1405292 Alberta Ltd., or such other corporation as may be substituted for ARC Subco;

Discovered Petroleum Initially In Place means the quantity of hydrocarbons that are estimated to be in place within a known accumulation. Discovered Petroleum Initially In Place is divided into recoverable and unrecoverable portions, with the estimated future recoverable portion classified as reserves and contingent resources;

Dawson West Area means our lands west of the Dawson area in north eastern British Columbia comprised of the Sunrise, Sundown, Sunset, Saturn and Monias areas;

Exchangeable Shares means the exchangeable shares of ARC Resources that are exchangeable for Trust Units;

Exchange Ratio means the ratio at which the Exchangeable Shares may be exchanged for Trust Units;

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

GLJ Report means the report prepared by GLJ dated February 19, 2009 evaluating the crude oil, natural gas, natural gas liquids and sulphur reserves attributable to the properties at December 31, 2008;

Long Term Notes means the unsecured long term notes issued by ARC Resources to the Trust from time to time bearing interest at rates per annum ranging from 11.25 per cent to 13 per cent payable monthly with maturity dates of 15 years from the date of issuance;

Royalties means, collectively, the royalties payable by ARC Resources to the Trust pursuant to the royalty agreements which equals 99 per cent of royalty income;

Tax Act means the *Income Tax Act* (Canada);

Trust Indenture means the trust indenture between Computershare Trust Company of Canada, as trustee, and ARC Resources Ltd., as amended and restated as of May 15, 2006;

Trust Units means the units of the Trust, each unit representing an equal undivided beneficial interest in the Trust;

TSX means the Toronto Stock Exchange; and

Unitholders means holders of Trust Units of the Trust.

Certain other terms used in this Annual Information Form but not defined herein are defined in NI 51-101 and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101.

SPECIAL NOTES TO READER

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 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 the oil and natural gas reserves and resources;
- projections of market prices and costs;
- 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 results 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;
- changes in foreign exchange rates;
- uncertainties relating to the weakened global economic situation and consequential restricted access to capital, increased borrowing costs and refinancing risk for existing debt;
- liabilities inherent in oil and natural gas operations;
- uncertainties associated with estimating oil and natural gas reserves and resources;
- risks and uncertainties inherent in exploration and development activities;
- competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel;
- incorrect assessments of the value, or failure to realize the anticipated benefits, of acquisitions;
- geological, technical, drilling and processing problems;
- changes in income tax laws or changes in tax or environmental laws and incentive programs or royalty regimes relating to the oil and gas industry and income trusts; and
- the other factors discussed under "*Risk Factors*".

The actual results could differ materially from those results anticipated in these forward-looking statements, which are based on assumptions, including as to the market prices for oil and natural gas; the continuation of the present policies of the Board of Directors of ARC Resources relating to management of ARC, and distributions, capital expenditures and other matters; the continued availability of capital, acquisitions of reserves, undeveloped lands and skilled personnel; the continuation of the current tax and regulatory regime and other assumptions contained in this Annual Information Form.

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 securities laws or regulations.

Access to Documents

Any document referred to in this Annual Information and described as being filed on SEDAR at www.sedar.com (including those documents referred to as being incorporated by reference in this Annual Information Form) may be obtained free of charge from us at 2100, 440 – 2nd Avenue S.W., Calgary, Alberta, T2P 5E9.

Abbreviations and Conversions

bbl	Barrel	Mcf	one thousand cubic feet
bbl/d	barrels per day	Mcfpd	one thousand cubic feet per day
Bcf	billion cubic feet	MMBTU	one million British Thermal Units
boe	barrels of oil equivalent converting 6 Mcf of natural gas or one barrel of natural gas liquids to one barrel of oil equivalent	MMcf	one million cubic feet
		MMcfpd	one million cubic feet per day
		$MM	one million dollars
boe/d	barrels of oil equivalent per day	MMbbl	one million barrels
Mbbl	one thousand barrels	NGLs	natural gas liquids
mboe	one thousand barrels of oil equivalent	Tcf	one trillion cubic feet

We have adopted the standard of 6 Mcf:1boe when converting natural gas to boes. Boes may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf per barrel is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

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

To Convert From	To	Multiply By
cubic metres	cubic feet	35.315
bbls	cubic metres	0.159
cubic metres	bbls	6.290
Feet	metres	0.305
Metres	feet	3.281
Miles	kilometres	1.609
Kilometres	miles	0.621
Acres	hectares	0.4047
Hectares	acres	2.471

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

ARC ENERGY TRUST

General

We are an open-end investment trust created on May 7, 1996 under the laws of the Province of Alberta pursuant to the Trust Indenture. Computershare Trust Company of Canada has been appointed as trustee under the Trust Indenture. The beneficiaries of the Trust are holders of the Trust Units. The principal and head office of the Trustee is located at Suite 600, 530 8th Avenue SW., Calgary, Alberta, T2P 3S8. The Trust Indenture has been amended from time to time, the latest amendments being approved at the annual and special meeting of Unitholders held on May 15, 2006.

The principal offices of the Trust and ARC Resources are located at 2100, 440 – 2nd Avenue S.W., Calgary, Alberta, T2P 5E9 and its registered office is located at 1400, 350 – 4th Avenue S.W., Calgary, Alberta, T2P 3N9.

The following are the names, the percentage of voting securities and the jurisdiction governing our material subsidiaries and trusts, either direct or indirect, as at December 31, 2008:

	Percentage of voting securities (directly or indirectly)	**Nature of Entity**	**Jurisdiction of Incorporation/ Formation**
ARC Resources Ltd.	100%	Corporation	Alberta

General Development of Our Business

A description of the general development of our business over the last three financial years follows.

In 2006, we incurred capital expenditures of $496.3 million, of which $312.5 million (63 per cent) was development and facility capital expenditures, $115.2 million (23 per cent) was property acquisitions costs net of disposition and property swaps and $49.4 million (10 per cent) was costs of lands acquired, geological and geophysical, and drilling costs for 2006 exploration wells drilled. We completed one corporate acquisition for total consideration of $16.6 million resulting in total acquisitions, net of dispositions, of $131.8 million in the year. We also distributed $484.2 million to Unitholders in 2006.

In 2007, we incurred capital expenditures of $439.7 million, of which $281.4 million (64 per cent) was development and facility capital expenditures, $42.5 million (10 per cent) was property acquisitions costs net of dispositions and $112.5 million (26 per cent) was costs of lands acquired, geological and geophysical, and drilling costs for 2007 exploration wells drilled. Included in these costs was the purchase of undeveloped land located primarily in the Dawson and Dawson West Area of British Columbia through Crown mineral sales for $77.5 million. We also distributed $498 million to Unitholders in 2007.

In 2008, we incurred capital expenditures of $599.6 million, of which $371.1 million (62 per cent) was development and facility capital expenditures, $51 million (nine per cent) was property acquisitions costs net of dispositions and $164.1 million (27 per cent) was costs of lands acquired, geological and geophysical, and drilling costs for 2008 exploration wells drilled. Included in these costs was the purchase of undeveloped acreage through Crown mineral sales for $122.4 million, of which $80.3 million was expended in the Dawson and Dawson West Area of British Columbia. We also distributed $570 million to Unitholders in 2008.

Effective January 1, 2008, we completed an internal reorganization wherein, among other things, all of ARC Sask's assets were transferred to ARC Resources and the royalty agreements between each of ARC Resources and ARC Sask and the Trust were exchanged for a new royalty agreement between ARC Resources and the Trust. In addition, the obligations under the Long Term Note from ARC Sask to the Trust were assumed by ARC Resources.

Recent Developments

On January 12, 2009, we announced that in light of the continuing weak commodity price environment and the increasing disparity between U.S. and Canadian oil prices, the cash distribution payable on February 16, 2009 to Unitholders of record on January 30, 2009 will be reduced from $0.15 per Trust Unit to $0.12 per Trust Unit. We also announced the reduction of our previously announced 2009 capital program from approximately $585 million to approximately $450 million through a reduction of certain capital costs and the deferral of certain capital spending into the first quarter of 2010.

On February 6, 2009, the Trust closed an equity offering to issue 15.5 million trust units at $16.35 per unit. The net proceeds of the transaction were $240 million and were used to reduce the Trust's indebtedness.

On February 11, 2009, Myron M. Stadnyk was appointed as President and Chief Operating Officer of ARC Resources. John P. Dielwart continues as Chief Executive Office of ARC Resources.

OUR BUSINESS

Overview

Our principal undertaking is to receive Royalties and other income on petroleum and natural gas properties and related assets and to acquire and hold securities of subsidiaries, trusts and partnerships. Our subsidiaries, trusts and partnerships are entitled to carry on a wide scope of energy related activities including the business of acquiring, developing, exploiting and disposing of all types of energy business related assets, which includes petroleum and natural gas related assets, oil sands interests, electricity or power generating assets and pipeline, gathering, processing and transportation assets. To date the Trust's business has been focused to the acquisition and development of oil and natural gas reserves in Western Canada. We issue Trust Units and may also issue securities of ARC Resources or an affiliate of ARC Resources which are exchangeable for Trust Units and confer voting rights in us.

Our principal investments are the Royalties granted by ARC Resources, the common shares of ARC Resources and the Long Term Notes. The Royalties consist of a 99 per cent share of royalty income on all of the properties held by ARC Resources. Royalty income is generally all production revenue less all operating and capital costs and all debt service charges including principal repayments. On each monthly distribution date, ARC Resources pays the Trust 99 per cent of royalty income and ARC Resources pays interest on outstanding Long Term Notes. The Trust will make distributions of such funds, subject only to the required deductions and its expenses. Such distributions may be wholly or in part taxable. See "Distributions to Unitholders".

We are structured with the objective of having income tax incurred only in the hands of Unitholders. Income distributed to Unitholders consists essentially of cash flow from operating activities generated by our oil and natural gas properties. More specifically, internally generated cash flow from operating activities, with the exception of such cash flow used for capital expenditures, reclamation fund contributions, interest expense, debt repayments, income taxes not passed on to Unitholders, and working capital requirements, is effectively returned to Unitholders.

As an open-ended investment, Unitholders have a right to redeem their Trust Units. As with most other open-ended funds, it is anticipated that trading on the TSX and not the right of retraction would continue as the primary mechanism for Unitholders to sell their Trust Units. For more detailed information regarding the right of redemption, see "Our Information - Right of Redemption".

As at December 31, 2008, we had approximately 496 employees and full time consultants.

Federal Tax Changes for Income Trusts and Corporations

On June 22, 2007, the federal legislation (Bill C-52) implementing the tax on publicly traded income trusts and limited partnerships (the "**SIFT Rules**") received Royal Assent. The SIFT Rules are not expected to effect the Trust until 2011 provided the Trust does not exceed the normal growth guidelines announced by the Department of Finance. Subsequent to the February 6, 2009 equity issuance, the Trust can increase its equity by approximately $5.1 billion before 2011 without exceeding the normal growth guidelines. The Trust does not anticipate that the normal growth guidelines will impair the Trust's ability to annually replace or grow reserves in the next two years as the guidelines allow sufficient growth targets.

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

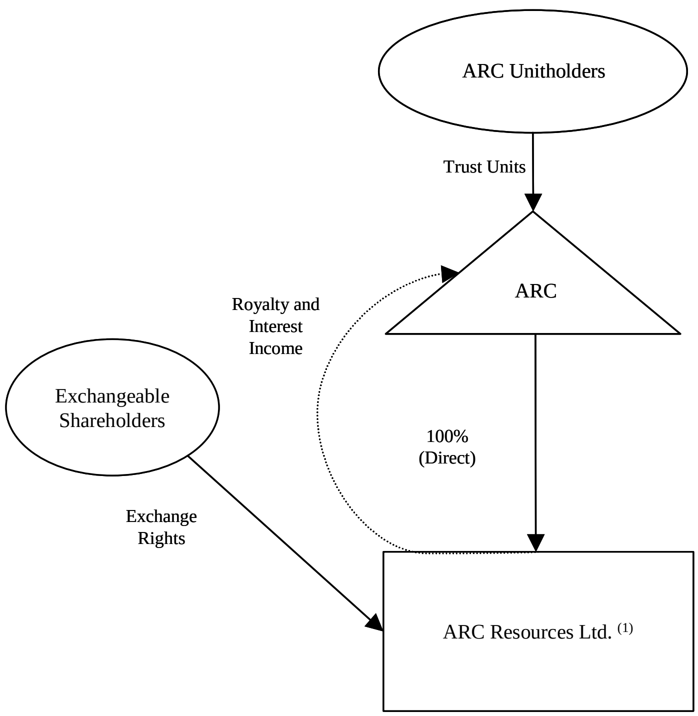
The Minister of Finance has tabled a Notice of Ways and Means which includes legislation facilitating the conversion of existing income trusts into corporations on a tax neutral basis.

Management and the Board of Directors continue to review the impact of the SIFT Rules on our business strategy and while there has not been a decision as to ARC's future direction at this time we are currently of the view that the conversion from a trust to a corporation may be the most logical and tax efficient alternative for Unitholders. Canadian investors who hold their Trust Units in a taxable account will be relatively indifferent on an after tax basis as to whether ARC is structured as a corporation or as a trust in 2011. However, Canadian tax deferred investors (those holding their Trust Units in a tax deferred vehicle such as an RRSP, RRIF or pension plan) and foreign investors will realize a lower return on distributions in 2011 due to the introduction of the SIFT tax that would apply should we remain a trust and their inability to claim the dividend tax credit if we convert to a corporation.

For more information, see "Risk Factors – Federal Tax Changes for Income Trusts and Corporations" and "Risk Factors – Changes in Legislation".

Our Organizational Structure

Our structure and the flow of cash from ARC Resources to the Trust as of December 31, 2008 are set forth below:



Notes:

(1) As at December 31, 2008, properties in British Columbia are held by ARC Petroleum Inc. as trustee and agent of ARC Resources.

(2) ARC Resources had a total of 1,091,414 Exchangeable Shares outstanding as at December 31, 2008 that were exchangeable for approximately 2,746,740 Trust Units.

Management Policies

All our activities are directed towards maximizing value creation for Unitholders. This is achieved through a combination of investing capital to enhance the value of our assets, operating our producing oil and gas properties in a low cost manner to maximize the recovery of reserves, and through making monthly distributions to our Unitholders. We direct our efforts to increase the value of our assets through development drilling and associated development activities and enhanced oil recovery activities as well as by the periodic acquisition of undeveloped and producing oil and gas properties. We acquire oil and natural gas producing properties and primarily participate in development activities that are generally considered to be of a low risk nature in the oil and gas industry. Also, a percentage of each year's capital budget will be devoted to moderate risk development and lower risk exploration opportunities on our properties. Recently, we have undertaken a more substantial program of purchasing undeveloped land, particularly in the Dawson area of north-eastern British Columbia, where we have spent approximately $250 million since January 1, 2006.

We have policies for the hiring, training and development of staff to provide the in house expertise to fully exploit ARC's assets. In addition, we have specific health and safety policies which set out procedures, practices and reporting of actions to assist in ensuring that ARC employees and contractors employ safety measures and act in a safe and prudent manner. We also have policies which encompass the cleanup, abandonment and site reclamation activities of ARC.

Distributions and Distribution Policy

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.

The Board of Directors of ARC Resources on behalf of the Trust reviews the distribution policy from time to time. The actual amount distributed is at the discretion of the Board of Directors and is principally dependent upon the commodity price environment and the amount of cash flow from operating activities utilized to fund the Trust's capital expenditure program and the annual contribution to the Trust's reclamation fund. In times of high commodity prices, we withhold a greater percentage of cash flow from operating activities so that more of the capital program can be funded internally.

Historically, ARC has strived for stability in distributions and has announced distribution levels on a quarterly basis. During times of extreme commodity price volatility, such as those we are currently experiencing, the distributions are reviewed on a monthly basis and adjusted as required.

See "Risk Factors – Maintenance of Distributions".

Capital Expenditures

We may approve future capital expenditures or farmouts under the terms of the royalty agreement. Future capital expenditures on the properties will generally be of the type that are intended to maintain or improve production from the properties. We may finance capital expenditures from production revenues, the proceeds of the issue of additional Trust Units or from the proceeds of disposition of the Royalties sold along with properties, borrowings, farmouts or with working capital.

We may acquire additional properties and related tangible equipment and fund such acquisitions from production revenues, the net proceeds of any issue of additional Trust Units or from the proceeds of disposition of the Royalties sold along with properties, or from borrowings, farmouts or with working capital. We may sell any of our interests in properties and release the Royalties from such properties in consideration of the allocation of a portion of the proceeds to the Trust. In connection with the sale of any interests in the properties, we will determine whether the net proceeds of the sale should be reinvested in additional properties, used to repay borrowings or make capital expenditures in ARC Resources or be distributed to Unitholders.

Potential Acquisitions

We continue to evaluate potential acquisitions of all types of petroleum and natural gas and other energy-related assets as part of our ongoing acquisition program. We are normally in the process of evaluating several potential acquisitions at any one time which individually or together could be material. We cannot predict whether any current or future opportunities will result in one or more acquisitions.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

The statement of reserves data and other oil and gas information is set forth below (the "**Statement**"). The effective date of the Statement is December 31, 2008 and the preparation date of the Statement is January 16, 2009. The Report of Management and Directors on Reserves Data and Other Information on Form 51-101F3 and the Report on Reserves Data by GLJ on Form 51-102F2 are attached as Appendices A and B to this Annual Information Form.

Disclosure of Reserves Data

The reserves data set forth below is based upon an evaluation by GLJ with an effective date of December 31, 2008 contained in the GLJ Report dated February 19, 2009. The reserves data summarizes our oil, liquids and natural gas reserves and the net present values of future net revenue for these reserves using forecast prices and costs prior to provision for interest, general and administrative expenses, the impact of any hedging activities or the liability associated with certain abandonment and well, pipeline and facilities reclamation costs which were not deducted by GLJ in estimating future net revenue. Future net revenues have been presented on a before and after tax basis. The reserves data conforms with the requirements of NI 51-101. We engaged GLJ to provide an evaluation of proved and proved plus probable reserves. See also "Definitions and Notes to Reserves Data Tables" below.

All of our reserves are in Canada and, specifically, in the provinces of Alberta, British Columbia, Saskatchewan and Manitoba.

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 reserves estimates of 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" in conjunction with the following tables and notes. For more information as to the risks involved, see "Risk Factors – Reserves and Resource Estimates" and "Risk Factors – 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, 2008
FORECAST PRICES AND COSTS

	RESERVES			
	LIGHT AND MEDIUM OIL		HEAVY OIL	
RESERVES CATEGORY	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)
PROVED				
Developed Producing	94,805	80,767	2,357	2,370
Developed Non-Producing	2,187	1,589	9	9
Undeveloped	7,919	6,448	0	0
TOTAL PROVED	104,912	88,804	2,366	2,379
PROBABLE	30,138	24,921	640	599
TOTAL PROVED PLUS PROBABLE	135,049	113,725	3,006	2,978

RESERVES CATEGORY	RESERVES			
	NATURAL GAS		NATURAL GAS LIQUIDS	
	Gross (Bcf)	Net (Bcf)	Gross (Mbbl)	Net (Mbbl)
PROVED				
Developed Producing	438	382	8,535	6,028
Developed Non-Producing	30	22	521	352
Undeveloped	269	201	2,000	1,467
TOTAL PROVED	737	604	11,057	7,847
PROBABLE	263	211	3,330	2,440
TOTAL PROVED PLUS PROBABLE	1,000	816	14,386	10,287

RESERVES CATEGORY	RESERVES	
	TOTAL	
	Gross (mboe)	Net (mboe)
PROVED		
Developed Producing	178,660	152,788
Developed Non-Producing	7,794	5,603
Undeveloped	54,700	41,350
TOTAL PROVED	241,154	199,742
PROBABLE	77,960	63,186
TOTAL PROVED PLUS PROBABLE	319,114	262,928

RESERVES CATEGORY	NET PRESENT VALUES OF FUTURE NET REVENUE									
	BEFORE INCOME TAXES DISCOUNTED AT (%/year)					AFTER INCOME TAXES DISCOUNTED AT (%/year)				
	0 (MM$)	5 (MM$)	10 (MM$)	15 (MM$)	20 (MM$)	0 (MM$)	5 (MM$)	10 (MM$)	15 (MM$)	20 (MM$)
PROVED										
Developed Producing	7,166	4,760	3,605	2,928	2,480	5,933	4,052	3,135	2,589	2,224
Developed Non-Producing	277	181	133	104	85	210	139	104	82	67
Undeveloped	1,500	915	606	419	295	1,106	663	426	283	188
TOTAL PROVED	8,943	5,856	4,344	3,450	2,861	7,248	4,854	3,665	2,953	2,479
PROBABLE	3,600	1,648	948	620	438	2,611	1,196	687	448	316
TOTAL PROVED PLUS PROBABLE	12,543	7,504	5,292	4,070	3,298	9,859	6,050	4,352	3,402	2,795

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
as of December 31, 2008
FORECAST PRICES AND COSTS

RESERVES CATEGORY	REVENUE (MM$)	ROYALTIES (MM$)	OPERATING COSTS (MM$)	DEVELOPMENT COSTS (MM$)	ABANDONMENT AND RECLAMATION COSTS (MM$)	FUTURE NET REVENUE BEFORE INCOME TAXES (MM$)	INCOME TAXES (MM$)	FUTURE NET REVENUE AFTER INCOME TAXES (MM$)
Proved Reserves	18,793	3,292	5,441	872	245	8,943	1,694	7,248
Proved Plus Probable Reserves	25,891	4,650	7,217	1,200	281	12,543	2,683	9,859

FUTURE NET REVENUE
BY PRODUCTION GROUP
as of December 31, 2008
FORECAST PRICES AND COSTS

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) (MM$)	PER UNIT
Proved Reserves	Light and Medium Crude Oil	2,520	$23.79/boe
	Heavy Oil	68	$27.28/boe
	Natural Gas	1,755	$3.21/Mcf
	Total	4,344	
Proved Plus Probable Reserves	Light and Medium Crude Oil	3,033	$22.46/boe
	Heavy Oil	81	$25.93/boe
	Natural Gas	2,178	$2.92/Mcf
	Total	5,292	

Definitions and Notes to Reserves Data Tables

In the tables set forth above in "Disclosure of Reserves Data" and elsewhere in this Annual Information Form the following definitions and other notes are applicable:

1. "**Gross**" means:

   (a) in relation to our interest in production and reserves, our interest (operating and non-operating) before deduction of royalties and without including any royalty interest of us;

   (b) in relation to wells, the total number of wells in which we have an interest; and

   (c) in relation to properties, the total area of properties in which we have an interest.

2. "**Net**" means:

   (a) in relation to our interest in production and reserves, our interest (operating and non-operating) after deduction of royalties obligations, plus our royalty interest in production or reserves;

(b) in relation to wells, the number of wells obtained by aggregating our working interest in each of our gross wells; and

(c) in relation to our interest in a property, the total area in which we have an interest multiplied by the working interest we owned.

3. Columns may not add due to rounding.

4. The crude oil, natural gas liquids and natural gas reserves estimates presented in the GLJ Report are based on the definitions and guidelines contained in the Canadian Oil and Gas Evaluation Handbook (COGE Handbook). A summary of those definitions are set forth below:

Reserves 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.

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

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

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

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

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

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

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

(d) **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 reserves entities (which refers to the lowest level at which reserves calculations are performed) and to reported reserves (which refers to the highest level sum of individual entity estimates for which reserves are presented). Reported reserves should target the following levels of certainty under a specific set of economic conditions:

(a) at least a 90 per cent probability that the quantities actually recovered will equal or exceed the estimated proved reserves; and

(b) at least a 50 per cent 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.

Additional clarification of certainty levels associated with reserves estimates and the effect of aggregation is provided in the COGE Handbook.

5. Forecast prices and costs

These are prices and costs that are generally acceptable as being a reasonable outlook of the future as of the evaluation effective date. To the extent that there are fixed or presently determinable future prices or costs to which we are legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs shall be incorporated into the forecast prices.

The forecast cost and price assumptions include increases in wellhead selling prices and take into account inflation with respect to future operating and capital costs. Crude oil, natural gas and natural gas liquids benchmark reference pricing, as at December 31, 2008, inflation and exchange rates utilized in the GLJ Report were as follows:

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
as of December 31, 2008
FORECAST PRICES AND COSTS

Year	OIL				NATURAL GAS	EDMONTON LIQUIDS PRICES				
	WTI Cushing Oklahoma ($US/bbl)	Edmonton Par Price 40° API ($Cdn/bbl)	Hardisty Heavy 12° API ($Cdn/bbl)	Cromer Medium 29.3° API ($Cdn/bbl)	AECO Gas Price ($Cdn/MMbtu)	Propane ($Cdn/bbl)	Butane ($Cdn/bbl)	Pentanes Plus ($Cdn/bbl)	INFLATION RATES(1) %/Year	EXCHANGE RATE(2) ($US/$Cdn)
Forecast										
2009	57.50	68.61	43.10	59.00	7.58	43.22	52.14	69.98	2%	0.825
2010	68.00	78.94	49.76	68.68	7.94	49.73	61.57	80.52	2%	0.850
2011	74.00	83.54	54.35	73.52	8.34	52.63	65.16	85.21	2%	0.875
2012	85.00	90.92	59.23	80.01	8.70	57.28	70.92	92.74	2%	0.925
2013	92.01	95.91	62.54	84.40	8.95	60.42	74.81	97.82	2%	0.950
2014	93.85	97.84	63.82	86.10	9.14	61.64	76.32	99.80	2%	0.950
2015	95.73	99.82	65.13	87.84	9.34	62.89	77.86	101.81	2%	0.950
2016	97.64	101.83	66.46	89.61	9.54	64.15	79.43	103.87	2%	0.950
2017	99.59	103.89	67.83	91.42	9.75	65.45	81.03	105.97	2%	0.950
2018	101.59	105.99	69.22	93.27	9.95	66.77	82.67	108.10	2%	0.950
Thereafter	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	2%	0.950

Notes:
(1) Inflation rates for forecasting prices and costs.
(2) Exchange rates used to generate the benchmark reference prices in this table.
(3) Prices escalate 2.0 per cent per year from 2018.

Weighted average actual prices realized for the year ended December 31, 2008, were $8.58/Mcf for natural gas, $94.97/bbl for light and medium crude oil, $77.85/bbl for heavy crude oil and $69.71/bbl for natural gas liquids. Only a minor amount of our production is characterized as heavy oil.

See "Risk Factors – Reserves and Resources Estimates."

6. Future Development Costs

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

Year	Forecast Prices and Costs	
	Proved Reserves (M$)	Proved Plus Probable Reserves (M$)
2009	284,922	324,618
2010	152,868	193,160
2011	126,674	175,751
2012	91,065	113,422
2013	72,294	89,364
Total: Undiscounted	871,656	1,199,839
Total: Discounted at 10%/year	666,291	885,996

We expect to fund the development costs of the reserves through a combination of cash flow from operating activities, debt, and the sale of existing assets and the issuance of Trust Units.

There can be no guarantee that funds will be available or that we will allocate funding to develop all of the reserves attributed in the GLJ Report. Failure to develop those reserves would have a negative impact on future cash flow from operating activities.

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

7. Estimated future well abandonment costs related to reserves wells have been taken into account by GLJ in determining the aggregate future net revenue therefrom.

8. The forecast price and cost assumptions assumed the continuance of current laws and regulations.

9. All factual data supplied to GLJ was accepted as represented. No field inspection was conducted.

10. The estimates of future net revenue presented in the tables above do not represent fair market value.

Reconciliations of Changes in Reserves

The following table sets forth the reconciliation of our gross reserves as at December 31, 2008, using forecast price and cost estimates derived from the GLJ Report. Gross reserves as at December 31, 2008 and as at December 31, 2007 include working interest reserves before royalties payable and without including gross royalties receivable.

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

	LIGHT AND MEDIUM OIL			HEAVY OIL			NATURAL GAS		
FACTORS	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (Bcf)	Probable (Bcf)	Proved Plus Probable (Bcf)
December 31, 2007	110,686	29,698	140,384	2,353	781	3,134	589.8	165.1	754.9
Discoveries	55	26	81	0	0	0	4.3	1.9	6.3
Extensions	860	477	1,337	15	5	20	50.5	52.3	102.8
Infill Drilling	2,685	709	3,394	160	(110)	50	141.2	37.4	178.6
Improved Recovery	1,108	300	1,408	0	0	0	0.6	0.3	0.8
Technical Revisions	(1,095)	(1,004)	(2,099)	137	(68)	68	18.6	5.3	23.8
Acquisitions	46	15	61	7	2	9	0.0	0.1	0.1
Dispositions	0	0	0	0	0	0	0.0	0.0	0.0
Economic Factors	496	(83)	413	58	30	88	1.9	0.7	2.6
Production	(9,930)	0	(9,930)	(363)	0	(363)	(69.9)	0.0	(69.9)
December 31, 2008	104,912	30,138	135,049	2,366	640	3,006	736.9	263.1	1,000.0

	NATURAL GAS LIQUIDS			TOTAL		
FACTORS	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (mboe)	Probable (mboe)	Proved Plus Probable (mboe)
December 31, 2007	11,249	2,969	14,218	222,592	60,958	283,550
Discoveries	17	8	25	794	355	1,149
Extensions	199	145	344	9,486	9,348	18,834
Infill Drilling	758	177	935	27,132	7,012	34,144
Improved Recovery	60	10	70	1,264	355	1,619
Technical Revisions	141	17	158	2,279	(178)	2,101
Acquisitions	0	0	0	54	37	91
Dispositions	0	0	0	0	0	0
Economic Factors	30	4	34	898	73	971
Production	(1,397)	0	(1,397)	(23,345)	0	(23,345)
December 31, 2008	11,057	3,330	14,386	241,154	77,960	319,114

Additional Information Relating to Reserves Data

Proved and Probable Undeveloped Reserves

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

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

Proved Undeveloped Reserves

	Light & Medium Oil (Mbbl)		Heavy Oil (Mbbl)		Natural Gas (MMcf)		Natural Gas Liquids (Mbbl)		Oil Equivalent (mboe)	
	First Attributed	Total at Year-end	First Attributed	Total at Year-end	First Attributed	Total at Year-end	First Attributed	Total at Year-end	First Attributed	Total at Year-end
Prior	19,863	19,863	40	40	118,645	118,645	1,346	1,346	41,023	41,023
2006	2,170	11,861	-	-	29,866	121,976	434	1,827	7,584	34,017
2007	2,401	11,131	11	11	40,101	122,061	235	1,484	9,331	32,970
2008	865	7,919	-	-	152,082	268,684	683	2,000	26,895	54,700

Probable Undeveloped Reserves

	Light & Medium Oil (Mbbl)		Heavy Oil (Mbbl)		Natural Gas (MMcf)		Natural Gas Liquids (Mbbl)		Oil Equivalent (mboe)	
	First Attributed	Total at Year-end	First Attributed	Total at Year-end	First Attributed	Total at Year-end	First Attributed	Total at Year-end	First Attributed	Total at Year-end
Prior	10,291	10,291	247	247	58,887	58,887	929	929	21,282	21,282
2006	3,698	10,331	-	258	3,782	56,020	300	1,002	4,628	20,928
2007	1,832	10,057	113	211	22,534	67,837	178	1,034	5,879	22,608
2008	972	8,511	-	93	79,623	153,050	283	1,346	14,526	35,458

Over 75 per cent of the proved plus probable undeveloped reserves are located in the Dawson, Ante Creek, Weyburn and Dawson West Area properties. In each case, we have planned a program for the development of a portion of the undeveloped reserves in these areas in 2009. For further information, see "Additional Information Relating to Reserve Data – Exploration and Development Activities".

In some cases it will take us longer than two years to develop these reserves. We plan to develop the majority of the proved undeveloped reserves in the reserves evaluation over the next four years and plan to develop the majority of the probable undeveloped reserves over the next seven years. The pace of development of these reserves is influenced by many factors, including the ongoing development of the infrastructure in the Montney assets, the outcomes of the yearly drilling and reservoir evaluations, as well as capital constraints related to the current economic conditions.

Significant Factors or Uncertainties

We have a significant amount of proved undeveloped and probable reserves assigned to the Dawson and the Dawson West Area gas fields in northeast British Columbia. Sophisticated and expensive technology is required for these wells to produce. At the current prices, these wells are economic; however, should gas prices fall materially, the wells may not be economic to drill.

Further degradation in future commodity price forecasts relative to the forecast in the GLJ Report can also have a negative impact on the economics of the development of the undeveloped reserves, unless significant moderation in the future costs of development are not also realized.

Other Oil and Gas Information

Our portfolio of properties as at December 31, 2008 includes both unitized and non-unitized oil and natural gas production. In general, the properties contain long life, low decline rate reserves and include interests in several major oil and gas fields.

Principal Properties

The following is a description of our principal oil and natural gas properties as at December 31, 2008. Reserves amounts are stated at December 31, 2008, based on escalated cost and price assumptions as evaluated in the GLJ Report prepared by GLJ (see "Statement of Reserves Data and Other Oil and Gas Information"). Information in respect of gross and net acres and well counts are as at December 31, 2008, and information in respect of production is for the year ended December 31, 2008 except where indicated otherwise. Due to the fact that we have been active at acquiring additional interests in our principal properties, the working interest share and interest in gross and net acres and wells as at December 31, 2008 may not directly correspond to the stated production for the year which only includes production since the date the interests were acquired by us. The estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.

All of the properties described below are located in the Western Canadian Sedimentary Basin and within the Canadian provinces of British Columbia, Alberta or Saskatchewan. The properties represent 62 per cent of the total gross proved plus probable reserves as assigned by GLJ in the GLJ Report. There are no other properties which individually account for more than 2.9 per cent of the total gross proved plus probable reserves as assigned by GLJ in the GLJ Report. The Dawson West Area property has gross proved reserves of 3,287 mboe and gross proved plus probable reserves of 7,550 mboe reserves attributed which are capable of producing, but which are not yet producing because of pipeline, processing and other infrastructure constraints. There are no other material properties to which reserves have been attributed which are capable of producing but which are not producing and there are no material statutory or mandatory relinquishments, surrenders, back-ins or changes in ownership provisions.

	Gross Reserves and Gross Production			
	2008 Production	Proved Reserves	Proved plus Probable Reserves	
	(boe/d)	(mboe)	(mboe)	(%)
Dawson	7,222	48,760	69,958	21.9
Ante Creek	5,084	20,042	26,075	8.2
Redwater	3,998	22,377	26,731	8.4
Lougheed	2,622	5,941	7,902	2.5
Jenner	2,615	10,067	12,809	4.0
Pouce Coupe	2,549	3,514	4,395	1.4
Hatton	2,117	8,072	9,603	3.0
North Pembina Cardium Unit	1,831	12,890	15,125	4.7
Weyburn Unit	1,824	10,197	15,805	5.0
Berrymoor Cardium Unit	1,668	8,384	10,640	3.3

Dawson

The Dawson property is located in northeast British Columbia. We are the operator and own an average land interest of 92 per cent in approximately 32,900 gross hectares (30,115 net hectares). We operate a large area compression facility where the natural gas and liquids are sent to a third party operated facility. During 2008, gross production from the area averaged 7,222 boe/d of natural gas and natural gas liquids from 85 net wells principally from the upper Montney zone. During 2008, 27 new wells were drilled. GLJ assigned gross proved reserves of 48,760 mboe and gross proved plus probable reserves of 69,958 mboe of natural gas and natural gas liquids to this area, or 21.9 per cent of total gross proved plus probable reserves. GLJ has estimated as at October 1, 2008, that the Dawson property contained 3.5 Tcf of natural gas classified as Discovered Petroleum Initially In Place ("**DPIIP**") of which 2.0 Tcf of natural gas classified as DPIIP are on sections to which reserves have been assigned by GLJ in the GLJ Report. The GLJ best estimate of DPIIP uses a three per cent porosity cut-off and an average drilling assumption of three horizontal equivalent wells per section. Further development drilling and testing is required to determine the scale of contingent resources. The proven and probable reserves assigned by GLJ to the Dawson property as at December 31, 2008 in the GLJ Report represents a 25 per cent recovery factor.

In addition to the Dawson property, we own an average land interest of 76 per cent in approximately 24,938 gross hectares (18,988 net hectares) in the Dawson West Area which we believe is prospective in the upper Montney zone. GLJ has estimated as at October 1, 2008 that the Dawson West Area contains 4.6 Tcf of natural gas classified as DPIIP in the upper Montney zone. This GLJ best estimate is based on a three per cent porosity cut-off and limited development drilling and testing data. Given the current stage of development, this best estimate will be subject to potentially significant changes with further development activity. Further development drilling and testing is required to determine the scale of contingent resources. The Dawson West Area has been assigned gross proved reserves of 3,287 boe and gross proved plus probable reserves of 7,550 mboe in the GLJ Report which is capable of producing but which are not yet producing because of pipeline, processing and other infrastructure constraints. We currently plan to construct a 60 MMcfpd gas plant for production in the Dawson and Dawson West Area.

The resources estimates of natural gas are estimates only and the actual resources may be greater than or less than the estimates provided herein. A capital development project for the recovery of this volume of DPIIP cannot be defined at this time. There is no certainty that it will be economically viable or technically feasible to produce any portion of this natural gas classified as DPIIP.

Ante Creek

The Ante Creek property is located in northwest Alberta. We are the operator and own an average land interest of 93 per cent. Oil production is processed through three operated facilities, while the gas is processed through one operated facility and one third party facility. During 2008, gross production from the area averaged 5,084 boe/d of oil, natural gas and natural gas liquids from 169 net wells. During 2008, 12 new wells were drilled. GLJ assigned gross proved reserves of 20,042 mboe and gross proved plus probable reserves of 26,075 mboe of oil, natural gas and natural gas liquids to this area, or 8.2 per cent of total gross proved plus probable reserves.

Redwater

The Redwater property is located in central Alberta. We are the operator and own an average land interest of 86 per cent. Oil and solution gas are both processed at an operated central facility. During 2008, gross production from the area averaged 3,998 boe/d of oil, natural gas and natural gas liquids from 404 net wells. During 2008, eight new wells were drilled. GLJ assigned gross proved reserves of 22,377 mboe and gross proved plus probable reserves of 26,731 mboe of oil, natural gas and natural gas liquids to this area, or 8.4 per cent of total gross proved plus probable reserves.

ARC believes that the Redwater field is a prime candidate for Enhanced Oil Recovery ("EOR") through the use of Carbon Dioxide ("CO_2") injection. Redwater is one of the largest conventional oil pools in Canada and has been producing for over 50 years. While production to date on our properties is approximately 600 million barrels of oil, we believe that there are substantial quantities of oil remaining in the reservoir which are unrecoverable with conventional technology. During 2008, ARC commenced the injection of CO_2 at a pilot EOR project in Redwater. The pilot is designed to confirm whether the Redwater reef is amenable to CO_2 flooding and that incremental oil can be mobilized and recovered. Definitive results from this CO_2 pilot project are not expected for at least another 12 months. Large amounts of CO_2 need to be acquired on economic terms for a large scale project like the Redwater EOR to proceed. Currently, there are no large scale CO_2 capture facilities or infrastructure to transport CO_2 in Alberta. Large infrastructure investments are required to capture, transport and inject CO_2 and long term agreements will need to be negotiated with emitters for the CO_2 supply. For these types of projects to be possible, higher commodity prices will need to prevail and most importantly, governments will need to clearly establish long term regulations surrounding the capture of CO_2 emissions. There is no assurance that this project will proceed or be economically viable.

Lougheed

The Lougheed property is located in southeast Saskatchewan. We are the operator and own an average land interest of 80 per cent. Production is handled by an operated battery and gas plant. During 2008, gross production from the area averaged 2,622 boe/d of oil and natural gas liquids from 122 net wells. During 2008, four new wells were drilled. GLJ assigned gross proved reserves of 5,941 mboe and gross proved plus probable reserves of 7,902 mboe of oil and natural gas liquids to this area, or 2.5 per cent of total gross proved plus probable reserves.

Jenner

The Jenner property is located in southeast Alberta. We own a combination of operated and non-operated acreage with an average land interest of 88 per cent. We operate four gas compression and dehydration facilities in the area. During 2008, gross production from the area averaged 2,615 boe/d of natural gas from 836 net wells. During 2008, no new wells were drilled. GLJ assigned gross proved reserves of 10,067 mboe and gross proved plus probable reserves of 12,809 mboe of natural gas to this area, or four per cent of total gross proved plus probable reserves.

Pouce Coupe

The Pouce Coupe property is located in northwest Alberta. We are the operator and own an average land interest of 74 per cent. The sweet gas is processed through an operated gas plant and the sour gas flows to a third party processing plant. During 2008, gross production from the area averaged 2,549 boe/d of oil, natural gas and natural gas liquids from 37 net wells. During 2008, two wells were drilled. GLJ assigned gross proved reserves of 3,514 mboe and gross proved plus probable reserves of 4,395 mboe of oil, natural gas and natural gas liquids to this area, or 1.4 per cent of total gross proved plus probable reserves.

Hatton

The Hatton property is located in southwest Saskatchewan. We own a combination of operated and non-operated acreage with an average land interest of 44 per cent. The operated production flows through three operated compression and dehydration facilities where our working interest ranges from 50 to 100 per cent. During 2008, gross production from the area averaged 2,117 boe/d of natural gas from 434 net wells. During 2008, 23 new wells were drilled. GLJ assigned gross proved reserves of 8,072 mboe and gross proved plus probable reserves of 9,603 mboe of natural gas to this area, or three per cent of total gross proved plus probable reserves.

North Pembina Cardium Unit

The North Pembina Cardium Unit No. 1 is located in central Alberta. We are the operator and own a 45.57 per cent interest in the unit. Production is processed through two operated oil treatment facilities and one operated solution gas plant. During 2008, gross production from the unit averaged 1,831 boe/d of oil, natural gas and natural gas liquids from 177 net wells. During 2008, ten new wells were drilled. GLJ assigned gross proved reserves of 12,890 mboe and gross proved plus probable reserves of 15,125 mboe of oil, natural gas and natural gas liquids to this unit, or 4.7 per cent of total gross proved plus probable reserves.

Weyburn Unit

The Weyburn unit is located in southeast Saskatchewan. EnCana Corporation operates the unit and we have a working interest of 6.95 per cent. The unit is currently undergoing a CO_2 flood for enhanced oil recovery. During 2008 gross production from the unit averaged 1,824 boe/d of oil from 58 net wells. During 2008, 34 new wells were drilled. GLJ assigned gross proved reserves of 10,197 mboe and gross proved plus probable reserves of 15,805 mboe of oil and natural gas liquids to this unit, or five per cent of total gross proved plus probable reserves.

Berrymoor Cardium Unit

The Berrymoor Cardium Unit is located in central Alberta. We are the operator and own a 73.25 per cent interest in the unit. Oil is processed at an operated battery while the solution gas flows to a third party facility. During 2008, gross production from the unit averaged 1,668 boe/d of oil, natural gas and natural gas liquids from 89 net wells. During 2008, seven new wells were drilled. GLJ assigned gross proved reserves of 8,384 mboe and gross proved plus probable reserves of 10,640 mboe of oil, natural gas and natural gas liquids to this unit, or 3.3 per cent of total gross proved plus probable reserves.

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, 2008.

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	4,066	1,604	1,109	138	4,387	1,908	199	38
British Columbia	7	1	1	-	256	91	38	16
Saskatchewan	2,141	802	286	89	5,498	868	54	20
Manitoba	561	125	20	2	-	-	-	-
Total	6,775	2,532	1,416	229	10,141	2,867	291	74

Properties with no Attributable Reserves

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

	Undeveloped Hectares	
	Gross	Net
Alberta	227,460	101,215
British Columbia	85,192	60,382
Manitoba	674	433
Saskatchewan	95,579	59,670
Total	408,905	221,700

In British Columbia, we have 55,800 gross hectares and 49,000 net hectares in Dawson and the Dawson West Area which have varying degrees of prospectively in the Montney zones. For more information, see "Additional Information Relating to Reserve Data – Principal Properties – Dawson and Dawson West Area".

We currently have no material work commitments on these lands. Approximately 38,000 net hectares of our undeveloped land holdings are slated to expire by December 31, 2009, however we anticipate that a portion of the undeveloped lands will be continued. There are no material expiries in our core holdings.

Forward Contracts

We are exposed to market risks resulting from fluctuations in commodity prices, foreign exchange rates and interest rates in the normal course of operations. A variety of derivative instruments are used to reduce our exposure to fluctuations in commodity prices, foreign exchange rates and interest rates. We may also potentially be exposed to losses in the event of default by the counterparties to these derivative instruments. We manage this risk by diversifying our derivative portfolio among a number of financially sound counterparties.

In general, without specific approval of the Board of Directors which is granted from time to time, management of ARC Resources is permitted to hedge up to a maximum of 50 per cent of forecasted production on a boe basis for up to six months, 35 per cent for up to nine months, 25 per cent for up to 15 months, and 15 per cent for up to 18 months.

We have a Risk Committee of the Board of Directors that reviews financial and business risks including activities related to our hedging program. Our management executes financial hedging transactions to reduce the Trust's exposure to market price fluctuations either by price protection, through derivatives or swaps, or diversifying its price exposure in accordance with the Board of Directors guidelines or approval on specific transactions.

A summary of financial and physical contracts in respect of hedging activities can be found in Note 13 "Market Risk Management" to our audited consolidated financial statements for the year ended December 31, 2008 and in the section under the heading "Risk Management and Hedging Activities" in our Management Discussion and Analysis and results of operations for the year ended December 31, 2008 which have been filed on SEDAR at www.sedar.com, and both of which note and section are incorporated in this Annual Information Form by reference.

Additional Information Concerning Abandonment and Reclamation Costs

The following table sets forth information respecting future abandonment and reclamation costs for surface leases, wells, facilities and pipelines which we expect to incur for the periods indicated.

	Abandonment and Reclamation Costs escalated at 2.0% Undiscounted ($MM)	Abandonment and Reclamation Costs escalated at 2.0% Discounted at 10% ($MM)
Total as at December 31, 2008	1,316.6	71.9
Anticipated to be paid in 2009	4.9	4.4
Anticipated to be paid in 2010	5.0	4.2
Anticipated to be paid in 2011	5.5	4.1

We will be liable for our share of ongoing environmental obligations and for the ultimate reclamation of the properties held by us upon abandonment. We estimate that we have an interest in 6,620 net wells that will require abandonment and reclamation over the next 51 years with the majority of payments being made in years 2049 to 2059. These ongoing environmental obligations are expected to be funded out of cash flow from operating activities and any balance available in our reclamation fund.

We have a reclamation fund to pay future asset retirement obligations costs. We currently estimate that the future environmental and reclamation obligations in respect of our properties will be approximately $1,317 million calculated by escalating costs at two per cent per year (reflected in our audited consolidated financial statements as an asset retirement obligation of $141.5 million calculated by escalating costs at two per cent per year and discounting at a blended rate of 6.6 per cent). For more information, see Note 11 of our audited consolidated financial statements and the section in our Management's Discussion and Analysis of operations of such financial statements under the heading "Asset Retirement Obligation and Reclamation Fund", which note and section are incorporated in this Annual Information Form by reference and are found on SEDAR at www.sedar.com. The Board of Directors of ARC Resources has approved voluntary contributions to our reclamation fund over a twenty year period that results in minimum annual contributions of $6 million ($6 million in 2008) based on properties owned as at December 31, 2008. During 2008, $9.7 million ($17.5 million for 2007) of actual expenditures were charged against the reclamation fund resulting in a net reduction of our reclamation fund for the year of $3.2 million ($10.4 million net addition in 2007). The balance of this fund as of December 31, 2008 is $11.2 million.

In addition we have committed to a restricted reclamation trust associated with the acquisition of the Redwater property pursuant to which ARC Resources has agreed with the vendor of the Redwater property to contribute to such trust certain minimum amounts, totalling approximately $110 million over a 50 year period, to fund future environmental and reclamation obligations in respect of the Redwater properties, or to expend certain minimum amounts towards discharging these obligations. The restricted contribution commenced in 2006 for $6.1 million and continues at a declining rate through 2055. The current balance of this trust as of December 31, 2008 is $17 million.

We estimate the costs to abandon and reclaim all our shut in and producing wells, pipelines and facilities. No estimate of salvage value is netted against the estimated cost. Our model for estimating the amount and timing of future abandonment and reclamation expenditures was created on an operating area level. Estimated expenditures for each operating area are based on the Energy Resources Conservation Board methodology which details the cost of abandonment and reclamation in eight specific geographic regions. Each region was assigned an average cost per well to abandon and reclaim the wells in that area.

Abandonment and reclamation costs have been estimated over a 50 year period. Facility abandonment and reclamation costs are scheduled to be incurred in the year following the end of the reserves life of its associated reserve.

The additional liability associated with well, pipelines and facilities reclamation costs which were not deducted by GLJ in estimating future net revenue in the GLJ Report are $1,071.6 million (escalating costs at two per cent and undiscounted) and $18.9 million (escalating costs at two per cent and discounted at 10 per cent). Only the abandonment costs associated with wells with reserves were deducted by GLJ in estimating future net revenue.

Tax Horizon

As a result of our tax efficient structure, annual taxable income is currently transferred from ARC Resources to the Trust and from the Trust to Unitholders. This is primarily accomplished through the deduction by ARC Resources of the Royalties on underlying oil and gas properties and the deduction of interest on the Long Term Notes.

The effect of the SIFT Rules is reflected in the after tax net revenue amounts disclosed in the Reserves Data (Forecast Prices and Costs) in this Annual Information Form, but uses a provincial rate of 13 per cent rather than 10 per cent as currently anticipated. See "Our Business – Federal Tax Changes for Income Trusts and Corporations".

Until the SIFT tax becomes applicable to the Trust, it is expected that minimal income taxes will be incurred by the Trust or its operating entities as currently structured. However, annual operating income retained to pay a portion of capital expenditures or used to repay debt may result in income tax liabilities within ARC Resources from time to time. In addition, any further declines in oil and natural gas prices and consequential reduced revenues may result in reduced distributions to Unitholders and income tax incurred by ARC Resources. See "Risk Factors – Federal Tax Changes for Income Trusts and Corporations" and "Risk Factors – Changes in Legislation".

Capital Expenditures

The following tables summarize capital expenditures (net of incentives and net of certain proceeds and including capitalized general and administrative expenses) related to our activities for the year ended December 31, 2008:

	2008 $MM
Property acquisition costs(1)	
Proved properties	6.3
Undeveloped properties	44.7
Exploration costs(2)	164.1
Development costs(3)	371.1
Corporate capital costs	13.4
Total	599.6

Notes:
(1) Represents acquisition costs net of dispositions and property swaps.
(2) Includes costs of land acquired ($119.6 million), geological and geophysical capital expenditures and drilling costs for 2008 exploration wells drilled.
(3) Includes costs of land acquired ($2.8 million), development and facilities capital expenditures and drilling costs for 2008 development wells drilled.

Exploration and Development Activities

The following table sets forth the gross and net exploratory and development wells that we participated in during the year ended December 31, 2008:

	Exploratory Wells		Development Wells		Total	
	Gross	Net	Gross	Net	Gross	Net
Light and Medium Oil	13	12	205	103	218	115
Heavy Oil	-	-	16	-	16	-
Natural Gas	25	11	210	87	235	98
Service	-	-	26	7	26	7
Dry	2	2	7	1	9	3
Total:	40	25	464	198	504	223

For 2009, the Trust has planned an extensive capital program of $450 million. The program comprises costs to develop the core assets of the Trust as well as construction costs for a new 60 mmcf per day gas plant for production in the Dawson and Dawson West Area. Our capital program is subject to variation throughout the year depending upon prices for oil and natural gas and there is no assurance that all or any part of our capital program will be expended as planned. In addition, capital expenditures may be made on the acquisition of undeveloped land or oil and natural gas reserves. See "Risk Factors – Volatility of Oil and Natural Gas Prices, "Risk Factors – Global Financial Crisis" and "Risk Factors – Capital Markets".

See "Risk Factors – Operational Matters" and "Risk Factors – Project Risks".

Production Estimates

The following table sets out the volume of our production estimated for the year ended December 31, 2009 which is reflected in the estimate of gross proved reserves and gross probable reserves disclosed in the tables contained under "Statement of Reserves Data and Other Oil and Gas Information - Disclosure of Reserves Data".

	Light and Medium Oil (bbl/d)		Heavy Oil (bbl/d)		Natural Gas (Mcfpd)		Natural Gas Liquids (bbl/d)		Total (boe/d)	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Total Proved	25,640	21,766	903	949	185,889	151,284	3,529	2,474	61,054	50,403
Total Proved Plus Probable	26,896	22,723	941	983	191,261	155,180	3,639	2,552	63,353	52,122

Production History

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

	Quarter Ended 2008				Year Ended
(6:1)	Mar. 31	June 30	Sept. 30	Dec. 31	2008
Average Daily Production[1]					
Light and Medium Crude Oil (bbl/d)	27,718	26,288	27,211	27,737	27,239
Heavy Oil (bbl/d)	1,346	1,253	1,298	1,198	1,274
Gas (MMcfpd)	204.3	194.7	192.0	195.1	196.5
NGLs (bbl/d)	3,856	3,906	3,822	3,858	3,861
Combined (boe/d)	66,975	63,896	64,325	65,313	65,126
Average Net Production Prices Received					
Light and Medium Crude Oil ($/bbl)	90.95	119.03	114.92	56.81	94.97
Heavy Oil ($/bbl)	64.43	103.38	98.97	43.47	77.85
Gas ($/Mcf)	7.80	10.41	8.68	7.48	8.58
NGLs ($/bbl)	68.54	82.29	82.87	45.22	69.71
Combined ($/boe)	66.94	88.04	82.06	50.06	71.59
Royalties Paid					
Light and Medium Crude Oil ($/bbl)	14.20	18.51	17.57	8.46	14.58
Heavy Oil ($/bbl)	6.71	11.38	10.53	4.95	8.41
Gas ($/Mcf)	1.54	2.15	1.99	1.59	1.82
NGLs ($/bbl)	19.64	22.96	23.83	11.91	19.58
Combined ($/boe)	11.85	15.79	15.00	9.14	12.91
Operating Expenses [2][3]					
Light and Medium Crude Oil ($/bbl)	11.35	15.50	13.80	13.63	13.91
Heavy Oil ($/bbl)	10.90	10.63	11.26	13.82	11.63
Gas ($/Mcf)	1.37	1.18	1.19	1.18	1.19
NGLs ($/bbl)	8.11	8.40	9.78	8.84	8.22
Combined ($/boe)	9.55	10.71	10.19	10.09	10.13

(6:1)	Quarter Ended 2008 Mar. 31	June 30	Sept. 30	Dec. 31	Year Ended 2008
Transportation Paid					
Light and Medium Crude Oil ($/bbl)	0.03	0.19	0.18	0.17	0.14
Heavy Oil ($/bbl)	1.31	1.06	1.10	1.19	1.17
Gas ($/Mcf)	0.22	0.23	0.24	0.26	0.24
NGLs ($/bbl)	-	-	-	-	-
Combined ($/boe)	0.73	0.79	0.80	0.86	0.80
(Gain)/Loss on Commodity and Foreign Exchange Contracts					
Light and Medium Crude Oil ($/bbl)	6.50	14.36	10.81	(3.05)	7.03
Heavy Oil ($/bbl)	-	-	-	-	-
Gas ($/Mcf)	(0.02)	0.60	0.43	(0.36)	0.16
NGLs ($/bbl)	-	-	-	-	-
Combined ($/boe)	2.63	7.67	5.79	(5.46)	3.17
Netback Received(4)					
Light and Medium Crude Oil ($/bbl)	58.87	70.47	72.56	37.60	59.31
Heavy Oil ($/bbl)	45.51	80.31	76.08	23.51	56.64
Gas ($/Mcf)	4.69	6.25	4.83	4.81	5.17
NGLs ($/bbl)	40.79	50.93	49.26	24.47	41.91
Combined ($/boe)	42.18	53.08	50.28	35.43	44.58

Notes:

(1) Before deduction of royalties.

(2) Operating expenses are composed of direct costs incurred to operate both oil and gas wells. A number of assumptions have been made in allocating these costs between oil, natural gas and natural gas liquids production.

(3) Operating recoveries associated with operated properties were excluded from operating costs and accounted for as a reduction to general and administrative costs.

(4) Netbacks are calculated by subtracting royalties, operating costs, transportation costs, and losses/gains on commodity and foreign exchange contracts from revenues.

No property accounts for more than 11.1 per cent of the production disclosed above. For more information, see "Other Oil and Gas Information – Principal Properties".

Marketing Arrangements

Natural Gas

During 2008, we continued our marketing strategy of maintaining a high level of direct control and diversification of marketing and transportation arrangements for our natural gas production.

The average natural gas price we received during 2008 was $8.58 per Mcf as compared to $6.75 per Mcf for 2007. This price was achieved with a portfolio mix that on average through the year received AECO index based pricing for 68 per cent, aggregator netback prices for 20 per cent, and Chicago Index Pricing for 12 per cent of total production.

To manage natural gas price volatility and to stabilize the revenue stream, our natural gas portfolio is directed towards maintaining balanced exposure to U.S. and Canadian markets with market sensitive and hedgeable pricing terms, as well as aggregator netback arrangements. Due to the winding up of two aggregator pools effective December 31, 2008, ARC's future aggregator contract obligations have reduced to 13 per cent of total gas sales. We also strive for a high utilization of contracted pipeline and processing capacity.

Crude Oil and Natural Gas Liquids

Our liquids production in 2008 was comprised of approximately 51 per cent light quality crude oil (greater than 35°API), 33 per cent medium quality crude oil (25 to 35 API), four per cent heavy quality crude (less than 25°API), four per cent condensate and eight per cent natural gas liquids. During 2008, our average sales prices were $94.97

per bbl for light and medium crude oil, $77.85 per bbl for heavy crude oil and $69.71 per bbl for natural gas liquids; these prices compare to 2007 prices of $70.77 per bbl for light and medium crude oil, $50.55 per bbl for heavy crude oil and $54.79 per bbl for natural gas liquids. Our crude oil is sold under contracts of varying terms of up to one year, based on market sensitive pricing terms. Natural gas liquids are sold under annual arrangements. Industry pricing benchmarks for crude oil and natural gas liquids are continuously monitored to ensure optimal netbacks.

SHARE CAPITAL OF ARC RESOURCES

Common Shares

ARC Resources has authorized for issuance an unlimited number of common shares of which 1,000,121 common shares are issued and outstanding and held by the Trust. The voting of such shares is delegated to ARC Resources under the Trust Indenture. The holders of common shares are entitled to notice of, to attend and to one vote per share held at any meeting of the shareholders of ARC Resources; to receive dividends as and when declared by the Board of Directors of ARC Resources on the common shares as a class, and subject to prior satisfaction of all preferential rights to dividends attached to all shares of other classes; and in the event of any liquidation, dissolution or winding-up of ARC Resources, whether voluntary or involuntary, or any other distribution of the assets of ARC Resources among its shareholders for the purpose of winding-up its affairs, and subject to prior satisfaction of all preferential rights to return of capital on dissolution attached to all shares of other classes of shares of ARC Resources ranking in priority to the common shares in respect of return of capital on dissolution, to share rateably, together with the shares of any other class of shares of ARC Resources ranking equally with the common shares in respect of return of capital on dissolution, in such assets of ARC Resources as are available for distribution.

Exchangeable Shares

ARC Resources is authorized to issue an unlimited number of Exchangeable Shares of which, as at December 31, 2008, 1,091,414 were outstanding. The Exchangeable Shares rank prior to the common shares of ARC Resources, the second preferred shares of ARC Resources 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 ARC Resources; provided that notwithstanding such ranking ARC Resources shall not be restricted in any way from repaying indebtedness of ARC Resources to the Trust from time to time. The Exchangeable Share provisions have been filed on SEDAR at www.sedar.com.

The Exchangeable Shares provide holders with a security having economic, ownership and voting rights which are substantially equivalent to those of Trust Units. As at December 31, 2008 the Exchange Ratio was 2.51668 Trust Units per Exchangeable Share. Holders of Exchangeable Shares will not receive distributions, rather the Exchangeable Shares are maintained economically equivalent to the Trust Units by the progressive increase in the Exchange Ratio to reflect distributions paid by the Trust to Unitholders. The Exchangeable Shares are provided equivalent voting rights as those of Unitholders through an agreement (the Exchangeable Share Voting and Exchange Trust Agreement) pursuant to which the holders of Exchangeable Shares can direct the Trustee to vote at meetings of Unitholders. The holders of Exchangeable Shares are further assured of the delivery of Trust Units by us in satisfaction of the obligations of ARC Resources under the Exchangeable Share terms through the provisions of another agreement (the Exchangeable Share Support Agreement). Copies of the Exchangeable Share Voting and Exchange Trust Agreement and the Exchangeable Share Support Agreement have been filed on SEDAR at www.sedar.com.

Computershare Trust Company of Canada acts as the transfer agent for the Exchangeable Shares.

Holders of Exchangeable Shares are entitled to receive, as and when declared by the Board of Directors in its sole discretion, from time to time, cumulative preferential cash dividends in an amount per share equal to the Exchange Ratio on the preceding business day multiplied by the fair market value of a Trust Unit as at the preceding business day (determined on the basis of the weighted average price of the Trust Unit on the TSX for the 10 trading days preceding that date). It is not anticipated that dividends will be declared or paid on the Exchangeable Shares, however the Board of Directors has the right in its sole discretion to do so, and if so, the Exchange Ratio would be reduced accordingly to reflect such dividends.

ARC Resources will not, without obtaining the approval of the holders of the Exchangeable Shares:

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

(b) redeem, purchase or make any capital distribution in respect of the common shares of ARC Resources, second preferred shares of ARC Resources or any other shares ranking junior to the Exchangeable Shares;

(c) redeem or purchase any other shares of ARC Resources ranking equally with respect to the payment of dividends or on any liquidation distribution; or

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

Notwithstanding the foregoing, the restrictions in paragraphs (a), (b) and (c) above shall only be applicable if dividends which have been declared on the outstanding Exchangeable Shares have not been paid in full.

The Exchangeable Share Provisions entitle the holder to exchange each Exchangeable Share at any time into the number of Trust Units equal to the Exchange Ratio then in effect. The Exchange Ratio is determined by reference to the distributions paid on Trust Units in a given month and the current market price of the Trust Units.

Second Preferred Shares

ARC Resources also has authorized an unlimited number of Second Preferred Shares which may at any time or from time to time be issued in one or more series. Before any shares of a particular series are issued, the Board of Directors of ARC Resources shall, by resolution, fix the number of shares that will form such series and shall, subject to the limitations set out herein, by resolution fix the designation, rights, privileges, restrictions and conditions to be attached to the Second Preferred Shares of such series. The Second Preferred Shares of each series shall rank behind the Exchangeable Shares and on parity with the Second Preferred Shares of every other series with respect to accumulated dividends and return of capital. The Second Preferred Shares are entitled to a preference over the Common Shares and over any other shares of ARC Resources ranking junior to the Second Preferred Shares with respect to priority in the payment of dividends and in the distribution of assets in the event of the liquidation, dissolution or winding-up of ARC Resources, whether voluntary or involuntary, or any other distribution of the assets of ARC Resources among its shareholders for the purpose of winding-up its affairs. As at the date hereof, there are Second Preferred Share, Series 1 and Second Preferred Share, Series 2 issued and outstanding which were issued to ARC Sask in consideration of the transfer of properties pursuant to an internal reorganization and which are redeemable by ARC Resources for $1,000 per share, together with all accrued and unpaid dividends.

OTHER INFORMATION RELATING TO OUR BUSINESS

Borrowing

We borrow funds from time to time to finance the purchase of properties, for capital expenditures or for other financial obligations or expenditures in respect of properties held by us or for working capital purposes. We have a policy relating to borrowing which requires a quarterly assessment by management, subject to review by the Board of Directors of ARC Resources, of the appropriateness of borrowing levels. We have granted security in priority to the Royalties to secure the loan of such funds.

Debt service charges on borrowed funds attributable to our properties, including funds borrowed by our subsidiaries from us, will be deducted in computing royalty income. The debt repayment will be scheduled to minimize any income tax payable by ARC Resources.

At December 31, 2008 we had an $800 million secured, extendible, financial covenant based three year syndicated credit facility that expires on April 15, 2011 and a $25 million demand working capital facility in addition to US

$212 million of senior secured notes outstanding. The credit facilities and senior secured notes rank equally and contain provisions which restrict the ability of ARC Resources to pay Royalties and interest under the Long Term Notes to ARC and thereby may restrict distributions to Unitholders, in the event of the occurrence of certain events of default. The credit agreement and note agreements are described under "Material Contracts" and have been filed on SEDAR at www.sedar.com. For more information, reference is made to Note 10 of our audited consolidated financial statements for the year ended December 31, 2008, which is incorporated by reference in this Annual Information Form and which has been filed on SEDAR at www.sedar.com.

See "Risk Factors – Refinancing Risk and Debt Service" and "Risk Factors – Variations in Interest Rates and Foreign Exchange Rates".

OUR INFORMATION

Trust Units

A maximum of 650,000,000 Trust Units have been created and may be issued pursuant to the Trust Indenture. The Trust Units represent equal undivided beneficial interests in the Trust. 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.

Special Voting Unit

The Trust Indenture also provides for the issuance of special voting units which are to be issued to a trustee 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 of ARC Resources when the Board authorizes issuing such special voting units.

A Special Voting Unit has been designated by the Board of Directors of ARC Resources as the Special Voting Unit, Exchangeable Shares ("**Special Voting Unit**"). The Special Voting Unit possesses a number of votes for the election of directors of ARC Resources and on all other matters submitted to a vote of Unitholders equal to the number of outstanding Exchangeable Shares from time to time not owned by Trust or ARC Subco. The holders of Trust Units and the holder of the Special Voting Unit vote together as a single class on all matters.

In the event of any liquidation, dissolution or winding-up of Trust, the holder of the Special Voting Unit will not be entitled to receive any of our assets available for distribution to Unitholders. The holder of the Special Voting Unit will not be entitled to receive dividends. The Special Voting Unit has been issued to Computershare Trust Company of Canada, as trustee. At such time as the Special Voting Unit has no votes attached to it because there are no Exchangeable Share outstanding that are not owned by Trust or ARC Subco, the Special Voting Unit will be cancelled.

For more information, see "Share Capital of ARC Resources – Exchangeable Shares".

The 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 the property of the Trust as an entirety or substantially as an entirety requires approval by Special Resolution of 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 "Meetings and Voting".

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, or may be obtained from the Trustee.

Trustee

Computershare Trust Company of Canada is the trustee of the Trust and also acts as the transfer agent for the Trust Units. The Trustee is responsible for, among other things: (a) accepting subscriptions for Trust Units and issuing Trust Units pursuant thereto; (b) maintaining books and records of the Trust and providing timely reports to holders of Trust Units; and (c) paying distributions to Unitholders. 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 the best interests of the Trust and 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 term of the Trustee's appointment is until the next annual meeting of Unitholders. At each annual meeting the Trustee may be reappointed or changed as determined by a majority of the votes cast at such meeting of Unitholders. The Trustee may resign upon 60 days' notice to the Trust. The Trustee may also be removed by a Special Resolution of the Unitholders. Such resignation or removal becomes effective upon the acceptance or appointment of a successor trustee.

ARC Resources presently administers the Trust on behalf of the Trustee. ARC Resources, on behalf of the Trustee, keeps such books and records as are necessary for the proper recording of the business transactions of the Trust.

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 the assets of the Trust 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.

Distributions and Allocations of Trust Income

The Trust Indenture provides that all of the distributable income of the Trust at the end of any calendar month including December 31 shall be declared payable and distributed to the Unitholders of record on the last day of each such calendar month. The distribution by the Trust of such distributable income is enforceable by such Unitholders of record. This distributable income is allocated to Unitholders for tax purposes.

In addition, the Trust Indenture provides that such distributable income may be paid in whole or in part by cash, in Trust Units, or promissory notes payable in whole or in part in cash or Trust Units on a specified date not more than 90 days after the record date to which the promissory note relates. The Trust Indenture also provides for the consolidation of the Trust Units in the discretion of the Board of Directors of ARC Resources to the pre-distribution number of Trust Units after any pro-rata distribution of additional Trust Units to all Unitholders.

For more information, see "Risk Factors – Allocations of Trust Income".

Future Offerings

Under the Trust Indenture, the Trust may offer additional Trust Units or rights to acquire additional Trust Units at such times and on such terms as the Board of Directors of ARC Resources may determine. At the option of the Trust, the net proceeds from any offerings may be used to finance the acquisition of additional properties, make additional capital expenditures or to repay indebtedness incurred in connection with such acquisitions. See "Risk Factors – Capital Markets".

Meetings and Voting

There will be at least one meeting of Unitholders 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 per cent 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 the Trustee, to appoint the auditors of the Trust and to elect all the members of the Board of Directors of ARC Resources.

Our Management

The Trust Indenture provides for delegation to ARC Resources by the Trustee of broad discretion to administer and manage our day to day operations, which includes responsibility and authority to make executive decisions on behalf of all of our direct or indirect subsidiaries and to exercise the powers of the Trustee. Without limitation of the foregoing, ARC Resources has been specifically delegated to provide certain administrative and support services to us, including those necessary: (i) to ensure compliance with continuous disclosure obligations under applicable securities legislation; (ii) to provide investor relations services; (iii) to provide or cause to be provided to Unitholders all information to which Unitholders are entitled under the Trust Indenture; (iv) to call, hold and distribute materials including notices of meetings and information circulars in respect of all necessary meetings of Unitholders; (v) to determine the amounts payable from time to time to Unitholders and to arrange for distributions to Unitholders of distributable income; and (vi) to determine the timing and terms of future offerings of Trust Units, if any.

ARC Resources 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 Unitholders and, in connection therewith, shall exercise that degree of care, diligence and skill that a reasonably prudent person would exercise in comparable circumstances.

Limitation on Non-Resident Ownership

The Trust intends to comply with the requirements under the Tax Act 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 Tax Act. In this regard, we may, from time to time, among other things, take all necessary steps to monitor the activities of the Trust and ownership of the Trust Units. If at any time we become aware that the activities of the Trust and ownership of the Trust Units by non-residents (non-residents of Canada and partnerships) may threaten the status of the Trust under the Tax Act as a "unit trust" or "mutual fund trust", we are authorized to take such action as may be necessary in the opinion of ARC Resources to maintain the status of the Trust as a unit trust and a mutual fund trust, including the imposition of restrictions on the issuance by the Trust, or the transfer by any Unitholder, of Trust Units to a non resident. See "Risk Factors – Changes in Legislation", "Risk Factors – Non-Resident Ownership of Trust Units" and "Risk Factors – Additional Risk Factors Applicable to Residents of the United States and Other Non-Residents of Canada".

Right of Redemption

Trust Units will be 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 requesting redemption. Upon receipt of the redemption request, all rights to and under the Trust Units tendered for redemption shall be surrendered and the holder thereof shall be entitled to receive a price per Unit ("**Market Redemption Price**") equal to the lesser of: (i) 90 per cent of the market price, being the weighted average trading 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 surrendered 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 surrendered for redemption.

The aggregate cash 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; provided that the entitlement of Unitholders to receive cash upon the redemption of their Trust Units is subject to a number of conditions, including the condition that the total amount payable by us in respect of such Trust Units and all other Trust Units tendered for retraction in the same calendar month must not exceed $100,000 provided that we may waive such condition in respect of any calendar month.

If a Unitholder is not entitled to receive cash upon the redemption of Trust Units then we shall, at the discretion of the Board of Directors of ARC Resources, pay the Market Redemption Price by distributing either: (i) unsecured subordinated promissory notes bearing interest at 4.5 per cent with a 20 year term, or (ii) distributing a portion of some or all of the assets of ARC having in the opinion of the Board of Directors of ARC Resources a fair market value equal to the Market Redemption Price. Alternatively, the Board of Directors of ARC Resources may decide to distribute a pro rata share of the assets of the Trust, net of any liabilities of the Trust.

It is anticipated that the foregoing retraction right will not be the primary mechanism for holders of Trust Units to dispose of their Trust Units. ARC Resources 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 in the ARC Resources Notes. ARC Resources Notes may be subject to resale restrictions under applicable securities laws. ARC Resources Notes so distributed may be qualified investments for trusts governed by registered retirement savings plans, registered retirement income trusts and deferred profit sharing plans. See "Risk Factors – Return of Capital and Right of Redemption."

Termination of the Trust

Unitholders may vote to terminate the Trust at any meeting of Unitholders, subject to the following: (a) a vote may only be held if requested in writing by the holders of not less than 20 per cent of the Trust Units; (b) a quorum of 50 per cent 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 Unitholders.

Unless the Trust is terminated or extended by vote of Unitholders earlier, the Trustee shall commence to wind-up the affairs of the Trust on December 31, 2095. In the event that the Trust is wound-up, the Trustee will liquidate all the assets of the Trust, pay, retire, discharge or make provision for some or all obligations of the Trust 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 to Unitholders and the unaudited interim financial statements of the Trust will be mailed to Unitholders as prescribed by securities legislation. Our year end is December 31. We are 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 certain material contracts, the Trust Indenture and a listing of the registered holders of Trust Units.

Distribution Reinvestment and Optional Trust Unit Purchase Plan

A plan has been established to provide Unitholders who are residents of Canada (within the meaning of the *Tax Act*) with a method to reinvest distributions by purchasing additional Trust Units.

CORPORATE GOVERNANCE

General

In general, ARC Resources has been delegated substantially all of our management decisions. Unitholders are entitled to elect all of the Board of Directors of ARC Resources pursuant to the terms of the Trust Indenture. The Articles of ARC Resources were amended on March 20, 2008 to provide that the Board of Directors of ARC Resources shall consist of a minimum of three and a maximum of 12 directors.

Trust Indenture

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

Decision Making

The Board of Directors of ARC Resources has a mandate to supervise the management of our business and affairs and to act with a view to our best interests. The Board of Directors of ARC Resources supervises the management of the business and affairs of our subsidiaries. The Board of Directors' mandate includes: (a) the responsibility for managing our affairs; (b) monitoring our management and our activities; (c) reviewing strategic operating, capital and financial plans; and (d) compliance reporting and corporate communications. In particular, significant operational decisions and all decisions relating to: (i) the acquisition and disposition of properties for a purchase price or proceeds in excess of an amount prescribed from time to time by the Board of Directors; (ii) the approval of capital expenditure budgets; and (iii) establishment of credit facilities are made by the Board of Directors of ARC Resources. In addition, the Trustee has delegated broad discretion in relation to our day to day operations to the Board of Directors of ARC Resources including all decisions relating to: (i) matters relating to any offers for Trust Units; (ii) issuances of additional Trust Units; and (iii) the determination of the amount of distributable income. Any amendment to the royalty agreements requires the approval of the Board of Directors of ARC Resources on our behalf. The Board of Directors of ARC Resources holds regularly scheduled meetings at least quarterly to review the business and affairs of our subsidiaries and make any necessary decisions relating thereto.

The Trust Indenture gives to the Board of Directors of ARC Resources 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.

Board of Directors of ARC Resources

ARC Resources has a Board of Directors consisting of eight individuals, all of whom have been elected by Unitholders, including by the holders of the Exchangeable Shares through the Special Voting Unit.

The name, municipality of residence, position held and principal occupation of each director and officer of ARC Resources as at December 31, 2008 are set out below:

Name and Municipality of Residence	Offices Held and Time as Director	Principal Occupation
Mac H. Van Wielingen[(3)(4)(5)] Calgary, Alberta, Canada	Chairman of the Board and Director since May 3, 1996	Co-Chairman of ARC Financial Corporation (an investment management company)
Walter DeBoni[(1) (3) (5)] Calgary, Alberta, Canada	Vice Chairman and Director since June 26, 1996	Independent Businessman
John P. Dielwart Calgary, Alberta, Canada	President, Chief Executive Officer and Director since May 3, 1996	President and Chief Executive Officer of ARC Resources
Fred J. Dyment[(1)(2)(3)] Calgary, Alberta, Canada	Director since April 17, 2003	Independent Businessman
James C. Houck[(1)(2)(6)] Calgary, Alberta, Canada	Director since February 14, 2008	President and Chief Executive Officer of The Churchill Corporation
Michael M. Kanovsky[(2)(3)(4)] Calgary, Alberta, Canada	Director since May 3, 1996	Independent Businessman
Herbert C. Pinder, Jr.[(4)(5)(6)] Saskatoon, Saskatchewan, Canada	Director since January 1, 2006	Independent Businessman

Name and Municipality of Residence	Offices Held and Time as Director	Principal Occupation
John M. Stewart(1)(4)(6) Scottsdale, Arizona, U.S.A.	Director since February 11, 1998	Vice Chairman of ARC Financial Corporation (an investment management company)
Doug J. Bonner Calgary, Alberta, Canada	Senior Vice-President, Corporate Development	Senior Vice-President, Corporate Development of ARC Resources
David P. Carey Calgary, Alberta, Canada	Senior Vice-President, Capital Markets	Senior Vice-President, Capital Markets of ARC Resources
Terry Gill Calgary, Alberta, Canada	Senior Vice-President, Corporate Services	Senior Vice-President, Corporate Services of ARC Resources
Steven W. Sinclair Calgary, Alberta, Canada	Senior Vice-President, Finance and Chief Financial Officer	Senior Vice-President, Finance and Chief Financial Officer of ARC Resources
Myron M. Stadnyk Calgary, Alberta, Canada	Senior Vice-President and Chief Operating Officer	Senior Vice-President and Chief Operating Officer of ARC Resources
Terry M. Anderson Calgary, Alberta, Canada	Vice-President, Operations	Vice-President, Operations of ARC Resources
Yvan Chrétien Calgary, Alberta, Canada	Vice-President, Land	Vice-President, Land of ARC Resources
Ingram B. Gillmore Calgary, Alberta, Canada	Vice-President, Engineering	Vice-President, Engineering of ARC Resources
Neil Groeneveld Calgary, Alberta, Canada	Vice-President, Geosciences	Vice-President, Geosciences of ARC Resources
P. Van R. Dafoe Calgary, Alberta, Canada	Vice-President and Treasurer	Vice-President and Treasurer of ARC Resources
Allan R. Twa Calgary, Alberta, Canada	Secretary	Partner, Burnet, Duckworth & Palmer LLP (barristers and solicitors)

Notes:
(1) Member of Audit Committee in 2008.
(2) Member of Reserves Committee in 2008.
(3) Member of Risk Committee in 2008.
(4) Member of Human Resources and Compensation Committee in 2008.
(5) Member of Policy and Board Governance Committee in 2008.
(6) Member of Health, Safety and Environment Committee in 2008.

With the exception of the following individuals, the officers and directors have held the position set forth as his principal occupation for the last five years: Prior to 2005, Walter DeBoni, was Vice-President, Canada Frontier & International Business of Husky Energy Inc. (a public oil and gas company). Prior to October 2007, Mr. James Houck was President and Chief Executive Officer and a director of Western Oil Sands Ltd. and prior to April 1, 2005, Mr. Houck held several senior positions with Chevron Texaco Inc. Prior to November 2005, Steven W. Sinclair, was Vice-President, Finance and Chief Financial officer, David P. Carey was Vice-President, Business Development, Doug Bonner was Vice-President, Engineering, Myron J. Stadnyk, was Vice-President, Operations and Land and prior to September 2004 was Vice President Operations, of ARC Resources. Prior to March 2005, P. Van R. Dafoe, was Controller of ARC Resources and prior to July 2007 was Treasurer of ARC Resources. Prior to November 2005, Terry M. Anderson, was Manager, Field Operations of ARC Resources, and Yvan Chretien was Land Manager of ARC Resources. Prior to January 2007, Ingram Gillmore was Engineering Manager of ARC Resources. Prior to September 2008, Terry Gill, was Senior Vice President Human Resources at Superior Propane. Prior to October 2008, Neil Groeneveld was Manager, Geology of ARC Resources.

The following comprises a brief description of the background of the officers of ARC Resources.

John P. Dielwart, B.Sc., P.Eng.

Mr. Dielwart was the President and Chief Executive Officer of ARC Resources Ltd. until February 11, 2009 and is now Chief Executive Officer of ARC Resources Ltd. and has overall management responsibility for the Trust. Prior to joining ARC in 1996, Mr. Dielwart spent 12 years with a major Calgary based oil and natural gas engineering consulting firm, as senior vice-president and a director, where he gained extensive technical knowledge of oil and natural gas properties in western Canada. He began his career working for five years with a major oil and natural gas company in Calgary. Mr. Dielwart is a Past-Chairman of the board of governors for the Canadian Association of Petroleum Producers (CAPP). He holds a Bachelor of Science with Distinction (Civil Engineering) degree, University of Calgary. He has also been a director of ARC since 1996.

Steven W. Sinclair, B. Comm., CA

Mr. Sinclair is Senior Vice-President Finance and Chief Financial Officer of ARC Resources Ltd. and oversees all of the financial and accounting affairs of ARC Energy Trust. Mr. Sinclair has a Bachelor of Commerce from the University of Calgary, and a Chartered Accountant's designation which he received in 1981. He has over 25 years experience within the finance, accounting and taxation areas of the oil and gas industry and has been with the Trust since 1996. Mr. Sinclair is also a member of the Alberta and Canadian Institutes of Chartered Accountants.

Myron M. Stadnyk, P.Eng.

Mr. Stadnyk was the Senior Vice-President and Chief Operating Officer of ARC Resources Ltd. until February 11, 2009 and is now the President and Chief Operating Officer of ARC Resources Ltd. and is responsible for all aspects of ARC's ongoing operational and production management and strategies. He has over 25 years experience in the oil and gas business. Prior to joining ARC Resources Ltd. in 1997, Mr. Stadnyk worked with a major oil and gas company in both domestic and international operations. He has a B.Sc. in Mechanical Engineering from the University of Saskatchewan and is a member of the Association of Professional Engineers.

Doug J. Bonner, P.Eng.

Mr. Bonner is Senior Vice-President, Corporate Development of ARC Resources Ltd. and is responsible for the strategic development of ARC's enhanced oil recovery assets. He holds a B.Sc. in Geological Engineering from the University of Manitoba. Mr. Bonner's major area of expertise is reservoir engineering and he has extensive technical knowledge of oil and natural gas fields throughout western Canada, the east coast and northern Canada. Prior to joining ARC in 1996, Mr. Bonner spent 18 years with various major oil and natural gas companies in positions of increasing responsibility.

David P. Carey, P.Eng., MBA

Mr. Carey is Senior Vice-President, Capital Markets of ARC Resources Ltd. and is responsible for all facets of investor relations and corporate governance. He holds both a B.Sc. in Geological Engineering and a MBA from Queen's University. Mr. Carey brings over 25 years of diverse experience in the Canadian and International energy industries covering exploration, production and project evaluations in western Canada, oil sands, the Canadian frontiers and internationally. Prior to joining ARC Resources in 2001, Mr. Carey held senior positions with Athabasca Oil Sands Trust and a major Canadian oil and gas company.

Terry Gill, B.PE.

Mr. Gill is Senior Vice-President, Corporate Services of ARC Resources Ltd. and oversees all human resources, information technology and office services related activities. Prior to joining ARC in September 2007, Mr. Gill spent eight years with a major national distribution company as a senior executive. He also spent 15 years in the oil and gas industry and has broad experience in all areas of talent management. Mr. Gill has coached high performance athletes at an elite level and holds a B.PE. in coaching leadership from the University of Alberta.

Terry M. Anderson, P.Eng.

Mr. Anderson is Vice-President, Operations of ARC Resources Ltd. and is responsible for all of ARC's operational activities. He has a B.Sc. in Petroleum Engineering and is a member of the Association of Professional Engineers in Alberta, Saskatchewan and British Columbia. Mr. Anderson has over 15 years of experience in drilling, completion, pipeline, facility and production operations. Prior to joining ARC in 2000, he worked at a major oil and gas company.

Yvan Chretien, B.Comm.

Mr. Chretien is Vice-President, Land of ARC Resources Ltd. and is responsible for all of ARC's land related activities. He has over 15 years of related experience in the oil and gas business. Prior to joining ARC in 2001, Mr Chretien worked for both senior and intermediate oil and gas companies.

Ingram B. Gillmore, P.Eng.

Mr. Gillmore is Vice-President, Engineering of ARC Resources Ltd. and is responsible for all of ARC's engineering and joint venture related activities. He holds a B.Sc. in Chemical engineering from the University of Waterloo (1991) and a Bachelor of Fine Arts. Mr. Gillmore has been at ARC since 2002. Prior to joining ARC, Mr. Gillmore held positions with several major oil and gas companies.

Neil Groeneveld, P. Geol.

Mr. Groeneveld is Vice-President, Geosciences of ARC Resources Ltd. and is responsible for ARC's geophysical and geological activities. He has over 20 years of experience in the western Canadian oil & gas business and brings a broad background in oil and gas development, exploration and operations. He holds a Master of Science degree in Geology from the University of Regina. Prior to joining ARC in 2003, Mr. Groeneveld held senior positions with large and intermediate oil and gas companies.

P. Van R. Dafoe, B. Comm., CMA

Mr. Dafoe is Vice-President and Treasurer of ARC Resources Ltd. and is responsible for all of ARC's Hedging and Treasury related activities. He has a Bachelor of Commerce – Honours from the University of Manitoba and obtained his Certified Management Accountant's designation in 1995. Mr. Dafoe joined ARC in 1999 after 13 years with various companies in the finance and accounting area of the oil and gas industry.

Allan R. Twa, Q.C.

Mr. Twa acts as Corporate Secretary of ARC Resources Ltd. A member of the Alberta Bar since 1971, Mr. Twa is a partner in the law firm Burnet, Duckworth & Palmer LLP. Mr. Twa holds a B.A. (Political Science) from the University of Calgary, a LL.B. from the University of Alberta and a LL.M. from the University of London, England. Over the last 30 years, Mr. Twa has been engaged in a legal practice involving legal administration of public companies and trusts, corporate finance, and mergers and acquisitions.

Mac Van Wielingen is the Chairman and a Director of ARC Resources and was a director of Gauntlet Energy Corporation which secured creditor protection pursuant to the *Companies' Creditors Arrangement Act* on June 17, 2003 and was subsequently acquired by Ketch Resources Ltd. in December, 2003.

All of the directors of ARC Resources were elected on May 12, 2008 to hold office until the next annual general meeting of ARC Resources, which is scheduled for May 20, 2009. As at December 31, 2008, the directors and officers of ARC Resources, as a group, beneficially owned, or controlled or directed, directly or indirectly, 807,010 Trust Units or approximately 0.37 per cent of the outstanding Trust Units, and 613,770 Exchangeable Shares or approximately 56 per cent of the outstanding Exchangeable Shares. If all of the Exchangeable Shares had been exchanged for Trust Units at the Exchange Ratio in effect on December 31, 2008, the directors and officers of ARC Resources as a group would hold 2,351,673 Trust Units or approximately 1.07 per cent of the outstanding Trust Units as at December 31, 2008.

See "Risk Factors – Reliance on Key Members of Management".

AUDIT COMMITTEE DISCLOSURES

Multilateral Instrument 52-110 ("**MI 52-110**") relating to audit committees has mandated certain disclosures for inclusion in this Annual Information Form. The text of the Audit Committee's mandate is attached as Appendix C to this Annual Information Form.

Members of the Audit Committee

As of December 31, 2008, the members of the Audit Committee were Fred J. Dyment, chairman, and Walt DeBoni, James C. Houck and John M. Stewart, each of whom is independent and financially literate within the meaning of MI 52-110. The following comprises a brief summary of each member's education and experience:

Fred J. Dyment

Mr. Dyment has 30 years experience in the oil and gas business and is currently an independent businessman. His past business career included positions as President and CEO for Maxx Petroleum and President and CEO of Ranger Oil Limited. Mr. Dyment received a Chartered Accountant designation from the province of Ontario in 1972. Mr. Dyment currently sits as a Director on the Boards of Tesco Corporation, Western Oil Sands and Transglobe Energy Corporation. He has been a Director of ARC since 2003.

Walt DeBoni

Mr. DeBoni retired from Husky Energy Inc. where he held the position of VP, Canada Frontier & International Business. Prior to this Mr. DeBoni was CEO of Bow Valley Energy for a number of years. In addition to his time at Husky and Bow Valley he has also held numerous top executive posts in the oil and gas industry with major corporations. Mr. DeBoni holds a B.A.Sc. Chem. Eng. from the University of British Columbia, a MBA degree with a major in Finance from the University of Calgary and is a member of the association of Professional Engineers, Geologists and Geophysicists of Alberta and the Society of Petroleum Engineers. He is a past Chairman of the Petroleum Society of CIM, a past Director of the Society of Petroleum Engineers and has been a Director of ARC Resources since 1996.

James C. Houck

Mr. James C. Houck is currently the President and Chief Executive Officer and a director of The Churchill Corporation. Prior to January 2009 Mr. Houck was an independent businessman and prior to October 18, 2007 was the President and Chief Executive Officer and a director of Western Oil Sands Ltd. Mr. Houck has a B.Sc. from Trinity University and an MBA from the University of Houston. Mr. Houck has over 37 years of industry experience, primarily with Chevron Texaco Inc. where he held a number of senior management positions.

John M. Stewart

Mr. Stewart is Vice-Chairman and a founder of ARC Financial Corporation. Mr. Stewart has a B.Sc. in Engineering from the University of Calgary and an MBA from the University of British Columbia. Prior to ARC Financial he was a director and Vice-President of a major investment dealer.

Principal Accountant Fees and Services

The Audit Committee has not adopted specific policies and procedures for the engagement of non-audit services and pre-approves each such engagement or type of engagement for every fiscal year.

Our external auditor is Deloitte & Touche LLP. The following is a summary of the external audit services fees by category.

Audit Fees

The aggregate fees billed by our external auditor for audit services are:

2008	$677,834
2007	$768,375

Audit Related Fees

The aggregate fees billed by our external auditor for assurance and related services that are reasonably related to the performance of the audit or review of the financial statements (not included in audit services fees) are:

2008	$36,199
2007	$71,724

Tax Fees

The aggregate fees billed by our external auditor for professional services for municipal property tax compliance, tax advice and tax planning are:

2008	$114,013
2007	$139,780

All Other Fees

The aggregate fees billed by our external auditor for products and services not included under the headings: Audit Fees, Audit Related Fees, Tax Fees and All Other Fees.

2008	$Nil
2007	$Nil

CONFLICTS OF INTEREST

The Board of Directors has adopted a Code of Business Conduct and Ethics and a Code of Ethics for Senior Financial Officers (the "**Codes**"). In general, the private investment activities of employees, directors and officers are not prohibited, however, should an existing investment pose a potential conflict of interest the potential conflict is required by the Codes to be disclosed to the President or the Board of Directors. Any other activities of employees which pose a potential conflict of interest are also required by the Codes to be disclosed to the President or the Board of Directors. Any such potential conflicts of interests will be dealt with openly with full disclosure of the nature and extent of the potential conflicts of interests with the Trust.

It is acknowledged in the Codes that employees, officers and directors may be directors or officers of other entities engaged in the oil and gas business, and that such entities may compete directly or indirectly with the Trust. No assurance can be given that opportunities identified by directors of ARC Resources will be provided to us. Passive investments in public or private entities of less than one per cent of the outstanding shares will not be viewed as "competing" with the Trust. Any director, officer or employee of ARC Resources which is a director or officer of any entity engaged in the oil and gas business shall disclose such occurrence to the Board of Directors. Any director, officer or employee of ARC Resources who is actively engaged in the management of, or who owns an investment of one per cent or more of the outstanding shares, in public or private entities shall disclose such holding to the Board of Directors. In the event that any circumstance should arise as a result of such positions or investments being held or otherwise which in the opinion of the Board of Directors constitutes a conflict of interest which reasonably affects such person's ability to act with a view to the best interests of the Trust, the Board of Directors will take such actions as are reasonably required to resolve such matters with a view to the best interests of the Trust. Such actions, without limitation, may include excluding such directors, officers or employees from certain information or activities of the Trust.

The *Business Corporations Act* (Alberta) provides that in the event that an officer or director 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 material transaction or proposed material contract or proposed material transaction, such officer or director shall disclose the nature and extent of his or her interest and shall refrain from voting to approve such contract or transaction.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

There is no material interest, direct or indirect, of any director or senior officer, or to our knowledge any person or company that is the direct or beneficial owner, or who exercises control or direction over more than 10 per cent of outstanding Trust Units, or any associate or affiliate of any of the foregoing, in any transaction within the three most recently completed financial years.

DISTRIBUTIONS TO UNITHOLDERS

The following per Trust Unit distributions have been made in the last three completed financial years:

2006	Distribution Per Trust Unit
First Quarter	$0.60
Second Quarter	$0.60
Third Quarter	$0.60
Fourth Quarter	$0.60
2007	
First Quarter	$0.60
Second Quarter	$0.60
Third Quarter	$0.60
Fourth Quarter	$0.60
2008	
First Quarter	$0.60
Second Quarter	$0.68
Third Quarter	$0.80
Fourth Quarter	$0.59

In certain circumstances, distributions may be restricted by our borrowing agreements. For more information see "Other Information Relating to Our Business – Borrowing". Distributions paid to Unitholders in 2006 were two per cent tax deferred, 2007 distributions were three per cent tax deferred and 2008 distributions were two per cent tax deferred. For more information, see "Our Business –Distributions and Distribution Policy".

PRICE RANGE AND TRADING VOLUME OF TRUST UNITS AND EXCHANGEABLE SHARES

The Trust Units are listed and posted for trading on the TSX. The trading symbol for the Trust Units is AET.UN. The following table sets forth the high and low closing prices and the aggregate volume of trading of the Trust Units on the TSX for the periods indicated (as quoted by the TSX):

2008 Period	Toronto Stock Exchange High $	Low $	Volume
January	22.35	19.30	15,607,492
February	24.49	21.50	17,999,702
March	27.19	22.97	20,477,332
April	28.12	24.84	13,428,991
May	31.57	25.40	16,885,970
June	34.02	28.90	11,815,283
July	34.47	27.49	17,391,202
August	30.40	27.98	14,746,900
September	29.49	21.99	20,159,234
October	23.10	14.14	39,453,166
November	20.70	16.56	22,175,682
December	20.10	14.88	33,877,468

The Exchangeable Shares are listed and posted for trading on the TSX. The trading symbol for the Exchangeable Shares is ARX. The following table sets forth the high and low closing prices and the aggregate volume of trading of the Exchangeable Shares on the TSX for the periods indicated (as quoted by the TSX):

2008 Period	Toronto Stock Exchange High $	Low $	Volume
January	50.00	45.00	1,000
February	54.00	52.50	1,400
March	62.50	51.01	2,377
April	66.00	60.40	1,600
May	72.03	67.00	10,606
June	75.70	71.00	5,300
July	80.00	69.50	3,200
August	71.80	68.05	2,633
September	72.50	54.88	6,109
October	56.00	37.00	7,500
November	48.00	48.00	300
December	48.00	46.60	1,100

INDUSTRY REGULATIONS

The oil and natural gas industry is subject to extensive controls and regulations governing its operations (including land tenure, exploration, development, production, refining, transportation, and marketing) imposed by legislation enacted by various levels of government and with respect to pricing and taxation of oil and natural gas by agreements among the governments of Canada, Alberta, British Columbia, and Saskatchewan, all of which should be carefully considered by investors in the oil and gas industry. It is not expected that any of these controls or regulations will affect our operations in a manner materially different than they would affect other oil and gas companies of similar size. All current legislation is a matter of public record and we are unable to predict what additional legislation or amendments may be enacted. See "Risk Factors – Changes in Legislation" and "Risk Factors – Regulatory." Outlined below are some of the principal aspects of legislation, regulations and agreements governing the oil and gas industry.

Pricing and Marketing - Oil and Natural Gas

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

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

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

Pipeline Capacity

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

The North American Free Trade Agreement

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

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

Provincial Royalties and Incentives

General

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

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

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

Alberta

In Alberta, companies are granted the right to explore, produce and develop petroleum and natural gas resources in exchange for royalties, bonus bid payments and rents. On October 25, 2007, the Government of Alberta released a report entitled "The New Royalty Framework" (the "**NRF**") containing the Government's proposals for Alberta's new royalty regime, which was followed by the *Mines and Minerals (New Royalty Framework) Amendment Act*, 2008, which was given Royal Assent on December 2, 2008. The NRF and the applicable new legislation became effective on January 1, 2009. The NRF establishes new royalty rates for conventional oil, natural gas and oil sands. The new royalty rates for conventional oil are set by a single sliding rate formula which is applied monthly and increases the old royalty from 30 per cent to 35 per cent applied to the old and new tiers, to up to 50 per cent and with rate caps once the price of conventional oil reaches $120 per barrel. The sliding rate formula includes in its calculation the price of oil and well production.

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

Oil sands projects are now subject to the NRF, and regulated, among others, by the *Oil Sands Royalty Regulation, 2009 Oil Sands Allowed Costs (Ministerial) Regulation* and the *Bitumen Valuation Methodology (Ministerial) Regulation, 2009*, all approved by the Government of Alberta on December 10, 2008.

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

Regulations made pursuant to the *Mines and Minerals Act* (Alberta) provided various incentives for exploring and developing oil reserves in Alberta. However, the Alberta Government announced in August of 2006 that four royalty programs were to be amended, a new program was to be introduced and the Alberta Royalty Tax Credit

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

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

On March 3, 2009, the Government of Alberta announced a three-point incentive program to stimulate new and continued economic activity in Alberta which included a drilling royalty credit for new conventional oil and natural gas wells and a new well royalty incentive program. Under the drilling royalty credit program a $200 per meter royalty credit will be available on new conventional oil and natural gas wells drilled between April 1, 2009 and March 31, 2010, subject to certain maximum amounts. The maximum credits available will be determined by our Crown production level in 2008 and our drilling activity between April 1, 2009 and March 31, 2010. Based on our 2008 production we will be entitled to a maximum credit of 10 per cent of royalties payable in the period April 1, 2009 and March 31, 2010. The new well incentive program will apply to wells beginning production of conventional oil and natural gas between April 1, 2009 and March 31, 2010 and provides for a maximum five per cent royalty rate for the first 12 months of production, up to a maximum of 50,000 barrels or 500 Mmcf of natural gas.

The three-point incentive program also includes an investment of $30,000,000 by the Government of Alberta in abandonment and reclamation projects for orphan wells. The stated objective of this investment is to encourage the cleanup of inactive oil and gas wells and to stimulate new activity within the services sector.

British Columbia

Producers of oil and natural gas in British Columbia are required to pay annual rental payments with respect to the Crown leases and royalties and freehold production taxes in respect of oil and natural gas produced from Crown and freehold lands. The amount payable as a royalty in respect of oil depends on the type of oil, the value of the oil, the quantity of oil produced in a month, and the vintage of the oil. Generally, the vintage of oil is based on the determination of whether the oil is produced from a pool discovered before October 31, 1975 (old oil), between October 31, 1975, and June 1, 1998 (new oil), or after June 1, 1998 (third-tier oil). The royalty rates are calculated in three stages, which take into account the vintage of the oil, if the oil produced has already been sold and any royalty exempt value applicable (exempt wells). Oil produced from newly discovered pools may be exempt from the payment of a royalty for the first 36 months of production or 11,450m^3 produced, whichever comes first; and the royalties for third-tier oil are the lowest reflecting the higher costs of exploration and extraction that the producers would incur. The royalty payable on natural gas is determined by a sliding scale based on a reference price, which is the greater of the price obtained by the producer, and a prescribed minimum price. However, when the reference price is below the select price (a parameter used in the royalty rate formula), the royalty rate is fixed. As an incentive for the production and marketing of natural gas, which may have been flared, natural gas produced in association with oil has a lower royalty then the royalty payable on non-conservation gas.

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

Some of the financial incentives in the Strategy include:

- Royalty credits towards the construction, upgrading, and maintenance of road infrastructure in support of resource exploration and development. Funding will be contingent upon an equal contribution from industry. This program has evolved over past years as a result of the Province's stated objective to increase competitiveness, and on March 2, 2009 the Government of British Columbia announced the 2009 Infrastructure Royalty Credit Program ("**Program**") which allocates $120 million in royalty credits for oil and gas companies. The Program provides access to royalty credits to oil and gas companies with respect to certain approved road construction or pipeline infrastructure projects intended to improve, or make possible, the access to new and underdeveloped oil and gas areas. Companies must apply to the Ministry of Energy and Mines for British Columbia prior to 2:00 p.m. on April 30, 2009 to be considered for approval under the program.

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

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

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

Saskatchewan

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

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

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

- A new Crown royalty and freehold production tax regime applicable to associated natural gas (gas produced from oil wells) that is gathered for use or sale and is produced from: (a) oil wells with a finished drilling date on or after October 1, 2002, and (b) oil wells with a finished drilling date prior to October 1, 2002, where the individual oil well has a gas-oil production ratio in any month of more than 3,500 cubic metres of gas for every cubic metre of oil. The royalty/tax will be payable on associated natural gas produced from an oil well that exceeds approximately 65,000 cubic metres in a month. The associated natural gas royalty/tax regime will apply to gas produced from oil wells affected by concurrent production approvals after October 1, 2002 if the oil wells meet (a) or (b) above.

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

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

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

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

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

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

Land Tenure

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

Environmental Regulation

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

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

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

British Columbia's *Environmental Assessment Act* became effective June 30, 1995. This legislation rolls the previous processes for the review of major energy projects into a single environmental assessment process with public participation in the environmental review process. On February 27, 2007 the Government of British Columbia unveiled the Energy Plan outlining its strategy towards the environment and which includes targeting for zero net greenhouse gas emissions, promoting new investments in innovation, and becoming the world's leader in sustainable environmental management. For this purpose, on December 18, 2007 proposals were sought for applications to the Innovative Clean Energy Fund, in order to attract new technologies that will help solve energy and environmental issues. With regards to the oil and natural gas industry the objective is to achieve clean energy through conservation and energy efficient practices, whilst competitiveness is advocated in order to attract investment for the development of the oil and natural gas sector. Among the changes to be implemented are: (i) a new Net Profit Royalty Program; (ii) the creation of a Petroleum Registry; (iii) the establishment of an infrastructure royalty program (combining roads and pipelines); (iv) the elimination of routine flaring at producing wells; (v) the creation of policies and measures for the reduction of emissions; (vi) the development of unconventional resources such as tight gas and coalbed gas; and (vii) the Oil and Gas Technology Transfer Incentive Program that encourages the research, development and use of innovative technologies to increase recoveries from existing reserves and promotes responsible development of new oil and gas reserves. Furthering these initiatives, the Government of British Columbia introduced on July 1, 2008, revenue-neutral carbon tax legislation that is applied to all fossil fuels used in the Province of British Columbia. The tax would be phased in, and the initial rate would be based on CO_2 of $10 per tonne for the first six months of 2009 and $15 per tonne for the last six months of 2009, following $5 per tonne increases on July of every year until 2012. Tax credits and reductions will be used in order to offset the tax revenues that the Government of British Columbia would receive otherwise. On April 3, 2008, the Government of British Columbia introduced the *Greenhouse Gas Reduction (Cap and Trade) Act* which will allow participation in the Western Climate Initiative cap and trade systems being developed. The system establishes a limit on emissions, and allows regulated emitters to buy/sell emission allowances or offset emits. The emitter is obliged to obtain emission allowances (compliance units) equal to the amount of greenhouse gases emitted within a certain period of time, and that are supposed to be surrendered to the Government of British Columbia as compliance proof.

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

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

In order to strengthen the Action Plan, on March 10, 2008, the Government of Canada released "Turning the Corner – Taking Action to Fight Climate Change" (the "**Updated Action Plan**") which provides some additional guidance with respect to the Government's plan to reduce greenhouse gas emissions by 20 per cent by 2020 and by 60 per cent to 70 per cent 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 per cent from the 2006 baseline starting in 2010 and an additional two per cent in subsequent years for existing facilities. This target will be applied to regulated sectors on a facility-specific, sector-wide or corporate basis; in the case of oil sands production, petroleum refining, natural gas pipelines and upstream oil and gas the target will be considered facility-specific (sectors in which the facilities are complex and diverse, or where emissions are affected by factors beyond the control of the facility operator). Emissions from new facilities, which are those built between 2004 and 2011, will be based on a cleaner fuel standard to encourage continuous emissions intensity reductions over time, and will be granted a three-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 two per cent continuous annual emission intensity improvement required. The definition of new facility also includes greenfield facilities, major expansions constituting more than a 25 per cent increase in a facility's physical capacity, as well as transformations to a facility that involve significant changes to its processes. For upstream oil and gas and natural gas pipelines, it will be applied using a sector-specific approach. For the oil sands, its application will be process-specific, oil sands plants built in 2012 and later, those which use heavier hydrocarbons, up-graders and *in-situ* production will have mandatory standards in 2018 that will be based on carbon capture and storage.

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

Four separate compliance mechanisms are provided in respect of the above targets: Technology Fund contributions, offset credits, clean development credits and credits for early action. The most significant of these compliance mechanisms, at least initially, will be the Technology Fund and for which regulated entities will be able to contribute in order to comply with emissions intensity reductions. The contribution rate will increase over time, beginning at $15 per tonne for the 2010-12 period, rising to $20 per tonne in 2013, and thereafter increasing at the nominal rate of GDP growth. Contribution limits will correspondingly decline from 70 per cent in 2010 to zero per cent 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 per cent of each firm's regulatory obligation, with the added restriction that credits generated through forest sink projects will not be available for use in complying with the Canadian regulations.

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

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

RISK FACTORS

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

We are a limited purpose trust and are entirely dependent upon the operations and assets of ARC Resources through our ownership, directly and indirectly, of securities of ARC Resources, including the common shares of ARC Resources, the Notes and the Royalties. Accordingly, our ability to pay distributions to Unitholders is dependent upon the ability of ARC Resources to meet its interest, principal, dividend and other distribution obligations on the securities of ARC Resources and to pay the Royalties. ARC Resources' income is received from the production of oil and natural gas from its Canadian resource properties and is susceptible to the risks and uncertainties associated with the oil and natural gas industry generally. If the oil and natural gas reserves associated with ARC Resources' resource properties are not supplemented through additional development or the acquisition of additional oil and natural gas properties, the ability of ARC Resources to meet its obligations to us and our ability to pay distributions to Unitholders may be adversely affected.

Volatility of Oil and Natural Gas Prices

Our operational results and financial condition, and therefore the amounts we pay to Unitholders, will be dependent on the prices received for oil and natural gas production. Oil and natural gas prices have recently declined precipitously and monthly distributions that reached a high point of $0.28 per Trust Unit in August of 2008 declined to $0.15 per Trust Unit at December 31, 2008. Current distributions are $0.12 per Trust Unit and continued low oil and natural gas prices or further declines in oil and natural gas prices will result in further declines in, or elimination of, such distributions. Oil and natural gas prices are determined by economic factors and in the case of oil prices, political factors and a variety of additional factors beyond our control. These factors include economic conditions, in the United States and Canada, 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 natural gas would have an adverse effect on the carrying value of our proved and probable reserves, borrowing capacity, revenues, profitability and cash flows from operating activities. 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 may forego some of the benefits we would otherwise experience if commodity prices were to increase. In addition, commodity hedging activities could expose us to losses. 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. For more information in relation to our hedging program, see "Statement of Reserve Data and Other Oil and Gas Information – Other Oil and Gas Information – Forward Contracts".

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 – Purchase of Properties" and "Risk Factors – 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, and could 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 negatively impacts our production revenue.

Over the last two years, the Canadian dollar has experienced significant volatility, impacting the amount of Canadian dollars received by the Trust for its production. Continued volatility in the Canadian dollar may affect future distributions. We may initiate certain hedges to attempt to mitigate the risk of the Canadian dollar appreciating against the U.S. dollar. These hedging activities could expose us to losses. To the extent that we engage in risk management activities related to foreign exchange rates and interest rates, it 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 independent evaluators.

Global Financial Crisis

Recent market events and conditions, including disruptions in the international credit markets and other financial systems and the deterioration of global economic conditions, have caused significant volatility to commodity prices. These conditions worsened in 2008 and are continuing in 2009, causing a loss of confidence in the broader U.S. and global credit and financial markets and resulting in the collapse of, and government intervention in, major banks, financial institutions and insurers and creating a climate of greater volatility, less liquidity, widening of credit spreads, a lack of price transparency, increased credit losses and tighter credit conditions. Notwithstanding various actions by governments, concerns about the general condition of the capital markets, financial instruments, banks, investment banks, insurers and other financial institutions caused the broader credit markets to further deteriorate and stock markets to decline substantially. These factors have negatively impacted company and trust valuations and will impact the performance of the global economy going forward.

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

Refinancing Risk and Debt Service

We currently have an $800 million syndicated credit facility with eleven banks. In normal circumstances, borrowers such as us rely on the fact that the banks will honour their contractual commitments to fund draws as required. In today's economic environment there is a risk that one or more of the banks included in our syndicate may not honour draws requested by us and thereby effect our ability to maintain our capital expenditure programs. In the event that the facility is not extended before April 11, 2011, indebtedness under the facility will be repayable at that date. There is also a risk that the credit facility will not be renewed for the same amount or on the same terms. Variations in interest rates and scheduled principal repayments could result in significant changes in the amount required to be applied to debt service before payment of the Royalties and interest on the Long Term Notes and distributable income. Furthermore, any of these events could affect our ability to fund ongoing operations.

We currently have U.S. $212 million of U.S. denominated long-term debt outstanding which requires principal repayments starting in April 2009 and continuing until December 2017. We intend to fund these debt maturities with existing credit facilities. In the event we are unable to refinance our debt obligations it may impact our ability to fund our ongoing operations and distribute cash.

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

At December 31, 2008, we had approximately $296 million of unused credit available under our bank credit facility. In addition, we have the ability to issue an additional U.S. $113 million of long-term notes under an agreement with one lender. This option, which will expire in May 2009 unless it is renewed, would allow us to issue long-term notes at a rate equal to the related U.S. treasuries corresponding to the term of notes plus an appropriate credit spread adjustment at the time of issuance. There is no assurance that this option will be exercised or renewed.

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

For more information, see "Other Information Relating to Our Business – Borrowing".

Capital Markets

As a result of the weakened global economic situation, the Trust along with all other oil and gas entities will have restricted access to capital and increased borrowing costs. Although our business and asset base have not changed, the lending capacity of all financial institutions has diminished and risk premiums have increased. As future capital expenditures will be financed out of cash generated from operating activities, borrowings and possible future equity sales, our ability to do so is dependent on, among other factors, the overall state of capital markets and investor appetite for investments in the energy industry and our securities in particular.

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

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

Based on current funds available and expected cash flow from operating activities, we believe we have sufficient funds available to fund our projected capital expenditures. However, if cash flow from operating activities is lower than expected or capital costs for these projects exceed current estimates, or if we incur major unanticipated expenses related to development or maintenance of our existing properties, we may be required to seek additional capital to maintain our capital expenditures at planned levels. Failure to obtain financing necessary for our capital expenditure plans may result in a delay in development or production on our properties or a decrease in distributions.

Third Party Credit Risk

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

Maintenance of Distributions

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

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. There is no assurance that such changes will not be materially adverse to our assets, reserves, financial condition or results of operations or prospects. 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 Regulations".

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 *Tax Act*. We may not, however, always be able to satisfy any future requirements for the maintenance of mutual fund trust status. Should our status as a mutual fund trust be lost or successfully challenged by a relevant tax authority, certain adverse consequences may arise for us and Unitholders. Some of the significant consequences of losing mutual fund trust status are as follows:

- We would be taxed on certain types of income distributed to Unitholders, including income generated by the Royalties 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 cease 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 ("**RESPs**") 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 the 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 *Tax Act*.

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

For more information, see "Risk Factors – Non-resident Ownership of Trust Units", "Risk Factors – Federal Tax Changes for Income Trusts and Corporations", "Risk Factors – Environmental Concerns", and "Industry Regulations – Environmental Regulation".

Reserves and Resource Estimates

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and natural gas liquids reserves and resources and the future revenue 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. 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 revenue flows derived from reserves will vary from the reserves estimates contained in the GLJ Report, and such variations could be material. The estimates in the GLJ Report are based in part on the timing and success of activities we intend to undertake in future years. The reserves and estimated future net revenues to be derived therefrom contained in the GLJ Report will be reduced in future years to the extent that such activities do not achieve the production performance set forth in the GLJ Report.

The reserves and recovery information contained in the GLJ 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 GLJ. The GLJ 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 revenues for our reserves would be reduced and the reduction could be significant. In particular, we have experienced extreme volatility in the prices received for oil and natural gas production and the difference between the forecast prices and costs reflected in the GLJ Report and our proceeds from the sale of our oil and natural gas could be materially lower.

We have resource estimates of natural gas classified as DPIIP. The resources estimates of natural gas are estimates only and the actual resources may be greater than or less than the estimates provided herein. A capital development project for the recovery of this volume of DPIIP cannot be defined at this time. There is no certainty that it will be economically viable or technically feasible to produce any portion of this natural gas classified as DPIIP.

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.

Federal Tax Changes for Income Trusts and Corporations

New federal legislation passed in June 2007, will apply a tax ("**SIFT tax**") at the trust level on distributions of certain income from trusts, such as the Trust, 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 the Trust and certain Unitholders (including most particularly Unitholders that are tax deferred or non-residents of Canada) and may impact distributions from the Trust.

Generally, there will be a transition period for an existing trust, such as the Trust, 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.

The normal growth restrictions could adversely affect the cost of raising capital and the Trust's ability to undertake more significant acquisitions. The SIFT tax substantially eliminates the competitive advantage that the Trust and other Canadian energy trusts enjoyed relative to their corporate peers in raising capital in a tax-efficient manner, and makes the Trust Units less attractive as an acquisition currency. As a result, it may become more difficult for the Trust to compete effectively for acquisition opportunities. There can be no assurance that the Trust will be able to reorganize its legal and tax structure to substantially mitigate the expected impact of the SIFT tax.

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

Operational Matters

Acquiring, developing and exploring for oil and natural gas involves many risks, which even a combination of experience, knowledge and careful evaluation may not be able to overcome. These risks include, but are not limited to, encountering unexpected formations or pressures, premature declines of reservoirs, blow-outs, equipment failures and other accidents, sour gas releases, uncontrollable flows of oil, natural gas or well fluids, adverse weather conditions, pollution, other environmental risks, fires and spills. Although we maintain insurance in accordance with customary industry practice, we are not fully insured against all of these risks. Losses resulting from the occurrence of these risks could have a material adverse impact on us. Like other oil and natural gas trusts and companies, we attempt to conduct our business and financial affairs so as to protect against political and economic risks applicable to operations in the jurisdictions where we operate but there can be no assurance that we will be successful in so protecting our assets.

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 us, 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 the properties or the establishment by the operator of reserves for such expenses.

Continuing production from a property, and to some extent the marketing of production therefrom, are largely dependent upon the ability of the operator of the property. Other companies operate some of the properties in which we have an interest and as a result our returns on assets operated by others depends upon a number of factors outside our control. Operating costs on most properties have increased steadily over recent years. To the extent the operator fails to perform these functions properly, operating income may be reduced. Payments from production generally flow through the operator and there is a risk of delay and additional expense in receiving such revenues if the operator becomes insolvent. A reduction of the income available for distributions could result in such circumstances.

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

Allocations of Trust Income

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

In addition, the Trust Indenture provides that such distributable income may be paid in whole or in part by cash, in Trust Units, or promissory notes payable in whole or in part in cash or Trust Units on a specified date not more than 90 days after the record date to which the promissory note relates. The Trust Indenture also provides for the consolidation of the Trust Units in the discretion of the Board of Directors of ARC Resources to the pre-distribution number of Trust Units after any pro-rata distribution of additional Trust Units to all Unitholders. Accordingly, the Trust Indenture allows for the payment of distributions in a form other than cash and Unitholders may have taxable income and cash taxes payable.

Purchase of Properties

The price we pay for the purchase of the 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 flow from operating activities and distributions to Unitholders. See "ARC Energy Trust – General Development of the Business".

Enhanced Oil Recovery

We believe our ownership of assets in Redwater and North Pembina Cardium Unit #1 strategically positions us for participation in properties with large reserves of unrecovered original resources in place which may be amenable to secondary recovery techniques such as CO_2 miscible or immiscible flooding. The implementation of enhanced oil recovery techniques on properties like Redwater or the North Pembina Cardium Unit #1 are subject to significant risk factors, including the requirements of long term supply agreements for CO_2 and large scale infrastructure investments. We have just begun to devote resources to the study of such matters and no reserves are reflected in the GLJ Report for any of these enhanced recovery techniques for the two subject properties. There is no assurance as to when or if such enhanced recovery techniques will be implemented, or if implemented, when or if such enhanced recovery techniques would be successful.

Currently, companies are permitted to emit CO_2 into the atmosphere with no requirement to capture and re-inject the emissions. In order for ARC Resources to carry out its enhanced oil recovery program it is necessary to obtain CO_2 at a cost effective rate. Given that companies are not forced to capture their emissions, the infrastructure has not been put in place to facilitate this process. Under the current regulatory environment, the economic parameters of the Trust's enhanced oil recovery programs would be limited. For more information, see "Risk Factors – Environmental Concerns".

Project Risks

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

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

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

Expansion of Operations

Our operations and expertise are currently focused on oil and gas production and development in the Western Canadian Sedimentary Basin. In the future, we may acquire oil and gas properties outside this geographic area. 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 the exposure to one or more of the present risk factors which may adversely affect our future operational and financial conditions.

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 the Trust. 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.

Non-resident Ownership of Trust Units

The Trust intends to comply with the requirements under the *Tax Act* 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 *Tax Act*. In this regard, we may, from time to time, among other things, take all necessary steps to monitor the activities of the Trust and ownership of the Trust Units. If at any time we become aware that the activities of the Trust and ownership of the Trust Units by non-residents (non-residents of Canada and partnerships) may threaten the status of the Trust under the *Tax Act* as a "unit trust" or "mutual fund trust", we are authorized to take such action as may be necessary in the opinion of ARC Resources to maintain the status of the Trust as a unit trust and a mutual fund trust, including the imposition of restrictions on the issuance by the Trust, or the transfer by any Unitholder, of Trust Units to a non resident. See "Limitations on Non-Resident Ownership" and "Risk Factors – Changes in Legislation".

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. 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 the Trust. See "Industry Regulations – Environmental Regulation". Although we have established a reclamation fund for the purpose of funding our currently estimated future environmental and reclamation obligations 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 proposed in Alberta's Bill 37 Climate Change and Emissions Management, 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.

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.

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 of Canada's plan to reduce greenhouse gas emissions by 20 per cent by 2020 and by 60 per cent to 70 per cent by 2050.

There has been much public debate with respect to the Government's strategy or alternative strategies with respect to climate change and the control of greenhouse gases. Implementation of strategies 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 – Changes in 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 and prospects. See "Industry Regulations– Environmental Regulation".

Competition

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

The Trust competes with other oil and gas entities to hire and retain skilled personnel necessary for the 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.

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 revenues 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 - Volatility of Oil and Natural Gas Prices".

Under US GAAP, companies using the full cost method of accounting for oil and gas producing activities perform a ceiling test on each cost centre using discounted estimated future net revenue from proved oil and gas reserves using a discount rate of 10 per cent. Prices used in the US GAAP ceiling tests are those in effect at year-end. For the year ended 2008, a ceiling test write-down of $1.15 billion was recorded for US GAAP purposes ($nil in 2007). The amounts recorded for depletion and depreciation have been adjusted in the periods following similar additional write-downs taken under US GAAP in prior years to reflect the impact of the reduction of delectable costs. For further information, see Note 24 of our audited consolidated financial statements for the year ended December 31, 2008 which is incorporated by reference in this Annual Information Form and which has been filed on SEDAR at www.sedar.com.

On December 31, 2008, the Securities Exchange Commission published final rules and interpretations updating its oil and gas reporting requirements. Key revisions include changes to the pricing used to estimate reserves to utilize a twelve month average price, the ability to include non-traditional resources in reserves, the use of new technology for determining reserves, and permitting disclosure of probable and possible reserves. The Securities Exchange Commission will require companies to comply with the amended disclosure requirements for registration statements filed after January 1, 2010, and for annual reports for fiscal years ending on or after December 15, 2009. Early adoption is not permitted. We are currently assessing the impact of adoption in 2009; however, it is anticipated that the new requirements will result in changes to our method of calculating the impairment test under US GAAP.

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, 2008 we had $157.6 million recorded on our balance sheet as goodwill arising out of our acquisition of Star Oil & Gas Ltd. in 2003. 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.

Under GAAP, the 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.

Reliance on Key Members of Management

Our success depends in large measure on certain key personnel. The loss of such key personnel could delay the completion of certain projects or otherwise have a material adverse effect on us. Unitholders will be dependent on our management in respect of the administration and management of all matters relating to our properties, the Royalties and Trust Units. As of December 31, 2008, we operated approximately 75 per cent of the total daily production of our properties. Investors who are not willing to rely on our management should not invest in Trust Units.

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 cash flow from operating activities in the same manner as other industry participants as we distribute significant amounts of our cash flow to Unitholders. Accordingly, absent capital injections, our initial production levels and reserves may decline and the level of distributable income will be reduced.

Our future oil and natural gas reserves and production, and therefore our cash flows from operating activities, will be highly dependent on our success in exploiting our reserves base and acquiring additional reserves. Without reserves additions through acquisition or development activities, our reserves and production may decline over time as reserves are produced.

There can be no assurance that we will be successful in developing or acquiring additional reserves on terms that meet our investment objectives.

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 than the net asset value of our assets.

Return of Capital and Right of Redemption

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 "Our Information – 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 material limitations. Any securities which may be distributed *in specie* to Unitholders in connection with a redemption may not be listed on any stock exchange and a market may not develop for such securities and such securities may be illiquid. In addition, there may be resale restrictions imposed by law upon the recipients of the securities pursuant to the redemption right.

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

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

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, and will be satisfied only out of our assets. Pursuant to the Trust Indenture, we will indemnify and hold harmless each Unitholder from any costs, damages, liabilities, expenses, charges and losses suffered by a Unitholder resulting from or arising out of such Unitholder not having such limited liability.

The Trust Indenture provides that all written instruments signed by or on behalf of the Trust must contain a provision to the effect that such obligation will not be binding upon Unitholders personally. The principal investment of the Trust is the royalty agreements which contain such provisions. Personal liability may also arise in respect of claims against the Trust 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 the Trust.

Title to Properties

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

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 us and our operations.

Although satisfactory title reviews are generally conducted in accordance with industry standards, such reviews do not guarantee or certify that a defect in the chain of title may not arise to defeat our claim to certain properties. In certain situations there may be multiple mineral resource owners claiming various ownership over the same parcel of land. Any settlement of a dispute of ownership may result in the forfeiture of the mineral resource by us or the payment of cash compensation to the mineral resource owner.

Additional Risk Factors Applicable to Residents of the United States and Other Non-Residents of Canada

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

Both ARC and ARC Resources are organized under the laws of Alberta, Canada and have their 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 all 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 ARC or ARC Resources 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 judgements of United States courts of liabilities based solely upon the United States federal securities laws or securities laws of any state within the United States.

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 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 Securities Exchange Commission and practices in the United States. We follow the Canadian practice of reporting gross production and reserve volumes (before deduction of Crown and other royalties); however, we also follow the United States practice of separately reporting reserve volumes on a net basis (after the deduction of royalties and similar payments). We also follow the Canadian practice of using forecast prices and costs when we estimate our reserves; whereas the Securities Exchange Commission requires that prices and costs be held constant at levels in effect at the date of the reserve report. For additional information on reporting differences, see "Risk Factors – Accounting Write - Downs as a Result of GAAP".

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

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

Additional Taxation Applicable to Non-Residents

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

Additionally, the reduced "Qualified Dividend" rate of 15 per cent 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 strengthens with respect to their currency, the amount of the distribution will be reduced when converted to their home currency.

TRANSFER AGENTS AND REGISTRARS

The transfer agent and registrar for the Trust Units and the Exchangeable Shares is Computershare Trust Company of Canada at its principal offices in Calgary and Toronto.

MATERIAL CONTRACTS

The following comprises particulars of every material contract to the Trust that was entered into within the most recently completed financial year, or entered into before the most recently completed financial year which is still in effect, other than a contract entered into in the ordinary course of business:

1. Trust Indenture. For information, see "Our Information" and "Corporate Governance".

2. Exchangeable Share Provisions. For information, see "Share Capital of ARC Resources – Exchangeable Shares".

3. Exchangeable Share Voting and Exchange Trust Agreement dated January 31, 2001 among the trust, 908563 Alberta Ltd. (the predecessor to ARC Subco) ARC Resources and Computershare Trust Company of Canada, as amended. For information, see "Share Capital of ARC Resources – Exchangeable Shares".

4. Exchangeable Share Support Agreement dated January 31, 2001 among the trust, 908563 Alberta Ltd. (the predecessor to ARC Subco) ARC Resources and Computershare Trust Company of Canada, as amended. For information, see "Share Capital of ARC Resources – Exchangeable Shares".

5. Amended and Restated Credit Agreement dated as of March 24, 2006 between ARC Resources and a syndicate of lenders, and an administrative agent as amended on March 30, 2007 for an extendible revolving credit facility up to Cdn. $800 million. For information, see "Other Information Relating to Our Business - Borrowings".

6. Amended and Restated Uncommitted Master Shelf Agreement as of December 15, 2005 between ARC Resources and various purchasers for an aggregate principal amount of US $150 million. For information, see "Other Information Relating to Our Business - Borrowings".

7. Note Agreement as of April 27, 2004 between ARC Resources and various purchasers for US $62.5 million 4.62 per cent Senior Secured Notes – Series A due April 27, 2014 and US $62.5 million 5.10 per cent Senior Secured Notes – Series B due April 27, 2016. For information, see "Other Information Relating to Our Business -Borrowings".

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

INTEREST OF EXPERTS

There is no person or company whose profession or business gives authority to a statement made by such person or company and who is named as having prepared or certified a statement, report or valuation described or included in a filing, or referred to in a filing, made under National Instrument 51-102 by us during, or related to, our most recently completed financial year other than GLJ, our independent engineering evaluator, and Deloitte & Touche LLP, our auditors. As at the date hereof the designated professionals of GLJ Petroleum Consultants Ltd., as a group, beneficially owned, directly or indirectly, less than one per cent of our outstanding securities, including the securities of our associates and affiliates. Deloitte & Touche LLP is the auditor of the Trust and is independent within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of Alberta.

In addition, none of the aforementioned persons or companies, nor any director, officer or employee of any of the aforementioned persons or companies, is or is expected to be elected, appointed or employed as a director, officer or employee of ARC Resources or of any of our associate or affiliate entities. Allan R. Twa, the Corporate Secretary of ARC Resources, is a partner of Burnet, Duckworth & Palmer LLP, which law firm renders legal services to us.

ADDITIONAL INFORMATION

Additional information including remuneration and indebtedness of directors and officers of ARC Resources, principal holders of the Trust Units, Exchangeable Shares and rights to purchase Trust Units, is contained in the Information Circular - Proxy Statement of the Trust which relates to the Annual Meeting of Unitholders to be held on May 20, 2009. Additional financial information is provided in our consolidated financial statements and accompanying management's discussion and analysis for the year ended December 31, 2008, which have been filed on SEDAR at www.sedar.com.

APPENDIX A
FORM 51-101F2

REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR

To the board of directors of ARC Resources Ltd. (the "**Company**") on behalf of ARC Energy Trust (the "**Trust**"):

1. We have prepared an evaluation of the Company's and other Trust's subsidiaries' reserves data as at December 31, 2008. The reserves data are estimates of proved reserves and probable reserves and related future net revenues as at December 31, 2008 estimated using forecast prices and costs.

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

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

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

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 per cent, included in the reserves data of the Company evaluated by us for the year ended December 31, 2008, and identifies the respective portions thereof that we have evaluated and reported on to the Company's board of directors:

Independent Qualified Reserves Evaluator	Description and Preparation Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate, millions dollars)			
			Audited	Evaluated	Reviewed	Total
GLJ Petroleum Consultants Ltd.	January 16, 2009	Canada	-	$5,292	-	$5,292

5. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook.

6. We have no responsibility to update this evaluation for events and circumstances occurring after the preparation dates.

7. 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.

Executed as to our report referred to above:

GLJ Petroleum Consultants Ltd.
Calgary, Alberta, Canada

Dated February 19, 2009

(signed) "James H. Willmon"
James H. Willmon, P.Eng
Vice President

APPENDIX B
FORM 51-101F3

REPORT OF MANAGEMENT AND DIRECTORS ON RESERVES DATA AND OTHER INFORMATION

Management of ARC Resources Ltd. (the "**Company**") on behalf of ARC Energy Trust (the "**Trust**") are responsible for the preparation and disclosure of information with respect to the Company's and the other Trust's subsidiaries' 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 revenues as at December 31, 2008 estimated using forecast prices and costs.

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

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

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

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

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

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

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

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

(f) the content and filing of this report.

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

(signed) "*John P. Dielwart*"
John P. Dielwart
Chief Executive Officer

(signed) "*Myron Stadnyk*"
Myron Stadnyk
President and Chief Operating Officer

(signed) "*James Houck*"
James Houck
Director and Chairman of the Reserves Committee

(signed) "*Fred J. Dyment*"
Fred J. Dyment
Director and Member of the Reserves Committee

March 18, 2009

APPENDIX C

MANDATE OF THE AUDIT COMMITTEE

Role and Objective

The Audit Committee (the "Committee") is a committee of the Board of Directors of ARC Resources Ltd. ("ARL") 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. The objectives of the Committee, with respect to ARL and ARC Energy Trust (the "Trust") (hereinafter collectively referred to as "ARC"), are as follows:

- To assist Directors to meet their responsibilities in respect of the preparation and disclosure of the financial statements of ARC and related matters.
- To provide better communication between directors and external auditors.
- To ensure the external auditors' independence.
- To increase the credibility and objectivity of financial reports.
- To strengthen the role of the outside directors by facilitating in depth discussions between directors on the Committee, management and external auditors.

Mandate and Responsibilities of Committee

- It is the responsibility of the Committee to satisfy itself on behalf of the Board with respect to ARC's internal control systems, including in particular relating to derivative instruments:
    - identifying, monitoring and mitigating business risks.
    - ensuring compliance with legal and regulatory requirements.
- It is a primary responsibility of the Committee to review the annual and quarterly financial statements of ARC 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;
    - reviewing the Trust's status as a "mutual fund trust" under the *Income Tax Act* (Canada);
    - ascertaining compliance with covenants under loan agreements and Trust Indenture;
    - reviewing financial reporting relating to asset retirement obligations;
    - 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;
    - obtain explanations of significant variances with comparative reporting periods; and

    - determine through inquiry if there are any related party transactions and ensure the nature and extent of such transactions are properly disclosed.

- The Committee is to review the financial statements and related information included in prospectuses, management discussion and analysis (MD&A), information circular-proxy statements and annual information forms (AIF), prior to Board approval.

- With respect to the appointment of external auditors by the Board, the Committee shall:

    - be directly responsible for overseeing the work of the external auditors engaged for the purpose of issuing an auditors' report or performing other audit, review or attest services for the Trust, including the resolution of disagreements between management and the external auditor regarding financial reporting;
    - review management's recommendation for the appointment of external auditors and recommend to the Board appointment of external auditors and the compensation of the external auditors;
    - review the terms of engagement of the external auditors, including the appropriateness and reasonableness of the auditors' fees;
    - 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.

- Review with external auditors (and internal auditor if one is appointed by ARC) their assessment of the internal controls of ARC, 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 ARC and its subsidiaries.

- Review all public disclosure containing audited or unaudited financial information before release.

- Review financial reporting relating to risk exposure.

- Satisfy itself that adequate procedures are in place for the review of the Trust's public disclosure of financial information from the Trust's financial statements and periodically assess the adequacy of those procedures.

- Establish procedures for:

    - the receipt, retention and treatment of complaints received by the Trust regarding accounting, internal accounting controls, or auditing matters; and
    - the confidential, anonymous submission by employees of the Trust of concerns regarding questionable accounting or auditing matters.

- Review and approve ARC's hiring policies regarding partners, employees and former partners and employees of the present and external auditors of ARC.

- Review any other matters that the Audit Committee feels are important to its mandate or that the Board chooses to delegate to it.

- Undertake annually a review of this mandate and make recommendations to the Policy and Board Governance Committee as to proposed changes.

Composition

- This Committee shall be composed of at least three individuals appointed by the Board from amongst its members, all of which members will be independent (within the meaning of Multilateral Instrument 52-110 Audit Committees) unless the Board determines to rely on an exemption in NI 52-110. "Independent" generally means free from any business or other direct or indirect material relationship with ARC that could, in the view of the Board of Directors, reasonably interfere with the exercise of the member's independent judgment.

- The Secretary to the Board shall act as Secretary of the Committee.

- A quorum shall be a majority of the members of the Committee.

- All of the members must be financially literate within the meaning of NI 52-110 unless the Board has determined to rely on an exemption in NI 52-110. Being "financially literate" means members have the ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of issues that can reasonably be expected to be raised by the Trust's financial statements.

Meetings

- The Committee shall meet at least four times per year and/or as deemed appropriate by the Committee Chair.

- The Committee shall meet not less than quarterly with the auditors, independent of the presence of management.

- Agendas, with input from management, shall be circulated to Committee members and relevant management personnel along with background information on a timely basis prior to the Committee meetings.

- Minutes of each meeting shall be prepared by the Secretary to the Committee.

- The Chief Executive Officer and the Chief Financial Officer or their designates shall be available to attend at all meetings of the Committee upon the invitation of the Committee.

- The Controller, Treasurer and such other staff as appropriate to provide information to the Committee shall attend meetings upon invitation by the Committee.

Reporting / Authority

- Following each meeting, in addition to a verbal report, the Committee will report to the Board by way of providing copies of the minutes of such Committee meeting at the next Board meeting after a meeting is held (these may still be in draft form).

- Supporting schedules and information reviewed by the Committee shall be available for examination by any director.

- The Committee shall have the authority to investigate any financial activity of the Corporation and to communicate directly with the internal and external auditors. All employees are to cooperate as requested by the Committee.

- The Committee may retain, and set and pay the compensation for, persons having special expertise and/or obtain independent professional advice to assist in fulfilling its duties and responsibilities at the expense of ARC.