ARC Energy Trust

2009 Annual Information Form

March 17, 2010

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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 Subco means 1485275 Alberta Ltd., or such other corporation as may be substituted for ARC Subco;

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 22, 2010 evaluating the crude oil, natural gas, natural gas liquids and sulphur reserves attributable to the properties at December 31, 2009;

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 10.5 per cent to 13 per cent payable monthly with maturity dates of 15 years from the date of issuance;

Montney 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;

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 and Risk Factors

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. In addition there are forward looking statements in this Annual Information Form under the headings: "ARC Energy Trust – Federal Tax Changes for Income Trusts and Corporations" as to our anticipated conversion to a corporation and related tax matters; "Statement of Reserves Data and Other Oil and Gas Information" as to our reserves and future net revenues from our reserves, pricing and inflation rates and future development costs; "Statement of Reserves Data and Other Oil and Gas Information - Additional Information Relating to Reserves Data" as to the development of our proved undeveloped reserves and probable undeveloped reserves; and "Statement of Reserves Data and Other Oil and Gas Information - Other Oil and Gas Information" as to our future development activities, the status of our enhanced recovery projects, hedging policies, reclamation and abandonment obligation, tax horizon, exploration and development activities and production estimates. 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 addition to the forward looking statements identified above, this Annual Information Form, and the documents incorporated by reference, contain forward-looking statements pertaining to 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; 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.

Actual results achieved during the forecast period will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. In addition, these risks and uncertainties are material factors affecting the success of our business. Such factors include, but are not limited to: declines in oil and natural gas prices; variations in interest rates and foreign exchange rates; uncertainties relating to the weakened global economy and consequential restricted access to capital, stock market volatility, market valuations and increased borrowing costs; refinancing risk for existing debt and debt service costs; access to external sources of capital; risks associated with our hedging activities; third party credit risk; risks associated with the exploitation of our properties and our ability to acquire reserves; government regulation and control and changes in governmental legislation; changes in income tax laws, royalty rates and other incentive programs; uncertainties associated with estimating oil and natural gas reserves; risks associated with our conversion to a corporate structure; risks associated with acquiring, developing and exploring for natural gas and other aspects of our operations; the timing of payment of distributions, if any; certain of our enhanced recovery projects are not currently economically feasible; risks associated with large projects or expansion of our activities; the failure to realize anticipated benefits of acquisitions and dispositions or to manage growth; risks associated with residency restrictions in the ownership of our Trust Units; changes in climate change laws and other environmental regulations; competition in the oil and gas industry for, among other things, acquisitions of reserves, undeveloped lands, skilled personnel and drilling and related equipment; risks of non-cash losses as a result of the application of accounting policies; our operating activities and ability to retain key personnel; depletion of our reserves; risks associated with securing and maintaining title to our properties; risks associated with our structure and ownership of Trust Units; risks for United States and other non-resident Unitholders and other factors, many of which are beyond our control.

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" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions that the 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 Form and described as being filed on SEDAR at www.sedar.com (including those documents referred to as being incorporated by reference in this Annual Information Form) may be obtained free of charge from us at 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.

OUR BUSINESS

Overview

ARC Energy Trust ("ARC" or "the Trust"), is located in Calgary, Alberta and is one of Canada's largest conventional oil and gas companies. Currently structured as a trust, ARC develops and acquires long-life, low declining oil and gas properties in western Canada. ARC's Unitholders receive a monthly cash distribution from our producing oil and gas assets owned by ARC Resources Ltd. ARC plans to convert to a dividend-paying corporation on January 1, 2011.

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 on 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.

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.

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 and Montney West area of north-eastern British Columbia, where we have spent approximately $229 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 experienced over the past 24 months, the distributions are reviewed on a monthly basis and adjusted as required.

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.

General Development of Our Business

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

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 Montney 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 Montney West Area of British Columbia. We also distributed $570 million to Unitholders in 2008.

In 2009, we incurred capital expenditures of $518 million, of which $326.3 million (63 per cent) was development and facility capital expenditures and $17.4 million (three per cent) was costs of lands acquired, geological and geophysical, and drilling costs for 2009 exploration wells drilled. We completed net property dispositions of $20.5 million and we completed one corporate acquisition for total consideration of $178.9 million (resulting in total acquisitions, net of dispositions, of $158.4 million in the year). We also distributed $299 million to Unitholders in 2009.

Pursuant to the corporate acquisition, we acquired an average 75 percent working interest in 26,000 gross acres of developed lands which include 38 net oil wells and 24 net gas wells, a 30 percent interest in our gas plant located at 10-36-66-25 W5M (which will bring the interest of ARC Resources in such plant to 100 percent) and 121,000 gross (106,000 net) acres of undeveloped lands. Oil production from these assets is processed through three facilities, all of which are operated by us, while gas production from these assets is processed through two facilities currently operated by third parties. We anticipate that we will operate nearly all of the production from these assets. Production from these assets for the nine months ended September 30, 2009 was approximately 2,000 boe/d and was weighted approximately 75 percent to natural gas and approximately 25 percent to crude oil and natural gas liquids.

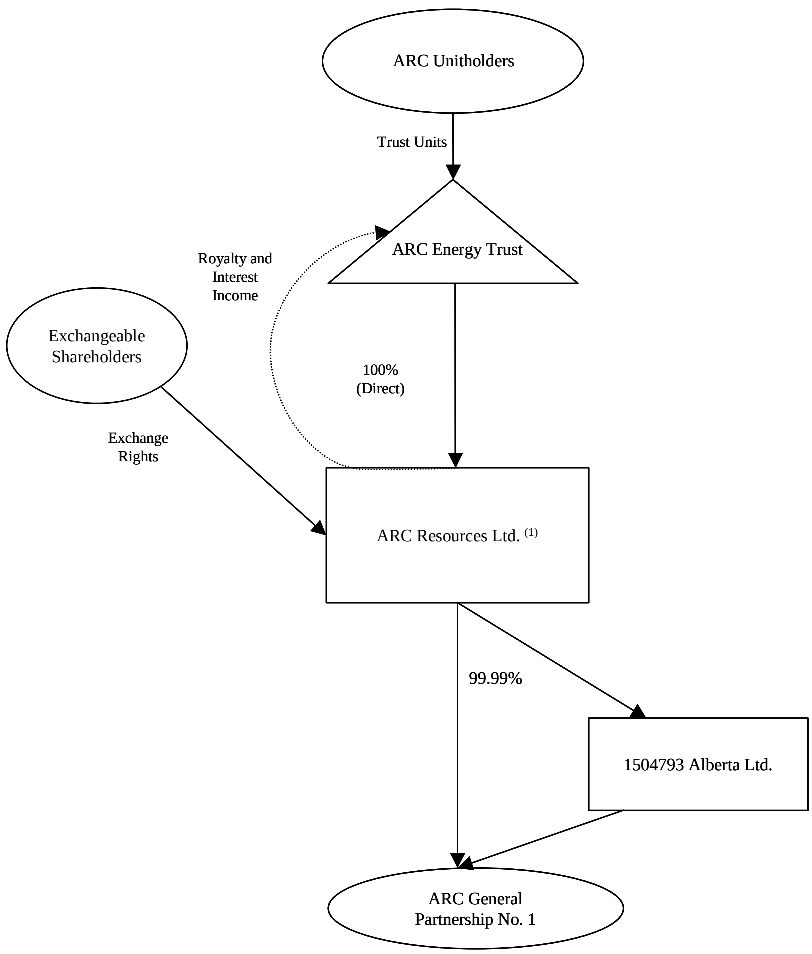
On February 6, 2009, the Trust closed an equity offering to issue 15.5 million Trust Units at $16.35 per unit. The net proceeds of the transaction were $240 million and were used to reduce our bank indebtedness.

Recent Developments

On January 5, 2010, the Trust closed an equity offering to issue 13 million Trust Units at $19.40 per unit. The net proceeds of the offering were $239.5 million and were used to reduce our bank indebtedness.

Our Organizational Structure

Our structure and the flow of cash from ARC Resources to the Trust as of December 31, 2009 are set forth below:



Notes:

(1) As at December 31, 2009, properties in British Columbia are held by ARC Petroleum Inc. as trustee and agent of ARC Resources.

(2) ARC Resources had a total of 870,841 Exchangeable Shares outstanding as at December 31, 2009 that were exchangeable for approximately 2,368,278 Trust Units.

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 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, 2009:

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

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 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, 2009, we had approximately 514 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 January 5, 2010 equity issuance, the Trust can increase its equity by approximately $4.8 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 year 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 will be 16.5 per cent in 2011 and 15 per cent after 2011 and the provincial component will be 10 per cent.

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

Management and the Board of Directors continue to work on the plan for converting our Trust to a corporation on January 1, 2011. After the conversion, the corporation would expect to allocate its cash flow among funding a portion of capital expenditures, periodic debt repayments, site reclamation expenditures, and cash payments to shareholders in the form of dividends. Current taxes payable by us after converting to a corporation will be subject to normal corporate tax rates. Taxable income as a corporation will vary depending on total income and expenses and vary with changes to commodity prices, costs, claims for both accumulated tax pools and tax pools associated with current year expenditures. As we have $2.2 billion of income tax pools, it is expected that taxable income will be reduced or potentially eliminated for the initial approximate two year period post conversion.

Returns to shareholders after conversion to a corporation will be impacted by the reduction of cash flow required to pay current income taxes, if any. Over the longer term, we would expect Canadian investors who hold their Trust Units in a taxable account to be relatively indifferent on an after tax basis as to whether 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 after tax return on distributions in taxable years after 2011 due to the introduction of the SIFT Tax should ARC stay as a trust, and their inability to claim the dividend tax credit if ARC converts to a corporation.

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

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, 2009 and the preparation date of the Statement is January 18, 2010. 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, 2009 contained in the GLJ Report dated February 22, 2010. 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 –Risks Relating to Our Business and Operations".

Reserves Data (Forecast Prices and Costs)

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

	RESERVES			
	LIGHT AND MEDIUM OIL		HEAVY OIL	
RESERVES CATEGORY	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)
PROVED				
Developed Producing	92,989	79,083	2,199	2,157
Developed Non-Producing	1,112	921	13	12
Undeveloped	8,655	7,151	0	0
TOTAL PROVED	102,756	87,154	2,212	2,168
PROBABLE	31,607	25,765	622	577
TOTAL PROVED PLUS PROBABLE	134,363	112,919	2,834	2,745

	RESERVES			
	NATURAL GAS		NATURAL GAS LIQUIDS	
RESERVES CATEGORY	Gross (Bcf)	Net (Bcf)	Gross (Mbbl)	Net (Mbbl)
PROVED				
Developed Producing	481	419	8,299	5,857
Developed Non-Producing	38	30	420	297
Undeveloped	388	320	2,636	2,062
TOTAL PROVED	907	769	11,355	8,216
PROBABLE	435	355	4,281	3,183
TOTAL PROVED PLUS PROBABLE	1,342	1,124	15,637	11,399

	RESERVES	
	TOTAL	
RESERVES CATEGORY	Gross (mboe)	Net (mboe)
PROVED		
Developed Producing	183,663	156,959
Developed Non-Producing	7,862	6,194
Undeveloped	76,018	62,525
TOTAL PROVED	267,543	225,678
PROBABLE	109,000	88,672
TOTAL PROVED PLUS PROBABLE	376,543	314,350

NET PRESENT VALUES OF FUTURE NET REVENUE

RESERVES CATEGORY	BEFORE INCOME TAXES DISCOUNTED AT (%/year) 0 (MM$)	5 (MM$)	10 (MM$)	15 (MM$)	20 (MM$)	AFTER INCOME TAXES DISCOUNTED AT (%/year) 0 (MM$)	5 (MM$)	10 (MM$)	15 (MM$)	20 (MM$)
PROVED										
Developed Producing	7,164	4,755	3,618	2,956	2,520	6,023	4,095	3,173	2,629	2,267
Developed Non-Producing	230	157	119	96	80	177	121	92	74	62
Undeveloped	1,889	1,219	847	615	458	1,416	891	598	415	291
TOTAL PROVED	9,283	6,130	4,584	3,666	3,058	7,616	5,107	3,863	3,118	2,621
PROBABLE	4,285	2,072	1,222	806	569	3,220	1,548	903	588	409
TOTAL PROVED PLUS PROBABLE	13,568	8,202	5,805	4,472	3,627	10,836	6,655	4,766	3,706	3,030

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
as of December 31, 2009
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	19,123	3,184	5,344	1,060	251	9,283	1,667	7,616
Proved Plus Probable Reserves	27,468	4,779	7,221	1,612	287	13,568	2,732	10,836

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

RESERVES CATEGORY	PRODUCTION GROUP[(1)(2)]	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) (MM$)	PER UNIT[(3)]
Proved Reserves	Light and Medium Crude Oil	2,461	$25.64/boe
	Heavy Oil	68	$29.61/boe
	Natural Gas	2,055	$2.69/Mcf
	Total	4,584	
Proved Plus Probable Reserves	Light and Medium Crude Oil	2,997	$23.97/boe
	Heavy Oil	80	$27.80/boe
	Natural Gas	2,728	$2.44/Mcf
	Total	5,805	

Notes:
(1) Including solution gas and other by-products.
(2) Including by-products but excluding solution gas.
(3) Unit values are based on Company Net Reserves.

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 royalty 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 CSA Notice 51-324 – Glossary to NI 51-101 Standards of Disclosure for Oil and Gas Activities and 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, 2009, inflation and exchange rates utilized in the GLJ Report were as follows:

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

Year	OIL: WTI Cushing Oklahoma ($US/bbl)	OIL: Edmonton Par Price 40° API ($Cdn/bbl)	OIL: Hardisty Heavy 12° API ($Cdn/bbl)	OIL: Cromer Medium 29.3° API ($Cdn/bbl)	NATURAL GAS AECO Gas Price ($Cdn/MMbtu)	EDMONTON LIQUIDS PRICES: Propane ($Cdn/bbl)	EDMONTON LIQUIDS PRICES: Butane ($Cdn/bbl)	EDMONTON LIQUIDS PRICES: Pentanes Plus ($Cdn/bbl)	INFLATION RATES(1) %/Year	EXCHANGE RATE(2) ($US/$Cdn)
Forecast										
2010	80.00	83.26	64.99	76.60	5.96	52.46	64.11	84.93	2%	0.950
2011	83.00	86.42	65.24	78.64	6.79	54.45	66.54	88.15	2%	0.950
2012	86.00	89.58	65.33	80.62	6.89	56.43	68.98	91.37	2%	0.950
2013	89.00	92.74	65.26	82.54	6.95	58.42	71.41	94.59	2%	0.950
2014	92.00	95.90	67.52	85.35	7.05	60.42	73.84	97.82	2%	0.950
2015	93.84	97.84	68.90	87.07	7.16	61.64	75.33	99.79	2%	0.950
2016	95.72	99.81	70.32	88.83	7.42	62.88	76.85	101.81	2%	0.950
2017	97.64	101.83	71.76	90.63	7.95	64.15	78.41	103.86	2%	0.950
2018	99.59	103.88	73.22	92.46	8.52	65.45	79.99	105.96	2%	0.950
2019	101.58	105.98	74.72	94.32	8.69	66.77	81.60	108.10	2%	0.950
Thereafter	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	2%	0.950

Notes:
(1) Inflation rates for forecasting costs.
(2) Exchange rates used to generate the benchmark reference prices in this table.
(3) Prices escalate 2.0 per cent per year from 2019.

Weighted average actual prices realized for the year ended December 31, 2009, were $4.18/Mcf for natural gas, $62.51/bbl for light and medium crude oil, $55.74/bbl for heavy crude oil and $40.67/bbl for natural gas liquids. Only a minor amount of our production is characterized as heavy oil.

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	Proved Reserves (M$)	Proved Plus Probable Reserves (M$)
2010	378,193	434,015
2011	284,629	376,677
2012	140,518	220,160
2013	110,333	237,255
2014	20,337	127,927
Remainder	126,147	215,846
Total: Undiscounted	1,060,157	1,611,880
Total: Discounted at 10%/year	847,109	1,249,200

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, 2009, using forecast price and cost estimates derived from the GLJ Report. Gross reserves as at December 31, 2009 and as at December 31, 2008 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, 2008	104,912	30,137	135,049	2,366	640	3,006	736.9	263.1	1,000.0
Discoveries	11	4	15	0	0	0	1.3	0.4	1.7
Extensions	449	572	1,021	0	0	0	110.9	109.5	220.5
Infill Drilling	1,961	432	2,393	12	2	14	61.4	33.3	94.6
Improved Recovery	1,862	360	2,222	16	2	18	0.8	0.1	0.9
Technical Revisions	2,123	(1,510)	613	106	(30)	76	31.0	3.5	34.6
Acquisitions	1,366	1,841	3,207	0	0	0	37.5	26.2	63.7
Dispositions	(241)	(183)	(424)	0	0	0	(0.1)	0.0	(0.1)
Economic Factors	(69)	(46)	(115)	36	8	44	(3.2)	(1.2)	(4.4)
Production	(9,618)	0	(9,618)	(324)	0	(324)	(69.3)	0.0	(69.3)
December 31, 2009	102,756	31,607	134,363	2,212	622	2,834	907.3	434.9	1,342.3

	NATURAL GAS LIQUIDS			TOTAL		
FACTORS	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (mboe)	Probable (mboe)	Proved Plus Probable (mboe)
December 31, 2008	11,057	3,329	14,386	241,154	77,959	319,114
Discoveries	3	1	4	225	77	302
Extensions	371	218	588	19,310	19,045	38,355
Infill Drilling	456	295	750	12,661	6,271	18,932
Improved Recovery	14	5	19	2,024	382	2,406
Technical Revisions	202	5	207	7,600	(945)	6,655
Acquisitions	606	440	1,046	8,225	6,646	14,871
Dispositions	(1)	0	(1)	(257)	(186)	(443)
Economic Factors	(19)	(11)	(30)	(583)	(248)	(831)
Production	(1,333)	0	(1,333)	(22,817)	0	(22,817)
December 31, 2009	11,355	4,281	15,637	267,543	109,000	376,543

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	11,861	11,861	-	-	121,976	121,976	1,827	1,827	34,017	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
2009	2,093	8,655	-	-	118,891	388,364	642	2,636	22,550	76,018

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	10,331	10,331	258	258	56,020	56,020	1,002	1,002	20,928	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
2009	4,244	10,435	-	100	156,403	299,771	840	2,083	31,151	62,580

Over 87 per cent of the proved plus probable undeveloped reserves are located in the Dawson, Montney West, Ante Creek, and Weyburn area properties. In each case, we have planned a program for the development of a portion of the undeveloped reserves in these areas in 2010 and beyond.

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 six years. The pace of development of these reserves is influenced by many factors, including the ongoing development of the infrastructure in the Montney and West Montney areas, and the outcomes of the yearly drilling and reservoir evaluations and a variety of other economic factors.

Significant Factors or Uncertainties

We have a significant amount of proved undeveloped and probable reserves assigned to the Dawson and the Montney 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.

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, 2009 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, 2009. Reserves amounts are stated at December 31, 2009, 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, 2009, and information in respect of production is for the year ended December 31, 2009 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, 2009 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 72 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 2.2 per cent of the total gross proved plus probable reserves as assigned by GLJ in the GLJ Report. Other than Montney West, which commenced production in January, 2010, there are no other material properties to which reserves have been attributed which are capable of producing but which are not producing at December 31, 2009 and there are no material statutory or mandatory relinquishments, surrenders, back-ins or changes in ownership provisions.

	2009 Gross Reserves and Gross Production							
	Light & Medium Crude Oil	Heavy Oil	Natural Gas	Natural Gas Liquids	Total Oil equivalent Production	Proved Reserves	Proved plus Probable Reserves	
	(bbl/d)	(bbl/d)	(mmcf/d)	(bbl/d)	(boe/d)	(mboe)	(mboe)	(%)
Dawson	2	-	52.1	225	8,914	67,152	101,798	27.0
Ante Creek	2,154	52	16.3	393	5,308	25,705	38,139	10.1
Redwater	3,783	-	1.1	178	4,141	22,067	26,896	7.1
Lougheed	2,341	-	-	96	2,437	5,552	6,924	1.8
Jenner	-	-	13.8	-	2,305	9,317	11,860	3.1
Pouce Coupe	20	-	12.6	61	2,178	2,773	3,487	0.9
Hatton	-	-	11.9	-	1,986	7,327	8,746	2.3
Weyburn Unit	1,902	-	-	-	1,902	10,381	15,500	4.1
North Pembina Cardium Unit	1,614	-	1.0	83	1,857	12,511	15,072	4.0
Berrymoor Cardium Unit	1,422	-	1.4	112	1,764	7,957	10,174	2.7
Montney West	-	-	-	-	-	14,704	32,216	8.6

Dawson

The Dawson property is located in northeast British Columbia. We are the operator and own an average land interest of 94 per cent in approximately 38,126 gross hectares (35,848 net hectares). We operate a large area compression facility where the natural gas and liquids are sent to a third party operated facility. During 2009, gross production from the area averaged 8,914 boe/d of natural gas and natural gas liquids from 95 net wells principally from the upper Montney zone. During 2009, 29 new wells were drilled and construction began on a 60 mmcf per day gas processing facility. GLJ assigned gross proved reserves of 67,152 mboe and gross proved plus probable reserves of 101,798 mboe of natural gas and natural gas liquids to this area, or 27 per cent of total gross proved plus probable reserves. We are in the process of completing a 60 MMcfpd gas plant for production from the Dawson area which is capable of being tied into the gas plant on completion and have initiated planning for the construction of an additional 60 MMcfpd gas plant for anticipated production from the Dawson area.

Ante Creek

The Ante Creek property is located in northwest Alberta. We are the operator and own an average land interest of 95 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 2009, gross production from the area averaged 5,308 boe/d of oil, natural gas and natural gas liquids from 180 net wells. During 2009, five new wells were drilled. GLJ assigned gross proved reserves of 25,705 mboe and gross proved plus probable reserves of 38,139 mboe of oil, natural gas and natural gas liquids to this area, or 10.1 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 2009, gross production from the area averaged 4,141 boe/d of oil, natural gas and natural gas liquids from 380 net wells. During 2009, three new wells were drilled. GLJ assigned gross proved reserves of 22,067 mboe and gross proved plus probable reserves of 26,896 mboe of oil, natural gas and natural gas liquids to this area, or 7.1 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 significant oil production from our property has occurred to date, we believe that there are substantial quantities of oil remaining in the reservoir which are unrecoverable with conventional technology.

During 2009, ARC commenced production operations at the pilot EOR project in Redwater, while continuing the injection of CO_2. 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. Results are not expected before the end of 2010. Additionally, prior to commercial operations, large amounts of CO_2 need to be acquired on economic terms for the Redwater EOR project 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 the Redwater EOR project will proceed to a commercial phase or become 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 2009, gross production from the area averaged 2,437 boe/d of oil and natural gas liquids from 125 net wells. During 2009, no new wells were drilled. GLJ assigned gross proved reserves of 5,552 mboe and gross proved plus probable reserves of 6,924 mboe of oil and natural gas liquids to this area, or 1.8 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 2009, gross production from the area averaged 2,305 boe/d of natural gas from 835 net wells. During 2009, no new wells were drilled. GLJ assigned gross proved reserves of 9,317 mboe and gross proved plus probable reserves of 11,860 mboe of natural gas to this area, or 3.1 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 75 per cent. The sweet gas is processed through an operated gas plant and the sour gas flows to a third party processing plant. During 2009, gross production from the area averaged 2,178 boe/d of oil, natural gas and natural gas liquids from 39 net wells. During 2009, one well was drilled. GLJ assigned gross proved reserves of 2,773 mboe and gross proved plus probable reserves of 3,487 mboe of oil, natural gas and natural gas liquids to this area, or 0.9 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 2009, gross production from the area averaged 1,986 boe/d of natural gas from 468 net wells. During 2009, 23 new wells were drilled. GLJ assigned gross proved reserves of 7,327 mboe and gross proved plus probable reserves of 8,746 mboe of natural gas to this area, or 2.3 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 2009 gross production from the unit averaged 1,902 boe/d of oil from 58 net wells. During 2009, six new wells were drilled. GLJ assigned gross proved reserves of 10,381 mboe and gross proved plus probable reserves of 15,500 mboe of oil and natural gas liquids to this unit, or 4.1 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 2009, gross production from the unit averaged 1,857 boe/d of oil, natural gas and natural gas liquids from 179 net wells. During 2009, four new wells were drilled. GLJ assigned gross proved reserves of 12,511 mboe and gross proved plus probable reserves of 15,072 mboe of oil, natural gas and natural gas liquids to this unit, or four 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 2009, gross production from the unit averaged 1,764 boe/d of oil, natural gas and natural gas liquids from 91 net wells. During 2009, one new well was drilled. GLJ assigned gross proved reserves of 7,957 mboe and gross proved plus probable reserves of 10,174 mboe of oil, natural gas and natural gas liquids to this unit, or 2.7 per cent of total gross proved plus probable reserves.

Montney West

The Montney West property is located in northeast British Columbia. We own an average land interest of 79 per cent in approximately 24,425 gross hectares (19,254 net hectares) in the Montney West Area which we believe is prospective in the upper Montney and other horizons. The Montney West Area has been assigned gross proved reserves of 14,704 boe and gross proved plus probable reserves of 32,216 mboe in the GLJ Report which are capable of producing but which are not yet producing material volumes due to pipeline, processing and other infrastructure constraints. In 2009, we had royalty income in the area resulting from interests we hold in third party wells, equivalent to 7 boe/d of natural gas and natural gas liquids. We currently plan to construct a 60 MMcfpd gas plant for production from the Montney West Area in 2012.

Oil And Gas Wells

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

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	3,809	1,596	1,162	163	4,517	1,965	253	53
British Columbia	7	1	1	-	307	101	55	31
Saskatchewan	2,173	812	319	91	5,577	902	60	20
Manitoba	589	137	20	3	-	-	-	-
Total	6,578	2,547	1,502	257	10,401	2,968	368	103

Properties with no Attributable Reserves

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

	Undeveloped Hectares	
	Gross	Net
Alberta	245,000	134,500
British Columbia	82,100	61,300
Manitoba	3,900	3,700
Saskatchewan	91,600	60,500
Total	422,600	260,000

In British Columbia, we have 55,800 gross hectares and 50,700 net hectares in Dawson and the Montney West Area which have varying degrees of prospectively in the Montney zones. For more information, see "Statement of Reserves Data and Other Oil and Gas Information - Additional Information Relating to Reserve Data – Principal Properties – Dawson and Montney West ".

We currently have no material work commitments on these lands. 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 and by monitoring their ongoing credit risks.

In general, under authorities approved by the Board of Directors, 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, 40 per cent between seven and 12 months, and 25 per cent between 13 and 18 months. In addition to these authorizations to management, the Board of Directors may approve longer term hedging transactions to mitigate risks relating to, and protect the economics of, major capital expenditures.

We have a Risk Committee of the Board of Directors that reviews policies, procedures and provides oversight to management in the areas of 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 "Financial Instruments and Risk Management" to our audited consolidated financial statements for the year ended December 31, 2009 and in the section under the heading "Risk Management and Hedging Activities" in our Management Discussion and Analysis for the year ended December 31, 2009 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, 2009	1,358.7	74.9
Anticipated to be paid in 2010	5.6	5.1
Anticipated to be paid in 2011	5.4	4.5
Anticipated to be paid in 2012	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 6,888 net wells that will require abandonment and reclamation over the next 51 years with the majority of payments being made in years 2050 to 2060. 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 obligation costs. We currently estimate that the future environmental and reclamation obligations in respect of our properties will be approximately $1,359 million calculated by escalating costs at two per cent per year (reflected in our audited consolidated financial statements as an asset retirement obligation of $149.9 million calculated by escalating costs at two per cent per year and discounting at a blended rate of 6.5 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 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 2009) based on properties owned as at December 31, 2009. During 2009, $5.9 million ($9.7 million for 2008) of actual expenditures were charged against the reclamation fund resulting in a net reduction of our reclamation fund for the year of $1.4 million ($3.2 million net reduction in 2008). The balance of this fund as of December 31, 2009 is $12.6 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, 2009 is $20.6 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.

Our estimated 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 $1,071.7 million (escalating costs at two per cent and undiscounted) and $26.9 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. See "ARC Energy Trust – 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 us Resources. See "Risk Factors – Risks Relating to Our Business and Operations".

Management and the Board of Directors continue to work on the plan for converting our Trust to a corporation on January 1, 2011. After the conversion, the corporation would expect to allocate its cash flow among funding a portion of capital expenditures, periodic debt repayments, site reclamation expenditures, and cash payments to shareholders in the form of dividends. Current taxes payable by us after converting to a corporation will be subject to normal corporate tax rates. Taxable income as a corporation will vary depending on total income and expenses and vary with changes to commodity prices, costs, claims for both accumulated tax pools and tax pools associated with current year expenditures. As we have $2.2 billion of income tax pools, it is expected that taxable income will be reduced or potentially eliminated for the initial approximate two year period post conversion.

Capital Expenditures

The following table summarizes 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, 2009:

	2009 $MM
Property acquisition costs(1)	
Proved properties	(29.1)
Undeveloped properties	8.6
Corporate acquisition costs(2)	178.9
Exploration costs(3)	17.4
Development costs(4)	326.4
Corporate capital costs	15.8
Total	518.0

Notes:
(1) Represents acquisition costs net of dispositions and property swaps.
(2) For further details on Corporate acquisition costs for 2009, see "Our Business – General Development of the Business".
(3) Includes costs of land acquired ($2.6 million), geological and geophysical capital expenditures and drilling costs for 2009 exploration wells drilled.
(4) Includes costs of land acquired ($4.4 million), development and facilities capital expenditures and drilling costs for 2009 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, 2009:

	Exploratory Wells		Development Wells		Total	
	Gross	Net	Gross	Net	Gross	Net
Light and Medium Oil	2	2	62	38	64	39
Heavy Oil	-	-	10	-	10	-
Natural Gas	2	2	167	97	169	99
Service	-	-	8	1	8	1
Dry	2	1	2	2	4	2
Total:	7	4	248	137	255	141

For 2010, the Trust has planned an extensive capital program of $610 million. The program comprises costs to develop the core assets of the Trust, including the Dawson, Montney West, Ante Creek and Weyburn areas, as well as expansion of the facilities in the Dawson and Montney West Areas. 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 – Risks Relating to our Business and Operations".

Production Estimates

The following table sets out the volume of our production estimated for the year ended December 31, 2010 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	25,298	21,519	846	845	236,148	202,028	3,809	2,768	69,310	58,803
Total Proved Plus Probable	26,598	22,575	878	874	245,185	208,696	3,968	2,887	72,308	61,119

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 2009				Year Ended
(6:1)	Mar. 31	June 30	Sept. 30	Dec. 31	2009
Average Daily Production[1]					
Light and Medium Crude Oil (bbl/d)	27,720	25,901	25,930	26,299	26,423
Heavy Oil (bbl/d)	1,086	1,016	991	1,116	1,086
Gas (MMcfpd)	193.8	200.2	193.1	189.0	194.0
NGLs (bbl/d)	3,764	3,679	3,717	3,597	3,689
Combined (boe/d)	64,872	63,969	62,824	62,520	63,538
Average Net Production Prices Received					
Light and Medium Crude Oil ($/bbl)	46.76	62.92	58.99	72.95	62.51
Heavy Oil ($/bbl)	38.11	57.96	52.59	64.52	55.74
Gas ($/Mcf)	5.20	3.73	4.05	4.58	4.18
NGLs ($/bbl)	38.86	38.89	38.89	46.12	40.67
Combined ($/boe)	38.57	40.41	40.11	48.42	42.17

(6:1)	Quarter Ended 2009 Mar. 31	June 30	Sept. 30	Dec. 31	Year Ended 2009
Royalties Paid					
Light and Medium Crude Oil ($/bbl)	6.95	8.65	8.73	12.28	9.63
Heavy Oil ($/bbl)	2.73	3.59	4.73	7.61	5.34
Gas ($/Mcf)	0.85	0.17	0.47	0.58	0.50
NGLs ($/bbl)	13.47	10.86	12.33	15.15	13.03
Combined ($/boe)	6.34	4.72	5.86	7.94	6.37
Operating Expenses [(2)(3)]					
Light and Medium Crude Oil ($/bbl)	12.74	13.20	13.11	12.19	12.88
Heavy Oil ($/bbl)	16.03	12.65	12.52	12.34	12.46
Gas ($/Mcf)	1.30	1.52	1.34	1.30	1.33
NGLs ($/bbl)	8.01	7.75	8.45	6.40	7.85
Combined ($/boe)	10.12	11.02	10.28	9.91	10.19
Transportation Paid					
Light and Medium Crude Oil ($/bbl)	0.18	0.14	0.15	0.27	0.18
Heavy Oil ($/bbl)	1.50	1.29	1.12	1.09	1.15
Gas ($/Mcf)	0.28	0.25	0.26	0.27	0.26
NGLs ($/bbl)	-	-	-	-	-
Combined ($/boe)	0.95	0.85	0.88	0.92	0.89
Loss/(Gain) on Commodity and Foreign Exchange Contracts					
Light and Medium Crude Oil ($/bbl)	0.76	2.11	1.56	1.91	1.65
Heavy Oil ($/bbl)	-	-	-	-	-
Gas ($/Mcf)	(0.77)	(0.15)	(0.50)	(0.11)	(0.40)
NGLs ($/bbl)	-	-	-	-	-
Combined ($/boe)	(1.97)	0.46	(0.88)	0.47	(0.54)
Netback Received[(4)]					
Light and Medium Crude Oil ($/bbl)	26.13	38.82	35.44	46.30	38.17
Heavy Oil ($/bbl)	17.85	40.43	34.22	43.48	36.79
Gas ($/Mcf)	3.54	1.94	2.48	2.54	2.49
NGLs ($/bbl)	17.38	20.28	18.11	24.57	19.79
Combined ($/boe)	23.13	23.36	23.97	29.18	25.26

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.

Each of the Dawson, Ante Creek and Redwater areas account for approximately 14 per cent, 8 per cent and 7 per cent of the production disclosed above. For more information, see "Statement of Reserves Data and Other Oil and Gas Information - Other Oil and Gas Information – Principal Properties".

Marketing Arrangements

Natural Gas

During 2009, 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 2009 was $4.18 per Mcf as compared to $8.58 per Mcf for 2008. This price was achieved with a portfolio mix that on average through the year received AECO index based pricing for 82 per cent, aggregator netback prices for 11 per cent, and Chicago Index Pricing for 7 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. We also strive for a high utilization of contracted pipeline and processing capacity.

Crude Oil and Natural Gas Liquids

Our liquids production in 2009 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 2009, our average sales prices were $62.49 per bbl for light and medium crude oil, $55.64 per bbl for heavy crude oil and $40.67 per bbl for natural gas liquids; these prices compare to 2008 prices of $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. 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 1,000,131 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 there were 870,841 outstanding as at December 31, 2009. 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, 2009 the Exchange Ratio was 2.71953 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 no Second Preferred Shares, Series 1 and Second Preferred Shares, Series 2 issued and outstanding.

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.

Our credit facilities are comprised of both a bank credit facility and long-term notes issued to major financial institutions. We may choose to repay a portion of our debt from one source and borrow from other parties in order to reduce borrowing costs and provide more financial flexibility.

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, 2009 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 $298.1 million and Cdn $29 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, 2009, which is incorporated by reference in this Annual Information Form and which has been filed on SEDAR at www.sedar.com.

See "Risk Factors – Risks Relating to Our Business and Operations".

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 the 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 "Our Information - 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.

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.

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 – Risks Relating to Our Structure and Ownership of Trust Units" and "Risk Factors –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.

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 nine individuals, all of whom have been elected by Unitholders, except for Kathleen M. O'Neill who joined the Board on June 1, 2009, 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, 2009 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

Name and Municipality of Residence	Offices Held and Time as Director	Principal Occupation
John P. Dielwart Calgary, Alberta, Canada	Chief Executive Officer and Director since May 3, 1996	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)(5) Calgary, Alberta, Canada	Director since May 3, 1996	Independent Businessman
Harold N. Kvisle(6) Calgary, Alberta Canada	Director since May 20, 2009	President and Chief Executive Officer of TransCanada Corporation and TransCanada Pipelines Ltd.
Kathleen M. O'Neill (1)(4) Toronto, Ontario, Canada	Director since June 1, 2009	Independent Businesswoman
Herbert C. Pinder, Jr.(4)(5)(6) Saskatoon, Saskatchewan, Canada	Director since January 1, 2006	Independent Businessman
Myron M. Stadnyk Calgary, Alberta, Canada	President and Chief Operating Officer	President and Chief Operating Officer of ARC Resources
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
Terry M. Anderson Calgary, Alberta, Canada	Vice-President, Operations	Vice-President, Operations 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 2009.
(2) Member of Reserves Committee in 2009.
(3) Member of Risk Committee in 2009.
(4) Member of Human Resources and Compensation Committee in 2009.

(5) Member of Policy and Board Governance Committee in 2009.
(6) Member of Health, Safety and Environment Committee in 2009.

With the exception of the following individuals, the officers and directors have held the position set forth as their principal occupation for the last five years: 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, 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 and Myron J. Stadnyk, was Vice-President, Operations and Land and prior to February 2009 was Senior Vice-President of ARC Resources. Prior to July 2007 P. Van R. Dafoe was Treasurer of ARC Resources. Prior to November 2005, Terry M. Anderson was Manager, Field Operations 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. Prior to February 2009 John P. Dielwart was President 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 is the 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 is 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.

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 20, 2009, except Kathleen O'Neill who was appointed as an addition to the Board of Directors on June 1, 2009, to hold office until the next annual general meeting of ARC Resources, which is scheduled for May 18, 2010. As at December 31, 2009, the directors and officers of ARC Resources, as a group, beneficially owned, or controlled or directed, directly or indirectly, 1,083,218 Trust Units or approximately 0.46 per cent of the outstanding Trust Units, and 441,466 Exchangeable Shares or approximately 51 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, 2009, the directors and officers of ARC Resources as a group would hold 2,283,798 Trust Units or approximately 0.96 per cent of the outstanding Trust Units as at December 31, 2009.

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, 2009, the members of the Audit Committee were Fred J. Dyment, chairman, and Walter DeBoni, James C. Houck and Kathleen O'Neill, 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 over 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, Transglobe Energy Corporation and WesternZagros Resources Ltd. He has been a Director of ARC since 2003.

Walter 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. 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 a MBA from the University of Houston. Mr. Houck has over 40 years of industry experience, primarily with Chevron Texaco Inc. where he held a number of senior management positions.

Kathleen M. O'Neill

Ms. O’Neill is a corporate director and has extensive experience in accounting and financial services. Prior to 2005, she was an Executive Vice-President of BMO Financial Group with accountability for a number of major business units. Prior to joining BMO Financial Group in 1994, she was a partner with PricewaterhouseCoopers. Ms. O’Neill is an FCA (Fellow of Institute of Chartered Accountants) and has her ICD.D designation from the Institute of Corporate Directors. Ms. O’Neill currently serves on the board of directors of Finning International Inc., which is the world’s largest Caterpillar dealer; Invesco Trimark Funds and the TMX Group Inc., which operates cash and derivative markets (including the TSX, TSX Venture Exchange, NGX, and the Montreal Exchange), clearing facilities and data services. Ms. O’Neill is Chair of St. Joseph’s Health Centre Foundation.

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:

2009	$733,250
2008	$677,834

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:

2009	$63,095
2008	$36,199

Tax Fees

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

2009	$Nil
2008	$114,013

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.

2009	$Nil
2008	$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, Chief Executive Officer 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, Chief Executive Officer 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 or during the current financial year that has materially affected or is reasonably expected to affect the Trust.

DISTRIBUTIONS TO UNITHOLDERS

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

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
2009	
First Quarter	$0.36
Second Quarter	$0.32
Third Quarter	$0.30
Fourth Quarter	$0.30

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 2007 were three per cent tax deferred, 2008 distributions were two per cent tax deferred and 2009 distributions were three 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):

2009 Period	Toronto Stock Exchange High	Low	Volume
	$	$	
January	21.48	16.07	22,123,293
February	16.70	12.46	24,297,428
March	15.95	11.41	27,362,678
April	16.19	13.66	15,541,209
May	17.82	15.52	21,227,035
June	19.55	16.26	22,704,115
July	17.79	15.16	17,962,304
August	18.38	17.08	16,005,250
September	20.20	15.92	20,664,113
October	22.10	18.15	22,501,148
November	21.47	18.92	15,112,772
December	20.65	18.78	15,236,851

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):

2009 Period	Toronto Stock Exchange High	Low	Volume
	$	$	
January	51.00	42.85	420
February	41.50	35.35	1,900
March	46.98	30.39	5,012
April	41.98	33.03	190
May	44.24	37.50	1,700
June	51.50	37.00	1,970
July	44.70	40.01	2,266
August	N/A	N/A	0
September	54.00	48.99	15,400
October	57.00	53.00	18,000
November	57.50	53.00	30,728
December	56.00	52.00	6,222

INDUSTRY REGULATIONS

Companies operating in the oil and natural gas industry are subject to extensive regulation and control of operations (including land tenure, exploration, development, production, natural gas processing, refining, transportation, and marketing) as a result of legislation enacted by various levels of government and with respect to the pricing and taxation of oil and natural gas through agreements among the governments of Canada, Alberta, British Columbia 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 regulations or controls will affect the Corporation's operations in a manner materially different than they will affect other oil and natural gas companies of similar size. All current legislation is a matter of public record and the Corporation is unable to predict what additional legislation or amendments may be enacted. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the oil and gas industry.

Pricing and Marketing

Oil

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

Natural Gas

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

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

Pipeline Capacity

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

The North American Free Trade Agreement

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

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

Royalties and Incentives

General

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

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

Alberta

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

On October 25, 2007, the Government of Alberta released a report entitled "The New Royalty Framework" ("**NRF**") containing the Government's proposals for Alberta's new royalty regime which were subsequently implemented by the *Mines and Minerals (New Royalty Framework) Amendment Act, 2008*. The NRF took effect on January 1, 2009.

On March 11, 2010, the Government of Alberta announced changes to Alberta's royalty system intended to increase Alberta's competitiveness in the upstream oil and natural gas sectors; specifically, the maximum royalty rates for conventional oil and natural gas production will be decreased effective for the January 2011 production month and certain temporary incentive programs currently in place will be made permanent. Further details with respect to the changes to Alberta's royalty system are expected to be provided in the coming months.

With respect to conventional oil, the NRF eliminated the classification system used by the previous royalty structure which classified oil based on the date of discovery of the pool. Under the NRF, royalty rates for conventional oil are set by a single sliding rate formula which is applied monthly and incorporates separate variables to account for production rates and market prices. Royalty rates for conventional oil under the NRF range from 0-50 per cent, an increase from the previous maximum rates of 30-35 per cent depending on the vintage of the oil, and rate caps are set at $120 per barrel. Effective January 1, 2011, the maximum royalty payable under the NRF will be reduced to 40 per cent.

Royalty rates for natural gas under the NRF are similarly determined using a single sliding rate formula incorporating separate variables to account for production rates and market prices. Royalty rates for natural gas under the NRF range from 5-50 per cent, an increase from the previous maximum rates of 5-35 per cent, and rate caps are set at $17.75/GJ. Effective January 1, 2011, the maximum royalty payable under the NRF will be reduced to 36 per cent.

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

In August 2006, the Government of Alberta introduced the Innovative Energy Technologies Program (the "**IETP**"), which has a stated objective of promoting producers' investment in research, technology and innovation for the purposes of improving environmental performance while creating commercial value. The IETP is backed by a $200 million funding commitment over a five-year period beginning April 1, 2005 and provides royalty adjustments to specific pilot and demonstration projects that utilize innovative technologies to increase recovery from existing reserves.

On April 10, 2008, the Government of Alberta introduced two new royalty programs to be implemented along with the NRF and intended to encourage the development of deeper, higher cost oil and gas reserves. A five-year program for conventional oil exploration wells over 2,000 metres provides qualifying wells with up to a $1 million or 12 months of royalty relief, whichever comes first, and a five-year program for natural gas wells deeper than 2,500 metres provides a sliding scale royalty credit based on depth of up to $3,750 per metre.

On November 19, 2008, in response to the drop in commodity prices experienced during the second half of 2008, the Government of Alberta announced the introduction of a five-year program of transitional royalty rates with the intent of promoting new drilling. The five-year transition option is designed to provide lower royalties at certain price levels in the initial years of a well's life when production rates are expected to be the highest. Under this new program companies drilling new natural gas or conventional oil deep wells (between 1,000 and 3,500 m) are given a one-time option, on a well-by-well basis, to adopt either the new transitional royalty rates or those outlined in the NRF. Pursuant to the changes made to Alberta's royalty structure announced on March 11, 2010, producers will only be able to elect to adopt the transitional royalty rates prior to January 1, 2011 and producers that have already elected to adopt the transitional royalty rates as of that date will be permitted to switch to Alberta's conventional royalty structure. On December 31, 2013, all producers operating under the transitional royalty rates will automatically become subject to Alberta's conventional royalty structure.

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

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

British Columbia

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

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

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

As at the beginning of 2009, British Columbia maintained a number of targeted royalty programs for key resource areas intended to increase the competitiveness of British Columbia's low productivity wells. These include both royalty credit and royalty reduction programs, including the following:

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

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

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

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

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

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

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

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

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

On March 2, 2009, the Government of British Columbia announced the 2009 Infrastructure Royalty Credit Program (the "**Infrastructure Royalty Credit Program**") which allocates \$120 million in royalty credits for oil and gas companies. The Infrastructure Royalty Credit Program provides royalty credits for up to 50 per cent of the cost of certain approved road construction or pipeline infrastructure projects intended to improve, or make possible, the access to new and underdeveloped oil and gas areas. The Government of British Columbia has recently announced the same level of funding for the 2010 Infrastructure Royalty Credit Program.

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

Saskatchewan

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

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

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

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

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

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

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

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

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

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

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

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 if Canada's plan to reintroduce full deductibility of provincial resource royalties for corporate income tax purposes.

Land Tenure

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

Each of the provinces of Alberta, British Columbia and Saskatchewan has implemented legislation providing for the reversion to the Crown of mineral rights to deep, non-productive geological formations at the conclusion of the primary term of a lease or license.

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

Environmental Regulation

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

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

Climate Change Regulation

Federal

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

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

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

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

On April 26, 2007, the Government of Canada released "Turning the Corner: An Action Plan to Reduce Greenhouse Gases and Air Pollution" (the "**Action Plan**") which set forth a plan for regulations to address both greenhouse gases and air pollution. An update to the Action Plan, "Turning the Corner: Regulatory Framework for Industrial Greenhouse Gas Emissions" was released on March 10, 2008 (the "**Updated Action Plan**"). Although draft regulations for the implementation of the Updated Action Plan were intended to be published in the fall of 2008 and become binding on January 1, 2010, no such regulations have been proposed to date. Further, representatives the Government of Canada have recently indicated that the proposals contained in the Updated Action Plan will be modified to ensure consistency with the direction ultimately taken by the United States with respect to greenhouse gas emissions regulation. The approach of the Unites States is expected to include an absolute cap on emissions combined with allowances to be used for compliance that may be partially auctioned off to regulated entities. It is also unclear whether the approach adopted by the United States will provide for the payment into a technology fund as a compliance mechanism, as is currently permitted in Alberta and by the Updated Action Plan. As a result, many provisions of the Updated Action Plan, described below, are expected to be significantly modified.

The stated goal of the Updated Action Plan, as currently drafted, is to reduce greenhouse gas emissions to 20 per cent below 2006 levels by 2020 and 60-70 per cent by 2050. As noted above, the goal has now been modified by the Government of Canada. The Updated Action Plan outlines emissions intensity-based targets which will be applied to regulated sectors on either a facility-specific, sector-wide or company-by-company basis. Facility-specific targets applied to the upstream oil and gas, oil sands, petroleum refining and natural gas pipelines sectors. Unless a minimum regulatory threshold applies, all facilities within a regulated sector will be subject to the emissions intensity targets.

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

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

Four separate compliance mechanisms are provided for in the Updated Action Plan in respect of the above targets: Technology Fund contributions, offset credits, clean development credits and credits for early action. Regulated entities will be able to use Technology Fund contributions to meet their emissions intensity targets. The contribution rate for Technology Fund contributions will increase over time, beginning at $15 per tonne of CO_2 equivalent for the 2010-12 period, rising to $20 in 2013, and thereafter increasing at the nominal rate of GDP growth. Maximum contribution limits will also decline from 70 per cent in 2010 to 0 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 described above.

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

Under the Updated Action Plan, regulated entities will also be able to purchase credits created through the Clean Development Mechanism of the Kyoto Protocol which facilitates investment by developed nations in emissions-reduction projects in developing countries. The purchase of such Emissions Reduction Credits will be restricted to 10 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.

Alberta

Alberta enacted the *Climate Change and Emissions Management Act* (the "**CCEMA**") on July 1, 2007, amending it through the *Climate Change and Emissions Management Amendment Act* which received royal asset on November 4, 2008. The CCEMA is based on an emissions intensity approach similar to the Updated Action Plan and aims for a 50 per cent reduction from 1990 emissions relative to GDP by 2020.

Alberta facilities emitting more than 100,000 tonnes of greenhouse gases a year are subject to comply with the CCEMA. Similarly to the Updated Action Plan, the CCEMA and the associated *Specified Gas Emitters Regulation* make a distinction between "Existing Facilities" and "New Facilities". Existing Facilities are defined as facilities that completed their first year of commercial operation prior to January 1, 2008 or that have completed 8 or more years of commercial operation. Existing Facilities were required to reduce their emissions intensity by March 31, 2008 by 12 per cent from a baseline established by their average emissions intensity between 2003 and 2005. New

Facilities are defined as facilities that completed their first year of commercial operation subsequent to December 31, 2008, have completed less than 8 years of commercial operation, or are designated as New Facilities in accordance with the *Specified Gas Emitters Regulation*. New Facilities are also required to reduce their emissions intensity by 12 per cent but this target is based on the emissions intensity of the facility in its third year of commercial operation and does not apply during the first 3 years of operation of the New Facility. Unlike the Updated Action Plan, the CCEMA does not contain any provision for continuous annual improvements beyond the 12 per cent emissions intensity required.

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

British Columbia

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

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

Saskatchewan

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

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 "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.

Risk Relating to Our Business and Operations

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

Our operational results and financial condition, and therefore the amounts we pay to Unitholders as distributions, will be dependent on the prices received for oil and natural gas production. Oil and natural gas prices have exhibited extreme volatility over the past few years and monthly distributions that reached a high point of $0.28 per Trust Unit in August of 2008 declined to $0.10 per Trust Unit at December 31, 2009. 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, Canada and worldwide, the actions of the Organization of Petroleum Exporting Countries, governmental regulation, political stability in the Middle East and elsewhere, internal capacity to produce natural gas in the United States from shale deposits, the foreign supply of oil and natural gas, risks of supply disruption, the price of foreign imports and the availability of alternative fuel sources. Any substantial and extended decline in the price of oil and natural gas would have an adverse effect on the carrying value of our proved and probable reserves, net asset value, borrowing capacity, revenues, profitability and cash flows from operating activities and ultimately on our financial condition and therefore on the amounts to be distributed to our Unitholders.

Increases in interest rates or the value of the Canadian dollar against the U.S. dollar will adversely affect our financial condition

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

World oil prices are quoted in United States dollars and the price received by Canadian producers is therefore affected by the Canadian/U.S. dollar exchange rate that may fluctuate over time and in fact increased in 2009 by eight per cent. A material increase in the value of the Canadian dollar negatively impacts our production revenue and our ability to maintain future distributions.

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

Market events and conditions, including disruptions in the international credit markets and other financial systems and the deterioration of global economic conditions, caused significant volatility to commodity prices over the last few years. These conditions worsened in 2008 and early 2009, causing a loss of confidence in the broader U.S. and global credit and financial markets and resulting in the collapse of, and government intervention in, major banks, financial institutions and insurers and creating a climate of greater volatility, less liquidity, widening of credit spreads, a lack of price transparency, increased credit losses and tighter credit conditions. Notwithstanding various actions by governments, concerns about the general condition of the capital markets, financial instruments, banks, investment banks, insurers and other financial institutions caused the broader credit markets to further deteriorate and stock markets to decline substantially. Although economic conditions improved towards the latter portion of 2009 and continue to improve in early 2010, these factors have negatively impacted company and trust valuations and continue to impact the performance of the global economy going forward.

Our bank credit facility will need to be renewed prior to April 11, 2011 and failure to renew, in whole or in part, or at higher interest charges will adversely affect our financial condition

We currently have an $800 million syndicated credit facility with eleven banks of which we had drawn $497.3 million as at December 31, 2009. 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.

We had U.S. $298.1 million of U.S. denominated and Cdn $29 million of long-term debt outstanding as at December 31, 2009, which requires principal repayments starting in April 2010 and continuing until April 2021. We intend to fund these debt maturities with existing credit facilities.

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.

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 the Royalties and interest on the Long Term Notes and distributable income. 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 future capital expenditure programs, or that additional funds will be able to be obtained.

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

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

As future capital expenditures will be financed out of 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 or expand existing assets and reserves may be impaired, and our assets, liabilities, business, financial condition, results of operations and distributions may be materially and adversely affected as a result.

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 optimal capital structure.

Our hedging activities may negatively impact our income and the financial condition of the Corporation.

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. For more information in relation to our commodity hedging program, see "Statement of Reserve Data and Other Oil and Gas Information – Other Oil and Gas Information – Forward Contracts". We may initiate certain hedges to attempt to mitigate the risk of the Canadian dollar appreciating against the U.S. dollar. The increase in the exchange rate for the Canadian dollar and future Canadian/United States exchange rates will impact future distributions and the future value of our reserves as determined by independent evaluators. These hedging activities could expose us to losses and to credit risk associated with counterparties with which we contract.

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

We are exposed to third party credit risk through our contractual arrangements with our current or future joint venture partners, third party operators, marketers of our petroleum and natural gas production and other parties. Poor credit conditions in the industry and of joint venture partners may impact a joint venture partner's willingness to participate in our ongoing capital program, potentially delaying the program and the results of such program until we find a suitable alternative partner.

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

Our ability to add to our oil and natural gas reserves is highly dependent on our success in exploiting existing properties and acquiring additional reserves. We currently distribute a significant proportion of our cash flow from operating activities to Unitholders rather than reinvesting it in reserves additions. Our ability to make the necessary capital investments to maintain or expand our oil and natural gas reserves is dependent on external sources of capital and maintenance of our cash flow from operating activities. 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. There is no assurance we will be successful in developing additional reserves or acquiring additional reserves on terms that meet our investment objectives. Without these reserves additions, our reserves will deplete and as a consequence, either production from, or the average reserves life of, our properties will decline, which will result in a reduction in the value of Trust Units and in a reduction in cash flow from operating activities available for distributions to Unitholders.

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

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

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

We 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.

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 and our ability to maintain distributions.

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.

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

In general, estimates of economically recoverable oil and natural gas reserves and resources, the future net revenues and finding and development costs 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.

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 and net asset value would be reduced and the reduction could be significant. 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.

Estimates of proved undeveloped reserves are sometimes based upon volumetric calculations and upon analogy to similar types of reserves rather than actual production history. Recovery factors and drainage areas were estimated by experience and analogy to similar producing pools. Estimates based on these methods are generally less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history and production practices will result in variations in the estimated reserves and such variations could be material.

The Trust is in the process of converting to a corporate structure which may result in adverse consequences to our financial condition

New federal legislation passed in June 2007, will apply a tax ("**SIFT tax**") at the trust level on distributions of certain income from trusts, such as 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 effective January 1, 2011. 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.

The SIFT tax will substantially eliminate 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 will make 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.

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, spills and delays in payments between parties caused by operation or economic matters. These risks will increase as the Trust undertakes more exploratory activity. Although we maintain insurance in accordance with customary industry practice, we are not fully insured against all of these risks.

Continuing production from a property, and to some extent the marketing of production therefrom, are largely dependent upon the ability of the operator of the property. Other companies operate some of the properties in which we have an interest and as a result our returns on assets operated by others depends upon a number of factors outside our control. To the extent the operator fails to perform these functions properly, operating income may be reduced.

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

The Board of ARC Resources has discretion in the payment of distributions and may not choose to maintain distributions in certain circumstances

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.

Our enhanced oil projects are not economically feasible in today's economic environment

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 successful results from field pilot programs, 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. 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 which requires infrastructure to be 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. 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.

We are participating in larger projects and have more concentrated risk in certain areas of our operations

We manage a variety of small and large projects in the conduct of our business. We have undertaken large development projects, including the construction of three gas processing plants, in north eastern British Columbia for the development of our natural gas reserves. Project delays may impact expected revenues from operations. Significant project cost over-runs could make a project uneconomic. Our ability to execute projects and market oil and natural gas depends upon numerous factors beyond our control, including:

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

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

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

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.

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

The price we pay for the purchase of any material properties is based on engineering and economic estimates of the reserves made by management and independent engineers modified to reflect our technical and economic views. These assessments include a number of material factors and assumptions. 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".

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. There is no assurance that we will be able to continue to complete acquisitions or dispositions of oil and natural gas properties which realize all the synergistic benefits.

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

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".

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

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, some of which may be material. Furthermore, management believes the political climate appears to favour new programs for environmental laws and regulation, particularly in relation to the reduction of emissions or emissions intensity, and there is no assurance that any such programs, laws or regulations, if proposed and enacted, will not contain emission reduction targets which we cannot meet, and financial penalties or charges could be incurred as a result of the failure to meet such targets. For more information on the evolution and status of climate change and related environmental legislation, see "Industry Conditions – Climate Change Regulation".

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

Although we believe that we are in material compliance with current applicable environmental regulations, no assurance can be given that environmental laws will not result in a curtailment of production 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 Conditions – Climate Change Regulation".

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 planning, realizing on available technical advances and 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.

Application of GAAP or US GAAP to our financial results may result in non-cash losses which may adversely affect the market price of our Trust Units

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.

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 12 month average prices, as at December 31, 2009. For the year ended 2009, a ceiling test write-down of $145 million was recorded for US GAAP purposes ($1.15 billion in 2008). For further information, see Note 24 of our audited consolidated financial statements for the year ended December 31, 2009 which is incorporated by reference in this Annual Information Form and which has been filed on SEDAR at www.sedar.com.

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.

Our success depends in large measure on certain key personnel and our ability to retain our 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 and the safekeeping of our primary workspace and computer systems. As of December 31, 2009, we operated approximately 79 per cent of the total daily production of our properties.

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

Distributions of distributable income in respect of properties, absent commodity price increases or cost effective acquisition and development activities, will decline over time in a manner consistent with declining production from typical oil, natural gas and natural gas liquids reserves. Our future oil and natural gas reserves and production, and therefore our 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.

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

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

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

Risk Relating to Our Structure and Ownership of Trust Units

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

Trust Units will have no value when reserves from 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. It is anticipated that the redemption right will not be the primary mechanism for Unitholders to liquidate their investment. The right to receive cash in connection with a redemption is subject to material limitations. Any securities which may be distributed *in specie* to Unitholders in connection with a redemption may not be listed on any stock exchange and a market may not develop for such securities and such securities may be illiquid. In addition, there may be resale restrictions imposed by law upon the recipients of the securities pursuant to the redemption right. See "Our Information – Right of Redemption."

The Trust Units do not represent a traditional investment in the oil and natural gas sector and should not be viewed by investors as shares in 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 is subject to contractual and statutory assurances which may have some enforcement risks

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

The Trust Indenture provides that all written instruments signed by or on behalf of the Trust must contain a provision to the effect that such obligation will not be binding upon Unitholders personally. The principal investment of the Trust is the 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.

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

There is limited liability 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.

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

We report our production and reserve quantities in accordance with Canadian practices and specifically in accordance with NI 51-101. These practices are different from the practices used to report production and to estimate reserves in reports and other materials filed with the 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 averaged for the 12 months as of the date of the reserve report.

We included in this Annual Information Form estimates of proved and proved plus probable reserves. Probable reserves are higher risk and are generally believed to be less likely to be accurately estimated or recovered than proved reserves. The 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.

There is 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.

There is a 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. (a 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. (a 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 April 15, 2008 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 $225 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".

8. Note Agreement as of April 14, 2009 between ARC Resources and various purchasers for US $67.5 million 7.19 per cent Senior Secured Notes – Series C due April 14, 2016, US $35 million 8.21 per cent Senior Secured Notes – Series D due April 14, 2021 and Cdn $29 million 6.50 per cent Senior Secured Notes – Series E due April 14, 2021. 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, 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 18, 2010. Additional financial information is provided in our consolidated financial statements and accompanying management's discussion and analysis for the year ended December 31, 2009, which have been filed on SEDAR at www.sedar.com.

APPENDIX A
FORM 51-101F2

REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

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

1. We have prepared an evaluation of the Company's reserves data as at December 31, 2009. The reserves data are estimates of proved reserves and probable reserves and related future net revenues as at December 31, 2009, 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, 2009, and identifies the respective portions thereof that we have audited, evaluated and reviewed 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)			
			Audited	Evaluated	Reviewed	Total
GLJ Petroleum Consultants Ltd.	January 18, 2010	Canada	-	5,805	-	5,805

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 our report referred to in paragraph 4 for events and circumstances occurring after its preparation date.

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 22, 2010

(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, 2009 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 16, 2010

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.