ARC Resources Ltd.

2010 Annual Information Form

March 22, 2011

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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, Corporation** or **Trust** means ARC Resources and all its controlled entities as a consolidated body and, prior to the completion of the Trust Conversion, the Trust and all its controlled entities as a consolidated body;

ARC Partnership means ARC Resources General Partnership;

ARC Resources means ARC Resources Ltd., the corporation resulting from the amalgamation of ARC Energy Ltd., ARC Resources Ltd., 1485275 Alberta Ltd., ARC Petroleum Inc. and Smiley Gas Conservation Limited which occurred pursuant to the Trust Conversion;

COGE Handbook means the Canadian Oil and Gas Evaluation Handbook prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum;

Common Shares means the common shares in the capital of ARC Resources;

Exchangeable Shares means, prior to the completion of the Trust Conversion, the series A exchangeable shares and the series B exchangeable shares of ARC Resources Ltd.;

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

GLJ Report means the report prepared by GLJ dated February 15, 2011 evaluating the crude oil, natural gas, natural gas liquids and sulphur reserves attributable to ARC's properties at December 31, 2010 and the natural gas contingent resources located in the Dawson, Parkland and Montney West Areas in north eastern British Columbia;

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 and may also be referred to as West Montney;

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

Shareholders means holders of Common Shares of ARC Resources.

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

Trust means ARC Energy Trust, the income trust which was reorganized into ARC Resources pursuant to the Trust Conversion;

Trust Conversion means the Plan of Arrangement under Section 193 of the *Business Corporations Act* (Alberta) involving, among others, the Trust, ARC Resources Ltd. and the securityholders of the Trust and ARC Resources Ltd. which resulted in the reorganization of the Trust into a dividend paying, publicly traded exploration and production company, being ARC Resources, which together with its subsidiaries carries on the business formerly carried on by the Trust and its subsidiaries;

Trust Units means, prior to the completion of the Trust Conversion, the units of the Trust; and

TSX means the Toronto Stock Exchange.

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: "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 – Other Oil and Gas Information" as to the development of our proved undeveloped reserves and probable undeveloped reserves, 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; and under the heading "Statement of Reserves Data and Other Oil and Gas Information – Contingent Resource Estimates" as to our economic contingent resource estimates on a portion of our properties in north-eastern British Columbia. 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 and of our economic contingent resources, projections of market prices and costs; expectations regarding the ability to raise capital and to continually add to reserves through acquisitions and development; treatment under governmental regulatory regimes and tax laws; and capital expenditures programs.

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 and resources; risks associated with acquiring, developing and exploring for natural gas and other aspects of our operations; the timing of payment of dividends, 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; 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 for United States and other non-resident Shareholders 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 relating to management of ARC, and the payment of dividends, 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" and "resources" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions that the reserves and resources 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 1200, 308 – 4th Avenue SW, Calgary, Alberta, T2P 0H7.

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
Bcfe	billion cubic feet equivalent converting one million barrels of oil or natural gas liquids into 6 billion cubic feet equivalent of natural gas		
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 MMcfpd $MM	one million cubic feet one million cubic feet per day one million dollars
boe/d	barrels of oil equivalent per day	MMbbl	one million barrels
Mbbl	one thousand barrels	NGLs	natural gas liquids
mboe	one thousand barrels of oil equivalent	Tcf	one trillion cubic feet

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

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

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

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

ARC RESOURCES LTD.

General

ARC Resources was formed by amalgamation under the *Business Corporations Act* (Alberta). Our principal office is located at 1200, 308 – 4th Avenue SW, Calgary, Alberta, T2P 0H7 and our registered office is located at 1400, 350 – 7th Avenue SW, Calgary, Alberta, T2P 3N9.

Prior to January 1, 2011, ARC was one of Canada's largest conventional oil and gas royalty trusts. ARC is now one of Canada's 15 largest conventional oil and gas companies with 2010 average production of 73,954 boe/d, all of which comes from western Canada. ARC has focussed on the acquisition and development of resource rich properties that provide an option for near term growth. ARC currently pays a monthly dividend to its Shareholders.

As at December 31, 2010, ARC had approximately 550 employees and consultants.

Business Activities

Strategy

ARC's business activities include the exploration for, development and production of crude oil, natural gas and natural gas liquids in western Canada. ARC's focus is on value creation. Our aim is to produce superior, long-term returns to Shareholders. At ARC, we utilize a disciplined approach to capital allocation and believe growth is not a mandate, but rather an option. ARC's goal is to develop new production and reserves while allocating a portion of our cash flow to pay out a monthly dividend. Production from individual oil and natural gas wells naturally decline over time. On an annual basis ARC approves a capital budget with the objective of first replacing production declines and secondly increasing production and reserves. While much of our development activity is considered to be of a low risk nature, a percentage of each year's capital budget will be devoted to moderate risk development and low to moderate risk exploration opportunities to add value.

Our staff use their expertise combined with continuously evolving technologies to unlock additional reserves that will lead to future production through the exploration for and development of large oil and natural gas pools. We have policies for hiring and a staff succession, progression and development program to provide the in house expertise to fully exploit ARC's assets.

ARC's operating practices and procedures are aimed at maximizing reservoir recovery of oil and natural gas over time while controlling costs in a safe operating environment.

We have rigorous health and safety policies which set out procedures, practices and reporting of actions to assist in ensuring that ARC employees and contractors employ continuously improving 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.

Financial Objectives

ARC's financial objectives include the maintenance of a strong balance sheet with the target of keeping debt under 2.0 times cash flow from operating activities and under 20% of total capitalization. In addition ARC's risk management program actively hedges up to 55% of our production for periods of up to 2 years to provide stability to cash flow from operating activities a portion of which is paid out in monthly dividends with the remaining portion funding capital expenditures. The economics of specific projects and certain acquisitions may be hedged for periods longer than 2 years with Board approval.

The development of ARC's properties will require future capital expenditures, which will be financed through a combination of cash flow, proceeds of disposition of properties, borrowings, farmouts, working capital or through the proceeds of the issuance of additional Common Shares.

ARC considers acquisitions of all types of petroleum and natural gas and other energy-related assets and the potential disposition of existing assets with limited upside potential to be part of our ongoing business operations.

General Development of Our Business

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

2008

ARC set records for production volumes of 65,126 boe/d and cash flow from operating activities of $944 million.

Distributions to investors were a record $570 million, but were reduced to $0.12 per Trust Unit per month at the end of the year in light of collapsing commodity prices.

Capital expenditures were $599.6 million, of which $371.1 million (62%) was development and facility capital expenditures, $51 million (9%) was property acquisition costs net of dispositions and $164.1 million (27%) was spent on the purchase of lands, geological and geophysical expenditures, and drilling costs for exploratory wells.

$122.4 million of additional expenditures was for the purchase of the oil and gas rights on undeveloped acreage through Crown land sales, with a particular focus on the greater Dawson area of British Columbia.

2009

Production volumes and cash flow declined in 2009 from the record highs achieved in 2008. Production volumes were 63,538 boe/d and cash flow from operating activities was $497.4 million.

Distributions to investors decreased to $298.5 million and were reduced to $0.10 per Trust Unit per month in light of continued low commodity prices.

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

Capital expenditures were $518 million, of which $326.3 million (63%) was development and facility capital expenditures and $17.4 million (3%) was property acquisition costs, geological and geophysical expenditures, and drilling costs for exploratory wells. Total acquisitions, net of $20.5 million in dispositions, were $158.4 million.

The major acquisition was a $178.9 million purchase in the Ante Creek area of northwestern Alberta. Through this acquisition, we acquired an average 75% working interest in 26,000 gross acres of developed lands which include 38 net oil wells and 24 net gas wells, a 30% interest in an ARC operated gas plant (which will bring the interest of ARC Resources in such plant to 100%) and 121,000 gross (106,000 net) acres of undeveloped lands. Production from these assets for the nine months ended September 30, 2009 was approximately 2,000 boe/d and was weighted approximately 75% to natural gas and approximately 25% to crude oil and natural gas liquids.

2010

Production was a record 73,954 boe/d while cash flow from operating activities was $673.9 million.

Distributions to investors were maintained at $0.10 per Trust Unit per month throughout the year resulting in a total of $313.4 million being distributed.

On January 5, 2010, the Trust closed an equity offering and issued 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 following the $178.9 million acquisition of assets in the Ante Creek area which closed in the middle of December 2009.

On August 17, 2010, ARC Resources Ltd. acquired all of the existing and outstanding common shares of Storm Energy Inc. ("**Storm**") pursuant to a plan of arrangement under the provisions of Section 192 of the *Canada Business Corporations Act* involving Storm, Storm Resources Ltd., the Trust and ARC Resources Ltd. (the "**Storm Arrangement**"). The transaction was valued at approximately $652.1 million (including the assumption of debt) based on the August 17, 2010 closing price of $19.53 per Trust Unit. Storms primary asset was the Parkland field in northeastern British Columbia, a Montney gas field located approximately 10 km from ARC's Dawson field. Production from the Storm assets averaged 7,800 boe per day over the last four months of 2010.

Pursuant to the Storm Arrangement, the Trust issued 23,514,456 Trust Units and ARC Resources issued 1,744,038 series B exchangeable shares (which shares, as at the closing date, were exchangeable for 4,927,797 ARC Trust Units) to holders of Storm shares and assumed approximately $89 million of total net debt.

Including the $652.1 million Storm Arrangement, capital expenditures were $1,248.0 million, of which $477.2 million (38%) was development and facility capital expenditures, $77.5 million (6%) was property acquisition costs, geological and geophysical expenditures, and drilling costs for exploratory wells. $24.6 million was spent on corporate leasehold costs for new office space.

In the second quarter, ARC started up the 60 MMcfpd Dawson Phase 1 gas plant. A second 60 MMcfpd gas plant is under construction at Dawson and is expected to start up in the second quarter of 2011.

Recent Developments

The Trust Conversion was completed on January 1, 2011 and resulted in the reorganization of the Trust into ARC Resources, a new publicly traded exploration and development corporation formed upon the amalgamation of ARC Energy Ltd., ARC Resources Ltd., 1485275 Alberta Ltd., ARC Petroleum Inc. and Smiley Gas Conservation Limited.

In accordance with the terms of the Trust Conversion, the holders ("**Unitholders**") of Trust Units of the Trust received, through a series of steps, one Common Share of ARC Resources for each Trust Unit held and the holders of Exchangeable Shares of ARC Resources Ltd. received, through a series of steps, 2.89162 Common Shares of ARC Resources for each Exchangeable Share held, such number being the exchangeable share ratio of the Exchangeable Shares as at December 31, 2010. In addition, pursuant to the Trust Conversion, the Trust was dissolved and ARC Resources acquired all of the assets of the Trust and ARC Resources assumed all of the liabilities of the Trust.

ARC Resources, together with its subsidiaries, now carries on the business formerly carried on by the Trust and its subsidiaries.

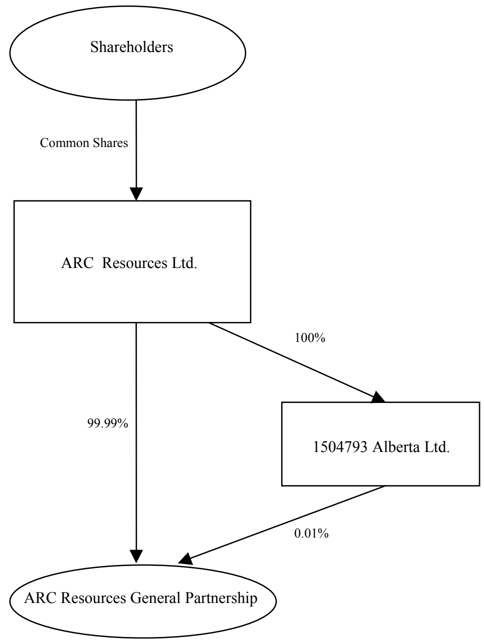
The Common Shares of ARC Resources began trading on the TSX under the trading symbol ARX on January 6, 2011. Beginning with the payment of dividends to Shareholders of ARC of record on January 31, 2011, Shareholders of ARC will receive payments in the form of dividends. Prior to the conversion of the Trust to a corporation on December 31, 2010, distributions were paid to unitholders. Previous historical references to "unitholders", "distributions" "trust units", and "per unit" have now been replaced by "Shareholders", "dividends", "Common Shares", and "per share", respectively where applicable.

Despite the change in legal structure from a trust to a dividend paying corporation, ARC's business activities and business strategy remain unchanged and the board of directors and officers remain the same.

Our Organizational Structure

The ARC Partnership owns substantially all of our oil and natural gas properties and is owned 100% directly or indirectly by ARC Resources. ARC Resources is the manager of the ARC Partnership. The ARC Partnership is a general partnership formed under the laws of Alberta.

The following diagram sets forth the organizational structure of ARC immediately following completion of the Trust Conversion:



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, 2010 and the preparation date of the Statement is January 18, 2011. 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, 2010 contained in the GLJ Report dated February 15, 2011. 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 –Risk Relating to Our Business and Operations".

Reserves Data (Forecast Prices and Costs)

SUMMARY OF OIL AND GAS RESERVES
AND NET PRESENT VALUES OF FUTURE NET REVENUE
as of December 31, 2010
FORECAST PRICES AND COSTS

	RESERVES			
	LIGHT AND MEDIUM OIL		HEAVY OIL	
RESERVES CATEGORY	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)
PROVED				
Developed Producing	90,258	77,421	2,071	1,972
Developed Non-Producing	1,761	1,482	4	4
Undeveloped	11,085	9,441	30	29
TOTAL PROVED	103,104	88,343	2,105	2,005
PROBABLE	33,750	28,210	672	615
TOTAL PROVED PLUS PROBABLE	136,854	116,553	2,777	2,620

	RESERVES			
	NATURAL GAS		NATURAL GAS LIQUIDS	
RESERVES CATEGORY	Gross (Bcf)	Net (Bcf)	Gross (Mbbl)	Net (Mbbl)
PROVED				
Developed Producing	643	551	11,302	8,301
Developed Non-Producing	78	66	835	677
Undeveloped	544	460	6,193	4,956
TOTAL PROVED	1,265	1,076	18,329	13,935
PROBABLE	650	527	8,003	6,144
TOTAL PROVED PLUS PROBABLE	1,915	1,604	26,332	20,079

	RESERVES	
	TOTAL	
RESERVES CATEGORY	Gross (mboe)	Net (mboe)
PROVED		
Developed Producing	210,860	179,481
Developed Non-Producing	15,678	13,097
Undeveloped	107,894	91,114
TOTAL PROVED	334,432	283,692
PROBABLE	150,689	122,852
TOTAL PROVED PLUS PROBABLE	485,121	406,543

RESERVES CATEGORY	NET PRESENT VALUES OF FUTURE NET REVENUE — 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	7,690	5,084	3,839	3,116	2,643	6,375	4,305	3,303	2,715	2,326
Developed Non-Producing	452	292	215	170	141	336	216	157	123	101
Undeveloped	2,305	1,365	866	569	378	1,720	985	593	359	210
TOTAL PROVED	10,446	6,740	4,919	3,855	3,162	8,432	5,505	4,053	3,197	2,637
PROBABLE	5,475	2,499	1,430	931	656	4,086	1,848	1,042	666	460
TOTAL PROVED PLUS PROBABLE	15,921	9,240	6,350	4,786	3,818	12,518	7,353	5,095	3,863	3,097

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
as of December 31, 2010
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	21,180	3,238	5,728	1,514	253	10,446	2,014	8,432
Proved Plus Probable Reserves	31,741	5,109	8,123	2,291	297	15,921	3,403	12,518

FUTURE NET REVENUE
BY PRODUCTION GROUP
as of December 31, 2010
FORECAST PRICES AND COSTS

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) ($MM)	PER UNIT(3)
Proved Reserves	Light and Medium Crude Oil(1)	2,698	$26.25/bbl
	Heavy Oil(1)	62	$31.39/bbl
	Natural Gas(2)	2,159	$2.01/Mcf
	Total	4,919	
Proved Plus Probable Reserves	Light and Medium Crude Oil(1)	3,377	$24.45/bbl
	Heavy Oil(1)	75	$29.09/bbl
	Natural Gas(2)	2,898	$1.82/Mcf
	Total	6,350	

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 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% probability that the quantities actually recovered will equal or exceed the estimated proved reserves; and

(b) at least a 50% 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, 2010, inflation and exchange rates utilized in the GLJ Report were as follows:

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
as of December 31, 2010
FORECAST PRICES AND COSTS

	OIL					EDMONTON LIQUIDS PRICES				
Year	WTI Cushing Oklahoma ($US/bbl)	Edmonton Par Price 40° API ($Cdn/bbl)	Hardisty Heavy 12° API ($Cdn/bbl)	Cromer Medium 29.3° API ($Cdn/bbl)	NATURAL GAS AECO Gas Price ($Cdn/MMbtu)	Propane ($Cdn/bbl)	Butane ($Cdn/bbl)	Pentanes Plus ($Cdn/bbl)	INFLATION RATES(1) %/Year	EXCHANGE RATE(2) ($US/$Cdn)
Forecast										
2011	88.00	86.22	68.79	82.78	4.16	54.32	67.26	90.54	2%	0.980
2012	89.00	89.29	68.33	83.04	4.74	56.25	68.75	91.96	2%	0.980
2013	90.00	90.92	67.03	83.64	5.31	57.28	70.01	92.74	2%	0.980
2014	92.00	92.96	67.84	84.59	5.77	58.56	71.58	94.82	2%	0.980
2015	95.17	96.19	70.23	87.54	6.22	60.60	74.07	98.12	2%	0.980
2016	97.55	98.62	72.03	89.75	6.53	62.13	75.94	100.59	2%	0.980
2017	100.26	101.39	74.08	92.26	6.76	63.87	78.07	103.42	2%	0.980
2018	102.74	103.92	75.95	94.57	6.90	65.47	80.02	106.00	2%	0.980
2019	105.45	106.68	78.00	97.08	7.06	67.21	82.15	108.82	2%	0.980
2020	107.56	108.84	79.59	99.04	7.21	68.57	83.80	111.01	2%	0.980
Thereafter	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	2%	0.980

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 year from 2020.

Weighted average actual prices realized for the year ended December 31, 2010, were $3.83/Mcf for natural gas, $76.54/bbl for light and medium crude oil, $63.29/bbl for heavy crude oil and $55.10/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 ($MM)	Proved Plus Probable Reserves ($MM)
2011	416.2	459.4
2012	322.7	394.3
2013	391.5	468.1
2014	267.2	284.6
2015	15.9	304.4
Remainder	100.6	380.4
Total: Undiscounted	1,514.1	2,291.2
Total: Discounted at 10%/year	1,220.4	1,738.2

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

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, 2010, using forecast price and cost estimates derived from the GLJ Report. Gross reserves as at December 31, 2010 and as at December 31, 2009 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, 2009	102,756	31,607	134,363	2,212	622	2,834	907.3	434.9	1,342.3
Discoveries	0	0	0	0	0	0	1.9	.8	2.7
Extensions	2,871	3,458	6,329	95	(55)	40	64.6	55.5	120.2
Infill Drilling	3,355	1,114	4,469	30	15	45	138.9	75.1	214.0
Improved Recovery	538	95	633	0	0	0	.8	.3	1.1
Technical Revisions	3,266	(2,472)	794	66	10	76	100.8	25.0	125.9
Acquisitions	408	106	514	0	0	0	154.5	61.4	215.8
Dispositions	0	0	0	0	0	0	0	0	0
Economic Factors	(531)	(158)	(689)	0	80	80	(12.2)	(3.5)	(15.7)
Production	(9,559)	0	(9,559)	(298)	0	(298)	(91.3)	0	(91.3)
December 31, 2010	103,104	33,750	136,854	2,105	672	2,777	1,265.4	649.6	1,914.9

	NATURAL GAS LIQUIDS			TOTAL		
FACTORS	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (mboe)	Probable (mboe)	Proved Plus Probable (mboe)
December 31, 2009	11,355	4,281	15,637	267,543	109,000	376,543
Discoveries	9	4	13	320	140	459
Extensions	414	526	940	14,154	13,187	27,341
Infill Drilling	1,852	775	2,627	28,385	14,425	42,810
Improved Recovery	24	3	27	695	148	843
Technical Revisions	1,027	253	1,280	21,165	1,963	23,127
Acquisitions	5,458	2,223	7,681	31,609	12,559	44,168
Dispositions	0	0	0	0	0	0
Economic Factors	(277)	(63)	(340)	(2,838)	(732)	(3,570)
Production	(1,533)	0	(1,533)	(26,600)	0	(26,600)
December 31, 2010	18,329	8,003	26,332	334,432	150,689	485,121

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.

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

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	11,131	11,131	11	11	122,061	122,061	1,484	1,484	32,970	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
2010	4,299	11,085	30	30	223,762	543,518	4,259	6,193	45,882	107,894

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	10,057	10,057	211	211	67,837	67,837	1,034	1,034	22,608	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
2010	7,477	12,523	-	150	155,242	439,484	2,589	4,768	35,940	90,689

Undeveloped reserves represent 32% of total proved reserves and 41% of proved plus probable reserves. Over 85% of the proved plus probable undeveloped reserves are located in the Dawson, Montney West, Ante Creek, and Parkland area properties. In each case, we have planned a program for the development of a portion of the undeveloped reserves in these areas in 2011 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 West Area, the outcomes of the yearly drilling and reservoir evaluations, the price for oil and natural gas, and a variety of 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 natural 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 reduction in the future costs of development are not also realized.

Other Oil and Gas Information

Our portfolio of properties as at December 31, 2010 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, 2010. Reserves amounts are stated at December 31, 2010, 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, 2010, and information in respect of production is for the year ended December 31, 2010 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, 2010 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 76% 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 1.3% of the total gross proved plus probable reserves as assigned by GLJ in the GLJ Report. Except as set forth under the heading "Statement of Reserves Data and Other Oil and Gas Information – Other Oil and Gas Information – Proved and Probable Undeveloped Reserves", there are no material properties to which reserves have been attributed which are capable of producing but which are not producing at December 31, 2010 and there are no material statutory or mandatory relinquishments, surrenders, back-ins or changes in ownership provisions.

	2010 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)	(MMcfpd)	(bbl/d)	(boe/d)	(mboe)	(mboe)	(%)
Dawson	3	-	87.5	440	15,020	100,551	151,136	31.2%
Ante Creek	2,569	51	24.5	577	7,287	28,352	45,238	9.3%
Redwater	3,818	-	1.2	138	4,160	21,386	26,234	5.4%
Parkland	14	-	14.9	436	2,926	27,240	38,844	8.0%
Lougheed	2,078	-	-	79	2,157	5,264	6,364	1.3%
Jenner	-	-	12.4	-	2,062	8,571	10,956	2.3%
North Pembina Cardium Unit	1,583	-	0.9	83	1,819	11,316	13,587	2.8%
Hatton	-	-	10.9	-	1,813	6,833	8,478	1.7%
Weyburn Unit	1,804	-	-	-	1,804	10,393	15,109	3.1%
Berrymoor Cardium Unit	1,383	-	1.6	139	1,792	7,882	10,149	2.1%
Montney West	-	-	7.6	12	1,285	18,590	42,381	8.7%

Dawson

The Dawson property is located in northeast British Columbia. We are the operator and own an average land interest of 93.8% in approximately 36,551 gross hectares (34,273 net hectares). We operate a large area compression facility where the natural gas and liquids are processed through an operated 60 MMcfpd gas plant and a third party facility. During 2010, gross production from the area averaged 15,020 boe/d of natural gas and natural gas liquids from 123 net wells principally from the upper Montney zone. During 2010, 28 new wells were drilled and construction began on a second 60 MMcfpd gas processing facility. GLJ assigned gross proved reserves of 100,551 mboe and gross proved plus probable reserves of 151,136 mboe of natural gas and natural gas liquids to this area, or 31.2% of total gross proved plus probable reserves.

Ante Creek

The Ante Creek property is located in northwest Alberta. We are the operator and own an average land interest of 95.1%. Oil production is processed through three operated facilities, while the gas is processed through one operated facility and one third party facility. During 2010, gross production from the area averaged 7,287 boe/d of oil, natural gas and natural gas liquids from 218 net wells. During 2010, 12 new wells were drilled. GLJ assigned gross proved reserves of 28,352 mboe and gross proved plus probable reserves of 45,238 mboe of oil, natural gas and natural gas liquids to this area, or 9.3% 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 85.8%. Oil and solution gas are both processed at an operated central facility. During 2010, gross production from the area averaged 4,160 boe/d of oil, natural gas and natural gas liquids from 386 net wells. During 2010, eight new wells were drilled. GLJ assigned gross proved reserves of 21,386 mboe and gross proved plus probable reserves of 26,234 mboe of oil, natural gas and natural gas liquids to this area, or 5.4% of total gross proved plus probable reserves.

During 2010, ARC continued production operations at the pilot EOR project in Redwater. The pilot is designed to confirm whether the Redwater reef is amenable to CO_2 flooding and that incremental oil can be mobilized and recovered. The CO2 injection phase of the pilot has been completed, while the observation of producing wells will continue at least until year end. Additionally, prior to commercial operations, large amounts of CO_2 need to be acquired on economic terms for the Redwater EOR project to proceed. There is no assurance that the Redwater EOR project will proceed to a commercial phase or become economically viable.

Parkland

The Parkland property is located in northeast British Columbia. We own an average land interest of 76.7% in approximately 29,860 gross hectares (22,915 net hectares) in the Parkland Area. The Parkland Area has been assigned gross proved reserves of 27,240 boe and gross proved plus probable reserves of 38,844 mboe, or 8.0% of total gross proved plus probable reserves in the GLJ Report. On a full year basis, gross production from the area averaged 2,926 boe/d of oil, natural gas and natural gas liquids from 52 net wells. The Parkland property was acquired in August 2010, after which production averaged 7,800 boe/d. During 2010, two new wells were drilled. Natural gas and natural gas liquids are processed through third party facilities.

Lougheed

The Lougheed property is located in southeast Saskatchewan. We are the operator and own an average land interest of 80.6%. Production is handled by an operated battery and gas plant. During 2010, gross production from the area averaged 2,157 boe/d of oil and natural gas liquids from 126 net wells. During 2010, no new wells were drilled. GLJ assigned gross proved reserves of 5,264 mboe and gross proved plus probable reserves of 6,364 mboe of oil and natural gas liquids to this area, or 1.3% 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 87.8%. We operate four gas compression and dehydration facilities in the area. During 2010, gross production from the area averaged 2,062 boe/d of natural gas from 835 net wells. During 2010, no new wells were drilled. GLJ assigned gross proved reserves of 8,571 mboe and gross proved plus probable reserves of 10,956 mboe of natural gas to this area, or 2.3% of total gross proved plus probable reserves.

North Pembina Cardium Unit

The North Pembina Cardium Unit is located in central Alberta. We are the operator and own a 45.6% interest in the unit. Production is processed through two operated oil treatment facilities, one operated and one non-operated solution gas plant. During 2010, gross production from the unit averaged 1,819 boe/d of oil, natural gas and natural gas liquids from 178 net wells. During 2010, three new wells were drilled. GLJ assigned gross proved reserves of 11,316 mboe and gross proved plus probable reserves of 13,587 mboe of oil, natural gas and natural gas liquids to this unit, or 2.8% 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 44.5%. The operated production flows through three operated compression and dehydration facilities where our working interest ranges from 50 to 100%. During 2010, gross production from the area averaged 1,813 boe/d of natural gas from 469 net wells. During 2010, no new wells were drilled. GLJ assigned gross proved reserves of 6,833 mboe and gross proved plus probable reserves of 8,478 mboe of natural gas to this area, or 1.7% of total gross proved plus probable reserves.

Weyburn Unit

The Weyburn Unit is located in southeast Saskatchewan. Cenovus Energy Inc. operates the unit and we have a working interest of 6.9%. The unit is currently undergoing a CO_2 flood for enhanced oil recovery. During 2010 gross production from the unit averaged 1,804 boe/d of oil from 59 net wells. GLJ assigned gross proved reserves of 10,393 mboe and gross proved plus probable reserves of 15,109 mboe of oil and natural gas liquids to this unit, or 3.1% 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 73.3% interest in the unit. Oil is processed at an operated battery while the solution gas flows to a third party facility. During 2010, gross production from the unit averaged 1,792 boe/d of oil, natural gas and natural gas liquids from 94 net wells. During 2010, seven new wells were drilled. GLJ assigned gross proved reserves of 7,882 mboe and gross proved plus probable reserves of 10,149 mboe of oil, natural gas and natural gas liquids to this unit, or 2.1% 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 78.8% in approximately 24,942 gross hectares (19,655 net hectares) in the Montney West Area. The Montney West Area has been assigned gross proved reserves of 18,590 boe and gross proved plus probable reserves of 42,381 mboe in the GLJ Report. During 2010, gross production from the area averaged 1,285 boe/d of natural gas and natural gas liquids, processed through a third party facility.

Contingent Resource Estimates

We also engaged GLJ to provide an evaluation of our Economic Contingent Resources (as defined below) for our interest in certain of our properties located in north-eastern British Columbia. The following table sets forth arithmetic sums of the estimates of the Economic Contingent Resources for natural gas contained in the GLJ Report for ARC's interest with respect to the Dawson area, Montney West Area and Parkland area. The evaluation procedures employed by GLJ are in compliance with standards contained in the COGE Handbook and the GLJ Report is based on GLJ's January 1, 2010 pricing. See "*Statement of Reserves Data and Other Oil and Gas Information - Definitions and Notes to Reserves Data Tables*". Our interest in these areas is set forth above under "Principal Properties".

The estimates of Economic Contingent Resources should not be confused with reserves and readers should review the definitions and notes set forth below. Actual natural gas resources may be greater than or less

than the estimates provided herein. There is no certainty that it will be commercially viable to produce any portion of the resources.

Montney Gas Region	Estimated Economic Contingent Resource (Bcfe)(1) Low Estimate(2)	Best Estimate(3)	High Estimate(4)
Dawson Area	318	381	477
Montney West Area	272	331	708
Parkland Area	17	18	23
Total	607	730	1,208

Notes:

(1) "**Contingent Resources**" are defined in the COGE Handbook as those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political and regulatory matters or a lack of markets. It is also appropriate to classify as "**Contingent Resources**" the estimated discovered recoverable quantities associated with a project in the early evaluation stage. Contingent Resources are further classified in accordance with the level of certainty associated with the estimates and may be subclassified based on project maturity and/or characterized by their economic status. "**Economic Contingent Resources**" are those Contingent Resources that are currently economically recoverable.

(2) "**Low Estimate**" is a classification of estimated resources described in the COGE Handbook as being considered to be a conservation estimate of the quantity that will actually be recovered. It is likely that the actual remaining quantities recovered will exceed the Low Estimate. If probabilistic methods are used, there should be a 90% probability (P90) that the quantities actually recovered will equal or exceed the Low Estimate.

(3) "**Best Estimate**" is a classification of estimated resources described in the COGE Handbook as being considered to be the best estimate of the quantity that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the Best Estimate. If probabilistic methods are used, there should be 50% probability (P50) that the quantities actually recovered will equal or exceed the Best Estimate.

(4) "**High Estimate**" is a classification of estimated resources described in the COGE Handbook as being considered to be an optimistic estimate of the quantity that will actually be recovered. It is unlikely that the actual remaining quantities recovered will exceed the High Estimate. If probabilistic methods are used, there should be a 10% probability (P10) that the quantities actually recovered will equal or exceed the High Estimate.

(5) Based on the GLJ Report dated effective as of December 31, 2010.

(6) These volumes are arithmetic sums of multiple estimates of contingent resources, which statistical principles indicate may be misleading as to volumes that may actually be recovered. Readers should give attention to the estimates of individual classes of resources and appreciate the differing probabilities of recovery associated with each class as explained. In particular, readers should be aware that the likelihood of attaining the sum of the High Estimate is extremely low and of the Low Estimate quite high.

(7) The estimates of resources for individual properties may not reflect the same confidence level as estimates of resources for all properties due to the effects of aggregation. There is no certainty that it will be commercially viable to produce any portion of the resources.

(8) Totals may not add due to rounding.

In the core of ARC's Montney gas region in north-eastern British Columbia; the contingencies that prevent the economic contingent resources from being classified as reserves are associated with the early evaluation stage of these potential development opportunities. Additional drilling, completion and testing data is generally required before ARC can commit to their development. ARC's Montney gas region has historically been developed sequentially over a number of drilling seasons and is subject to annual budget constraints, ARC's policy of orderly development on a staged basis, the timing of the growth of third party infrastructure, the short and long-term view of ARC on gas prices, the results of exploration and development activities of ARC and others in the area and infrastructure capacity constraints.

For more information, see "*Risk Factors – Risk Relating to our Business and Operations – There are many uncertainties inherent in estimating quantities of recoverable oil and gas reserves and resources including many factors beyond our control*".

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, 2010.

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	3,901	1,674	1,172	172	4,599	2,063	311	61
British Columbia	8	2	3	1	418	189	79	47
Saskatchewan	2,142	833	303	96	5,617	905	51	18
Manitoba	585	138	20	3	-	-	-	-
Total	6,636	2,647	1,498	272	10,634	3,157	441	126

Properties with no Attributable Reserves

The following table sets out our undeveloped land holdings as at December 31, 2010.

	Undeveloped Hectares	
	Gross	Net
Alberta	226,148	128,355
British Columbia	127,081	100,711
Manitoba	4,035	3,712
Saskatchewan	84,663	54,016
Total	441,927	286,794

In British Columbia, we have 28,685 gross and 25,165 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 – Other Oil and Gas Information – Principal Properties – Dawson and Montney West". ARC's Montney gas region has historically been developed sequentially over a number of drilling seasons and is subject to annual budget constraints, ARC's policy of orderly development on a staged basis, the timing of the growth of third party infrastructure, the short and long-term view of ARC on gas prices, the results of exploration and development activities of ARC and others in the area and infrastructure capacity constraints.

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 55% of forecasted production on a boe basis for up to two years. Management may also use financial instruments to diversify both location and time of sale exposure. 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, including acquisitions.

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 Corporation'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 14 "Financial Instruments and Risk Management" to our audited consolidated financial statements for the year ended December 31, 2010 and in the section under the heading "Risk Management and Hedging Activities" in our Management Discussion and Analysis for the year ended December 31, 2010 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, 2010	1,479.0	80.3
Anticipated to be paid in 2011	2.5	2.3
Anticipated to be paid in 2012	2.5	2.3
Anticipated to be paid in 2013	2.2	2.0

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 8,430 net wells that will require abandonment and/or reclamation over the next 61 years with the majority of payments being made in years 2060 to 2071. These ongoing environmental obligations are expected to be funded out of cash flow from operating activities.

We currently estimate that the future abandonment and reclamation obligations in respect of our properties will be approximately $1,479 million calculated by escalating costs at 2% per year (reflected in our audited consolidated financial statements as an asset retirement obligation of $169.1 million calculated by escalating costs at 2% per year and discounting at a blended rate of 6.5%). For more information, see Note 12 of our audited consolidated financial statements for the year ended December 31, 2010 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*. During 2010, $7.8 million ($8.7 million for 2009) of actual expenditures were expended on abandonment and reclamation activities.

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, 2010 is $25 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 benchmarked from numerous sources including the provincial regulatory agencies, industry peer groups, third party engineering firms and actual data from our operations. All wells, pipelines, facilities and associated costs are then assigned to a specific geographic region which is consistent with the methodology used by the Energy Resources Conservation Board.

Abandonment and reclamation costs have been estimated over a 60 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 $1,182 million (escalating costs at 2% and undiscounted) and $29.3 million (escalating costs at 2% and discounted at 10%). Only the abandonment costs associated with wells with reserves were deducted by GLJ in estimating future net revenue.

Tax Horizon

The Corporation expects 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 ARC are subject to normal corporate tax rates. Taxable income varies depending on total income and expenses and varies with changes to commodity prices, costs, claims for both accumulated tax pools and tax pools associated with current year expenditures. As ARC has accumulated $2.4 billion of income tax pools for federal tax purposes, it is expected that taxable income will be reduced or potentially eliminated for the initial period following the Trust Conversion. Using the current forward commodity price outlook and a modeled future production volume forecast, ARC does not expect to be in a material cash tax-paying position until 2013.

ARC's oil and gas properties are owned and operated by the ARC Partnership, which has a January 31st year end. The Canadian federal budget presented on March 22, 2011 proposes to eliminate the ability of corporations to defer income tax by taking advantage of the timing of the year-ends of partnerships of which it is a member. If these proposals are enacted, it is expected that ARC will be taxable in 2012 instead of 2013 as a result of the loss of the deferral on partnership income.

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, 2010:

	2010 $MM
Property acquisition costs(1)	
Proved properties	5.0
Undeveloped properties	-
Corporate acquisition costs(2)	652.1
Exploration costs(3)	77.5
Development costs(4)	477.2
Corporate capital costs	36.2
Total	1,248.0

Notes:

(1) Represents acquisition costs net of dispositions and property swaps.

(2) For further details on corporate acquisition costs for 2010, see "ARC Resources Ltd. – General Development of the Business".

(3) Includes costs of land acquired ($57 million), geological and geophysical capital expenditures and drilling costs for 2010 exploration wells drilled.

(4) Includes costs of land acquired ($3.9 million), development and facilities capital expenditures and drilling costs for 2010 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, 2010:

	Exploratory Wells		Development Wells		Total	
	Gross	Net	Gross	Net	Gross	Net
Light and Medium Oil	1	1	89	68	90	69
Heavy Oil	-	-	14	-	14	-
Natural Gas	6	6	193	108	199	114
Service	-	-	40	3	40	3
Dry	4	2	3	2	7	4
Total:	11	9	339	181	350	190

For 2011, ARC Resources has planned an extensive capital program of $625 million. The program comprises costs to develop the core assets of the Corporation, including the Dawson, Montney West, Ante Creek and Pembina areas, as well as expansion of the facilities in the Dawson and Ante Creek 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 – Risk Relating to our Business and Operations".

Production Estimates

The following table sets out the volume of production estimated for the year ended December 31, 2011 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										
Dawson	0	0	0	0	144,024	127,994	675	581	24,679	21,913
Other Properties	25,689	21,957	808	791	187,459	166,304	4,868	3,668	62,608	54,135
Total: Total Proved	25,689	21,957	808	791	331,483	294,298	5,543	4,249	87,287	76,048
Total Proved Plus Probable										
Dawson	0	0	0	0	144,024	127,994	675	581	24,679	21,913
Other Properties	27,872	23,930	865	846	195,960	172,224	5,123	3,875	66,520	57,355
Total: Total Proved Plus Probable	27,872	23,930	865	846	339,984	300,218	5,798	4,456	91,199	79,268

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 2010				Year Ended
(6:1)	Mar. 31	June 30	Sept. 30	Dec. 31	2010
Average Daily Production[1]					
Light and Medium Crude Oil (bbl/d)	26,676	26,439	25,994	26,455	26,390
Heavy Oil (bbl/d)	964	915	965	962	951
Gas (MMcfpd)	217.9	211.2	275.0	311.5	254.2
NGLs (bbl/d)	3,252	3,655	4,690	5,355	4,245
Combined (boe/d)	67,207	66,208	77,483	84,686	73,954

(6:1)	Quarter Ended 2010 Mar. 31	June 30	Sept. 30	Dec. 31	Year Ended 2010
Average Net Production Prices Received					
Light and Medium Crude Oil ($/bbl)	76.57	72.29	71.42	76.54	74.24
Heavy Oil ($/bbl)	67.50	63.00	61.74	63.29	64.07
Gas ($/Mcf)	5.42	4.12	3.79	3.83	4.21
NGLs ($/bbl)	60.33	53.02	49.13	55.10	53.98
Combined ($/boe)	51.93	45.93	41.19	42.26	44.96
Royalties Paid					
Light and Medium Crude Oil ($/bbl)	13.34	12.65	11.42	12.50	12.50
Heavy Oil ($/bbl)	8.61	8.68	6.80	6.03	7.39
Gas ($/Mcf)	0.69	0.57	0.45	0.28	0.47
NGLs ($/bbl)	18.79	16.17	16.63	16.09	16.77
Combined ($/boe)	8.58	7.89	6.51	6.03	7.14
Operating Expenses (2)(3)					
Light and Medium Crude Oil ($/bbl)	11.15	15.74	13.61	15.32	13.94
Heavy Oil ($/bbl)	11.19	15.42	15.03	16.14	14.39
Gas ($/Mcf)	1.36	1.38	1.13	0.98	1.18
NGLs ($/bbl)	6.15	10.10	8.33	7.38	8.47
Combined ($/boe)	9.29	11.46	9.31	9.01	9.70
Transportation Paid					
Light and Medium Crude Oil ($/bbl)	0.14	0.38	0.34	0.26	0.28
Heavy Oil ($/bbl)	0.97	1.18	0.90	0.66	0.99
Gas ($/Mcf)	0.28	0.34	0.26	0.28	0.29
NGLs ($/bbl)	-	-	-	-	-
Combined ($/boe)	0.99	1.28	1.07	1.08	1.10
Loss/(Gain) on Commodity Contracts					
Light and Medium Crude Oil ($/bbl)	0.11	(1.73)	(1.39)	(1.06)	(0.95)
Heavy Oil ($/bbl)	-	-	-	-	-
Gas ($/Mcf)	(0.01)	(0.75)	(0.74)	(0.59)	(0.54)
NGLs ($/bbl)	-	-	-	-	-
Combined ($/boe)	0.01	(3.08)	(3.09)	(2.50)	(2.20)
Netback Received(4)					
Light and Medium Crude Oil ($/bbl)	51.83	45.25	47.44	49.52	48.47
Heavy Oil ($/bbl)	46.73	37.72	39.01	40.46	41.30
Gas ($/Mcf)	3.10	2.58	2.69	2.88	2.81
NGLs ($/bbl)	35.39	26.75	24.17	31.63	28.74
Combined ($/boe)	33.06	28.38	27.39	28.64	29.22

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 contracts from revenues.

Each of the Dawson, Ante Creek and Redwater areas account for approximately 20%, 10% and 6%, respectively, of the total 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 2010, 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 2010 was $4.21 per Mcf before hedging as compared to $4.18 per Mcf before hedging for 2009. This price was achieved with a portfolio mix that on average through the year received AECO index based pricing for 77%, Western Canadian Station 2 index based pricing for 12 %, aggregator netback prices for 6%, and Chicago index pricing for 5% of total production.

Our natural gas sales portfolio is directed towards liquid markets and pricing terms that allow us to reduce price volatility and to stabilize the revenue stream. We also strive for a high utilization of contracted pipeline and processing capacity.

Crude Oil and Natural Gas Liquids

Our liquids production in 2010 was comprised of approximately 51% light quality crude oil (greater than 35°API), 32% medium quality crude oil (25 to 35 API), 4% heavy quality crude (less than 25°API), 4.5% condensate and 8.5% natural gas liquids. During 2010, our average sales prices were $74.33 per bbl for light and medium crude oil, $63.88 per bbl for heavy crude oil and $53.98 per bbl for natural gas liquids; these prices compare to 2009 prices of $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. Our crude oil is sold under contracts of varying terms of up to one year and is 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

The authorized capital of ARC Resources of an unlimited number of Common Shares without nominal or par value (defined in this Annual Information Form as "Common Shares") and 50,000,000 preferred shares without nominal or par value issuable in series of which 284,379,730 Common Shares and no preferred shares are outstanding as at December 31, 2010.

The following is a summary of the rights, privileges, restrictions and conditions which attach to the securities of ARC Resources.

Common Shares

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 the Corporation (other than meetings of a class or series of shares of the Corporation other than the Common Shares as such).

Holders of Common Shares are entitled to receive dividends as and when declared by the board of directors of the Corporation on the Common Shares as a class, subject to prior satisfaction of all preferential rights to dividends attached to shares of other classes of shares of the Corporation ranking in priority to the Common Shares in respect of dividends.

Holders of Common Shares are entitled in the event of any liquidation, dissolution or winding-up of the Corporation, whether voluntary or involuntary, or any other distribution of the assets of the Corporation 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 the Corporation ranking in priority to the Common Shares in respect of return of capital on dissolution, to share rateably, together with the holders of shares of any other class of shares of the Corporation ranking equally with the Common Shares in respect of return of capital on dissolution, in such assets of the Corporation as are available for distribution.

Preferred Shares

The preferred shares 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 shall, by resolution, fix the number of shares that will form such series and shall, subject to the limitations set out in ARC Resources' articles, by resolution fix the designation, rights, privileges, restrictions and conditions to be attached to the preferred shares of such series, including, but without in any way limiting or restricting the generality of the foregoing, the rate, amount or method of calculation of dividends thereon, the time and place of payment of dividends, the consideration for and the terms and conditions of any purchase for cancellation, retraction or redemption thereof, conversion or exchange rights (if any), and whether into or for securities of ARC Resources or otherwise, voting rights attached thereto (if any), the terms and conditions of any share purchase or retirement plan or sinking fund, and restrictions on the payment of dividends on any shares other than preferred shares or payment in respect of capital on any shares in the capital of ARC Resources or creation or issue of debt or equity securities. Notwithstanding the foregoing, other than in the case of a failure to declare or pay dividends specified in any series of preferred shares, the voting rights attached to the preferred shares shall be limited to one vote per preferred share at any meeting where the preferred shares and Common Shares vote together as a single class.

The preferred shares of ARC Resources are intended to provide future financing flexibility and are not intended to be used to block any takeover bid for ARC Resources. ARC Resources confirms that it will not, without prior shareholder approval, issue any preferred shares for any anti-takeover purpose.

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.

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 income. Debt repayment will be scheduled to the extent possible to minimize any income tax payable by ARC Resources.

As at December 31, 2010, we had credit facilities consisting of a syndicated, financial covenant based credit facility of $1 billion with a syndicate of major chartered banks, a $30 million working capital facility with its agent bank and U.S.$417.8 million and Cdn.$29 million of senior notes outstanding with an additional amount of U.S.$109.4 million of senior notes available to be issued on the U.S.$225 Master Shelf Agreement entered into with a large insurance company (the "**Master Shelf**"). Our long-term debt balance was $803.5 million excluding a working capital deficit of $69.1 million as at December 31, 2010. Borrowings under the credit facility bear interest at bank prime or, at ARC Resources' option, Canadian dollar bankers' acceptances or U.S. dollar LIBOR loans plus a stamping fee. At the option of ARC Resources, the lenders will review the credit facility each year and determine whether they will extend the revolving three year period for another year. In the event the credit facility is not extended at any time before the maturity date, the loan will become repayable on the maturity date. The maturity date of the current credit facility is August 3, 2013. ARC Resources has the option to draw the remaining capacity of the Master Shelf. This option, which will expire in April 2012, would allow ARC Resources to issue senior notes at a rate equal to the related U.S. treasuries corresponding to the term of the notes plus an appropriate credit risk adjustment at the time of issuance. The senior notes were issued in nine tranches and bear interest at a fixed rate. Each tranche requires certain repayments of principal prior to the final maturity thereof. The following are significant financial covenants governing the revolving credit facilities:

- Long-term debt and letters of credit not to exceed three times trailing twelve month net income before non-cash items and interest expense;

- Long-term debt, letters of credit and subordinated debt not to exceed four times trailing twelve month net income before non-cash items and interest expense; and

- Long-term debt and letters of credit not to exceed 50% of Shareholders' equity and long-term debt, letters of credit and subordinated debt.

ARC Resources is in compliance in all material respects with the terms of the agreements governing the credit facilities described above.

The credit facilities and senior notes rank equally and contain provisions which restrict the payment of dividends to Shareholders, 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 11 of our audited consolidated financial statements for the year ended December 31, 2010, which is incorporated by reference in this Annual Information Form and which has been filed on SEDAR at *www.sedar.com*.

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

Dividend Reinvestment and Optional Common Share Purchase Plan

A plan has been established to provide Shareholders who are residents of Canada (within the meaning of the *Tax Act*) with a method to reinvest dividends by purchasing additional Common Shares.

DIRECTORS AND EXECUTIVE OFFICERS

The name and municipality of residence, positions held and principal occupation of each director and officer of ARC Resources as at December 31, 2010 are set out below:

Name and Municipality of Residence	Offices Held and Time as Director	Principal Occupation
Mac H. Van Wielingen (1) 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 Calgary, Alberta, Canada	Vice Chairman and Director since June 26, 1996	Independent Businessman
John P. Dielwart Calgary, Alberta, Canada	Chief Executive Officer and Director since May 3, 1996	Chief Executive Officer of ARC Resources
Fred J. Dyment Calgary, Alberta, Canada	Director since April 17, 2003	Independent Businessman
James C. Houck Calgary, Alberta, Canada	Director since February 14, 2008	President and Chief Executive Officer of The Churchill Corporation
Michael M. Kanovsky Calgary, Alberta, Canada	Director since May 3, 1996	Independent Businessman
Harold N. Kvisle Calgary, Alberta Canada	Director since May 20, 2009	Independent Businessman
Kathleen M. O'Neill Toronto, Ontario, Canada	Director since June 1, 2009	Independent Businesswoman
Herbert C. Pinder, Jr. Saskatoon, Saskatchewan, Canada	Director since January 1, 2006	Independent Businessman

Name and Municipality of Residence	Offices Held and Time as Director	Principal Occupation
Myron M. Stadnyk Calgary, Alberta, Canada	President and Chief Operating Officer	President and Chief Operating Officer 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, Engineering	Vice-President, Engineering of ARC Resources
P. Van R. Dafoe Calgary, Alberta, Canada	Vice-President, Finance	Vice-President, Finance of ARC Resources
George Gervais Calgary, Alberta, Canada	Vice-President, Corporate Development	Vice-President, Corporate Development of ARC Resources
Neil Groeneveld Calgary, Alberta, Canada	Vice-President, Geosciences	Vice-President, Geosciences of ARC Resources
Al Roberts Calgary, Alberta, Canada	Vice-President, Operations	Vice-President, Operations of ARC Resources
Allan R. Twa Calgary, Alberta, Canada	Secretary	Partner, Burnet, Duckworth & Palmer LLP (barristers and solicitors)

Notes:

(1) Mr. Van Wielingen is the Chairman and a Director of ARC Resources and was a director of Gauntlet Energy Corporation that 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.

(2) The term of each director is until the next annual meeting of ARC Resources or until his or her successor is elected, but not later than the date of the next annual meeting of ARC Resources.

COMMITTEES OF THE BOARD OF DIRECTORS

Name of Director	Audit Committee	Reserves Committee	Risk Committee	Human Resources & Compensation Committee	Policy and Board Governance Committee	Health, Safety & Environment Committee
Independent Outside Directors						
Mac H. Van Wielingen			√	√	√	
Walter DeBoni	√		√		Chair	
Fred J. Dyment	Chair	√	√			
James C. Houck	√	Chair				√
Michael M. Kanovsky		√	Chair		√	
Harold N. Kvisle						Chair
Kathleen M. O'Neill	√			√		
Herbert C. Pinder, Jr.				Chair	√	√

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 February 2009, John P. Dielwart was President and Chief Executive Officer of ARC Resources. Prior to October 2007, Mr. James Houck was President and Chief Executive

Officer and a director of Western Oil Sands Ltd. Prior to July 2010, Mr. Harold N. Kvisle was President and Chief Executive Officer of TransCanada Corporation and TransCanada Pipelines Ltd. Prior to February 2009, Myron M. Stadnyk was Senior Vice-President and Chief Operating Officer of ARC Resources. Prior to March 2010, P. Van R. Dafoe was Vice President and Treasurer of ARC Resources and prior to July 2007, was Treasurer of ARC Resources. Prior to May 2010, Terry M. Anderson was Vice President, Operations of ARC Resources. Prior to September 2007, Terry Gill was Senior Vice President Human Resources at Superior Propane. Prior to March 2010, George Gervais was Manager of Business Development of ARC Resources. Prior to October 2008, Neil Groeneveld was Manager, Geology of ARC Resources. Prior to May 2010, Al Roberts was Manager, Southern Operations 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 and has overall management responsibility for the Corporation. He holds a Bachelor of Science with Distinction (Civil Engineering) degree from the University of Calgary. 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 has 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 and oversees all of the financial and accounting affairs of ARC. 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 ARC since 1996. Mr. Sinclair is 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 and is responsible for all aspects of ARC's ongoing operational and production management and strategies. He has a B.Sc. in Mechanical Engineering from the University of Saskatchewan and is a graduate of the Harvard Business School Advanced Management program. Mr. Stadnyk has over 25 years experience in the oil and gas business. Prior to joining ARC in 1997, he worked with a major oil and gas company in both domestic and international operations. Mr. Stadnyk is a member of the Association of Professional Engineers.

David P. Carey, P.Eng., MBA

Mr. Carey is Senior Vice-President, Capital Markets of ARC Resources 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 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 and oversees all human resources, information technology and legal services related activities. Mr. Gill holds a B.PE. in coaching leadership from the University of Alberta. 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 10 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.

Terry M. Anderson, P.Eng.

Mr. Anderson is Vice-President, Engineering of ARC Resources and is responsible for all of ARC's engineering and joint venture activities. He has a B.Sc. in Petroleum Engineering from the University of Wyoming. 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. Mr. Anderson is a member of the Association of Professional Engineers in Alberta, Saskatchewan and British Columbia.

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

Mr. Dafoe is Vice-President, Finance of ARC Resources and is responsible for all of ARC's hedging, marketing, tax 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.

George Gervais, B.Sc, P.Eng.

Mr. Gervais is Vice-President, Corporate Development of ARC Resources and is responsible for all of ARC's EOR, Acquisition and Divestment and Land related activities. He has a B.Sc. in Geological Engineering with Distinction from the University of Saskatchewan. Mr. Gervais brings over 15 years of experience in the oil and gas business covering production and engineering and reserves evaluation. Prior to joining ARC in 2000, Mr. Gervais held a position with a major E&P company. Mr. Gervais is a member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta.

Neil Groeneveld, MSc., P. Geol.

Mr. Groeneveld is Vice-President, Geosciences of ARC Resources and is responsible for ARC's geophysical and geological activities. He holds a Master of Science degree in Geology from the University of Regina. Mr. Groeneveld 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. Prior to joining ARC in 2003, he held senior positions with large and intermediate oil and gas companies. Mr. Groeneveld is a member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta.

Al Roberts

Mr. Roberts is Vice-President, Operations of ARC Resources and is responsible for the execution of ARC's capital programs and manages all the field production operations. He has over 30 years of broad experience across the western Canadian sedimentary basin in production operations, completions and facilities construction. Prior to joining ARC in 1997, Mr. Roberts spent 18 years managing field operations in both junior and intermediate producers.

Allan R. Twa, Q.C.

Mr. Twa acts as Corporate Secretary of ARC Resources. 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.

All of the directors of ARC Resources were elected as directors of ARC Resources Ltd. on May 18, 2010 to hold office until the next annual general meeting of ARC Resources, which is scheduled for May 18, 2011. As at December 31, 2010, the directors and officers of ARC Resources, as a group, beneficially owned, or controlled or directed, directly or indirectly, 2,419,301 Common Shares or approximately 0.85% of the outstanding Common Shares.

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, 2010, 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. in 2005 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.

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.

	2009	2010
Audit Fees	$733,250	$684,133
Audit Related Fees(1)	$63,095	$167,722
Tax Fees(2)	$0	$0
All Other Fees	$0	$0

Notes:
(1) 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 but which are not included in audit services fees.
(2) The aggregate fees billed by our external auditor for professional services for municipal property tax compliance, tax advice and tax planning.

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 Chief Executive Officer, President or the Board of Directors. Any other activities of employees which pose a potential conflict of interest are also required by the Codes to be disclosed to the Chief Executive Officer, President or the Board of Directors. Any such potential conflicts of interests will be dealt with openly with full disclosure of the nature and extent of the potential conflicts of interests with the Trust.

It is acknowledged in the Codes that employees, officers and directors may be directors or officers of other entities engaged in the oil and gas business, and that such entities may compete directly or indirectly with the Corporation. 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 1% of the outstanding shares will not be viewed as "competing" with the Corporation. 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 1% 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 Corporation, 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 Corporation. Such actions, without limitation, may include excluding such directors, officers or employees from certain information or activities of the Corporation.

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% of outstanding Common Shares, 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 Corporation.

DIVIDENDS AND DISTRIBUTIONS

Dividend Policy

In conjunction with the completion of the Trust Conversion, the Board of Directors of ARC Resources established a dividend policy of paying monthly dividends to holders of Common Shares, initially set at $0.10 per Common Share, which will be paid to Shareholders of record on or about the 15th day of each month. In general, the Board of Directors attempts to set the dividend amount at a level which at that time appears sustainable for a period of six months. The payment of dividends by the Corporation commenced with a dividend declared to Shareholders of record on January 31, 2011 in the amount of $0.10 per Common Shares made payable on February 15, 2011.

It is expected that the dividends declared and paid will be "eligible dividends" for income tax purposes and thus qualify for the enhanced gross-up and tax credit regime available to certain holders of Common Shares. Although it is expected that dividends of ARC Resources will qualify as "eligible dividends" for the purposes of the Tax Act, and thus qualify for the enhanced gross-up and tax credit regime available to certain holders of Common Shares, no assurances can be given that all dividends will be designated as "eligible dividends" or qualify as "eligible dividends".

Notwithstanding the foregoing, the amount of future cash dividends, if any, will be subject to the discretion of the Board of Directors of ARC Resources and may vary depending on a variety of factors and conditions existing from time to time, including fluctuations in commodity prices, production levels, capital expenditure requirements, debt service requirements, operating costs, royalty burdens, foreign exchange rates and the satisfaction of solvency tests imposed by the *Business Corporations Act* (Alberta) for the declaration and payment of dividends.

For information relating to risks relating to dividends, see "*Risk Factors - Risk Relating to Our Business and Operations– The Board of Directors has discretion in the payment of dividends and may not chose to maintain the payment of dividends in certain circumstances*".

In certain circumstances, the payment of dividends may be restricted by our borrowing agreements. For more information see "Other Information Relating to Our Business – Borrowing".

Distribution History

Prior to the completion of the Trust Conversion, the following per Trust Unit distributions were made in the last three completed financial years of ARC:

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

2010	
First Quarter	$0.30
Second Quarter	$0.30
Third Quarter	$0.30
Fourth Quarter	$0.30

Distributions paid to Unitholders in 2008 were 2% tax deferred, 2009 distributions were 3% tax deferred and 2010 distributions were 15% tax deferred.

MARKET FOR SECURITIES

Common Shares

The Common Shares commenced trading on the TSX on January 6, 2011 following the completion of the Trust Conversion. The trading symbol for the Common Shares is ARX.

Trust Units

Prior to the completion of the Trust Conversion, the Trust Units were listed and posted for trading on the TSX. The trading symbol for the Trust Units was 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):

	Toronto Stock Exchange		
2010 Period	**High**	**Low**	**Volume**
	$	**$**	
January	21.75	19.80	16,630,046
February	22.36	20.04	15,326,484
March	22.49	20.50	26,348,625
April	22.33	20.79	12,124,151
May	21.88	19.59	14,039,448
June	21.98	19.73	23,698,234
July	20.95	19.43	15,525,781
August	20.28	19.02	20,502,186
September	20.55	19.83	19,969,921
October	21.56	20.63	17,623,284
November	24.36	21.57	21,632,284
December	25.97	23.14	18,784,271

Series A Exchangeable Shares

Prior to the completion of the Trust Conversation, the series A exchangeable shares of ARC Resources Ltd. were listed and posted for trading on the TSX. The trading symbol for the series A exchangeable shares of ARC Resources Ltd. was ARX.A (ARX prior to October 18, 2010). The following table sets forth the high and low closing prices and the aggregate volume of trading of the series A exchangeable shares on the TSX for the periods indicated (as quoted by the TSX):

	Toronto Stock Exchange		
2010 Period	**High**	**Low**	**Volume**
	$	**$**	
January	58.98	53.89	1,628
February	60.00	55.30	550
March	59.01	57.15	1,540
April	58.70	57.45	729
May	59.00	55.58	1,650
June	69.99	55.01	630
July	59.99	55.00	1,900
August	56.39	54.25	507
September	57.85	55.01	400
October	59.76	59.76	240
November	70.20	64.00	3,993
December	73.91	66.70	3,243

INDUSTRY CONDITIONS

Companies operating in the oil and natural gas industry are subject to extensive regulation and control of operations (including land tenure, exploration, development, production, refining, transportation, and marketing) as a result of legislation enacted by various levels of government and with respect to the pricing and taxation of oil and natural gas through agreements among the governments of Canada, Alberta, British Columbia 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 price of the vast majority of natural gas produced in western Canada is now determined through highly liquid market hubs such as the Alberta "NIT" (Nova Inventory Transfer) hub rather than through direct negotiation between buyers and sellers. Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet certain other criteria prescribed by the NEB and the Government of Canada. Natural gas (other than propane, butane and ethane) exports for a term of less than two years or for a term of two to 20 years (in quantities of not more than 30,000 m^3/day) must be made pursuant to an NEB order. Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 25 years) or for a larger quantity requires an exporter to obtain an export licence from the NEB and the issuance of such a licence requires a public hearing and the approval of the Governor in Council.

The governments of Alberta, 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 levels of oil and natural gas in western Canada and pipeline capacity does not generally limit the ability to produce and market such production.

The North American Free Trade Agreement

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

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

Royalties and Incentives

General

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

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

Alberta

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

On October 25, 2007, the Government of Alberta released a report entitled "The Alberta Royalty Framework" ("**NRF**") containing the Government's proposals for Alberta's new royalty regime which were subsequently implemented by the *Mines and Minerals (Alberta Royalty Framework) Amendment Act, 2008*. The NRF took effect on January 1, 2009. On March 11, 2010, the Government of Alberta announced changes to Alberta's royalty system intended to increase Alberta's competitiveness in the upstream oil and natural gas sectors, which changes included a decrease in the maximum royalty rates for conventional oil and natural gas production effective for the January 2011 production month. Royalty curves incorporating the changes announced on March 11, 2010 were released on May 27, 2010. Alberta royalties in effect after December 31, 2010 are known as the "Alberta Royal Framework" ("**ARF**").

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 ARF, 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 ARF ranged from 0-50%, an increase from the previous maximum rates of 30-35% depending on the vintage of the oil, and rate caps were set at $120 per barrel. Effective January 1, 2011, the maximum royalty payable under the ARF was reduced to 40%. The royalty curve for conventional oil announced on May 27, 2010 amends the price component of the conventional oil royalty formula to moderate the increase in the royalty rate at prices higher than $535/m^3$ compared to the previous royalty curve.

Royalty rates for natural gas under the ARF 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 ARF ranged from 5-50%, an increase from the previous maximum rates of 5-35%, and rate caps were set at $16.59/GJ. Effective January 1, 2011, the maximum royalty payable under the ARF was reduced to 36%. The royalty curve for natural gas announced on May 27, 2010 amends the price component of the natural gas royalty formula to moderate the increase in the royalty rate at prices higher than $5.25/GJ compared to the previous royalty curve.

Oil sands projects are also subject to the ARF. Prior to payout, the royalty is payable on gross revenues of an oil sands project. Gross revenue royalty rates range between 1-9% depending on the market price of oil determined using the average monthly price, expressed in Canadian dollars, for WTI crude oil at Cushing, Oklahoma: rates are

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

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

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

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

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

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

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

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

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

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

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

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

British Columbia

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

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

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

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

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

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

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

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

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

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

- *Ultra-Marginal Royalty Reduction Program* providing additional royalty reductions 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 that is located on either Crown or freehold land and completed in a new pool discovered subsequent to June 30, 1974 may also be exempt from the payment of a royalty for the first 36 months of production or 11,450 m^3 of production, whichever comes first.

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

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

Saskatchewan

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

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

The amount payable as a Crown royalty or freehold production tax in respect of natural gas production is determined by a sliding scale based on the actual price received, the quantity produced in a given month, the type of natural gas, and the vintage of the natural gas. Like conventional oil, natural gas may be 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.

On December 9, 2010, the Government of Saskatchewan enacted the *Freehold Oil and Gas Production Tax Act, 2010* which replaces the existing *Freehold Oil and Gas Production Tax Act* and is intended to facilitate more efficient payment of freehold production taxes by industry. No regulations have been passed with respect to the calculation of freehold production taxes under the new Act.

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

The Government of Saskatchewan currently provides 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;

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

- *Royalty Tax Regime for High Water-Cut Oil Wells* granting "third tier oil" royalty/tax rates to incremental high water-cut oil production resulting from qualifying investments made to rejuvenate eligible oil wells and/or associated facilities; and

- *Royalty/Tax Incentive Volumes for Horizontal Gas Wells drilled on or after June 1, 2010 and before April 1, 2013* providing reduced Crown royalty and freehold tax rates on incentive volumes of 25,000,000 m^3 for horizontal gas wells.

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

Land Tenure

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

Each of the provinces of Alberta, 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. On March 29, 2007, British Columbia's policy of deep rights reversion was expanded for new leases to provide for the reversion of both shallow and deep formations that cannot be shown to be capable of production at the end of their primary term.

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

Environmental Regulation

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

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

Climate Change Regulation

Federal

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

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

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

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

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

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

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

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

10% of each firm's regulatory obligation, with the added restriction that credits generated through forest sink projects will not be available for use in complying with the Canadian regulations.

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

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

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

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

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

Alberta

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

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

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

Due to the immateriality of our working interests in various facilities in Alberta, these legislative changes will not have a material effect on our business or operations.

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

British Columbia

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

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

We are subject to the reporting and verification requirements at our gas plant at Dawson.

Saskatchewan

On May 11, 2009, the Government of Saskatchewan announced *The Management and Reduction of Greenhouse Gases Act* (the "**MRGGA**") to regulate GHG emissions in the province. The MRGGA received Royal Assent on May 20, 2010 and will come into force on proclamation. Regulations under the MRGGA have also yet to be proclaimed, but draft versions indicate that Saskatchewan will adopt the goal of a 20% reduction in GHG emissions from 2006 levels by 2020 and permit the use of pre-certified investment credits, early action credits 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 our business which prospective investors should carefully consider before deciding whether to purchase Common 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".

Our income and cash flow is derived 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, including those risks set forth below. If the oil and natural gas reserves associated with our resource properties are not supplemented through additional development or the acquisition of additional oil and natural gas properties, our ability to pay dividends to Shareholders may be adversely affected. The price at which the Common Shares trade is dependent on a variety of economic, political and regulatory factors many of which are beyond our control and only, in part, on our ability to manage the risks set forth below, some of which are beyond our control.

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 Shareholders as dividends, 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 and declined to $0.10 per Trust Unit in 2009 and throughout 2010, such $0.10 amount being the current monthly dividend paid on the Common Shares. Declines in oil and natural gas prices may result in further declines in, or elimination of, dividends paid on the Common Shares. 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. Recent political unrest in the countries of North Africa and the Middle East may create more volatility in the price of oil and may threaten the ongoing recovery of the global economy or may have other unforeseen consequences. 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 dividends to be paid to our Shareholders.

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 dividends to Shareholders, and could impact the market price of the Common Shares.

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 during 2009 by 8% and in 2010 by 4% relative to the U.S. dollar. A material increase in the value of the Canadian dollar negatively impacts our production revenue and our ability to maintain future dividends.

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 continued to improve throughout 2010, these factors have negatively impacted company valuations and continue to impact the performance of the global economy going forward. Recent political unrest in the countries of North Africa and the Middle East may create more volatility in the price of oil and may threaten the ongoing recovery of the global economy or may have other unforeseen consequences.

We have been historically reliant on external sources of capital, borrowings and equity sales, and if unavailable, our financial condition could 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 dividend payments may be materially and adversely affected as a result.

Alternatively, we may issue additional Common Shares from treasury at prices which may result in a decline in production per Common Share and reserves per Common Share 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 actively manage the risk associated with changes in commodity prices by entering into oil or natural gas price hedges. If we hedge our commodity price exposure, we will forego some of the benefits we would otherwise experience if commodity prices were to increase, and some of these foregone benefits may be material. 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 may impact future dividend payments and the future value of our reserves as determined by independent evaluators. These hedging activities could expose us to losses, which may be material, and to credit risk associated with counterparties with which we contract.

Our bank credit facility will need to be renewed prior to August 3, 2013 and failure to renew, in whole or in part, or at higher interest charges will adversely affect our financial condition

We currently have a $1 billion syndicated credit facility with thirteen banks of which we had drawn $357.7 million as at December 31, 2010. In the event that the facility is not extended before August 3, 2013 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. $417.8 million of U.S. denominated and Cdn $29 million of long-term debt outstanding in the form of Long-Term Notes ("**Notes**") as at December 31, 2010. The next scheduled principal repayment of the Notes is in April 2011 and the final scheduled principal repayment is in May 2022. We intend to fund these repayments with existing credit facilities.

We are required to comply with covenants under the credit facility and under our U.S. and Canadian 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 pay dividends to our Shareholders may be restricted.

Amounts paid in respect of interest and principal on debt may reduce dividends. 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 dividends on the Common Shares. Certain covenants of the agreements with our lenders may also limit the payment of dividends. 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".

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 dividend payments is dependent on a number of factors including our success in exploiting existing properties and acquiring additional reserves

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 proportion of our cash flow from operating activities, by way of dividend payments, to Shareholders 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 the payment of dividends to Shareholders 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 Common Shares and in a reduction in cash flow from operating activities available for the payment of dividends to Shareholders.

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 Shareholders

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

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

There are numerous uncertainties inherent in estimating quantities of recoverable oil and natural gas reserves and resources 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 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 and the resource information contained in the GLJ Report is only an estimate and the actual production and ultimate reserves and resources 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 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.

Estimates of Economic Contingent Resources contained in the GLJ Report are subject to the definitions, disclaimers, contingencies and warnings set forth under the heading "Statement of Reserves Data and Other Oil and Gas Information – Contingent Resource Estimates". There is no certainty that it will be commercially viable to produce any portion of the resources.

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 we undertake 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, 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 the payment of dividends.

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

Dividends on the Common Shares are not preferential, nor cumulative nor stipulated by their terms to be at a fixed amount or rate. As such dividends 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. Dividends are conditionally declared by our Board in its sole discretion and are subject to confirmation by a monthly press release and are specifically subject to change in accordance with the dividend policy of ARC. The dividend policy is also subject to change in the sole discretion of ARC. See "Dividends and Distributions – Dividend Policy". Dividends may be varied or discontinued at any time.

Our future enhanced operated opportunities may not be economically or technically feasible

We believe our ownership of assets in Redwater and North Pembina Cardium Unit #1 strategically positions us for participation in properties with large 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 Corporation'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 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, 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 the payment of dividends to Shareholders. See "ARC Resources Ltd. – 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 Corporation. 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.

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

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. We have established a reclamation fund for the purpose of funding our currently estimated future environmental and reclamation obligations for our assets at Redwater. We have not established a reclamation fund for any of our other assets. There can be no assurance that we will be able to satisfy our actual future environmental and reclamation obligations for our assets at Redwater or elsewhere.

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

We compete with other oil and gas entities to hire and retain skilled personnel necessary for our daily operations 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 Canadian GAAP, US GAAP or International Financial Reporting Standards may result in non-cash losses which may adversely affect the market price of our Common shares

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 price of ARC's Common Shares.

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.

Under GAAP, the net amounts at which petroleum and natural gas properties are carried are subject to a cost-recovery test which is based in part upon estimated future net revenues from reserves. A decline in the estimated net recoverable value of oil and natural gas properties could cause capitalized costs to exceed the cost ceiling, resulting in a charge against earnings. The estimated net recoverable value of oil and gas properties is 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 cost recovery test on each cost centre using discounted estimated future net revenue from proved oil and gas reserves discounted at a rate of 10%. The US GAAP ceiling test is based on 12 month average prices, as at December 31, 2010. For the year ended 2010, the future net revenues from our reserves exceeded the capitalized cost and therefore no write-down was recorded (write-downs of $145 million and $1.15 billion were recorded in 2009 and 2008, respectively under US GAAP). For further information, see Note 24 of our audited consolidated financial statements for the year ended December 31, 2010 which is incorporated by reference in this Annual Information Form and which has been filed on SEDAR at *www.sedar.com*.

Effective January 1, 2011, all Canadian publicly accountable enterprises will be required to apply International Financial Reporting Standards ("**IFRS**"). Upon initial adoption of IFRS, our 2010 financial statements will be restated for comparative purposes to reflect the retrospective application of IFRS's which differ from Canadian GAAP. Differences in accounting policies between GAAP and IFRS may result in non-cash charges and/or write-downs of net assets in the financial statements under IFRS both at initial adoption and in future periods. Such non-cash charges and write-downs under IFRS 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 price of the Common Shares.

IFRS requires that impairment testing be performed at a producing unit rather than on a total operating segment which is permitted under GAAP. Under IFRS, if net capitalized costs of the producing unit exceed the estimated net recoverable value of the reserves at a producing unit level, the excess amount is charged to earnings. Under IFRS, write-downs may be reversed in a subsequent period if there is an increase in the net recoverable value of the reserves at the producing unit level. As a result, there may be greater risk of more volatile earnings relating to impairment testing under IFRS.

IFRS requires that expenditures that meet the definition of exploration activities be classified and assessed separately for impairment. If such exploration activities are deemed to be "unsuccessful", the related expenditures must be written-off against earnings. Under GAAP these expenditures can be capitalized as part of the full cost pool and depleted over time. As a result, there may be a greater risk of more frequent write-downs and in turn more volatile earnings relating to exploration expenditures under IFRS.

IFRS requires that gains and losses on sale of properties be recorded through earnings when realized. Under GAAP, gains and losses on property sales were typically not recorded through earnings as they were included in the full cost pool and depleted over time with the remaining properties. As a result, there may a risk of more volatile earnings relating to gains and losses on sale of assets under IFRS.

For more information as to the effect of initial adoption of IFRS, see the section in our Management's Discussion and Analysis for the year ended December 31, 2010 under the heading "First Time Adoption of IFRS" which section is incorporated in this Annual Information Form by reference and is found on SEDAR at *www.sedar.com*.

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. Shareholders will be dependent on our management in respect of the administration and management of all matters relating to our properties, the Common Shares and the safekeeping of our primary workspace and computer systems. Any deterioration of our corporate culture could adversely affect our long term success. As of December 31, 2010, we operated approximately 84% 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

The payment of dividends out of cash flow generated from 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 Factors Applicable to Residents of the United States and Other Non-Residents of Canada

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

ARC Resources is a corporation formed under the laws of Alberta, Canada and has its 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 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.

We have included in the Annual Information Form estimates of Economic Contingent Resources. Economic Contingent Resources are a class of resources and should not be confused with reserves and are subject to the definitions, disclaimers and warnings set forth under the heading "*Statement of Reserves Data and Other Oil and Gas information – Contingent Resource Estimates*". The Securities Exchange Commission prohibits the inclusion of Contingent Resource estimates 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 dividends paid to non-residents

Dividends paid to a non-resident of Canada on Common Shares are subject to Canadian withholding tax at a rate of 25% unless the rate is reduced under the provisions of an applicable double taxation treaty. Where a non-resident is a United States resident entitled to benefits of the *Canada – United States Income Tax Convention, 1980* and is the beneficial owner of the dividends then the rate of Canadian withholding tax is generally reduced to 15%.

There is a foreign exchange risk to non-resident Shareholders

Our dividends 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 dividend will be reduced when converted to their home currency.

TRANSFER AGENT AND REGISTRAR

The transfer agent and registrar for the Common 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 of ARC 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. Amended and Restated Credit Agreement dated as of August 4, 2010 between ARC Resources and a syndicate of lenders, and an administrative agent, as amended January 1, 2011 providing for an extendible revolving credit facility up to Cdn. $1 billion.

2. Amended and Restated Uncommitted Master Shelf Agreement as of December 15, 2005 between ARC Resources and various purchasers, as amended on May 17, 2006, April 14, 2009, February 22, 2010 and January 1, 2011, providing for the issuance and sale of up to an aggregate principal amount of US $225 million in notes of which U.S. $75 million 5.42% Series C Notes due December 15, 2017 and U.S. $50 million 4.98% Series D Notes due March 5, 2019 are currently outstanding.

3. Note Purchase Agreement dated as of April 27, 2004 between ARC Resources and various purchasers, as amended on April 14, 2009, March 31, 2010 and January 1, 2011, with respect to US $62.5 million 4.62% Series A Notes due April 27, 2014 and US $62.5 million 5.10% Series B Notes due April 27, 2016.

4. Note Purchase Agreement dated as of April 14, 2009 between ARC Resources and various purchasers, as amended January 1, 2011 with respect to U.S.$67.5 million 7.19% Series C Notes due April 14, 2016, U.S.$35 million 8.21% Series D Notes due April 14, 2021 and Cdn.$29 million 6.50% Series E Notes due April 14, 2016.

5. Note Purchase Agreement dated as of May 27, 2010 between ARC Resources and various purchasers, as amended January 1, 2011 with respect to U.S.$150 million 5.36% Series F Notes due May 27, 2022.

For more information in relation to these material contracts, 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 1% of our outstanding securities, including the securities of our associates and affiliates. Deloitte & Touche LLP was the auditor of the Trust prior to the Trust Conversion and is the auditor of ARC Resources 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 Common Shares and rights to purchase Common Shares, is contained in the Information Circular - Proxy Statement of the Corporation which relates to the Annual and Special Meeting of Shareholders to be held on May 18, 2011. Additional financial information is provided in our consolidated financial statements and accompanying management's discussion and analysis for the year ended December 31, 2010, which have been filed on SEDAR at *www.sedar.com*. Other additional information relating to us may be found 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**"):

1. We have prepared an evaluation of the Company's reserves data as at December 31, 2010. The reserves data are estimates of proved reserves and probable reserves and related future net revenues as at December 31, 2010, 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%, included in the reserves data of the Company evaluated by us for the year ended December 31, 2010, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the 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, 2011	Canada	-	6,350	-	6,350

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, consistently applied.

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.

Executed as to our report referred to above:

GLJ Petroleum Consultants Ltd.
Calgary, Alberta, Canada

Dated February 15, 2011

(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**") is responsible for the preparation and disclosure of information with respect to the Company's and its 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, 2010 estimated using forecast prices and costs.

An independent qualified reserves evaluator has evaluated the Company's and its 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.

(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 22, 2011

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. (the "**Corporation**") to which the Board has delegated its responsibility for oversight of the nature and scope of the annual audit, management's reporting on internal accounting standards and practices, financial information and accounting systems and procedures, financial reporting and statements and recommending, for Board of Director approval, the audited financial statements and other mandatory disclosure releases containing financial information. The objectives of the Committee, with respect to the Corporation and its subsidiaries, are as follows:

- To assist Directors to meet their responsibilities in respect of the preparation and disclosure of the financial statements of the Corporation 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 the Corporation'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 the Corporation prior to their submission to the Board of Directors for approval. The process should include but not be limited to:
    - reviewing changes in accounting principles, or in their application, which may have a material impact on the current or future years' financial statements;
    - reviewing significant accruals, reserves or other estimates such as the ceiling test calculation;
    - reviewing accounting treatment of unusual or non-recurring transactions;
    - ascertaining compliance with covenants under loan agreements;
    - reviewing 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 Corporation, 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 the Corporation) their assessment of the internal controls of the Corporation, 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 the Corporation 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 Corporation's public disclosure of financial information from the Corporation's financial statements and periodically assess the adequacy of those procedures.

- Establish procedures for:

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

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

- 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 National 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 the Corporation that could, in the view of the Board, 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 Corporation'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 the Corporation.