CREW ENERGY INC.

ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2009

March 29, 2010

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ABBREVIATIONS

Oil and Natural Gas Liquids

bbl	barrel
Mbbl	thousand barrels
Mmbbl	million barrels
bbl/d	barrels per day
BOPD	barrels of oil per day
NGLs or ngls	natural gas liquids

Natural Gas

Mcf	thousand cubic feet
Mmcf	million cubic feet
Mcf/d	thousand cubic feet per day
Mmcf/d	million cubic feet per day
Mmbtu	million British Thermal Units
Bcf	billion cubic feet
GJ	Gigajoule
Tcf	trillion cubic feet

Other

AECO	the natural gas storage facility located at Suffield, Alberta.
API	American Petroleum Institute
°API	an indication of the specific gravity of crude oil measured on the API gravity scale.
ARTC	Alberta Royalty Tax Credit
BOE or boe	barrel of oil equivalent on the basis of 6 Mcf/BOE for natural gas and 1 bbl/BOE for crude oil and natural gas liquids (this conversion factor is an industry accepted standard)
BOE/d or Boe/d	barrel of oil equivalent per day
CSA	Canadian Securities Administrators
m^3	cubic metres
Mboe	1,000 barrels of oil equivalent
M$	thousands of dollars
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade

CONVERSIONS

To Convert From	To	Multiply By
Mcf	Cubic metres	28.174
Cubic metres	Cubic feet	35.494
bbl	Cubic metres	0.159
Cubic metres	bbl oil	6.290
Feet	Metres	0.305
Metres	Feet	3.281
Miles	Kilometres	1.609
Kilometres	Miles	0.621
Acres (Alberta)	Hectares	0.400
Hectares (Alberta)	Acres	2.500
Acres (British Columbia)	Hectares	0.405
Hectares (British Columbia)	Acres	2.471

FORWARD LOOKING STATEMENTS

Certain of the statements contained herein including, without limitation, financial and business prospects and financial outlook, reserves and production estimates, drilling and re-completion plans, timing of drilling, re-completion and tie in of wells, productive capacity of wells and capital expenditures and the timing thereof, the effect of government announcements, proposals and legislation, plans regarding hedging, expected or anticipated production rates, timing of expected production increases, weighting of production between different commodities, expected commodity prices, exchange rates, production expenses, transportations costs and other costs and expenses, maintenance of productive capacity and capital expenditures and methods of financing thereof, may be forward looking statements. Words such as "may", "will", "should", "could", "anticipate", "believe", "expect", "intend", "plan", "potential", "continue" and similar expressions may be used to identify these forward looking statements. These statements reflect management's current beliefs and are based on information currently available to management. Forward looking statements involve significant risk and uncertainties. A number of factors could cause actual results to differ materially from the results discussed in the forward looking statements including, but not limited to, risks associated with oil and gas exploration, development, exploitation, production, marketing and transportation, loss of markets, volatility of commodity prices, currency fluctuations, imprecision of reserves estimates, environmental risks, competition from other producers, inability to retain drilling rigs and other services, incorrect assessment of the value of acquisitions, failure to realize the anticipated benefits of acquisitions, delays resulting from or inability to obtain required regulatory approvals and ability to access sufficient capital from internal and external sources and the risk factors outlined under "Risk Factors" and elsewhere herein. The recovery and reserves estimates of Crew's reserves and resources provided herein are estimates only and there is no guarantee that the estimated reserves and resources will be recovered. As a consequence, actual results may differ materially from those anticipated in the forward-looking statements.

Forward-looking statements or information are based on a number of factors and assumptions which have been used to develop such statements and information but which may prove to be incorrect. Although Crew believes that the expectations reflected in such forward-looking statements or information are reasonable, undue reliance should not be placed on forward-looking statements because Crew can give no assurance that such expectations will prove to be correct. In addition to other factors and assumptions which may be identified in this document, assumptions have been made regarding, among other things: the impact of increasing competition; the general stability of the economic and political environment in which Crew operates; the timely receipt of any required regulatory approvals; the ability of Crew to obtain qualified staff, equipment and services in a timely and cost efficient manner; drilling results; the ability of the operator of the projects which Crew has an interest in to operate the field in a safe, efficient and effective manner; the ability of Crew to obtain financing on acceptable terms; field production rates and decline rates; the ability to replace and expand oil and natural gas reserves through acquisition, development of exploration; the timing and costs of pipeline, storage and facility construction and expansion and the ability of Crew to secure adequate product transportation; future oil and natural gas prices; currency, exchange and interest rates; the regulatory framework regarding royalties, taxes and environmental matters in the jurisdictions in which Crew operates; and the ability of Crew to successfully market its oil and natural gas products.

Readers are cautioned that the foregoing list of factors is not exhaustive. Additional information on these and other factors that could effect Crew's operations and financial results are included in reports on file with Canadian securities regulatory authorities and may be accessed through the SEDAR website (www.sedar.com) or on Crew's website (www.Crewenergy.com). Although the forward looking statements contained herein are based upon what management believes to be reasonable assumptions, management cannot assure that actual results will be consistent with these forward looking statements. Investors should not place undue reliance on forward looking statements. These forward looking statements are made as of the date hereof and the Corporation assumes no obligation to update or review them to reflect new events or circumstances except as required by applicable securities laws.

Forward looking statements and other information contained herein concerning the oil and gas industry and the Corporation's general expectations concerning this industry is based on estimates prepared by management using data from publicly available industry sources as well as from reserves reports, market research and industry analysis and on assumptions based on data and knowledge of this industry which the Corporation believes to be reasonable. However, this data is inherently imprecise, although generally indicative of relative market positions, market shares and performance characteristics. While the Corporation is not aware of any misstatements regarding any industry data presented herein, the industry involves risks and uncertainties and is subject to change based on various factors.

CERTAIN DEFINITIONS

In this Annual Information Form, the following words and phrases have the following meanings, unless the context otherwise requires:

"**ABCA**" means *Business Corporations Act* (Alberta);

"**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 the Corporation;

"**Crew**" or the "**Corporation**" means Crew Energy Inc., a corporation incorporated pursuant to the ABCA;

"**Crew Energy Partnership**" means Crew Energy Partnership, a general partnership formed under the laws of Alberta, the partners of which are Crew and Crew Resources;

"**Crew Resources**" means Crew Resources Inc., a corporation incorporated pursuant to the ABCA;

"**Edson Disposition**" means the Corporation's pending disposition of assets in the Edson area as more particularly described under the heading "*Description and General Development of the Business – Recent Developments*";

"**GLJ**" means GLJ Petroleum Consultants Ltd.;

"**GLJ Report**" means the report of GLJ dated February 25, 2010 evaluating the crude oil, natural gas liquids and natural gas reserves of the Corporation as at December 31, 2009;

"**Gross**" or "**gross**" means:

(a) in relation to the Corporation's interest in production and reserves, its "company gross reserves", which are the Corporation's working interest (operating and non-operating) share before deduction of royalties and without including any royalty interest of the Corporation;

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

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

"**Net**" or "**net**" means:

(a) in relation to the Corporation's interest in production and reserves, the Corporation's working interest (operating and non-operating) share after deduction of royalty obligations, plus the Corporation's royalty interests in production or reserves;

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

(c) in relation to the Corporation's interest in a property, the total area in which the Corporation has an interest multiplied by the working interest owned by the Corporation.

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

"**TSX**" means the Toronto Stock Exchange.

Certain other terms used herein 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.

Unless otherwise specified, information in this Annual Information Form is as at the end of the Corporation's most recently completed financial year, being December 31, 2009.

All dollar amounts herein are in Canadian dollars, unless otherwise stated.

CORPORATE STRUCTURE

Crew was originally incorporated pursuant to the provisions of the ABCA as 1046546 Alberta Ltd. on May 12, 2003. On June 27, 2003, Crew filed Articles of Amendment to change its name to "Crew Energy Inc."

On January 1, 2009 Crew completed a short form amalgamation with its wholly-owned subsidiary, Gentry Resources Ltd., to form "Crew Energy Inc."

Crew has one wholly-owned subsidiary, Crew Resources. Crew is also the managing partner of the Crew Energy Partnership which owns substantially all of Crew's producing oil and gas properties. Crew and Crew Resources are the only partners in the Crew Energy Partnership and, as at December 31, 2009 owned 80.8% and 19.2%, respectively, of the Crew Energy Partnership.

Crew's head office is located at Suite 1400, 425 - 1st Street SW, Calgary, Alberta T2P 3L8 and its registered office is located at Suite 1400, 350 – 7th Avenue SW, Calgary, Alberta T2P 3N9.

The Common Shares of Crew trade on the TSX under the symbol "CR".

Unless the context otherwise requires, reference herein to "Crew" or the "Corporation" means Crew Energy Inc. together with its wholly-owned subsidiary and the Crew Energy Partnership.

DESCRIPTION AND GENERAL DEVELOPMENT OF THE BUSINESS

Corporate History

Crew has been engaged in the business of exploring for, developing, producing and acquiring crude oil and natural gas in western Canada since it began active operations on September 2, 2003 following completion of the plan of arrangement among the Corporation, Baytex Energy Ltd. and Baytex Energy Trust (the "**Baytex Arrangement**").

Pursuant to the Baytex Arrangement, Crew acquired certain oil and gas properties and undeveloped land from Baytex Energy Ltd. and the Baytex Energy Partnership. Crew did not carry on any active business until completion of the Baytex Arrangement.

At the effective date of the Baytex Arrangement, production from the properties acquired by Crew was approximately 1,500 Boe/d comprised of 7.8 Mmcf/d of natural gas production and 200 bbl/d of oil and natural gas liquids production. The properties acquired by Crew also included approximately 227,008 net acres of undeveloped land. Crew's fourth quarter 2009 production averaged 14,470 Boe/d, representing an 865% increase since Crew's inception and the Corporation owned 585,731 net acres of undeveloped land at December 31, 2009.

The business plan of Crew has been to create sustainable and profitable growth in the oil and gas industry in western Canada. To accomplish this, Crew has focused on enhancing its asset base through land acquisition and exploratory and development drilling within its core project areas in Alberta and northeast British Columbia. In addition, Crew also evaluates strategic acquisition opportunities of producing oil and natural gas properties where it views further exploration, exploitation and development opportunities exist.

To achieve sustainable and profitable growth, management of Crew believes in controlling the timing and costs of its projects wherever possible. To minimize competition within its geographic areas of interest, Crew strives to maximize its working interest ownership in its properties where reasonably possible. While Crew believes that it has the skills and resources necessary to achieve its objectives, participation in the exploration and development of oil and natural gas has a number of inherent risks. See "*Risk Factors*".

In reviewing potential drilling or acquisition opportunities, Crew gives consideration to the following criteria: (i) the at risk capital required to secure or evaluate the investment opportunity; (ii) if successful, the potential return on the project; (iii) the likelihood of success; (iv) the risked return versus cost of capital; and (v) the strategic benefits to Crew.

In general, Crew uses a portfolio approach in developing a number of opportunities with a balance of risk profiles and commodity exposure, in an attempt to generate sustainable high levels of profitable production and financial growth.

Funding for Crew's growth has come from a combination of cash flow from on-going operations, the Corporation's bank facility and equity financings undertaken from time to time as noted herein. Crew has also completed several material acquisitions since its inception as described below.

On May 13, 2004, Crew completed a bought deal private placement of 3,000,000 Common Shares at a price of $5.35 per share, for aggregate gross proceeds of approximately $16 million.

On December 2, 2004, Crew completed a bought deal private placement of 800,000 Common Shares, issued on a "flow-through" basis, at a price of $11.00 per share for aggregate gross proceeds of approximately $8.8 million.

On December 20, 2005, Crew completed a bought deal short form prospectus offering of 1,373,900 Common Shares at an issue price of $18.20 per share, and 416,700 Common Shares issued on a "flow-through" basis at an issue price of $24.00 per share, for aggregate gross proceeds of approximately $35 million.

On August 17, 2006, the Corporation completed a bought deal short form prospectus offering of 1,666,800 Common Shares at an issue price of $15.00 per share, and 759,500 Common Shares issued on a "flow-through" basis at an issue price of $19.75 per share, for aggregate gross proceeds of approximately $40 million.

On November 21, 2006 Crew completed the acquisition (the "**Gladius Acquisition**") of all of the outstanding shares of Gladius Energy Inc. ("**Gladius**"), a private oil and gas company. Gladius held certain producing oil and natural gas properties and undeveloped land primarily in Crew's Ferrier area in west central Alberta. At the time of closing of the Gladius Acquisition, the principal properties of Gladius were producing approximately 1,000 Boe/d, comprised of approximately 59% natural gas and 41% natural gas liquids and light oil. The Gladius assets also included approximately 10,730 net acres of undeveloped land. The shares of Gladius were acquired by Crew on the basis of 0.47875 of a Common Share of Crew for each share of Gladius. The former shareholders of Gladius received an aggregate of approximately 5.32 million Common Shares of Crew in exchange for all of the outstanding shares of Gladius. Following the Gladius Acquisition, the producing properties of Gladius were transferred into the Crew Energy Partnership and Gladius was amalgamated with Crew effective January 17, 2007.

On April 30, 2007, the Corporation completed a short form prospectus offering of 5,750,000 subscription receipts at an issue price of $10.30 per subscription receipt for aggregate gross proceeds of approximately $59.2 million. The gross proceeds of this offering were used to partially fund the Corporation's acquisition (the "**Enco Acquisition**") of all of the outstanding shares of ENCO Gas, Ltd. ("**Enco**"), a private oil and gas company. Each subscription receipt issued in connection with the Enco Acquisition entitled the holder thereof to receive, without payment of additional consideration or further action, one Common Share of the Corporation upon closing of the Enco Acquisition. The remainder of the purchase price for the Enco Acquisition was provided by a newly arranged credit facility.

On May 3, 2007 Crew completed the Enco Acquisition. Enco held certain producing oil and natural gas properties and undeveloped land located primarily in northeast British Columbia. At the time of closing the Enco Acquisition, the principal properties of Enco were producing approximately 3,100 boe/d, comprised of approximately 95% natural gas and 5% natural gas liquids and light oil. The Enco assets also included approximately 33,410 net acres of undeveloped land. Following the Enco Acquisition, the producing properties of Enco were transferred into the Crew Energy Partnership and Enco was amalgamated with Crew effective January 1, 2008.

On October 25, 2007, the Corporation completed a bought deal short form prospectus offering of 4,181,860 Common Shares at an issue price of $8.25 per share, and 1,860,500 Common Shares issued on a "flow-through" basis at an issue price of $10.75 per share, for aggregate gross proceeds of approximately $54.5 million.

On May 1, 2008, the Corporation completed a bought deal short form prospectus offering of 5,000,000 Common Shares at an issue price of $13.35 per share for aggregate gross proceeds of approximately $66.8 million. The gross proceeds of this offering were used to partially fund the Corporation's acquisition (the "**Montney Acquisition**") of Crown leasehold interests in approximately 102.2 net sections of undeveloped Montney formation rights located in the Corporation's core operating area in Northeast British Columbia for approximately $63 million in cash pursuant to the terms of a purchase and such agreement dated April 14, 2008. The Montney Acquisition was completed by Crew on May 12, 2008.

On August 22, 2008 Crew completed the acquisition of all of the outstanding shares of Gentry Resources Ltd. pursuant to a plan of arrangement under the ABCA (the "**Gentry Acquisition**"). Prior to completion of the Gentry Acquisition, Gentry was a reporting issuer in certain provinces of Canada and its common shares were listed for trading on the TSX under the symbol "GNY". Pursuant to the terms of the arrangement agreement dated June 23, 2008 among Crew and Gentry (the "**Gentry Acquisition Agreement**"), shareholders of Gentry received, for each outstanding share of Gentry held by them, 0.22 of a Common Share of Crew. The former shareholders of Gentry received in the aggregate approximately 12.28 million Common Shares of Crew in exchange for all of the outstanding shares of Gentry. Crew also assumed approximately $73.6 million of Gentry net debt upon closing of the Gentry Acquisition. Following completion of the Gentry Acquisition, the common shares of Gentry were delisted from trading on the TSX and Gentry ceased to be a reporting issuer.

Gentry was a junior oil and natural gas company with its principal and head office located in Calgary, Alberta and carried on the business of acquiring crude oil and natural gas properties and exploring for, developing and producing crude oil and natural gas in Alberta and Saskatchewan. At the time of closing of the Gentry Acquisition, the principal properties of Gentry were producing approximately 4,000 Boe/d, comprising approximately 50% natural gas, 45% oil and 5% natural gas liquids. The Gentry assets also included approximately 280,000 net acres of undeveloped land.

Immediately following completion of the Gentry Acquisition, Crew's $195 million revolving line of credit was increased to $270 million which, together with a $15 million operating line of credit, represented aggregate available credit facilities of $285 million. Gentry's credit facilities in the aggregate amount of $61.4 million were paid out by Crew in conjunction with the increase in Crew's credit facilities.

Following the Gentry Acquisition, the producing properties of Gentry were transferred into the Crew Energy Partnership and Gentry was amalgamated with Crew effective January 1, 2009.

Crew commenced a normal course issuer bid on October 15, 2008. The bid expired on October 14, 2009. During the course of the bid, Crew purchased an aggregate of 110,000 Common Shares at an average purchase price of $4.67 per Common Share.

On May 28, 2009, the Corporation completed a bought deal short form prospectus offering of 7,000,000 Common Shares at an issue price of $6.20 per share for aggregate gross proceeds of approximately $43.4 million.

Recent Developments

On March 10, 2010, Crew entered into an agreement (the "**Edson Disposition Agreement**") for the divestiture of a portion of its oil and natural gas assets (the "**Edson Assets**") in the Edson area of west central Alberta for gross proceeds of $126 million, subject to closing adjustments, effective January 1, 2010. Closing of the Edson Disposition is anticipated to occur on or about April 1, 2010 and is subject to customary conditions including, without limitation, customary purchaser due diligence. The Edson Assets comprise Crew's interests in 72 gross (50 net) sections, excluding the Cardium formation rights on 32 net sections. Production attributed to the Edson Assets, estimated at the time of entering into of the Edson Disposition Agreement, was approximately 1,700 Boe/d (21% liquids and 79% natural gas). Based upon the GLJ Report, effective as at December 31, 2009, the Edson Assets represent GLJ assigned proved reserves of 4.6 million Boe and proved plus probable reserves of 7.1 million Boe, respectively (19% liquids and 81% natural gas).

In conjunction with the Edson Disposition, Crew has agreed to a farmout arrangement (the "**Edson Cardium Farmout**") on standard industry terms with the purchaser (the "**Farmee**") of the Edson Assets in respect of the Cardium formation rights which were excluded from the Edson Disposition and retained by Crew. Under the terms of the Edson Cardium Farmout, the Farmee: (i) commits to drill and complete two horizontal Cardium wells to earn a 50% interest in eight sections of Cardium mineral rights; (ii) has the right to drill additional wells, on a rolling option basis, to earn a 50% interest in four sections of Cardium mineral rights for every option well drilled; and (iii) has until December 31, 2011 to drill up to 9 earning wells. The Edson Cardium Farmout is contingent upon completion of the Edson Disposition.

Subject to completion of the Edson Disposition as presently contemplated, Crew's oil and gas properties on a post Edson Disposition basis represent assigned reserves, as evaluated by GLJ effective December 31, 2009, of 35,062 Mboe of proved reserves and 58,597 Mboe of proved plus probable reserves, respectively. The net present value of the future net revenue from proved plus probable reserves, before income taxes, from Crew's oil and gas properties on a post Edson Disposition basis, as evaluated by GLJ effective December 31, 2009, was $889.4 million and $712.9 million at 10% and 15% discount rates, respectively, based on GLJ's forecast pricing at December 31, 2009.

The proceeds from the Edson Disposition will be used by Crew to initially reduce outstanding indebtedness under its credit facilities which will be redrawn and applied as may be required to fund Crew's expanded 2010 capital expenditure program. Subject to completion of the Edson Disposition, the Corporation has expanded its 2010 capital expenditure budget to $175 million.

Significant Acquisitions

There were no significant acquisitions completed by Crew during its most recently completed financial year for which disclosure is required under Part 8 of National Instrument 51-102.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

The statement of reserves data and other oil and gas information set forth below (the "**Statement**") is dated March 29, 2010. The effective date of the Statement is December 31, 2009 and the preparation date of the Statement was February 25, 2010.

Disclosure of Reserves Data

The reserves data set forth below (the "**Reserves Data**") is based upon an evaluation by GLJ with an effective date of December 31, 2009 and is contained in the GLJ Report. The Reserves Data summarizes the crude oil, natural gas liquids, natural gas and coal bed methane reserves of the Corporation and the net present values of future net revenue for these reserves using forecast prices and costs prior to the provision for interest, general and administrative expenses, the impact of hedging activities, certain well abandonment costs and all reclamation costs, which were not deducted by GLJ in estimating future net revenue. The GLJ Report has been prepared in accordance with the standards contained in the COGE Handbook and the reserves definitions contained in NI 51-101. Additional information not required by NI 51-101 has been presented to provide continuity and additional information which we believe is important to the readers of this information. The Corporation engaged GLJ to provide an evaluation of proved and proved plus probable reserves and no attempt was made to evaluate possible reserves.

The Reserves Data includes the reserves attributed to Crew's Edson Assets which are subject to the Edson Disposition. See "*Recent Developments*".

All of the Corporation's reserves are in Canada and, specifically, in the provinces of Alberta and British Columbia.

The Report of Management and Directors on Oil and Gas Disclosure and the Report on Reserves Data by the Independent Qualified Reserves Evaluator are attached at Appendices A and B hereto, respectively.

Disclosure provided herein in respect of BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

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 cost assumptions will be attained and variances could be material. The recovery and reserves estimates of the Corporation's 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 liquids reserves may be greater than or less than the estimates provided herein.

Reserves Data (Forecast Prices and Costs)

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

FORECAST PRICES AND COSTS

RESERVES SUMMARY

RESERVES CATEGORY	LIGHT AND MEDIUM OIL Gross (Mbbl)	LIGHT AND MEDIUM OIL Net (Mbbl)	HEAVY OIL Gross (Mbbl)	HEAVY OIL Net (Mbbl)	NATURAL GAS LIQUIDS Gross (Mbbl)	NATURAL GAS LIQUIDS Net (Mbbl)	CONVENTIONAL NATURAL GAS Gross (Mmcf)	CONVENTIONAL NATURAL GAS Net (Mmcf)	COAL BED METHANE Gross (Mmcf)	COAL BED METHANE Net (Mmcf)	TOTAL OIL EQUIVALENT Gross (Mboe)	TOTAL OIL EQUIVALENT Net (Mboe)
PROVED												
Developed Producing	3,702	2.895	357	286	2,464	1,764	86,533	70,622	963	946	21,106	16,873
Developed Non-Producing	258	200	4	4	349	256	17,793	14,019	541	514	3,667	2,882
Undeveloped	2,644	2,093	0	0	1,394	1,119	57,320	43,749	7,474	6,537	14,837	11,594
TOTAL PROVED	6,605	5,189	360	289	4,207	3,139	161,647	128,391	8,978	7,998	39,609	31,349
TOTAL PROBABLE	8,131	6,229	127	102	2,434	1,830	85,627	67,182	6,460	5,681	26,039	20,305
TOTAL PROVED PLUS PROBABLE	14,736	11,418	487	391	6,640	4,969	247,273	195,573	15,438	13,679	65,649	51,653

NET PRESENT VALUES OF FUTURE NET REVENUE

RESERVES CATEGORY	BEFORE INCOME TAXES DISCOUNTED AT (%/year) 0% (M$)	5% (M$)	10% (M$)	15% (M$)	20% (M$)	AFTER INCOME TAXES DISCOUNTED AT (%/year) 0% (M$)	5% (M$)	10% (M$)	15% (M$)	20% (M$)
PROVED										
Developed Producing	584,390	469,373	396,421	345,916	308,730	560,075	454,564	386,879	339,494	304,257
Developed Non-Producing	86,721	70,540	58,774	49,947	43,151	65,037	53,516	45,177	38,926	34,102
Undeveloped	355,899	244,932	179,576	137,131	107,728	267,645	180,444	129,443	96,523	73,878
TOTAL PROVED	1,027,010	784,845	634,772	532,995	459,609	892,757	688,524	561,499	474,943	412,237
TOTAL PROBABLE	893,375	536,165	364,465	267,473	206,449	669,306	399,410	269,569	196,249	150,191
TOTAL PROVED PLUS PROBABLE	1,920,386	1,321,010	999,236	800,468	666,058	1,562,063	1,087,934	831,067	671,192	562,428

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

RESERVES CATEGORY	REVENUE (M$)	ROYALTIES (M$)	OPERATING COSTS (M$)	DEVELOPMENT COSTS (M$)	ABANDONMENT AND RECLAMATION COSTS (M$)	FUTURE NET REVENUE BEFORE INCOME TAXES (M$)	INCOME TAXES (M$)	FUTURE NET REVENUE AFTER INCOME TAXES (M$)
Total Proved	2,157,100	412,355	524,550	173,999	19,186	1,027,010	134,253	892,757
Total Proved Plus Probable	3,924,544	788,435	935,206	255,339	25,178	1,920,386	358,323	1,562,063

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

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES[(3)] (discounted at 10%/year) (M$)	UNIT VALUE BEFORE INCOME TAXES[(4)] (discounted at 10%/year) (Units as noted)
Proved Producing	Light and Medium Crude Oil [(1)]	126,104	$31.47 per boe
	Heavy Oil[(1)]	294	$21.31 per boe
	Natural Gas [(2)]	267,351	$3.51 per mcfe
	Coal Bed Methane	2,672	$2.82 per mcf
Total Proved	Light and Medium Crude Oil [(1)]	183,139	$28.82 per boe
	Heavy Oil[(1)]	315	$16.05 per boe
	Natural Gas [(2)]	439,931	$3.10 per mcfe
	Coal Bed Methane	11,387	$1.42 per mcf
Total Proved Plus Probable	Light and Medium Crude Oil [(1)]	352,365	$26.57 per boe
	Heavy Oil[(1)]	380	$14.05 per boe
	Natural Gas [(2)]	626,777	$2.89 per mcfe
	Coal Bed Methane	19,714	$1.44 per mcf

Notes:
(1) Including solution gas and other by-products.
(2) Including by-products but excluding solution gas.
(3) Other company revenue and costs not related to specific production group have been allocated proportionately to production groups.
(4) Unit values are based on Net reserves.

Notes to Reserves Data Tables:

1. Columns may not add due to rounding.

2. The crude oil, natural gas liquids, natural gas and non-conventional natural gas reserves estimates presented in the GLJ Report are based on the definitions and guidelines contained in the COGE Handbook. A summary of those definitions are set forth below.

Reserves Categories

Reserves are estimated remaining quantities of crude oil, natural gas, non-conventional 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 (see the discussion of "Economic Assumptions" below) which are generally accepted as reasonable and shall be disclosed.

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 certainly.

(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 reserve estimates are prepared). Reported reserves should target the following levels of certainty under a specific set of economic conditions:

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

(b) at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves.

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

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

3. Forecast Prices and Costs

GLJ has prepared its January 1, 2010, price and market forecasts as summarized in the tables below after a comprehensive review of information. Information sources include numerous government agencies, industry publications, Canadian oil refiners and natural gas marketers. The forecasts presented herein are based on an informed interpretation of currently available data. While these forecasts are considered reasonable at this time, users of these forecasts should understand the inherent high uncertainty in forecasting any commodity or market.

These forecasts will be revised periodically as market, economic and political conditions change. These future revisions may be significant.

The forecast cost and price assumptions assume increases in wellhead selling prices and take into account inflation with respect to future operating and capital costs. Crude oil and natural gas benchmark reference pricing, as at January 1, 2010, inflation and exchange rates utilized by GLJ in the GLJ Report were as follows:

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
AS OF JANUARY 1, 2010
FORECAST PRICES AND COSTS

	OIL			ALBERTA NGLS			NATURAL GAS			
Year	WTI Cushing @ Oklahoma ($US/bbl)	LIGHT, SWEET OIL @ Edmonton (40 API, 0.3% S) ($Cdn/bbl)	MEDIUM CRUDE OIL @ Cromer (29 API, 2.0% S) ($Cdn/bbl)	EDMONTON PROPANE ($Cdn/bbl)	EDMONTON BUTANE ($Cdn/bbl)	EDMONTON PENTANES PLUS ($Cdn/bbl)	NATURAL GAS AECO/NIT Spot Gas Price ($Cdn/MmBtu)	NATURAL GAS Westcoast Station 2 Spot Gas Price ($Cdn/MmBtu)	INFLATION RATES[1] %/Year	EXCHANGE RATE[2] ($US/$Cdn)
Forecast										
2010	80.00	83.25	76.60	52.46	64.11	84.93	5.96	5.76	2.0%	0.95
2011	83.00	86.42	78.64	54.45	66.54	88.15	6.79	6.59	2.0%	0.95
2012	86.00	89.58	80.62	56.43	68.98	91.37	6.89	6.69	2.0%	0.95
2013	89.00	92.74	82.54	58.42	71.41	94.59	6.95	6.75	2.0%	0.95
2014	92.00	95.90	85.35	60.42	73.84	97.82	7.05	6.85	2.0%	0.95
2015	93.84	97.84	87.07	61.64	75.33	99.79	7.16	6.96	2.0%	0.95
2016	95.72	99.81	88.83	62.88	76.85	101.81	7.42	7.22	2.0%	0.95
2017	97.64	101.83	90.63	64.15	78.41	103.86	7.95	7.75	2.0%	0.95
2018	99.59	103.88	92.46	65.45	79.99	105.96	8.52	8.32	2.0%	0.95
2019	101.58	105.98	94.32	66.77	81.60	108.10	8.69	8.49	2.0%	0.95
2020	103.61	108.10	96.21	68.11	83.23	110.62	8.86	8.66	2.0%	0.95
Thereafter	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	0.95

Notes:

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

Weighted average historical prices realized by the Corporation for the year ended December 31, 2009, were $4.27/mcf for natural gas, $59.39/bbl for crude oil and $36.28/bbl for natural gas liquids.

4. Well abandonment costs for wells with reserves have been included at the property level. Additional abandonment costs associated with non-reserves wells, lease reclamation costs and facility abandonment and reclamation expenses have not been included in this analysis.

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

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

7. On March 11, 2010 the Alberta government announced changes to Alberta's royalty system intended to increase Alberta's competitiveness in the oil and natural gas industry, which included a decrease in the maximum royalty rates for conventional oil and natural gas production effective for the January 2011 production month and certain temporary incentive programs currently in place being made permanent. See "*Industry Conditions*". Further details with respect to the changes to Alberta's royalty system are expected to be provided in the coming months. Reserves and net present values reflected in the above tables do not reflect the potential effect of these new changes to Alberta's royalty system and no sensitivities were provided by GLJ as to the potential impact of same.

Reconciliation of Changes in Reserves

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

	LIGHT AND MEDIUM OIL			HEAVY OIL			NATURAL GAS LIQUIDS		
FACTORS	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)
December 31, 2008	4,779	3,243	8,022	797	263	1,060	4,003	2,518	6,521
Discoveries	0	0	0	0	0	0	0	0	0
Extensions and Improved Recovery	2,236	4,987	7,223	121	(121)	0	678	186	863
Infill Drilling	433	118	551	0	0	0	307	97	404
Technical Revisions	1,104	(40)	1,064	(416)	(4)	(420)	216	(35)	181
Acquisitions	0	0	0	0	0	0	0	0	0
Dispositions	(750)	(164)	(914)	(20)	(9)	(29)	(502)	(322)	(825)
Economic Factors	20	(12)	8	7	(2)	5	(3)	(9)	(12)
Production	(1,217)	0	(1,217)	(129)	0	(129)	(492)	0	(492)
December 31, 2009	6,605	8,131	14,736	360	127	487	4,207	2,434	6,640

	CONVENTIONAL NATURAL GAS			COAL BED METHANE			OIL EQUIVALENT		
FACTORS	Proved (Mmcf)	Probable (Mmcf)	Proved Plus Probable (Mmcf)	Proved (Mmcf)	Probable (Mmcf)	Proved Plus Probable (Mmcf)	Proved (Mboe)	Probable (Mboe)	Proved Plus Probable (Mboe)
December 31, 2008	148,170	95,148	243,318	8,669	7,344	16,014	35,719	23,106	58,825
Discoveries	0	0	0	0	0	0	0	0	0
Extensions and Improved Recovery	29,021	8,197	37,218	685	(685)	0	7,986	6,302	14,288
Infill Drilling	11,400	(2,324)	9,076	14	(14)	0	2,643	(176)	2,467
Technical Revisions	1,166	(9,929)	(8,762)	(180)	(174)	(354)	1,068	(1,761)	(693)
Acquisitions	0	0	0	0	0	0	0	0	0
Dispositions	(8,492)	(5,216)	(13,707)	0	0	0	(2,688)	(1,365)	(4,053)
Economic Factors	(347)	(250)	(597)	(10)	(11)	(21)	(36)	(66)	(102)
Production	(19,271)	0	(19,271)	(201)	0	(201)	(5,083)	0	(5,083)
December 31, 2009	161,647	85,627	247,273	8,978	6,460	15,348	39,609	26,040	65,649

Note:

(1) Gross Reserves in the tables above are the Corporation's interest share before deduction of royalties and without including any royalty interests of the Corporation.

Additional Information Relating to Reserves Data

Undeveloped Reserves

The following tables set forth the proved undeveloped reserves and the probable undeveloped reserves, each by product type, attributed to Crew's assets for the years ended December 31, 2009, 2008 and 2007 and, in the aggregate, before that time based on forecast prices and costs. These reserves are included in the "Summary of Oil and Gas Reserves" table on page 4.

Proved Undeveloped Reserves

Year	Light and Medium Oil (Mbbl)		Heavy Oil (Mbbl)		Conventional Natural Gas (Mmcf)		Coal Bed Methane (Mmcf)		NGLs (Mbbl)	
	First Attributed	Booked at Year End	First Attributed	Booked at Year End	First Attributed	Booked at Year End	First Attributed	Booked at Year End	First Attributed	Booked at Year End
Prior thereto	90	90	0	0	1,988	1,988	4,236	4,236	53	53
2007	0	0	0	0	1,796	2,595	2,537	5,899	58	78
2008	1,278	1,278	120	120	24,800	25,870	1,111	6,490	517	585
2009	2,097	2,644	0	0	40,943	57,320	686	7,474	963	1,394

Probable Undeveloped Reserves

Year	Light and Medium Oil (Mbbl)		Heavy Oil (Mbbl)		Conventional Natural Gas (Mmcf)		Coal Bed Methane (Mmcf)		NGLs (Mbbl)	
	First Attributed	Booked at Year End	First Attributed	Booked at Year End	First Attributed	Booked at Year End	First Attributed	Booked at Year End	First Attributed	Booked at Year End
Prior thereto	134	134	0	0	5,767	5,767	8,806	8,806	258	258
2007	0	25	0	0	4,857	8,649	1,246	7,319	118	279
2008	2,108	2,133	30	30	40,127	47,006	1,726	6,710	848	1,238
2009	5,427	6,451	0	0	32,985	48,749	0	6,035	819	1,377

Proved and probable undeveloped reserves have been estimated in accordance with procedures and standards contained in the COGE Handbook. The majority of undeveloped reserves are scheduled to be developed within the next three years.

A number of factors that could result in delayed or cancelled development of the Corporation's undeveloped reserves are as follows:

- changing economic conditions (due to pricing, royalty structure, operating and capital expenditure fluctuations);
- changing technical conditions (production anomalies (such as accelerated depletion));
- multi-zone developments (such as a prospective formation completion may be delayed until the initial completion is no longer economic);
- a larger development program may need to be spread out over several years to optimize capital allocation and facility utilization; and
- surface access issues (landowners, weather conditions, regulatory approvals).

Significant Factors or Uncertainties

The process of evaluating reserves is inherently complex. It requires significant judgments and decisions based on available geological, geophysical, engineering and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change. The reserve estimates contained herein are based on current production forecasts, prices and economic conditions and other factors and assumptions that may affect the reserve estimates and the present worth of the future net revenue therefrom. These factors and assumptions include, among others: (i) historical production in the area compared with production rates from analogous producing areas; (ii) initial production rates; (iii) production decline rates; (iv) ultimate recovery of reserves; (v) success of future development activities; (vi) marketability of production; (vii) effects of government regulations; and (viii) other government levies imposed over the life of the reserves.

As circumstances change and additional data becomes available, reserve estimates also change. Estimates are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, prices, economic conditions and government restrictions. Revisions to reserve estimates can arise from changes in year end prices, reservoir performance and geologic conditions or production. These revisions can be either positive or negative.

The Corporation does not anticipate any significant economic factors or significant uncertainties that may affect any particular components of the reserves data. However, the reserves can be affected significantly by fluctuations in product pricing, capital expenditures, operating costs, royalty regimes and well performance that are beyond the Corporation's control (see "*Risk Factors*").

Future Development Costs

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

	Forecast Prices and Costs	
Year	**Proved Reserves (M$)**	**Proved Plus Probable Reserves (M$)**
2010	59,370	71,645
2011	54,053	85,964
2012	42,704	60,619
2013	12,405	29,318
2014	2,127	3,419
Thereafter	3,340	4,374
Total Undiscounted	173,999	255,339

The Corporation currently expects that the capital listed in the preceding table will be funded through internally generated cash flows and will not have any associated funding costs. We do not expect that the costs of funding, if any, will have an effect on the disclosed reserves or future net revenue.

Other Oil and Gas Information

Principal Properties

The following is a description of Crew's important oil and natural gas properties as at December 31, 2009. Production stated is production before deduction of royalties and includes royalty interests to Crew and, unless otherwise stated, is average production for 2009. Reserves amounts are total proved plus probable reserves based on forecast prices and costs, stated before deduction of royalties and include royalty interests as at December 31, 2009 based on forecast prices and costs as evaluated in the GLJ Report (see "*Reserves Data*"). **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.** Unless otherwise specified, gross and net acres and well count information are as at December 31, 2009.

Overview

Crew's operations are divided into two core areas, the 'North Core' which includes all operations in northeast British Columbia and northwest Alberta, and the 'Plains Core' which includes all operations in central and southern Alberta. These core areas include six main operating areas: Princess, Killam, Pine Creek and Edson in Alberta and Septimus and Sierra in northeast British Columbia.

Crew will continue the development of its main operating areas in 2010. The Corporation has currently budgeted approximately $175 million towards the continued growth and development of these core areas. This development will be the foundation upon which the Corporation will continue to grow its base production and will include the drilling of an estimated 56 development wells in 2010.

In 2010, Crew plans to drill approximately nine exploration wells on the Corporation's undeveloped lands. These wells will expose the Corporation to opportunities that have the potential to significantly increase natural gas and light oil reserves and production. Currently the Corporation plans to direct between $15 to $18 million of its 2010 drilling program toward these opportunities.

PLAINS CORE

Princess, Alberta

The Princess area comprises 442 contiguous sections of Crew controlled freehold and crown land directly south of Brooks, Alberta. The area lies in a unique geographic position in Alberta where the structural effects of the Sweetgrass Arch and the regional dip of the Western Canadian Sedimentary basin intersect to form an area where the subsurface structure is essentially flat. Numerous northwest trending Mannville channels have eroded the Mississippian Pekisko formation forming hydrocarbon traps on the subcrop edge (Tilley and West Tide Lake) and in elongated outliers (Alderson). These outliers can be two to three miles wide and up to 12 miles long. Crew has three dimensional seismic control over the block and has in excess of 500 drilling locations identified. In 2009, production from this area averaged 4.5 Mmcf/d of natural gas and 2,861 bbl/d of oil and ngls. At December 31, 2009 the Corporation owned 7 (5.0 net) producing gas wells, 111 (110.6 net) producing oil wells and 14 (14 net) service wells in the area along with three 100% owned oil batteries. In 2009, Crew drilled twenty-six (26.0 net) wells in this area resulting in twenty-two (22.0 net) oil wells, three (3.0 net) service wells and one (1.0 net) dry and abandoned well.

As at December 31, 2009, the GLJ Report showed the Princess area to have reserves of 13,072 Mbbl of oil and ngls and 12,379 Mmcf of natural gas. At year end, the Corporation owned 245,632 net acres of land with an average working interest of 92% in the area.

Crew plans to drill 50 horizontal wells in 2010 in the Princess area where 470 locations have been identified.

Killam, Alberta

Killam is located in central Alberta, approximately 120 kilometers southeast of Edmonton. At December 31, 2009, the Corporation had 44 (21.7 net) producing gas wells and 8 (7.6 net) producing oil wells in the area and in 2009 produced an average of 183 bbl/d of oil and ngls along with 2.8 Mmcf/d of natural gas. This area's production is natural gas and oil production mainly from the Cretaceous formations. Production is gathered and shipped to third party facilities.

Crew drilled four (4.0 net) wells in the Killam area in 2009 resulting in 4 (4.0 net) cased oil wells.

As at December 31, 2009 the GLJ Report showed Killam to have total reserves of 823 Mbbl of oil and ngls and 5,550 Mmcf of natural gas. At year-end, the Corporation owned 38,533 net acres of land with an average working interest of 63% in this area.

Pine Creek, Alberta

The Pine Creek area is in west central Alberta, approximately 200 kilometers west of Edmonton. Production from this area is mainly characterized by high heat content natural gas with associated natural gas liquids produced from several Cretaceous and Jurassic sandstone formations. At December 31, 2009 the Corporation had 6 (6.0 net) producing gas wells and 1 (1.0 net) producing oil well in the area. Production averaged 80 bbl/d of oil and ngls along with 1.7 Mmcf/d of natural gas in 2009. Crew owns a compression and dehydration facility at Pine Creek where all of the production goes through.

As at December 31, 2009, the GLJ Report showed the Pine Creek area to have reserves of 331 Mbbl of oil and ngls and 7,426 Mmcf of natural gas. At year end, the Corporation owned 22,682 net acres of land with an average working interest of 90% in the area.

Crew lands in the Pine Creek area include 27 net sections of land that have been identified as prospective for the Cardium resource play. Crew plans to drill two to three Cardium horizontal wells in 2010 in the Pine Creek area where 80 locations have been identified.

Edson, Alberta

The Edson area is in west central Alberta, approximately 160 kilometers west of Edmonton. Production from this area is mainly characterized by high heat content natural gas with associated natural gas liquids produced from several Cretaceous and Jurassic sandstone formations. At December 31, 2009 the Corporation had 41 (35.2 net) producing gas wells and 2 (2.0 net) producing oil wells in the area. Production averaged 367 bbl/d of oil and ngls along with 8.5 Mmcf/d of natural gas in 2009. Crew owns facilities at Edson where a significant amount of the area's gas production is gathered into these 100% owned facilities. Crew also has a 15% interest in a 90 Mmcf/d sour gas processing facility in the area.

As at December 31, 2009, the GLJ Report showed the greater Edson area to have reserves of 1,369 Mbbl of oil and ngls and 34,438 Mmcf of natural gas. At year end, the Corporation owned 32,074 net acres of land with an average working interest of 70% in the area.

On March 10, 2010, Crew announced that it had entered into an agreement for the sale of the Edson area assets (excluding Cardium formation rights) for $126 million. Closing of the Edson Disposition is expected on or about April 1, 2010. Crew also entered into a farm-out arrangement with respect to the Cardium rights on the same lands. Under the arrangement, the purchaser commits to drill and complete two horizontal Cardium wells to earn a 50% interest in eight sections of Cardium mineral rights. The purchaser has the right to drill additional wells on a rolling option basis, to earn a 50% interest in four sections of Cardium mineral rights for every option well drilled. The purchaser will have until December 31, 2011 to drill up to nine earning wells. See "*Description and General Development of the Business – Recent Developments*".

NORTH CORE

Septimus, British Columbia

The Septimus area is located 15 kilometers south of Fort St. John, British Columbia. At December 31, 2009 the Corporation had an interest in 9 (8.7 net) producing gas wells in this area. Production averaged 313 bbl/d of oil and ngls along with 6.0 Mmcf/d of natural gas in 2009. The Corporation's operations at Septimus include natural gas production from the Montney formation. The Corporation drilled a total of four (3.2 net) wells in the Septimus area in 2009.

Crew constructed a 25 mmcf per day Septimus gas plant which became operational on October 1, 2009 allowing the Company to increase production volumes. In December, Crew completed the sale of the Septimus gas processing facility to a third party for the as built cost of approximately $19 million. Under the sale arrangement, Crew operates the facility and retained an option to expand the facility to 50 mmcf per day and equalize into a 50% ownership position. The third party recently announced regulatory approval of a 20 inch pipeline connecting the

Septimus gas plant to the Alliance pipeline. Construction of the pipeline is currently underway and will facilitate a significant (350 mmcf per day) increase in takeaway capacity from the greater Septimus area.

As at December 31, 2009, the GLJ Report showed Crew's Septimus area to have total Proved plus Probable reserves of 3,145 Mbbl of oil and ngls along with 110,840 Mmcf of natural gas. At year end, the Corporation owned 24,764 net acres of land with an average working interest of 79% in this area.

Current plans for 2010 are to drill ten wells targeting the Montney formation and expansion of the Septimus gas processing facility to a capacity of 50 mmcf per day including Crew's equalization to a 50% owner in the facility.

Crew engaged GLJ to prepare a best estimate of the Discovered Petroleum Initially in Place ("**DPIIP**"), as such term is defined in the COGE Handbook, on 56 net sections of Crew's Montney lands at Septimus in the Inga area. Unless noted otherwise, the DPIIP estimates and reserve information in this section are presented on a company interest basis.

Based on the independent evaluation by GLJ effective as at December 31, 2009, the best estimate of DPIIP for 56 net sections of Montney rights owned in Crew's Septimus area is 2.7 Tcf net to Crew, of which 0.91 Tcf is on 13 net sections to which reserves have been assigned. In the GLJ Report, GLJ have assigned proved plus probable non-associated gas reserves of 110.8 bcf to the 13 net sections in the Septimus area, which includes 68.5 bcf of proved reserves.

GLJ has assigned a best estimate of 1.8 Tcf of DPIIP (of the 2.7 Tcf in total DPIIP) on the balance of the 43 net evaluated sections of Crew's lands at Septimus that do not currently have any reserves assigned in the GLJ Report and there are additional Crew interest lands adjacent to these lands that have not yet been independently evaluated. Additional drilling will be required to explore and delineate these properties before it will be possible to define the timing of potential development projects. GLJ has provided a best estimate of the DPIIP for the upper Montney on only 56 out of 215 Crew controlled net sections or 26% of Crew's Montney land base at Septimus.

It should be noted that, given the current early stage of development, the best estimate of DPIIP might change significantly in the future with further development activity and the amount of Contingent Resources as defined in the COGE Handbook has yet to be estimated. Crew is in the early stages of development of this Montney asset. Additional drilling and testing is required to confirm deliverability potential and commercial economic development. The resource estimates provided herein are estimates only and the actual resources may be greater than or less than the estimates provided herein. A recovery project has not been defined for the volumes of DPIIP which are not classified as reserves. At this time, there is no certainty that it will be technically feasible or commercially viable to produce any portion of these resources. See "*Risk Factors – Resource Estimates*".

Sierra, British Columbia

The greater Sierra area includes Crew's operations situated near Fort Nelson, British Columbia. At December 31, 2009, the Corporation had an interest in 11 (6.9 net) producing gas wells in this area. In 2009, Crew produced an average of 6.4 Mmcf/d of natural gas from the Sierra area. Natural gas production from this area comes predominantly from a Pine Point natural gas well. Production from this well is tied into a Crew owned compression facility that compresses the gas for delivery to the Fort Nelson natural gas processing facility.

Crew lands in the Sierra area include 15 net sections of land that have been identified as prospective for the Horn River Basin's Muskwa Shale natural gas resource play. The Muskwa Shale is approximately 500 feet thick and appears to be prospective over a large area in a relatively homogeneous geologic environment. Crew does not have any drilling plans for the Muskwa Shales in 2010. The Corporation continues to monitor the evolution of this prospect and gain knowledge that will aid in the future development of Crew's lands.

As at December 31, 2009, the GLJ Report showed Sierra to have total reserves of 19,688 Mmcf of natural gas. At year end, the Corporation owned 22,055 net acres of land with an average working interest of 57% in this area.

Oil and Gas Wells

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

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	158	136.6	246	198.8	266	173.6	114	80.9
British Columbia	12	6.3	6	3.8	96	50.7	74	46.6
Saskatchewan	6	1.8	20	6.1	-	-	3	2.3
Total	176	144.7	272	208.7	362	224.3	191	129.8

Land Holdings Including Properties With No Attributed Reserves

The following table sets out the Corporation's developed and undeveloped land holdings as at December 31, 2009.

	Developed Acres		Undeveloped Acres	
	Gross	Net	Gross	Net
Alberta	360,777	201,749	455,582	384,575
British Columbia	110,756	49,389	222,757	163,372
Other Canada	1,448	406	377,321	37,785
Total	472,981	251,544	1,055,660	585,732

The Corporation has a commitment to drill two wells in northeastern British Columbia in 2010. The Corporation estimates that the total cost for this commitment is $6.0 million. Of the Corporation's undeveloped land, the rights to explore, develop and exploit 84,499 net acres may expire by December 31, 2010 if the Corporation takes no action to retain the land. Crew plans to drill or submit applications to continue selected portions of this acreage.

Forward Contracts and Marketing

With the exception of the following financial derivative contracts entered into pursuant to the Corporation's risk management program, as of December 31, 2009, Crew does not have any material commitments to buy or sell natural gas or crude oil production.

Subject of Contract	Notional Quantity	Term	Reference	Strike Price	Option Traded
Natural Gas	2,500 gj/day	November 1, 2009 – December 31, 2010	AECO C Monthly Index	$6.00	Swap
Natural Gas	5,000 gj/day	January 1, 2010 – December 31, 2010	AECO C Monthly Index	$8.00	Call
Natural Gas	10,000 gj/day	January 1, 2010 – December 31, 2010	AECO C Monthly Index	$7.75	Call
Natural Gas	2,500 gj/day	January 1, 2010 – December 31, 2010	AECO C Monthly Index	$6.20	Swap
Natural Gas	5,000 gj/day	January 1, 2010 – December 31, 2010	AECO C Monthly Index	$6.08	Swap
Natural Gas	2,500 gj/day	January 1, 2010 – December 31, 2010	AECO C Monthly Index	$5.25	Swap
Natural Gas	2,500 gj/day	January 1, 2010 – December 31, 2010	AECO C Monthly Index	$5.55	Swap
Natural Gas	5,000 mmbtu/day	January 1, 2010 – December 31, 2010	AECO/NYMEX Basis diff	US$($0.55)	Swap
Oil	250 bbl/day	January 1, 2010 – December 31, 2010	CDN$ WTI	$78.50	Swap
Oil	500 bbl/day	January 1, 2010 – December 31, 2010	CDN$ WTI	$72.00 - $88.00	Collar
Oil	250 bbl/day	January 1, 2010 – December 31, 2010	CDN$ WTI	$82.50	Swap
Oil	500 bbl/day	January 1, 2010 – December 31, 2010	CDN$ WTI	$80.50	Swap
Oil	500 bbl/day	January 1, 2010 – December 31, 2010	US$ WTI	US$81.00	Swap
Oil	250 bbl/day	January 1, 2010 – December 31, 2010	CDN$ WTI	$80.00 - $95.02	Collar

Additional Information Concerning Abandonment and Reclamation Costs

The total net cost to abandon and reclaim Crew's assets was estimated by management and was based on Crew's net ownership interest, the estimated future cost to abandon and reclaim the Corporation's wells and facilities, the estimated future value of salvaged equipment and the estimated timing of when the costs and recoveries will be incurred. As at December 31, 2009, management expected to incur abandonment and reclamation costs on 708 net wells. The total of such costs, net of estimated salvage value, was $26.0 million ($13.3 million discounted at 10%).

Future net revenues in the GLJ Report include abandonment liabilities only for wells assigned reserves and no salvage values. Reclamation costs of $35.7 million ($12.9 million discounted at 10%) and salvage values of $38.0 million ($9.0 million discounted at 10%) are not considered in future net revenue in the GLJ Report. Within the next three financial years, it is estimated that abandonment and reclamation costs will total approximately $2.2 million ($1.7 million discounted at 10%).

Tax Horizon

The Corporation was not required to pay any cash income taxes for the period ended December 31, 2009. Based on current estimates of the Corporation's future taxable income and levels of tax deductible expenditures, management believes that the Corporation will not be required to pay cash income taxes in 2010 and does not anticipate being in a cash income tax payable situation through 2011 and beyond at the currently anticipated rate of capital expenditures and forecasted commodity prices.

Capital Expenditures

The following tables summarize capital expenditures (net of incentives and net of disposition proceeds and including capitalized general and administrative expenses) related to the Corporation's activities for the year ended December 31, 2009:

	($ thousands)
Property acquisition (disposition) costs	
Proved properties	(74,837)
Undeveloped properties	6,644
Exploration costs	16,341
Development costs	101,726
Total	49,874

Exploration and Development Activities

The following table sets forth the gross and net exploratory and development wells in which the Corporation participated in drilling during the year ended December 31, 2009.

	Gross			**Net**		
	Exploration	**Development**	**Total**	**Exploration**	**Development**	**Total**
Crude Oil	15	11	26	15.0	11.0	26.0
Natural Gas	2	10	12	1.3	4.7	6.0
Dry[(1)]	-	2	2	-	1.1	1.1
Service[(2)]	-	3	3	-	3.0	3.0
Total:	17	26	43	16.3	19.8	36.1

Notes:

(1) "Dry well" means a well which is not a productive well or a service well. A productive well is a well which is capable of producing oil and gas in commercial quantities or in quantities considered by the operator to be sufficient to justify the costs required to complete, equip and produce the well.

(2) A service well means a well such as a water or gas-injection, water-source or water-disposal well. Such wells do not have marketable reserves of crude oil or natural gas attributed to them but are essential to the production of the crude oil and natural gas reserves.

The Corporation intends to continue to develop its principal properties in central Alberta and northeastern British Columbia. The Corporation is currently budgeting for a $175 million exploration and development expenditure program in 2010, which is currently planned to be financed through cash flow from operations and non-core asset dispositions. See "*Principal Properties*" for a description of the Corporation's exploration and development plans.

Production Estimates

The following table sets out the volume of the Corporation's average estimated daily production for the year ended December 31, 2010 as estimated in the GLJ Report which is reflected in the estimate of gross proved reserves and gross probable reserves disclosed in the tables contained under "*Disclosure of Reserves Data*".

	LIGHT AND MEDIUM OIL		HEAVY OIL		NATURAL GAS LIQUIDS		NATURAL GAS(2)		TOTAL OIL EQUIVALENT	
RESERVES CATEGORY	**Gross (bbl/d)**	**Net (bbl/d)**	**Gross (bbl/d)**	**Net (bbl/d)**	**Gross (bbl/d)**	**Net (bbl/d)**	**Gross (Mcf/d)**	**Net (Mcf/d)**	**Gross (Boe/d)**	**Net (Boe/d)**
Total Proved										
Princess	3,103	2,171	258	200	34	22	5,164	3,369	4,255	2,954
Septimus	62	61	0	0	424	372	19,125	15,976	3,674	3,096
Other Properties	666	578	11	11	916	649	35,680	29,235	7,721	6,112
	3,832	2,810	269	211	1,374	1,044	59,969	48,580	15,470	12,162
Total Proved Plus Probable										
Princess	3,705	2,565	264	204	37	24	5,524	3,594	4,927	3,392
Septimus	66	65	0	0	450	394	20,284	16,898	3,897	3,275
Other Properties	1,103	607	12	12	951	675	36,951	30,276	7,824	6,340
	4,474	3,237	276	216	1,438	1,093	62,759	50,768	16,648	13,007

Notes:

(1) The Corporation's Septimus and Princess fields are the only properties that have greater than 20% or more of the Corporation's estimated 2010 production in the December 31, 2009 GLJ Report.

(2) Estimated 2010 average daily natural gas production includes coal bed methane production of 1% or less in each reserve category.

(3) Includes production attributed to Crew's oil and gas properties which are subject to the Edson Disposition. See "*Recent Developments*".

Production History

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

	Quarter Ended 2009			
	Dec. 31	**Sept. 30**	**June 30**	**Mar. 31**
Average Daily Production(1)				
Light and Medium Crude Oil (bbl/d)	4,159	3,135	2,838	3,356
Heavy Oil (bbl/d)	255	241	416	358
Natural Gas (Mcf/d)(3)	51,871	49,478	54,036	59,539
NGLs (bbl/d)	1,412	1,443	1,206	1,385
Combined (BOE/d)	14,470	13,065	13,466	15,022
Average Price Received				
Light and Medium Crude Oil ($/bbl) (4)	68.22	64.03	60.94	43.15
Heavy Oil ($/bbl)	67.04	62.39	59.46	45.04
Natural Gas ($/Mcf)(3) (4)	4.98	3.23	3.66	5.09
NGLs ($/bbl)	47.91	29.94	30.46	36.02
Combined ($/BOE) (4)	43.30	32.04	32.10	34.28

	Quarter Ended			
	2009			
	Dec. 31	**Sept. 30**	**June 30**	**Mar. 31**
Transportation Expenses				
Light and Medium Crude Oil ($/bbl)	1.47	2.17	1.28	1.60
Heavy Oil ($/bbl)	1.25	1.22	1.33	1.22
Natural Gas ($/Mcf)(3)	0.51	0.47	0.41	0.44
NGLs ($/bbl)	0.89	0.20	-	0.01
Combined ($/BOE)	2.35	2.35	1.96	2.12
Royalties Paid				
Light and Medium Crude Oil ($/bbl)	21.63	18.06	16.76	10.55
Heavy Oil ($/bbl)	11.88	11.70	14.36	10.98
Natural Gas ($/Mcf)(3)	0.68	0.02	0.08	1.25
NGLs ($/bbl)	10.51	8.22	9.48	12.17
Combined ($/BOE)	9.89	5.55	4.50	7.90
Operating Expenses				
Light and Medium Crude Oil ($/bbl)	9.97	10.92	13.79	10.71
Heavy Oil ($/bbl)	15.71	15.27	11.01	10.53
Natural Gas ($/Mcf)(3)	2.02	2.03	1.91	1.71
NGLs ($/bbl)	9.64	9.58	9.81	8.60
Combined ($/BOE)	11.33	11.65	11.79	10.21
Netback Received (2)				
Light and Medium Crude Oil ($/bbl)	35.15	32.87	29.10	20.29
Heavy Oil ($/bbl)	38.20	34.20	32.80	22.31
Natural Gas ($/Mcf)(3)	1.77	0.71	1.26	1.69
NGLs ($/bbl)	26.87	11.94	11.17	15.24
Combined ($/BOE)	19.73	12.49	13.85	14.05

Notes:

(1) Before deduction of royalties and including royalty interests.

(2) Netbacks are calculated by subtracting transportation, royalties and operating costs from revenues.

(3) Average daily coal bed methane production in 2009 was less than 1% of the total natural gas production and, therefore, was not considered material.

(4) Average price received does not include the impact of the Corporation's realized gains and losses on financial instruments.

The following table indicates the Corporation's average daily production, before deduction of royalties and including royalty interests, from its important fields for the year ended December 31, 2009:

	Light and Medium Crude Oil (bbl/d)	Heavy Oil (bbl/d)	Natural Gas[(1)] (Mcf/d)	NGLS (bbl/d)	Oil Equivalent (BOE/d)
Edson	81	-	11,596	420	2,434
Viking	182	-	2,797	-	648
Princess	2,520	304	4,569	41	3,627
Other	396	13	16,411	432	3,575
Total Alberta	3,179	317	35,373	893	10,284
Inga	73	-	4,749	166	1,031
Septimus	24	-	6,041	289	1,320
Greater Sierra	-	-	6,469	-	1,078
Other	97	-	1,066	14	289
Total British Columbia	194	-	18,325	469	3,718
Total	3,373	317	53,698	1,362	14,002

Notes:

(1) Average daily coal bed methane production in 2009 was less than 1% of the total natural gas production and, therefore, was not considered material.

For the year ended December 31, 2009, approximately 54% of Crew's gross revenue was derived from crude oil and natural gas liquids production and 46% was derived from natural gas production.

DIVIDEND POLICY

Crew has not paid any dividends on the outstanding Common Shares. The Board of Directors of Crew will determine the actual timing, payment and amount of dividends, if any, that may be paid by Crew from time to time based upon, among other things, the cash flow, results of operations and financial conditions of the Corporation, the need for funds to finance ongoing operations and other business considerations as the board of directors of Crew considers relevant.

DESCRIPTION OF CAPITAL STRUCTURE

The Corporation is authorized to issue an unlimited number of Common Shares and 1,881,000 Class C performance shares ("**Performance Shares**"). The following is a description of the rights, privileges, restrictions and conditions attaching to the share capital of the Corporation.

Common Shares

The Corporation is authorized to issue an unlimited number of Common Shares without nominal or par value. Holders of Common Shares are entitled to one vote per share at meetings of shareholders of the Corporation and are entitled to dividends if, as and when declared by the board of directors and, upon liquidation, dissolution or winding-up, to receive the remaining property of the Corporation.

Performance Shares

Holders of Performance Shares are not entitled to any voting rights or to receive notice of or to attend any meeting of the shareholders of the Corporation, are not entitled to receive any dividends on the Performance Shares and are not entitled upon any liquidation, dissolution or winding-up of the Corporation to any return of capital other than payment of the redemption price for each Performance Share in preference to the holders of Common Shares.

All of the previously outstanding Performance Shares vested and were converted into Common Shares on or prior to September 3, 2007. No further Performance Shares may be issued by the Corporation.

MARKET FOR SECURITIES

The Common Shares are listed and posted for trading on the TSX and trade under the symbol "CR". The following sets forth the price range and trading volume of the Common Shares on the TSX (as reported by the TSX) for the periods indicated.

	Price Range		
	High	**Low**	**Volume**
2009			
January	6.15	3.32	9,781,245
February	4.20	2.38	13,333,989
March	5.00	2.60	15,633,378
April	6.06	3.76	14,063,422
May	6.91	5.56	16,799,387
June	6.64	5.20	13,514,169
July	5.61	4.11	10,616,188
August	6.19	5.31	11,573,518
September	8.92	6.05	23,128,717
October	11.11	9.91	14,765,554
November	12.30	11.87	17,780,781
December	14.81	11.60	12,912,271
2010			
January	15.60	12.93	14,902,341
February	14.96	13.22	11,892,075
March (1-26)	17.80	14.43	19,920,906

ESCROWED SECURITIES

There are no securities of the Corporation currently held in escrow.

DIRECTORS AND OFFICERS

The names, province and country of residence, positions with the Corporation and principal occupation of the directors and officers of the Corporation are set out below and in the case of directors, the period each has served as a director of the Corporation.

Name, Age, Province and Country of Residence	Office Held	Principal Occupation	Director Since
John A. Brussa(2)(3)(4)(7) Alberta, Canada Age: 53	Chairman	Partner, Burnet, Duckworth & Palmer LLP (a law firm).	September, 2003
Jeffery E. Errico(1)(2)(3) Alberta, Canada Age: 59	Director	Chairman of Insignia Energy Ltd., a public energy company, since 2007; prior thereto, President and Chief Executive Officer of Petro Fund Energy Trust, a public oil and gas trust, from April, 2003 to June 2006.	September, 2008
Dennis L. Nerland(1)(3)(4)(6) Alberta, Canada Age: 57	Director	Partner, Shea Nerland Calnan (a law firm).	September, 2003
David G. Smith(1)(2)(4) Alberta, Canada Age: 52	Director	Executive Vice President, Liquids Business Unit, Keyera Facilities Income Fund since November 2008; prior thereto, Executive Vice President and Chief Financial Officer, Keyera Facilities Income Fund since February 2006; prior thereto, Senior Vice President and Chief Financial Officer, Keyera Facilities Income Fund.	January, 2009
Dale O. Shwed Alberta, Canada Age: 51	President, Chief Executive Officer and Director	President and Chief Executive Officer of the Corporation since June, 2003; prior thereto President and Chief Executive Officer of Baytex.	June, 2003
John G. Leach, CA Alberta, Canada Age: 45	Senior Vice-President and Chief Financial Officer	Senior Vice-President and Chief Financial Officer of the Corporation since January, 2009; prior thereto, Vice-President and Chief Financial Officer of the Corporation since September, 2003; prior thereto, Vice President, Finance and Administration of Baytex.	N/A

Name, Age, Province and Country of Residence	Office Held	Principal Occupation	Director Since
Gary Smith Alberta, Canada Age: 51	Vice-President, Exploration	Vice-President, Exploration of the Corporation since January, 2009; prior thereto, Exploration Manager of the Corporation since March, 2008; prior thereto, Senior Geologist of the Corporation since October, 2007; prior thereto, Vice-President, Exploration, Greenbank Energy since September, 2004; prior thereto, Senior Geologist, Storm Energy since February, 2002; prior thereto, Senior Geologist, Canadian Hunter.	N/A
Ken Truscott Alberta, Canada Age: 51	Senior Vice-President, Business Development and Land	Senior Vice-President, Business Development and Land of the Corporation since January, 2009; prior thereto, Vice-President, Land of the Corporation since September, 2007; prior thereto, Independent businessman since May, 2006; prior thereto President and Chief Executive Officer of Morpheus Energy Corporation.	N/A
Dean Tucker Alberta, Canada Age: 48	Vice-President, Production & Operations	Vice-President, Production & Operations since March, 2009; prior thereto, Vice-President, Operations of Pearl Exploration and Development since March, 2008; prior thereto, Vice President, Canadian Business Unit, Pearl Exploration and Development since August, 2007; prior thereto, Vice-President, Operations of Real Resources Inc.	N/A
Shawn A. Van Spankeren Alberta, Canada Age: 37	Vice-President, Finance and Controller	Vice-President, Finance and Controller of the Corporation since January, 2009; prior thereto, Controller of the Corporation since September, 2003; prior thereto, Controller of Baytex.	N/A
Michael D. Sandrelli Alberta, Canada Age: 41	Corporate Secretary	Partner, Burnet, Duckworth & Palmer LLP (a law firm).	N/A

Notes:

(1) Member of the Audit Committee.
(2) Member of the Reserves Committee.
(3) Member of the Compensation Committee.
(4) Member of the Corporate Governance Committee.
(5) Crew does not have an Executive Committee of its board of directors.
(6) Mr. Nerland was a director of Samsports.com Inc., a public company incorporated under the ABCA. In April 2001, a receiver-manager was appointed over the assets of Samsports.
(7) Mr. Brussa was a director of Imperial Metals Limited, a corporation engaged in both oil and gas and mining operations, in the year prior to that corporation implementing a plan of arrangement under the *Company Act* (British Columbia) and under the *Companies' Creditors Arrangement Act* (Canada) which resulted in the separation of its two businesses and the creation of two public corporations: Imperial Metals Corporation and IEI Energy Inc. (now Rider Resources Ltd.). The plan of arrangement was completed in April 2002.

All of the directors and officers of Crew have been engaged for more than five years in their present principal occupations or executive positions with the same companies except as described above.

The term of office of each director expires at the next annual meeting of shareholders of the Corporation.

As at December 31, 2009, the directors and officers of Crew, as a group, beneficially owned, directly or indirectly, 4,590,825 Common Shares or approximately 6% of the issued and outstanding Common Shares.

Conflicts of Interest

There are potential conflicts of interest to which the directors and officers of Crew will be subject to in connection with the operations of Crew. In particular, certain of the directors and officers of Crew are or may be involved in managerial or director positions with other oil and gas companies whose operations may, from time to time, be in direct competition with Crew or with entities which may, from time to time, provide financing to, or make equity investments in, our competitors. In accordance with ABCA, directors who have a material interest or any person who is a party to a material contract or a proposed material contract with Crew are required, subject to certain exceptions, to disclose that interest and generally abstain from voting on any resolution to approve the contract.

AUDIT COMMITTEE INFORMATION

The Audit Committee of Crew is composed of the following members:

Name	Independent	Financially Literate	Relevant Education and Experience
David G. Smith	Yes	Yes	Mr. Smith is Executive Vice President, Liquids Business Unit and Corporate Secretary of Keyera Facilities Income Fund, a public energy infrastructure company. Prior to that he was Chief Financial Officer and Corporate Secretary of Keyera Facilities Income Fund and its predecessor companies from June 1998 until November 2008. Previously Mr. Smith was employed with Gulf Canada Resources Limited and Imperial Oil Limited, and he has more than 25 years of experience in the oil and gas industry. Mr. Smith holds a Bachelor of Mathematics degree from the University of Waterloo and a Master of Business Administration degree from Harvard University.

Name	Independent	Financially Literate	Relevant Education and Experience
Dennis L. Nerland	Yes	Yes	Mr. Nerland is a lawyer practicing primarily in the area of tax and estate planning. Mr. Nerland has been a partner of Shea Nerland Calnan since 1990 and was a partner at Burnet, Duckworth & Palmer LLP prior thereto. Mr. Nerland is a member of the Law Society of Alberta, the Canadian Tax Foundation, the Calgary Bar Association, and the Society of Trusts and Estates Practitioners. Mr. Nerland is also a director of a number of public and private companies.
Jeffery E. Errico	Yes	Yes	Mr. Errico is the Executive Chairman of Insignia Energy Ltd., a public energy company. Prior to that he was the President and CEO of Petro Fund Corp. from April 2003 to June 2006. He is a professional engineer who received a Bachelor of Science degree in chemical engineering from the University of British Columbia. He has over 30 years of experience in the oil and gas industry, having served as a senior executive for several oil and gas companies.

Pre Approval of Policies and Procedures

Crew has adopted the following policies and procedures with respect to the pre-approval of audit and permitted non-audit services to be provided by KPMG LLP: The Audit Committee approves a schedule which summarizes the services to be provided that the Audit Committee believes to be typical, recurring or otherwise likely to be provided by KPMG LLP. The schedule generally covers the period between the adoption of the schedule and the end of the year, but at the option of the Audit Committee, may cover a shorter or longer period. The list of services is sufficiently detailed as to the particular services to be provided to ensure that (i) the Audit Committee knows precisely what services it is being asked to pre-approve and (ii) it is not necessary for any member of the Corporation's management to make a judgment as to whether a proposed service fits within the pre-approved services. Services that arise that were not contemplated in the schedule must be pre-approved by the Audit Committee chairman or a delegate of the audit committee. The full Audit Committee is informed of the services at its next meeting.

Crew has not approved any non-audit services on the basis of the de minimis exemptions. All non-audit services are pre-approved by the Audit Committee in accordance with the pre-approval policy referenced herein.

The following table provides information about the fees billed to us and our subsidiaries for professional services rendered by KPMG LLP, our external auditors, during fiscal 2009 and 2008:

	Aggregate fees billed	
	2009	2008
Audit fees	154,000	159,000
Audit-related fees	50,000	81,500
Tax fees	12,310	18,350
All other fees	-	-
	216,310	258,850

Audit Fees. Audit fees consist of fees for the audit of our annual financial statements or services that are normally provided in connection with statutory and regulatory filings or engagements.

Audit-Related Fees. Audit-related services include audit and review of certain subsidiaries and financial aspects, as well as prospectus review and IFRS consulting for Crew and its subsidiary and partnership.

Tax Fees. Tax fees included tax planning and various taxation matters.

All Other Fees. Other services provided by our external auditor other than audit, audit-related and tax services.

The text of the Audit Committee's Mandate and Terms of Reference is attached hereto as Appendix C.

HUMAN RESOURCES

Crew currently employs 71 full-time employees, of which 63 are located in the head office and 8 are field employees, and 2 part-time consultants. Crew intends to add additional professional and administrative staff as the need arises.

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

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

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

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

Royalties and Incentives

General

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

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

Alberta

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

On October 25, 2007, the Government of Alberta released a report entitled "The New Royalty Framework" ("**NRF**") containing the Government's proposals for Alberta's new royalty regime which were subsequently implemented by the *Mines and Minerals (New Royalty Framework) Amendment Act, 2008*. The NRF took effect on January 1, 2009. On March 11, 2010, the Government of Alberta announced changes to Alberta's royalty system intended to increase Alberta's competitiveness in the upstream oil and natural gas sectors; specifically, the maximum royalty rates for conventional oil and natural gas production will be decreased effective for the January 2011 production month and certain temporary incentive programs currently in place will be made permanent. Further details with respect to the changes to Alberta's royalty system are expected to be provided in the coming months.

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

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

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

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

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

On November 19, 2008, in response to the drop in commodity prices experienced during the second half of 2008, the Government of Alberta announced the introduction of a five-year program of transitional royalty rates with the intent of promoting new drilling. The 5-year transition option is designed to provide lower royalties at certain price levels in the initial years of a well’s life when production rates are expected to be the highest. Under this new program companies drilling new natural gas or conventional oil deep wells (between 1,000 and 3,500 m) are given a one-time option, on a well-by-well basis, to adopt either the new transitional royalty rates or those outlined in the NRF. Pursuant to the changes made to Alberta's royalty structure announced on March 11, 2010, producers will only be able to elect to adopt the transitional royalty rates prior to January 1, 2011 and producers that have already elected to adopt the transitional royalty rates as of that date will be permitted to switch to Alberta's conventional royalty structure. On December 31, 2013, all producers operating under the transitional royalty rates will automatically become subject to Alberta's conventional royalty structure.

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

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

British Columbia

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Saskatchewan

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

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

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

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

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

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

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

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

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

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

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

In 1975, the Government of Saskatchewan introduced a Royalty Tax Rebate ("**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 from two years, and on conditions set forth in provincial legislation including requirements to perform specific work or make payments. Oil and natural gas located in such provinces can also be privately owned and rights to explore for and produce such oil and natural gas are granted by lease on such terms and conditions as may be negotiated.

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

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

Environmental Regulation

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

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

Climate Change Regulation

Federal

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

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

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

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

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

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

The Updated Action Plan makes a distinction between "Existing Facilities" and "New Facilities". For Existing Facilities, the Updated Action Plan requires an emissions intensity reduction of 18% below 2006 levels by 2010 followed by a continuous annual emissions intensity improvement of 2%. "New Facilities" are defined as facilities beginning operations in 2004 or later 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 year per upstream oil and gas facility; and (iii) 10,000 boe/d/company. These regulatory thresholds are significantly lower than the regulatory threshold in force in Alberta, discussed below. In all other sectors govern by the Updated Action Plan, all facilities will be subject to regulation

Four separate compliance mechanisms are provided for in the Updated Action Plan in respect of the above targets: Technology Fund contributions, offset credits, clean development credits and credits for early action. Regulated entities will be able to use Technology Fund contributions to meet their emissions intensity targets. The contribution rate for Technology Fund contributions will increase over time, beginning at \$15 tonnes per CO_2 equivalent for the 2010-12 period, rising to \$20 in 2013, and thereafter increasing at the nominal rate of GDP growth. Maximum contribution limits will also decline from 70% in 2010 to 0% in 2018. Monies raised through contributions to the Technology Fund will be used to invest in technology to reduce greenhouse gas emissions. Alternatively, regulated entities may be able to receive credits for investing in large-scale and transformative projects at the same contribution rate and under similar requirements as described above.

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

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

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

Alberta

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

Alberta facilities emitting more than 100,000 tonnes of greenhouse gases a year are subject to comply with the CCEMA. Similarly to the Updated Action Plan, the CCEMA and the associated *Specified Gas Emitters Regulation* make a distinction between "Existing Facilities" and "New Facilities". Existing Facilities are defined as facilities that completed their first year of commercial operation prior to January 1, 2008 or that have completed 8 or more years of commercial operation. Existing Facilities were required to reduce their emissions intensity by March 31, 2008 by 12% from a baseline established by their average emissions intensity between 2003 and 2005. New Facilities are defined as facilities that completed their first year of commercial operation subsequent to December 31, 2008, have completed less than 8 years of commercial operation, or are designated as New Facilities in accordance with the *Specified Gas Emitters Regulation*. New Facilities are also required to reduce their emissions intensity by 12% but this target is based on the emissions intensity of the facility in its third year of commercial operation and does not apply during the first 3 years of operation of the New Facility. Unlike the Updated Action Plan, the CCEMA does not contain any provision for continuous annual improvements beyond the 12% emissions intensity required.

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

British Columbia

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

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

Saskatchewan

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

RISK FACTORS

Investors should carefully consider the risk factors set out below and consider all other information contained herein and in the Corporation's other public filings before making an investment decision.

Exploration, Development and Production Risks

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

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

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

Global Financial Crisis

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

Prices, Markets and Marketing

The marketability and price of oil and natural gas that may be acquired or discovered by the Corporation is and will continue to be affected by numerous factors beyond its control. The Corporation's ability to market its oil and natural gas may depend upon its ability to acquire space on pipelines that deliver natural gas to commercial markets. The Corporation may also be affected by deliverability uncertainties related to the proximity of its reserves to pipelines and processing and storage facilities and operational problems affecting such pipelines and facilities as well as extensive government regulation relating to price, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and many other aspects of the oil and natural gas business.

The prices of oil and natural gas prices may be volatile and subject to fluctuation. Any material decline in prices could result in a reduction of the Corporation's net production revenue. The economics of producing from some wells may change as a result of lower prices, which could result in reduced production of oil or gas and a reduction in the volumes of the Corporation's reserves. The Corporation might also elect not to produce from certain wells at lower prices. All of these factors could result in a material decrease in the Corporation's expected net production revenue and a reduction in its oil and gas acquisition, development and exploration activities. Prices for oil and gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and gas, market uncertainty and a variety of additional factors beyond the control of the Corporation. These factors include economic conditions, in the United States and Canada, the actions of OPEC, governmental regulation, political stability in the Middle East and elsewhere, the foreign supply of oil and gas, risks of supply disruption, the price of foreign imports and the availability of alternative fuel sources. Any substantial and extended decline in the price of oil and gas would have an adverse effect on the Corporation's carrying value of its reserves, borrowing capacity, revenues, profitability and cash flows from operations and may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Petroleum prices are expected to remain volatile for the near future as a result of market uncertainties over the supply and the demand of these commodities due to the current state of the world economies, OPEC actions and the ongoing credit and liquidity concerns. Volatile oil and gas prices make it difficult to estimate the value of producing properties for acquisition and often cause disruption in the market for oil and gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for and project the return on acquisitions and development and exploitation projects.

In addition, bank borrowings available to the Corporation may, in part, be determined by the Corporation's borrowing base. A sustained material decline in prices from historical average prices could reduce the Corporation's borrowing base, therefore reducing the bank credit available to the Corporation which could require that a portion, or all, of the Corporation's bank debt be repaid.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

The Corporation makes 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 the Corporation's ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of the Corporation. The integration of acquired business may require substantial management effort, time and resources and may divert management's focus from other strategic opportunities and operational matters. Management continually assesses the value and contribution of services provided and assets required to provide such services. In this regard, non-core assets are periodically disposed of, so that the Corporation can focus its efforts and resources more efficiently. Depending on the state of the market for such non-core assets, certain non-core assets of the Corporation, if disposed of, could be expected to realize less than their carrying value on the financial statements of the Corporation.

Operational Dependence

Other companies operate some of the assets in which the Corporation has an interest. As a result, the Corporation has limited ability to exercise influence over the operation of those assets or their associated costs, which could adversely affect the Corporation's financial performance. The Corporation's return on assets operated by others therefore depends upon a number of factors that may be outside of the Corporation's control, including the timing and amount of capital expenditures, the operator's expertise and financial resources, the approval of other participants, the selection of technology and risk management practices.

Project Risks

The Corporation manages a variety of small and large projects in the conduct of its business. Project delays may delay expected revenues from operations. Significant project cost over-runs could make a project uneconomic. The Corporation's ability to execute projects and market oil and natural gas depends upon numerous factors beyond the Corporation's 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;
- currency fluctuations;

- 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, the Corporation 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 it produces.

Competition

The petroleum industry is competitive in all its phases. The Corporation competes with numerous other organizations in the search for, and the acquisition of, oil and natural gas properties and in the marketing of oil and natural gas. The Corporation's competitors include oil and natural gas companies that have substantially greater financial resources, staff and facilities than those of the Corporation. The Corporation's ability to increase its reserves in the future will depend not only on its ability to explore and develop its present properties, but also on its ability to select and acquire other suitable producing properties or prospects for exploratory drilling. Competitive factors in the distribution and marketing of oil and natural gas include price and methods and reliability of delivery and storage. Competition may also be presented by alternate fuel sources.

Regulatory

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

Environmental

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and natural gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach of applicable environmental legislation may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require the Corporation to incur costs to remedy such discharge. Although the Corporation believes that it will be 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 have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Climate Change

Canada is a signatory to the United Nations Framework Convention on Climate Change and has ratified the Kyoto Protocol established thereunder to set legally binding targets to reduce nationwide emissions of carbon dioxide, methane, nitrous oxide and other so-called "greenhouse gases". Recently, representatives from approximately 170 countries met in Copenhagen, Denmark to attempt to negotiate a successor to the Kyoto Protocol. Pursuant to the resulting Copenhagen Accord, a non-binding political consensus rather than a binding international treaty such as the Kyoto Protocol, the Government of Canada revised its emissions reduction targets slightly. There has been much public debate with respect to Canada's ability to meet these targets and the Government's strategy or alternative strategies with respect to climate change and the control of greenhouse gases. The Corporation's exploration and production facilities and other operations and activities emit greenhouse gases and require the Corporation to comply with greenhouse gas emissions legislation contained in the Climate Change and Emissions Management Act and the Specified Gas Emitters Regulation. The Corporation may also be required comply with the regulatory scheme for greenhouse gas emissions ultimately adopted by the federal government, which is now expected to be modified to ensure consistency with the regulatory scheme for greenhouse gas emissions adopted by the United States. The direct or indirect costs of these regulations may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. The future implementation or modification of greenhouse gases regulations, whether to meet the limits required by the Kyoto Protocol, the Copenhagen Accord or as otherwise determined, could have a material impact on the nature of oil and natural gas operations, including those of the Corporation. 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 the impact on the Corporation and its operations and financial condition. See "*Industry Conditions – Climate Change Regulation*".

Variations in Foreign Exchange Rates and Interest Rates

World oil and gas 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, which will fluctuate over time. In recent years, the Canadian dollar has increased materially in value against the United States dollar. Material increases in the value of the Canadian dollar negatively impact the Corporation's production revenues. Future Canadian/United States exchange rates could accordingly impact the future value of the Corporation's reserves as determined by independent evaluators.

To the extent that the Corporation engages in risk management activities related to foreign exchange rates, there is a credit risk associated with counterparties with which the Corporation may contract.

An increase in interest rates could result in a significant increase in the amount the Corporation pays to service debt, which could negatively impact the market price of the Common Shares of the Corporation.

Substantial Capital Requirements

The Corporation anticipates making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. If the Corporation's revenues or reserves decline, it may not have access to the capital necessary to undertake or complete future drilling programs. In addition, uncertain levels of near term industry activity coupled with the present global credit crisis exposes the Corporation to additional access to capital risk. There can be no assurance that debt or equity financing, or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to the Corporation. The inability of the Corporation to access sufficient capital for its operations could have a material adverse effect on the Corporation's business financial condition, results of operations and prospects.

Additional Funding Requirements

The Corporation's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times. From time to time, the Corporation may require additional financing in order to carry out its oil and gas acquisition, exploration and development activities. Failure to obtain such financing on a timely basis could cause the Corporation to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If the Corporation's revenues from its reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect the Corporation's ability to expend the necessary capital to replace its reserves or to maintain its production. If the Corporation's cash flow from operations is not sufficient to satisfy its capital expenditure requirements, there can be no assurance that additional debt or equity financing will be available to meet these requirements or, if available, on terms acceptable to the Corporation. The Corporation's bank facility consists of a revolving line of credit and an operating line of credit and is funded by a syndicate of banks. The available lending limits of the facility are reviewed semi-annually and are based on the bank syndicate's interpretation of the Corporation's reserves and future commodity prices. There can be no assurance that the amount of the available facility will not be adjusted. Continued uncertainty in domestic and international credit markets could materially affect the Corporation's ability to access sufficient capital for its capital expenditures and acquisitions, and as a result, may have a material adverse effect on the Corporation's ability to execute its business strategy and on its business, financial condition, results of operations and prospects.

Issuance of Debt

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

Hedging

From time to time the Corporation may enter into agreements to receive fixed prices on its oil and natural gas production to offset the risk of revenue losses if commodity prices decline; however, if commodity prices increase beyond the levels set in such agreements, the Corporation will not benefit from such increases and the Corporation may nevertheless be obligated to pay royalties on such higher prices, even though not received by it, after giving effect to such agreements. Similarly, from time to time the Corporation may enter into agreements to fix the exchange rate of Canadian to United States dollars in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to the United States dollar; however, if the Canadian dollar declines in value compared to the United States dollar, the Corporation will not benefit from the fluctuating exchange rate. The Corporation may also enter into contracts to fix the interest rate on a portion of its outstanding debt in order to offset the risk of an increased cost of borrowing resulting from an increase in future interest rates. However, if the future interest rates decline, the Corporation will not receive the benefit of the decline due to the fixed interest rate contracts.

Availability of Drilling Equipment and Access

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

Title to Assets

Although title reviews may be conducted prior to the purchase of oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise to defeat the Corporation's claim which may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Reserve and Resource Estimates

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and natural gas liquids reserves and the future cash flows attributed to such reserves. The reserve, resource and associated cash flow information set forth herein are estimates only. In general, estimates of economically recoverable oil and natural gas reserves and resources and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve and resource recovery, timing and amount of capital expenditures, marketability of oil and gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially from actual results. For those reasons, estimates of the economically recoverable oil and natural gas reserves and resources attributable to any particular group of properties, classification of such reserves and resources based on risk of recovery and estimates of future net revenues associated with reserves prepared by different engineers, or by the same engineers at different times, may vary. The Corporation's actual production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates thereof and such variations could be material.

Estimates of proved reserves that may be developed and produced in the future are often 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.

In accordance with applicable securities laws, the Corporation's independent reserves evaluator has used forecast prices and costs in estimating the reserves and future net cash flows as summarized herein. Actual future net cash flows will be affected by other factors, such as actual production levels, supply and demand for oil and natural gas, curtailments or increases in consumption by oil and natural gas purchasers, changes in governmental regulation or taxation and the impact of inflation on costs.

Actual production and cash flows derived from the Corporation's oil and gas reserves will vary from the estimates contained in the reserve evaluation, and such variations could be material. The reserve evaluation is based in part on the assumed success of activities the Corporation intends to undertake in future years. The reserves and estimated cash flows to be derived therefrom contained in the reserve evaluation will be reduced to the extent that such activities do not achieve the level of success assumed in the reserve evaluation. The reserve evaluation is effective as of a specific effective date and has not been updated and thus does not reflect changes in the Corporation's reserves since that date.

Resource Estimates

The estimates of gas contained herein under the section "*Other Oil and Gas Information – Principal Properties – Septimus, British Columbia*" which are classified as Discovered Petroleum Initially in Place ("**DPIIP**") are not, and should not be confused with oil and gas reserves. "Discovered Petroleum Initially in Place" is defined in the COGE Handbook as the quantity of hydrocarbons that are estimated, as of a given date, to be contained in known accumulations. DPIIP is divided into recoverable and unrecoverable portions, with the estimated future recoverable portion classified as reserves and contingent resources and the remainder as at the evaluation date is by definition unrecoverable. There is no certainty that it will be economically viable or technically feasible to produce any portion of this DPIIP except to the extent identified as proved or probable reserves. Resources do not constitute, and should not be confused with reserves.

Crew has not categorized the resources disclosed as DPIIP into all of the sub-categories of discovered resources as projects have not been defined to develop them as at the evaluation date. Such projects, in the case of the Montney resource described, have historically been developed sequentially over a number of drilling seasons and are subject to annual budget constraints, Crew'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 Crew on commodity prices, the results of exploration and development activities of Crew and others in the area and possible infrastructure capacity constraints.

Crew's belief that it may recognize additional reserves in the Septimus area is based on a combination of historic recoveries of the more fully developed acreage, available well log and production test data, and the application of drilling densities of Crew and third parties in the areas and assumes continuous development through multi-year exploration and development programs, changing economic circumstances and further development and completion refinements. The principal risks of not achieving reserve additions on these lands relate to the potential for variations in the quality of the Montney formation where no current well data exists, access to capital, low gas prices that would impact the economics of development and the future performance of the wells.

Insurance

The Corporation's involvement in the exploration for and development of oil and natural gas properties may result in the Corporation becoming subject to liability for pollution, blow outs, leaks of sour natural gas, property damage, personal injury or other hazards. Although the Corporation maintains insurance in accordance with industry standards to address certain of these risks, such insurance has limitations on liability and may not be sufficient to cover the full extent of such liabilities. In addition, such risks are not, in all circumstances, insurable or, in certain circumstances, the Corporation may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or other reasons. The payment of any uninsured liabilities would reduce the funds available to the Corporation. The occurrence of a significant event that the Corporation is not fully insured against, or the insolvency of the insurer of such event, may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Geo-Political Risks

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

In addition, the Corporation's oil and natural gas properties, wells and facilities could be subject to a terrorist attack. If any of the Corporation's properties, wells or facilities are the subject of terrorist attack it may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. The Corporation will not have insurance to protect against the risk from terrorism.

Dilution

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

Management of Growth

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

Expiration of Licences and Leases

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

Dividends

The Corporation has not paid any dividends on its outstanding shares. Payment of dividends in the future will be dependent on, among other things, the cash flow, results of operations and financial condition of the Corporation, the need for funds to finance ongoing operations and other considerations as the board of directors of the Corporation considers relevant.

Aboriginal Claims

Aboriginal peoples have claimed aboriginal title and rights to portions of western Canada. The Corporation is not aware that any claims have been made in respect of its properties and assets; however, if a claim arose and was successful such claim may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Seasonality

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

Third Party Credit Risk

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

Conflicts of Interest

Certain directors of the Corporation are also directors of other oil and gas companies and as such may, in certain circumstances, have a conflict of interest requiring them to abstain from certain decisions. Conflicts, if any, will be subject to the procedures and remedies of the ABCA. See "*Directors and Officers – Conflicts of Interest*".

Reliance on Key Personnel

The Corporation's success depends in large measure on certain key personnel. The loss of the services of such key personnel may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. The Corporation does not have any key person insurance in effect for the Corporation. The contributions of the existing management team to the immediate and near term operations of the Corporation are likely to be of central importance. In addition, the competition for qualified personnel in the oil and natural gas industry is intense and there can be no assurance that the Corporation will be able to continue to attract and retain all personnel necessary for the development and operation of its business. Investors must rely upon the ability, expertise, judgment, discretion, integrity and good faith of the management of the Corporation.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

Crew is not a party to any legal proceeding nor was it a party to, nor is or was any of its property the subject of any legal proceeding, during the financial year ended December 31, 2009, nor is Crew aware of any such contemplated legal proceedings, which involve a claim for damages, exclusive of interest and costs, that may exceed 10% of the current assets of Crew.

During the year ended December 31, 2009, there were no (i) penalties or sanctions imposed against the Corporation by a court relating to securities legislation or by a securities regulatory authority; (ii) penalties or sanctions imposed by a court or regulatory body against the Corporation that would likely be considered important to a reasonable investor in making an investment decision, or (iii) settlement agreements the Corporation entered into before a court relating to securities legislation or with a securities regulatory authority.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

There were no material interests, direct or indirect, of directors or executive officers of Crew, any holder of Common Shares who beneficially owns or controls or directs, directly or indirectly, more than 10% of the outstanding Common Shares, or any known associate or affiliate of such persons, in any transactions within the three most recently completed financial years or during the current financial year which has materially affected or is reasonably expected to materially affect Crew.

TRANSFER AGENT AND REGISTRAR

Valiant Trust Company, at its principal offices in Calgary, Alberta and Toronto, Ontario is the transfer agent and registrar of the Common Shares.

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business (unless otherwise required by applicable securities requirements to be disclosed), neither the Corporation or its subsidiaries have entered into any material contracts within the most recently completed financial year, or before the most recently completed financial year that are still in effect.

INTERESTS OF EXPERTS

There is no person or company whose profession or business gives authority to a statement made by such person or company and who is named as having prepared or certified a statement, report or valuation described or included in a filing, or referred to in a filing, made under National Instrument 51-102 by the Corporation during, or related to, the Corporation's most recently completed financial year other than GLJ, the Corporation's independent engineering evaluator and KPMG LLP, the Corporation's auditors. As at the date hereof, the designated professionals of GLJ, as a group, beneficially owned, directly or indirectly less than 1% of Crew's outstanding securities, including securities of our associates and affiliates, either at the time it prepared the statement, report or valuation prepared by it, at any time thereafter or to be received by them. KPMG LLP is independent in accordance with the auditor's 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 the Corporation or of any associate or affiliate of the Corporation.

ADDITIONAL INFORMATION

Additional information relating to the Corporation can be found on SEDAR at www.sedar.com. Additional information, including directors' and officers' remuneration and indebtedness, principal holders of the Corporation's securities and securities authorized for issuance under equity compensation plans will be contained in the Corporation's information circular for the Corporation's most recent annual meeting of securityholders to be held on May 25, 2010. Additional financial information is contained in the Corporation's consolidated financial statements and the related management's discussion and analysis for its most recently completed financial year. Alternatively, additional information relating to the Corporation is available on SEDAR at www.sedar.com.

For copies of our information circular, our comparative consolidated financial statements, including any interim consolidated comparative financial statements and additional copies of the Annual Information Form please contact:

Crew Energy Inc.
Suite 1400, 425 – 1st Street SW
Calgary, Alberta T2P 3L8
Tel: (403) 266-2088
Fax: (403) 266-6259
www.Crewenergy.com

APPENDIX "A"
FORM 51-101F3
REPORT OF MANAGEMENT AND DIRECTORS ON RESERVES DATA AND OTHER INFORMATION

Management of Crew Energy Inc. (the "**Corporation**") is responsible for the preparation and disclosure of information with respect to the Corporation's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data, which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2009 estimated using forecast prices and costs:

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

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

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

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

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

(c) the content and filing of this report.

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

(signed) "*Dale O. Shwed*"
Dale O. Shwed
President and Chief Executive Officer

(signed) "*John G. Leach*"
John G. Leach
Senior Vice-President and Chief Financial Officer

(signed) "*Jeffery E. Errico*"
Jeffery E. Errico
Director and Chairman of the Reserves Committee

(signed) "*John A. Brussa*"
John A. Brussa
Director and Member of the Reserves Committee

March 29, 2010

APPENDIX "B"
FORM 51-101F2
REPORT ON RESERVES DATA

To the board of directors of Crew Energy Inc. (the "**Company**"):

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

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

3. 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).

4. 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.

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

Independent Qualified Reserves Evaluator or Auditor	Description and Preparation Date of Evaluation Report	Location of Reserves (County or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate, M$)			
			Audited	Evaluated	Reviewed	Total
GLJ Petroleum Consultants	February 25, 2010	Canada	-	$999,236	-	$999,236

6. 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.

7. We have no responsibility to update our reports referred to in paragraph 4 for events and circumstances occurring after its preparation dates.

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

(signed) "*GLJ Petroleum Consultants*"
GLJ Petroleum Consultants

Calgary, Alberta
February 25, 2010

Originally signed by:
James H. Willmon, P. Eng.
Vice President

APPENDIX "C"
CREW ENERGY INC.
AUDIT COMMITTEE
MANDATE AND TERMS OF REFERENCE

Role and Objective

The Audit Committee (the "**Committee**") is a committee of the board of directors (the "**Board**") of Crew Energy Inc. ("**Crew**" or the "**Corporation**") to which the Board has delegated its responsibility for the oversight of the nature and scope of the annual audit, the oversight of management's reporting on internal accounting standards and practices, the review of financial information, accounting systems and procedures, financial reporting and financial statements and has charged the Committee with the responsibility of recommending, for approval of the Board, the audited financial statements, interim financial statements and other mandatory disclosure releases containing financial information.

The primary objectives of the Committee are as follows:

1. To assist directors in meeting their responsibilities (especially for accountability) in respect of the preparation and disclosure of the financial statements of Crew and related matters;

2. To provide better communication between directors and external auditors;

3. To enhance the external auditor's independence;

4. To increase the credibility and objectivity of financial reports; and

5. To strengthen the role of the outside directors by facilitating in depth discussions between directors on the Committee, management and external auditors.

Membership of Committee

1. The Committee will be comprised of at least three (3) directors of Crew or such greater number as the Board may determine from time to time and all members of the Committee shall be "independent" (as such term is used in Multilateral Instrument 52-110 — Audit Committees ("**MI 52-110**") unless the Board determines that the exemption contained in MI 52-110 is available and determines to rely thereon.

2. The Board of Directors may from time to time designate one of the members of the Committee to be the Chair of the Committee.

3. All of the members of the Committee must be "financially literate" (as defined in MI 52-110) unless the Board determines that an exemption under MI 52-110 from such requirement in respect of any particular member is available and determines to rely thereon in accordance with the provisions of MI 52-110.

Mandate and Responsibilities of Committee

It is the responsibility of the Committee to:

1. Oversee the work of the external auditors, including the resolution of any disagreements between management and the external auditors regarding financial reporting.

2. Satisfy itself on behalf of the Board with respect to Crew's internal control systems:

    - identifying, monitoring and mitigating business risks; and

    - ensuring compliance with legal, ethical and regulatory requirements.

3. Review the annual and interim financial statements of Crew and related management's discussion and analysis ("**MD&A**") prior to their submission to the Board for approval. The process should include but not be limited to:

   - reviewing changes in accounting principles and policies, or in their application, which may have a material impact on the current or future years' financial statements;

   - reviewing significant accruals, reserves or other estimates such as the ceiling test calculation;

   - reviewing accounting treatment of unusual or non-recurring transactions;

   - ascertaining compliance with covenants under loan agreements;

   - reviewing disclosure requirements for commitments and contingencies;

   - reviewing adjustments raised by the external auditors, whether or not included in the financial statements;

   - reviewing unresolved differences between management and the external auditors; and

   - obtain explanations of significant variances with comparative reporting periods.

4. Review the financial statements, prospectuses, MD&A, annual information forms ("**AIF**") and all public disclosure containing audited or unaudited financial information (including, without limitation, annual and interim press releases and any other press releases disclosing earnings or financial results) before release and prior to Board approval. The Committee must be satisfied that adequate procedures are in place for the review of Crew's disclosure of all other financial information and will periodically assess the accuracy of those procedures.

5. With respect to the appointment of external auditors by the Board:

   - recommend to the Board the external auditors to be nominated;

   - recommend to the Board the terms of engagement of the external auditor, including the compensation of the auditors and a confirmation that the external auditors will report directly to the Committee;

   - on an annual basis, review and discuss with the external auditors all significant relationships such auditors have with the Corporation to determine the auditors' independence;

   - 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 pre-approve any non-audit services to be provided to Crew or its subsidiaries by the external auditors and consider the impact on the independence of such auditors. The Committee may delegate to one or more independent members the authority to pre–approve non–audit services, provided that the member(s) report to the Committee at the next scheduled meeting such pre–approval and the member(s) comply with such other procedures as may be established by the Committee from time to time.

6. Review with external auditors (and internal auditor if one is appointed by Crew) their assessment of the internal controls of Crew, their written reports containing recommendations for improvement, and management's response and follow-up to any identified weaknesses. The Committee will 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 Crew and its subsidiaries.

7. Review risk management policies and procedures of Crew (i.e. hedging, litigation and insurance).

8. Establish a procedure for:

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

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

9. Review and approve Crew's hiring policies regarding partners and employees and former partners and employees of the present and former external auditors of Crew.

The Committee has authority to communicate directly with the internal auditors (if any) and the external auditors of the Corporation. The Committee will also have the authority to investigate any financial activity of Crew. All employees of Crew are to cooperate as requested by the Committee.

The Committee may also retain persons having special expertise and/or obtain independent professional advise to assist in filling their responsibilities at such compensation as established by the Committee and at the expense of Crew without any further approval of the Board.

Meetings and Administrative Matters

1. At all meetings of the Committee every question shall be decided by a majority of the votes cast. In case of an equality of votes, the Chairman of the meeting shall be entitled to a second or casting vote.

2. The Chair will preside at all meetings of the Committee, unless the Chair is not present, in which case the members of the Committee that are present will designate from among such members the Chair for purposes of the meeting.

3. A quorum for meetings of the Committee will be a majority of its members, and the rules for calling, holding, conducting and adjourning meetings of the Committee will be the same as those governing the Board unless otherwise determined by the Committee or the Board.

4. Meetings of the Committee should be scheduled to take place at least four times per year. Minutes of all meetings of the Committee will be taken. The Chief Financial Officer will attend meetings of the Committee, unless otherwise excused from all or part of any such meeting by the Chairman.

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

6. Agendas, approved by the Chair, will be circulated to Committee members along with background information on a timely basis prior to the Committee meetings.

7. The Committee may invite such officers, directors and employees of the Corporation as it sees fit from time to time to attend at meetings of the Committee and assist in the discussion and consideration of the matters being considered by the Committee.

8. Minutes of the Committee will be recorded and maintained and circulated to directors who are not members of the Committee or otherwise made available at a subsequent meeting of the Board.

9. The Committee may retain persons having special expertise and may obtain independent professional advice to assist in fulfilling its responsibilities at the expense of the Corporation.

10. Any members of the Committee may be removed or replaced at any time by the Board and will cease to be a member of the Committee as soon as such member ceases to be a director. The Board may fill vacancies on the Committee by appointment from among its members. If and whenever a vacancy exists on the Committee, the remaining members may exercise all its powers so long as a quorum remains. Subject to the foregoing, following appointment as a member of the Committee, each member will hold such office until the Committee is reconstituted.

11. Any issues arising from these meetings that bear on the relationship between the Board and management should be communicated to the Chairman of the Board by the Committee Chair.