



crew
energy inc.

2003

2004

2005

2006

2007

2008

FINANCIAL REVIEW **2009**

RESOURCE FOCUS • OPPORTUNITY • SUSTAINABILITY

CORPORATE PROFILE

Crew Energy Inc. (“Crew”) or (“the Company”) is a growth-oriented oil and natural gas producer. Crew’s activities are concentrated in central Alberta and northeast British Columbia and focus on the development and expansion of its core natural gas and light oil producing areas and exploration of its undeveloped land base. Crew’s experienced management team is committed to the pursuit of sustainable per share growth through a balanced mix of financially responsible exploration and development, complemented by strategic acquisitions.

ANNUAL MEETING

The Annual Meeting of Shareholders of Crew Energy Inc. will be held at 3:00 p.m. (MDT) on Tuesday, May 25, 2010 in the Angus/Northcote Room of Bow Valley Square, + 30 level, 255 – 5th Avenue S.W., Calgary, Alberta.

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MANAGEMENT'S DISCUSSION & ANALYSIS

December 31, 2009

HIGHLIGHTS

Financial (\$ thousands, except per share amounts)	December 31, 2009	December 31, 2008
Petroleum and natural gas sales	181,829	235,856
Cash provided by operations	82,659	123,356
Funds from operations ⁽¹⁾	83,453	127,790
Per share – basic	1.11	2.08
– diluted	1.11	2.06
Net loss	(37,815)	(53,319)
Per share – basic	(0.50)	(0.87)
– diluted	(0.50)	(0.87)
Exploration and development expenditures	128,567	191,677
Property acquisitions (net of dispositions)	(78,693)	70,414
	As at	As at
Capital Structure (\$ thousands)	December 31, 2009	December 31, 2008
Working capital deficiency ⁽²⁾	46,654	31,822
Bank loan	135,601	223,628
Net debt ⁽²⁾	182,255	255,450
Bank facility	250,000	285,000
Common shares outstanding (thousands)	78,152	71,084
	December 31, 2009	December 31, 2008
Operations		
Daily production		
Natural gas (mcf/d)	53,698	52,595
Oil (bbl/d)	3,690	1,393
Natural gas liquids (bbl/d)	1,362	1,458
Oil equivalent (boe/d @ 6:1)	14,002	11,617
Average prices ⁽³⁾		
Natural gas (\$/mcf)	4.27	8.37
Oil (\$/bbl)	59.39	74.89
Natural gas liquids (\$/bbl)	36.28	62.32
Oil equivalent (\$/boe)	35.58	55.47
Operating expenses		
Natural gas (\$/mcf)	1.91	1.42
Oil (\$/bbl)	11.30	12.24
Natural gas liquids (\$/bbl)	9.40	7.41
Oil equivalent (\$/boe @ 6:1)	11.22	8.82
Netback (\$/boe)		
Operating netback ⁽⁴⁾	17.96	32.64
Realized gain on financial instruments	(0.76)	–
G&A	1.12	0.98
Interest and other	1.27	1.60
Funds from operations netback	16.33	30.06
Drilling Activity		
Gross wells	43	53
Working interest wells	36.1	43.3
Success rate, net wells	97%	95%

Notes:

- (1) Funds from operations is calculated as cash provided by operating activities, adding the change in non-cash working capital, asset retirement expenditures and the transportation liability charge. Funds from operations is used to analyze the Company's operating performance and leverage. Funds from operations does not have a standardized measure prescribed by Canadian Generally Accepted Accounting Principles (GAAP) and therefore may not be comparable with the calculations of similar measures for other companies.
- (2) Working capital deficiency includes only accounts receivable less accounts payable and accrued liabilities. Net debt includes bank working capital deficiency plus bank loans.
- (3) Average prices are before deduction of transportation costs and do not include realized gains and losses on financial instruments.
- (4) Operating netback equals petroleum and natural gas sales including realized hedging gains and losses on commodity contracts less royalties, operating costs and transportation costs calculated on a boe basis. Operating netback and funds from operations netback do not have a standardized measure prescribed by Canadian GAAP and therefore may not be comparable with the calculations of similar measures for other companies.

ADVISORIES

Management's discussion and analysis ("MD&A") is the Company's explanation of its financial performance for the period covered by the financial statements along with an analysis of the Company's financial position. Comments relate to and should be read in conjunction with the audited consolidated financial statements of the Company for the years ended December 31, 2009 and 2008. The consolidated financial statements have been prepared in accordance with generally accepted accounting principles ("GAAP") in Canada and all figures provided herein and in the December 31, 2009 consolidated financial statements are reported in Canadian dollars.

Forward-looking Statements

This MD&A contains forward-looking statements. Management's assessment of future plans and operations, capital expenditures, timing of capital expenditures and methods of financing capital expenditures and the ability to fund financial liabilities, production estimates, expected commodity prices and the impact on Crew, future operating costs, future transportation costs, expected royalty rates, general and administrative expenses, interest rates, anticipated reductions in depletion and depreciation rates, debt levels, funds from operations and the timing of and impact of adoption of IFRS and other accounting policies may constitute forward-looking statements under applicable securities laws and necessarily involve risks including, without limitation, risks associated with oil and gas exploration, development, exploitation, production, marketing and transportation, loss of markets, volatility of commodity prices, currency fluctuations, imprecision of reserve 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, the inability to fully realize the benefits of acquisitions, delays resulting from or inability to obtain required regulatory approvals and ability to access sufficient capital from internal and external sources. As a consequence, the Company's actual results may differ materially from those expressed in, or implied by, 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 the Company 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 and other documents filed by the Company, 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 ability of the Company 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 the Company has an interest in to operate the field in a safe, efficient and effective manner; Crew's ability to obtain financing on acceptable terms; field production rates and decline rates; the ability to reduce operating costs; the ability to replace and expand oil and natural gas reserves through acquisition, development or exploration; the timing and costs of pipeline, storage and facility construction and expansion; the ability of the Company to secure adequate product transportation; future petroleum and natural gas prices; currency, exchange and interest rates; the regulatory framework regarding royalties, taxes and environmental matters in the jurisdictions in which the Company operates; and Crew's ability to successfully market its petroleum 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 affect the Company'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 at the Company's website (www.crewenergy.com). Furthermore, the forward looking statements contained in this document are made as at the date of this document and the Company does not undertake any obligation to update publicly or to revise any of the included forward looking statements, whether as a result of new information, future events or otherwise, except as may be required by applicable securities laws.

Conversions

The oil and gas industry commonly expresses production volumes and reserves on a "barrel of oil equivalent" basis ("boe") whereby natural gas volumes are converted at the ratio of six thousand cubic feet to one barrel of oil. The intention is to sum oil and natural gas measurement units into one basis for improved analysis of results and comparisons with other industry participants.

Throughout this MD&A, Crew has used the 6:1 boe measure which is the approximate energy equivalency of the two commodities at the burner tip. Boe does not represent a value equivalency at the plant gate which is where Crew sells its production volumes and therefore may be a misleading measure if used in isolation.

Non-GAAP Measures

One of the benchmarks Crew uses to evaluate its performance is funds from operations. Funds from operations is a measure not defined in GAAP that is commonly used in the oil and gas industry. It represents cash provided by operating activities before changes in non-cash working capital, asset retirement expenditures and the transportation liability charge. The Company considers it a key measure as it demonstrates the ability of the business to generate the cash flow necessary to fund future growth through capital

investment and to repay debt. Funds from operations should not be considered as an alternative to, or more meaningful than cash provided by operations as determined in accordance with GAAP as an indicator of the Company's performance. Crew's determination of funds from operations may not be comparable to that reported by other companies. Crew also presents funds from operations per share whereby per share amounts are calculated using weighted average shares outstanding consistent with the calculation of income per share. The following table reconciles Crew's cash provided by operating activity to funds from operations:

(\$ thousands)	Three months ended December 31		Year ended December 31	
	2009	2008	2009	2008
Cash provided by operating activities	16,734	25,700	82,659	123,356
Asset retirement expenditures	111	152	589	775
Transportation liability charge	329	328	1,314	1,313
Change in non-cash working capital	10,082	3,466	(1,109)	2,346
Funds from operations	27,256	29,646	83,453	127,790

Management uses certain industry benchmarks such as operating netback to analyze financial and operating performance. This benchmark as presented does not have any standardized meaning prescribed by Canadian GAAP and therefore may not be comparable with the calculation of similar measures for other entities. Operating netback equals total petroleum and natural gas sales including realized gains and losses on commodity contracts less royalties, operating costs and transportation costs calculated on a boe basis. Management considers operating netback an important measure to evaluate its operational performance as it demonstrates its field level profitability relative to current commodity prices.

RESULTS OF OPERATIONS

Overview

The past year marked the beginning of a long recovery from the worst financial crisis in decades. Financial intervention by governments around the world aided in the stabilization of the world's financial system and helped inject confidence into the global economy thereby creating increased global demand for products and hence commodities. This recovery was evident in the world's oil markets as the price of benchmark West Texas Intermediate ("WTI") recovered from a first quarter average price of US\$43 per barrel to a fourth quarter average of US\$76 per bbl.

Natural gas prices did not experience a similar recovery. North American natural gas markets have been dramatically impacted by low industrial demand brought on by the recession and increasing supplies from new technologies recovering natural gas from unconventional resource plays such as "shale gas". This has created an oversupplied market and a weak price environment. Prices for natural gas sold in Canada opened 2009 above \$6.00 per million cubic feet but steadily declined to average a low of \$3 per million cubic feet in the third quarter. With the anticipation of stronger demand from the winter heating season, prices strengthened marginally in the fourth quarter to average \$4.50 per million cubic feet but the market continues to suffer from weak industrial demand and continued oversupply.

As a result of the low commodity price environment encountered in the first half of 2009, Crew limited its first half capital spending in order to preserve its financial position. In addition the Company was successful in strengthening its balance sheet with the sale of approximately 670 boe per day of production and 2.4 mmoeb of proved plus probable reserves for \$33.2 million in two first half dispositions and completed a bought deal equity financing in May for gross proceeds of \$43.4 million. The Company also entered into a number of 2009 commodity and foreign exchange hedging agreements that ensured a certain level of cash flow to help fund a more active second half exploration and development program.

With a strengthened financial position, the Company executed an expanded second half exploration and development program drilling all but seven of its total 43 well 2009 program in the second half of the year. This program focused on development of the Company's medium grade oil play at Princess, Alberta and continued expansion of the Company's natural gas Montney resource play at Septimus, British Columbia. At Princess, the Company has successfully applied horizontal drilling to exploit only a small portion of the 444 net sections of land it controls in the area to grow current production to over 5,200 boe per day representing a 136% increase in production from when the property was acquired in the latter half of 2008. At Septimus, the Company completed construction of a 25 mmcf per

day natural gas processing facility in October 2009 which allowed the Company to increase its production volumes in the area to current levels of approximately 21 mmcf per day and reduce operating costs per unit on Septimus produced natural gas by over 60%.

The Company further strengthened its balance sheet in the second half of 2009 with the sale of an additional 600 boe per day of non-core production and 1.8 mmboe proved plus probable reserves for \$25 million. The Company also sold the Septimus gas facility to a third party for its as built cost of \$19 million. Under the arrangement Crew will operate the facility and retains an option to expand the facility in the future and equalize into a 50% ownership position.

As a result of the limited capital spending and to a larger degree, the sale of assets and shutting in of uneconomic natural gas production, Crew's production declined from a first quarter average of 15,022 boe per day to average 14,002 boe per day for the year. Despite the limited first half activity and the sale of 1,270 boe per day of production, a very successful second half drilling program resulted in exit production, represented by December 2009 average production, exceeding the Company's first quarter average.

The Company's financial results were impacted by the depressed gas prices and average oil prices below 2008 levels. Funds from operations declined 34% to \$83.5 as a result of the weaker commodity price environment. This level of funds from operations was bolstered by an \$18.5 million gain realized on the Company's risk management program. The Company's capital management program significantly improved the Company's financial position reducing net debt by 29% to \$182.3 million at year end.

Production

	Three months ended December 31, 2009				Three months ended December 31, 2008			
	Oil (bbl/d)	Ngl (bbl/d)	Natural gas (mcf/d)	Total (boe/d)	Oil (bbl/d)	Ngl (bbl/d)	Natural gas (mcf/d)	Total (boe/d)
Plains Core	4,256	828	30,844	10,224	2,845	989	42,890	10,982
North Core	157	584	21,027	4,246	278	680	17,574	3,887
Total	4,413	1,412	51,871	14,470	3,123	1,669	60,464	14,869

	Year ended December 31, 2009				Year ended December 31, 2008			
	Oil (bbl/d)	Ngl (bbl/d)	Natural gas (mcf/d)	Total (boe/d)	Oil (bbl/d)	Ngl (bbl/d)	Natural gas (mcf/d)	Total (boe/d)
Plains Core	3,496	893	35,373	10,285	1,187	991	37,010	8,346
North Core	194	469	18,325	3,717	206	467	15,585	3,271
Total	3,690	1,362	53,698	14,002	1,393	1,458	52,595	11,617

Fourth quarter production decreased by 3% over the fourth quarter of 2008 as a result of property dispositions of approximately 1,270 boe per day of non-core production in Alberta and Saskatchewan during 2009 as well as the shut-in of approximately 400 boe per day of uneconomic natural gas production in Alberta. These dispositions were partially offset by a successful drilling program that added new natural gas liquids ("ngl") rich natural gas production at Septimus, British Columbia and oil production at Killam and Princess, Alberta.

Production increased 21% in 2009 due to the previously mentioned successful drilling program at Septimus, Killam and Princess and a full year of production from the acquisition of Gentry Resources Ltd. ("Gentry") which closed in August 2008. Natural gas production increased 2% over 2008 due to a successful drilling program in the Company's Septimus, British Columbia area which was partially offset by the disposition of approximately 1,270 boe per day of predominantly Alberta natural gas production. Oil production increased 165% due a successful drilling program in Killam and Princess, Alberta and a full year of production from the Gentry properties with oil production in the Princess, Alberta area.

Revenue

	Three months ended December 31		Year ended December 31	
	2009	2008	2009	2008
Revenue (\$ thousands)				
Natural gas	23,746	38,537	83,699	161,192
Oil	27,674	14,425	79,997	38,196
Natural gas liquids	6,226	5,720	18,035	33,249
Sulphur	–	124	98	3,219
Total	57,646	58,806	181,829	235,856
Crew average prices				
Natural gas (\$/mcf)	4.98	6.93	4.27	8.37
Oil (\$/bbl)	68.16	50.21	59.39	74.89
Natural gas liquids (\$/bbl)	47.91	37.24	36.28	62.32
Oil equivalent (\$/boe)	43.30	42.99	35.58	55.47
Benchmark pricing				
Natural Gas – AECO C daily index (Cdn \$/mcf)	4.49	6.79	4.03	8.27
Oil – Bow River Crude Oil (Cdn \$/bbl)	77.45	59.30	68.71	94.40
Oil and ngl – Light Sweet @ Edmonton (Cdn \$/bbl)	77.90	62.54	66.21	102.02

Crew's 2009 fourth quarter revenue decreased by 2% over the fourth quarter of 2008 due to the 3% decrease in production partially offset by a 1% increase in average pricing. In the fourth quarter, the Company's natural gas price decreased 28% as compared to a 34% decrease in Crew's natural gas benchmark price. The disproportionate decrease was attributable to a higher price received for the Company's additional Septimus, British Columbia natural gas production. In the fourth quarter of 2009, the Company's oil price increased disproportionately as compared with the Company's benchmark Bow River Crude oil price primarily due to the oil volumes in the Princess, Alberta area attracting a price that includes a fixed price quality differential off of the Bow River stream price. The Company's ngl price increased 29% in the fourth quarter of 2009 compared to a 25% increase in the Company's benchmark Light Sweet at Edmonton due to the Company's 2009 property dispositions which included lower valued ethane production which historically has decreased the overall corporate ngl realized price.

The Company's 2009 revenue decreased 23% as a result of its 36% decrease in product pricing partially offset by a 21% increase in production. For the year, Crew's natural gas price decreased 49% over 2008 which was comparable to the 51% decrease in the Company's benchmark price. The sales price for Crew's oil production decreased 21% compared to a 27% decrease in the benchmark. In 2008, the majority of the Company's oil production came from the Princess, Alberta property acquired in August 2008 and was therefore produced in a lower price environment thus lowering the overall corporate average oil price for 2008 as compared to the average benchmark for the same period. In 2009, with a full year of oil production from the Princess property, Crew's average oil price is within expectations as compared to the benchmark. Crew's average ngl price decreased 42% as compared with the benchmark decrease of 35% due to additional lower valued ethane production from wells in northeastern British Columbia.

Royalties

	Three months ended December 31		Year ended December 31	
	2009	2008	2009	2008
<i>(\$ thousands, except per boe)</i>				
Royalties	13,167	12,035	36,027	49,961
Per boe	\$ 9.89	\$ 8.80	\$ 7.05	\$ 11.75
Percentage of revenue	22.8%	20.5%	19.8%	21.2%

Royalties as a percentage of revenue increased in the fourth quarter of 2009 compared to the same quarter of 2008 due to the addition of oil volumes on freehold lands in the Princess, Alberta area which currently attract a higher

royalty rate. This was partially offset by lower gas royalties as a percentage of revenue due to a lower natural gas price experienced during the fourth quarter of 2009 compared with the same period in 2008.

Overall, royalties as a percentage of revenue decreased in 2009 over 2008 due to decreased Alberta natural gas royalties associated with lower natural gas prices. In Alberta, under the new royalty structure, the Company's Crown royalty percentages decrease as natural gas prices decrease. This was partially offset by the royalties from the additional oil volumes on the Company's freehold lands in the Princess, Alberta area. Crew estimates royalties as a percentage of revenue to average 23% to 25% in 2010.

Financial Instruments

Commodities

The Company enters into derivative and physical risk management contracts in order to reduce volatility in financial results, to protect acquisition economics and to ensure a certain level of cash flow to fund planned capital projects. Crew's strategy focuses on the use of puts, costless collars, swaps and fixed price contracts to limit exposure to fluctuations in commodity prices, interest rates and foreign exchange rates while allowing for participation in commodity price increases. The Company's financial derivative trading activities are conducted pursuant to the Company's Risk Management Policy approved by the Board of Directors. In 2009, these contracts had the following impact on the consolidated statements of operations:

	Three months ended December 31		Year ended December 31	
	2009	2008	2009	2008
<i>(\$ thousands)</i>				
Realized gain (loss) on financial instruments	4,471	2,646	18,461	(675)
Unrealized gain (loss) on financial instruments	(6,225)	131	(2,089)	2,608

As at December 31, 2009, the Company held derivative commodity contracts as follows:

Subject of Contract	Notional Quantity	Term	Reference	Strike Price	Option Traded	Fair Value (\$000s)
Natural Gas	2,500 gj/day	November 1, 2009 – December 31, 2010	AECO C Monthly Index	\$6.00	Swap	534
Natural Gas	5,000 gj/day	January 1, 2010 – December 31, 2010	AECO C Monthly Index	\$8.00	Call	(183)
Natural Gas	10,000 gj/day	January 1, 2010 – December 31, 2010	AECO C Monthly Index	\$7.75	Call	(434)
Natural Gas	2,500 gj/day	January 1, 2010 – December 31, 2010	AECO C Monthly Index	\$6.20	Swap	724
Natural Gas	5,000 gj/day	January 1, 2010 – December 31, 2010	AECO C Monthly Index	\$6.08	Swap	1,214
Natural Gas	2,500 gj/day	January 1, 2010 – December 31, 2010	AECO C Monthly Index	\$5.25	Swap	(148)
Natural Gas	2,500 gj/day	January 1, 2010 – December 31, 2010	AECO C Monthly Index	\$5.55	Swap	133
Natural Gas	5,000 mmbtu/day	January 1, 2010 – December 31, 2010	AECO/NYMEX Basis diff	US\$(\$0.55)	Swap	(356)
Oil	250 bbl/day	January 1, 2010 – December 31, 2010	CDN\$ WTI	\$78.50	Swap	(734)
Oil	500 bbl/day	January 1, 2010 – December 31, 2010	CDN\$ WTI	\$72.00 – \$88.00	Collar	(700)
Oil	250 bbl/day	January 1, 2010 – December 31, 2010	CDN\$ WTI	\$82.50	Swap	(366)
Oil	500 bbl/day	January 1, 2010 – December 31, 2010	CDN\$ WTI	\$80.50	Swap	(1,100)
Oil	500 bbl/day	January 1, 2010 – December 31, 2010	US\$ WTI	US\$81.00	Swap	(249)
Oil	250 bbl/day	January 1, 2010 – December 31, 2010	CDN\$ WTI	\$80.00 – \$95.02	Collar	81
Total						(1,584)

Foreign currency

Although all of the Company's petroleum and natural gas sales are conducted in Canada and are denominated in Canadian dollars, Canadian commodity prices are influenced by fluctuations in the Canadian to U.S. dollar exchange rate.

At December 31, 2009, the Company held derivative foreign currency contracts as follows:

Subject of Contract	Notional Quantity	Term	Reference	Strike Price	Option Traded	Fair Value (\$000s)
USD / CDN \$ exchange	US \$2M/ Month	January 1, 2010 – December 31, 2010	CDN/USD	1.094	Swap	1,022
Total						1,022

Interest rate

The Company is exposed to interest rate fluctuations on its bank loan which bears a floating rate of interest. As shown below, at December 31, 2009, Crew had contracts in place fixing the rate on \$150 million of its bank loan borrowed as banker's acceptances for a period of 24 months at rates of 1.10% to 1.12%. The Company pays an additional stamping fee and margins on bankers' acceptances as outlined in note 6 of the financial statements.

Subject of Contract	Notional Quantity	Term	Reference	Strike Price	Option Traded	Fair Value (\$000s)
BA Rate	\$50M / year	February 10, 2009 – February 10, 2011	BA - CDOR	1.10%	Swap	(156)
BA Rate	\$50M / year	February 12, 2009 – February 12, 2011	BA - CDOR	1.10%	Swap	(116)
BA Rate	\$50M / year	May 28, 2009 – May 28, 2011	BA - CDOR	1.12%	Swap	–
Total						(272)

Subsequent to December 31, 2009, the Company entered into the following financial instrument contracts:

Subject of Contract	Notional Quantity	Term	Reference	Strike Price	Option Traded
Natural Gas	2,500 gj/day	April 1, 2010 – October 31, 2010	AECO C – Monthly Index	\$5.30 / gj	Swap
Oil	250 bbl/day	March 1, 2010 – December 31, 2010	CDN \$WTI	\$84.00 / bbl	Swap

Operating Costs

	Three months ended December 31		Year ended December 31	
	2009	2008	2009	2008
<i>(\$ thousands, except per boe)</i>				
Operating costs	15,084	13,952	57,342	37,520
Per boe	\$ 11.33	\$ 10.20	\$ 11.22	\$ 8.82

The Company's operating costs and operating costs per unit increased in the fourth quarter as compared to the same period in 2008 as a result of additional oil production from the Company's Princess, Alberta area which currently has higher operating costs per unit than the Company's natural gas production. During 2009, the Company disposed of lower cost natural gas production which increased the Company's per unit costs in the fourth quarter of 2009 as compared with the same period in 2008. In addition, in the fourth quarter, the Company also received higher than expected third party prior year equalizations inflating its operating costs and operating costs per unit.

Crew's increase in operating costs per unit in 2009 was a result of the higher operating cost oil properties acquired in the Gentry acquisition in August 2008. A combination of the increasing oil production in the Princess area throughout 2009 and the disposition of lower operating cost natural gas properties in 2009 has also contributed to the Company's overall increase in operating costs per unit. Crew has identified a number of cost cutting measures associated with water handling at Princess and expects lower operating costs per unit from production in the Septimus, British

Columbia area which will reduce the Company's operating costs per unit in 2010. The Company expects operating costs to range between \$10.00 and \$10.50 per boe in 2010.

Transportation Costs

	Three months ended December 31		Year ended December 31	
	2009	2008	2009	2008
<i>(\$ thousands, except per boe)</i>				
Transportation costs	3,134	2,607	11,229	8,924
Per boe	\$ 2.35	\$ 1.91	\$ 2.20	\$ 2.10

The Company's 2009 fourth quarter increase in transportation costs per boe was a result of an increase in unutilized demand charges for transportation and treatment through northeastern British Columbia pipelines and facilities in which Crew's production is decreasing. This production was replaced by production at Septimus, British Columbia where gas transportation costs are lower. Additional trucking costs associated with ngl production in the Septimus, British Columbia area also increased the Company's transportation costs in the fourth quarter of 2009.

In 2009, Crew's transportation costs per unit were slightly above 2008 levels. A combination of a reduction in certain British Columbia gas sales to offset the Company's fixed transportation commitments in northeastern British Columbia with additional trucking costs of natural gas liquids produced in the Septimus, British Columbia has increased the transportation costs and transportation costs per unit for the year. This has been partially offset by lower clean oil trucking costs per unit in the Princess, Alberta area. The Company forecasts transportation costs in 2010 to approximate fourth quarter 2009 levels and range between \$2.00 and \$2.50 per boe.

Operating Netbacks

	Three months ended December 31, 2009				Three months ended December 31, 2008			
	Oil (\$/bbl)	Ngl (\$/bbl)	Natural gas (\$/mcf)	Total (\$/boe)	Oil (\$/bbl)	Ngl (\$/bbl)	Natural gas (\$/mcf)	Total (\$/boe)
Revenue	68.16	47.91	4.98	43.30	50.21	37.24	6.93	42.99
Realized commodity hedging gain (loss)	(0.61)	-	0.60	1.90	5.12	-	0.21	1.93
Royalties	(21.07)	(10.51)	(0.68)	(9.89)	(15.32)	(11.37)	(1.08)	(8.80)
Operating costs	(10.30)	(9.64)	(2.02)	(11.33)	(12.86)	(8.57)	(1.61)	(10.20)
Transportation costs	(1.45)	(0.89)	(0.51)	(2.35)	(1.54)	(0.04)	(0.39)	(1.91)
Operating netbacks	34.73	26.87	2.37	21.63	25.61	17.26	4.06	24.01

	Year ended December 31, 2009				Year ended December 31, 2008			
	Oil (\$/bbl)	Ngl (\$/bbl)	Natural gas (\$/mcf)	Total (\$/boe)	Oil (\$/bbl)	Ngl (\$/bbl)	Natural gas (\$/mcf)	Total (\$/boe)
Revenue	59.39	36.28	4.27	35.58	74.89	62.32	8.37	55.47
Realized commodity hedging gain (loss)	(0.01)	-	0.74	2.85	2.88	-	(0.11)	(0.16)
Royalties	(16.66)	(10.09)	(0.43)	(7.05)	(15.67)	(17.30)	(1.67)	(11.75)
Operating costs	(11.30)	(9.40)	(1.91)	(11.22)	(12.24)	(7.41)	(1.42)	(8.82)
Transportation costs	(1.59)	(0.29)	(0.46)	(2.20)	(1.93)	(0.03)	(0.41)	(2.10)
Operating netbacks	29.83	16.50	2.21	17.96	47.93	37.58	4.76	32.64

General and Administrative Costs

	Three months ended December 31		Year ended December 31	
	2009	2008	2009	2008
<i>(\$ thousands, except per boe)</i>				
Gross costs	4,026	3,076	14,160	11,099
Operator's recoveries	(1,080)	(591)	(2,689)	(2,761)
Capitalized costs	(1,473)	(1,243)	(5,735)	(4,169)
General and administrative expenses	1,473	1,242	5,736	4,169
Per boe	\$ 1.11	\$ 0.91	\$ 1.12	\$ 0.98

Increased general and administrative costs before recoveries and capitalization was the result of increased staff levels and higher salary levels in the fourth quarter of 2009 compared to 2008. Increased capital expenditures and production levels in the fourth quarter of 2009 resulted in higher operator recoveries and capitalized costs.

General and administrative expenses increased in 2009 as compared to 2008 due to the addition of new staff to handle the Company's increased activity. Operator recoveries were marginally lower in 2009 as a result of decreased capital expenditures in 2009. Crew expects general and administrative costs per boe to average approximately \$1.00 to \$1.15 per boe in 2010.

Interest

	Three months ended December 31		Year ended December 31	
	2009	2008	2009	2008
<i>(\$ thousands, except per boe)</i>				
Interest expense	2,003	1,970	6,503	7,085
Average debt level	158,937	191,535	194,818	138,395
Effective interest rate	5.1%	4.1%	3.3%	5.1%
Per boe	\$ 1.50	\$ 1.44	\$ 1.27	\$ 1.67

In the fourth quarter of 2009, increased margins applied to the Company's bank facility have increased the Company's interest expense and effective interest rate over the same period in 2008. The additional interest has been partially offset due to lower prime and bankers' acceptance interest rates and lower average debt levels that were the result of a reduced 2009 exploration and development capital program, asset dispositions and the equity financing completed in May, 2009.

In 2009, despite higher average debt levels, lower prime interest rates and rates on bankers' acceptances have decreased the Company's interest expense and effective interest rate. This has been partially offset by increased margins applied to the Company's bank facility in the last half of 2009. In 2010, the Company's interest rate hedges will continue to partially offset the higher margins charged on the Company's bank facility. The Company's effective interest rate is expected to average between 4.75% and 5.25% in 2010.

Stock-Based Compensation

	Three months ended December 31		Year ended December 31	
	2009	2008	2009	2008
<i>(\$ thousands)</i>				
Gross costs	1,586	1,178	6,642	6,664
Capitalized costs	(793)	(589)	(3,321)	(3,332)
Total stock-based compensation	793	589	3,321	3,332

The Company's stock-based compensation expense has increased in the fourth quarter of 2009 due to the Company's increasing share price creating a higher fair value for stock options issued. In the fourth quarter of 2008, there was a reversal of expense due to the forfeiture of options in the fourth quarter of 2008. In 2009, stock based compensation expense has been equivalent to the same period in 2008, but is expected to increase in 2010 as the fair value of the Company's stock options issued increases as its share price increases.

Depletion, Depreciation and Accretion

	Three months ended December 31		Year ended December 31	
	2009	2008	2009	2008
<i>(\$ thousands, except per boe)</i>				
Depletion, depreciation and accretion	31,677	35,329	131,613	104,866
Per boe	\$ 23.80	\$ 25.83	\$ 25.75	\$ 24.66

The Company's per unit depletion, depreciation and accretion decreased in the fourth quarter of 2009 compared to the fourth quarter of 2008 due to low cost reserve additions from a successful drilling program in the Company's Septimus, British Columbia and Princess, Alberta areas.

In 2009, per unit depletion, depreciation and accretion costs increased 4%. Per unit costs increased due to a full year of depletion, depreciation and accretion on the Gentry assets acquired in August 2008. The assets acquired were recorded at the fair market value at the acquisition date which was higher than the Company's historic carrying value for proved reserves. However as observed with the fourth quarter 2009 rate of \$23.80 per boe, the Company expects depletion and depreciation rates to decrease in 2010 with continued successful drilling results.

Crew performed a ceiling test as at December 31, 2009. Based on the calculation, the carrying values of the Company's property, plant and equipment are less than the sum of the undiscounted cash flows of the Company's proved reserves; therefore, the Company's property, plant and equipment was considered recoverable.

Taxes

The future income tax recovery for 2009 was \$15.8 million compared to an expense of \$6.4 million in 2008. The recovery was as expected given the loss before income taxes for the year. In 2008, the Company's loss was the result of a write-down of goodwill which was non-deductible for tax purposes.

A summary of the Company's estimated income tax pools at December 31, 2009 is outlined below:

<i>(\$ thousands)</i>	December 31, 2009	December 31, 2008
Cumulative Canadian Exploration Expense	108,900	85,000
Cumulative Canadian Development Expense	132,200	124,000
Cumulative Canadian Oil and Gas Property Expense	110,000	167,000
Undepreciated Capital Cost	103,800	111,000
Share issue costs	5,000	7,700
Non-capital loss	32,000	26,700
	491,900	521,400

The estimated income tax pools have been reduced by the estimated deferred partnership income for 2009 and were impacted by the sale of properties in 2009 totaling \$59.6 million. The Company did not pay cash taxes in 2009 and estimates it has sufficient tax pools to shelter estimated income until 2011 or beyond.

Cash and Funds from Operations and Net Income

	Three months ended December 31		Year ended December 31	
	2009	2008	2009	2008
<i>(\$ thousands, except per share amounts)</i>				
Cash provided by operations	16,734	25,700	82,659	123,356
Funds from operations	27,256	29,646	83,453	127,790
Per share – basic	0.35	0.42	1.11	2.08
– diluted	0.35	0.42	1.11	2.06
Net loss	(9,154)	(74,853)	(37,815)	(53,319)
Per share – basic	(0.12)	(1.05)	(0.50)	(0.87)
– diluted	(0.12)	(1.05)	(0.50)	(0.87)

The fourth quarter 2009 decline in cash provided by operations and funds from operations was the result of decreased production and an increase in costs.

The Company's 2009 decrease in cash provided by operations and funds from operations primarily resulted from the decrease in the Company's price received for oil and natural gas in 2009 as compared to 2008. The Company's net loss decreased in the fourth quarter and year as the 2008 net loss was largely the result of the goodwill write-down in 2008.

Capital Expenditures, Acquisitions and Dispositions

During the fourth quarter, the Company drilled a total of 23 (21.3 net) wells resulting in four (2.3 net) natural gas wells, 17 (17.0 net) oil wells, one (1.0 net) service well and one (1.0 net) dry and abandoned well. In addition, in the quarter, the Company completed 13 (12.8 net) wells and recompleted nine (8.6 net) wells. During the fourth quarter, the Company added to its undeveloped land base, acquiring crown land in northeastern British Columbia and closed the disposition of approximately 600 boe per day of non-core Alberta natural gas production for \$25.3 million. In the fourth quarter, the Company also completed construction of the Septimus gas processing facility, which in December was sold to a third party for its as built cost of \$19.1 million.

During 2009, Crew drilled a total of 43 (36.1 net) wells resulting in 12 (5.9 net) natural gas wells, 26 (26.0 net) oil wells, three (3.0 net) service wells and two (1.2 net) dry and abandoned wells representing a success rate of 95% (97% net). In 2009, Crew closed non-core property dispositions of approximately 1,270 boe per day of production and 4.2 mmboc of proved plus probable reserves for \$59.6 million as well as the aforementioned Septimus facility for \$19.1 million. During 2009, the Company reduced its capital expenditures by \$4.9 million due to government incentive programs for drilling and infrastructure credits in Alberta and British Columbia.

Total exploration and development expenditures for 2009 were \$128.6 million compared to \$191.7 million for the same period in 2008. The expenditures are detailed below:

(\$ thousands)	Three months ended December 31		Year ended December 31	
	2009	2008	2009	2008
Land	5,619	1,148	10,500	25,317
Seismic	2,426	2,779	4,602	5,595
Drilling and completions	37,302	35,283	65,469	124,894
Facilities, equipment and pipelines	8,371	13,071	41,755	30,902
Other	1,594	1,331	6,241	4,969
Total exploration and development	55,312	53,612	128,567	191,677
Property acquisitions (dispositions)	(44,315)	(245)	(78,693)	70,414
Total	10,997	53,367	49,874	262,091

The Company's Board of Directors has approved a net \$120 million exploration and development budget for 2010.

LIQUIDITY AND CAPITAL RESOURCES

Capital Funding

The Company has a credit facility with a syndicate of banks (the "Syndicate") that includes a revolving line of credit of \$235 million and an operating line of credit of \$15 million (the "Facility"). The Facility revolves for a 364 day period and will be subject to its next 364 day extension by June 14, 2010. If not extended, the Facility will cease to revolve, the margins thereunder will increase by 0.50 percent and all outstanding balances under the Facility will become repayable in one year. The available lending limits of the Facility are reviewed semi-annually and are based on the Syndicate's interpretation of the Company's reserves and future commodity prices. There can be no assurance that the amount of the available Facility will not be adjusted at the next scheduled review on or before June 14, 2010. Borrowing margins and fees will also be reviewed as part of the Syndicate's annual review prior to June 14, 2010. At December 31, 2009, the Company had drawings of \$135.6 million on the Facility and had issued letters of credit totaling \$2.8 million.

On May 28, 2009, Crew issued 7,000,000 Common shares at an issue price of \$6.20 per share for total gross proceeds of approximately \$43.4 million. The proceeds were used to pay down the Company's bank debt and to fund the Company's ongoing capital program.

The Company will continue to fund its on-going operations from a combination of cash flow, debt, asset dispositions, and equity financings as needed. As the majority of Crew's on-going capital expenditure program is directed to the further growth of reserves and production volumes, Crew is readily able to adjust its budgeted capital expenditures should the need arise. See discussion under "Capital Structure" below.

Working Capital

The capital intensive nature of Crew's activities generally results in the Company carrying a working capital deficit. However, the Company maintains a sufficient amount of unused bank credit facility to satisfy such working capital deficiencies. At December 31, 2009, the Company's working capital deficiency totaled \$46.7 million which, when combined with the drawings on its bank line, represented 73% of its current bank facility.

Share Capital

As at December 31, 2009, Crew had 78,152,368 Common Shares outstanding along with 5,751,500 options to acquire Common Shares of the Company. As at March 8, 2010, Crew had 78,607,368 Common Shares outstanding along with 7,158,900 options to acquire Common Shares of the Company.

Capital Structure

The Company considers its capital structure to include working capital, bank loan, and shareholders' equity. The Company monitors debt levels based on the ratio of net debt to annualized funds from operations. The ratio represents the time period it would take to pay off the debt if no further capital expenditures were incurred and if funds from operations remained constant. This ratio is calculated as net debt, defined as outstanding bank loan plus or minus net working capital, divided by funds from operations for the most recent calendar quarter, annualized (multiplied by four). The Company's strategy is to maintain a ratio of no more than 2.0 to 1. This ratio may increase at certain times as a result of acquisitions or low commodity prices.

As at December 31, 2009, the Company's ratio of net debt to annualized funds from operations was 1.67 to 1 (2008 – 2.15 to 1). Despite a decrease in commodity prices, the ratio decreased due to non-core property dispositions and the equity raised in May 2009.

<i>(\$ thousands, except ratio)</i>	December 31, 2009	December 31, 2008
Accounts receivable	37,574	42,800
Accounts payable and accrued liabilities	(84,228)	(74,622)
Working capital deficiency	(46,654)	(31,822)
Bank loan	(135,601)	(223,628)
Net debt	(182,255)	(255,450)
Fourth quarter funds from operations	27,256	29,646
Annualized	109,024	118,584
Net debt to annualized funds from operations ratio	1.67	2.15

Contractual Obligations

Throughout the course of its ongoing business, the Company enters into various contractual obligations such as credit agreements, purchase of services, royalty agreements, operating agreements, processing agreements, right of way agreements and lease obligations for office space and automotive equipment. All such contractual obligations reflect market conditions prevailing at the time of contract and none are with related parties. The Company believes it has adequate sources of capital to fund all contractual obligations as they come due. The following table lists the Company's obligations with a fixed term.

(\$ thousands)	Total	2010	2011	2012	2013	2014	Thereafter
Bank Loan ⁽¹⁾	135,601	–	135,601	–	–	–	–
Operating Leases	4,795	1,743	1,743	1,309	–	–	–
Capital commitments	6,000	3,000	3,000	–	–	–	–
Firm transportation agreements	13,977	7,339	6,638	–	–	–	–
Firm processing agreement	29,935	2,493	3,049	3,049	3,049	3,049	15,246
Total	190,308	14,575	150,031	4,358	3,049	3,049	15,246

(1) Based on the existing terms of the Company's bank facility the first possible repayment date may come in 2011. However, it is expected that the revolving bank facility will be extended and no repayment will be required in the near term.

The firm transportation commitments were acquired as part of the Company's May 2007 private company acquisition and represent firm service commitments for transportation and processing of natural gas in British Columbia.

During 2009, Crew entered into the firm processing agreement to process natural gas through a third party owned gas processing facility in the Septimus area of northeast British Columbia. Under the terms of the agreement Crew has committed to process a minimum monthly volume of gas through the facility commencing on December 1, 2009 and continuing through November 30, 2019. The commitment is included in the above table.

The agreement additionally provides Crew the option to participate in an expansion of the facility at a cost of 50% of the total expanded facility construction costs and subsequently become a 50% owner in the facility. If the facility is not expanded prior to January 1, 2013, the current owner of the facility can require Crew to purchase the existing facility for the total construction costs plus \$0.7 million or alter the fees associated with Crew's commitment in order to recover the amount of Crew's full commitment prior to January 1, 2016.

OUTLOOK

One year ago we were mired in one of the worst recessions in decades. The situation has improved dramatically with the world's economy and banking systems generally stabilizing and moving into the early stages of a recovery. Commodity prices have rebounded with oil leading the group; however, natural gas prices remain depressed due to an oversupplied market. Crew intends to focus its capital investments on projects that have the ability to provide the best returns on capital in the current commodity price environment.

The Board of Directors of Crew has approved a net \$120 million 2010 capital expenditure budget which is expected to incorporate the drilling of a minimum of 40 wells of which the majority will be horizontal wells targeting oil at Princess, Alberta. The \$120 million budget is expected to result in average production of between 15,500 and 15,750 boe per day with an exit 2010 production rate in excess of 17,000 boe per day.

ADDITIONAL DISCLOSURES

Risk Assessment

There are a number of risks facing participants in the Canadian oil and gas industry. Some risks are common to all businesses while others are specific to the Company. The following are a number of identifiable business risks faced by Crew which will evolve and additional risks will emerge periodically. The risks shown are those identified by management at the date of completion of this report and may not describe all of the risks faced by the Company.

Substantial Capital Requirements

The Company anticipates making substantial capital expenditures for the acquisition, exploration, development and production of petroleum and natural gas reserves in the future. As the Company's revenues may decline as a result of decreased commodity pricing, it may be required to reduce capital expenditures. In addition, uncertain levels of near term industry activity coupled with the uncertainty in global markets exposes the Company to additional access to capital risk. There can be no assurance that debt or equity financing or funds 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 Company. The inability of the Company to access sufficient capital

for its operations could have a material adverse effect on the Company's financial condition, results of operations and prospects.

Third Party Credit Risk

The Company 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 Company, such failures may have a material adverse effect on the Company's business, financial condition, results of operations and prospects. In addition, poor credit conditions in the industry and the financial condition of its joint venture partners may impact a joint venture partner's willingness to participate in the Company's ongoing capital program, potentially delaying the program and the results of such program until the Company finds a suitable alternative partner.

Global Financial Crisis

Past market events and conditions, including disruptions in international credit markets and other financial systems and the deterioration of global economic conditions have caused significant volatility in commodity prices. These conditions which began in 2008 and continued into 2009, caused a loss of confidence in the broader U.S. and global credit and financial markets and resulted in the collapse of, and government intervention in, major banks, financial institutions and insurers and created 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 taken by governments around the world, 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 deteriorate and stock markets to decline substantially.

During the second half of 2009 the environment improved and the world's credit markets, financial systems and general economy have generally stabilized. Despite this improvement, these factors will continue to fuel economic volatility which will impact the performance of the global economy and may negatively impact company valuations and performance for the foreseeable future.

Quarterly Analysis

The following table summarizes the Company's key quarterly financial results in 2009 and 2008:

<i>(\$ thousands, except per share amounts)</i>	Dec. 31 2009	Sept. 30 2009	June 30 2009	Mar. 31 2009	Dec. 31 2008	Sept. 30 2008	June 30 2008	Mar. 31 2008
Total daily production (boe/d)	14,470	13,065	13,466	15,022	14,869	11,505	9,445	10,614
Average wellhead price (\$/boe)	43.30	32.04	32.10	34.28	42.99	61.74	70.18	53.20
Petroleum and natural gas sales	57,646	38,510	39,331	46,342	58,806	65,345	60,316	51,389
Cash provided by operations	16,734	24,902	21,517	19,506	25,700	36,208	31,908	29,540
Funds from operations	27,256	19,640	20,036	16,521	29,646	35,004	34,102	29,038
Per share – basic	0.35	0.25	0.27	0.23	0.42	0.54	0.60	0.54
– diluted	0.35	0.25	0.27	0.23	0.42	0.54	0.58	0.54
Net income (loss)	(9,154)	(7,376)	(12,267)	(9,018)	(74,853)	15,178	5,415	941
Per share – basic	(0.12)	(0.10)	(0.17)	(0.13)	(1.05)	0.24	0.09	0.02
– diluted	(0.12)	(0.10)	(0.17)	(0.13)	(1.05)	0.23	0.09	0.02

Significant factors and trends that have impacted the Company's results during the above periods include:

- Revenue is directly impacted by the Company's ability to replace existing declining production and add incremental production through its on-going capital expenditure program.
- Production in the second quarter of 2008 and 2009 was negatively impacted by scheduled and unscheduled third party facility shutdowns.
- In August 2008, the Company acquired Gentry Resources Ltd. with approximately 4,000 boe per day of production at closing.

- Revenue and royalties are significantly impacted by underlying commodity prices. The Company utilizes derivative contracts and forward sales contracts to reduce the exposure to commodity price fluctuations. These contracts can cause volatility in net income as a result of unrealized gains and losses on commodity derivative contracts held for risk management purposes.
- Throughout 2008, the Company's operating costs, general and administrative costs and capital expenditures were subject to inflationary pressures brought on by increasing demand for services and supplies within the Canadian oil and gas industry.
- In the fourth quarter of 2008, Crew performed an impairment test on its goodwill and determined that its carrying value exceeded its fair value and therefore an impairment charge of \$69.1 million was required.
- In 2009, the Company sold non-core assets with approximately 1,270 boe per day of production for \$59.6 million. The major dispositions closed as follows:
 - First quarter 2009 – 130 boe per day for \$10.7 million
 - Second quarter 2009 – 540 boe per day for \$22.5 million
 - Fourth quarter 2009 – 600 boe per day for \$25.3 million
- In the fourth quarter of 2009, the Company completed the construction of its Septimus gas processing facility and subsequently sold it to a third party for its as built cost of \$19.1 million.

The following table summarizes Crew's key financial results over the past three years:

<i>(\$ thousands, except per share amounts)</i>	Year ended December 31, 2009	Year ended December 31, 2008	Year ended December 31, 2007
Petroleum and natural gas sales	181,829	235,856	140,466
Cash provided by operations	82,660	123,356	74,400
Funds from operations	83,453	127,790	81,433
Per share – basic	1.11	2.08	1.75
– diluted	1.11	2.06	1.74
Net income (loss)	(37,815)	(53,319)	9,110
Per share – basic	(0.50)	(0.87)	0.20
– diluted	(0.50)	(0.87)	0.19
Daily production (boe/d)	14,002	11,617	8,696
Crew average sales price (\$/boe)	35.58	55.47	44.45
Total assets	963,248	1,045,510	602,193
Working capital deficiency	46,654	31,822	14,643
Bank loan	135,601	223,628	95,028
Total other long-term liabilities	136,992	152,679	98,472

Crew's petroleum and natural gas sales, cash provided by operations, funds from operations and net income are all impacted by production levels and commodity pricing. Despite increasing production, these performance measures have all fluctuated throughout 2008 and 2009 as a result of volatile oil and natural gas prices combined with the increased cost of the Company's operations.

Change in Accounting Policies

In January 2009, the CICA issued Section 1582, Business Combinations. This section is effective January 1, 2011 and applies prospectively to business combinations for which the acquisition date is on or after January 1, 2011 for the Company. Early adoption is permitted. This section replaces Section 1581, "Business Combinations" and harmonizes the Canadian standards with International Financial Reporting Standards ("IFRS").

In January 2009, the AcSB issued Section 1601, "Consolidated Financial Statements", and Section 1602, "Non-controlling Interests", which together replace Section 1600, "Consolidated Financial Statements", and harmonize the Cana-

dian standards with International Financial Reporting Standards. Section 1601 establishes standards for the preparation of consolidated financial statements subsequent to a business combination. These sections are effective on or after January 1, 2011 for the Company. Early adoption is permitted.

New Accounting Pronouncements

International Financial Reporting Standards (IFRS)

In February 2008, the CICA Accounting Standards Board (“AcSB”) confirmed the changeover to IFRS from Canadian GAAP will be required for publicly accountable enterprises for interim and annual financial statements effective for fiscal years beginning on or after January 1, 2011, including comparatives for 2010. Crew’s financial statements up to and including the December 31, 2010 financial statements will continue to be reported in accordance with Canadian GAAP as it exists on each reporting date. Financial statements for the quarter ended March 31, 2011, including comparative amounts, will be prepared on an IFRS basis.

In July 2009, the International Accounting Standards Board (“IASB”) issued amendments to IFRS 1 “First time adoption of IFRS” allowing additional exemptions for first-time adopters. Under these amendments, full cost oil and gas companies can elect to use the recorded amount under a previous GAAP as the deemed cost for oil and gas assets on the transition date to IFRS. Crew is currently planning to adopt this exemption.

In order to transition to IFRS, Management has established a project team and formed an executive steering committee. A transition plan has been developed to convert the financial statements to IFRS. External advisors have been retained and will assist management with the project on an as needed basis. Staff training programs will continue throughout 2010. During 2009, the project team completed the diagnostic phase of our project and identified key differences between Canadian GAAP and IFRS. Subsequently, we focused on accounting policy decisions, modifications to our IT systems and accounting processes as well as reviewing our internal controls over financial reporting. The project team and steering committee continue to provide updates to senior management and the Audit Committee. Changes in IFRS are likely and may materially impact the financial statements. Possible differences between current accounting policies under Canadian GAAP and expected accounting policies under IFRS include the following:

- Depletion and depreciation of property, plant and equipment (“PP&E”) will be based on significant components. Under IFRS 1, the net book value of the PP&E will be allocated to the new cost centres on the basis of Crew’s reserve volumes or values as per the deemed cost election. Depletion of resource properties will generally continue to be calculated using the unit-of-production method but Crew has the option to base the calculation using proved reserves or proved and probable reserves. Crew has not concluded at this time which method it will use and will continue to monitor its peers to ensure comparability.
- Oil and gas properties will be classified as either PP&E or Exploration and Evaluation assets (E&E). Upon transition to IFRS, Crew will reclassify all E&E expenditures that are currently included in the PP&E balance on the Consolidated Balance Sheet. These assets will be measured at cost and will not be depleted but will be assessed for impairment when indicators suggest the possibility of impairment. E&E will primarily consist of undeveloped land and exploratory drilling costs.
- Business Combinations – IFRS 1 allows Crew to use the IFRS rules for business combinations on a prospective basis rather than re-stating all business combinations. Crew will likely use this exemption on any acquisitions prior to January 1, 2010.
- Currently Crew expenses its stock-based compensation on a straight-line basis while under IFRS, share-based payments are expensed based on a graded vesting schedule. Crew will also be required to incorporate a forfeiture multiplier rather than account for forfeitures as they occur under Canadian GAAP.
- Under Canadian GAAP, impairment testing on oil and gas properties is performed at a cost centre level, while under IFRS, it will be performed at a lower level, referred to as a cash generating unit. This will result in a greater number of impairment tests.

- Under Canadian GAAP, Crew's Asset Retirement Obligation calculation utilizes a credit adjusted risk free rate; however, IFRS requires the use of a discount rate that reflects the risks specific to the obligation.
- Due to the recent withdrawal of the exposure draft on IAS 12 Income Taxes in November 2009, and the issuance of the exposure draft on IAS 37 Provisions, Contingent Liabilities and Contingent Assets in January 2010, Crew is still determining the impact of these revised standards on its IFRS transition.

In addition to accounting policy differences, Crew's transition to IFRS will impact the internal controls over financial reporting, disclosure controls and procedures, Crew's business activities and IT systems as follows:

- Throughout 2010, Crew will be updating our internal control documentation but do not expect that the transition to IFRS will have a significant impact on either our internal controls over financial reporting or our disclosure controls and procedures.
- With ongoing communication throughout the Company, management does not expect the adoption of IFRS to have a significant impact or influence on our business activities or strategies.
- We have completed a review of the expected changes that will be required for our IT systems. Testing has been completed and upgrades and system changes will commence in 2010.

Application of Critical Accounting Estimates

Crew's significant accounting policies are disclosed in note one to the December 31, 2009 consolidated financial statements. Certain accounting policies require that management make appropriate decisions with respect to the formulation of estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. These accounting policies are discussed below and are included to aid the reader in assessing the critical accounting policies and practices of the Company and the likelihood of materially different results being reported. Crew's management reviews its estimates regularly. The emergence of new information and changed circumstances may result in actual results or changes to estimate amounts that differ materially from current estimates.

The following assessment of significant accounting policies and associated estimates is not meant to be exhaustive. The Company might realize different results from the application of new accounting standards promulgated, from time to time, by various rule-making bodies.

Proved Oil and Gas Reserves

Proved oil and gas reserves, as defined by the Canadian Securities Administrators in National Instrument 51-101 with reference to the Canadian Oil and Gas Evaluation Handbook, 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.

An independent reserve evaluator using all available geological and reservoir data as well as historical production data has prepared Crew's oil and gas reserve estimate. Estimates are reviewed and revised as appropriate. Revisions occur as a result of changes in prices, costs, fiscal regimes, reservoir performance or a change in the Company's development plans. The effect of changes in proved oil and gas reserves on the financial results and position of the Company is described below under the heading "Full-Cost Accounting" and "Full-Cost Accounting Ceiling Test".

Full-Cost Accounting

The Company follows the full cost method of accounting for petroleum and natural gas properties, whereby all costs of exploring for and developing petroleum and natural gas properties and related reserves are capitalized. The capitalized costs are depleted and depreciated using the unit-of-production method based on estimated proved reserves. Reserve estimates can have a significant impact on earnings, as they are a key component in the calculation of depletion and depreciation. A downward revision in a reserve estimate could result in a higher depletion and depreciation charge to earnings. In addition, if net capitalized costs are determined to be in excess of the calculated ceiling, which is based largely on reserve estimates (see Full-Cost Accounting Ceiling Test) the excess must be written off as an expense charged against earnings. In the event of property disposition, proceeds are normally deducted

from the full cost pool without recognition of gain or loss unless there is a change in the depletion rate of 20 percent or greater.

Unproved Properties

Certain costs related to unproved properties are excluded from costs subject to depletion until proved reserves have been determined or their value is impaired. These properties are reviewed quarterly and any impairment is transferred to the costs being depleted.

Full Cost Accounting Ceiling Test

Petroleum and natural gas assets are evaluated in each reporting period to determine that the carrying amount in a cost centre is recoverable and does not exceed the fair value of the properties in the cost centre.

The carrying amounts are assessed to be recoverable if the sum of the undiscounted cash flows expected from the production of proved reserves, the lower of cost and market of unproved properties and the cost of major development projects exceeds the carrying amount of the cost centre. When the carrying amount is not assessed to be recoverable, an impairment loss is recognized to the extent that the carrying amount of the cost centre exceeds the sum of the discounted cash flows expected from the production of proved and probable reserves, the lower of cost and market of unproved properties and the cost of major development projects of the cost centre. The cash flows are estimated using forecast product prices and costs and are discounted using a risk-free interest rate. By their nature, these estimates are subject to measurement uncertainty and the impact on the financial statements could be material. Any impairment loss would be charged as additional depletion and depreciation expense.

Goodwill

In accordance with Section 1581 of the CICA handbook, goodwill must be recorded on a business combination when the total purchase consideration exceeds the fair value of the net identifiable assets and liabilities of the acquired entity. The goodwill balance is not amortized, however, must be assessed for impairment at least annually. Impairment is determined based on the fair value of the reporting entity compared to its book value. Any impairment must be charged to net income or loss in the period the impairment occurs. In order to estimate fair values of the net identifiable assets and liabilities of the acquired entity, management makes various assumptions, including commodity prices and discount rates. Differences from these estimates may impact the future financial statements of the Company.

Asset Retirement Obligations

The fair value of an asset's retirement obligation must be recognized in the period in which it is incurred if a reasonable estimate of the fair value can be made. The present value of the estimated asset retirement cost is capitalized as part of the carrying amount of the long-lived asset. The depletion and depreciation of the capitalized asset retirement cost is determined on a basis consistent with depletion and depreciation. With the passage of time, accretion will increase the carrying amount of the asset retirement obligation. The actual cost and timing of the Company's asset retirement expenditures may vary significantly from management's current estimates.

Income Taxes

The determination of the Company's income and other tax liabilities requires interpretation of complex laws and regulations often involving multiple jurisdictions. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, the actual income tax liability may differ from that estimated and recorded by management.

Stock-based Compensation

Crew accounts for its stock based compensation program, which includes stock options using the fair value method. The determination of the fair value of options requires management to make assumptions about risk-free interest rates and expected volatility. Such assumptions may change from time to time and the estimated fair value of options calculated at the grant date may differ on subsequent dates. The fair value of stock options being amortized to compensation expense is not revised for any changes to the grant date.

Fair Value of Financial Derivatives

Crew uses financial derivatives to manage commodity price risk, foreign currency risk, and interest rate risk. The fair value of derivative contracts is estimated on Crew's balance sheet with the change in fair value recognized in net income for the period. The fair value of each derivative is based on forward prices or rates and therefore any change in commodity prices, interest rates or foreign currency rates will impact the fair value and net income for the period.

Disclosure Controls and Procedures and Internal Controls over Financial Reporting

The Company's Chief Executive Officer and Chief Financial Officer have designed, or caused to be designed under their supervision, disclosure controls and procedures to provide reasonable assurance that: (i) material information relating to the Company is made known to the Company's Chief Executive Officer and Chief Financial Officer by others, particularly during the period in which the annual and interim filings are being prepared; and (ii) information required to be disclosed by the Company in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time period specified in securities legislation. Such officers have evaluated, or caused to be evaluated under their supervision, the effectiveness of the Company's disclosure controls and procedures at the financial year end of the Company and have concluded that the Company's disclosure controls and procedures are effective at the financial year end of the Company for the foregoing purposes.

The Company's Chief Executive Officer and Chief Financial Officer have designed, or caused to be designed under their supervision, internal controls over financial reporting to provide reasonable assurance regarding the reliability of the Company's financial reporting and the preparation of financial statements for external purposes in accordance with Canadian GAAP. Such officers have evaluated, or caused to be evaluated under their supervision, the design and effectiveness of the Company's internal control over financial reporting at the financial year end of the Company and concluded that the Company's internal control over financial reporting is effective, at the financial year end of the Company, for the foregoing purpose. From 2006 to 2009 Crew engaged external consultants to assist in documenting and assessing the Company's internal controls over financial reporting.

The Company is required to disclose herein any change in the Company's internal control over financial reporting that occurred during the period beginning on October 1, 2009 and ended on December 31, 2009 that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting. No material changes in the Company's internal control over financial reporting were identified during such period, that has materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

It should be noted that a control system, including the Company's disclosure and internal controls and procedures, no matter how well conceived, can provide only reasonable, but not absolute, assurance that the objectives of the control system will be met and it should not be expected that the disclosure and internal controls and procedures will prevent all errors or fraud.

Additional information relating to Crew, including the Company's Annual Information Form, can be found on SEDAR at www.sedar.com.

Dated as of March 8, 2010

MANAGEMENT'S REPORT

Management, in accordance with Canadian generally accepted accounting principles, has prepared the accompanying consolidated financial statements of Crew Energy Inc. Financial and operating information presented throughout this report is consistent with that shown in the consolidated financial statements.

Management is responsible for the integrity of the financial information. Internal control systems are designed and maintained to provide reasonable assurance that assets are safeguarded from loss or unauthorized use and to produce reliable accounting records for financial reporting purposes.

KPMG LLP were appointed by the Company's Board of Directors to conduct an audit of the consolidated financial statements. Their examination included a review and evaluation of Crew's internal control systems and included such test and procedures, as they considered necessary, to provide a reasonable assurance that the consolidated financial statements are presented fairly in accordance with Canadian generally accepted accounting principles.

The Board of Directors is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal control. The Board exercises this responsibility through the Audit Committee, with assistance from the Reserves Committee regarding the annual evaluation of our petroleum and natural gas reserves. The Audit Committee meets regularly with management and the independent auditors to ensure that management's responsibilities are properly discharged, to review the consolidated financial statements and recommend that the consolidated financial statements be presented to the Board of Directors for approval. The Audit Committee also considers the independence of the external auditors and reviews their fees. The external auditors have access to the Audit Committee without the presence of management.

(signed)

Dale O. Shwed
President and CEO

(signed)

John G. Leach
Senior Vice-President and CFO

March 8, 2010

AUDITORS' REPORT TO THE SHAREHOLDERS

We have audited the consolidated balance sheets of Crew Energy Inc. as at December 31, 2009 and 2008 and the consolidated statements of operations, comprehensive loss and retained earnings (deficit) and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2009 and 2008 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

(signed)

Chartered Accountants

Calgary, Canada

March 8, 2010

CONSOLIDATED BALANCE SHEETS

<i>(thousands)</i>	December 31, 2009	December 31, 2008
ASSETS		
Current Assets:		
Accounts receivable	\$ 37,574	\$ 42,800
Fair value of financial instruments (note 10)	-	1,255
Future income taxes (note 12)	542	15
	38,116	44,070
Property, plant and equipment (note 4)	925,132	1,001,440
	\$ 963,248	\$ 1,045,510
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities:		
Accounts payable and accrued liabilities	\$ 84,228	\$ 74,622
Fair value of financial instruments (note 10)	834	-
Current portion of other long-term obligations (note 7)	1,313	1,313
	86,375	75,935
Bank loan (note 6)	135,601	223,628
Other long-term obligations (note 7)	132	1,446
Asset retirement obligations (note 8)	35,341	34,941
Future income taxes (note 12)	101,519	116,292
SHAREHOLDERS' EQUITY		
Share capital (note 9)	617,605	575,191
Contributed surplus (note 9(c))	22,769	16,356
Retained earnings (deficit)	(36,094)	1,721
	604,280	593,268
Commitments (note 14)		
	\$ 963,248	\$ 1,045,510

See accompanying notes to the consolidated financial statements.

On Behalf of the Board of Directors:

(signed)
David G. Smith
Director

(signed)
Dennis L. Nerland
Director

CONSOLIDATED STATEMENTS OF OPERATIONS, COMPREHENSIVE LOSS AND RETAINED EARNINGS (DEFICIT)

<i>(thousands, except per share amounts)</i>	Year ended December 31, 2009	Year ended December 31, 2008
Revenue		
Petroleum and natural gas sales	\$ 181,829	\$ 235,856
Royalties	(36,027)	(49,961)
Realized gain (loss) on financial instruments (note 10)	18,461	(675)
Unrealized gain (loss) on financial instruments (note 10)	(2,089)	2,608
Other income	-	268
	162,174	188,096
Expenses		
Operating	57,342	37,520
Transportation	11,229	8,924
Interest	6,503	7,085
General and administrative	5,736	4,169
Stock-based compensation (note 9(d))	3,321	3,332
Depletion, depreciation and accretion	131,613	104,866
Write-down of goodwill (note 5)	-	69,071
	215,744	234,967
Loss before income taxes	(53,570)	(46,871)
Future income tax expense (reduction) (note 12)	(15,755)	6,448
Loss and comprehensive loss	(37,815)	(53,319)
Retained earnings, beginning of year	1,721	55,040
Retained earnings (deficit), end of year	\$ (36,094)	\$ 1,721
Loss per share (note 9(e))		
Basic	\$ (0.50)	\$ (0.87)
Diluted	\$ (0.50)	\$ (0.87)

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

<i>(thousands)</i>	Year ended December 31, 2009	Year ended December 31, 2008
Cash provided by (used in):		
Operating activities:		
Net loss	\$ (37,815)	\$ (53,319)
Items not involving cash:		
Depletion, depreciation and accretion	131,613	104,866
Write-down of goodwill (note 5)	–	69,071
Stock-based compensation	3,321	3,332
Future income tax expense (reduction)	(15,755)	6,448
Unrealized (gain) loss on financial instruments (note 10)	2,089	(2,608)
Transportation liability charge (note 7)	(1,314)	(1,313)
Asset retirement expenditures (note 8)	(589)	(775)
Change in non-cash working capital (note 13)	1,109	(2,346)
	82,659	123,356
Financing activities:		
Increase (decrease) in bank loan	(88,027)	60,396
Issue of common shares	43,961	69,846
Share issue costs	(2,442)	(3,654)
Repurchase of common shares	–	(514)
	(46,508)	126,074
Investing activities:		
Exploration and development	(128,567)	(191,677)
Property acquisitions	–	(70,414)
Property dispositions	78,693	–
Business acquisition (note 3)	–	(1,500)
Change in non-cash working capital (note 13)	13,723	14,161
	(36,151)	(249,430)
Change in cash and cash equivalents	–	–
Cash and cash equivalents, beginning of year	–	–
Cash and cash equivalents, end of year	\$ –	\$ –

See accompanying notes to the consolidated financial statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

For years ended December 31, 2009 and 2008 (Tabular amounts in thousands)

1. SIGNIFICANT ACCOUNTING POLICIES:

The consolidated financial statements of Crew Energy Inc. (“the Company”) have been prepared by management in accordance with Canadian generally accepted accounting principles. Since the determination of certain assets, liabilities, revenues and expenses is dependent upon future events, the preparation of these financial statements requires the use of estimates and assumptions, which have been made with careful judgment. Specifically, the amounts recorded for depletion and depreciation of property, plant and equipment and the provision for asset retirement obligations and abandonment costs are based on estimates. The ceiling test is based on estimates of reserves, future production rates, future petroleum and natural gas prices, future costs and other relevant assumptions. The amounts for stock-based compensation are based on estimates of risk-free rates, expected option life and volatility. Future incomes taxes are based on estimates as to the timing of the reversal of temporary differences and tax rates currently substantively enacted. The fair value of derivative contracts are based on the discounted value of the market for future commodity prices, interest rates and the exchange rate between United States and Canadian dollars. By their nature, these estimates and amounts are subject to measurement uncertainty and the effect on the financial statements of such changes in such estimates in future periods could be significant. In the opinion of management, these financial statements have been properly prepared in accordance with Canadian generally accepted accounting principles within reasonable limits of materiality and within the framework of the significant accounting policies summarized below.

(a) Principles of consolidation:

The consolidated financial statements include the accounts of the Company and its wholly owned subsidiary, Crew Resources Inc., and a partnership, Crew Energy Partnership. All inter-entity balances and transactions have been eliminated.

(b) Cash and cash equivalents:

Cash and cash equivalents include monies on deposit and highly liquid short-term investments having a maturity date of not more than 90 days.

(c) Petroleum and natural gas properties:

The Company follows the full cost method of accounting for petroleum and natural gas properties, whereby all costs of exploring for and developing petroleum and natural gas properties and related reserves are capitalized. Capitalized costs include land acquisition costs, geological and geophysical expenses, cost of drilling both productive and non-productive wells, production facilities, the fair value of asset retirement obligations and related overhead expenses.

Capitalized costs, excluding costs relating to unproved properties, are depleted using the unit-of-production method based on estimated proved reserves of petroleum and natural gas before royalties determined using forecast product prices and as determined by independent petroleum engineers. For purposes of the depletion calculation, natural gas reserves and production are converted to equivalent volumes of crude oil based on relative energy content of six thousand cubic feet of gas to one barrel of oil. Proceeds from the sale of petroleum and natural gas properties are applied against capitalized costs, with no gain or loss recognized unless such a sale would alter the depletion rate by more than 20%.

The costs of acquiring unproved properties are initially excluded from depletion calculations. These unevaluated properties are assessed periodically for impairment. When proved reserves are assigned or the property is considered impaired the costs of the property or the amount of impairment is added to the costs subject to depletion.

Petroleum and natural gas assets are evaluated in each reporting period (the “ceiling test”) to determine that the carrying amount in a cost centre is recoverable and does not exceed the fair value of the properties in the cost centre. The carrying amounts are assessed to be recoverable if the sum of the undiscounted

cash flows expected from the production of proved reserves, the lower of cost and market of unproved properties and the cost of major development projects exceeds the carrying amount of the cost centre. When the carrying amount is not assessed to be recoverable, an impairment loss is recognized to the extent that the carrying amount of the cost centre exceeds the sum of the discounted cash flows expected from the production of proved and probable reserves, the lower of cost and market of unproved properties and the cost of major development projects of the cost centre. The cash flows are estimated using forecast product prices and costs and are discounted using a risk-free interest rate.

(d) Goodwill:

Goodwill is the residual amount that results when the purchase price of a business exceeds the fair value of the net identifiable assets and liabilities acquired. Goodwill is stated at cost and is not amortized. Any goodwill balance is assessed for impairment each year end or more frequently if events or changes in circumstances indicate that the asset may be impaired. The test for impairment is conducted by comparing the book value to the fair value of the reporting entity. Impairment is charged to income in the period it occurs.

(e) Interest in joint operations:

A portion of the Company's petroleum and natural gas exploration and development activity is conducted jointly with others and, accordingly, the financial statements reflect only the Company's proportionate interest in such activities.

(f) Asset retirement obligations:

The fair value of the liability for the Company's asset retirement obligation is recorded in the period in which it is incurred, discounted to its present value using Crew's credit adjusted risk-free interest rate and the corresponding amount is recognized by increasing the carrying amount of the petroleum and natural gas properties. The liability is accreted each period, and the capitalized cost is depleted over the useful life of the related petroleum and natural gas properties. Revisions to the estimated timing of cash flows or to the original estimated undiscounted cost would result in an increase or decrease to the asset retirement obligation. Actual costs incurred upon settlement of the asset retirement obligation are charged against the asset retirement obligation.

(g) Revenue recognition:

Revenues from the sale of petroleum and natural gas are recorded when title passes to a third party.

(h) Financial instruments:

A financial instrument is any contract that gives rise to a financial asset of one entity and a financial liability or equity instrument to another entity. Upon initial recognition all financial instruments, including all derivatives, are recognized on the balance sheet at fair value. Subsequent measurement is then based on the financial instruments being classified into one of five categories: held for trading, held to maturity, loans and receivables, available for sale and other liabilities. The Company has designated its cash and cash equivalents as held for trading which are measured at fair value.

Accounts receivable are classified as loans and receivables which are measured at amortized cost. Accounts payable and accrued liabilities and the bank loan are classified as other liabilities which are measured at amortized cost, which is determined using the effective interest method.

The Company assesses at each reporting period whether its financial assets are impaired.

The Company is exposed to market risks resulting from fluctuations in commodity prices, foreign exchange rates and interest rates in the normal course of operations. A variety of derivative instruments may be used by the Company to reduce its exposure to fluctuations in commodity prices, foreign exchange rates, and interest rates. The Company does not use these derivative instruments for trading or speculative purposes. The Company considers all of these transactions to be economic hedges; however, the majority of the Company's contracts do not qualify or have not been designated as hedges for accounting purposes.

As a result, all derivative contracts are classified as held for trading and are recorded on the balance sheet at fair value, with changes in the fair value recognized in net income. The fair values of these derivative instruments are based on an estimate of the amounts that would have been received or paid to settle these instruments prior to maturity given future market prices and other relevant factors. Proceeds and costs realized from holding the derivative contracts are recognized in net income at the time each transaction under a contract is settled.

The Company measures and recognizes embedded derivatives separately from the host contracts when the economic characteristics and risks of the embedded derivative are not closely related to those of the host contract, when it meets the definition of a derivative and when the entire contract is not measured at fair value. Embedded derivatives are recorded at fair value.

The Company immediately expenses all transaction costs incurred in relation to the acquisition of a financial asset or liability. The bank loan is presented net of deferred interest payments, with interest recognized in net income on an effective interest basis.

The Company applies trade-date accounting for the recognition of a purchase or sale of cash equivalents and derivative contracts.

(i) Flow through shares:

Flow through shares are issued at a fixed price and the proceeds are used to fund qualifying exploration expenditures within a defined period. The expenditures funded by flow through arrangements are renounced to investors in accordance with income tax legislation. Share capital is reduced and future income tax liability is increased by the total estimated future income tax costs of the renounced income tax deductions in the period of renouncement.

(j) Per share amounts:

Basic per share amounts are calculated using the weighted average number of shares outstanding during the period. Diluted per share amounts are calculated based on the treasury-stock method, which assumes that any proceeds obtained on exercise of options would be used to purchase common shares at the average market price. The weighted average number of shares outstanding is then adjusted by the net change.

(k) Stock-based compensation plans:

The Company accounts for its stock-based compensation program, which includes stock options, using the fair value method. Under this method compensation expense related to these programs is recorded in net income over the vesting period with a corresponding increase in contributed surplus. Consideration received on the exercise of stock options together with the amount previously recognized in contributed surplus is credited to share capital.

(l) Income taxes:

The Company uses the asset and liability method of accounting for future income taxes. The future income tax asset or liability is calculated assuming the financial assets and liabilities will be settled at their carrying amount. This amount is compared to the income tax assets and the difference is multiplied by the substantively enacted income tax rate when the temporary differences are expected to reverse.

(m) Comparative amounts:

Certain comparative amounts have been reclassified to conform with presentation adopted in the current year.

2. CHANGES IN ACCOUNTING POLICY:

Future accounting pronouncements

In January 2009, the CICA issued Section 1582, "Business Combinations". This section is effective January 1, 2011 and applies prospectively to business combinations for which the acquisition date is on or after January 1, 2011 for the Company. Early adoption is permitted. This section replaces Section 1581, "Business Combinations" and harmonizes the Canadian standards with International Financial Reporting Standards.

In January 2009, the AcSB issued Section 1601, "Consolidated Financial Statements", and Section 1602, "Non-controlling Interests", which together replace Section 1600, "Consolidated Financial Statements", and harmonize the Canadian standards with International Financial Reporting Standards. Section 1601 establishes standards for the preparation of consolidated financial statements subsequent to a business combination. These sections are effective on or after January 1, 2011 for the Company. Early adoption is permitted.

3. BUSINESS ACQUISITION:

On August 22, 2008, Crew acquired all of the issued and outstanding shares of Gentry Resources Ltd. ("Gentry"). As consideration, Crew issued an aggregate of 12,276,749 common shares at an ascribed value of \$17.49 per share. The ascribed value per share was determined based on Crew's five-day weighted average trading price before and after the announcement of the acquisition on June 23, 2008. The operating results of Gentry were included in the accounts of the Company from August 22, 2008.

The acquisition has been accounted for using the purchase method of accounting as follows:

	Amount
Consideration	
Shares issued	\$ 214,714
Transaction costs	1,500
	\$ 216,214
Net assets received at fair value	
Property, plant and equipment	283,731
Goodwill	48,271
Working capital deficiency	(5,364)
Fair value of financial instruments	(930)
Bank loan	(68,204)
Asset retirement obligations	(13,854)
Future income taxes	(27,436)
	\$ 216,214

4. PROPERTY, PLANT AND EQUIPMENT:

December 31, 2009	Cost	Accumulated depletion & depreciation	Net book value
Petroleum and natural gas properties and equipment	\$ 1,302,399	\$ 377,267	\$ 925,132

December 31, 2008	Cost	Accumulated depletion & depreciation	Net book value
Petroleum and natural gas properties and equipment	\$ 1,249,859	\$ 248,419	\$ 1,001,440

The costs of unproved properties at December 31, 2009 of \$153,674,000 (2008 - \$170,453,000) were excluded from the depletion calculation. Estimated future development costs associated with the development of the Company's proved reserves of \$173,999,000 (2008 - \$108,258,000) have been included in the depletion calculation and estimated salvage values of \$38,039,000 (2008 - \$38,514,000) have been excluded from the depletion calculation.

The following directly attributable general and administrative and stock-based compensation expenses related to exploration and development activities were capitalized:

	Year ended December 31, 2009	Year ended December 31, 2008
General and administrative expense	\$ 5,736	\$ 4,169
Stock-based compensation expense, including future income taxes	4,442	4,485
	\$ 10,178	\$ 8,654

Crew performed a ceiling test as at December 31, 2009. Based on the calculation, the carrying values of the Company's property, plant and equipment are less than the sum of the undiscounted cash flows of the Company's proved reserves based on the following benchmark and Company prices.

Years	WTI Oil (\$US/Bbl)	F/X Rate (\$Cdn/\$US)	Bow River Oil (\$/bbl)	Company Liquids (\$/bbl)	AECO Gas (\$/mmbtu)	Company Gas (\$/mcf)
2010	\$80.00	0.950	\$71.61	\$69.09	\$5.96	\$5.81
2011	\$83.00	0.950	\$72.59	\$70.56	\$6.79	\$6.79
2012	\$86.00	0.950	\$73.45	\$72.13	\$6.89	\$6.91
2013	\$89.00	0.950	\$74.19	\$73.97	\$6.95	\$6.99
2014	\$92.00	0.950	\$76.72	\$76.18	\$7.05	\$7.12
2015	\$93.84	0.950	\$78.27	\$77.38	\$7.16	\$7.20
2016	\$95.72	0.950	\$79.85	\$78.72	\$7.42	\$7.48
2017	\$97.64	0.950	\$81.46	\$80.19	\$7.95	\$8.04
2018	\$99.59	0.950	\$83.11	\$81.56	\$8.52	\$8.66
2019	\$101.58	0.950	\$84.78	\$83.02	\$8.69	\$8.84

Annual escalation thereafter +2.0%/yr.

5. GOODWILL:

As at December 31, 2008, the Company determined that its corporate fair value was below the Company's book value. As a result, an impairment of the Company's carried goodwill was recognized and the full amount of \$69.1 million was written-off as a non-cash charge to income in 2008.

	December 31, 2009	December 31, 2008
Balance, beginning of year	\$ -	\$ 20,800
Business acquisition (note 3)	-	48,271
Goodwill impairment recognized	-	(69,071)
Balance, end of year	\$ -	\$ -

6. BANK LOAN:

The Company's bank facility consists of a revolving line of credit of \$235 million and an operating line of credit of \$15 million (the "Facility"). The Facility revolves for a 364 day period and will be subject to its next 364 day extension by June 14, 2010. If not extended, the Facility will cease to revolve, the margins thereunder will increase by 0.50 per cent and all outstanding advances thereunder will become repayable

in one year. The available lending limits of the Facility are reviewed semi-annually and are based on the bank syndicate's interpretation of the Company's reserves and future commodity prices. There can be no assurance that the amount of the available Facility will not be adjusted at the next scheduled review on or before June 14, 2010.

Advances under the Facility are available by way of prime rate loans with interest rates between 1.75 percent and 3.5 percent over the bank's prime lending rate and bankers' acceptances and LIBOR loans, which are subject to stamping fees and margins ranging from 2.75 percent to 4.5 percent depending upon the debt to EBITDA ratio of the Company calculated at the Company's previous quarter end. Drawings on the facility will be subject to unanimous syndicate approval and an additional 0.50 percent increase in fees and margins at any time drawings on the facility exceed \$235 million. Standby fees are charged on the undrawn facility at rates ranging from 0.70 percent to 1.2 percent depending upon the debt to EBITDA ratio.

As at December 31, 2009, the Company's applicable pricing included a 2.25 percent margin on prime lending and a 3.25 percent stamping fee and margin on bankers' acceptances and LIBOR loans along with a 0.80 percent per annum standby fee on the portion of the facility that is not drawn. Borrowing margins and fees are reviewed annually as part of the bank syndicate's annual renewal. At December 31, 2009, the Company had issued letters of credit totaling \$2.8 million which are considered to be drawings on the facility. The effective interest rate on the Company's borrowings under its bank facility for the year ended December 31, 2009 was 3.3% (2008 – 4.9%).

7. OTHER LONG-TERM OBLIGATIONS:

As part of a May 3, 2007 private company acquisition, the Company acquired several firm transportation agreements. These agreements had a fair value at the time of the acquisition of a \$4.9 million liability. This amount was accounted for as part of the acquisition cost and is charged as a reduction to transportation expenses over the life of the contracts as they are incurred. The charge for the year ended December 31, 2009 was \$1.3 million (2008 - \$1.3 million).

8. ASSET RETIREMENT OBLIGATIONS:

Total future asset retirement obligations were determined by management and were based on Crew's net ownership interest, the estimated future costs to reclaim and abandon the wells and facilities and the estimated timing of when the costs will be incurred. Crew estimated the net present value of its total asset retirement obligations as at December 31, 2009 to be \$35,341,000 (2008 - \$34,941,000) based on a total future liability of \$64,030,000 (2008 - \$67,588,000). These payments are expected to be made over the next 30 years. An 8% to 10% (2008 – 8% to 10%) credit adjusted risk free discount rate and 2% (2008 – 2%) inflation rate were used to calculate the present value of the asset retirement obligation.

The following table reconciles Crew's asset retirement obligations:

	Year ended December 31, 2009	Year ended December 31, 2008
Carrying amount, beginning of year	\$ 34,941	\$ 18,668
Liabilities incurred	385	1,228
Liabilities acquired (disposed)	(2,161)	13,927
Accretion expense	2,765	1,893
Liabilities settled	(589)	(775)
Carrying amount, end of year	\$ 35,341	\$ 34,941

9. SHARE CAPITAL:**(a) Authorized:**

Unlimited number of Common Shares

1,881,000 Class C non-voting performance shares ("performance shares")

(b) Common Shares issued:

	Number of shares	Amount
Common Shares, December 31, 2007	53,577	\$ 298,129
Business acquisition (note 3)	12,277	214,714
Public offering issued for cash	5,000	66,750
Exercise of stock options	340	3,096
Shares repurchased under normal course issuer bid	(110)	(890)
Stock-based compensation	–	1,241
Share issue costs, net of future income taxes of \$1,005	–	(2,649)
Flow through shares income tax adjustment on 2007 issuance	–	(5,200)
Common Shares, December 31, 2008	71,084	\$ 575,191
Public offering issued for cash	7,000	43,400
Exercise of stock options	68	561
Stock-based compensation	–	229
Share issue costs, net of future income taxes of \$666	–	(1,776)
Common Shares, December 31, 2009	78,152	\$ 617,605

On May 28, 2009, the Company issued 7,000,000 Common Shares at a price of \$6.20 per share for aggregate gross proceeds of \$43.4 million (\$40.9 million net of issue costs).

On October 10, 2008 Crew filed notice with the Toronto Stock Exchange ("TSX") to make a normal course issuer bid to purchase and cancel up to a maximum of 5,587,988 of the outstanding Common Shares of the Company. The bid ("NCIB") commenced on October 15, 2008 and terminated on October 14, 2009. The Company paid for all Common Shares acquired under the bid at the prevailing market price on the TSX at the time of the purchase. During the year ended December 31, 2008, the Company repurchased and cancelled 110,000 Common Shares at a net cost of \$0.5 million. The average carrying value of the Common Shares repurchased of \$0.9 million was charged to share capital with the excess of \$0.4 million included in contributed surplus. The Company did not repurchase any Common Shares in 2009.

In conjunction with the Company's August 22, 2008 acquisition (note 3), the Company issued 12,276,749 Common Shares to Gentry shareholders in exchange for 100% of the Gentry common shares.

On May 1, 2008, Crew issued 5,000,000 Common Shares at \$13.35 per share for aggregate proceeds of \$66.8 million (\$63.1 million net of issue costs).

(c) Contributed Surplus:

	Amount
Contributed surplus, December 31, 2007	\$ 10,557
Stock-based compensation	6,664
Excess of Common Share redemption amount over Common Share carrying amount	376
Exercise of stock options	(1,241)
Contributed surplus, December 31, 2008	\$ 16,356
Stock-based compensation	6,642
Exercise of stock options	(229)
Contributed surplus, December 31, 2009	\$ 22,769

(d) Stock-based compensation:

The Company measures compensation costs associated with stock-based compensation using the fair market value method and the cost is recognized over the vesting period of the underlying security. The fair value of each stock option is determined at each grant date using the Black-Scholes model with the following weighted average assumptions: risk free interest rate 1.58% (2008 – 4.05%), expected life 4 years (2008 – 4 years), volatility 53% (2008 – 45%), and an expected dividend of nil (2008 – nil). The Company has not incorporated an estimated forfeiture rate for stock options that will not vest, rather the Company accounts for actual forfeitures as they occur.

During 2009 the Company recorded \$6,642,000, (2008 - \$6,664,000) of stock-based compensation expense related to the stock options, of which \$3,321,000 (2008 - \$3,332,000) was capitalized in accordance with the Company's full cost accounting policy. As stock-based compensation is non-deductible for income tax purposes, a future income tax liability of \$1,121,000 (2008 - \$1,153,000) associated with the current year's capitalized stock-based compensation has been recorded.

Stock options

The Company has a floating stock option plan by which the Company may grant options to its employees, directors and consultants for up to 10% of its outstanding Common Shares. Under this plan, the exercise price of each option equals the market price of the Company's Common Shares on the date of grant. All granted options vest over a three-year period and have a four-year term to expiry. Stock options are granted periodically throughout the year. The fair value of the stock options granted during the year as calculated by the Black-Scholes method was \$2.14 per option (2008 - \$3.66).

	Number of options	Weighted average exercise price
Balance December 31, 2007	3,271	\$ 11.41
Granted	2,664	\$ 9.19
Exercised	(340)	\$ 9.12
Forfeited	(875)	\$ 10.43
Cancelled	(444)	\$ 17.75
Balance December 31, 2008	4,276	\$ 9.76
Granted	1,742	\$ 5.08
Exercised	(68)	\$ 8.17
Forfeited	(199)	\$ 10.64
Balance December 31, 2009	5,751	\$ 8.33

The following table summarizes information about the stock options outstanding at December 31, 2009:

Range of exercise prices	Outstanding at December 31, 2009	Weighted average remaining life (years)	Weighted average exercise price	Exercisable at December 31, 2009	Weighted average exercise price
\$2.50 to \$6.50	1,625	3.0	\$ 4.87	2	\$ 4.50
\$6.51 to \$9.50	1,804	2.0	\$ 7.45	637	\$ 7.49
\$9.51 to \$12.50	1,822	1.4	\$ 10.45	1,142	\$ 10.55
\$12.51 to \$18.70	500	2.5	\$ 14.96	167	\$ 14.96
	5,751	2.1	\$ 8.33	1,948	\$ 9.92

(e) Per share amounts:

Per share amounts have been calculated on the weighted average number of shares outstanding. The weighted average shares outstanding for the year ended December 31, 2009 was 75,252,000 (2008 – 61,580,000).

In computing diluted earnings per share for the year ended December 31, 2009, nil (2008 - nil) shares were added to the weighted average Common Shares outstanding to account for the dilution of stock options. There were 5,751,000 (2008 - 4,276,000) stock options that were not included in the diluted earnings per share calculation because they were anti-dilutive.

10. FINANCIAL INSTRUMENTS:

Overview

The Company has exposure to credit, liquidity and market risks from its use of financial instruments. This note provides information about the Company's exposure to each of these risks, the Company's objectives, policies and processes for measuring and managing risk. Further quantitative disclosures are included throughout these financial statements.

The Board of Directors has overall responsibility for the establishment and oversight of the Company's risk management framework. The Board has implemented and monitors compliance with risk management policies. The Company's risk management policies are established to identify and analyze the risks faced by the Company, to set appropriate risk limits and controls, and to monitor risks and adherence to market conditions and the Company's activities.

(a) Credit risk:

Credit risk is the risk of financial loss to the Company if a customer or counterparty to a financial instrument fails to meet its contractual obligations, and arises principally from the Company's receivables from petroleum and natural gas marketers and joint venture partners and the fair value of derivative instruments.

Substantially all of the Company's petroleum and natural gas production is marketed under standard industry terms. Receivables from petroleum and natural gas marketers are normally collected on the 25th day of the month following production. The Company's policy to mitigate credit risk associated with these balances is to establish marketing relationships with large credit worthy purchasers and to sell through multiple purchasers. The Company historically has not experienced any collection issues with its petroleum and natural gas marketers. Joint venture receivables are typically collected within one to three months of the joint venture bill being issued to the partner. The Company attempts to mitigate the risk from joint venture receivables by obtaining partner approval of significant capital expenditures prior to the expenditure. However, the receivables are from participants in the petroleum and natural gas sector, and collection of the outstanding balances can be impacted by industry factors such as commodity price fluctuations, limited capital availability and unsuccessful drilling programs. The Company does not typically obtain collateral from petroleum and natural gas marketers or joint venture partners; however the Company can cash call for major projects and does have the ability in most cases to withhold production from joint venture partners in the event of non-payment.

Derivative assets can consist of commodity, interest rate and foreign exchange contracts used to manage the Company's exposure to fluctuations in commodity prices, interest rates and the exchange rate between United States and Canadian dollars. The Company manages the credit risk exposure related to derivative assets by selecting investment grade counterparties and by not entering into contracts for trading or speculative purposes.

The carrying amount of accounts receivable and derivative assets, when outstanding, represents the maximum credit exposure. As at December 31, 2009 the Company's receivables consisted of \$17.2 (2008 - \$18.4) million of receivables from petroleum and natural gas marketers which has subsequently been collected, \$9.2 (2008 - \$12.4) million from joint venture partners of which \$1.5 million has been subsequently collected, and \$11.2 (2008 - \$12.0) million of Crown deposits, prepaids and other accounts receivable. The Company does not consider any receivables to be past due.

(b) Liquidity risk:

Liquidity risk is the risk that the Company will encounter difficulty in meeting obligations associated with the financial liabilities. The Company's financial liabilities consist of accounts payable and bank loan. Accounts payable consists of invoices payable to trade suppliers for office, field operating activities and capital expenditures. The Company processes invoices within a normal payment period. Accounts payable and financial instruments have contractual maturities of less than one year. The Company maintains a revolving credit facility, as outlined in note 6, that is subject to renewal annually by the lenders and has a contractual maturity in 2011. The Company also maintains and monitors a certain level of cash flow which is used to partially finance all operating and capital expenditures as the Company does not pay dividends.

(c) Market risk:

Market risk is the risk that changes in market conditions, such as commodity prices, interest rates, and foreign exchange rates will affect the Company's net income or the value of financial instruments. The objective of market risk management is to manage and control market risk exposures within acceptable limits, while maximizing the Company's returns.

The Company utilizes both financial derivatives and physical delivery sales contracts to manage market risks. All such transactions are conducted in accordance with the Company's risk management policy that has been approved by the Board of Directors.

(i) Commodity price risk

Commodity price risk is the risk that future cash flows will fluctuate as a result of changes in commodity prices. Commodity prices for petroleum and natural gas are impacted by not only the relationship between the Canadian and United States dollar, as outlined below, but also global economic events that dictate the levels of supply and demand. The Company has attempted to mitigate a portion of the commodity price risk through the use of various financial derivative and physical delivery sales contracts as outlined below. The Company's policy is to enter into commodity price contracts when considered appropriate to a maximum of 50% of forecasted production volumes for a period of not more than two years.

Derivatives are recorded on the balance sheet at fair value at each reporting period with the change in fair value being recognized as an unrealized gain or loss on the consolidated statement of operations.

(ii) Foreign currency exchange rate risk

Foreign currency exchange risk is the risk that the fair value of future cash flows will fluctuate as a result of changes in foreign exchange rates. All of the Company's petroleum and natural gas sales are conducted in Canada and are denominated in Canadian dollars. Canadian commodity prices are influenced by fluctuations in the Canadian to U.S. dollar exchange rate. The Company has attempted to mitigate a portion of its foreign exchange fluctuation risk through the use of financial derivatives as outlined below.

(iii) Interest rate risk

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. The Company is exposed to interest rate fluctuations on its bank loan which bears a floating rate of interest. For the year ended December 31, 2009, a 1.0 percent change to the effective interest rate would have a \$1.5 million impact on net income (2008 - \$0.8 million). The sensitivity for 2009 is higher as compared to 2008 because of an increase in average outstanding bank debt in 2009 compared to 2008.

The Company has attempted to mitigate the impact of future fluctuations in interest rates on its outstanding debt by entering into contracts fixing the base interest rate on \$150 million of banker's acceptance borrowings as outlined below. These rates are, under the Company's bank Facility, subject to additional stamping fees ranging from 2.75 per cent to 4.50 per cent depending upon the debt to EBITDA ratio calculated at the Company's previous quarter end.

The Company's derivative contracts in place as of December 31, 2009 are as follows:

Subject of Contract	Notional Quantity	Term	Reference	Strike Price	Option Traded	Fair Value (\$000s)
Commodity contracts						
Natural Gas	2,500 gj/day	November 1, 2009 – December 31, 2010	AECO C Monthly Index	\$6.00	Swap	534
Natural Gas	5,000 gj/day	January 1, 2010 – December 31, 2010	AECO C Monthly Index	\$8.00	Call	(183)
Natural Gas	10,000 gj/day	January 1, 2010 – December 31, 2010	AECO C Monthly Index	\$7.75	Call	(434)
Natural Gas	2,500 gj/day	January 1, 2010 – December 31, 2010	AECO C Monthly Index	\$6.20	Swap	724
Natural Gas	5,000 gj/day	January 1, 2010 – December 31, 2010	AECO C Monthly Index	\$6.08	Swap	1,214
Natural Gas	2,500 gj/day	January 1, 2010 – December 31, 2010	AECO C Monthly Index	\$5.25	Swap	(148)
Natural Gas	2,500 gj/day	January 1, 2010 – December 31, 2010	AECO C Monthly Index	\$5.55	Swap	133
Natural Gas	5,000 mmbtu/day	January 1, 2010 – December 31, 2010	AECO/NYMEX Basis diff	US\$(0.55)	Swap	(356)
Oil	250 bbl/day	January 1, 2010 – December 31, 2010	CDN\$ WTI	\$78.50	Swap	(734)
Oil	500 bbl/day	January 1, 2010 – December 31, 2010	CDN\$ WTI	\$72.00 – \$88.00	Collar	(700)
Oil	250 bbl/day	January 1, 2010 – December 31, 2010	CDN\$ WTI	\$82.50	Swap	(366)
Oil	500 bbl/day	January 1, 2010 – December 31, 2010	CDN\$ WTI	\$80.50	Swap	(1,100)
Oil	500 bbl/day	January 1, 2010 – December 31, 2010	US\$ WTI	US\$81.00	Swap	(249)
Oil	250 bbl/day	January 1, 2010 – December 31, 2010	CDN\$ WTI	\$80.00 – \$95.02	Collar	81
Total commodity contracts						(1,584)
Foreign exchange contracts						
USD / CDN \$ exchange	US \$2M / Month	January 1, 2010 – December 31, 2010	CDN/USD	1.094	Swap	1,022
Total foreign exchange contracts						1,022
Interest rate contracts						
BA Rate	\$50M / year	February 10, 2009 – February 10, 2011	BA - CDOR	1.10%	Swap	(156)
BA Rate	\$50M / year	February 12, 2009 – February 12, 2011	BA - CDOR	1.10%	Swap	(116)
BA Rate	\$50M / year	May 28, 2009 – May 28, 2011	BA - CDOR	1.12%	Swap	–
Total interest rate contracts						(272)
Total financial instruments						(834)

As at December 31, 2009, a \$0.10 change to the price per thousand cubic feet of natural gas on the natural gas contracts outlined above would have a \$0.1 million impact on net income.

As at December 31, 2009, a \$1.00 per barrel change to the price on the oil contracts outlined above would have a \$0.6 million impact on net income.

As at December 31, 2009, a \$0.01 change to the exchange rate on the foreign exchange contracts outlined above would have a \$0.2 million impact on net income.

As at December 31, 2009, a 0.1% change to the interest rate on the interest rate contracts outlined above would have a \$0.1 million impact on net income.

Subsequent to December 31, 2009, the Company entered into the following financial derivative contracts:

Subject of Contract	Notional Quantity	Term	Reference	Strike Price	Option traded
Natural Gas	2,500 gj/day	April 1, 2010 – October 31, 2010	AECO C – Monthly Index	\$ 5.30 / gj	Swap
Oil	250 bbl/day	March 1, 2010 – December 31, 2010	CDN \$WTI	\$84.00 / bbl	Swap

Fair value of financial instruments

The Company's financial instruments as at December 31, 2009 and 2008 include accounts receivable, derivative contracts, accounts payable and accrued liabilities, and bank debt. The fair value of accounts receivable and accounts payable and accrued liabilities approximate their carrying amounts due to their short-terms to maturity.

The fair value of derivative contracts is determined by discounting the difference between the contracted price and published forward price curves as at the balance sheet date, using the remaining contracted petroleum and natural gas volumes.

Bank debt bears interest at a floating market rate and accordingly the fair market value approximates the carrying value.

Financial Instrument Classification and Measurement

Financial instruments of Crew carried on the consolidated balance sheet are carried at amortized cost with the exception of risk management contracts, which are carried at fair value. There were no significant differences between the carrying value of financial instruments and their estimated fair values as at December 31, 2009.

All of Crew's risk management contracts are transacted in active markets. Crew classifies the fair value of these transactions according to the following hierarchy based on the amount of observable inputs used to value the instrument.

- Level 1:* Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions occur in sufficient frequency and volume to provide pricing information on an ongoing basis.
- Level 2:* Pricing inputs are other than quoted prices in active markets included in Level 1. Prices in Level 2 are either directly or indirectly observable as of the reporting date. Level 2 valuations are based on inputs including quoted forward prices for commodities, time value and volatility factors, which can be substantially observed or corroborated in the marketplace.
- Level 3:* Valuations in this level are those with inputs for the asset or liability that are not based on observable market data.

Crew's risk management contracts have been assessed on the fair value hierarchy described above. Crew's risk management contracts are classified as Level 2. Assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement within the fair value hierarchy level.

11. CAPITAL MANAGEMENT:

The Company's objective when managing capital is to maintain a flexible capital structure which will allow it to execute on its capital expenditure program, which includes expenditures on oil and gas activities which may or may not be successful. Therefore, the Company monitors the level of risk incurred in its capital expenditures to balance the proportion of debt and equity in its capital structure.

The Company considers its capital structure to include working capital, bank loan, and shareholders' equity. Crew's primary capital management objective is to maintain a strong balance sheet in order to continue to fund the future growth of the Company. Crew monitors its capital structure and makes adjustments on an on-going basis in order to maintain the flexibility needed to achieve the Company's long-term objectives. To manage the capital structure the Company may adjust capital spending, hedge future revenue and costs, issue new equity, issue new debt or repay existing debt through asset sales.

The Company monitors debt levels based on the ratio of net debt to annualized funds from operations. The ratio represents the time period it would take to pay off the debt if no further capital expenditures were incurred and if funds from operations remained constant. This ratio is calculated as net debt, defined as outstanding bank debt and net working capital, divided by annualized funds from operations for the most recent quarter.

The Company monitors this ratio and endeavours to maintain it at or below 2.0 to 1.0 in a normalized commodity price environment. This ratio may increase at certain times as a result of acquisitions or low commodity prices. As shown below, as at December 31, 2009, the Company's ratio of net debt to annualized funds from operations was 1.67 to 1 (December 31, 2008 – 2.15 to 1). The ratio improved over the prior year as a result of the equity financing completed in May 2009 and non-core asset dispositions during the year.

	2009	2008
Net debt:		
Accounts receivable	\$ 37,574	\$ 42,800
Accounts payable and accrued liabilities	(84,228)	(74,622)
Working capital deficiency	\$ (46,654)	\$ (31,822)
Bank loan	(135,601)	(223,628)
Net debt	\$ (182,255)	\$ (255,450)

	Three months ended December 31, 2009	Three months ended December 31, 2008
Annualized funds from operations:		
Cash provided by operating activities	\$ 16,734	\$ 25,700
Asset retirement expenditures	111	152
Transportation liability charge	329	328
Change in non-cash working capital	10,082	3,466
Fourth quarter funds from operations	27,256	29,646
Annualized	\$ 109,024	\$ 118,584
Net debt to annualized funds from operations	1.67	2.15

The Company will execute a conservative capital spending program in 2010 currently estimated at a net \$120 million. The Company has commodity, interest rate and foreign exchange hedging for 2010 to provide support for its funds from operations and assist in funding its capital expenditure program. The Company may also consider the sale of additional non-core assets and will consider other forms of financing to improve the Company's financial position if cash flow does not adequately fund the programs planned to achieve the Company's long term objectives.

There has been no change in the Company's approach to capital management during the year ended December 31, 2009.

12. INCOME TAXES:

(a) Future income tax expense:

The provision for income tax expense in the financial statements differs from the result which would have been obtained by applying the combined federal and provincial income tax rate to the Company's loss before income taxes. This difference results from the following items:

	Year ended, December 31, 2009	Year ended December 31, 2008
Loss before income taxes	\$ (53,570)	\$ (46,871)
Combined federal and provincial income tax rate	29.10%	29.70%
Computed "expected" income tax reduction	\$ (15,589)	\$ (13,921)
Increase (decrease) in income taxes resulting from:		
Non-deductible stock-based compensation	966	990
Non-deductible write-down of goodwill	-	20,514
Benefits relating to change in income tax rates	(731)	(1,169)
Other	(401)	34
Future income tax expense (reduction)	\$ (15,755)	\$ 6,448

(b) Future income tax liability:

The components of the Company's future income tax liability are as follows:

	December 31, 2009	December 31, 2008
Future income tax:		
Property, plant and equipment	\$ 121,282	\$ 136,597
Asset retirement obligations	(8,953)	(9,062)
Share issue costs	(2,381)	(2,956)
Non-capital loss	(8,287)	(7,813)
Other	(684)	(489)
Future income tax liability	\$ 100,977	\$ 116,277

The non-capital losses expire during the years 2026 to 2028, except for \$1.2 million which expires in the year 2015.

13. SUPPLEMENTAL CASH FLOW INFORMATION:

	Year ended December 31, 2009	Year ended December 31, 2008
Changes in non-cash working capital:		
Accounts receivable	\$ 5,226	\$ 8,660
Accounts payable and accrued liabilities	9,606	3,155
	\$ 14,832	\$ 11,815
Operating activities	\$ 1,109	\$ (2,346)
Investing activities	13,723	14,161
	\$ 14,832	\$ 11,815

The Company made the following cash outlays in respect of interest expense:

	Year ended December 31, 2009	Year ended December 31, 2008
Interest	\$ 6,246	\$ 6,471

14. COMMITMENTS:

The Company has the following fixed term commitments related to its on-going business:

	Total	2010	2011	2012	2013	2014	Thereafter
Operating leases	\$ 4,795	\$ 1,743	\$ 1,743	\$ 1,309	-	-	-
Capital commitments	6,000	3,000	3,000	-	-	-	-
Transportation agreements	13,977	7,339	6,638	-	-	-	-
Processing agreement	29,935	2,493	3,049	3,049	3,049	3,049	15,246
Total	\$ 54,707	\$ 14,575	\$ 14,430	\$ 4,358	\$ 3,049	\$ 3,049	\$ 15,246

The firm transportation commitments were acquired as part of the Company's May 2007 private company acquisition and represent firm service commitments for transportation and processing of natural gas in British Columbia.

During 2009, Crew entered into an agreement to process natural gas through a third party owned gas processing facility in the Septimus area of northeast British Columbia. Under the terms of the agreement, Crew has committed to process a minimum monthly volume of gas through the facility commencing on December 1, 2009 and continuing through November 30, 2019. The commitment is included in the above table.

The agreement additionally provides Crew the option to participate in an expansion of the facility at a cost of 50% of the total expanded facility construction costs and subsequently become a 50% owner in the facility. If the facility is not expanded prior to January 1, 2013, the current owner of the facility can require Crew to purchase the existing facility for the total construction costs of \$19.1 million plus \$0.7 million or alter the fees associated with Crew's commitment in order to recover the amount of Crew's full commitment prior to January 1, 2016.

CORPORATE INFORMATION

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 Bank of Montreal
 Bank of Nova Scotia

LEGAL COUNSEL

Burnet, Duckworth & Palmer LLP

RESERVE ENGINEERS

GLJ Petroleum Consultants

TRANSFER AGENT

Valiant Trust Company

EXCHANGE LISTING

Toronto Stock Exchange
 Stock Symbol: CR

BOARD OF DIRECTORS

John A. Brussa, Chairman
 Independent Director

Jeffery E. Errico
 Independent Director

Dennis L. Nerland
 Independent Director

Dale O. Shwed
 President, Crew Energy Inc.

David G. Smith
 Independent Director

OFFICERS

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 President and
 Chief Executive Officer

John G. Leach, CA
 Senior Vice President and
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 Vice President, Finance
 and Controller

Michael D. Sandrelli
 Secretary
 Partner, Burnet, Duckworth
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ABBREVIATIONS

bbl	barrels
bbl/d	barrels per day
bcf	billion cubic feet
boe	barrels of oil equivalent (6 mcf: 1 bbl)
bopd	barrels of oil per day
mmbtu	million British thermal units
mboe	thousand barrels of oil equivalent (6 mcf: 1 bbl)
mmboe	million barrels of oil equivalent (6 mcf: 1 bbl)
mcf	thousand cubic feet
mcf/d	thousand cubic feet per day
mmcf	million cubic feet
mmcf/d	million cubic feet per day
ngl	natural gas liquids



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