crew energy inc.

Crew Energy Announces 2010 Fourth Quarter and Annual Financial and Operating Results

March 8, 2011

CALGARY, ALBERTA--(Marketwire - March 8, 2011) - Crew Energy Inc. (TSX:CR) of Calgary, Alberta is pleased to present its operating and financial results for the three month period and year ended December 31, 2010.

Highlights

- Fourth quarter funds from operations of $28.4 million represents an 18% increase over the third quarter of 2010 and annual funds from operations increased 22% to $101.5 million over 2009;

- Funds from operations per share increased 21% over the third quarter of 2010 and annual funds from operations per share increased 12% over 2009;

- Achieved all in finding, development and acquisition costs of $11.03 per boe on proved reserves and $11.40 per boe on proved plus probable reserves including future development costs and revisions;

- Fourth quarter production averaged 14,654 boe per day which was a 12% increase over the third quarter of 2010;

- A fourth quarter 2010 operating netback of $23.55 per boe and exceptional finding, development and acquisition costs of $11.40 per boe yielded a recycle ratio of 2.1x representing a 10% improvement over 2009;

- Operating costs were 8% lower in the fourth quarter of 2010 compared with the same period in 2009.

Financial ($ thousands, except per share amounts)	Three months ended December 31, 2010	Three months ended December 31, 2009	Year ended December 31, 2010	Year ended December 31, 2009
Petroleum and natural gas sales	56,620	57,646	206,343	181,829
Funds from operations (note 1)	28,436	27,256	101,450	83,453
Per share - basic	0.35	0.35	1.27	1.11
- diluted	0.35	0.35	1.24	1.11
Net income (loss)	(9,525)	(9,154)	(17,161)	(37,815)
Per share - basic	(0.12)	(0.12)	(0.22)	(0.50)
- diluted	(0.12)	(0.12)	(0.22)	(0.50)
Exploration and development investment	61,348	55,312	248,870	128,567
Property acquisitions (net of dispositions)	620	(44,315)	(132,020)	(78,693)
Net capital expenditures	61,968	10,997	116,850	49,874

Capital Structure ($ thousands)	As at Dec. 31, 2010	As at Dec. 31, 2009
Working capital deficiency (note 2)	40,707	46,654
Bank loan	138,700	135,601
Net debt	179,407	182,255
Bank facility	240,000	250,000
Common Shares Outstanding (thousands)	80,368	78,152

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 and therefore may not be comparable with the calculations of similar measures for other companies.

(2) Working capital deficiency includes accounts receivable and assets held for sale less accounts payable and accrued liabilities.

Operations	Three months ended December 31, 2010	Three months ended December 31, 2009	Year ended December 31, 2010	Year ended December 31, 2009
Daily production				
Natural gas (mcf/d)	49,104	51,871	49,672	53,698
Oil (bbl/d)	5,321	4,413	4,175	3,690
Natural gas liquids (bbl/d)	1,149	1,412	1,235	1,362
Oil equivalent (boe/d @ 6:1)	14,654	14,470	13,689	14,002
Average prices (note) 1)				
Natural gas ($/mcf)	3.92	4.98	4.45	4.27
Oil ($/bbl)	68.17	68.16	67.48	59.39
Natural gas liquids ($/bbl)	52.57	47.91	50.70	36.28
Oil equivalent ($/boe)	42.00	43.30	41.30	35.58
Netback ($/boe)				
Operating netback (note 2)	23.55	23.29	22.86	18.87
Realized loss/(gain) on financial instruments (note 3)	(0.02)	0.20	0.10	0.15
G&A	1.41	1.11	1.30	1.12
Interest and other	1.06	1.50	1.16	1.27
Funds from operations	21.10	20.48	20.30	16.33
Drilling Activity				
Gross wells	21	23	80	43
Working interest wells	19.8	21.3	75.2	36.1
Success rate, net wells	95%	95%	99%	97%
Undeveloped land				
Gross acres			1,108,552	1,055,660
Net acres			612,003	585,732
Reserves (Proved plus probable) (note 4)				
Oil (Mbbl)			22,186	15,226
Ngl (Mbbl)			6,724	6,650
Gas (Mmcf)			274,685	263,187
BOE (Mboe)			74,691	65,741
Finding, Development & Acquisition Costs ($/boe)			11.40	9.68

Notes:

(1) Average prices are before deduction of transportation costs and do not include realized gains and losses on financial instruments.

(2) Operating netback equals petroleum and natural gas sales including realized hedging gains and losses on commodity related 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 Generally Accepted Accounting Principles and therefore may not be comparable with the calculations of similar measures for other companies.

(3) Amount includes realized gains and losses on non-commodity related financial instruments.

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(4) More detailed information in respect of the results of Crew's
    independent reserve evaluation for the year ended December 31, 2010 as
    evaluated by GLJ Petroleum Consultants Ltd. ("GLJ") and related
    information was contained in Crew's press release dated February 23,
    2011 and will be contained in Crew's Annual Information Form to be filed
    on or before March 31, 2011.
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OVERVIEW

During 2010, economies around the world continued to slowly recover from the financial crisis of 2008 and 2009. The financial stimulus that was injected by governments around the globe continued to aid this recovery as modest economic growth was experienced in many countries including the United States and Canada. Asia, and in particular, China remained a bright spot as its economy continued its torrid growth with an insatiable appetite for raw materials. Oil prices benefited from improved demand for commodities as the pricing volatility that had been experienced in the previous two years calmed with West Texas Intermediate ("WTI") prices trading between US$75 to US $85 for most of the year.

The North American natural gas market paints a contrasting picture. With continued aggressive development of unconventional natural gas resource plays throughout North America the supply of natural gas has significantly outpaced North American demand. Prices for natural gas sold in Canada opened 2010 above $5.00 per million cubic feet in January and February as a result of a cold North American winter but rapidly declined in March to average below $4 per million cubic feet for the remainder of the year.

With a depressed natural gas market, Crew focused more of its 2010 capital expenditure program towards development of its oil resource play in the Princess area of Southern Alberta. The Company directed 62% of its exploration and development budget towards continued growth of this top tier oil play drilling 54 net oil wells and eight service wells in the area, increasing area production to approximately 8,000 boe per day at year end. Expenditures at Princess were also directed to continued development of the area's extensive pipeline and facility infrastructure and the acquisition of 58 sections of undeveloped lands prospective for Pekisko and Mannville development.

During 2010, Crew also continued to develop its Montney assets in northeast British Columbia. The primary focus of the Company's efforts was the continued development of liquids rich natural gas development at Septimus. During the year the Company directed 24% of its total exploration and development budget toward Septimus, drilling a total of 10 (9.5 net) wells which increased production 81% from January to December. To accommodate the Company's planned Septimus production growth, Crew proceeded with the expansion of the area's gas processing facility that was completed in the first quarter of 2011. Crew also drilled and completed a horizontal Montney exploration well at Portage, British Columbia which completed the earning of 32 net sections of land prospective for Doig and Montney natural gas.

The Company strengthened its balance sheet in the second quarter of 2010 with the sale of assets in the Edson, Alberta area which included 1,700 boe per day of natural gas and natural gas liquids production and 7.1 mmboe of proved plus probable reserves for proceeds of $126 million. The sale of these natural gas assets allowed the Company to continue to accelerate development of its oil assets and resource capture at Princess.

The sale of assets at Edson and the impact of poor spring and summer weather on production at Princess resulted in a decline in production from a first quarter average of 15,001 boe per day to an average of 13,689 boe per day for the year. While the Company's average production was impacted by an unusually wet summer in southern Alberta, an aggressive third and fourth quarter capital expenditure program resulted in the Company averaging 16,900 boe per day in December with production over 17,500 boe per day in the latter part of December.

The Company's financial results were aided by increased oil production, stronger oil prices and lower operating costs in 2010 with funds from operations increasing 22% to $101.5 million. The Company's financial position remained strong with net debt at year end of $179 million or 1.6 times annualized fourth quarter funds from operations.

OPERATIONS UPDATE

Pekisko Play, Princess, Alberta

Crew is pleased with the progress made in the Pekisko play at Princess. In 2010, Crew increased proved plus probable reserves by 59% to 24.1 million boe and 240% since the asset was acquired in 2008. At the end of 2010, Crew had 52 horizontal wells on production that have first month initial production rates averaging 218 boe per day (90% oil) which led to an exit rate of approximately 8,000 boe per day in the area. Crew currently plans on drilling 73 net horizontal wells, 25 net vertical wells and 21 net service wells in 2011 which is expected to generate average annual production of approximately 9,400 boe per day and exit production of over 12,000 boe per day.

In the first quarter of 2011, Crew currently has five drilling rigs and five service rigs working at Princess. To date, the Company has drilled 16 net horizontal wells with two currently drilling and five more scheduled to be drilled in the first quarter. Six vertical wells have been drilled with two currently drilling and seven additional wells planned in the first quarter. Two service wells have been drilled and one is currently drilling to complete the first quarter drilling program at Princess. Crew has tied in two wells thus far in the quarter that are currently averaging 290 boe per day.

Montney Play, Septimus, British Columbia

In the Montney play at Septimus, Crew's 2010 drilling program was very successful increasing reserves by 19% over 2009 to 25.7 million boe. Reserves per well also increased to 2.9 bcf representing a 7% increase. The Company believes this area holds significant upside as the reserves currently assigned represent an estimated 14% recovery factor.

Crew has drilled two (1.33 net) wells and is currently drilling one well with a fourth well scheduled to be drilled in the first quarter. The first well of this program is currently being completed with one additional well expected to be completed by spring breakup. Of the wells expected to be drilled in the area in the first quarter, there are three (3.0 net) targeting liquids rich natural gas and one (0.33 net) targeting the oil window in the upper Montney zone. Plans for 2011 are to drill 6 (5.33 net) wells at Septimus.

In early February, Crew completed the expansion of the Septimus gas processing facility doubling its capacity to approximately 50 mmcf per day. Upon completion of the expansion, the Company completed a previously arranged transaction recovering the $16.9 million cost of the expansion from Aux Sable Canada ("ASC") who now owns 100% of the expanded facility. Under the terms of the arrangement, Crew will remain operator of the facility and has retained the option to re-purchase a 50% interest in the facility, at Crew's option, on or before January 1, 2014.

EXPANDED DRILLING PROGRAM

The previously announced expansion of the capital program as a result of the Company's recent equity financing will allow Crew to test a number of resource exploration concepts on its land base. The Company has also identified additional opportunities for resource capture that it plans to pursue over the balance of the year.

In West Central Alberta, the Company plans to drill two wells targeting light oil in the Cardium formation where the Company owns 40 net sections of prospective land and three wells targeting liquids rich gas in the Mannville group where Crew owns 30 net sections of land.

At Provost, Alberta, Crew plans to drill two to three wells targeting light oil from the Viking formation where the Company owns 16 net sections of prospective land.

At Kobes, British Columbia, Crew plans to drill its first horizontal well targeting the lower Montney offsetting a vertical well that tested 2.5 mmcf per day and 125 bbls per day of condensate. The Company believes there is potentially 1,000 feet of gas saturated rock on 23 net sections at Kobes that, if successful, may ultimately require eight to twelve wells per section to adequately deplete the resource.

OUTLOOK

The Board of Directors of Crew has approved an increase in the 2011 capital expenditure budget to $260 million which is expected to include the drilling of a record 130 net wells. Over 90% of this drilling program is dedicated to the Company's Princess oil play. This program is expected to be adequately financed through the recently closed $100 million bought deal financing, cash flow and the Company's recently expanded $240 million bank facility. With an emphasis on oil drilling, the Company is expecting the liquids component of its production to increase to approximately 55% to 60% of total oil and natural gas production by year end resulting in average production of between 18,300 and 19,300 boe per day and exit production of 21,000 to 22,000 boe per day.

We are confident in the quality of our assets and the opportunities they provide our shareholders. The Company will continue to strive to improve operating metrics and the efficient execution of our very active capital program. We are well positioned to deliver sustainable reserve and production growth in 2011 and beyond and look forward to reporting our progress in the first quarter 2011 report.

Management's Discussion and Analysis

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 unaudited consolidated financial statements of the Company for the three month periods and years ended December 31, 2010 and 2009 and the audited consolidated financial statements and Management Discussion and Analysis for the year ended December 31, 2009. 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, 2010 and 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, drilling plans and the timing thereof, plans for the tie-in and completion of wells and the timing thereof, capital expenditures, timing of capital expenditures and methods of financing capital expenditures and the ability to fund financial liabilities, production estimates, expected commodity mix and prices and the impact on Crew, future operating costs, future transportation costs, expected royalty rates, future general and administrative expenses, interest rates, debt levels, funds from operations, the timing of and impact of adoption of IFRS, policy choices to be made under 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 and partner 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, regulatory and partner approvals, 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 wellhead nor at the plant gate which is where Crew sells its production volumes and therefore may be a misleading measure, particularly 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 operating activities, 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 activities to funds from operations:

($ thousands)	Three months ended December 31, 2010	Three months ended December 31, 2009	Year ended December 31, 2010	Year ended December 31, 2009
Cash provided by operating activities	21,212	16,734	97,170	82,659
Asset retirement expenditures	606	111	1,512	589
Transportation liability charge (note 1)	120	329	758	1,314
Change in non-cash working capital	6,498	10,082	2,010	(1,109)
Funds from operations	28,436	27,256	101,450	83,453

Notes:
(1) The amount for the year ended December 31, 2010 does not include the transportation liability write-down of $344,000 as described in the Transportation Costs section.

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 related 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

Production

	Three months ended December 31, 2010				Three months ended December 31, 2009			
	Oil (bbl/d)	Ngl (bbl/d)	Nat. gas (mcf/d)	Total (boe/d)	Oil (bbl/d)	Ngl (bbl/d)	Nat. gas (mcf/d)	Total (boe/d)
Alberta	5,172	393	23,358	9,458	4,256	828	30,844	10,224
British Columbia	149	756	25,746	5,196	157	584	21,027	4,246
Total	5,321	1,149	49,104	14,654	4,413	1,412	51,871	14,470

Production for the fourth quarter of 2010 was slightly higher than the same period in 2009 due to a successful drilling program at Princess, Alberta. Natural gas and associated liquids production decreased in the fourth quarter compared with the fourth quarter of 2009 due to the disposition of approximately 2,300 boe per day of primarily natural gas production from two separate dispositions at Ferrier and Edson, Alberta which closed in late 2009 and at the end of the first quarter of 2010, respectively. These dispositions were partially offset by production additions from a successful drilling program which added liquids rich natural gas production in the Septimus, British Columbia area. Oil production increased 21% in the fourth quarter of 2010 compared to the same period in 2009 due to production additions from Princess.

	Year ended December 31, 2010				Year ended December 31, 2009			
	Oil (bbl/d)	Ngl (bbl/d)	Nat. gas (mcf/d)	Total (boe/d)	Oil (bbl/d)	Ngl (bbl/d)	Nat. gas (mcf/d)	Total (boe/d)
Alberta	4,043	500	24,502	8,627	3,496	893	35,373	10,285
British Columbia	132	735	25,170	5,062	194	469	18,325	3,717
Total	4,175	1,235	49,672	13,689	3,690	1,362	53,698	14,002

Production for 2010 decreased over 2009 due to the previously mentioned asset dispositions but was partially offset by production additions from a successful drilling program as described above. Weather related delays hampered activity in the second and third quarter of 2010 in southern Alberta which created delays in bringing on new oil production; consequently, the Company's annual oil production for 2010 was below its original expectations.

Revenue

	Three months ended December 31, 2010	Three months ended December 31, 2009	Year ended December 31, 2010	Year ended December 31, 2009
Revenue ($ thousands)				
Natural gas	17,691	23,746	80,656	83,699
Oil	33,373	27,674	102,824	79,997
Natural gas liquids	5,556	6,226	22,863	18,035
Sulphur	-	-	-	98
Total	56,620	57,646	206,343	181,829
Crew average prices				
Natural gas ($/mcf)	3.92	4.98	4.45	4.27
Oil ($/bbl)	68.17	68.16	67.48	59.39
Natural gas liquids ($/bbl)	52.57	47.91	50.70	36.28
Oil equivalent ($/boe)	42.00	43.30	41.30	35.58
Benchmark pricing				
Natural Gas - AECO C daily index (Cdn $/mcf)	3.68	4.61	4.06	4.03
Oil - Bow River Crude Oil (Cdn $/bbl)	78.25	77.45	77.22	68.71
Oil and ngl - Cdn$ West Texas Int. (Cdn $/bbl)	86.25	80.48	81.86	69.59

Crew's fourth quarter 2010 revenue decreased 2% over the same period in 2009 primarily due to a 21% decrease in its natural gas price partially offset by a 21% increase in oil production. Crew's average price received for natural gas production decreased 21% which was comparable to the decrease in the Company's AECO C benchmark price. The Company's oil price was consistent from the fourth quarter of 2010 to the same period in 2009 which was in line with a minor change in the Company's benchmark Bow River Crude price. The price received for the Company's natural gas liquids ("ngl") production increased 10% in the fourth quarter of 2010 as compared to the same period in 2009 which was comparable to the increase in the Company's Cdn$ West Texas Intermediate benchmark.

For 2010, Crew's natural gas price increased 4% compared to a minor increase in the Company's benchmark. Decreased production of lower valued Sierra, British Columbia natural gas production that was replaced by higher valued Septimus natural gas production accounts for the disproportionate increase in pricing. Crew's oil price increased proportionately with the Bow River Crude Oil benchmark for the year ended December 31, 2010. The Company's ngl price increased disproportionately as compared to the Company's Cdn$ West Texas Intermediate benchmark due to the disposition of lower valued ethane production in the Ferrier area in late 2009 and increased sales of higher valued condensate production in the Septimus area.

Royalties

($ thousands, except per boe)	Three months ended Dec. 31, 2010	Three months ended Dec. 31, 2009	Year ended Dec. 31, 2010	Year ended Dec. 31, 2009
Royalties	11,311	13,167	41,799	36,027
Per boe	$ 8.39	$ 9.89	$ 8.37	$ 7.05
Percentage of revenue	20.0%	22.8%	20.3%	19.8%

Royalties as a percentage of revenue decreased in the fourth quarter of 2010 as compared with the same period in 2009 due to new natural gas production at Septimus which currently attracts a lower royalty rate and due to a lower natural gas price which decreases the natural gas royalty rates in Alberta. This was partially offset by new oil production in the Princess area which attracts a higher royalty rate than the Company's existing production.

For the year ended December 31, 2010, royalties as a percentage of revenue slightly increased over the same period in 2009 due to additional higher royalty rate production from the Princess area combined with the disposition of lower royalty rate natural gas production from the Edson properties in early 2010. Corporately, with an increase in forecasted Princess area production, Crew expects annual royalties as a percentage of revenue to average approximately 25% for 2011.

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 primarily on the use of puts, costless collars, swaps and fixed price contracts to reduce 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 2010, these contracts had the following impact on the consolidated statement of operations:

($ thousands)	Three months ended December 31, 2010	Three months ended December 31, 2009	Year ended December 31, 2010	Year ended December 31, 2009
Realized gain on financial instruments	3,284	4,471	13,082	18,461
Unrealized loss on financial instruments	(12,586)	(6,225)	(7,380)	(2,089)

As at December 31, 2010, 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	January 1, 2011 - December 31, 2011	AECO C Monthly Index	$ 4.85	Swap(1)	961
Natural Gas	2,500 gj/day	January 1, 2011 - December 31, 2011	AECO C Monthly Index	$ 4.90	Swap(1)	1,001
Natural Gas	2,500 gj/day	January 1, 2011 - December 31, 2011	AECO C Monthly Index	$ 4.95	Swap(1)	1,046

Natural Gas	2,500 gj/day	January 1, 2011 - December 31, 2011	AECO C Monthly Index	$ 4.965	Swap(1)	1,058
Natural Gas	7,500 gj/day	January 1, 2011 - December 31, 2011	AECO C Monthly Index	$ 5.00	Swap(1)	3,276
Oil	500 bbl/day	January 1, 2011 - December 31, 2011	US$ WTI	US$80.15	Swap	(2,478)
Oil	250 bbl/day	January 1, 2011 - December 31, 2011	CDN$ WTI	$ 86.00	Swap	(723)
Oil	500 bbl/day	January 1, 2011 - December 31, 2011	CDN$ WTI	$ 88.00	Swap	(1,031)
Oil	250 bbl/day	January 1, 2011 - December 31, 2011	CDN$ WTI	$ 88.50	Swap	(474)
Oil	250 bbl/day	January 1, 2011 - December 31, 2011	CDN$ WTI	$ 90.00	Swap	(332)
Oil	500 bbl/day	January 1, 2011 - December 31, 2011	CDN$ WTI	$ 90.20	Swap	(641)
Oil	500 bbl/day	January 1, 2011 - December 31, 2011	CDN$ WTI	$ 93.00	Swap	15
Oil	250 bbl/day	January 1, 2011 - December 31, 2011	CDN$ WTI	$80.00 - $ 95.45	Collar	(307)
Oil	250 bbl/day	January 1, 2011 - December 31, 2011	CDN$ WTI	$82.00 - $ 94.62	Collar	(340)
Oil	250 bbl/day	January 1, 2011 - December 31, 2011	CDN$ WTI	$85.00 - $ 100.50	Collar	(24)
Oil	500 bbl/day	January 1, 2011 - June 30, 2011	CDN$ WCS - WTI diff	($18.00)	Swap	(46)
Oil	500 bbl/day	January 1, 2012 - December 31, 2012	CDN$ WTI	$ 85.00	Call(1)	(3,081)
Oil	750 bbl/day	January 1, 2012 - December 31, 2012	CDN$ WTI	$ 90.00	Call(1)	(3,548)
Oil	500 bbl/day	January 1, 2012 - December 31, 2012	US$ WTI	US$90.00	Call(1)	(2,566)
Total						(8,234)

(1) Derivative contracts are part of a paired transaction in which the proceeds from the sale of 2012 oil calls were used to fund the 2011 natural gas swaps at the prices indicated.

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, 2010, Crew had contracts in place fixing the interest rate on $100 million of bankers' acceptances at a rate of 1.10%. The Company pays additional stamping fees and margins on bankers' acceptances as outlined in note 4 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	8
BA Rate	$50M / year	February 12, 2009 - February 12, 2011	BA - CDOR	1.10%	Swap	12
Total						20

Subsequent to December 31, 2010, the Company entered into the following derivative contracts:

Subject of Contract	Volume	Term	Reference	Strike Price (per bbl)	Option Traded
Oil	500 bbl/day	January 1, 2012 - December 31, 2012	CDN $WTI	$ 101.00/bbl	Swap
Oil	250 bbl/day	January 1, 2012 - December 31, 2012	CDN $WTI	$ 100.45/bbl	Swap
Oil	250 bbl/day	January 1, 2012 - December 31, 2012	CDN $WTI	$ 100.50/bbl	Swap

Operating Costs

($ thousands, except per boe)	Three months ended December 31, 2010	Three months ended December 31, 2009	Year ended December 31, 2010	Year ended December 31, 2009
Operating costs	14,009	15,084	53,976	57,342
Per boe	$ 10.39	$ 11.33	$ 10.80	$ 11.22

In the fourth quarter of 2010, the Company's operating costs and costs per unit decreased over the same period in 2009 due to the addition of lower cost natural gas and associated liquids production in the Septimus area. This was partially offset by the addition of higher cost production from the Princess area and the disposition of lower cost production in the Ferrier and Edson areas in late 2009 and early 2010.

For 2010, additional oil production at Princess with higher costs was more than offset by lower cost natural gas and associated liquids production additions in the Septimus area thus decreasing overall corporate operating costs. In 2010, although additional production partially offset fixed costs, Crew continued to contend with fluid handling in the Princess area. Delays in regulatory approval of water injection wells hampered the timing of activating these wells thus increasing oil operating costs for the year. The Company continues to research and identify cost cutting measures in order to be proactive in water handling and lowering oil operating costs in the area. With increased forecasted production in the Princess area, the Company forecasts corporate operating costs to average between $10.50 and $11.00 per boe for 2011.

Transportation Costs

($ thousands, except per boe)	Three months ended December 31, 2010	Three months ended December 31, 2009	Year ended December 31, 2010	Year ended December 31, 2009
Transportation costs	2,819	3,134	9,582	11,229
Transportation liability write-down	-	-	344	-
Transportation costs excluding liability write-down	2,819	3,134	9,926	11,229
Per boe	$ 2.09	$ 2.35	$ 1.99	$ 2.20

In the fourth quarter of 2010, the Company's transportation costs and transportation costs per unit decreased over the same period in 2009 due to the Company permanently assigning a significant portion of its unutilized firm transportation commitment in northeastern British Columbia in March 2010. Transportation costs increased in the fourth quarter of 2010 compared to the 2010 annual average due to the increased costs per unit of transporting Septimus natural gas volumes to the Alliance pipeline system, additional condensate production at Septimus, which attracts a higher trucking cost, and added clean oil trucking costs at Princess for delivering a portion of the area's volumes to an alternative terminal in order to receive enhanced pricing.

For 2010, the Company's transportation costs and transportation costs per unit decreased over 2009 due to the previously mentioned assignment of the unutilized firm transportation commitment as well as additional oil production from the Princess area which currently attracts a lower clean oil trucking cost than the corporate average transportation cost per boe. The Company forecasts transportation costs to range between $1.90 and $2.15 per boe for 2011.

Operating Netbacks

	Three months ended December 31, 2010			
	Oil ($/bbl)	Ngl ($/bbl)	Natural gas ($/mcf)	Total ($/boe)
Revenue	68.17	52.57	3.92	42.00
Realized commodity hedging gain (loss)	(1.37)	-	0.87	2.42
Royalties	(19.28)	(11.89)	(0.14)	(8.39)
Operating costs	(13.31)	(7.84)	(1.47)	(10.39)
Transportation costs	(1.56)	(1.94)	(0.41)	(2.09)
Operating netbacks	32.65	30.90	2.77	23.55

	Three months ended December 31, 2009			
	Oil ($/bbl)	Ngl ($/bbl)	Natural gas ($/mcf)	Total ($/boe)
Revenue	68.16	47.91	4.98	43.30
Realized commodity hedging gain (loss)	(0.61)	-	1.06	3.56
Royalties	(21.07)	(10.51)	(0.68)	(9.89)
Operating costs	(10.30)	(9.64)	(2.02)	(11.33)
Transportation costs	(1.45)	(0.89)	(0.51)	(2.35)
Operating netbacks	34.73	26.87	2.83	23.29

	Year ended December 31, 2010			
	Oil ($/bbl)	Ngl ($/bbl)	Natural gas ($/mcf)	Total ($/boe)
Revenue	67.48	50.70	4.45	41.30
Realized commodity hedging gain (loss)	0.45	-	0.71	2.72
Royalties	(19.41)	(10.88)	(0.40)	(8.37)
Operating costs	(13.85)	(8.31)	(1.61)	(10.80)
Transportation costs	(1.46)	(1.42)	(0.37)	(1.99)
Operating netbacks	33.21	30.09	2.78	22.86

	Year ended December 31, 2009			
	Oil ($/bbl)	Ngl ($/bbl)	Natural gas ($/mcf)	Total ($/boe)
Revenue	59.39	36.28	4.27	35.58
Realized commodity hedging gain (loss)	(0.01)	-	0.98	3.76
Royalties	(16.66)	(10.09)	(0.43)	(7.05)

Operating costs	(11.30)	(9.40)	(1.91)	(11.22)
Transportation costs	(1.59)	(0.29)	(0.46)	(2.20)
Operating netbacks	29.83	16.50	2.45	18.87

General and Administrative Costs

($ thousands, except per boe)	Three months ended December 31, 2010	Three months ended December 31, 2009	Year ended December 31, 2010	Year ended December 31, 2009
Gross costs	4,698	4,026	16,420	14,160
Operator's recoveries	(890)	(1,080)	(3,463)	(2,689)
Capitalized costs	(1,904)	(1,473)	(6,478)	(5,735)
General and administrative expenses	1,904	1,473	6,479	5,736
Per boe	$ 1.41	$ 1.11	$ 1.30	$ 1.12

Increased fourth quarter 2010 general and administrative costs before recoveries and capitalization were mainly due to increased staff levels, increased salary levels and the cost of additional office space added in 2010 in order to accommodate the Company's growth. In the fourth quarter of 2010, recoveries slightly decreased over the same period in 2009 due to the Company contract operating fewer wells, while capitalized costs increased over the same period of 2009 due to increased capital related activities during the fourth quarter of 2010.

For 2010, gross costs before recoveries and capitalization as well as net general and administrative costs have increased as a result of increased staff levels and increased office rent costs to accommodate the Company's larger operations in Princess and Septimus. As the Company continues to expand, combined with International Financial Reporting Standards being introduced in 2011 altering capitalization of general and administrative expenses, Crew expects general and administrative expenses to average between $1.50 and $1.75 per boe for 2011.

Interest

($ thousands, except per boe)	Three months ended December 31, 2010	Three months ended December 31, 2009	Year ended December 31, 2010	Year ended December 31, 2009
Interest expense	1,425	2,003	5,795	6,503
Average debt level	120,596	158,937	96,538	194,818
Effective interest rate	4.7%	5.1%	6.0%	3.3%
Per boe	$ 1.06	$ 1.50	$ 1.16	$ 1.27

Crew's fourth quarter 2010 interest expense has decreased over the same period in 2009 due to a decrease in outstanding average debt levels. During the fourth quarter, the margin charged on the Company's borrowings under its prime loans and the stamping fees charged on its outstanding bankers' acceptances have decreased but this has been partially offset by increased prime interest rates and interest rates charged on bankers' acceptances.

Total interest expense for 2010 has decreased compared to 2009 due to a significant decrease in outstanding average debt levels. Effective interest rates increased in 2010 due to increased standby fees charged on the unutilized bank facility and the amortization of annual renewal fees against the significantly decreased drawn facility as the denominator. Crew's effective interest rate is expected to average approximately 5.00% in 2011.

Stock-Based Compensation

	Three months ended December	Three months ended December	Year ended December	Year ended December

($ thousands)	31, 2010	31, 2009	31, 2010	31, 2009
Gross costs	2,186	1,586	9,034	6,642
Capitalized costs	(1,093)	(793)	(4,517)	(3,321)
Total stock-based compensation	1,093	793	4,517	3,321

The Company's stock-based compensation expense has increased in the fourth quarter and for 2010 over the same periods in 2009 due to an increase in the fair value of stock options that were issued to Crew employees and service providers, resulting from the Company's increased share price.

Depletion, Depreciation and Accretion

($ thousands, except per boe)	Three months ended December 31, 2010	Three months ended December 31, 2009	Year ended December 31, 2010	Year ended December 31, 2009
Depletion, depreciation and accretion	27,736	31,677	113,214	131,613
Per boe	20.57	23.80	22.66	25.75

Depletion, depreciation and accretion costs and per unit costs have decreased in the fourth quarter of 2010 compared with the same period in 2009 due to low cost reserve additions from a successful drilling program in the Company's Septimus and Princess areas as well as the sale of the Edson assets which received a greater price per unit than the Company's corporate depletion rate.

In 2010, per unit depletion rates decreased 12% over 2009. The Company's successful drilling program in Septimus and Princess continued to add low cost proven reserves. During 2010, the Company was also successful in reducing its infrastructure costs by taking advantage of government incentive programs in British Columbia. The disposition of the Edson assets in March 2010 also received a greater price per unit than the Company's corporate depletion rate thus lowering the corporate depletion rate.

Crew performed a ceiling test as at December 31, 2010. 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 carrying value of the Company's property plant and equipment was considered recoverable.

Future Income Taxes

The provision for future income taxes was a recovery of $3.5 million in the fourth quarter of 2010 and a recovery of $6.2 million for 2010 compared to recoveries of $2.3 million and $15.8 million, respectively, for the same periods of 2009. In the fourth quarter of 2010, the increased recovery was a result of a greater pre-tax loss. For 2009, the Company had a greater pre-tax loss for the year as compared with 2010 and therefore had an increased future tax recovery.

A summary of the Company's estimated income tax pools at December 31, 2010 is outlined below:

($ thousands)	Dec. 31, 2010	Dec. 31, 2009
Cumulative Canadian Exploration Expense	120,600	108,900
Cumulative Canadian Development Expense	223,800	132,200
Cumulative Canadian Oil and Gas Property Expense	23,000	110,000
Undepreciated Capital Cost	109,700	103,800
Share issue costs	1,300	5,000
Non-capital loss	31,400	32,000
	509,800	491,900

The estimated income tax pools for 2010 have been reduced by the estimated deferred partnership income for 2010. The Company did not pay cash taxes in 2010 and estimates it has sufficient tax pools to shelter estimated income until 2012 or beyond.

Cash and Funds from Operations and Net Loss

($ thousands, except per share amounts)	Three months ended December 31, 2010	Three months ended December 31, 2009	Year ended December 31, 2010	Year ended December 31, 2009
Cash provided by operating activities	21,212	16,734	97,170	82,659
Funds from operations	28,436	27,256	101,450	83,453
Per share - basic	0.35	0.35	1.27	1.11
- diluted	0.35	0.35	1.24	1.11
Net loss	(9,525)	(9,154)	(17,161)	(37,815)
Per share - basic	(0.12)	(0.12)	(0.22)	(0.50)
- diluted	(0.12)	(0.12)	(0.22)	(0.50)

For the fourth quarter and year ended December 31, 2010, an increase in cash provided by operating activities and funds from operations was the result of an increase in oil production which attracted a higher price than natural gas production as well as reduced operating and transportation costs. For the fourth quarter of 2010, the net loss was consistent with the same period in 2009 as reduced depletion costs were offset by a net unrealized loss on financial instruments. The net loss for 2010 was less than the net loss for the same period in 2009 due to significantly reduced depletion, depreciation and accretion costs which was partially offset by an increase in the unrealized loss on financial instruments in 2010.

Capital Expenditures, Acquisitions and Dispositions

During the fourth quarter of 2010, the Company drilled 21 (19.8 net) wells, resulting in 19 (18.5 net) oil wells, one (0.25 net) gas well and one (1.0 net) dry & abandoned well. The Company completed 23 (21.8 net) wells during the quarter, consisting of 18 (18.0 net) oil wells at Princess, one (0.25 net) gas well at Kakwa, Alberta, three (3.0 net) gas wells at Septimus and one (0.5 net) gas well at Portage, British Columbia. The Company brought a total of three Septimus gas wells and 18 Princess oil wells on production throughout the quarter. The Company continued adding fluid handling capacity to its three main oil treating and water disposal facilities at Princess.

In 2010, the Company drilled 80 (75.2 net) wells resulting in 56 (54.8 net) oil wells, 15 (11.3 net) gas wells, eight (8.0 net) water disposal wells and one (1.0 net) dry and abandoned well. During 2010, the Company continued to add to its undeveloped land base acquiring over 50,000 net undeveloped acres of land at crown land sales primarily within its core area of Princess. Crew continued to add to its infrastructure in Princess expanding its batteries and significantly increasing its pipeline capabilities. Late in 2010, the Company substantially completed the expansion of the Septimus facility with final testing completed in early 2011. At the time of construction, the Company had an agreement in place to sell the Septimus gas plant expansion for its as built cost, which closed in early 2011. As the facility expansion was sold in early 2011, the asset was reclassified as an asset held for sale and therefore is not included in the capital expenditures for the year. During the year, Crew was notified that it was granted a $7.6 million infrastructure credit from the British Columbia government which was applied as an offset to capital expenditures in the year.

Exploration and development capital expenditures for the fourth quarter and full year of 2010 were $61.3 million and $248.9 million, respectively, compared to $55.3 million and $128.6 million for the same periods in 2009. The expenditures are detailed below:

($ thousands)	Three months ended December 31, 2010	Three months ended December 31, 2009	Year ended December 31, 2010	Year ended December 31, 2009
Land	1,098	5,619	38,835	10,500
Seismic	194	2,426	5,471	4,602
Drilling and completions	47,419	37,302	163,992	65,469
Facilities, equipment and pipelines	10,605	8,371	33,679	41,755
Other	2,032	1,594	6,893	6,241
Exploration and development	61,348	55,312	248,870	128,567
Property acquisitions (dispositions)	620	(44,315)	(132,020)	(78,693)
Total net	61,968	10,997	116,850	49,874

The Company's Board of Directors has approved a $260 million exploration and development budget for 2011.

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 $220 million and an operating line of credit of $20 million (the "Facility"). The Facility revolves for a 364 day period and will be subject to its next 364 day extension by June 13, 2011. 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 from the extension date. 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 13, 2011. At December 31, 2010, the Company had committed drawings of $138.7 million on the Facility and had issued letters of credit totaling $1.1 million.

During 2010, the Company received proceeds of $20.6 million due to the exercise of 2,216,066 employee stock options.

On March 2, 2011, the Company closed a bought deal sale of 4,820,000 Common Shares of the Company at a price of $20.75 per share for aggregate gross proceeds of $100 million. Crew has also granted the Underwriters an over-allotment option to purchase, on the same terms, up to an additional 723,000 Common Shares for additional gross proceeds of up to $15.0 million exercisable by the Underwriters, in whole or in part, at any time up to 30 days following closing of the offering to cover the Underwriters' over-allotments, if any.

The Company will continue to fund its on-going operations from a combination of cash flow, debt, the proceeds from future non-core asset dispositions and equity financings as needed. As the majority of our 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.

Working Capital

The capital intensive nature of Crew's activities generally results in the Company carrying a working capital deficit. However, the Company maintains sufficient unused bank credit lines to satisfy such working capital deficiencies. At December 31, 2010, the Company's working capital deficiency (including accounts receivable, assets held for sale, accounts payable and accrued liabilities) totaled $40.7 million which, when combined with the drawings on its bank line, represented 75% of its current bank facility.

Share Capital

As at March 7, 2011, Crew had issued and outstanding 85,544,234 Common Shares and had options to acquire 5,193,500 Common Shares outstanding.

Capital Structure

The Company considers its capital structure to include working capital, bank debt, 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 some costs, issue new equity, issue new debt or repay existing debt through non-core 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. This ratio may increase at certain times as a result of acquisitions or low commodity prices. As shown below, as at December 31, 2010, the Company's ratio of net debt to annualized funds from operations was 1.58 to 1 (December 31, 2009 - 1.67 to 1).

($ thousands, except ratio)	Dec. 31, 2010	Dec. 31, 2009
Accounts receivable (including assets held for sale)	60,038	37,574
Accounts payable and accrued liabilities	(100,745)	(84,228)
Working capital deficiency	(40,707)	(46,654)
Bank loan	(138,700)	(135,601)
Net debt	(179,407)	(182,255)
Fourth quarter 2010 funds from operations	28,436	27,256
Annualized	113,744	109,024
Net debt to annualized funds from operations ratio	1.58	1.67

Contractual Obligations

Throughout the course of its ongoing business, the Company enters into various contractual obligations such as credit agreements, purchases 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 the 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	2011	2012	2013	2014	2015	Thereafter
Bank Loan (note 1)	138,700	-	-	138,700	-	-	-
Operating Leases	3,052	1,743	1,309	-	-	-	-
Capital commitments	2,000	2,000	-	-	-	-	-
Transportation agreements	22,618	4,600	1,535	1,535	2,110	2,110	10,728
Processing agreement	77,936	6,526	6,526	6,526	8,239	8,239	41,880
Total	244,306	14,869	9,370	146,761	10,349	10,349	52,608

Note 1 - Based on the existing terms of the Company's bank facility the first possible repayment date may come in 2013; however, it is expected that the revolving bank facility will be extended and no repayment will be required in the near term.

The transportation agreements include a $19.5 million commitment to a third party to transport natural gas from the gas processing facility in the Septimus area to the Alliance pipeline system. The remaining commitment relates to firm transportation commitments that were acquired as part of the Company's May 2007 private company acquisition. In 2010, the Company permanently assigned approximately $6.2 million of its firm commitments to third parties.

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. 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.

In the fourth quarter of 2010, the Company amended the agreement with the owner of this facility. Under the terms of the amended agreement, Crew constructed a facility expansion during the fourth quarter of 2010 and subsequently closed the sale of the Septimus facility expansion in early 2011. Upon completion of the expansion, Crew was reimbursed for the full cost of the facility of $16.9 million in return for an expanded processing commitment that will extend to December 2020. As this asset was classified as an asset held for sale, the commitment is included in the above table. As part of the amended agreement, Crew has also retained the option to re-purchase a 50% interest in the facility at certain dates prior to January 1, 2014, at a cost of 50% of the total expanded facility's construction cost. If the Company re-purchases a 50% interest on January 1, 2014 for approximately $18.0 million, the remaining commitment would be reduced by approximately $29.0 million.

Outlook

The Board of Directors of Crew has approved an increase in the 2011 capital expenditure budget to $260 million which is expected to include the drilling of a record 130 net wells. Over 90% of this drilling program is dedicated to the Company's Princess oil play. This program is expected to be adequately financed through the recently closed $100 million bought deal financing, cash flow and the Company's recently expanded $240 million bank facility. With an emphasis on oil drilling, the Company is expecting the liquids component of its production to increase to approximately 55% to 60% of total oil and natural gas production by year end resulting in average production of between 18,300 and 19,300 boe per day and exit production of 21,000 to 22,000 boe per day.

Additional Disclosures

Quarterly Analysis

The following table summarizes Crew's key quarterly financial results for the past eight financial quarters:

($ thousands, except per share amounts)	Dec. 31 2010	Sept. 30 2010	June 30 2010	Mar. 31 2010
Total daily production (boe/d)	14,654	13,061	12,048	15,001
Average wellhead price ($/boe)	42.00	37.39	39.25	45.75
Petroleum and natural gas sales	56,620	44,924	43,027	61,772
Cash provided by operations	21,212	19,596	24,149	32,213
Funds from operations	28,436	24,104	20,693	28,217
Per share - basic	0.35	0.30	0.26	0.36

- diluted	0.35	0.29	0.25	0.35
Net income (loss)	(9,525)	(7,387)	(2,691)	2,442
Per share - basic	(0.12)	(0.09)	(0.03)	0.03
- diluted	(0.12)	(0.09)	(0.03)	0.03

($ thousands, except per share amounts)	Dec. 31 2009	Sept. 30 2009	June 30 2009	Mar. 31 2009
Total daily production (boe/d)	14,470	13,065	13,466	15,022
Average wellhead price ($/boe)	43.30	32.04	32.10	34.28
Petroleum and natural gas sales	57,646	38,510	39,331	46,342
Cash provided by operations	16,734	24,902	21,517	19,506
Funds from operations	27,256	19,640	20,036	16,521
Per share - basic	0.35	0.25	0.27	0.23
- diluted	0.35	0.25	0.27	0.23
Net income (loss)	(9,154)	(7,376)	(12,267)	(9,018)
Per share - basic	(0.12)	(0.10)	(0.17)	(0.13)
- diluted	(0.12)	(0.10)	(0.17)	(0.13)

Crew's petroleum and natural gas sales, cash and funds from operations and net income are all impacted by production levels and volatile commodity pricing. From 2009 to 2010, these performance measures have fluctuated as a result of volatile oil and natural gas prices.

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.

- Over the past two years, the price of natural gas has been negatively impacted by an increasing supply of natural gas coming from new technology tapping into abundant supplies of tight shale gas reservoirs in North America. With depressed natural gas prices, Crew has focused its capital expenditures towards oil development with higher netbacks. This has resulted in the commodity mix moving towards more oil and the Company's overall netbacks improving revenues and funds from operations.

- Production in the second quarter of 2009 and 2010 was negatively impacted by scheduled and unscheduled third party facility shutdowns and poor weather experienced in southern Alberta during the second and third quarters of 2010.

- 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 on a portion of its production. 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.

- In 2009 and 2010, the Company sold assets with approximately 2,970 boe per day of production for $182.9 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

-- Second quarter 2010 - 1,700 boe per day for $123.3 million

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

($ thousands, except per share amounts)	Year ended Dec. 31, 2010	Year ended Dec. 31, 2009	Year ended Dec. 31, 2008
Petroleum and natural gas sales	206,343	181,829	235,856
Cash provided by operations	97,170	82,660	123,356
Funds from operations	101,450	83,453	127,790
Per share - basic	1.27	1.11	2.08
- diluted	1.24	1.11	2.06
Net income (loss)	(17,161)	(37,815)	(53,319)
Per share - basic	(0.22)	(0.50)	(0.87)
- diluted	(0.22)	(0.50)	(0.87)

Daily production (boe/d)	13,689	14,002	11,617
Crew average sales price ($/boe)	41.30	35.58	55.47
Total assets	998,070	963,248	1,045,510
Working capital deficiency (note 1)	40,707	46,654	31,822
Bank loan	138,700	135,601	223,628
Total other long-term liabilities	132,403	136,992	152,679

(Note 1) Working capital includes accounts receivable, assets held for sale and accounts payable and accrued liabilities.

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. These performance measures have all fluctuated throughout 2008 to 2010 as a result of volatile oil and natural gas prices combined with the increased cost of the Company's operations. In addition, the Company disposed of assets producing 1,270 boe per day for $58.5 million in 2009 and 1,700 boe per day for $123.3 million in 2010.

New Accounting Pronouncements

International Financial Reporting Standards

Effective January 1, 2011, Canadian public companies are required to adopt International Financial Reporting Standards ("IFRS") which will include comparatives for 2010. Crew's financial statements up to and including December 31, 2010 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 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 continue to assist management with the project on an as needed basis. Training has been provided to key employees and staff training programs will continue as needed. The Company continues to assess the effect of the transition on information systems, internal controls over financial reporting and disclosure controls and procedures. Systems and controls are being updated as IFRS accounting processes are implemented. Significant system and control changes are not anticipated. The project team and steering committee continue to provide updates to senior management and the Audit Committee. Calculations of the impact of changes in accounting policy have been prepared by management and have been approved by the Company's Board of Directors and the Company's auditors. The Company's auditors have been involved throughout the process to ensure the Company's policies are in accordance with the new standards.

There are significant accounting policy changes anticipated on adoption of IFRS which are described in more detail below. Most adjustments required on transition to IFRS will be made retrospectively against opening retained earnings as of the date of the first comparative balance sheet being January 1, 2010. 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 planning to adopt this exemption. Management has analyzed the various other accounting policy choices available under IFRS 1 and has determined the following to be most appropriate for Crew:

- Oil and gas properties will be classified as Property, Plant and Equipment ("PP&E") or Exploration and Evaluation assets ("E&E"). Upon transition to IFRS, Crew will reclassify all E&E expenditures included in the PP&E balance under Canadian GAAP, as a separate item under IFRS. 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. Once these E&E assets have reached technical feasibility and commercial viability, they will be transferred to PP&E. At the time of transfer, they will be subjected to an impairment test. Crew's E&E assets will primarily consist of undeveloped exploration lands and at January 1, 2010 are estimated at $35.6 million.

- Under IFRS PP&E assets are grouped into areas designated as cash generating units ("CGU") for the purposes of impairment testing and further broken down into components within the CGU for purposes of depletion and depreciation. IFRS 1 provides for the allocation of the Canadian GAAP net book value of PP&E assets, excluding E&E assets, to CGUs and components on a pro rata basis using the reserve volumes or values as at December 31, 2009. Crew has elected to allocate the PP&E balance using reserve values and at January 1, 2010, the value allocated to the PP&E assets is $889.5 million.

- Under Canadian GAAP, impairment testing on oil and gas properties is performed at a cost centre level. Under IFRS, impairment testing will be performed at the CGU level. This will result in a greater number of impairment tests. At January 1, 2010, Crew did not have any impairment on its PP&E under IFRS.

- Depletion and depreciation of PP&E will be calculated at a component level. Depletion of resource properties within PP&E will be calculated using the unit-of-production method under IFRS with the option to base the calculation on proved reserves or proved plus probable reserves. Crew will use proved plus probable reserves to calculate the depletion of resource properties. Depreciation of office equipment will continue to be calculated using a declining balance method.

- IFRS 1 allows Crew to use the IFRS rules for business combinations on a prospective basis rather than restating all business combinations. Crew will elect to use this exemption; therefore, Crew will not be recording any adjustments to retrospectively restate any of its business combinations that have occurred prior to January 1, 2010.

- Under Canadian GAAP, Crew's Asset Retirement Obligation is discounted over its life based on a credit adjusted risk free rate which was 10% at December 31, 2009. Under IFRS, Crew is required to revalue its liability for asset retirement costs at each balance sheet date using a current liability-specific discount rate. As a result, the Company's asset retirement obligation will increase upon transition to IFRS as the liability will be re-valued using a discount rate of 4% to reflect the Company's estimated risk-free rate of interest. The revalued Asset Retirement Obligation at the transition date is estimated at $53.1 million with the offsetting $17.7 million increase in the liability being charged to retained earnings.

- Currently Crew expenses stock-based compensation on a straight-line basis. 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 as currently practiced under Canadian GAAP. The adjustment to contributed surplus to account for the graded vesting and forfeitures will be an increase of $2.7 million with the offset being charged to retained earnings.

- Under Canadian GAAP, the future tax liability associated with the renouncement of tax deductions from the issuance of flow through shares was recorded as a reduction in share capital at the time of renouncement. Under IFRS, the difference between the future tax liability associated with the renouncement of the tax deductions and the premium price received on the issuance of flow through shares over the market value of the Company's common shares at the time of issue is recorded as a future tax expense at the time of the renouncement. This future tax expense effectively represents the net loss on the distribution of the tax deductions to investors. The transitional adjustment results in an increase of $3.4 million to share capital with a resulting offset being charged to retained earnings.

In the first quarter of 2011, the Company plans to prepare its 2010 IFRS comparative quarterly financial statements and will assess and continue to review the impact of the IFRS changes on disclosure controls and internal controls, including identification of instances where controls may require amendments or additions in order to address the accounting policy changes required under IFRS. No material changes in control procedures are presently expected.

Application of Critical Accounting Estimates

Crew's significant accounting policies are disclosed in note one to the December 31, 2010 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 currently 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.

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, expected option lives 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 in assumptions from 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 ("CEO") and Chief Financial Officer ("CFO") 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 CEO and CFO 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.

Crew's CEO and CFO have designed, or caused to be designed under their supervision, internal controls over financial reporting to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with Canadian generally accepted accounting principles. Such officers have evaluated, or caused to be evaluated under their supervision, the effectiveness of the Company's internal controls over financial reporting at the financial year end of the Company and concluded that the Company's internal controls over financial reporting are effective, at the financial year end of the Company, for the foregoing purpose. The Company is required to disclose herein any change in the Company's internal controls over financial reporting that occurred during the period beginning on October 1, 2010 and ended on December 31, 2010 that has materially affected, or is reasonably likely to materially affect, the Company's internal controls over financial reporting. No material changes in the Company's internal controls over financial reporting were identified during such period that have materially affected, or are reasonably likely to materially affect, the Company's internal controls 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 7, 2011

Cautionary Statements

Forward-looking information and statements

This news release contains certain forward-looking information and statements within the meaning of applicable securities laws. The use of any of the words "expect", "anticipate", "continue", "estimate", "may", "will", "project", "should", "believe", "plans", "intends", "forecasts" and similar expressions are intended to identify forward-looking information or statements. In particular, but without limiting the foregoing, this news release contains forward-looking information and statements pertaining to the following: the volume and product mix of Crew's oil and gas production; production estimates including forecast 2011 average and exit rates; future oil and natural gas prices and Crew's commodity risk management programs; future liquidity and financial capacity; future results from operations and operating metrics; potential prospectivity of the Company's lands at Kobes, British Columbia, Pine Creek, Alberta and Provost, Alberta; future general and administrative costs, royalty rates; future interest costs; the exchange rate between the $US and $Cdn; future development, exploration, acquisition and development activities and related capital expenditures and the timing thereof; the number of wells to be drilled, completed and tied-in and the timing thereof; the amount and timing of capital projects; operating costs; transportation costs; the total future capital associated with development of reserves and resources; forecasts in operating expenses.

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

The forward-looking information and statements included in this news release are not guarantees of future performance and should not be unduly relied upon. Such information and statements, including the assumptions made in respect thereof, involve known and unknown risks, uncertainties and other factors that may cause actual results or events to defer materially from those anticipated in such forward-looking information or statements including, without limitation: changes in commodity prices; changes in the demand for or supply of Crew's products; unanticipated operating results or production declines; changes in tax or environmental laws, royalty rates or other regulatory matters; changes in development plans of Crew or by third party operators of Crew's properties, increased debt levels or debt service requirements; inaccurate estimation of Crew's oil and gas reserve and resource volumes; limited, unfavourable or a lack of access to capital markets; increased costs; a lack of adequate insurance coverage; the impact of competitors and partners; and certain other risks detailed from time-to-time in Crew's public disclosure documents (including, without limitation, those risks identified in this news release and Crew's Annual Information Form).

The forward-looking information and statements contained in this news release speak only as of the date of this news release, and Crew does not assume any obligation to publicly update or revise any of the included forward-looking statements or information, whether as a result of new information, future events or otherwise, except as may be required by applicable securities laws.

BOE equivalent

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

Crew is an oil and gas exploration and production company whose shares are traded on The Toronto Stock Exchange under the trading symbol "CR".

Financial statements for the three month periods and years ended December 31, 2010 and 2009 are attached.

CREW ENERGY INC.
Consolidated Balance Sheets
(thousands)
(unaudited)

	December 31, 2010	December 31, 2009
Assets		
Current Assets:		
Accounts receivable	$ 44,922	$ 37,574
Fair value of financial instruments (note 8)	982	-
Future income taxes (note 10)	-	542
Asset held for sale (notes 3 & 12)	15,116	-
	61,020	38,116
Property, plant and equipment (note 3)	937,050	925,132
	$ 998,070	$ 963,248
Liabilities and Shareholders' Equity		
Current Liabilities:		
Accounts payable and accrued liabilities	$ 100,745	$ 84,228
Fair value of financial instruments (note 8)	-	834
Current portion of other long-term obligations (note 5)	343	1,313
	101,088	86,375
Fair value of financial instruments (note 8)	9,196	-
Bank loan (note 4)	138,700	135,601
Other long-term obligations (note 5)	-	132
Asset retirement obligations (note 6)	36,073	35,341
Future income taxes (note 10)	96,330	101,519
Shareholders' Equity		
Share capital (note 7)	646,385	617,605
Contributed surplus (note 7(c))	23,553	22,769
Deficit	(53,255)	(36,094)
	616,683	604,280

Commitments (note 12)
Subsequent events (notes 3,8,9 & 12)

	$ 998,070	$ 963,248

See accompanying notes to the consolidated financial statements.

CREW ENERGY INC.

Consolidated Statements of Operations, Comprehensive Loss and Deficit
(thousands, except per share amounts)
(unaudited)

	Three months ended Dec. 31, 2010	Three months ended Dec. 31, 2009	Year ended Dec. 31, 2010	Year ended Dec. 31, 2009
Revenue				
Petroleum and natural gas sales	$ 56,620	$ 57,646	$206,343	$ 181,829
Royalties	(11,311)	(13,167)	(41,799)	(36,027)
Realized gain on financial instruments (note 8)	3,284	4,471	13,082	18,461
Unrealized loss on financial instruments (note 8)	(12,586)	(6,225)	(7,380)	(2,089)
	36,007	42,725	170,246	162,174
Expenses				
Operating	14,009	15,084	53,976	57,342
Transportation (note 5)	2,819	3,134	9,582	11,229
General and administrative	1,904	1,473	6,479	5,736
Interest	1,425	2,003	5,795	6,503
Stock-based compensation (note 7(d))	1,093	793	4,517	3,321
Depletion, depreciation and accretion	27,736	31,677	113,214	131,613
	48,986	54,164	193,563	215,744
Loss before income taxes	(12,979)	(11,439)	(23,317)	(53,570)
Future income tax reduction (note 10)	(3,454)	(2,285)	(6,156)	(15,755)
Loss and comprehensive loss	(9,525)	(9,154)	(17,161)	(37,815)
Retained earnings (deficit), beginning of period	(43,730)	(26,940)	(36,094)	1,721
Deficit, end of period	$ (53,255)	$(36,094)	$(53,255)	$(36,094)
Loss per share (note 7(e))				
Basic	$ (0.12)	$ (0.12)	$ (0.22)	$ (0.50)
Diluted	$ (0.12)	$ (0.12)	$ (0.22)	$ (0.50)

See accompanying notes to the consolidated financial statements.

CREW ENERGY INC.

Consolidated Statements of Cash Flows
(thousands)
(unaudited)

	Three months	Three months	Year	Year

	ended Dec. 31, 2010	ended Dec. 31, 2009	ended Dec. 31, 2010	ended Dec. 31, 2009
Cash provided by (used in):				
Operating activities:				
Loss	$ (9,525)	$ (9,154)	$(17,161)	$(37,815)
Items not involving cash:				
Depletion, depreciation and accretion	27,736	31,677	113,214	131,613
Stock-based compensation	1,093	793	4,517	3,321
Future income tax reduction	(3,454)	(2,285)	(6,156)	(15,755)
Unrealized loss on financial instruments (note 8)	12,586	6,225	7,380	2,089
Transportation liability charge (note 5)	(120)	(329)	(1,102)	(1,314)
Asset retirement expenditures (note 6)	(606)	(111)	(1,512)	(589)
Change in non-cash working capital (note 11)	(6,498)	(10,082)	(2,010)	1,109
	21,212	16,734	97,170	82,659
Financing activities:				
Increase (decrease) in bank loan	27,930	(31,167)	3,099	(88,027)
Issue of common shares	1,753	539	20,566	43,961
Share issue costs	-	-	(48)	(2,442)
	29,683	(30,628)	23,617	(46,508)
Investing activities:				
Exploration and development	(61,348)	(55,312)	(248,870)	(128,567)
Property acquisitions	(446)	-	(446)	-
Property dispositions	(174)	44,315	132,466	78,693
Cost incurred on asset held for sale	(15,116)	-	(15,116)	-
Change in non-cash working capital (note 11)	26,189	24,891	11,179	13,723
	(50,895)	13,894	(120,787)	(36,151)
Change in cash and cash equivalents	-	-	-	-
Cash and cash equivalents, beginning of period	-	-	-	-
Cash and cash equivalents, end of period	$ -	$ -	$ -	$ -

See accompanying notes to the consolidated financial statements.

CREW ENERGY INC.

Notes to Consolidated Financial Statements

For years ended December 31, 2010 and 2009

(Tabular amounts in thousands)

(unaudited)

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, cost less impairment 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 plus probable reserves, cost less impairment 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) 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.

(e) 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.

(f) Revenue recognition:

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

(g) 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 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.

(h) 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.

(i) 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.

(j) 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.

(k) Comparative amounts:

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

2. Changes in accounting policy:

Future accounting pronouncements

Adoption of International Financial Reporting Standards ("IFRS")

On January 1, 2011 International Financial Reporting Standards ("IFRS"), as issued by the Accounting Standards Board, will become the generally accepted accounting principles in Canada. The transition from Canadian GAAP to IFRS will result in significant differences affecting financial position and results of operations. The Company will be reporting under IFRS for all periods beginning after January 1, 2011.

3. Property, plant and equipment:

December 31, 2010	Cost	Accumulated depletion & depreciation	Net book value
Petroleum and natural gas properties and equipment	$ 1,424,892	$ 487,842	$ 937,050

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

The cost of unproved properties at December 31, 2010 of $164,652,000 (2009 - $153,674,000) were excluded from the depletion calculation. Estimated future development costs associated with the development of the Company's proved reserves of $176,893,000 (2009 - $173,999,000) have been included in the depletion calculation and estimated salvage values of $35,845,000 (2009 - $38,039,000) have been excluded from the depletion calculation.

In April 2010, the Company closed the disposition of oil and gas assets in the Edson, Alberta area for gross proceeds of $126 million, before closing adjustments. Proceeds from the sale of this disposition were applied against capitalized petroleum and natural gas properties with no gain or loss recognized, and also resulted in the elimination of $3.5 million of asset retirement obligations.

During the fourth quarter of 2010, the Company entered into an agreement to sell the Septimus facility expansion for its as built cost. The Company also commenced construction of the Septimus facility expansion and as at December 31, 2010, the cumulative costs incurred on the expansion totaled $15.1 million with an additional $1.8 million incurred subsequent to year end, to bring the total cost to $16.9 million. The costs of the facility expansion have been recorded as an asset held for sale. The sale of the asset was completed on February 14, 2011 for total proceeds equal to the facility's cost of $16.9 million.

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

	Year ended December 31, 2010	Year ended December 31, 2009
General and administrative expense	$ 6,381	$ 5,736
Stock-based compensation expense, including future income taxes	6,038	4,442
	$ 12,419	$ 10,178

Crew performed a ceiling test as at December 31, 2010. 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)
2011	$ 88.00	0.980	$ 75.87	$ 70.76	$ 4.16	$ 4.21
2012	$ 89.00	0.980	$ 75.89	$ 70.83	$ 4.74	$ 4.87
2013	$ 90.00	0.980	$ 75.10	$ 70.27	$ 5.31	$ 5.51
2014	$ 92.00	0.980	$ 76.23	$ 71.16	$ 5.77	$ 6.01
2015	$ 95.17	0.980	$ 78.88	$ 73.57	$ 6.22	$ 6.52
2016	$ 97.55	0.980	$ 80.87	$ 75.34	$ 6.53	$ 6.84
2017	$ 100.26	0.980	$ 83.14	$ 77.35	$ 6.76	$ 7.12
2018	$ 102.74	0.980	$ 85.21	$ 79.02	$ 6.90	$ 7.30
2019	$ 105.45	0.980	$ 87.48	$ 81.01	$ 7.06	$ 7.50
2020	$ 107.56	0.980	$ 89.25	$ 82.47	$ 7.21	$ 7.69
Annual escalation thereafter +2.0%/yr.						

4. Bank loan:

The Company's bank facility consists of a revolving line of credit of $220 million and an operating line of credit of $20 million (the "Facility"). The Facility revolves for a 364 day period and will be subject to its next 364 day extension by June 13, 2011. 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 borrowing base review on or before June 13, 2011.

Advances under the Facility are available by way of prime rate loans with interest rates between 1.25 percent and 2.75 percent over the bank's prime lending rate and bankers' acceptances and LIBOR loans, which are subject to stamping fees and margins ranging from 2.25 percent to 3.75 percent depending upon the debt to EBITDA ratio of the Company calculated at the Company's previous quarter end. Standby fees are charged on the undrawn facility at rates ranging from 0.56 percent to 0.94 percent depending upon the debt to EBITDA ratio.

As at December 31, 2010, the Company's applicable pricing included a 1.5 percent margin on prime lending and a 2.5 percent stamping fee and margin on bankers' acceptances and LIBOR loans along with a 0.625 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, 2010, the Company had issued letters of credit totaling $1.1 million (2009 - $2.8 million). The effective interest rate on the Company's borrowings under its bank facility for the year ended December 31, 2010 was 6.6% (2009 - 3.3%).

5. 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, 2010 was $0.8 million (2009 - $1.3 million).

In March 2010, the Company permanently assigned a portion of the firm transportation agreements to third parties at no cost to Crew. As a result, the remaining liability associated with the assigned contracts was written-off during the first quarter of 2010 as a $0.3 million reduction of transportation expense.

6. 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, 2010 to be $36,073,000 (2009 - $35,341,000) based on a total future liability of $63,355,000 (2009 - $64,030,000). These payments are expected to be made over the next 30 years. An 8% to 10% (2009 - 8% to 10%) credit adjusted risk free discount rate and 2% (2009 - 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, 2010	Year ended December 31, 2009
Carrying amount, beginning of year	$ 35,341	$ 34,941
Liabilities incurred	980	385
Liabilities disposed	(3,456)	(2,161)
Accretion expense	2,639	2,765
Liabilities settled	(1,512)	(589)
Change in estimate	2,081	-
Carrying amount, end of year	$ 36,073	$ 35,341

7. 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, 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
Exercise of stock options	2,216	20,566
Stock-based compensation	-	8,250
Share issue costs, net of future income taxes of $12	-	(36)
Common Shares, December 31, 2010	80,368	$ 646,385

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).

(c) Contributed Surplus:

	Amount
Contributed surplus, December 31, 2008	$ 16,356
Stock-based compensation	6,642
Exercise of stock options	(229)
Contributed surplus, December 31, 2009	$ 22,769
Stock-based compensation	9,034
Exercise of stock options	(8,250)
Contributed surplus, December 31, 2010	$ 23,553

(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 2.26% (2009 - 1.58%), expected life 4 years (2009 - 4 years), volatility 61% (2009 - 53%), and an expected dividend of nil (2009 - 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 2010 the Company recorded $9,034,000, (2009 - $6,642,000) of stock-based compensation expense related to the stock options, of which $4,517,000 (2009 - $3,321,000) 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 $1,521,000 (2009 - $1,121,000) 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 weighted average fair value of the stock options granted during the year as calculated by the Black-Scholes method was $7.32 per option (2009 - $2.14).

	Number of options	Weighted average exercise price
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
Granted	2,237	$ 15.18
Exercised	(2,216)	$ 9.28
Forfeited	(442)	$ 8.50
Balance December 31, 2010	5,330	$ 10.79

The following table summarizes information about the stock options outstanding at December 31, 2010:

Range of exercise prices	Outstanding at December 31, 2010	Weighted average Remaining life (years)	Weighted average exercise price	Exercisable at December 31, 2010	Weighted average exercise price
$ 3.43 to $ 7.01	1,175	2.0	$ 5.14	272	$ 5.17
$ 7.02 to $ 9.94	1,284	1.1	$ 7.51	758	$ 7.47

$ 9.95 to $14.63	576	0.9	$	11.43	464	$	11.02
$14.64 to $18.70	2,295	2.9	$	15.35	118	$	16.99
	5,330	2.1	$	10.79	1,612	$	8.80

(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, 2010 was 79,747,000 (2009 - 75,252,000).

In computing diluted earnings per share for the year ended December 31, 2010, nil (2009 - nil) shares were added to the weighted average Common Shares outstanding to account for the dilution of stock options. There were 5,330,000 (2009 - 5,751,000) stock options that were not included in the diluted earnings per share calculation because they were anti-dilutive.

8. 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, 2010 the Company's receivables consisted of $22.5 (2009 - $17.2) million of receivables from petroleum and natural gas marketers which has subsequently been collected, $6.7 (2009 - $9.2) million from joint venture partners of which $0.3 million has been subsequently collected, and $15.7 (2009 - $11.2) million of Crown incentives, deposits, prepaids and other accounts receivable of which $3.0 million has subsequently been collected. 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, financial instruments and the 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 4, that is subject to renewal annually by the lenders and has a contractual maturity in 2012. 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. Any contracts extending beyond two years require Board approval.

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 rate 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.

(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, 2010, a 1.0 percent change to the effective interest rate would have a $1.1 million impact on net income (2009 - $1.5 million). The sensitivity for 2010 is lower as compared to 2009 because of a decrease in average outstanding bank debt in 2010 compared to 2009.

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 $100 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 2.25 per cent to 3.75 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, 2010 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	January 1, 2011 - December 31, 2011	AECO C Monthly Index	$ 4.85	Swap(1)	961
Natural Gas	2,500 gj/day	January 1, 2011 - December 31, 2011	AECO C Monthly Index	$ 4.90	Swap(1)	1,001
Natural Gas	2,500 gj/day	January 1, 2011 - December 31, 2011	AECO C Monthly Index	$ 4.95	Swap(1)	1,046
Natural Gas	2,500 gj/day	January 1, 2011 - December 31, 2011	AECO C Monthly Index	$ 4.965	Swap(1)	1,058
Natural Gas	7,500 gj/day	January 1, 2011 - December 31, 2011	AECO C Monthly Index	$ 5.00	Swap(1)	3,276
Oil	500 bbl/day	January 1, 2011 - December 31, 2011	US$ WTI	US$80.15	Swap	(2,478)
Oil	250 bbl/day	January 1, 2011 - December 31, 2011	CDN$ WTI	$ 86.00	Swap	(723)
Oil	500 bbl/day	January 1, 2011 - December 31, 2011	CDN$ WTI	$ 88.00	Swap	(1,031)
Oil	250 bbl/day	January 1, 2011 - December 31, 2011	CDN$ WTI	$ 88.50	Swap	(474)
Oil	250 bbl/day	January 1, 2011 - December 31, 2011	CDN$ WTI	$ 90.00	Swap	(332)
Oil	500 bbl/day	January 1, 2011 - December 31, 2011	CDN$ WTI	$ 90.20	Swap	(641)
Oil	500 bbl/day	January 1, 2011 - December 31, 2011	CDN$ WTI	$ 93.00	Swap	15
Oil	250 bbl/day	January 1, 2011 - December 31, 2011	CDN$ WTI	$ 80.00 - $ 95.45	Collar	(307)
		January 1, 2011 -		$ 82.00 -		

Oil	250 bbl/day	December 31, 2011	$ 94.62 CDN$ WTI		Collar	(340)
Oil	250 bbl/day	January 1, 2011 - December 31, 2011	$ 85.00 - $ 100.50 CDN$ WTI		Collar	(24)
Oil	500 bbl/day	January 1, 2011 - June 30, 2011	CDN$ WCS-WTI diff	($18.00)	Swap	(45)
Oil	500 bbl/day	January 1, 2012 - December 31, 2012	CDN$ WTI	$ 85.00	Call(1)	(3,082)
Oil	750 bbl/day	January 1, 2012 - December 31, 2012	CDN$ WTI	$ 90.00	Call(1)	(3,548)
Oil	500 bbl/day	January 1, 2012 - December 31, 2012	US$ WTI	US$90.00	Call(1)	(2,566)
Total commodity contracts						(8,234)

Subject of Contract	Notional Quantity	Term	Reference	Strike Price	Option Traded	Fair Value ($000s)
Interest rate contracts						
BA Rate	$50M / year	February 10, 2009 - February 10, 2011	BA - CDOR	1.10%	Swap	8
BA Rate	$50M / year	February 12, 2009 - February 12, 2011	BA - CDOR	1.10%	Swap	12
Total interest rate contracts						20
Total financial instruments						(8,214)

(1) These derivative contracts are part of a paired transaction in which the proceeds from the sale of 2012 oil calls were used to fund the 2011 natural gas swaps at the prices indicated.

As at December 31, 2010, a $0.10 change to the price per thousand cubic feet of natural gas on the natural gas contracts outlined above would have a $0.5 million impact on net income.

As at December 31, 2010, a $1.00 per barrel change to the price on the oil contracts outlined above would have a $1.4 million impact on net income.

As at December 31, 2010, a 0.1% change to the interest rate on the interest rate contracts outlined above would have less than a $0.1 million impact on net income.

Subsequent to December 31, 2010, the Company entered into the following financial derivative contracts:

Subject of Contract	Notional Quantity	Term	Reference	Strike Price	Option traded
Oil	500 bbl/day	January 1, 2012 - December 31, 2012	CDN $WTI	$ 101.00/bbl	Swap
Oil	250 bbl/day	January 1, 2012 - December 31, 2012	CDN $WTI	$ 100.45/bbl	Swap
Oil	250 bbl/day	January 1, 2012 - December 31, 2012	CDN $WTI	$ 100.50/bbl	Swap

Fair value of financial instruments

The Company's financial instruments as at December 31, 2010 and 2009 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 interest rates and published forward price and interest rate curves as at the balance sheet date, using the remaining contracted petroleum and natural gas volumes and notional debt amounts.

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, 2010.

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.

9. 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, the 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 non-core 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, 2010, the Company's ratio of net debt to annualized funds from operations was 1.58 to 1 (December 31, 2009 - 1.67 to 1). The ratio improved over the prior year as a result of the sale of assets in 2010 and the higher funds from operations earned in the fourth quarter of 2010.

	Dec. 31, 2010	Dec. 31, 2009
Net debt:		
Accounts receivable (including assets held for sale)	$ 60,038	$ 37,574
Accounts payable and accrued liabilities	(100,745)	(84,228)
Working capital deficiency	$ (40,707)	$ (46,654)
Bank loan	(138,700)	(135,601)
Net debt	$ (179,407)	$ (182,255)
Annualized funds from operations:		
Cash provided by operating activities	$ 21,212	$ 16,734
Asset retirement expenditures	606	111
Transportation liability charge	120	329
Change in non-cash working capital	6,498	10,082
Fourth quarter funds from operations	28,436	27,256
Annualized	$ 113,744	$ 109,024
Net debt to annualized funds from operations	1.58	1.67

The Company's capital spending program for 2011 is estimated at $260 million. The Company has commodity and interest rate hedging for 2011 to provide support for its funds from operations and assist in funding its capital expenditure program.

On March 2, 2011, the Company issued 4,820,000 Common Shares at a price of $20.75 per share for aggregate gross proceeds of $100 million. Crew has also granted the Underwriters an over-allotment option to purchase, on the same terms, up to an additional 723,000 Common Shares for additional gross proceeds of up to $15.0 million exercisable by the Underwriters, in whole or in part, at any time up to 30 days following closing of the offering, to cover the Underwriters' over-allotments, if any.

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 capital 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, 2010.

10. 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 Dec. 31, 2010	Year ended Dec. 31, 2009
Loss before income taxes	$ (23,317)	$ (53,570)
Combined federal and provincial income tax rate	28.10%	29.10%
Computed "expected" income tax reduction	$ (6,552)	$ (15,589)
Increase (decrease) in income taxes resulting from:		
Non-deductible stock-based compensation	1,269	966
Benefits relating to change in income tax rates	(925)	(731)
Other	52	(401)
Future income tax reduction	$ (6,156)	$ (15,755)

(b) Future income tax liability:

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

	December 31, 2010	December 31, 2009
Future income tax:		
Property, plant and equipment	$ 117,129	$ 121,282
Asset retirement obligations	(9,061)	(8,953)
Share issue costs	(1,325)	(2,381)
Non-capital loss	(8,156)	(8,287)
Other	(2,257)	(684)
Future income tax liability	$ 96,330	$ 100,977

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

11. Supplemental cash flow information:

	Year ended Dec. 31, 2010	Year ended Dec. 31, 2009
Changes in non-cash working capital:		
Accounts receivable	$ (7,348)	$ 5,226
Accounts payable and accrued liabilities	16,517	9,606
	$ (9,169)	$ 14,832

Operating activities	$ (2,010)	$ 1,109
Investing activities	11,179	13,723
	$ (9,169)	$ 14,832

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

	Year ended Dec. 31, 2010	Year ended Dec. 31, 2009
Interest	$ 5,415	$ 6,246

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

	Total	2011	2012	2013	2014	2015	Thereafter
Operating leases	$ 3,052	$ 1,743	$ 1,309	-	-	-	-
Capital commitments	2,000	2,000	-	-	-	-	-
Transportation agreements	22,618	4,600	1,535	1,535	2,110	2,110	10,728
Processing agreement	77,936	6,526	6,526	6,526	8,239	8,239	41,880
Total	$105,606	$ 14,869	$ 9,370	$ 8,061	$10,349	$10,349	$ 52,608

The transportation agreements include a $19.5 million commitment to a third party to transport natural gas from the gas processing facility in the Septimus area to the Alliance pipeline system. The remaining commitment relates to firm transportation commitments that were acquired as part of the Company's May 2007 private company acquisition. In 2010, the Company permanently assigned approximately $6.2 million of its firm commitments to third parties.

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. 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.

In the fourth quarter of 2010, the Company amended the agreement with the owner of this facility. Under the terms of the amended agreement, Crew undertook construction of the facility expansion during the fourth quarter of 2010 and then subsequently sold the Septimus facility expansion in February 2011. Upon completion of the expansion, Crew was reimbursed for the full cost of the facility of $16.9 million in return for an expanded processing commitment that will extend to December 2020. The commitment is included in the above table. Crew has also retained the option to re-purchase a 50% interest in the facility at certain dates prior to January 1, 2014, at a cost of 50% of the total expanded facility's construction cost. If the Company re-purchases a 50% interest on January 1, 2014 for approximately $18.0 million, the remaining commitment would be reduced by approximately $29.0 million.

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