crew energy inc.

TSX: CR

Crew Energy Inc. of Calgary, Alberta is pleased to present its financial and operating results for the three and six month periods ended June 30, 2010.

2010 Q2

HIGHLIGHTS

- Second quarter funds from operations of $20.7 million was 3% higher than the second quarter of 2009;
- On April 1, 2010, Crew closed a strategic farmout and property disposition of 1,700 boe per day reducing corporate debt by 44% from the first quarter of 2010;
- Crew spent $26.5 million on Crown land acquisitions in the quarter adding 47 net sections at Princess, Alberta to increase the Company's Princess land base to over 500 sections;
- Crew tested three oil wells at Princess in the quarter at 242, 345 and 362 bbls of oil per day with ten additional wells awaiting completion;
- A recent Crew Montney well at Septimus, British Columbia tested at 12 mmcf per day and 360 bbl per day of condensate at a flowing casing pressure of 1,670 psi after seven days of production;
- Crew has added seven net sections of land through Crown land sales in northeastern British Columbia to increase the Company's Montney land base to over 220 net sections.

FINANCIAL	Three months ended		Six months ended	
($ thousands, except per share amounts)	**June 30, 2010**	June 30, 2009	**June 30, 2010**	June 30, 2009
Petroleum and natural gas sales	**43,027**	39,331	**104,799**	85,673
Funds from operations (1)	**20,693**	20,036	**48,910**	36,557
Per share – basic	**0.26**	0.27	**0.62**	0.51
– diluted	**0.25**	0.27	**0.60**	0.51
Net income (loss)	**(2,691)**	(12,267)	**(249)**	(21,285)
Per share – basic	**(0.03)**	(0.17)	**(0.00)**	(0.29)
– diluted	**(0.03)**	(0.17)	**(0.00)**	(0.29)
Exploration and development investment	**63,309**	14,187	**122,384**	37,865
Property acquisitions (net of dispositions)	**(121,724)**	(23,688)	**(132,640)**	(34,378)
Net capital expenditures	**(58,415)**	(9,501)	**(10,256)**	3,487
CAPITAL STRUCTURE *($ thousands)*			**As at June 30, 2010**	As at Dec. 31, 2009
Working capital deficiency (2)			**34,886**	46,654
Bank loan			**71,845**	135,601
Net debt			**106,731**	182,255
Bank facility			**210,000**	250,000
Common Shares Outstanding *(thousands)*			**80,096**	78,152

(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 only accounts receivable less accounts payable and accrued liabilities.

	Three months ended		Six months ended	
OPERATIONS	**June 30, 2010**	June 30, 2009	**June 30, 2010**	June 30, 2009
Daily production				
Natural gas (mcf/d)	**45,753**	54,036	**50,715**	56,773
Oil (bbl/d)	**3,305**	3,254	**3,780**	3,483
Natural gas liquids (bbl/d)	**1,117**	1,206	**1,284**	1,295
Oil equivalent (boe/d @ 6:1)	**12,048**	13,466	**13,517**	14,240
Average prices (1)				
Natural gas ($/mcf)	**4.31**	3.66	**4.89**	4.41
Oil ($/bbl)	**65.86**	60.75	**69.36**	51.52
Natural gas liquids ($/bbl)	**52.01**	30.46	**53.50**	33.42
Oil equivalent ($/boe)	**39.25**	32.10	**42.83**	33.24
Netback				
Operating netback ($/boe) (2)	**21.33**	17.89	**22.55**	16.16
Realized gain on financial instruments (3)	**(0.17)**	(0.56)	**(0.09)**	(0.20)
G&A ($/boe)	**1.50**	1.15	**1.35**	1.14
Interest and other ($/boe)	**1.12**	0.95	**1.30**	1.03
Funds from operations ($/boe)	**18.88**	16.35	**19.99**	14.19
Drilling Activity				
Gross wells	**11**	1	**33**	8
Working interest wells	**10.3**	1.0	**30.5**	2.8
Success rate, net wells	**100%**	100%	**100%**	94%

(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 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 financial instruments.

OVERVIEW

Operations during the second quarter of 2010 were highlighted by the drilling of 11 (10.3 net) wells with 100% success. The Company drilled six (6.0 net) oil wells at Princess, Alberta, three (3.0 net) liquids rich natural gas wells in northeast British Columbia and one (1.0 net) water disposal well at Princess. In addition, a third party drilled one (0.33 net) well on the previously announced Edson Cardium farmout.

Production in the second quarter was 12,048 boe per day, down from the first quarter of 2010 as a result of asset sales of 1,700 boe per day as well as production declines and curtailments. An early spring breakup, late season winter storms and extreme wet weather at Princess during the quarter severely hampered drilling, completion, pipelining and workover activity resulting in a drop in production from the area. Currently, activity at Princess is ramping up with four drilling rigs working and 14 wells to be placed on production.

In the second quarter, Crew continued to expand its land base in the Company's main oil property at Princess. The Company purchased 47 net sections of land for $25 million. In addition, Crew acquired seven net sections of land offsetting its Montney discovery well at Portage, British Columbia in the second and early third quarter. Crew added to its oil resource base in the second quarter by acquiring the remaining 52 percent working interest in nine sections of land and 35 boe per day of production in the Viking oil play at Provost, Alberta for $1.4 million. Crew has identified over 30 drilling locations on this light oil play.

OPERATIONS UPDATE

Pekisko Play, Princess, Alberta

During the second quarter, Crew drilled six (6.0 net) oil wells and one (1.0 net) salt water disposal well at Princess. Due to an early spring break up, late season winter storms and extreme wet weather, only one of these wells was brought on production in the second quarter. The unprecedented weather conditions severely hampered all drilling, completion, pipelining and workover activity in the area, resulting in a reduction of production. Crew has four drilling rigs currently active at Princess and has an inventory of 14 wells to place on production which is expected to increase area production to 5,500 to 6,000 boe per day.

Crew's Tilley waterflood is proceeding as planned. Current primary recoveries are estimated at 13% from the pool with waterflood modelling suggesting potential recoveries to increase to approximately 30%. The Company believes widespread application of secondary recovery schemes could be applied to other Pekisko reservoirs in the Princess area once pools have been delineated.

Crew fracture stimulated two older vertical low productivity wells in the first quarter with the first well's production improving from 18 boe per day to a current 45 boe per day. The second well's production improved from one boe per day to a current 12 boe per day. Wet weather delayed the planned fracture stimulation of five additional wells which are now expected to be completed later in the third quarter.

Crew expanded its land base at Princess in the second quarter by adding 47 (47.0 net) Crown sections primarily in the Tide Lake area. With the addition of these lands, the Company now plans to drill 60 to 70 wells in 2010 out of a current inventory of over 600 locations on 102 sections, with a targeted 2010 exit rate from the area in excess of 8,000 boe per day.

Montney Play, Northeast British Columbia

Crew drilled three (3.0 net) gas wells in the Montney formation at Septimus in the second quarter of 2010. One of these wells has been recently completed and has a production rate of 12 mmcf per day at a flowing casing pressure of 1,670 psi after seven days of in line production testing. In addition, the well was flowing 40 bbls per mmcf per day of natural gas liquids during the test, of which over 30 bbls per mmcf was condensate. This region of Septimus appears to be more liquids rich than the main core area which customarily yields 24 bbls of natural gas liquids per mmcf of natural gas. The other two wells off the same drilling pad are currently being tested.

The planned expansion of the Septimus gas processing facility to 50 mmcf per day from its current capacity of 25 mmcf per day is underway. The expansion is expected to be completed in the fourth quarter, and upon equalization with the current owner, Aux Sable Canada ("ASC"), Crew will become a 50% owner and will remain operator of the facility. ASC expects to complete the installation of a 20 inch pipeline from the Septimus gas facility to the Alliance pipeline in the third quarter of 2010 which is expected to be capable of transporting over 350 mmcf per day of gas and associated liquids.

Crew completed and tested its Portage exploration well in the second quarter. The Portage well (0.5 net) had a final test rate of 1.7 mmcf per day at 580 psi flowing casing pressure. This well had a short lateral of 900 meters, and compares very favourably to competitor wells drilled immediately north at Farrell Creek on a gas flow rate per frac basis. These competitor wells are currently producing at a restricted rate of over 5 mmcf per day. Crew controls 69 (34.5 net) sections of land at Portage.

Crew currently plans to drill four (4.0 net) additional wells at Septimus over the remainder of 2010. These wells are expected to be completed and brought on production in the fourth quarter timed to the Septimus gas plant expansion. In addition, the Company has drilled a horizontal exploration well on a large 100 percent working interest land block in the Goose area which is 20 miles northwest of Septimus and Crew has begun drilling a second horizontal earning well at Portage following up on its recent gas discovery and Crown land purchases.

Cardium Play, West Central Alberta

In the Edson-Pine Creek, Alberta area, Crew owns 60 net sections of oil prone Cardium rights. The Company is in the process of licensing three Cardium wells at Pine Creek in 2010 where the Company has identified 80 net drilling locations. Crew owns pipeline infrastructure and an underutilized gas processing facility in the area to accommodate future production volume growth.

In the second quarter, the first of two Cardium horizontal wells was drilled by a third party as part of the previously announced Edson farmout. The well (0.33 net) was completed with a multi-stage oil frac, and had a final test rate of 1.4 mmcf per day of natural gas and 150 bbls per day of oil (53 percent frac oil recovered). The well will be tied in and is expected to begin production in the third quarter. A second farmout well is licensed and is planned to be drilled in the third quarter.

RISK MANAGEMENT ACTIVITY

Crew remains well protected against commodity price fluctuations for the remainder of 2010. For the second half of 2010, the Company has an average of 20 mmcf per day of natural gas hedged at an average fixed price of $6.22 per mcf and 3,000 bbl per day of oil hedged at a minimum floor price of Canadian dollar WTI $81.24 per bbl. These hedges are in place to protect the Company's capital program and balance sheet against the commodity price volatility that we have experienced over the past two years.

The Company has also established commodity hedges to secure cash flow for 2011. Crew has entered into Canadian dollar WTI oil price swaps and floors on an average of 2,000 bbl per day for 2011. These transactions averaged a minimum price floor of approximately CDN $86.50 per bbl for WTI oil. A detailed list of the Company's hedge positions is included in the attached management's discussion and analysis.

OUTLOOK

Business Environment

Oil prices have remained strong as world economies continue to recover from recession resulting in increasing demand for most commodities. Natural gas prices, on the other hand, continue to be depressed as aggressive development of unconventional resources continues unabated across North America leading to an over supplied market. Costs, particularly hydraulic fracturing costs, continue to escalate as a result of increased activity levels which, in the current pricing environment, can, in our opinion, only lead to reduced natural gas activity. Crew has the ability to direct its capital and intellectual resources to both oil and liquids rich natural gas plays which both provide superior economics in the current environment. The Company will continue to focus its efforts on the liquids rich Montney play at Septimus in British Columbia and, more heavily, weight its capital program on the Princess Pekisko oil play in Alberta.

Active Drilling Program

Crew continues to build upon its experience at Septimus and Princess. Drilling and completion programs continue to be refined in an effort to reduce costs and improve well results. A number of initiatives are planned to be tested in the last half of the year in both of these areas. Drilling costs at Septimus have declined as a result of reducing the drilling time from 37 days to 17 days for the latest well representing a 55% reduction taking drill and case costs down to approximately $1.4 million. Crew has a $225 million capital expenditure budget for 2010, the majority of which will be directed to oil related drilling and land acquisitions at Princess. As a result of the weather related delays in southeast Alberta over the last four months, Crew is now forecasting its average production in 2010 to be 14,500 to 15,000 boe per day. Exit production is forecasted to be 18,000 boe per day with an increased weighting on liquids production.

Crew is in an enviable position possessing a number of resource plays that offer our shareholders significant upside with scale, repeatability and very attractive investment metrics. The Company is well financed to execute an active second half 2010 program which is expected to result in record production levels while continuing to de-risk its resource plays for years of future growth. We are excited about our recent well results and the potential of our asset base and look forward to reporting our third quarter results in November.

On behalf of the Board,

Dale Shwed
President and C.E.O.

August 9, 2010

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 and six month periods ended June 30, 2010 and 2009 and the audited consolidated financial statements and Management's 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, 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, general and administrative expenses, interest rates, debt levels, funds from operations and the timing of and impact of adoption of IFRS and other accounting policies may constitute forward-looking statements under applicable securities laws and necessarily involve risks including, without limitation, risks associated with oil and gas exploration, development, exploitation, production, marketing and transportation, loss of markets, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other producers, inability to retain drilling rigs and other services, incorrect assessment of the value of acquisitions, failure to realize the anticipated benefits of acquisitions, the inability to fully realize the benefits of acquisitions, delays resulting from or inability to obtain required regulatory approvals and ability to access sufficient capital from internal and external sources. As a consequence, the Company's actual results may differ materially from those expressed in, or implied by, the forward looking statements. Forward looking statements or information are based on a number of factors and assumptions which have been used to develop such statements and information but which may prove to be incorrect. Although Crew believes that the expectations reflected in such forward-looking statements or information are reasonable, undue reliance should not be placed on forward looking statements because the Company can give no assurance that such expectations will prove to be correct. In addition to other factors and assumptions which may be identified in this document and other documents filed by the Company, assumptions have been made regarding, among other things: the impact of increasing competition; the general stability of the economic and political environment in which Crew operates; the ability of the Company to obtain qualified staff, equipment and services in a timely and cost efficient manner; drilling results; the ability of the operator of the projects which the Company has an interest in to operate the field in a safe, efficient and effective manner; Crew's ability to obtain financing on acceptable terms; field production rates and decline rates; the ability to reduce operating costs; the ability to replace and expand oil and natural gas reserves through acquisition, development or exploration; the timing and costs of pipeline, storage and facility construction and expansion; the ability of the Company to secure adequate product transportation; future petroleum and natural gas prices; currency, exchange and interest rates; the regulatory framework regarding royalties, taxes and environmental matters in the jurisdictions in which the Company operates; and Crew's ability to successfully market its petroleum and natural gas products. Readers are cautioned that the foregoing list of factors is not exhaustive. Additional information on these and other factors that could affect the Company's operations and financial results are included in reports on file with Canadian securities regulatory authorities and may be accessed through the SEDAR website (www.sedar.com) or at the Company's website (www.crewenergy.com). Furthermore, the forward looking statements contained in this document are made as at the date of this document and the Company does not undertake any obligation to update publicly or to revise any of the included forward looking statements, whether as a result of new information, future events or otherwise, except as may be required by applicable securities laws.

Conversions

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

Throughout this MD&A, Crew has used the 6:1 boe measure which is the approximate energy equivalency of the two commodities at the burner tip. Boe does not represent a value equivalency at the 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:

	Three months ended		Six months ended	
($ thousands)	**June 30, 2010**	June 30, 2009	**June 30, 2010**	June 30, 2009
Cash provided by operating activities	**24,149**	21,517	**56,362**	41,023
Asset retirement expenditures	**129**	181	**705**	282
Transportation liability charge (1)	**154**	329	**482**	657
Change in non-cash working capital	**(3,739)**	(1,991)	**(8,639)**	(5,405)
Funds from operations	**20,693**	20,036	**48,910**	36,557

(1) The amount for the three and six months ended June 30, 2010 does not include the transportation liability write-down of $344,000 as shown 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 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							
	June 30, 2010				June 30, 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	**3,184**	**420**	**21,633**	**7,210**	3,042	898	37,065	10,117
British Columbia	**121**	**697**	**24,120**	**4,838**	212	308	16,971	3,349
Total	**3,305**	**1,117**	**45,753**	**12,048**	3,254	1,206	54,036	13,466

Second quarter 2010 production decreased compared with the second quarter of 2009 as a result of the sale of approximately 2,300 boe per day of primarily natural gas production from two separate dispositions in Ferrier, Alberta 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 and oil production in the Princess, Alberta area. However, in the second quarter of 2010, the Company's oil production was below the Company's expectations as poor weather throughout southern Alberta during the second quarter hampered activity in the Princess area.

	Six months ended							
	June 30, 2010				June 30, 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	**3,659**	**612**	**26,232**	**8,643**	3,264	932	38,574	10,625
British Columbia	**121**	**672**	**24,483**	**4,874**	219	363	18,199	3,615
Total	**3,780**	**1,284**	**50,715**	**13,517**	3,483	1,295	56,773	14,240

Production for the first six months of 2010 decreased due to the previously mentioned asset dispositions but was partially offset due to production additions from a successful drilling program.

Revenue

	Three months ended		Six months ended	
	June 30, 2010	June 30, 2009	**June 30, 2010**	June 30, 2009
Revenue *($ thousands)*				
Natural gas	**17,929**	17,998	**44,913**	45,268
Oil	**19,809**	17,988	**47,457**	32,473
Natural gas liquids	**5,289**	3,345	**12,429**	7,834
Sulphur	**–**	–	**–**	98
Total	**43,027**	39,331	**104,799**	85,673
Crew average prices				
Natural gas ($/mcf)	**4.31**	3.66	**4.89**	4.41
Oil ($/bbl)	**65.86**	60.75	**69.36**	51.52
Natural gas liquids ($/bbl)	**52.01**	30.46	**53.50**	33.42
Oil equivalent ($/boe)	**39.25**	32.10	**42.83**	33.24
Benchmark pricing				
Natural Gas – AECO C daily index (Cdn $/mcf)	**3.94**	3.43	**4.49**	4.21
Oil – Bow River Crude Oil (Cdn $/bbl)	**75.24**	70.73	**77.75**	62.10
Oil and ngl – CDN$ West Texas Int. (Cdn $/bbl)	**80.12**	69.27	**81.01**	61.48

Crew's second quarter 2010 revenue increased 9% from the second quarter of 2009 due to the 22% increase in average commodity prices partially offset by an 11% decrease in the Company's production.

Crew's second quarter 2010 average natural gas price increased 18% which was comparable to a 15% increase in its benchmark index. In the second quarter of 2010, the Company's oil price increased 8% as compared with a 7% increase in the Company's comparable benchmark Bow River Crude. The price received for the Company's ngl production increased 71% as compared to a 16% increase in the Company's benchmark CDN$ West Texas Intermediate pricing. This was due to the sale of the assets in the Ferrier area in 2009 which included lower valued ethane production. In addition, the Company increased production of higher valued condensate from the Septimus area.

For the six months ended June 30, 2010, Crew's gas price increased 11% as compared with a 7% increase in the benchmark. Decreased production of lower valued natural gas production in the Sierra, British Columbia area replaced by higher valued natural gas from the Septimus area accounts for Crew's increased pricing as compared to the benchmark. The Company's realized oil price increased 35% as compared with a 25% increase in the benchmark Bow River Crude primarily due to higher 2010 Bow River Oil pricing combined with Crew receiving a similar fixed price quality differential off of the Bow River price for oil volumes in the Princess area. The Company's ngl price increased 60% as compared with a 32% increase in the benchmark due to the sale of Ferrier, Alberta assets as mentioned above which included lower valued ethane production combined with increased higher valued condensate production from Septimus.

Royalties

	Three months ended		Six months ended	
($ thousands, except per boe)	**June 30, 2010**	June 30, 2009	**June 30, 2010**	June 30, 2009
Royalties	**8,419**	5,512	**21,568**	16,192
Per boe	**7.68**	4.50	**8.82**	6.28
Percentage of revenue	**19.6%**	14.0%	**20.6%**	18.9%

Royalties as a percentage of revenue increased in the second quarter and first half of 2010 compared to the same periods of 2009 due to increased oil production from Princess which currently attracts a higher royalty rate and the sale of the properties in the Ferrier and Edson areas which attracted a lower royalty rate. Corporately, with an increase in forecasted second half oil sales from production in the Princess area, Crew forecasts annual royalties as a percentage of revenue to average 21% to 23% for 2010.

Financial Instruments

Commodities

The Company enters into derivative and physical risk management contracts in order to reduce volatility in financial results, to protect acquisition economics and to ensure a certain level of cash flow to fund planned capital projects. Crew's strategy focuses on the use of puts, costless collars, swaps and fixed price contracts to 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:

	Three months ended		Six months ended	
($ thousands)	**June 30, 2010**	June 30, 2009	**June 30, 2010**	June 30, 2009
Realized gain on financial instruments	**3,756**	5,643	**4,684**	6,196
Unrealized gain (loss) on financial instruments	**2,334**	(3,816)	**10,532**	1,054

As at June 30, 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	November 1, 2009 – December 31, 2010	AECO C Monthly Index	$6.00/gj	Swap	894
Natural Gas	5,000 gj/day	January 1, 2010 – December 31, 2010	AECO C Monthly Index	$8.00/gj	Call	(5)
Natural Gas	10,000 gj/day	January 1, 2010 – December 31, 2010	AECO C Monthly Index	$7.75/gj	Call	(12)
Natural Gas	2,500 gj/day	January 1, 2010 – December 31, 2010	AECO C Monthly Index	$6.20/gj	Swap	986
Natural Gas	5,000 gj/day	January 1, 2010 – December 31, 2010	AECO C Monthly Index	$6.08/gj	Swap	2,217
Natural Gas	2,500 gj/day	January 1, 2010 – December 31, 2010	AECO C Monthly Index	$5.25/gj	Swap	550
Natural Gas	2,500 gj/day	January 1, 2010 – December 31, 2010	AECO C Monthly Index	$5.55/gj	Swap	688
Natural Gas	2,500 gj/day	April 1, 2010 – October 31, 2010	AECO C Monthly Index	$5.30/gj	Swap	471
Natural Gas	5,000 mmbtu/day	January 1, 2010 – December 31, 2010	AECO/NYMEX Basis diff	US$($0.55)	Swap	250
Oil	250 bbl/day	January 1, 2010 – December 31, 2010	CDN$ WTI	$78.50/bbl	Swap	(159)
Oil	500 bbl/day	January 1, 2010 – December 31, 2010	CDN$ WTI	$72.00 – $88.00/bbl	Collar	(75)
Oil	250 bbl/day	January 1, 2010 – December 31, 2010	CDN$ WTI	$82.50/bbl	Swap	25
Oil	500 bbl/day	January 1, 2010 – December 31, 2010	CDN$ WTI	$80.50/bbl	Swap	(117)
Oil	500 bbl/day	January 1, 2010 – December 31, 2010	US$ WTI	US$81.00/bbl	Swap	387
Oil	250 bbl/day	January 1, 2010 – December 31, 2010	CDN$ WTI	$80.00 – $95.02/bbl	Collar	136
Oil	250 bbl/day	March 1, 2010 – December 31, 2010	CDN$ WTI	$84.00/bbl	Swap	136
Oil	250 bbl/day	July 1, 2010 – December 31, 2010	CDN$ WTI	$88.10	Swap	281
Oil	250 bbl/day	July 1, 2010 – December 31, 2010	CDN$ WTI	$91.50	Swap	438
Oil	250 bbl/day	January 1, 2011 – December 31, 2011	CDN$ WTI	$86.00/bbl	Swap	79
Oil	250 bbl/day	January 1, 2011 – December 31, 2011	CDN$ WTI	$90.00	Swap	441
Oil	500 bbl/day	January 1, 2011 – December 31, 2011	CDN$ WTI	$90.20	Swap	914
Oil	250 bbl/day	January 1, 2011 – December 31, 2011	CDN$ WTI	$82.00 – $94.62	Collar	216
Oil	250 bbl/day	January 1, 2011 – December 31, 2011	CDN$ WTI	$80.00 – $95.45	Collar	167
Oil	250 bbl/day	January 1, 2011 – December 31, 2011	CDN$ WTI	$85.00 – $100.50	Collar	533
Total						9,441

Foreign currency

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

At June 30, 2010, the Company held the following derivative foreign currency contract:

Subject of Contract	Notional Quantity	Term	Reference	Strike Price	Option Traded	Fair Value ($000s)
USD / CAD $ exchange	US $2M / Month	January 1, 2010 – December 31, 2010	CAD/USD	1.094	Swap	342
Total						342

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 June 30, 2010, Crew had contracts in place fixing the interest rate on $150 million of bankers' acceptances at rates of 1.10% to 1.12%. The Company pays additional stamping fees and margins on bankers' acceptances as outlined in note 3 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	(58)
BA Rate	$50M / year	February 12, 2009 – February 12, 2011	BA - CDOR	1.10%	Swap	(39)
BA Rate	$50M / year	May 28, 2009 – May 28, 2011	BA - CDOR	1.12%	Swap	12
Total						(85)

Subsequent to June 30, 2010, the Company unwound the $50 million per year 1.12% swaps maturing on May 28, 2011 for net proceeds to the Company of $12,000.

Subsequent to June 30, 2010, the Company entered into the following financial instrument contract:

Subject of Contract	Volume	Term	Reference	Strike Price (per bbl)	Option Traded
Oil	250 bbl/day	January 1, 2011 – December 31, 2011	CDN$ WTI	$88.50	Swap

Operating Costs

	Three months ended		**Six months ended**	
($ thousands, except per boe)	**June 30, 2010**	June 30, 2009	**June 30, 2010**	June 30, 2009
Operating costs	**12,663**	14,448	**27,649**	28,258
Per boe	**11.55**	11.79	**11.30**	10.96

In the second quarter of 2010, the Company's operating costs per unit slightly decreased over the same period in 2009 due to additional production from the Septimus area where operating costs per boe are lower than the Company's total corporate average. This was partially offset by the sale of lower cost production in the Edson area and the impact of poor weather at Princess which inhibited production and increased costs for the period. For the first six months of 2010, operating costs per boe were slightly higher than the same period in 2009 due to the aforementioned sale of lower cost production in the Edson area and decreased production from the Sierra area where the operating costs have a high fixed cost component and the impact of poor weather at Princess which inhibited production and increased costs for the period. With additional forecasted production to offset fixed costs in the Princess and Septimus areas and cost cutting measures associated with water handling at Princess, the Company forecasts total operating costs to decrease from the current level to average between $10.00 and $10.75 per boe for 2010.

Transportation Costs

($ thousands, except per boe)	Three months ended June 30, 2010	Three months ended June 30, 2009	Six months ended June 30, 2010	Six months ended June 30, 2009
Transportation costs including liability write-down	**2,143**	2,397	**4,520**	5,265
Transportation liability write-down	**–**	–	**344**	–
Transportation costs	**2,143**	2,397	**4,864**	5,265
Per boe	**1.95**	1.96	**1.99**	2.04

In the second quarter of 2010, the Company's transportation costs per unit were at the same levels as the same period in 2009. The disposition of lower transportation cost production in Edson and Ferrier was offset by the Company permanently assigning its unutilized firm transportation commitment in northeastern British Columbia in March 2010. For the first six months of 2010, the Company's transportation costs per unit have decreased as compared with the same period in 2009 due to the assignment of the firm transportation commitment and increased natural gas production in Septimus and oil production in Princess which both currently attract a lower transportation costs per boe. The Company continues to expect transportation costs to range between $1.50 and $2.00 for 2010.

Operating Netbacks

	Three months ended							
	June 30, 2010				June 30, 2009			
	Oil ($/bbl)	**Ngl ($/bbl)**	**Natural gas ($/mcf)**	**Total ($/boe)**	Oil ($/bbl)	Ngl ($/bbl)	Natural gas ($/mcf)	Total ($/boe)
Revenue	**65.86**	**52.01**	**4.31**	**39.25**	60.75	30.46	3.66	32.10
Realized commodity hedging gain	**1.02**	**–**	**0.07**	**3.26**	–	–	1.01	4.04
Royalties	**(18.30)**	**(10.69)**	**(0.44)**	**(7.68)**	(16.45)	(9.48)	(0.08)	(4.50)
Operating costs	**(15.69)**	**(9.89)**	**(1.69)**	**(11.55)**	(13.44)	(9.81)	(1.91)	(11.79)
Transportation costs	**(1.94)**	**(1.08)**	**(0.35)**	**(1.95)**	(1.28)	–	(0.41)	(1.96)
Operating netbacks	**30.95**	**30.35**	**1.90**	**21.33**	29.58	11.17	2.27	17.89

	Six months ended							
	June 30, 2010				June 30, 2009			
	Oil ($/bbl)	**Ngl ($/bbl)**	**Natural gas ($/mcf)**	**Total ($/boe)**	Oil ($/bbl)	Ngl ($/bbl)	Natural gas ($/mcf)	Total ($/boe)
Revenue	**69.36**	**53.50**	**4.89**	**42.83**	51.52	33.42	4.41	33.24
Realized commodity hedging gain	**0.42**	**–**	**0.03**	**1.83**	–	–	0.55	2.20
Royalties	**(19.84)**	**(12.28)**	**(0.56)**	**(8.82)**	(13.35)	(10.91)	(0.50)	(6.28)
Operating costs	**(14.15)**	**(9.44)**	**(1.72)**	**(11.30)**	(11.98)	(9.17)	(1.81)	(10.96)
Transportation costs	**(1.38)**	**(1.26)**	**(0.36)**	**(1.99)**	(1.43)	–	(0.42)	(2.04)
Operating netbacks	**34.41**	**30.52**	**2.28**	**22.55**	24.76	13.34	2.23	16.16

General and Administrative Costs

($ thousands, except per boe)	Three months ended June 30, 2010	Three months ended June 30, 2009	Six months ended June 30, 2010	Six months ended June 30, 2009
Gross costs	**3,875**	3,219	**8,047**	6,699
Operator's recoveries	**(596)**	(388)	**(1,427)**	(812)
Capitalized costs	**(1,639)**	(1,416)	**(3,310)**	(2,944)
General and administrative expenses	**1,640**	1,415	**3,310**	2,943
Per boe	**1.50**	1.15	**1.35**	1.14

Increased general and administrative costs before recoveries and capitalization were mainly the result of increased staff levels to accommodate the Company's larger operations at Septimus and Princess in the second quarter and first half of 2010 compared to 2009. In the second quarter and first half of 2010, net general and administrative costs per boe have increased over the same period of 2009. This is primarily due to increased gross costs and decreased production due to the sale of the Ferrier and Edson production for these periods as compared with the same periods in 2009. The Company expects general and administrative expenses to average between $1.00 and $1.25 per boe for the year as forecasted production increases in the last half of 2010 and second half costs historically decline as annual reporting costs are now complete.

Interest

	Three months ended		Six months ended	
($ thousands, except per boe)	**June 30, 2010**	June 30, 2009	**June 30, 2010**	June 30, 2009
Interest expense	**1,225**	1,166	**3,182**	2,654
Average debt level	**50,446**	223,864	**92,908**	225,754
Effective interest rate	**9.7%**	2.1%	**6.9%**	2.4%
Per boe	**1.12**	0.95	**1.30**	1.03

Crew's 2010 second quarter and first half interest expense increased over the same periods in 2009 despite a significant decrease in outstanding average debt levels. This increase resulted from an increase in the stamping fees charged on the Company's outstanding banker's acceptances from 1.1% in 2009 to 3.5% in 2010 and a significant increase in the standby fees charged on the unutilized portion of the Company's bank facility. The effective interest rate increased for both the three and six month periods as a result of the higher margins charged on the Company's drawn facility. In addition, effective interest rates were impacted by higher standby fees charged on the unutilized facility and the amortization of annual renewal fees against the significantly decreased drawn facility as a denominator.

With the Company's recently renegotiated bank facility and decreased average debt to EBITDA ratios, the stamping fees and margins applied to its facility are expected to decrease in the latter half of 2010.

Stock-Based Compensation

	Three months ended		Six months ended	
($ thousands)	**June 30, 2010**	June 30, 2009	**June 30, 2010**	June 30, 2009
Gross costs	**2,139**	1,663	**4,779**	3,421
Capitalized costs	**(1,069)**	(832)	**(2,389)**	(1,711)
Total stock-based compensation	**1,070**	831	**2,390**	1,710

The Company's stock-based compensation expense has increased in the second quarter and first half of 2010 compared with 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 due to the Company's share price increasing.

Depletion, Depreciation and Accretion

	Three months ended		Six months ended	
($ thousands, except per boe)	**June 30, 2010**	June 30, 2009	**June 30, 2010**	June 30, 2009
Depletion, depreciation and accretion	**25,647**	32,823	**57,767**	67,794
Per boe	**23.39**	26.79	**23.61**	26.30

Per unit depletion has decreased in the second quarter and first half of 2010 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 than the Company's corporate depletion rate.

Future Income Taxes

The provision for future income taxes was a recovery of $1.0 million in the second quarter of 2010 compared to a recovery of $5.2 million in the same period of 2009. The decrease in the future tax recovery was a result of a larger pre-tax loss in 2009. For the first six months of 2010, the Company had a future tax recovery of $0.1 million as compared with a recovery of $10.6 million for the same period of 2009. The larger recovery in 2009 was a result of a greater pre-tax loss in 2009 and a corporate rate reduction in British Columbia from 11 percent to 10.5 percent in 2010 and a further reduction to 10 percent in 2011.

Cash and Funds from Operations and Net Loss

	Three months ended		Six months ended	
($ thousands, except per share amounts)	**June 30, 2010**	June 30, 2009	**June 30, 2010**	June 30, 2009
Cash provided by operating activities	**24,149**	21,517	**56,362**	41,023
Funds from operations	**20,693**	20,036	**48,910**	36,557
Per share – basic	**0.26**	0.27	**0.62**	0.51
– diluted	**0.25**	0.27	**0.60**	0.51
Net loss	**(2,691)**	(12,267)	**(249)**	(21,285)
Per share – basic	**(0.03)**	(0.17)	**0.00**	(0.29)
– diluted	**(0.03)**	(0.17)	**0.00**	(0.29)

The second quarter and first half of 2010 increase in cash provided by operations and funds from operations was the result of increased commodity pricing but was partially offset by the lower production due to the asset sales completed in late 2009 and early 2010 and the poor weather at Princess. The second quarter and first half of 2010 net loss was lower than the same periods in 2009 due to increased commodity pricing, increased unrealized gains on financial instruments and decreased depletion costs.

Capital Expenditures, Acquisitions and Dispositions

During the second quarter of 2010, the Company drilled 11 (10.3 net) wells resulting in seven (6.3 net) oil wells, three (3.0 net) gas wells and one (1.0 net) water disposal wells. In addition, the Company also completed eight (7.5 net) wells in the Princess and Septimus areas. Crew continued to add to its infrastructure spending $7.5 million primarily on infrastructure improvements at Princess and the gas plant expansion at Septimus. In the second quarter of 2010, the Company continued to add to its undeveloped land base spending $26.5 million on crown land in southern Alberta and northeastern British Columbia. The Company also closed its previously announced disposition of approximately 1,700 boe per day of mainly natural gas production in the Edson area for net proceeds of $123.3 million.

Total exploration and development capital expenditures for the second quarter and first half of 2010 were $63.3 million and $122.4 million, respectively compared to $14.2 million and $37.9 million for the same periods in 2009. The expenditures are detailed below:

	Three months ended		Six months ended	
($ thousands)	**June 30, 2010**	June 30, 2009	**June 30, 2010**	June 30, 2009
Land	**27,155**	716	**34,872**	3,868
Seismic	**164**	322	**5,095**	2,095
Drilling and completions	**26,561**	4,745	**66,891**	10,400
Facilities, equipment and pipelines	**7,490**	6,889	**11,770**	18,345
Other	**1,939**	1,515	**3,756**	3,157
Total exploration and development	**63,309**	14,187	**122,384**	37,865
Property dispositions	**(121,724)**	(23,688)	**(132,640)**	(34,378)
Total	**(58,415)**	(9,501)	**(10,256)**	3,487

As at June 30, 2010, budgeted exploration and development expenditures for 2010 are estimated at $225 million.

LIQUIDITY AND CAPITAL RESOURCES

Capital Funding

During the second quarter of 2010, the Company completed the extension of its credit facility with a syndicate of banks (the "Syndicate"). The credit facility was amended to a revolving line of credit of $190 million and an operating line of credit of $20 million for a total borrowing facility of $210 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 review 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 October 31, 2010. At June 30, 2010, the Company had drawings of $71.8 million on the Facility and had issued letters of credit totaling $3.6 million.

During the first half of 2010, the Company has received proceeds of $17.6 million due to the exercise of 1,943,300 employee stock options.

The Company will continue to fund its on-going operations from a combination of cash flow, debt, asset dispositions and equity financings as needed. As the majority of 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. The working capital deficiency includes only accounts receivable less accounts payable and accrued liabilities. The Company maintains sufficient unused bank credit lines to satisfy such working capital deficiencies. At June 30, 2010, the Company's working capital deficiency totaled $34.9 million which, when combined with the drawings on its bank line, represented 51% of its current bank facility.

Share Capital

As at August 9, 2010, Crew had 80,112,401 Common Shares and 5,662,867 options to acquire Common Shares of the Company issued and 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 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 June 30, 2010, the Company's ratio of net debt to annualized funds from operations was 1.29 to 1 (December 31, 2009 – 1.67 to 1).

($ thousands, except ratio)	**June 30, 2010**	Dec. 31, 2009
Accounts receivable	**29,634**	37,574
Accounts payable and accrued liabilities	**(64,520)**	(84,228)
Working capital deficiency	**(34,886)**	(46,654)
Bank loan	**(71,845)**	(135,601)
Net debt	**(106,731)**	(182,255)
Funds from operations	**20,693**	27,256
Annualized	**82,772**	109,024
Net debt to annualized funds from operations ratio	**1.29**	1.67

Contractual Obligations

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

($ thousands)	Total	2010	2011	2012	2013	2014	Thereafter
Bank Loan (1)	71,845	–	–	71,845	–	–	–
Operating Leases	3,930	872	1,743	1,315	–	–	–
Capital commitments	8,000	4,000	4,000	–	–	–	–
Transportation agreements	4,918	1,853	3,065	–	–	–	–
Processing agreement	28,967	1,525	3,049	3,049	3,049	3,049	15,246
Total	117,660	8,250	11,857	76,209	3,049	3,049	15,246

(1) Based on the existing terms of the Company's bank facility the first possible repayment date may come in 2012. However, it is expected that the revolving bank facility will be extended and no repayment will be required in the near term.

The firm transportation commitments were acquired as part of the Company's May 2007 private company acquisition and represent firm service commitments for transportation and processing of natural gas in British Columbia. In 2010, the Company permanently assigned approximately $6.2 million of its firm transportation commitments to third parties. The amount shown represents the remaining contractual obligation.

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

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

Guidance

Crew continues to build upon its experience at Septimus and Princess. Drilling and completion programs continue to be refined in an effort to reduce costs and improve well results. A number of initiatives are planned to be tested in the last half of the year in both of these areas. Crew has a $225 million capital expenditure budget for 2010, the majority of which will be directed to oil related drilling and land acquisitions at Princess, Alberta. As a result of weather related delays in southern Alberta over the last four months, Crew is now forecasting average production in 2010 to be 14,500 to 15,000 boe per day. Exit production is forecasted to be 18,000 boe per day with an increased weighting on liquids production.

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)	**June 30 2010**	Mar. 31 2010	Dec. 31 2009	Sept. 30 2009	June 30 2009	Mar. 31 2009	Dec. 31 2008	Sept. 30 2008
Total daily production (boe/d)	**12,048**	15,001	14,470	13,065	13,466	15,022	14,869	11,505
Average wellhead price ($/boe)	**39.25**	45.75	43.30	32.04	32.10	34.28	42.99	61.74
Petroleum and natural gas sales	**43,027**	61,772	57,646	38,510	39,331	46,342	58,806	65,345
Cash provided by operations	**24,149**	32,213	16,734	24,902	21,517	19,506	25,700	36,208
Funds from operations	**20,693**	28,217	27,256	19,640	20,036	16,521	29,646	35,004
Per share – basic	**0.26**	0.36	0.35	0.25	0.27	0.23	0.42	0.54
– diluted	**0.25**	0.35	0.35	0.25	0.27	0.23	0.42	0.54
Net income (loss)	**(2,691)**	2,442	(9,154)	(7,376)	(12,267)	(9,018)	(74,853)	15,178
Per share – basic	**(0.03)**	0.03	(0.12)	(0.10)	(0.17)	(0.13)	(1.05)	0.24
– diluted	**(0.03)**	0.03	(0.12)	(0.10)	(0.17)	(0.13)	(1.05)	0.23

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 2008 to 2010, these performance measures have fluctuated as a result of volatile oil and natural gas prices resulting from the current unstable global economy.

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

- Revenue is directly impacted by the Company's ability to replace existing declining production and add incremental production through its on-going capital expenditure program.
- Production in the second quarter of 2009 and 2010 was negatively impacted by scheduled and unscheduled third party facility shutdowns and poor weather experienced in southern Alberta in 2010.
- In August 2008, the Company acquired Gentry Resources Ltd. with approximately 4,000 boe per day of production at closing.
- Revenue and royalties are significantly impacted by underlying commodity prices. The Company utilizes derivative contracts and forward sales contracts to reduce the exposure to commodity price fluctuations 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 the fourth quarter of 2008, Crew performed an impairment test on its goodwill and determined that its carrying value exceeded its fair value and therefore an impairment charge of $69.1 million was required.
- In 2009 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

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 the December 31, 2010 financial statements will continue to be reported in accordance with Canadian GAAP as it exists on each reporting date. Financial statements for the quarter ended March 31, 2011, including comparative amounts, will be prepared on an IFRS basis.

In order to transition to IFRS, management has established a project team and formed an executive steering committee. A transition plan has been developed to convert the financial statements to IFRS. External advisors have been retained and will assist management with the project on an as needed basis. Staff training programs will continue throughout 2010. The Company continues to assess the effect of the transition on information systems, internal controls over financial reporting and disclosure controls and procedures. The project team and steering committee continue to provide updates to senior management and the Audit Committee. The Company's auditors are involved throughout the process to ensure the Company's policies are in accordance with the new standards.

Analysis of differences between IFRS and Canadian GAAP is continuing. There are significant accounting policy changes anticipated on adoption of IFRS which are described in more detail in the Company's December 31, 2009 MD&A. Management is continuing to finalize its accounting policies and as such is unable to quantify the impact on the financial statements at this time. In addition, anticipated changes to IFRS and International Accounting Standards prior to adoption could cause changes to certain items based on new facts and circumstances.

In accordance with its plan, Crew has analyzed accounting policy alternatives and drafted its IFRS position papers. Crew is in the process of completing its January 1, 2010 IFRS opening balance sheet and having its external auditors review the Company's draft IFRS balance sheet impacts.

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.

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 generally accepted accounting principles. The Company is required to disclose herein any change in the Company's internal control over financial reporting that occurred during the period beginning on April 1, 2010 and ended on June 30, 2010 that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting. No material changes in the Company's internal control over financial reporting were identified during such period that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

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

Dated as of August 9, 2010

CONSOLIDATED BALANCE SHEETS

(unaudited) (thousands)	**June 30, 2010**	December 31, 2009
ASSETS		
Current Assets:		
Accounts receivable	**$ 29,634**	$ 37,574
Fair value of financial instruments (note 7)	**9,698**	–
Future income taxes	**–**	542
	39,332	38,116
Property, plant and equipment (note 2)	**859,248**	925,132
	$ 898,580	$ 963,248
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities:		
Accounts payable and accrued liabilities	**$ 64,520**	$ 84,228
Fair value of financial instruments (note 7)	**–**	834
Future income taxes	**2,306**	–
Current portion of other long-term obligations (note 4)	**619**	1,313
	67,445	86,375
Bank loan (note 3)	**71,845**	135,601
Other long-term obligations (note 4)	**–**	132
Asset retirement obligations (note 5)	**33,582**	35,341
Future income taxes	**99,341**	101,519
SHAREHOLDERS' EQUITY		
Share capital (note 6)	**642,208**	617,605
Contributed surplus (note 6 (c))	**20,502**	22,769
Deficit	**(36,343)**	(36,094)
	626,367	604,280
Commitments (note 10)		
	$ 898,580	$ 963,248

See accompanying notes to the consolidated financial statements.

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

	Three months ended		Six months ended	
(unaudited) (thousands, except per share amounts)	**June 30, 2010**	June 30, 2009	**June 30, 2010**	June 30, 2009
Revenue				
Petroleum and natural gas sales	**$ 43,027**	$ 39,331	**$ 104,799**	$ 85,673
Royalties	**(8,419)**	(5,512)	**(21,568)**	(16,192)
Realized gain on financial instruments (note 7)	**3,756**	5,643	**4,684**	6,196
Unrealized gain (loss) on financial instruments (note 7)	**2,334**	(3,816)	**10,532**	1,054
	40,698	35,646	**98,447**	76,731
Expenses				
Operating	**12,663**	14,448	**27,649**	28,258
Transportation (note 4)	**2,143**	2,397	**4,520**	5,265
General and administrative	**1,640**	1,415	**3,310**	2,943
Interest	**1,225**	1,166	**3,182**	2,654
Stock-based compensation (note 6(d))	**1,070**	831	**2,390**	1,710
Depletion, depreciation and accretion	**25,647**	32,823	**57,767**	67,794
	44,388	53,080	**98,818**	108,624
Loss before income taxes	**(3,690)**	(17,434)	**(371)**	(31,893)
Future income tax reduction	**(999)**	(5,167)	**(122)**	(10,608)
Loss and comprehensive loss	**(2,691)**	(12,267)	**(249)**	(21,285)
Retained earnings (deficit), beginning of period	**(33,652)**	(7,297)	**(36,094)**	1,721
Deficit, end of period	**$ (36,343)**	$ (19,564)	**$ (36,343)**	$ (19,564)
Loss per share (note 6(e))				
Basic	**$ (0.03)**	$ (0.17)	**$ (0.00)**	$ (0.29)
Diluted	**$ (0.03)**	$ (0.17)	**$ (0.00)**	$ (0.29)

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Three months ended		Six months ended	
(unaudited) (thousands)	**June 30, 2010**	June 30, 2009	**June 30, 2010**	June 30, 2009
Cash provided by (used in):				
Operating activities:				
Loss	**$ (2,691)**	$ (12,267)	**$ (249)**	$ (21,285)
Items not involving cash:				
Depletion, depreciation and accretion	**25,647**	32,823	**57,767**	67,794
Stock-based compensation	**1,070**	831	**2,390**	1,710
Future income tax reduction	**(999)**	(5,167)	**(122)**	(10,608)
Unrealized (gain) loss on financial instruments	**(2,334)**	3,816	**(10,532)**	(1,054)
Transportation liability charge (note 4)	**(154)**	(329)	**(826)**	(657)
Asset retirement expenditures	**(129)**	(181)	**(705)**	(282)
Change in non-cash working capital (note 9)	**3,739**	1,991	**8,639**	5,405
	24,149	21,517	**56,362**	41,023
Financing activities:				
Decrease in bank loan	**(81,756)**	(64,762)	**(63,756)**	(48,700)
Issue of common shares	**6,356**	43,400	**17,593**	43,400
Share issue costs	**(48)**	(2,439)	**(48)**	(2,439)
	(75,448)	(23,801)	**(46,211)**	(7,739)
Investing activities:				
Exploration and development	**(63,309)**	(14,187)	**(122,384)**	(37,865)
Property dispositions	**121,724**	23,688	**132,640**	34,378
Change in non-cash working capital (note 9)	**(7,116)**	(7,217)	**(20,407)**	(29,797)
	51,299	2,284	**(10,151)**	(33,284)
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.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

For the three and six months ended June 30, 2010 and 2009

(Unaudited) (Tabular amounts in thousands)

1. SIGNIFICANT ACCOUNTING POLICIES:

The interim consolidated financial statements of Crew Energy Inc. ("Crew" or the "Company") have been prepared by management in accordance with accounting principles generally accepted in Canada. The interim consolidated financial statements have been prepared following the same accounting policies and methods of computation as the consolidated financial statements for the year ended December 31, 2009. The disclosure which follows is incremental to the disclosure included with the December 31, 2009 consolidated financial statements. These interim consolidated financial statements should be read in conjunction with the audited consolidated financial statements and notes thereto for the year ended December 31, 2009.

Certain comparative amounts have been reclassified to conform to current period presentation.

2. PROPERTY, PLANT AND EQUIPMENT:

June 30, 2010	**Cost**	**Accumulated depletion & depreciation**	**Net book value**
Petroleum and natural gas properties and equipment	**$ 1,292,920**	**$ 433,672**	**$ 859,248**

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 June 30, 2010 of $177,193,000 (2009 – $163,820,000) was excluded from the depletion calculation. Estimated future development costs associated with the development of the Company's proved reserves of $150,055,000 (2009 – $106,968,000) have been included in the depletion calculation and estimated salvage values of $33,323,000 (2009 – $38,246,000) have been excluded from the depletion calculation.

During the quarter, the Company closed the disposition of oil and gas assets in the Edson, Alberta area for gross proceeds of $126 million, before closing adjustments.

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

	Six months ended June 30, 2010	Year ended December 31, 2009
General and administrative expense	**$ 3,310**	$ 5,736
Stock-based compensation expense, including future income taxes	**3,193**	4,442
	$ 6,503	$ 10,178

3. BANK LOAN:

The Company's bank facility consists of a revolving line of credit of $190 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 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 October 31, 2010.

Advances under the Facility are available by way of prime rate loans with interest rates of 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 same debt to EBITDA ratio.

As at June 30, 2010, the Company's applicable pricing included a 2.50 percent margin on prime lending and a 3.50 percent stamping fee and margin on bankers' acceptances and LIBOR loans along with a 0.875 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 June 30, 2010, the Company had issued letters of credit totaling $3.6 million. The effective interest rate on the Company's borrowings under its bank Facility for the three months ended June 30, 2010 was 9.7% (2009 – 2.4%).

4. OTHER LONG-TERM OBLIGATIONS:

As part of the May, 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 will be charged as a reduction to transportation expenses over the life of the contracts as they are incurred. The charge for the three and six months ended June 30, 2010 was $0.2 million and $0.5 million, respectively (2009 – $0.3 million and $0.7 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.

5. 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 obligation as at June 30, 2010 to be $33,582,000 (December 31, 2009 – $35,341,000) based on a total future liability of $60,094,000 (December 31, 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:

	Six months ended June 30, 2010	Year ended December 31, 2009
Carrying amount, beginning of period	**$ 35,341**	$ 34,941
Liabilities incurred	**424**	385
Liabilities disposed	**(2,840)**	(2,161)
Accretion expense	**1,362**	2,765
Liabilities settled	**(705)**	(589)
Carrying amount, end of period	**$ 33,582**	$ 35,341

6. SHARE CAPITAL:

(a) Authorized:

Unlimited number of Common Shares

(b) Common Shares issued:

	Number of shares	Amount
Common shares, December 31, 2009	78,152	$ 617,605
Exercise of stock options	1,944	17,593
Stock-based compensation	–	7,046
Share issue costs, net of income taxes of $12	–	(36)
Common shares, June 30, 2010	**80,096**	**$ 642,208**

(c) Contributed Surplus:

	Amount
Contributed surplus, December 31, 2009	$ 22,769
Exercise of options	(7,046)
Stock-based compensation	4,779
Contributed surplus, June 30, 2010	**$ 20,502**

(d) Stock-based compensation:

The Company measures compensation costs associated with stock-based compensation using the fair market value method under which 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 used for options granted during the three month period ended June 30, 2010: risk free interest rate 2.46% (2009 – 1.55%), expected life 4 years (2009 – 4 years), volatility 61% (2009 – 52%), 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 the first six months of 2010, the Company recorded $4,779,000, (2009 – $3,421,000) of stock-based compensation expense related to the stock options, of which $2,389,000 (2009 – $1,711,000) 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 $804,000 (2009 – $579,000) associated with the current year's capitalized stock-based compensation has been recorded.

The average fair value of the stock options granted during the six months ended June 30, 2010, as calculated by the Black-Scholes method, was $8.09 per option (2009 – $2.03).

	Number of Options	PriceRange	Weighted average exercise price
Balance December 31, 2009	5,751	$2.78 to $18.70	$8.33
Granted	2,165	$13.36 to $18.36	$15.13
Exercised	(1,944)	$2.78 to $16.60	$9.05
Forfeited	(294)	$2.78 to $14.68	$7.75
Balance June 30, 2010	5,678	$3.43 to $18.70	$10.70
Exercisable	1,657	$3.43 to $18.70	$8.86

(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 three month period ended June 30, 2010 was 79,888,000 (June 30, 2009 – 73,622,000) and for the six month period ended June 30, 2010 the weighted average number of shares outstanding was 79,272,000 (June 30, 2009 – 72,360,000).

In computing diluted per share amounts for the three month period ended June 30, 2010, no shares (June 30, 2009 – nil) were added to the weighted average number of Common Shares outstanding for the dilution added by the stock options and for the six month period ended June 30, 2010, no shares (June 30, 2009 – nil) were added to the weighted average number of common shares for the dilution. There were 5,678,000 (June 30, 2009 – 5,780,000) stock options that were not included in the diluted earnings per share calculation because they were anti-dilutive.

7. 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.

The carrying amount of accounts receivable and derivative assets, when outstanding, represents the maximum credit exposure. As at June 30, 2010 the Company's receivables consisted of $15.8 (2009 – $17.2) million of receivables from petroleum and natural gas marketers which has subsequently been collected, $8.1 (2009 – $9.2) million from joint venture partners of which $0.5 million has been subsequently collected, and $5.7 (2009 – $11.2) million of Crown deposits, prepaids and other accounts receivable. The Company does not consider any receivables to be past due.

(b) Liquidity risk:

Accounts payable and financial instruments have contractual maturities of less than one year. The Company maintains a revolving credit facility, as outlined in note 3, 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

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 Board of Directors approved policy is to enter into commodity price contracts when considered appropriate to a maximum of 50% of forecasted production volumes for a period of not more than two years.

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

(ii) Foreign currency exchange rate risk

The Company has attempted to mitigate a portion of its foreign exchange fluctuation risk through the use of financial derivatives as outlined below.

(iii) Interest rate risk

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. The Company is exposed to interest rate fluctuations on its bank loan which bears a floating rate of interest. For the three and six months ended June 30, 2010, a 1.0 percent change to the effective interest rate would have a \$0.1 million and \$0.3 million impact on net income (2009 – \$0.4 and \$0.9 million).

The Company has attempted to mitigate the impact of future fluctuations in interest rates on its outstanding debt by entering into contracts fixing the base interest rate on \$150 million of banker's acceptance borrowings as outlined below. These rates are, under the Company's bank Facility, subject to an additional stamping fee of 3.50 percent as of June 30, 2010.

The Company's derivative contracts in place as of June 30, 2010 are as follows:

Subject of Contract	Notional Quantity	Term	Reference	Strike Price	Option Traded	Fair Value ($000s)
Natural Gas	2,500 gj/day	November 1, 2009 – December 31, 2010	AECO C Monthly Index	$6.00	Swap	894
Natural Gas	5,000 gj/day	January 1, 2010 – December 31, 2010	AECO C Monthly Index less $0.09	$8.00	Call	(5)
Natural Gas	10,000 gj/day	January 1, 2010 – December 31, 2010	AECO C Monthly Index	$7.75	Call	(12)
Natural Gas	2,500 gj/day	January 1, 2010 – December 31, 2010	AECO C Monthly Index	$6.20	Swap	986
Natural Gas	5,000 gj/day	January 1, 2010 – December 31, 2010	AECO C Monthly Index	$6.08	Swap	2,217
Natural Gas	2,500 gj/day	January 1, 2010 – December 31, 2010	AECO C Monthly Index	$5.25	Swap	550
Natural Gas	2,500 gj/day	January 1, 2010 – December 31, 2010	AECO C Monthly Index	$5.55	Swap	688
Natural Gas	2,500 gj/day	April 1, 2010 – October 31, 2010	AECO C Monthly Index	$5.30	Swap	471
Natural Gas	5,000 mmbtu/ day	January 1, 2010 – December 31, 2010	AECO/NYMEX Basis diff	US$(0.55)	Swap	250
Oil	250 bbl/day	January 1, 2010 – December 31, 2010	CDN$ WTI	$78.50	Swap	(159)
Oil	500 bbl/day	January 1, 2010 – December 31, 2010	CDN$ WTI	$72.00 – $88.00	Collar	(75)
Oil	250 bbl/day	January 1, 2010 – December 31, 2010	CDN$ WTI	$82.50	Swap	25
Oil	500 bbl/day	January 1, 2010 – December 31, 2010	CDN$ WTI	$80.50	Swap	(117)
Oil	500 bbl/day	January 1, 2010 – December 31, 2010	US$ WTI	US$81.00	Swap	387
Oil	250 bbl/day	January 1, 2010 – December 31, 2010	CDN$ WTI	$80.00 – $95.02	Collar	136
Oil	250 bbl/day	March 1, 2010 – December 31, 2010	CDN$ WTI	$84.00	Swap	136
Oil	250 bbl/day	July 1, 2010 – December 31, 2010	CDN$ WTI	$88.10	Swap	281
Oil	250 bbl/day	July 1, 2010 – December 31, 2010	CDN$ WTI	$91.50	Swap	438
Oil	250 bbl/day	January 1, 2011 – December 31, 2011	CDN$ WTI	$86.00	Swap	79
Oil	250 bbl/day	January 1, 2011 – December 31, 2011	CDN$ WTI	$82.00 – $94.62	Collar	216
Oil	500 bbl/day	January 1, 2011 – December 31, 2011	CDN$ WTI	$90.20	Swap	914
Oil	250 bbl/day	January 1, 2011 – December 31, 2011	CDN$ WTI	$80.00 – $95.45	Collar	167
Oil	250 bbl/day	January 1, 2011 – December 31, 2011	CDN$ WTI	$90.00	Swap	441
Oil	250 bbl/day	January 1, 2011 – December 31, 2011	CDN$ WTI	$85.00 – $100.50	Collar	533
Total commodity contracts						9,441

Subject of Contract	Notional Quantity	Term	Reference	Strike Price	Option Traded	Fair Value ($000s)
USD / CAD $ exchange	US $2M / Month	January 1, 2010 – December 31, 2010	CAD/USD	1.094	Swap	342
Total foreign exchange contracts						342

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	(58)
BA Rate	$50M / year	February 12, 2009 – February 12, 2011	BA - CDOR	1.10%	Swap	(39)
BA Rate	$50M / year	May 28, 2009 – May 28, 2011	BA - CDOR	1.12%	Swap	12
Total interest rate contracts						(85)
Total financial instruments						9,698

Subsequent to June 30, 2010, the Company unwound the $50 million per year 1.12% swap maturing on May 28, 2011 for net proceeds to the Company of $12,000.

As at June 30, 2010, a $0.10 change to the price per thousand cubic feet of natural gas on the contracts outlined above would have a $0.5 million impact on net income.

As at June 30, 2010, a $1.00 per barrel change to the price on the oil contract outlined above would have a $0.9 million impact on net income.

As at June 30, 2010, a $0.01 change to the exchange rate on the foreign exchange contracts would have a $0.1 million impact on net income.

As at June 30, 2010, a 0.1% change to the interest rate on the interest rate contracts would have a $0.1 million impact on net income.

Subsequent to June 30, 2010, the Company entered into the following financial derivative contract:

Subject of Contract	Notional Quantity	Term	Reference	Strike Price	Option Traded
Oil	250 bbl/day	January 1, 2011 – December 31, 2011	CDN$ WTI	$88.50	Swap

Fair value of financial instruments

The Company's financial instruments as at June 30, 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 published forward price curves as at the balance sheet date, using the remaining contracted notional volumes.

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

8. CAPITAL MANAGEMENT:

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 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 June 30, 2010, the Company's ratio of net debt to annualized funds from operations was 1.29 to 1 (December 31, 2009 – 1.67 to 1).

	June 30, 2010	December 31, 2009
Net debt:		
Accounts receivable	**$ 29,634**	$ 37,574
Accounts payable and accrued liabilities	**(64,520)**	(84,228)
Working capital deficiency	**$ (34,886)**	$ (46,654)
Bank loan	**(71,845)**	(135,601)
Net debt	**$ (106,731)**	$ (182,255)
Annualized funds from operations:		
Cash provided by operating activities	**$ 24,149**	$ 16,734
Asset retirement expenditures	**129**	111
Transportation liability charge	**154**	329
Change in non-cash working capital	**(3,739)**	10,082
Funds from operations	**20,693**	27,256
Annualized	**$ 82,772**	$ 109,024
Net debt to annualized funds from operations	**1.29**	1.67

The Company has commodity, interest rate and foreign exchange hedging for 2010 and 2011 to provide support for its funds from operations and assist in funding its capital expenditure program.

There has been no change in the Company's approach to capital management during the period ended June 30, 2010.

9. SUPPLEMENTAL CASH FLOW INFORMATION:

	Three months ended		Six months ended	
	June 30, 2010	June 30, 2009	**June 30, 2010**	June 30, 2009
Changes in non-cash working capital:				
Accounts receivable	**$ 10,134**	$ 3,335	**$ 7,940**	$ 14,282
Accounts payable and accrued liabilities	**(13,511)**	(8,561)	**(19,708)**	(38,674)
	$ (3,377)	$ (5,226)	**$ (11,768)**	$ (24,392)
Operating activities	**$ 3,739**	$ 1,991	**$ 8,639**	$ 5,405
Investing activities	**(7,116)**	(7,217)	**(20,407)**	(29,797)
	$ (3,377)	$ (5,226)	**$ (11,768)**	$ (24,392)

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

	Three months ended		Six months ended	
	June 30, 2010	June 30, 2009	**June 30, 2010**	June 30, 2009
Interest	**$ 1,472**	$ 2,457	**$ 2,562**	$ 4,188

10. COMMITMENTS:

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

	Total	2010	2011	2012	2013	2014	Thereafter
Operating Leases	$ 3,930	$ 872	$ 1,743	$ 1,315	–	–	–
Capital commitments	8,000	4,000	4,000	–	–	–	–
Transportation agreements	4,918	1,853	3,065	–	–	–	–
Processing agreement	28,967	1,525	3,049	3,049	3,049	3,049	15,246
Total	$ 45,815	$ 8,250	$ 11,857	$ 4,364	$ 3,049	$ 3,049	$ 15,246

The firm transportation commitments were acquired as part of the Company's May 2007 private company acquisition and represent firm service commitments for transportation and processing of natural gas in British Columbia. In 2010, the Company permanently assigned approximately $6.2 million of its firm commitments to third parties. The amount shown represents the remaining contractual obligations.

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

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

CAUTIONARY STATEMENTS

Forward-looking information and statements

This report 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" and similar expressions are intended to identify forward-looking information or statements. In particular, but without limiting the foregoing, this report contains forward-looking information and statements pertaining to the following: the volume and product mix of Crew's oil and gas production; production estimates; anticipated disposal rates on water disposal wells; 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; anticipated reductions in operating costs; future costs, expenses and 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; the anticipated recoveries from Crew's waterflood program at Tilley; planned expansion of the Septimus gas processing facility; ASC completion of the Septimus pipeline and delivery capability thereof; operating costs; the total future capital associated with development of reserves and resources; and forecast reductions in operating expenses.

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 approvals; the ability of Crew to obtain qualified staff, equipment and services in a timely and cost efficient manner; drilling results; the ability of the operator of the projects 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 report 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 certain other risks detailed from time-to-time in Crew's public disclosure documents (including, without limitation, those risks identified in this report and Crew's Annual Information Form).

The forward-looking information and statements contained in this report speak only as of the date of this report, 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.

CORPORATE INFORMATION

HEAD OFFICE

Suite 1400, 425 - 1st Street S.W.
Calgary, Alberta T2P 3L8
Phone: (403) 266-2088
Fax: (403) 266-6259
www.crewenergy.com

AUDITORS

KPMG LLP

BANKERS

Toronto-Dominion Bank

Canadian Imperial Bank of Commerce

Union Bank

Bank of Montreal

Bank of Nova Scotia

LEGAL COUNSEL

Burnet, Duckworth & Palmer LLP

RESERVE ENGINEERS

GLJ Petroleum Consultants

TRANSFER AGENT

Valiant Trust Company

EXCHANGE LISTING

Toronto Stock Exchange
Stock Symbol: **CR**

BOARD OF DIRECTORS

John A. Brussa, Chairman
Independent Director

Jeffery E. Errico
Independent Director

Dennis L. Nerland
Independent Director

Dale O. Shwed
President, Crew Energy Inc.

David G. Smith
Independent Director

OFFICERS

Dale O. Shwed
President and
Chief Executive Officer

John G. Leach, CA
Senior Vice President and
Chief Financial Officer

Ken Truscott
Senior Vice President, Business
Development and Land

Noel Cronin, P.Eng
Vice President, Operations
and Production

Kurtis Fischer
Vice President, Acquisitions
and Divestitures

Gary P. Smith
Vice President, Exploration

Shawn A. Van Spankeren, CMA
Vice President, Finance
and Controller

Michael D. Sandrelli
Secretary
Partner, Burnet, Duckworth
& Palmer LLP

ABBREVIATIONS

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

crew energy inc.

crew energy inc.

Suite 1400, 425 - 1st Street S.W.
Calgary, Alberta T2P 3L8
Phone: (403) 266-2088
Fax: (403) 266-6259
www.crewenergy.com