Crew Energy Issues Record 2011 Third Quarter Financial and Operating Results

November 8, 2011

Calgary, Alberta - November 8, 2011

CALGARY, ALBERTA--(Marketwire - Nov. 8, 2011) - Crew Energy Inc. (TSX:CR) of Calgary, Alberta is pleased to present its operating and financial results for the three and nine month periods ended September 30, 2011.

Highlights

- Third quarter production of 27,510 boe per day was 111% higher than the same period of 2010 and 67% higher than the second quarter of 2011;
- Production per diluted share increased 43% over the same period of 2010 and 21% over the second quarter of 2011;
- Oil and natural gas liquids production increased 107% over the previous quarter to 14,164 bbls per day;
- Crew drilled a record 66 (65.2 net) wells in the third quarter of which 54 wells were oil wells;
- Operating costs decreased 5% over the second quarter of 2011 to $10.79 per boe;
- Funds from operations increased to $54.3 million or 131% over the same period of 2010 and 88% over the second quarter of 2011;
- Funds from operations per share increased 55% over the third quarter of 2010 and 36% over the second quarter of 2011;
- The Company completed the fall review of its bank facility with its banking syndicate who are now finalizing approvals to increase the Company's borrowing base to $430 million;
- Crew completed the acquisition of Caltex Energy Inc. on July 1, 2011 and fully integrated the operations of the two companies during the quarter.

Financial ($ thousands, except per share amounts)		**Three months ended September 30, 2011**	Three months ended September 30, 2010	**Nine months ended September 30, 2011**	Nine months ended September 30, 2010
Petroleum and natural gas sales		**114,719**	44,924	**246,103**	149,723
Funds from operations (note 1)		**54,260**	23,464	**107,262**	70,757
Per share	- basic	**0.45**	0.29	**1.12**	0.89
	- diluted	**0.45**	0.29	**1.10**	0.87
Net income (loss)		**12,232**	(17,281)	**18,367**	32,033
Per share	- basic	**0.10**	(0.22)	**0.19**	0.40
	- diluted	**0.10**	(0.22)	**0.19**	0.39
Capital expenditures		**138,671**	64,498	**267,021**	185,265
Property acquisitions (net of dispositions)		**-**	-	**(12,289)**	(132,640)
Net capital expenditures		**138,671**	64,498	**254,732**	52,625

Capital Structure ($ thousands)	**As at September 30, 2011**	As at December 31, 2010
Working capital deficiency (note 2)	**100,551**	40,707
Bank loan	**194,038**	138,700
Net debt	**294,589**	179,407
Bank facility (note 3)	**430,000**	240,000
Common Shares Outstanding (thousands)	**119,597**	80,368

Notes:

(1) Funds from operations is calculated as cash provided by operating activities, adding the change in non-cash working capital, decommissioning obligation expenditures, the transportation liability charge and acquisition costs. 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 International Financial Reporting Standards and therefore may not be comparable with the calculations of similar measures for other companies.

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

(3) The Company's bank syndicate is seeking the appropriate approvals for the increase in the Facility.

Operations	**Three months ended September 30, 2011**	Three months ended September 30, 2010	**Nine months ended September 30, 2011**	Nine months ended September 30, 2010
Daily production				

Natural gas (mcf/d)	**80,078**	48,188	**63,398**	49,863
Conventional Oil (bbl/d)	**4,910**	3,803	**5,384**	3,788
Heavy Oil (bbl/d)	**6,633**	-	**2,235**	-
Natural gas liquids (bbl/d)	**2,621**	1,227	**1,712**	1,265
Oil equivalent (boe/d @ 6:1)	**27,510**	13,061	**19,897**	13,364
Average prices (note 1)				
Natural gas ($/mcf)	**3.90**	4.07	**3.98**	4.63
Conventional oil ($/bbl)	**71.36**	62.86	**74.53**	67.16
Heavy oil ($/bbl)	**63.66**	-	**63.66**	-
Natural gas liquids ($/bbl)	**61.69**	43.21	**61.81**	50.13
Oil equivalent ($/boe)	**45.33**	37.39	**45.31**	41.04
Netback				
Operating netback ($/boe) (note 2)	**23.75**	21.87	**22.36**	22.32
Realized gain on financial instruments ($/boe)	**-**	(0.24)	**-**	(0.15)
G&A ($/boe)	**1.50**	1.59	**1.73**	1.87
Interest on bank debt ($/boe)	**0.81**	0.99	**0.88**	1.20
Funds from operations ($/boe)	**21.44**	19.53	**19.75**	19.40
Drilling Activity				
Gross wells	**66**	26	**121**	59
Working interest wells	**65.2**	24.9	**119.5**	55.4
Success rate, net wells	**98%**	100%	**99%**	100%

Notes:

(1) Average prices are before deduction of transportation costs and do not include hedging gains and losses.

(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 International Financial Reporting Standards and therefore may not be comparable with the calculations of similar measures for other companies.

Overview

Operations during the third quarter of 2011 were highlighted by the drilling of a record 66 (65.2 net) wells with a 98% success rate. At Princess, Alberta, the Company drilled 45 (45.0 net) oil wells, five (5.0 net) salt water disposal wells and one (1.0 net) dry and abandoned well. At Lloydminster, Saskatchewan, the Company drilled four (4.0 net) horizontal oil wells and three (2.8 net) vertical oil wells. In the Deep Basin of west central Alberta, the Company drilled eight (7.4 net) wells resulting in two (2.0 net) oil wells and six (5.4 net) natural gas liquids wells.

Production in the third quarter averaged 27,510 boe per day, up 67% from the second quarter reflecting a full quarter of production from the Caltex Energy Inc. ("Caltex") assets. On July 1, 2011, Crew closed the acquisition of Caltex adding approximately 10,500 boe per day of production.

Financial Summary and Risk Management

The Company's funds from operations increased to $54.3 million in the third quarter as a result of the increase in production that accompanied the Caltex acquisition. The acquisition of Caltex has increased the strength of the Company's financial position through an increased production weighting of higher valued liquids and lower costs resulting in higher netbacks despite a lower commodity price environment.

Year to date, the Company's hedging program has added $2.2 million of cash flow. For the fourth quarter of 2011, the Company has 17.5 mmcf per day of natural gas hedged at an average fixed price of $4.95 per mcf and 6,000 bbl per day of oil hedged at a minimum floor price of Canadian dollar WTI $83.43 per bbl.

Crew has also established commodity hedges to help underpin cash flow for 2012. Crew has entered into Canadian dollar WTI oil price swaps and floors on an average of 4,500 bbl per day for 2012. These transactions averaged a minimum floor price of approximately CDN $90.50 per bbl for WTI oil. The Company has also entered into derivative contracts to fix the differential price between CDN$ WTI and CDN$ Western Canadian Select crude pricing for 2,000 bbls per day at an average of $16.63. Natural gas pricing remains depressed as a result of oversupply in the North American market. With the forward price outlook of Canadian natural gas through 2012 remaining flat compared to current pricing, Crew has not entered into any 2012 natural gas hedges. The Company is continuing to monitor the market and will consider 2012 hedges if we see an increase above the current levels. A detailed list of the Company's hedge positions is included in the attached management's discussion and analysis.

The Company's capital program during the third quarter resulted in total expenditures for the quarter of $138.7 million. These expenditures were financed through a combination of funds flow from operations and an increase in the Company's net debt. Crew assumed net debt of $66 million on the closing of the Caltex acquisition bringing total net debt at the end of the third quarter to $295 million. The Company's balance sheet remains strong with a debt to annualized third quarter funds from operations of 1.36. The Company completed the fall review of its bank facility with the banks now finalizing approvals on an increase in the Company's borrowing base to $430 million.

OPERATIONS UPDATE

Pekisko Play - Princess, Alberta

During the third quarter, Crew drilled 45 (45.0 net) oil wells at Princess. The Company also drilled five (5.0 net) water disposal wells and completed turnarounds and infrastructure upgrades at the West Tide Lake and Alderson oil batteries to handle the increasing fluid production from the active third quarter drilling program. As these upgrades were recently completed, only 10 of the wells drilled in the third quarter were on production by the end of the quarter. With current production over 8,000 boe per day and 31 wells to place on production, Crew will focus on the tie-in and optimization of wells to meet its target exit rate of 10,000 to 12,000 boe per day.

Well results to date continue to track or exceed the current production type curve. The last eleven horizontal wells tied in during October and November tested at average swab or flow rates of 683 boe per day per well. Initial production rates from horizontal wells are generally 35% of the test rate, or 240 boe per day, which is above the current average initial production rate of 210 boe per day. Completion of the infrastructure upgrades will result in further production optimization from these wells and a corresponding higher initial production rate relative to swab and test rates. Low costs of $1.3 million per well, reduced capital associated with drilling fewer water disposal wells, declining operating costs and strong well performance result in a recycle ratio of approximately three to four times and rates of return in excess of 300%.

At Alderson South, the original vertical exploration discovery at 15-9-16-12 W4 has produced 103,600 boe in nine months. An offset vertical well drilled in the third quarter at 14-9 swab tested at 590 boe per day and is expected to be on production at 175 to 225 boe per day in November. With the drilling of another exploration well two miles south, Crew believes it has delineated a three to four square mile area for future development.

At Tilley, a second waterflood was initiated in the third quarter as the Company begins to implement its secondary recovery strategy with expectations that oil recovery factors could increase from an average of 9.2% currently booked effective December 31, 2010 on primary recovery by the Company's external reserve engineers, to 24% to 30%. Waterflood applications are expected to be submitted to the ERCB for an additional five pools prior to the end of the year with implementation to occur in the third and fourth quarters of 2012. As a result of the waterflood commencement at Tilley and Crew recently receiving approvals to inject into four additional water disposal wells, the Company is now only trucking oil and water from single well batteries. This initiative has resulted in a reduction of approximately $600,000 per month in operating costs from the area. Looking forward, the Company is not expecting to truck water from its batteries for disposal to third parties.

Crew is expanding capacity at Alderson through the installation of a compressor to accommodate solution gas from increased production volumes and is also installing an additional battery in the area early in 2012 to handle additional production. Currently 55,000 bbls per day of water are being disposed or injected at Princess. By year end, the Company expects to have capacity in its facilities for 17,400 bbls per day of oil and 131,000 bbls per day of water and will have well injection/disposal capacity of 98,000 bbls per day of water. This excess capacity is expected to adequately handle fluid volumes through 2012.

Heavy Oil, Lloydminster, Saskatchewan

Crew drilled four (4.0 net) horizontal wells for production from the Sparky formation and three (2.8 net) vertical wells for production from the McLaren and Sparky formations. The horizontal wells were drilled to evaluate the effectiveness of this technology on undeveloped pools, as well as a downspacing technique to increase recovery from pools previously developed with vertical wells. The Company expects to drill an additional five vertical wells in the fourth quarter and undertake up to 30 workovers and recompletions, with capital costs of less than $0.5 million per new drilling location and less than $0.1 million per workover resulting in estimated capital efficiencies of less than $10,000 per boe per day.

Montney Play - Northeast British Columbia

Efficiencies at Septimus continue to improve with production rates steadily improving over the last four years. Initial production rates have improved with wells completed in 2011 experiencing a 150% increase to an average 770 boe per day compared to wells completed in 2008. Production at Septimus has remained very economic in the current low gas environment. The significant condensate weighted liquids yield from the natural gas production combined with a low royalty rate and low operating costs resulted in an operating netback of over $21.00 per boe in the third quarter.

Prior to the end of the third quarter, the Company spudded the first horizontal well of a three well pad at Septimus. It is expected these wells will be completed and producing prior to the end of the year. An additional two wells at Septimus are planned to be drilled prior to year-end and drilling operations are planned through spring break-up in 2012.

The Company also spudded the first of two horizontal wells in the Kobes area of British Columbia to confirm productivity and reserve potential of the three Montney horizons in the area.

Deep Basin, West Central Alberta

In the Deep Basin of west central Alberta, Crew drilled eight (7.4 net) wells targeting oil and liquids rich gas. At Pine Creek, Alberta, the Company drilled two (2.0 net) Cardium horizontal wells and at Wapiti/Elmworth, Alberta the Company drilled two (1.6 net) Cardium horizontal wells and completed one additional horizontal well for liquids rich natural gas. At Wapiti/Elmworth, one well achieved a test rate of 4.3 mmcf per day with a flowing casing pressure of 5,200 kPa and an expected liquids recovery of 70 to 80 barrels per million cubic feet. One (0.8 net) Belly River well was drilled at Wapiti testing 2.1 mmcf per day with liquids recovery of 90 barrels per million cubic feet. The Company also drilled three (3.0 net) wells at Pine Creek which are now being completed.

Exploration

At Tower, British Columbia, east of Septimus, Crew completed one (0.33 net) horizontal Montney well for oil production. The well is awaiting tie-in and will be further evaluated once on production for an extended period of time. The Company has 23 net sections on this play which will continue to be developed and de-risked in 2012.

Outlook

Crew had its most active quarter in its history drilling 66 wells and spending $138.7 million. This allowed the Company to catch-up on its drilling program which was delayed due to a prolonged spring break up. Current production is estimated at 30,000 boe per day and the Company expects to tie in nine liquids rich gas wells and 31 oil wells in the fourth quarter to achieve our forecasted 2011 exit production rate of 32,500 to 34,500 boe per day.

We have moved forward with plans to accelerate our winter drilling program at Septimus and Kobes to avoid the expected shortage of available services in northeastern British Columbia. As a result, we have added six wells to our fourth quarter drilling program and plan to complete four of these later in the quarter. This program will result in an additional $20 million of capital expenditures increasing total net exploration and development expenditures to $350 million for the year.

As part of our continuous asset review process, Crew has a number of non-core properties for sale comprised of approximately 1,400 boe per day of production and 6.2 mmboe of proved plus probable reserves as independently evaluated effective December 31, 2010. Bids are due by November 15 with successfully negotiated transactions from this program expected to close in the first quarter of 2012.

The integration of the Caltex personnel and assets has gone extremely well. We are very pleased with the contribution of our "Crew" in this process and we would like to commend all of our staff for making this a very successful transaction. The Caltex assets have performed above expectation, which is confirmation of the abilities of the personnel, the quality of the assets and the successful integration into Crew.

Since Crew's inception in 2003, we have focused on successfully capturing accumulations of large hydrocarbons in place. The next phase is to realize the value of this resource through the efficient execution of our capital programs to profitably grow production. We will continue to focus on the development and exploration of the Princess Pekisko oil play and the Lloydminster heavy oil area in Saskatchewan, two of the most economic oil plays in North America. As well, Crew will continue to de-risk and add resource and reserves in the liquids rich window of the Montney play in British Columbia. We look forward to reporting our progress in this next phase of development in January 2012 when we will release our 2012 budget.

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 interim consolidated financial statements of the Company for the three and nine month periods ended September 30, 2011 and 2010 and the audited consolidated financial statements and Management's Discussion and Analysis for the year ended December 31, 2010. In 2010, the CICA Handbook was revised to incorporate International Fainancial Reporting Standards ("IFRS"), and require publicly accountable enterprises to apply such standards effective for years beginning on or after January 1, 2011. Previously, the Company prepared its interim and annual consolidated financial statements in accordance with Canadian generally accepted accounting principles ("previous GAAP"). The interim consolidated financial statements have been prepared in accordance with IFRS and all figures provided herein and in the December 31, 2010 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, 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 implementing accounting policies, estimates regarding undeveloped land position and estimated future drilling, recompletion or reactivation locations and anticipated impact upon Crew's forecasts in respect of production and cash flow for 2011 and resulting year-end net debt 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 inability 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; the anticipated increase to the Company's banking facility; 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-IFRS Measures

Funds from Operations

One of the benchmarks Crew uses to evaluate its performance is funds from operations. Funds from operations is a measure not defined in IFRS that is commonly used in the oil and gas industry. It represents cash provided by operating activities before changes in non-cash working capital, decommissioning obligation expenditures, the transportation liability charge and acquisition costs. The Company considers it a key measure as it demonstrates the ability of the Company's continuing operations 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 IFRS as an indicator of the Company's performance. Crew's determination of funds from operations may not be comparable to that reported by other companies. Crew also presents funds from operations per share whereby per share amounts are calculated using weighted average shares outstanding consistent with the calculation of income per share. The following table reconciles Crew's cash provided by operating activities to funds from operations:

($ thousands)	Three months ended September 30, 2011	Three months ended September 30, 2010	Nine months ended September 30, 2011	Nine months ended September 30, 2010
Cash provided by operating activities	54,095	18,956	113,460	73,701
Decommissioning obligation expenditures	540	201	661	906
Transportation liability charge (note 1)	104	156	308	638
Acquisition costs (note 2)	455	-	2,605	-
Change in non-cash working capital	(934)	4,151	(9,772)	(4,488)
Funds from operations	54,260	23,464	107,262	70,757

Notes:

(1) The amount for the nine months ended September 30, 2010 does not include the transportation liability write-down of $344,000 as shown in the transportation costs section.

(2) This amount relates to costs incurred for the Caltex acquisition that closed on July 1, 2011. See Finance Expenses section for further details.

Operating Netback

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 IFRS 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 derivative 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. The calculation of Crew's netbacks can be seen below in the Operating Netbacks section.

Working Capital and Net Debt

The Company closely monitors its capital structure with a goal of maintaining a strong balance sheet in order to fund the future growth of the Company. Crew monitors working capital and net debt as part of its capital structure. Working capital and net debt do not have a standardized meaning prescribed by IFRS and therefore may not be comparable with the calculation of similar measures for other entities. The following tables outline Crew's calculation of working capital and net debt:

($ thousands)	September 30, 2011	December 31, 2010
Current assets	86,078	61,020
Current liabilities	(180,640)	(101,088)
Fair value of financial instruments	(6,024)	(982)
Current portion of other long-term obligations	35	343
Working capital deficit	(100,551)	(40,707)

($ thousands)	September 30, 2011	December 31, 2010
Bank loan	(194,038)	(138,700)
Working capital deficit	(100,551)	(40,707)
Net debt	(294,589)	(179,407)

RESULTS OF OPERATIONS

Acquisition of Caltex

On July 1, 2011, Crew closed the previously announced acquisition whereby the Company acquired all of the issued and outstanding shares of Caltex Energy Inc. ("Caltex"), a Canadian private oil and gas company with operations in Saskatchewan and Alberta (the "Transaction"). Caltex shareholders received 0.38 of a Crew common share for each Caltex share held or an aggregate of approximately 33.6 million Crew shares. Upon closing of the Transaction, Caltex became a wholly owned subsidiary of Crew and immediately following closing, former Caltex shareholders owned approximately 28% of the combined entity.

Crew believes the Transaction represents the successful continuation of our strategy of exploiting high netback assets with significant resource potential. At the date of acquisition, the Caltex assets were producing approximately 10,500 boe per day.

The business combination has been accounted for using the purchase method with the results of operations of Caltex included in the Company's financial and operating results commencing July 1, 2011. The allocation of net assets acquired is based on the best available information at this time and could be subject to further change. The transaction was accounted for by the acquisition method, with the preliminary allocation of the purchase price based on estimated fair values as described in note 4 of the interim consolidated financial statements of the Company for the period ended September 30, 2011.

Production

	Three months ended Sept. 30, 2011					Three months ended Sept. 30, 2010				
	Conv. Oil (bbl/d)	Heavy Oil (bbl/d)	Ngl (bbl/d)	Nat. gas (mcf/d)	Total (boe/d)	Conv. Oil (bbl/d)	Heavy Oil (bbl/d)	Ngl (bbl/d)	Nat. gas (mcf/d)	Total (boe/d)
Alberta	4,795	8	1,618	41,747	13,379	3,670	-	388	22,243	7,765
British Columbia	115	-	1,003	37,796	7,417	133	-	839	25,945	5,296
Saskatchewan	-	6,625		535	6,714	-	-	-	-	-
Total	4,910	6,633	2,621	80,078	27,510	3,803	-	1,227	48,188	13,061

Crew's third quarter production increased 111% over the same period in 2010 due to the acquisition of Caltex on July 1, 2011 and the Company's successful organic drilling programs in Alberta and northeastern British Columbia. Third quarter conventional oil production increased 29% compared to the same period in 2010 as a result of the successful drilling program in the Princess, Alberta area. Heavy oil production was added through the acquisition of Caltex. In the third quarter of 2011, Alberta natural gas and associated natural gas liquids ("ngl") production increased 108% over the same period in 2010 predominantly due to production additions from the Caltex acquisition combined with additional natural gas production in the Princess area. British Columbia natural gas and associated ngl production increased 42% due to the successful drilling program in late 2010 and 2011 in the Septimus, British Columbia area.

	Nine months ended Sept. 30, 2011					Nine months ended Sept. 30, 2010				
	Conv. Oil (bbl/d)	Heavy Oil (bbl/d)	Ngl (bbl/d)	Nat. gas (mcf/d)	Total (boe/d)	Conv. Oil (bbl/d)	Heavy Oil (bbl/d)	Ngl (bbl/d)	Nat. gas (mcf/d)	Total (boe/d)
Alberta	5,270	3	809	28,735	10,871	3,663	-	537	24,887	8,348
British Columbia	114	-	903	34,483	6,764	125	-	728	24,976	5,016
Saskatchewan	-	2,232	-	180	2,262	-	-	-	-	-
Total	5,384	2,235	1,712	63,398	19,897	3,788	-	1,265	49,863	13,364

Production for the first nine months of 2011 increased due to the previously mentioned acquisition of Caltex and the successful drilling programs in the Septimus and Princess areas partially offset by the disposition of approximately 1,700 boe per day of natural gas and associated ngl production in the Edson, Alberta area in the second quarter of 2010.

Revenue

	Three months ended Sept. 30, 2011	Three months ended Sept. 30, 2010	Nine months ended Sept. 30, 2011	Nine months ended Sept. 30, 2010
Revenue ($ thousands)				
Conventional oil	32,233	21,994	109,539	69,451
Heavy oil	38,847	-	38,847	-
Natural gas	28,765	18,052	68,833	62,965
Natural gas liquids	14,874	4,878	28,884	17,307
Total	114,719	44,924	246,103	149,723
Crew average prices				
Conventional oil ($/bbl)	71.36	62.86	74.53	67.16
Heavy oil ($/bbl)	63.66	-	63.66	-
Natural gas ($/mcf)	3.90	4.07	3.98	4.63
Natural gas liquids ($/bbl)	61.69	43.21	61.81	50.13
Oil equivalent ($/boe)	45.33	37.39	45.31	41.04
Benchmark pricing				
Conv. oil – Bow River Crude Oil (Cdn $/bbl)	81.89	73.15	85.15	76.88
Heavy oil – Western Can. Select (Cdn $/bbl)	70.63	62.91	74.31	67.02
Natural Gas – AECO C daily index (Cdn $/mcf)	3.71	3.59	3.82	4.19
Oil and ngl – Cdn$ West Texas Int. (Cdn $/bbl)	87.89	79.18	93.28	80.40

Crew's third quarter revenue increased 155% as compared to the same period in 2010 as a result of the previously discussed 111% increase in production combined with a 21% increase in commodity prices made up of an increase in conventional oil and ngl pricing partially offset by a decrease in the Company's natural gas pricing.

In the third quarter of 2011, the Company's realized conventional oil price increased 14% which was comparable with the increase in the Bow River Crude benchmark of 12% for the same period in 2010. The Company's natural gas benchmark price increased 3% in the third quarter compared with same period in 2010 while the Company's realized average natural gas price decreased 4% over the same period in 2010. In the third quarter of 2010, Crew had a $5.85 per gj fixed price physical gas sales contract which increased the realized corporate gas price by approximately $0.25 per mcf. This contract expired in November 2010. The Company's realized ngl price increased disproportionately in the third quarter of 2011 compared with the increase in the Company's benchmark Cdn$ West Texas Intermediate price due to increased production of higher priced condensate in the Septimus area in 2011 and the addition of higher priced ngl volumes from the Caltex conventional assets in west central Alberta.

Heavy oil production was added July 1, 2011 as part of the Caltex acquisition. Heavy oil pricing was $6.97 below the benchmark Western Canadian Select pricing reflecting the Company's cost of diluent to blend its heavy oil production to pipeline specifications.

For the first nine months of 2011, both the Company's realized conventional oil price and ngl price increased proportionately to the increases in the respective Company benchmark prices as for the same period in 2010. For the first nine months of 2011, the Company's realized natural gas price decreased 14% over the same period in 2010 compared to the Company's Aeco benchmark which decreased 9% for the same period as a result of the previously mentioned $5.85 per gj fixed price physical contract that the Company held for January through October 2010.

Royalties

($ thousands, except per boe)	Three months ended Sept. 30, 2011	Three months ended Sept. 30, 2010	Nine months ended Sept. 30, 2011	Nine months ended Sept. 30, 2010
Royalties	25,897	8,920	56,827	30,488
Per boe	10.23	7.42	10.46	8.36
Percentage of revenue	22.6 %	19.9 %	23.1 %	20.4 %

Royalties as a percentage of revenue increased in the third quarter and first nine months of 2011 compared to the same period in 2010 due to the addition of heavy oil and liquids rich natural gas production from the Caltex acquisition which on average attracts a higher royalty rate than the Company's historical production. In addition, the Company increased production in the Princess area which also attracts a higher royalty rate than Crew's other producing areas. Crew continues to project royalty rates to average between 23% and 25% for 2011.

Financial Instruments

Commodities

The Company enters into derivative and physical risk management contracts in order to reduce volatility in financial results, to protect acquisition economics and to ensure a certain level of cash flow to fund planned capital projects. Crew's strategy focuses on the use of puts, costless collars, swaps and fixed price contracts to limit exposure to fluctuations in commodity prices, differentials, 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 2011, these contracts had the following impact on the consolidated statement of income:

($ thousands)	Three months ended Sept. 30, 2011	Three months ended Sept. 30, 2010	Nine months ended Sept. 30, 2011	Nine months ended Sept. 30, 2010
Realized gain on financial instruments	2,180	5,114	2,195	9,798
Unrealized gain/(loss) on financial instruments	17,025	(5,326)	16,762	5,206

As at September 30, 2011, the Company held derivative commodity contracts as follows:

Subject of Contract	Notional Quantity	Term	Reference	Strike Price	Option Traded	Fair Value ($000s)
Natural Gas	2,500 gj/day	January 1, 2011 – December 31, 2011	AECO C Monthly Index	$4.85	Swap(1)	313
Natural Gas	2,500 gj/day	January 1, 2011 – December 31, 2011	AECO C Monthly Index	$4.90	Swap(1)	322
Natural Gas	2,500 gj/day	January 1, 2011 – December 31, 2011	AECO C Monthly Index	$4.95	Swap(1)	333
Natural Gas	2,500 gj/day	January 1, 2011 – December 31, 2011	AECO C Monthly Index	$4.965	Swap(1)	448
Natural Gas	7,500 gj/day	January 1, 2011 – December 31, 2011	AECO C Monthly Index	$5.00	Swap(1)	1,160
Oil	500 bbl/day	January 1, 2011 – December 31, 2011	US$ WTI	US$80.15	Swap	37
Oil	250 bbl/day	January 1, 2011 – December 31, 2011	CDN$ WTI	$86.00	Swap	64
Oil	500 bbl/day	January 1, 2011 – December 31, 2011	CDN$ WTI	$88.00	Swap	233
Oil	250 bbl/day	January 1, 2011 – December 31, 2011	CDN$ WTI	$88.50	Swap	140
Oil	250 bbl/day	January 1, 2011 – December 31, 2011	CDN$ WTI	$90.00	Swap	155
Oil	500 bbl/day	January 1, 2011 – December 31, 2011	CDN$ WTI	$90.20	Swap	317
Oil	250 bbl/day	January 1, 2011 – December 31, 2011	CDN$ WTI	$80.00 - $95.45	Collar	54

Oil	250 bbl/day	January 1, 2011 – December 31, 2011	CDN$ WTI	$82.00 - $94.62	Collar	56
Oil	250 bbl/day	January 1, 2011 – December 31, 2011	CDN$ WTI	$85.00 - $100.50	Collar	118
Oil	1,000 bbl/day	July 1, 2011 – December 31, 2011	CDN$ WTI	$75.00 - $100.00	Collar	174
Oil	1,000 bbl/day	July 1, 2011 – December 31, 2011	CDN$ WTI	$80.00 - $98.50	Collar	292
Oil	1,000 bbl/day	July 1, 2011 – December 31, 2011	CDN$ WTI	$89.75	Swap	709
Oil	500 bbl/day	January 1, 2012 – December 31, 2012	US$ WTI	US$85.00	Call[1]	(1,738)
Oil	750 bbl/day	January 1, 2012 – December 31, 2012	CDN$ WTI	$90.00	Call[1]	(2,199)
Oil	500 bbl/day	January 1, 2012 – December 31, 2012	US$ WTI	US$90.00	Call[1]	(1,418)
Oil	250 bbl/day	January 1, 2012 – December 31, 2012	CDN$ WTI	$100.45	Swap	1,377
Oil	500 bbl/day	January 1, 2012 – December 31, 2012	CDN$ WTI	$101.00	Swap	2,847
Oil	250 bbl/day	January 1, 2012 – December 31, 2012	CDN$ WTI	$100.50	Swap	1,382
Oil	500 bbl/day	January 1, 2012 – December 31, 2012	CDN$ WTI	$85.00 - $93.55	Collar	671
Oil	500 bbl/day	January 1, 2012 – December 31, 2012	CDN$ WTI	$85.00 - $93.25	Collar	623
Oil	1,000 bbl/day	January 1, 2012 – December 31, 2012	CDN$ WCS – WTI Diff	$17.50	Swap	(446)
Total						6,024

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

Subsequent to September 30, 2011, the Company entered into the following financial instrument contracts:

Subject of Contract	Volume	Term	Reference	Strike Price (per bbl)	Option Traded
Oil	1,000 bbl/day	January 1, 2012 – December 31, 2012	CDN$ WTI	$85.00 - $95.00	Collar
Oil	500 bbl/day	January 1, 2012 – December 31, 2012	CDN$ WTI	$85.00 - $94.50	Collar
Oil	1,000 bbl/day	January 1, 2012 – December 31, 2012	CDN$ WTI	$94.00	Swap
Oil	1,000 bbl/day	January 1, 2012 – December 31, 2012	CDN$ WCS – WTI Diff	$15.75	Swap
US$ / CAD$ exchange	Sell US $1.0 mm per month	January 1, 2012 – December 31, 2012	US$/CDN$	1.0531	Swap
US$ / CAD$ exchange	Buy US $1.0 mm per month	January 1, 2012 – December 31, 2012	US$/CDN$	1.037	Swap

Operating Costs

($ thousands, except per boe)	Three months ended Sept. 30, 2011	Three months ended Sept. 30, 2010	Nine months ended Sept. 30, 2011	Nine months ended Sept. 30, 2010
Operating costs	27,303	12,318	60,754	39,967
Per boe	10.79	10.25	11.18	10.95

In the third quarter of 2011, the Company's operating costs per unit increased over the same period in 2010 due to the higher cost production added as part of the Caltex acquisition and increased higher cost production from the Princess area. This was partially offset by increased production in the Septimus area which has a lower cost per unit than the Company's average operating cost per boe. For the first nine months of 2011, the Company's operating costs per unit increased as compared to the same period in 2010 due to the second quarter 2010 sale of the Edson properties which had a lower cost per boe and the addition of the higher cost Caltex production on July 1, 2011. With the addition of the Caltex properties, the Company forecasts operating costs to average $11.00 to $11.50 per boe for 2011.

Transportation Costs

($ thousands, except per boe)	Three months ended Sept. 30, 2011	Three months ended Sept. 30, 2010	Nine months ended Sept. 30, 2011	Nine months ended Sept. 30, 2010
Transportation costs including liability write-down	3,598	2,243	9,265	6,763
Transportation liability write-down	-	-	-	344

Transportation costs	3,598	2,243	9,265	7,107
Per boe	1.42	1.87	1.71	1.95

In the third quarter and first nine months of 2011, the Company's transportation costs per boe decreased compared to the same periods in 2010 due to additional production at Princess and Septimus combined with production from the acquisition of Caltex which all attract a lower transportation cost per boe compared with the Company's other producing areas. The Company expects transportation costs per boe to range between $1.60 and $1.70 per boe for 2011.

Operating Netbacks

	Three months ended Sept. 30, 2011			Three months ended Sept. 30, 2010		
	Oil and ngl ($/bbl)	Natural gas ($/mcf)	Total ($/boe)	Oil and ngl ($/bbl)	Natural gas ($/mcf)	Total ($/boe)
Revenue	65.97	3.90	45.33	58.07	4.07	37.39
Realized commodity hedging gain (loss)	(0.10)	0.31	0.86	2.29	0.85	4.02
Royalties	(17.49)	(0.42)	(10.23)	(15.88)	(0.35)	(7.42)
Operating costs	(13.57)	(1.31)	(10.79)	(12.17)	(1.51)	(10.25)
Transportation costs	(1.16)	(0.30)	(1.42)	(1.44)	(0.36)	(1.87)
Operating netbacks	33.65	2.18	23.75	30.87	2.70	21.87

	Nine months ended Sept. 30, 2011			Nine months ended Sept. 30, 2010		
	Oil and ngl ($/bbl)	Natural gas ($/mcf)	Total ($/boe)	Oil and ngl ($/bbl)	Natural gas ($/mcf)	Total ($/boe)
Revenue	69.59	3.98	45.31	62.90	4.63	41.04
Realized commodity hedging gain (loss)	(1.76)	0.39	0.40	0.98	0.58	2.54
Royalties	(19.88)	(0.36)	(10.46)	(17.24)	(0.50)	(8.36)
Operating costs	(13.78)	(1.48)	(11.18)	(12.69)	(1.65)	(10.95)
Transportation costs	(1.41)	(0.35)	(1.71)	(1.38)	(0.38)	(1.95)
Operating netbacks	32.76	2.18	22.36	32.57	2.68	22.32

General and Administrative Costs

($ thousands, except per boe)	Three months ended Sept. 30, 2011	Three months ended Sept. 30, 2010	Nine months ended Sept. 30, 2011	Nine months ended Sept. 30, 2010
Gross costs	5,976	3,624	14,571	11,723
Operator's recoveries	(150)	(242)	(370)	(610)
Capitalized costs	(2,034)	(1,477)	(4,786)	(4,281)
General and administrative expenses	3,792	1,905	9,415	6,832
Per boe	1.50	1.59	1.73	1.87

Increased general and administrative costs after recoveries and capitalization for the third quarter and first nine months of 2011 were the result of increased staff levels to accommodate the Company's increased production levels and the acquisition of Caltex. The Company's general and administrative costs per boe have decreased in the third quarter and first nine months of 2011 due to the increased production levels over the same periods in 2010. The introduction of IFRS has resulted in the Company altering the recoveries and the capitalization of some general and administrative costs. As such, net general and administrative expenses for the three and nine months ended September 30, 2010, increased to $1.9 million and $6.8 million from $1.3 million and $4.6 million as reported under previous GAAP. The Company expects general and administrative expenses to average between $1.50 and $1.75 per boe for 2011.

Stock-Based Compensation

($ thousands)	Three months ended Sept. 30, 2011	Three months ended Sept. 30, 2010	Nine months ended Sept. 30, 2011	Nine months ended Sept. 30, 2010
Gross costs	4,215	2,514	8,927	7,303
Capitalized costs	(2,023)	(1,158)	(4,191)	(3,360)
Total stock-based compensation	2,192	1,356	4,736	3,943

In the third quarter of 2011, the Company's stock-based compensation expense has increased compared with the same period in 2010 due to an increase in the number of stock options outstanding combined with the Company incurring higher stock-based compensation costs in the first year of the option grants due to a graded vesting schedule under IFRS.

Depletion and Depreciation

($ thousands, except per boe)	Three months ended Sept. 30, 2011	Three months ended Sept. 30, 2010	Nine months ended Sept. 30, 2011	Nine months ended Sept. 30, 2010

Depletion and depreciation	51,699	20,332	95,793	57,919
Per boe	20.43	16.92	17.64	15.88

Total depletion and depreciation costs per boe have increased in the third quarter and first nine months of 2011 compared to the same periods in 2010 due to the addition of the fair market value of the Caltex assets at July 1, 2011 which was higher than the Company's book value for proved plus probable reserves. This was partially offset by successful lower cost reserve additions from the Company's drilling program over the past year. Under IFRS, Crew depletes its assets on a component basis utilizing total proved plus probable reserves including future development capital as opposed to depleting using total proved reserves under previous GAAP.

Finance Expenses

($ thousands, except per boe)	Three months ended Sept.30, 2011	Three months ended Sept.30, 2010	Nine months ended Sept.30, 2011	Nine months ended Sept.30, 2010
Interest on bank debt	2,049	1,188	4,775	4,370
Accretion of the decommissioning obligation	737	479	1,743	1,488
Acquisition costs	455	-	2,605	-
Total finance expense	3,241	1,667	9,123	5,858
Average debt level	155,053	79,623	118,329	88,431
Effective interest rate on bank debt	5.2%	5.9%	5.4%	6.6%
Interest on bank debt per boe	0.81	0.99	0.88	1.20

In the third quarter of 2011, interest on bank debt increased 72% over the same period in 2010 as higher average debt levels from the acquisition of Caltex and increased capital spending were partially offset by lower margins on the Company's bank facility. For the first nine months of 2011, the Company's effective interest rate on bank debt was lower than the same period in 2010 due to lower margins on the Company's bank facility combined with reduced deferred financing costs. The Company projects its effective interest rate on bank debt will average 5.0% to 5.5% in 2011.

The accretion of the decommissioning obligation increased in the third quarter and first nine months of 2011 compared to the same period in 2010 due to additional accretion on the Caltex decommissioning obligation which was acquired on July 1, 2011. Acquisition costs are those expenditures incurred by Crew during the three and nine months ended September 30, 2011 related to the acquisition of Caltex. Under IFRS, costs such as legal, accounting and regulatory fees associated with the acquisition of a business are expensed in the period in which they are incurred.

Deferred Income Taxes

In the third quarter of 2011, the provision for deferred income taxes was $4.0 million compared to a $5.5 million recovery for the same period in 2010 due to higher pre-tax earnings in the third quarter of 2011. For the first nine months, the provision for deferred incomes taxes was $5.5 million compared to $10.4 million for the same period in 2010 due to higher pre-tax earnings in 2010.

Cash and Funds from Operations and Net Income

($ thousands, except per share amounts)		Three months ended Sept. 30, 2011	Three months ended Sept. 30, 2010	Nine months ended Sept. 30, 2011	Nine months ended Sept. 30, 2010
Cash provided by operating activities		54,095	18,956	113,460	73,701
Funds from operations		54,260	23,464	107,262	70,757
Per share	– basic	0.45	0.29	1.12	0.89
	- diluted	0.45	0.29	1.10	0.87
Net income		12,232	(17,281)	18,367	32,033
Per share	- basic	0.10	(0.22)	0.19	0.40
	- diluted	0.10	(0.22)	0.19	0.39

The third quarter and first nine months of 2011 increase in cash provided by operating activities and funds from operations was the result of increased oil and ngl pricing combined with higher production levels. The increase in the third quarter net income compared with the same period in 2010 was the result of an impairment loss of approximately $18.7 million being recorded on the Company's natural gas properties in 2010. The decrease in net income in the first nine months of 2011 compared with the same period in 2010 was the result of a significant gain on sale recorded on the disposition of the Edson properties in the second quarter of 2010.

Capital Expenditures, Property Acquisitions and Dispositions

During the third quarter, the Company drilled a total of 66 (65.2 net) wells resulting in 54 (53.8 net) oil wells, six (5.4 net) natural gas wells, five (5.0 net) service wells and one (1.0 net) dry and abandoned well. In addition, the Company completed 64 (63.3 net) wells and recompleted 36 (33.6 net) wells in the quarter. The Company continued to add to its infrastructure spending $28.0 million on pipelines and upgrading its batteries and facilities predominantly in the Princess area. Total net capital expenditures for the quarter are detailed below:

($ thousands)	Three months ended Sept. 30, 2011	Three months ended Sept. 30, 2010	Nine months ended Sept. 30, 2011	Nine months ended Sept. 30, 2010
Land	1,299	2,866	3,715	37,738
Seismic	2,502	182	10,678	5,277

Drilling and completions	103,902	47,719	190,437	114,610
Facilities, equipment and pipelines	28,032	11,304	56,160	23,074
Other	2,936	2,427	6,031	4,566
Total exploration and development	138,671	64,498	267,021	185,265
Property acquisitions (dispositions)	-	-	(12,289)	(132,640)
Total	138,671	64,498	254,732	52,625

Liquidity and Capital Resources

Capital Funding

The Company has completed the fall review of its bank facility with its syndicate of lending banks (the "Syndicate"). The Syndicate is currently finalizing approvals on an increase in the Company's facility to $430 million. The increased credit facility will include a revolving line of credit of $400 million and an operating line of credit of $30 million (the "Facility"). The Facility revolves for a 364 day period and will be subject to its next 364 day extension by June 11, 2012. If not extended, the Facility will cease to revolve, the margins thereunder will increase by 0.50 percent and all outstanding balances under the Facility will become repayable in one year. The available lending limits of the Facility are reviewed semi-annually and are based on the Syndicate's interpretation of the Company's reserves and future commodity prices. There can be no assurance that the amount of the available Facility will not be adjusted at the next scheduled borrowing base review on or before June 11, 2012. At September 30, 2011, the Company had drawings of $194.0 million on the Facility and had issued letters of credit totaling $10.2 million.

On March 2, 2011, the Company closed a bought deal sale of 4,820,000 Common Shares of the Company at a price of $20.75 per share for aggregate gross proceeds of $100 million.

During the first nine months of 2011, the Company received proceeds of $7.4 million upon the exercise of 801,800 employee stock options.

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

Working Capital

The capital intensive nature of Crew's activities generally results in the Company carrying a working capital deficit. Working capital deficit includes accounts receivable less accounts payable and accrued liabilities. The Company maintains sufficient unused bank credit lines to satisfy working capital deficits. At September 30, 2011, the Company's working capital deficiency totaled $100.6 million which, when combined with the drawings on its bank line at September 30, 2011, represented approximately 69% of its increased $430 million bank facility.

Share Capital

As at November 7, 2011, Crew had 119,695,438 Common Shares and options to acquire 7,668,300 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 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. This ratio may increase at certain times as a result of acquisitions or low commodity prices. As shown below, as at September 30, 2011, the Company's ratio of net debt to annualized funds from operations was 1.36 to 1 (December 31, 2010 – 1.63 to 1).

($ thousands, except ratio)	Sept. 30, 2011	Dec. 31, 2010
Working capital deficit	(100,551)	(40,707)
Bank loan	(194,038)	(138,700)
Net debt	(294,589)	(179,407)
Funds from operations	54,260	27,449
Annualized	217,040	109,796
Net debt to annualized funds from operations ratio	1.36	1.63

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	2011	2012	2013	2014	2015	Thereafter

Bank Loan (note 1)	194,038	-	-	194,038	-	-	-
Operating leases	14,008	592	3,796	2,210	2,340	2,470	2,600
Capital commitments	2,100	-	2,100	-	-	-	-
Firm transportation agreements	19,632	1,613	1,535	1,535	2,110	2,110	10,728
Firm processing agreement	73,055	1,645	6,526	6,526	8,239	8,239	41,880
Total	302,833	3,850	13,957	204,309	12,689	12,819	55,208

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

The operating leases include the Company's contractual obligation to a third party for its new five year lease of additional office space.

The transportation agreements include an $18.4 million commitment to a third party to transport natural gas from a gas processing facility in the Septimus area to the Alliance pipeline system. The remaining commitment relates to firm transportation commitments that were acquired as part of the Company's May 2007 private company acquisition. In 2010, the Company permanently assigned approximately $6.2 million of its firm commitments to third parties.

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

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

Guidance

Crew had its most active quarter in its history drilling 66 wells and spending $138.7 million. This allowed the Company to catch-up on its drilling program which was delayed due to a prolonged spring break up. Current production is estimated at 30,000 boe per day and the Company expects to tie in nine liquids rich gas wells and 31 oil wells in the fourth quarter to achieve our forecasted 2011 exit production rate of 32,500 to 34,500 boe per day.

We have moved forward with plans to accelerate our winter drilling program at Septimus and Kobes to avoid the expected shortage of available services in northeastern British Columbia. As a result, we have added six wells to our fourth quarter drilling program and plan to complete four of these later in the quarter. This program will result in an additional $20 million of capital expenditures increasing total net exploration and development expenditures to $350 million for the year.

As part of our continuous asset review process, Crew has a number of non-core properties for sale comprised of approximately 1,400 boe per day of production and 6.2 mmboe of proved plus probable reserves as independently evaluated effective December 31, 2010. Successfully negotiated transactions from this program are expected to close in the first quarter of 2012.

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)		Sept. 30 2011	June 30 2011	Mar. 31 2011	Dec. 31 2010	Sept. 30 2010	June 30 2010	Mar. 31 2010	Dec. 31 2009
Total daily production (boe/d)		27,510	16,443	15,607	14,654	13,061	12,048	15,001	14,470
Average wellhead price ($/boe)		45.33	46.94	43.53	42.00	37.39	39.25	45.75	43.30
Petroleum and natural gas sales		114,719	70,236	61,148	56,620	44,924	43,027	61,772	57,646
Cash provided by operations		54,095	32,896	26,469	20,225	18,956	23,422	31,323	16,734
Funds from operations		54,260	28,891	24,111	27,449	23,464	19,966	27,327	27,256
Per share	– basic	0.45	0.34	0.29	0.34	0.29	0.25	0.35	0.35
	– diluted	0.45	0.33	0.29	0.34	0.29	0.24	0.34	0.35
Net income (loss)		12,232	16,261	(10,126)	(14,214)	(17,281)	31,544	17,770	(9,154)
Per share	– basic	0.10	0.19	(0.12)	(0.18)	(0.22)	0.39	0.23	(0.12)
	– diluted	0.10	0.19	(0.12)	(0.18)	(0.22)	0.39	0.22	(0.12)

(1) The 2010 and 2011 quarterly results have been adjusted to conform to IFRS. The quarterly results for 2009 have not been adjusted and reflect the results in accordance with previous GAAP.

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

- Revenue is directly impacted by the Company's ability to replace existing declining production and add incremental production through its on-going capital expenditure program.
- Over the past two years, the price of natural gas has been negatively impacted by an increasing supply of natural gas coming from new technology tapping into abundant supplies of tight shale gas reservoirs in North America. With depressed natural gas prices, Crew has focused its capital expenditures towards oil development with higher netbacks. This has

resulted in the commodity mix moving towards more oil and the Company's overall netbacks improving revenues and funds from operations.

- Production in the second quarters of 2010 and 2011 was negatively impacted by scheduled and unscheduled third party facility shutdowns and poor weather experienced in southern Alberta during the second quarters of 2010 and 2011 and third quarter of 2010.
- Revenue and royalties are significantly impacted by underlying commodity prices. The Company utilizes derivative contracts and forward sales contracts to reduce the exposure to commodity price fluctuations. 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.
- From 2009 to 2011, the Company sold assets with approximately 2,440 boe per day of production for $182.9 million. The major dispositions closed as follows:
    - Fourth quarter 2009 – 600 boe per day for $25.3 million
    - Second quarter 2010 – 1,700 boe per day for $123.3 million
    - Second quarter 2011 – 140 boe per day for $12.6 million
- Three dispositions of assets in the Ferrier and Edson areas resulted in gains on sale of assets of $9.9 million, $37.0 million and $4.7 million in the first and second quarters of 2010 and the second quarter of 2011, respectively.
- The Company acquired Caltex Energy Inc. on July 1, 2011 adding approximately 10,500 boe per day of production and the results of operations of Caltex are included in the Company's financial and operating results commencing July 1, 2011.
- The Company incurred impairment charges of $18.7 million and $10.4 million on two of its natural gas weighted CGUs in the third and fourth quarters of 2010, respectively.

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. Note 15 to the interim consolidated financial statements provides reconciliations between the Company's 2010 previous GAAP results and its 2010 results under IFRS. The reconciliations include the consolidated statement of financial position as at September 30, 2010, and consolidated statements of income and comprehensive income for the three and nine months ended September 30, 2010.

The following provides summary reconciliations of Crew's January 1, 2010 previous GAAP to IFRS transitional Summary Statement of Financial Position reconciliations along with a discussion of the significant IFRS accounting policy changes:

Summary Statement of Financial Position Reconciliations

As at Date of IFRS Transition – January 1, 2010

($ thousands)	Previous GAAP	Note	Effect of Transition to IFRS	IFRS
Current assets	38,116		(542)	37,574
Exploration and evaluation	-	(1)	35,591	35,591
Property, plant and equipment	925,132	(1)	(35,591)	889,541
	963,248		(542)	962,706
Current liabilities	86,375		-	86,375
Bank loan	135,601		-	135,601
Other long-term obligations	132		-	132
Decommissioning obligations	35,341	(6)	17,722	53,063
Deferred tax liability	101,519	(6)	(5,031)	96,488
Share capital	617,605	(8)	3,383	620,988
Contributed surplus	22,769	(7)	2,737	25,506
Deficit	(36,094)	(6,7,8)	(19,353)	(55,447)
	963,248		(542)	962,706

On transition to IFRS, on January 1, 2010, Crew used certain exemptions allowed under IFRS 1 First Time Adoption of International Financial Reporting Standards. The exemptions used were as follows:

1. Oil and gas properties are classified as Property, Plant and Equipment ("PP&E") or Exploration and Evaluation assets ("E&E"). Crew reclassified all E&E expenditures included in the PP&E balance under previous GAAP, as a separate item under IFRS. These assets are measured at cost and are not depleted but will be assessed for impairment when indicators suggest the possibility of impairment. Once these E&E assets have reached technical feasibility and commercial viability, they are transferred to PP&E. At the time of transfer, they were subjected to an impairment test. Crew's E&E assets primarily consist of undeveloped exploration lands and at January 1, 2010 were valued at $35.6 million.

2. Under IFRS, PP&E assets are grouped into areas designated as cash generating units ("CGU") for the purposes of impairment testing and further broken down into components within the CGU for purposes of depletion and depreciation.

IFRS 1 provides for the allocation of the previous GAAP net book value of PP&E assets, excluding E&E assets, to CGUs and components on a pro rata basis using the reserve volumes or values as at December 31, 2009. Crew has elected to allocate the PP&E balance using reserve values and at January 1, 2010, the value allocated to the PP&E assets is $889.5 million.

3. Under previous GAAP, impairment testing of oil and gas properties is performed at a cost centre level. Under IFRS, impairment testing is performed at the CGU level. This will result in a greater number of impairment tests. At January 1, 2010, Crew did not have any impairment of its PP&E under IFRS.
4. Depletion and depreciation of PP&E is calculated at a component level. Depletion of resource properties within PP&E is calculated using the unit-of-production method under IFRS using proved plus probable reserves. Depreciation of office equipment will continue to be calculated using a declining balance method.
5. IFRS 1 allows Crew to use the IFRS rules for business combinations on a prospective basis rather than restating all business combinations. Crew elected to use this exemption; therefore, Crew did not record any adjustments to retrospectively restate any of its business combinations that have occurred prior to January 1, 2010.
6. Under previous GAAP, Crew's decommissioning obligation was discounted over its life based on a credit adjusted risk free rate which was 8% to 10% at December 31, 2009. Under IFRS, Crew is required to revalue its liability for decommissioning costs at each balance sheet date using a current liability-specific discount rate. As a result, the Company's decommissioning obligation increased upon transition to IFRS as the liability was re-valued using a discount rate of 4% to reflect the Company's estimated risk-free rate of interest. The re-valued decommissioning obligation at the transition date was $53.1 million with the offsetting $17.7 million (net of $4.5 million of the deferred tax liability) increase in the liability being charged to retained earnings as also provided for under the deemed cost election for full cost oil and gas companies.
7. Under previous GAAP, Crew expensed stock-based compensation on a straight-line basis. Under IFRS, share-based payments are expensed based on a graded vesting schedule. Crew also incorporated a forfeiture multiplier rather than account for forfeitures as they occur as was practiced under previous GAAP. The adjustment to contributed surplus to account for the graded vesting and forfeitures was an increase of $2.7 million with the offset being charged to retained earnings.
8. Under previous GAAP, the deferred tax liability associated with the renouncement of tax deductions from the issuance of flow through shares was recorded as a reduction in share capital at the time of renouncement. Under IFRS, the difference between the deferred tax liability associated with the renouncement of the tax deductions and the premium price received on the issuance of flow through shares over the market value of the Company's common shares at the time of issue is recorded as a deferred tax expense at the time of the renouncement. This deferred tax expense effectively represents the net loss on the distribution of the tax deductions to investors. The transitional adjustment resulted in an increase of $3.4 million to share capital with a resulting offset being charged to retained earnings.

Use of estimates and judgments:

The preparation of financial statements in conformity with IFRS requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses. Actual results may differ from these estimates.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the year in which the estimates are revised and in any future years affected.

Reserve estimates including production profiles, future development costs, and discount rates are a critical part of many of the estimated amounts and calculations contained in the financial statements. These estimates are verified by third party professional engineers, who work with information provided by the Company to establish reserve determinations. These determinations are updated at least on an annual basis, and more frequently as significant business combinations take place.

Significant areas of estimation, uncertainty and critical judgments in applying accounting policies that impact the amounts recognized in the interim consolidated financial statements include:

- Impairment testing – estimates of reserves, future commodity prices, future costs, production profiles, discount rates, market value of land.
- Depletion and depreciation – oil and natural gas reserves, including future prices, costs and reserve base to use on calculation of depletion.
- Decommissioning obligations – estimates relating to amounts, likelihood, timing, inflation and discount rates.
- Stock-based compensation – forfeiture rates and volatility.
- Derivatives – expected future oil and natural gas prices and expected volatility in these prices; expected interest rates; expected future foreign exchange rates.
- Deferred tax – estimates of reversal of temporary differences, tax rates substantively enacted, and likelihood of assets

being realized.

- Provisions and contingencies – estimates relating to onerous contracts, including discount rates associated with long term contracts.

The following provides summary reconciliations of Crew's 2010 previous GAAP to IFRS results:

Summary Statement of Financial Position Reconciliations

As at December 31, 2010

($ thousands)	Previous GAAP	Note	Effect of Transition to IFRS	IFRS
Current assets	61,020		-	61,020
Exploration and evaluation	-	(1)	72,281	72,281
Property, plant and equipment	937,050	(1)	(24,410)	912,640
	998,070		47,871	1,045,941
Current liabilities	101,088		-	101,088
Bank loan	138,700		-	138,700
Fair value of financial instruments	9,196		-	9,196
Decommissioning obligations	36,073	(2)	18,755	54,828
Deferred tax liability	96,330	(1,2)	6,149	102,479
Share capital	646,385		3,383	649,768
Contributed surplus	23,553	(3)	3,958	27,511
Deficit	(53,255)	(1,2,3)	15,626	(37,629)
	998,070		47,871	1,045,941

1. The PP&E adjustment includes the impact of the reclassification of E&E assets ($72.3 million decrease in PP&E), lower depletion as a result of using proved plus probable reserves to calculate depletion ($31.6 million increase in PP&E), gains on sale of assets and gains on farmout of assets ($48.2 million increase in PP&E), impairment on the Company's gas focused CGUs ($29.1 million decrease in PP&E), reduction of capitalized G&A, capital recoveries and associated deferred tax impact ($2.8 million decrease in PP&E).
2. Includes the adjustment to revalue the liability to a risk free interest rate of 3.50% at December 31, 2010 and the related deferred tax impact.
3. Includes recalculation of stock based compensation incorporating graded vesting and a forfeiture multiplier.

Summary Net Earnings Reconciliations

			2010		
($ thousands)	Annual	Q4	Q3	Q2	Q1
Net earnings/(loss) – previous GAAP	(17,161)	(9,525)	(7,387)	(2,691)	2,442
Addition/(deduction):					
General and administrative	(3,244)	(987)	(640)	(727)	(890)
Stock-based compensation	(1,020)	(501)	(322)	(178)	(19)
Depletion and depreciation	31,559	6,002	6,739	7,489	11,329
Decommissioning obligation accretion	674	160	161	175	178
Gain on divestitures and farmouts	48,242	-	-	38,360	9,882
Property, plant and equipment impairment	(29,072)	(10,336)	(18,736)	-	-
Deferred income tax	(12,159)	973	2,904	(10,884)	(5,152)
	34,980	(4,689)	(9,894)	34,235	15,328
Net earnings/(loss) - IFRS	17,819	(14,214)	(17,281)	31,544	17,770

Impact of Transition to IFRS on 2010 Results:

- Exploration and Evaluation ("E&E") – In 2010, Crew incurred $36.7 million of E&E expenditures acquiring undeveloped land and evaluating its undeveloped land with seismic acquisitions. This amount was reclassified from PP&E, under previous GAAP, to E&E under IFRS.
- Divestitures and farmouts – Under previous GAAP, proceeds from divestitures were deducted from the full cost pool without recognition of a gain or loss unless the divestiture resulted in a change in the depletion rate of 20% or greater in which case a gain or loss was recorded. Under IFRS, gains and losses are recorded on divestitures and farmouts and are calculated as the difference between the proceeds and the net book value of the asset disposed of. For the year ended December 31, 2010, the Company recorded a $46.9 million gain on disposition of oil and gas properties and an additional $1.3 million gain on farmouts for IFRS as compared to nil under previous GAAP.
- Impairment of PP&E – Under IFRS, impairment tests of PP&E are performed at a CGU level as opposed to the entire Company's PP&E balance with a full cost ceiling test under previous GAAP. Impairment is recognized if the carrying value exceeds the recoverable amount for a CGU. The recoverable amount is determined using fair value less costs to sell

based on discounted future cash flows of proved plus probable reserves using forecast prices and costs. In the third quarter of 2010, as a result of decreased natural gas prices and a subsequent decrease in the Company's future natural gas prices used in the Company's reserves, Crew incurred an $18.7 million impairment charge in certain CGUs. Further deterioration in future natural gas pricing in the fourth quarter of 2010 resulted in the Company incurring an additional $10.4 million impairment charge on the same natural gas weighted CGUs. PP&E impairments can be reversed in the future if the recoverable amount increases.
- Depletion and depreciation expense – Under IFRS, Crew has chosen to calculate the depletion expense utilizing proved plus probable reserves as opposed to proved reserves under previous GAAP. This has resulted in a reduction of depletion and depreciation expense of approximately $31.6 million in 2010.

Future Accounting Changes

The following pronouncements may have an impact on the Company's financial statements and will become effective for financial reporting periods beginning on or after January 1, 2013 and have not yet been adopted by the Company.

- In November 2009, the IASB published IFRS 9, "Financial Instruments," which covers the classification and measurement of financial assets as part of its project to replace IAS 39, "Financial Instruments; Recognition and Measurement." In October 2010, the requirements for classifying and measuring financial liabilities were added to IFRS 9. Under this guidance, entities have the option to recognize financial liabilities at fair value through earnings. If this option is elected, entities would be required to reverse the portion of the fair value change due to a company's own credit risk out of earnings and recognize the change in other comprehensive income. IFRS 9 is effective for the Company on January 1, 2013. Early adoption is permitted and the standard is required to be applied retrospectively. The Company is currently evaluating the impact of adopting IFRS 9.
- IFRS 10 – Consolidated Financial Statements builds on existing principles and standards and identifies the concept of control as the determining factor in whether an entity should be included in the consolidated financial statements of the parent company.
- IFRS 11 – Joint Arrangements establishes the principles for financial reporting by entities when they have an interest in jointly controlled operations.
- IFRS 12 – Fair Value Measurement defines fair value and requires disclosure about fair value measurements.
- IAS 27 – Separate Financial Statements revised the existing standard which addresses the presentation of parent company financial statements that are not consolidated financial statements.
- IAS 28 – Investments in Associates and Joint Ventures revised the existing standard and prescribes the accounting for investments and set out the requirements for the application of the equity method when accounting for investments in associates and joint ventures.

The Company has not completed its evaluation of the effect of adopting these standards on its financial statements.

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.

The Company'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 IFRS. The Company is required to disclose herein any change in the Company's internal controls over financial reporting that occurred during the period beginning on July 1, 2011 and ended on September 30, 2011 that has materially affected, or is reasonably likely to materially affect, the Company's internal controls over financial reporting. No material changes in the Company's internal controls over financial reporting were identified during such period that have materially affected, or are reasonably likely to materially affect, the Company's internal controls over financial reporting. There were no changes to internal controls over financial reporting as a result of the transition to IFRS or the acquisition of Caltex.

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 November 7, 2011

Cautionary Statements

Forward-looking information and statements

This news release contains certain forward–looking information and statements within the meaning of applicable securities laws. The use of any of the words "expect", "anticipate", "continue", "estimate", "may", "will", "project", "should", "believe", "plans", "intends" and similar expressions are intended to identify forward-looking information or statements. In particular, but without limiting the foregoing, this news release contains forward-looking information and statements pertaining to the following: the volume and product mix of Crew's oil and gas production; production estimates; year-end production; 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 including new infrastructure at Princess and anticipated capacity; operating costs; the total future capital associated with development of reserves and resources; anticipated increases in recovery factors related to the Company's Tilley waterflood and forecast reductions in operating expenses; and the impact of possible non-core asset dispositions and the timing thereof.

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; the anticipated increase to the Company's banking facility; 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; the ability of Crew to successfully market its oil and natural gas products; ability to improve upon historical recovery factors.

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

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

BOE equivalent

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

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

CREW ENERGY INC.
Consolidated Statements of Financial Position
(unaudited)
(thousands)

	September 30, 2011	December 31, 2010
Assets		
Current Assets:		
Accounts receivable	**$ 80,054**	$ 44,922
Fair value of financial instruments (note 11)	**6,024**	982
Assets held for sale	**-**	15,116
	86,078	61,020
Exploration and evaluation assets (note 5)	**76,923**	72,281
Property, plant and equipment (note 6)	**1,817,567**	912,640
	$ 1,980,568	$ 1,045,941
Liabilities and Shareholders' Equity		
Current Liabilities:		
Accounts payable and accrued liabilities	**$ 180,605**	$ 100,745
Current portion of other long-term obligations (note 8)	**35**	343
	180,640	101,088
Fair value of financial instruments (note 11)	**-**	9,196

Bank loan (note 7)	**194,038**	138,700
Decommissioning obligations (note 9)	**99,465**	54,828
Deferred tax liability	**234,374**	102,479
Shareholders' Equity		
Share capital (note 10)	**1,257,907**	649,768
Contributed surplus	**33,406**	27,511
Deficit	**(19,262)**	(37,629)
	1,272,051	639,650
Commitments (note 14)		
	$ 1,980,568	$ 1,045,941

See accompanying notes to the consolidated financial statements.

CREW ENERGY INC.
Consolidated Statements of Income (Loss) and Comprehensive Income (Loss)
(unaudited)
(thousands, except per share amounts)

	Three months ended September 30, 2011	Three months ended September 30, 2010 (note 15)	**Nine months ended September 30, 2011**	Nine months ended September 30, 2010 (note 15)
Revenue				
Petroleum and natural gas sales	**$ 114,719**	$ 44,924	**$ 246,103**	$ 149,723
Royalties	**(25,897)**	(8,920)	**(56,827)**	(30,488)
Realized gain on financial instruments (note 11)	**2,180**	5,114	**2,195**	9,798
Unrealized gain (loss) on financial instruments (note 11)	**17,025**	(5,326)	**16,762**	5,206
	108,027	35,792	**208,233**	134,239
Expenses				
Operating	**27,303**	12,318	**60,754**	39,967
Transportation (note 8)	**3,598**	2,243	**9,265**	6,763
General and administrative	**3,792**	1,905	**9,415**	6,832
Share-based compensation	**2,192**	1,356	**4,736**	3,943
Depletion and depreciation	**51,699**	20,332	**95,793**	57,919
	88,584	38,154	**179,963**	115,424
Income (loss) from operations	**19,443**	(2,362)	**28,270**	18,815
Financing (note 13)	**(3,241)**	(1,667)	**(9,123)**	(5,858)
Gain on divestitures	**-**	-	**4,697**	48,242
Impairment of property, plant and equipment	**-**	(18,736)	-	(18,736)
Income (loss) before income taxes	**16,202**	(22,765)	**23,884**	42,463
Deferred tax expense (recovery)	**3,970**	(5,484)	**5,477**	10,430
Net income (loss) and comprehensive income (loss)	**$ 12,232**	$ (17,281)	**$ 18,367**	$ 32,033
Net income (loss) per share (note 10)				
Basic	**$ 0.10**	$ (0.22)	**$ 0.19**	$ 0.40
Diluted	**$ 0.10**	$ (0.22)	**$ 0.19**	$ 0.39

See accompanying notes to the consolidated financial statements.

CREW ENERGY INC.
Consolidated Statements of Changes in Shareholders' Equity
(unaudited)
(thousands)

	Number of shares	Share capital	Contributed surplus	Deficit	Total Shareholders' equity
Balance January 1, 2011	80,368	$649,768	$ 27,511	$(37,629)	$ 639,650

Net income for the period	-	-	-	18,367	18,367
Issue of shares (net of issue costs)	4,820	95,777	-	-	95,777
Shares issued on acquisition (note 4)	33,606	501,911	-	-	501,911
Share-based compensation expensed	-	-	4,736	-	4,736
Share-based compensation capitalized	-	-	4,191	-	4,191
Transfer of stock-based compensation on exercises	-	3,032	(3,032)	-	-
Issued on exercise of options	803	7,419	-	-	7,419
Balance September 30, 2011	119,597	$1,257,907	$ 33,406	$(19,262)	$ 1,272,051

	Number of shares	Share capital	Contributed surplus	Deficit	Total Shareholders' equity
Balance January 1, 2010	78,152	$ 620,988	$ 25,506	$(55,447)	$ 591,047
Net income for the period	-	-	-	32,033	32,033
Issue of shares (net of issue costs)	-	(36)	-	-	(36)
Share-based compensation expensed	-	-	3,943	-	3,943
Share-based compensation capitalized	-	-	3,359	-	3,359
Transfer of stock-based compensation on exercises	-	7,535	(7,535)	-	-
Issued on exercise of options	2,054	18,813	-	-	18,813
Balance September 30, 2010	80,206	$ 647,300	$ 25,273	$(23,414)	$ 649,159

See accompanying notes to the consolidated financial statements.

CREW ENERGY INC.

Consolidated Statements of Cash Flows
(unaudited)
(thousands)

	Three months ended September 30, 2011	Three months ended September 30, 2010	**Nine months ended September 30, 2011**	Nine months ended September 30, 2010
Cash provided by (used in):				
Operating activities:				
Net income	**$ 12,232**	$ (17,281)	**$ 18,367**	$ 32,033
Adjustments:				
Depletion and depreciation	**51,699**	20,332	**95,793**	57,919
Financing expenses (note 13)	**3,241**	1,667	**9,123**	5,858
Interest expense (note 13)	**(2,049)**	(1,188)	**(4,775)**	(4,370)
Acquisition costs (note 13)	**(455)**	-	**(2,605)**	-
Share-based compensation	**2,192**	1,356	**4,736**	3,943
Deferred tax expense (recovery)	**3,970**	(5,484)	**5,477**	10,430
Unrealized (gain) loss on financial instruments	**(17,025)**	5,326	**(16,762)**	(5,206)
Gain on divestitures	**-**	-	**(4,697)**	(48,242)
Impairment of property, plant and equipment	**-**	18,736	**-**	18,736
Transportation liability charge (note 8)	**(104)**	(156)	**(308)**	(982)
Decommissioning obligations settled	**(540)**	(201)	**(661)**	(906)
Change in non-cash working capital (note 12)	**934**	(4,151)	**9,772**	4,488
	54,095	18,956	**113,460**	73,701
Financing activities:				
Increase (decrease) in bank loan	**40,209**	38,925	**4,100**	(24,831)
Issue of common shares	**-**	-	**100,015**	-
Proceeds from exercise of share options	**17**	1,220	**7,419**	18,813
Share issue costs	**(420)**	-	**(5,664)**	(48)
	39,806	40,145	**105,870**	(6,066)
Investing activities:				
Exploration and evaluation asset expenditures	**-**	(1,687)	**(8,819)**	(37,206)
Property, plant and equipment expenditures	**(138,671)**	(62,811)	**(258,202)**	(148,059)
Property divestitures (net of acquisitions)	**-**	-	**12,289**	132,640
Proceeds on sale of asset held for sale	**-**	-	**15,116**	-
Change in non-cash working capital (note 12)	**44,770**	5,397	**20,286**	(15,010)
	(93,901)	(59,101)	**(219,330)**	(67,635)
Change in cash and cash equivalents	**-**	-	**-**	-
Cash and cash equivalents, beginning of period	**-**	-	**-**	-

Cash and cash equivalents, end of period	**$ -**	$ -	**$ -**	$ -

See accompanying notes to the consolidated financial statements.

CREW ENERGY INC.
Notes to Consolidated Financial Statements
For the three and nine months ended September 30, 2011 and 2010
(Unaudited)
(Tabular amounts in thousands)

1. Reporting entity:

Crew Energy Inc. ("Crew" or the "Company") is an oil and gas exploration, development and production Company based in Calgary, Alberta, Canada. Crew conducts its operations in the Western Canadian Sedimentary basin, primarily in the provinces of Alberta, British Columbia and Saskatchewan. The consolidated financial statements of the Company as at and for the three and nine months ended September 30, 2011 comprise of the Company and its wholly owned subsidiaries; Crew Resources Inc., Caltex Energy Inc., 1401466 Alberta Ltd. and 1401477 Alberta Ltd. (all of which are incorporated in Canada) and three partnerships; Crew Energy Partnership, Caltex Heavy Oil Partnership and Caltex Conventional Partnership. The consolidated financial statements of the Company as at and for the three and nine months ended September 30, 2010 comprise of the Company and its wholly owned subsidiary Crew Resources Inc. which are incorporated in Canada, and a partnership, Crew Energy Partnership. The Company conducts many of its activities jointly with others; these financial statements reflect only the Company's proportionate interest in such activities.

2. Basis of preparation:

(a) Statement of compliance:

The interim consolidated financial statements have been prepared in accordance with IAS 34 – Interim Financial Reporting of the International Financial Reporting Standards ("IFRS"). IFRS 1 – First-time adoption of International Financial Reporting Standards ("IFRS 1") has been applied to these interim consolidated financial statements.

An explanation of how the transition to IFRS has affected the reported financial position, financial performance and cash flows of the Company is provided in note 15. The note includes reconciliations of equity and net loss for comparative periods from former Canadian GAAP ("previous GAAP") to IFRS.

These interim consolidated financial statements follow the same accounting policies and method of computation as shown in note 3 of the Company's interim consolidated financial statements for the three months ended March 31, 2011. These are the accounting policies the Company expects to adopt in its annual consolidated financial statements for the year ended December 31, 2011, with the exception of certain disclosures that are normally required to be included in annual consolidated financial statements which have been condensed or omitted.

The consolidated financial statements were authorized for issue by the Board of Directors on November 7, 2011.

(b) Basis of measurement:

The consolidated financial statements have been prepared on the historical cost basis except for the derivative financial instruments that are measured at fair value.

The methods used to measure fair values are discussed in note 3.

(c) Functional and presentation currency:

These consolidated financial statements are presented in Canadian dollars, which is the Company's functional currency.

(d) Use of estimates and judgments:

The preparation of financial statements in conformity with IFRS requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses. Actual results may differ from these estimates.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the year in which the estimates are revised and in any future years affected.

Reserve estimates including production profiles, future development costs, and discount rates are a critical part of many of the estimated amounts and calculations contained in the financial statements. These estimates are verified by third party professional engineers, who work with information provided by the Company to establish reserve determinations. These determinations are updated at least on an annual basis.

Significant areas of estimation, uncertainty and critical judgments in applying accounting policies that impact the amounts recognized in the interim consolidated financial statements include:

- Impairment testing – estimates of reserves, future commodity prices, future costs, production profiles, discount rates, market value of land.
- Depletion and depreciation - oil and natural gas reserves, including future prices, costs and reserve base to use on calculation of depletion.
- Decommissioning obligations – estimates relating to amounts, likelihood, timing, inflation and discount rates.
- Stock-based compensation – forfeiture rates and volatility.
- Derivatives – expected future oil and natural gas prices and expected volatility in these prices; expected interest rates;

expected future foreign exchange rates.

- Deferred tax – estimates of reversal of temporary differences, tax rates substantively enacted, and likelihood of assets being realized.
- Provisions and contingencies – estimates relating to onerous contracts, including discount rates associated with long term contracts.

3. Determination of fair values:

A number of the Company's accounting policies and disclosures require the determination of fair value, for both financial and non-financial assets and liabilities. Fair values have been determined for measurement and/or disclosure purposes based on the following methods. When applicable, further information about the assumptions made in determining fair values is disclosed in the notes specific to that asset or liability.

(i) Property, plant and equipment and intangible exploration assets:

The fair value of property, plant and equipment recognized in an acquisition is based on market values. The market value of property, plant and equipment is the estimated amount for which property, plant and equipment could be exchanged on the acquisition date between a willing buyer and a willing seller in an arm's length transaction after proper marketing wherein the parties had each acted knowledgeably, prudently and without compulsion. The market value of oil and natural gas interests (included in property, plant and equipment) and intangible exploration assets is estimated with reference to the discounted cash flows expected to be derived from oil and natural gas production based on externally prepared reserve reports. The risk-adjusted discount rate is specific to the asset with reference to general market conditions.

The market value of other items of property, plant and equipment is based on the quoted market prices for similar items.

(ii) Cash and cash equivalents, accounts receivable, bank loans and accounts payable:

The fair value of cash and cash equivalents, accounts receivable, bank loans and accounts payable are estimated as the present value of future cash flows, discounted at the market rate of interest at the reporting date. At September 30, 2011 and December 31, 2010, the fair value of these balances approximated their carrying value due to their short term to maturity. Bank loans bear a floating rate of interest and therefore carrying value approximates fair value.

(iii) Derivatives:

The fair value of forward contracts and swaps is determined by discounting the difference between the contracted prices and published forward price curves as at the balance sheet date, using the remaining contracted oil and natural gas volumes and a risk-free interest rate (based on published government rates). The fair value of options and costless collars is based on option models that use published information with respect to volatility, prices and interest rates.

(iv) Stock options:

The fair value of employee stock options is measured using the Black Scholes option pricing model. Measurement inputs include share price on measurement date, exercise price of the instrument, expected volatility (based on weighted average historic volatility adjusted for changes expected due to publicly available information), weighted average expected life of the instruments (based on historical experience and general option holder behaviour), expected dividends, and the risk-free interest rate (based on government bonds).

4. Corporate Acquisition

On July 1, 2011, Crew Energy Inc. acquired all of the issued and outstanding shares of Caltex Energy Inc. ("Caltex Energy"), a private exploration and development company pursuing petroleum and natural gas production and reserves in western Canada for total consideration of $501.9 million. The Company issued 33,606,404 shares at $14.93 per share based on the Company's trading price on June 30, 2011, the last date of trading before Crew acquired control. Acquisition related costs of approximately $2.6 million have been expensed as period costs in the interim consolidated statement of income for the periods ending September 30, 2011 (note 13).

The Company believes that the acquisition of Caltex Energy will allow its shareholders to participate in the benefits of increased access to lower geological risk plays with large resources in place which include multi-zone, medium depth natural gas opportunities and multi-zone, shallow heavy oil opportunities.

The acquisition has been accounted for using the purchase method with the results of Caltex Energy's operations included in the Company's financial and operating results commencing July 1, 2011. The allocation of net assets acquired is based on the best available information at this time and could be subject to further change. The transaction was accounted for by the acquisition method, with the preliminary allocation of the purchase price based on estimated fair values as follows:

Consideration:	
Issue of 33,606,404 common shares	$501,911
Net assets acquired:	
Property, plant and equipment	729,074
Accounts receivable and other current assets	24,258
Accounts payable and other current liabilities	(38,928)
Risk management contract	(2,524)
Bank loan	(51,238)
Deferred tax liability	(127,844)
Decommissioning obligations	(30,887)
	$501,911

The value attributed to the property, plant and equipment acquired was determined in reference to an engineering report prepared by Caltex's third party reserve engineers using proved plus probable reserves discounted at a rate of 10%. Accounts receivable and payable are recognized at the contractual amount and are expected to be collected and paid. Estimates regarding deferred taxes may change as tax returns are finalized at the change of control and could result in changes to the allocation.

Included in the consolidated statements of income and comprehensive income are the following amounts:

Caltex Energy amounts since acquisition	
Petroleum and natural gas revenue	$52,826
Loss and comprehensive loss	(4,109)

If Caltex Energy had been acquired on January 1, 2011, the incremental petroleum and natural gas revenue and income recognized for the period ended September 30, 2011 and the pro forma results would have been as follows:

Period ended September 30, 2011	As stated	Caltex Energy prior to acquisition	Pro Forma
Petroleum and natural gas revenue	$ 246,103	$ 108,150	$ 354,253
Income and comprehensive income	18,367	8,396	26,763

5. Exploration and evaluation assets:

Cost or deemed cost	Total
Balance, January 1, 2010	$35,591
Additions	37,234
Transfer to property, plant and equipment	(544)
Balance, December 31, 2010	$72,281
Additions	8,819
Transfer to property, plant and equipment	(4,177)
Balance, September 30, 2011	$76,923

Exploration and evaluation assets consist of the Company's exploration projects which are pending the determination of proven or probable reserves. Additions represent the Company's share of costs incurred on exploration and evaluation assets during the period.

(a) Impairment charge***:***

The impairment of exploration and evaluation assets, and any eventual reversal thereof, is recognized as additional depletion and depreciation expense in the statement of income.

(b) Recoverability of exploration and evaluation assets:
The Company assesses the recoverability of exploration and evaluation assets, before and at the moment of reclassification to property, plant and equipment, using Cash Generating Units ("CGUs"). The CGU includes both the exploration and evaluation CGU and CGUs related to oil and natural gas interests for that area, but not larger than a segment.

6. Property, plant and equipment:

Cost or deemed cost	Total
Balance, January 1, 2010	$889,541
Additions	223,508
Property acquisition	2,522
Transfer from exploration and evaluation assets	544
Divestitures	(93,975)
Asset held for sale	(15,116)
Change in decommissioning obligations	6,524
Capitalized stock-based compensation	4,717
Balance, December 31, 2010	$1,018,265
Additions	258,563
Transfer from exploration and evaluation assets	4,177
Divestitures	(9,221)
Corporate acquisition (note 4)	729,074
Change in decommissioning obligations	13,671
Capitalized stock-based compensation	4,191
Balance, September 30, 2011	$2,018,720

Accumulated depletion and depreciation	Total
Balance, January 1, 2010	$-
Depletion and depreciation expense	79,016
Divestitures	(2,463)
Impairment	29,072
Balance, December 31, 2010	$105,625
Divestitures	(265)
Depletion and depreciation expense	95,793
Balance, September 30, 2011	$201,153

Net book value	Total
Balance, January 1, 2010	$889,541
Balance, December 31, 2010	$912,640
Balance, September 30, 2011	$1,817,567

The calculation of depletion for the period ended September 30, 2011 included estimated future development costs of $441.5 million (December 31, 2010 - $297.4 million) associated with the development of the Company's proved plus probable reserves and excludes salvage value of $83.9 million (December 31, 2010 - $51.1 million) and undeveloped land of $131.2 million (December 31, 2010 - $110.6 million) related to development acreage.

(a) Impairment charge*:*

The impairment of property, plant and equipment, and any eventual reversal thereof, are recognized in depletion and depreciation in the statement of income.

(b) Contingencies:

Although the Company believes that it has title to its oil and natural gas properties, it cannot control or completely protect itself against the risk of title disputes or challenges.

7. Bank loan:

The Company's bank facility as at September 30, 2011 consisted of a revolving line of credit of $370 million and an operating line of credit of $30 million (the "Facility"). The Facility revolves for a 364 day period and will be subject to its next 364 day extension by June 11, 2012. If not extended, the Facility will cease to revolve, the margins thereunder will increase by 0.50 per cent and all outstanding advances thereunder will become repayable in one year. The available lending limits of the Facility are reviewed semi-annually and are based on the bank syndicate's interpretation of the Company's reserves and future commodity prices. The Company's bank syndicate has completed its most recent borrowing base review and is finalizing approvals on an increase in the Company's facility to $430 million. The increased credit facility will include a revolving line of credit of $400 million and an operating line of credit of $30 million. There can be no assurance that the amount of the available Facility will not be adjusted at the next scheduled borrowing base review on or before June 11, 2012.

Advances under the Facility are available by way of prime rate loans with interest rates between 1.00 percent and 2.50 percent over the bank's prime lending rate and bankers' acceptances and LIBOR loans, which are subject to stamping fees and margins ranging from 2.00 percent to 3.50 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 0.50 percent to 0.875 percent depending upon the debt to EBITDA ratio.

As at September 30, 2011, the Company's applicable pricing included a 1.25 percent margin on prime lending and a 2.25 percent stamping fee and margin on bankers' acceptances and LIBOR loans along with a 0.563 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 September 30, 2011, the Company had issued letters of credit totaling $10.2 million (December 31, 2010 - $1.1 million). The effective interest rate on the Company's borrowings under its bank facility for the three months ended September 30, 2011 was 5.2% (2010 - 5.9%).

8. Other long-term obligations:

As part of a May 3, 2007 private company acquisition, the Company acquired several firm transportation agreements. These agreements had a fair value at the time of acquisition of $4.9 million liability. This amount was accounted for as part of the acquisition cost and is charged as a reduction to transportation expenses over the life of the contracts as they are incurred. The charge for the three months and nine months ended September 30, 2011 was $0.1 million and $0.3 million respectively (2010 - $0.2 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.

9. Decommissioning obligations:

	As at September 30, 2011	As at December 31, 2010
Decommissioning obligations, beginning of period	**$ 54,828**	$ 53,063
Obligations incurred	**4,920**	3,383
Obligations settled	**(661)**	(1,512)
Obligations divested	**(1,003)**	(5,212)
Obligations acquired (note 4)	**30,887**	-
Change in estimates	**8,751**	3,141
Accretion of decommissioning liabilities	**1,743**	1,965
Decommissioning obligations, end of period	**$ 99,465**	$ 54,828

The Company's decommissioning obligations result from its ownership interest in oil and natural gas assets including well sites and facilities. The total decommissioning obligation is estimated based on the Company's net ownership interest in all wells and facilities, estimated costs to reclaim and abandon these wells and facilities and the estimated timing of the costs to be incurred in future years. The Company has estimated the net present value of the decommissioning obligations to be $99.5 million as at September 30, 2011 (December 31, 2010 - $54.8 million) based on an undiscounted total future liability of $108.3 million (December 31, 2010 - $63.4 million). These payments are expected to be made over the next 25 years with the majority of costs to be incurred between 2012 and 2036. The discount factor, being the risk-free rate related to the liability, is 2.70% (December 31, 2010 – 3.50%).

10. Share capital:

At September 30, 2011, the Company was authorized to issue an unlimited number of common shares with the holders of common shares entitled to one vote per share.

Share based payments:

The Company has an option program that entitles officers, directors, employees and certain consultants to purchase shares in the Company. Options are granted at the market price of the shares at the date of grant, have a four year term and vest over three years.

The number and weighted average exercise prices of share options are as follows:

	Number of options	Weighted average exercise price
Balance January 1, 2010	5,751	$ 8.33
Granted	2,237	$ 15.18
Exercised	(2,216)	$ 9.28
Forfeited	(442)	$ 9.50
Balance December 31, 2010	5,330	$ 10.79
Granted	3,938	$ 16.40
Exercised	(802)	$ 9.25
Forfeited	(615)	$ 17.23
Balance at September 30, 2011	7,851	$ 13.26

The following table summarizes information about the stock options outstanding at September 30, 2011:

Range of exercise prices	Outstanding at September 30, 2011	Weighted average remaining life (years)	Weighted average exercise price	Exercisable at September 30, 2011	Weighted average exercise price
$ 3.43 to $ 7.01	1,020	1.3	$ 5.16	590	$ 5.17
$ 7.02 to $ 9.94	1,055	0.4	$ 7.48	1,000	$ 7.38
$ 9.95 to $14.63	516	2.9	$ 12.29	152	$ 12.96
$14.64 to $19.40	5,260	3.1	$ 16.08	743	$ 15.30
	7,851	2.4	$ 13.26	2,485	$ 9.58

The fair value of the options was estimated using a Black Scholes model with the following weighted average inputs:

Assumptions	**Three months ended September 30, 2011**	Three months ended, September 30, 2010	**Nine months ended September 30, 2011**	Nine months ended, September 30, 2010
Risk free interest rate (%)	**1.9**	1.9	**2.2**	2.3
Expected life (years)	**4.0**	4.0	**4.0**	4.0
Expected volatility (%)	**60**	61	**60**	61
Forfeiture rate (%)	**16.7**	17.3	**16.4**	17.3
Weighted average fair value of options	**$ 6.76**	$ 7.07	**$ 7.77**	$ 8.03

Net income per share:

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 September 30, 2011 was 119,595,000 (2010 – 80,129,000) and for the nine month period ended September 30, 2011, the weighted average number of shares outstanding was 96,069,000 (2010 – 79,561,000).

In computing diluted earnings per share for the three month period ended September 30, 2011, 1,091,000 (2010 – nil) were added to the weighted average Common Shares outstanding to account for the dilution of stock options and for the nine month period ended September 30, 2011, 1,334,000 (2010 – 1,983,000) were added to the weighted average number of common shares for the dilution. There were 2,145,000 (2010 – 5,492,000) stock options that were not included in the diluted earnings per share calculation because they were anti-dilutive.

11. Derivative contracts and capital management:

(a) Derivative contracts:

It is the Company's policy to economically hedge some oil and natural gas sales through the use of various financial derivative forward sales contracts and physical sales contracts. The Company does not apply hedge accounting for these contracts. The Company's production is usually sold using "spot" or near term contracts, with prices fixed at the time of transfer of custody or on the basis of a monthly average market price. The Company, however, may give consideration in certain circumstances to the appropriateness of entering into long term, fixed price marketing contracts. The Company does not enter into commodity contracts other than to meet the Company's expected sale requirements.

At September 30, 2011, the Company held derivative commodity contracts as follows:

Subject of Contract	Notional Quantity	Term	Reference	Strike Price	Option Traded	Fair Value ($000s)
Natural Gas	2,500 gj/day	January 1, 2011 – December 31, 2011	AECO C Monthly Index	$4.85	Swap(1)	313
Natural Gas	2,500 gj/day	January 1, 2011 – December 31, 2011	AECO C Monthly Index	$4.90	Swap(1)	322
Natural Gas	2,500 gj/day	January 1, 2011 – December 31, 2011	AECO C Monthly Index	$4.95	Swap(1)	333
Natural Gas	2,500 gj/day	January 1, 2011 – December 31, 2011	AECO C Monthly Index	$4.965	Swap(1)	448
Natural Gas	7,500 gj/day	January 1, 2011 – December 31, 2011	AECO C Monthly Index	$5.00	Swap(1)	1,160

Oil	500 bbl/day	January 1, 2011 – December 31, 2011	US$ WTI	US$80.15	Swap	37
Oil	250 bbl/day	January 1, 2011 – December 31, 2011	CDN$ WTI	$86.00	Swap	64
Oil	500 bbl/day	January 1, 2011 – December 31, 2011	CDN$ WTI	$88.00	Swap	233
Oil	250 bbl/day	January 1, 2011 – December 31, 2011	CDN$ WTI	$88.50	Swap	140
Oil	250 bbl/day	January 1, 2011 – December 31, 2011	CDN$ WTI	$90.00	Swap	155
Oil	500 bbl/day	January 1, 2011 – December 31, 2011	CDN$ WTI	$90.20	Swap	317
Oil	250 bbl/day	January 1, 2011 – December 31, 2011	CDN$ WTI	$80.00 - $95.45	Collar	54
Oil	250 bbl/day	January 1, 2011 – December 31, 2011	CDN$ WTI	$82.00 - $94.62	Collar	56
Oil	250 bbl/day	January 1, 2011 – December 31, 2011	CDN$ WTI	$85.00 - $100.50	Collar	118
Oil	1,000bbl/day	July 1, 2011 – December 31, 2011	CDN$ WTI	$75.00 - $100.00	Collar	174
Oil	1,000bbl/day	July 1, 2011 – December 31, 2011	CDN$ WTI	$80.00 - $98.50	Collar	292
Oil	1,000bbl/day	July 1, 2011 – December 31, 2011	CDN$ WTI	$89.75	Swap	709
Oil	500 bbl/day	January 1, 2012 – December 31, 2012	US$ WTI	US$85.00	Call[1]	(1,738)
Oil	750 bbl/day	January 1, 2012 – December 31, 2012	CDN$ WTI	$90.00	Call[1]	(2,199)
Oil	500 bbl/day	January 1, 2012 – December 31, 2012	US$ WTI	US$90.00	Call[1]	(1,418)
Oil	500 bbl/day	January 1, 2012 – December 31, 2012	CDN$ WTI	$100.45	Swap	1,377
Oil	500 bbl/day	January 1, 2012 – December 31, 2012	CDN$ WTI	$101.00	Swap	2,847
Oil	250 bbl/day	January 1, 2012 – December 31, 2012	CDN$ WTI	$100.50	Swap	1,382
Oil	250 bbl/day	January 1, 2012 – December 31, 2012	USD$ WTI	$85.00 - $93.55	Collar	671
Oil	500 bbl/day	January 1, 2012 – December 31, 2012	CDN$ WTI	$85.00 - $93.25	Collar	623
Oil	1,000 bbl/day	January 1, 2012 – December 31, 2012	CDN$ WCS – WTI Diff	$17.50	Swap	(446)
						6,024

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

Subsequent to September 30, 2011, the Company entered into the following financial instrument contracts:

Subject of Contract	Volume	Term	Reference	Strike Price (per bbl)	Option Traded
Oil	1,000 bbl/day	January 1, 2012 – December 31, 2012	CDN$ WTI	$85.00 - $95.00	Collar
Oil	500 bbl/day	January 1, 2012 – December 31, 2012	CDN$ WTI	$85.00 - $94.50	Collar
Oil	1,000 bbl/day	January 1, 2012 – December 31, 2012	CDN$ WTI	$94.00	Swap
Oil	1,000 bbl/day	January 1, 2012 – December 31, 2012	CDN$ WCS – WTI Diff	$15.75	Swap
US$ / CAD$ exchange	Sell US $1.0 mm per month	January 1, 2012 – December 31, 2012	CDN$/US$	1.0531	Swap
US$ / CAD$ exchange	Buy US $1.0 mm per month	January 1, 2012 – December 31, 2012	CDN$/US$	1.037	Swap

(b) Capital management:

The Company's policy is to maintain a strong capital base so as to maintain investor, creditor and market confidence and to sustain future development of the business. The Company manages its capital structure and makes adjustments to it in light of changes in economic conditions and risk characteristics of the underlying oil and natural gas assets. The Company considers its capital structure to include shareholders' equity, bank loans and working capital. In order to maintain or adjust the capital structure, the Company may issue shares and adjust its capital spending to manage current and projected debt levels.

The Company monitors capital based on the ratio of net debt to annualized cash flow. This ratio is calculated as net debt, defined as outstanding bank loans plus or minus working capital, divided by cash flow from operations before decommissioning obligations settled, transportation liability charges, acquisition costs and changes in non-cash working capital for the most recent calendar quarter and then annualized. The Company's strategy is to maintain a ratio of no more than 2 to 1. This ratio may increase at certain times as a result of acquisitions. In order to facilitate the management of this ratio, the Company prepares annual capital expenditure budgets, which are updated as necessary depending on varying factors including current and forecast prices, successful capital deployment and general industry conditions. The annual and updated budgets are approved by the Board of Directors.

As at September 30, 2011, the Company's ratio of net debt to annualized cash flow was 1.36 to 1, (December 31, 2010 – 1.63 to 1) within the range established by the Company. There were no changes in the Company's approach to capital management during the period.

	September 30, 2011	December 31, 2010
Net debt:		
Accounts receivable (including assets held for sale)	**$ 80,054**	$ 60,038
Accounts payable and accrued liabilities	**(180,605)**	(100,745)
Working capital deficiency	**$ (100,551)**	$ (40,707)
Bank loan	**(194,038)**	(138,700)
Net debt	**$ (294,589)**	$ (179,407)
Annualized funds from operations:		
Cash provided by operating activities	**$ 54,095**	$ 20,225
Decommissioning obligations settled	**540**	606
Transportation liability charge	**104**	120
Acquisition costs	**455**	-
Change in non-cash working capital	**(934)**	6,498
Funds from operations	**54,260**	27,449
Annualized	**$ 217,040**	$ 109,796
Net debt to annualized funds from operations	**1.36**	1.63

Neither the Company nor any of its subsidiaries are subject to externally imposed capital requirements. The credit facilities are subject to a semi-annual review of the borrowing base which is directly impacted by the value of the oil and natural gas reserves.

12. Supplemental cash flow information:

Changes in non-cash working capital is comprised of:

	Three months ended September 30, 2011	Three months ended September 30, 2010	**Nine months ended September 30, 2011**	Nine months ended September 30, 2010
Changes in non-cash working capital:				
Accounts receivable	**$ (37,802)**	$ (13,548)	**$ (35,132)**	$ (5,608)
Accounts payable and accrued liabilities	**98,176**	14,794	**79,860**	(4,914)
Non-cash working capital acquired	**(14,670)**	-	**(14,670)**	-
	$ 45,704	$ 1,246	**$ 30,058**	$ (10,522)
Operating activities	**$ 934**	$ (4,151)	**$ 9,772**	$ 4,488
Investing activities	**44,770**	5,397	**20,286**	(15,010)
	$ 45,704	$ 1,246	**$ 30,058**	$ (10,522)
Interest paid	**$ (1,536)**	$ (1,325)	**$ (4,262)**	$ (3,887)

13. Financing:

	Three months ended September 30, 2011	Three months ended September 30, 2010	**Nine months ended September 30, 2011**	Nine months ended September 30, 2010
Accretion of decommissioning obligations	**$ 737**	$ 479	**$ 1,743**	$ 1,488
Interest expense	**2,049**	1,188	**4,775**	4,370
Acquisition costs	**455**	-	**2,605**	-
	$ 3,241	$ 1,667	**$ 9,123**	$ 5,858

Acquisition costs relate to the Company's acquisition of Caltex Energy Inc. (note 4).

14. Commitments:

	Total	2011	2012	2013	2014	2015	There-

							after
Operating Leases	$14,008	$592	$3,796	$2,210	$2,340	$2,470	$2,600
Capital commitments	2,100	-	2,100	-	-	-	-
Firm trans-portation agreements	19,631	1,613	1,535	1,535	2,110	2,110	10,728
Firm processing agreement	73,055	1,645	6,526	6,526	8,239	8,239	41,880
Total	$108,794	$3,850	$13,957	$10,271	$12,689	$12,819	$55,208

The operating leases include the Company's contractual obligation to a third party for its new five year lease of additional office space.

The transportation agreements include an $18.4 million commitment to a third party to transport natural gas from a gas processing facility in the Septimus area to the Alliance pipeline system. The remaining commitment relates to firm transportation commitments that were acquired as part of the Company's May 2007 private company acquisition. In 2010, the Company permanently assigned approximately $6.2 million of its firm commitments to third parties.

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

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

15. Reconciliation of equity and income from previous GAAP to IFRS:

These interim consolidated financial statements are the Company's third under IFRS.

The adoption of IFRS requires the application of IFRS 1. IFRS 1 generally requires that an entity retrospectively apply all IFRS effective at the end of its first IFRS reporting period; however IFRS 1 provides certain mandatory exceptions and permits limited optional exemptions. Certain IFRS 1 optional exemptions have been applied including:

- Deemed cost exemption for full cost oil and gas entities whereby exploration and evaluation assets were classified from the full cost pool to intangible exploration assets at the amount that was recorded under previous GAAP and the remaining full cost pool was allocated to the development assets and components pro rata using reserve values.
- Decommissioning obligation exemption that allows any changes in decommissioning obligations on transition to IFRS to be adjusted through opening retained earnings.
- Stock-based compensation exemption that allows a company to only evaluate share based compensation awards that were unvested as of the date of transition and that were issued subsequent to November 7, 2002.
- Business combinations exemption that allows a company to not restate any business combinations that occurred prior to the date of transition.

The accounting policies in note 3 of the interim consolidated financial statements for the three months ended March 31, 2011 have been applied in preparing the interim consolidated financial statements for the three and nine months ended September 30, 2011 and the comparative information for the three and nine months ended September 30, 2010.

In preparing comparative information for the three and nine months ended September 30, 2010, the Company adjusted amounts previously reported in financial statements prepared in accordance with previous GAAP. An explanation of how the transition from previous GAAP to IFRS has affected the Company's financial position, financial performance and cash flows is set out in the following tables and the notes accompanying the tables.

As at September 30, 2010:

	Previous GAAP	Effect of transition to IFRS	Note	IFRS
Assets				
Current Assets:				
Accounts receivable	**$ 43,182**	$ -		$ 43,182
Fair value of financial instruments	**4,372**	-		4,372
	47,554	-		47,554
Exploration and evaluation assets	**-**	72,617	B	72,617
Property, plant and equipment	**898,413**	(20,917	)B,C,F	877,496
	$ 945,967	$ 51,700		$ 997,667
Liabilities and Shareholders' Equity				
Current Liabilities:				

Accounts payable and accrued liabilities	**$ 79,314**	$ -		$ 79,314
Deferred tax liability	**991**	(991)	A	-
Current portion of other long-term obligations	**463**	-		463
	80,768	(991)		79,777
Bank loan	**110,770**	-		110,770
Decommissioning obligations	**33,735**	17,320	D	51,055
Deferred tax liability	**98,425**	8,481	E	106,906
Shareholders' Equity				
Share capital	**643,917**	3,383	E	647,300
Contributed surplus	**22,082**	3,191	G	25,273
Deficit	**(43,730)**	20,316		(23,414)
	622,269	26,890		649,159
	$ 945,967	$ 51,700		$ 997,667

Reconciliation of consolidated statement of income (loss) for the three months ended September 30, 2010:

	Previous GAAP	Effect of transition to IFRS	Note	IFRS
Revenue				
Gross petroleum and natural gas sales	**$ 44,924**	$ -		$ 44,924
Royalties	**(8,920)**	-		(8,920)
Realized gain on financial instruments	**5,114**	-		5,114
Unrealized loss on financial instruments	**(5,326)**	-		(5,326)
	35,792	-		35,792
Expenses				
Operating	**12,318**	-		12,318
Transportation	**2,243**	-		2,243
General and administrative	**1,265**	640	H	1,905
Share-based compensation	**1,034**	322	G	1,356
Depletion and depreciation	**27,711**	(7,379)	C	20,332
	44,571	(6,417)		38,154
Income (loss) from operations	**(8,779)**	6,417		(2,362)
Financing	**(1,188)**	(479)	D	(1,667)
Impairment of property, plant and equipment	**-**	(18,736)	I	(18,736)
Net loss before taxes	**(9,967)**	(12,798)		(22,765)
Deferred tax expense (recovery)	**(2,580)**	(2,904)	E	(5,484)
Net loss and comprehensive loss	**$ (7,387)**	$ (9,894)		$ (17,281)
Net loss per share				
Basic	**$ (0.09)**			$ (0.22)
Diluted	**$ (0.09)**			$ (0.22)

Reconciliation of consolidated statement of income (loss) for the nine months ended September 30, 2010:

	Previous GAAP	Effect of transition to IFRS	Note	IFRS
Revenue				
Gross petroleum and natural gas sales	**$ 149,723**	$ -		$ 149,723
Royalties	**(30,488)**	-		(30,488)
Realized gain on financial instruments	**9,798**	-		9,798
Unrealized gain on financial instruments	**5,206**	-		5,206
	134,239	-		134,239
Expenses				
Operating	**39,967**	-		39,967
Transportation	**6,763**	-		6,763
General and administrative	**4,575**	2,257	H	6,832
Share-based compensation	**3,424**	519	G	3,943

Depletion and depreciation	**85,478**	(27,559	)C	57,919
	140,207	(24,783	)	115,424
Income (loss) from operations	**(5,968**	**)**24,783		18,815
Financing	**(4,370**	**)**(1,488	)D	(5,858)
Gain on divestitures	**-**	48,242	F	48,242
Impairment of plant, property and equipment	**-**	(18,736	)I	(18,736)
Net income (loss) before taxes	**(10,338**	**)**52,801		42,463
Deferred tax expense (recovery)	**(2,702**	**)**13,132	E	10,430
Net income (loss) and comprehensive income (loss)	$ **(7,636**	**)**$ 39,669		$ 32,033
Net income (loss) per share				
Basic	**$ (0.10**	**)**		$ 0.40
Diluted	**$ (0.10**	**)**		$ 0.39

Impact of Transition to IFRS on 2010 Results:

1. Under IFRS, all deferred tax assets and liabilities are classified as long-term. Under previous GAAP, deferred tax assets and liabilities were presented according to the classification of the underlying asset or liability that created the difference in the deferred tax amount.

2. Exploration and Evaluation assets – As required under IFRS 6, the Company reclassified $72.6 million at September 30, 2010.

3. Depletion and depreciation expense – Under IFRS, Crew has chosen to calculate depletion expense based on proved plus probable reserves as opposed to proved reserves under previous GAAP. This has resulted in a reduction of depletion and depreciation expense of approximately $7.4 million for the three months ended September 30, 2010 and $27.6 million for the nine months ended September 30, 2010.

4. Decommissioning obligations – Under previous GAAP, Crew's decommissioning obligations were discounted based on a credit adjusted risk-free rate which was 8-10% at December 31, 2009. Under IFRS, the Company is required to revalue its obligation at each balance sheet date using a current liability-specific discount rate. At transition, Crew revalued the obligation based on a risk-free rate of 4%, resulting in a $17.7 million increase (net of tax) to the liability, with the offset charged to retained earnings.

   As a result of the change in the discount rate applied, accretion of decommissioning obligation expense decreased by $161,000 for the three months ended September 30, 2010 and $513,000 for the nine months ended September 30, 2010.

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

   An additional deferred tax expense of $2.9 million for the three months and $13.1 million for the nine months ended September 30, 2010 was recognized as a result of changes in the temporary difference between the net book value and the tax basis of the assets and liabilities due to other adjustments discussed.

6. Divestitures – Under previous GAAP, proceeds from divestitures were deducted from the full cost pool without recognition of a gain or loss unless the divestiture resulted in a change in the depletion rate of 20% or greater in which case, a gain or loss was recorded. Under IFRS, gains and losses are recorded on divestitures and are calculated as the difference between the proceeds and the net book value of the asset disposed of. A gain on disposition of oil and gas properties of $48.2 million for the nine months ended September 30, 2010 was recorded under IFRS compared to nil under previous GAAP.

7. Under previous GAAP, Crew expensed stock-based compensation on a straight-line basis. Under IFRS, share-based payments are expensed based on a graded vesting schedule. Crew also incorporated a forfeiture multiplier rather than accounting for forfeitures as they occur as practiced under previous GAAP. At December 31, 2010, the adjustment to contributed surplus to account for the graded vesting and forfeitures was an increase of $2.7 million with the offset being charged to retained earnings. During the three and nine months ended September 30, 2010 Crew recognized an additional $0.3 million and $0.5 million of additional stock-based compensation to account for the graded vesting and forfeitures.

8. Under IFRS, the criteria for which general and administrative expenses ("G&A") can be capitalized is different than previous GAAP and as a result a greater portion of G&A costs have been expensed. This resulted in an additional $0.6 million of G&A expenses being recorded for the three months ended September 30, 2010 and $2.3 million for the nine months ended September 30, 2010.
9. Under IFRS, impairment tests of property, plant and equipment are performed at the CGU level, which is the smallest identifiable grouping of assets that generates largely independent cash inflows. The impairment assessment is based on the recoverable amount, which is the greater of value in use or fair value less costs to sell, compared with the asset's carrying amount. Under previous GAAP, impairment tests of property, plant and equipment are performed on the entire balance and is assessed based on the estimated undiscounted future cash flows compared with carrying amount and if impairment is indicated, discounted cash flows are used to quantify the amount of the impairment.

   Crew determined the recoverable amount using value in use based on discounted future cash flows of proved plus probable reserves using forecast prices and costs. In the periods ending September 30, 2010, an impairment charge of $18.8 million was recognized as a result of low forecast natural gas pricing. Under IFRS, property, plant and equipment impairments can be reversed in the future if the recoverable amount increases.

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