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Q2 2013

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Crew Energy Inc. ("Crew" or the "Company") is pleased to present its operating and financial results for the three and six month period ended June 30, 2013.

HIGHLIGHTS

- Funds from operations were $48.1 million or $0.40 per share, a 43% increase over the first quarter of 2013;
- Second quarter production averaged 27,109 boe per day or 4% higher than the 25,961 boe per day produced in the first quarter of 2013;
- Reduced net debt by $23.2 million to $315.7 million or 1.6x annualized second quarter funds from operations;
- Reduced operating costs by 11% over the first quarter of 2013 to $10.76 per boe;
- Recently completed three Septimus, British Columbia Montney wells which were drilled during the second quarter in the new Montney "A" zone which have seven day production tests of 7.6 mmcf per day and 205 bbls per day of ngls, 6.5 mmcf per day and 182 bbls per day of ngls and 6.2 mmcf per day and 170 bbls per day of ngls;
- Subsequent to the quarter-end, closed the acquisition of 81 additional Montney sections bringing Crew's aggregate holdings to 373 net sections of Montney rights in northeast British Columbia and adding 15 TCFE of Total Petroleum Initially in Place ("TPIIP") for a total of 91 TCFE of TPIIP. The Company's July 9, 2013 press release has complete details of the independently completed Montney Resource Evaluation;
- Crew continues with its front-end engineering work to significantly increase natural gas processing capacity in the Septimus area with plans to increase its takeaway capacity from its present capacity of 45 mmcf per day to up to 180 mmcf per day.

Financial *($ thousands, except per share amounts)*	**Three months ended June 30, 2013**	Three months ended June 30, 2012	**Six months ended June 30, 2013**	Six months ended June 30, 2012
Petroleum and natural gas sales	**110,793**	99,946	**202,060**	223,021
Funds from operations (1)	**48,087**	52,027	**82,275**	100,084
Per share – basic	**0.40**	0.43	**0.68**	0.83
– diluted	**0.40**	0.43	**0.68**	0.83
Net income (loss)	**2,007**	24,107	**(20,040)**	17,677
Per share – basic	**0.02**	0.20	**(0.16)**	0.15
– diluted	**0.02**	0.20	**(0.16)**	0.15
Exploration and Development expenditures	**30,348**	30,432	**95,600**	159,175
Property acquisitions (net of dispositions)	**(5,717)**	(4,290)	**8,946**	(4,290)
Net capital expenditures	**24,631**	26,142	**104,546**	154,885
Capital Structure *($ thousands)*			**As at June 30, 2013**	As at Dec. 31, 2012
Working capital deficiency (2)			**27,991**	48,522
Bank loan			**287,687**	242,834
Net debt			**315,678**	291,356
Current bank facility			**430,000**	400,000
Common Shares Outstanding *(thousands)*			**121,635**	121,620

(1) Funds from operations is calculated as cash provided by operating activities, adding the change in non-cash working capital, decommissioning obligation expenditures and the transportation liability charge. Funds from operations is used to analyze the Company's operating performance and leverage. Funds from operations does not have a standardized measure prescribed by 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 less accounts payable and accrued liabilities.

Operations	**Three months ended June 30, 2013**	Three months ended June 30, 2012	**Six months ended June 30, 2013**	Six months ended June 30, 2012
Daily production [1]				
Princess and other oil (bbl/d)	**4,561**	5,940	**4,748**	6,355
Lloydminster oil (bbl/d)	**5,981**	6,040	**5,712**	6,101
Natural gas liquids (bbl/d)	**3,085**	2,809	**3,035**	2,957
Natural gas (mcf/d)	**80,893**	80,419	**78,259**	83,237
Oil equivalent (boe/d @ 6:1)	**27,109**	28,192	**26,538**	29,286
Average prices [1 & 2]				
Princess and other oil ($/bbl)	**74.85**	70.41	**69.43**	76.11
Lloydminster oil ($/bbl)	**67.50**	58.95	**59.50**	65.05
Natural gas liquids ($/bbl)	**52.16**	56.27	**53.27**	54.58
Natural gas ($/mcf)	**3.85**	2.06	**3.64**	2.20
Oil equivalent ($/boe)	**44.91**	38.96	**42.07**	41.84
Netback ($/boe)				
Revenue	**44.91**	38.96	**42.07**	41.84
Realized commodity hedging gain (loss)	**(1.74)**	5.94	**(1.16)**	3.12
Royalties	**(8.52)**	(8.86)	**(7.98)**	(10.05)
Operating costs	**(10.76)**	(11.32)	**(11.38)**	(11.75)
Transportation costs	**(1.26)**	(1.39)	**(1.26)**	(1.38)
Operating netback [3]	**22.63**	23.33	**20.29**	21.78
G&A	**(1.93)**	(1.68)	**(1.96)**	(1.80)
Interest on bank debt	**(1.21)**	(1.37)	**(1.20)**	(1.21)
Funds from operations	**19.49**	20.28	**17.13**	18.77
Drilling Activity				
Gross wells	**3**	3	**42**	63
Working interest wells	**3.0**	1.6	**39.8**	59.4
Success rate, net wells	**100%**	100%	**100%**	97%

(1) Princess, Alberta oil (200 to 260 API oil) has historically been classified as medium or conventional oil. Effective December 31, 2012 Crew's reserves attributable to its Princess property have been classified as heavy oil to accord with definitions in the royalty regulations in Alberta. Princess and other oil production and pricing are shown separately from Lloydminster heavy oil volumes for clarity and comparison with historical classification.

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

(3) 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

During the second quarter, operations and drilling activity were reduced due to spring break-up. The Company continued to follow its disciplined approach to exploration and development, spending $30.3 million or 13% less than originally budgeted. Drilling activity during the quarter included three (3.0 net) wells at Septimus resulting in three natural gas wells. The Company completed three wells at Septimus and three wells at Lloydminster and also recompleted 18 wells at Lloydminster. In addition, during the quarter the Company exercised its option to purchase 81 additional net sections of Montney acreage in northeastern British Columbia for $35.2 million which closed in early July.

Unplanned third party facility outages in the Deep Basin area impacted second quarter production by 650 boe per day while production increased 4% over the first quarter of 2013 to average 27,109 boe per day. Production additions were the result of the Company's successful first quarter drilling program at Septimus, Princess and Lloydminster.

The June floods that caused major damage in southern Alberta resulted in restricted access to downtown Calgary for the week following the flood, including Crew's head office. The Company activated its business continuity plan and all critical systems, communications and business functions continued at remote or disaster recovery sites and therefore Crew's operations were minimally affected by the floods.

FINANCIAL

The Company's second quarter funds from operations increased 43% over the first quarter 2013 to $48.1 million or $0.40 per share. During the quarter, the Company's revenue benefited from stronger oil prices, narrower West Texas Intermediate ("WTI") to Western Canadian Select ("WCS") differentials and increased natural gas prices. Crew also successfully decreased its operating, transportation and general and administrative costs per boe by 9% as compared to the prior quarter which enhanced its funds from operations netback. After non-core property dispositions of $5.7 million, net capital expenditures were $24.6 million which allowed the Company to decrease its net debt by 7% to $316 million.

Revenue was bolstered by stronger oil and gas prices during the second quarter. Canadian dollar WTI averaged $96.43 per bbl for the second quarter, slightly up from the $95.20 in the first quarter. More importantly for the Company, the differential between WCS and WTI narrowed substantially during the quarter resulting in a 22% quarter over quarter increase in Crew's WCS oil benchmark price. Crew's Lloydminster heavy oil pricing was further enhanced in the second quarter by seasonally reduced blending costs. During the second quarter, AECO natural gas prices continued to benefit from an extended winter and decreased storage levels. The AECO benchmark increased 11% over the first quarter to average $3.59 per mcf.

The Company's hedging strategy is focused on partially protecting against significant declines in commodity prices that would negatively impact the cash flow needed to fund the Company's on-going capital program. Crew currently has hedged approximately 49% of its forecasted 2013 natural gas production at a price of approximately $3.22 per mcf. The Company also protects its liquids production from a significant decline in WTI and WCS pricing. Crew has approximately 43% of its forecasted 2013 liquids production protected against a decline in WTI pricing with hedged prices fixed at a floor of approximately $93.26 per barrel. The Company has hedged the differential between WTI and WCS pricing on 4,200 barrels per day at a differential of $21.08 for the second quarter of 2013, 5,329 barrels per day at $22.39 for the third quarter and 4,250 barrels per day at $22.67 for the fourth quarter. Crew has begun building its hedge position to provide a base level of cash flow for 2014. The Company currently has hedged approximately 16.6 mmcf per day of natural gas for 2014 at a price of approximately $3.83 per mcf, 3,000 barrels per day of WTI oil hedged at an average floor price of approximately $96.51 per barrel with additional hedges fixing the differential between WTI and WCS pricing on an average of 1,000 barrels per day at a differential of $22.75 per barrel.

OPERATIONS UPDATE

Septimus/Tower, British Columbia

Septimus area production for the quarter averaged 7,480 boe per day, up 21% from the first quarter and achieving yet another record for the area. Current production is in the 7,500 to 8,000 boe per day range based on field estimates with approximately 1,400 boe per day behind pipe as we are now running at the current capacity of the Septimus gas plant. Installation of the fourth compressor is on track for commissioning and start-up in the fourth quarter which will increase our processing capacity from the current level of approximately 45 mmcf per day to approximately 65 mmcf per day. Concurrent with the plant expansion, Crew is installing a 22.5 kilometer 10" pipeline from the western portion of the property to the gas plant. The Company anticipates achieving full utilization of this capacity by the end of the first quarter 2014.

The Company has been proving additional zones within the Montney to be productive. Crew drilled three (3.0 net) wells in the top of the Upper Montney (Montney "A" zone) with excellent results. The three wells had seven day production tests of 7.6 mmcf per day and 205 bbls per day of ngls, 6.5 mmcf per day and 182 bbls per day of ngls and 6.2 mmcf per day and 170 bbls per day of ngls. The Company has 29 unbooked locations in the Montney "A" on a 15 section block at Septimus. As the completion technology continues to evolve at Septimus, it has become apparent that a number of wells drilled early in the life of the project were not optimally completed. Crew has undertaken one of the first workovers in the area by successfully installing a frac port liner into an existing Montney horizontal well competed in 2009 with a plug and perf completion. The well was re-fractured and came on production at 2.2 mmcf per day (428 boe per day), ten times greater than the well's average production rate, in the first quarter of 2013 and four times greater than the peak initial production of the well in December of 2009. The net workover cost was approximately $1.5 million. The Company is in the process of identifying additional candidates where this technique can be applied.

Deep Basin, Alberta

Deep Basin production in the second quarter was 5,410 boe per day as unplanned third party plant outages and extended turnarounds experienced in the first quarter continued into the second and early third quarter, impacting production in the second quarter by approximately 650 boe per day. No new wells were drilled in the quarter, and two Cardium horizontal well completions at Elmworth originally planned for second quarter were not undertaken until early in the third quarter due to spring road bans being extended into the third quarter. Current production in the Deep Basin is 6,000 to 6,500 boe per day based on field estimates with all third party facilities operating as of the first week of August.

Princess, Alberta

Production for the second quarter averaged 5,500 boe per day with no new wells drilled and no completions undertaken due to spring break-up, high rainfall and approximately 150 boe per day of third party facility downtime. Two additional waterfloods were initiated in the quarter bringing the total to 11 pools currently on injection (approximately 40% of the developed Pekisko resource is now under waterflood). Crew is currently drilling the first of two 100% working interest wells targeting oil from the Mannville. Crew has 60 sections of Crown mineral rights that are prospective for Mannville oil at Princess.

Lloydminster, Saskatchewan

Production for the Lloydminster area averaged 6,015 boe per day for the quarter as the impact of spring break-up was not as significant as initially expected. However, the spring conditions did limit rig activity as no new wells were drilled, only three wells were completed and 18 wells recompleted. Current production levels are between 6,000 and 6,500 boe per day based on field estimates.

OUTLOOK

Crew is maintaining annual guidance to average 27,500 to 28,500 boe per day, exploration and development capital budget at $219 million as well as exit guidance of 29,000 to 30,000 boe per day as production is forecasted to steadily increase through the remainder of the year. Funds from operations was markedly improved over the first quarter as a result of higher production and higher realized product prices. Funds from operations increased to $48.1 million or $0.40 per share up 43% from $0.28 per share in the first quarter. Crew maintained its capital discipline in the second quarter spending $30.3 million on exploration and development activities, 13% less than budgeted while reducing net debt by $22.5 million to 1.6 times annualized second quarter funds from operations.

The Company's move to capture resource continued in northeastern British Columbia by closing the third tranche of our Montney acquisition in July for $35.2 million which added 15 TCFE of TPIIP to Crew's resource inventory. Crew now has 91 TCFE of TPIIP resource in the Montney formation comprised of 44.6 TCF of natural gas and 7.8 billion barrels of oil. We plan to continue to increase production from the current 8,000 boe per day to an estimated 10,000 boe per day in the first quarter of 2014 once the Septimus gas plant has been expanded to 65 mmcf per day of capacity. We will also advance the de-risking of our land base through the planned drilling of five exploratory horizontal wells over the next six months. Crew now has five drilling rigs running and expects to drill over 50 wells in the last half of 2013 as well as recompleting over 40 wells.

The Company will continue to divest of non-core assets to fund production growth in its core areas as well as actively engage in asset swaps to further concentrate our asset base. Crew's capital program will be funded by funds from operations, long-term debt and minor asset dispositions.

Oil prices have continued to strengthen as the WTI/Brent and WTI/WCS differentials have narrowed significantly over the first half of the year resulting in much improved price realizations. This has been partially offset by an approximate $0.50 per mcf reduction in realized natural gas prices. We are currently forecasting realized oil prices to be approximately $6 per bbl higher and natural gas prices to be $0.50 per mcf lower in the third quarter. When combined with higher forecasted production, funds from operations is expected to again be strong in the third quarter. Crew has a very active third quarter planned which we look forward to reporting in November.

Our thoughts are with those who were affected by the floods in southern Alberta. We would like to commend our staff and the people of southern Alberta for their resolve and community spirit in helping in this time of need.

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" "forecast" and similar expressions are intended to identify forward-looking information or statements. In particular, but without limiting the foregoing, this news release contains forward-looking information and statements pertaining to the following: the volume and product mix of Crew's oil and gas production; production estimates including 2013 forecast average and exit production and first quarter 2014 production estimates at Septimus; 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; increased processing capacity at Septimus; the total future capital associated with development of reserves and resources; and methods of funding our capital program, including possible non-core asset divestitures and asset swaps.

Forward-looking statements or information are based on a number of material factors, expectations or assumptions of Crew which have been used to develop such statements and information but which may prove to be incorrect. Although Crew believes that the expectations reflected in such forward-looking statements or information are reasonable, undue reliance should not be placed on forward-looking statements because Crew can give no assurance that such expectations will prove to be correct. In addition to other factors and assumptions which may be identified herein, assumptions have been made regarding, among other things: the impact of increasing competition; the general stability of the economic and political environment in which Crew operates; the timely receipt of any required regulatory approvals; the ability of Crew to obtain qualified staff, equipment and services in a timely and cost efficient manner; drilling results; the ability of the operator of the projects in which Crew has an interest in to operate the field in a safe, efficient and effective manner; the ability of Crew to obtain financing on acceptable terms; field production rates and decline rates; the ability to replace and expand oil and natural gas reserves through acquisition, development and exploration; the timing and cost of pipeline, storage and facility construction and expansion and the ability of Crew to secure adequate product transportation; future commodity prices; currency, exchange and interest rates; regulatory framework regarding royalties, taxes and environmental matters in the jurisdictions in which Crew operates; the ability of Crew to successfully market its oil and natural gas products. There are a number of assumptions associated with the potential of resource volumes including the quality of the Montney reservoir, future drilling programs, continued performance from existing wells and performance of new wells, the growth of infrastructure, well density per section, and recovery factors and discovery and development necessarily involves known and unknown risks and uncertainties, including those identified in this press release.

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; the early stage of development of some areas in the Evaluated Areas; the potential for variation in the quality of the Montney formation; 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.

Test Results and Initial Production Rates

A pressure transient analysis or well-test interpretation has not been carried out and thus certain of the test results provided herein should be considered to be preliminary until such analysis or interpretation has been completed. Test results and initial production rates disclosed herein may not necessarily be indicative of long term performance or of ultimate recovery.

Resource Estimates

This news release contains references to estimates of oil and gas classified as Total Petroleum Initially In Place ("TPIIP") in the Montney region in northeastern British Columbia which are not, and should not be confused with, oil and gas reserves. Such estimates are based upon an independent resource evaluation effective as at May 1, 2013, prepared in accordance with the Canadian Oil and Gas Evaluation Handbook. Such estimates are subject to a number of cautionary statements, assumptions, risks, positive and negative factors relevant to the estimates and contingencies, the details of which were set forth in Crew's previously disseminated press release dated July 9, 2013. Accordingly, readers are referred to and encouraged to review the sections entitled "Montney Resource Evaluation", "Definitions of Oil and Gas Resources and Reserves" and "Information Regarding Disclosure on Oil and Gas Reserves, Resources and Operational Information" in the July 9, 2013 press release for applicable definitions, cautionary language, explanations and discussion of resources estimated herein, all of which is incorporated herein by reference.

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

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 six month periods ended June 30, 2013 and 2012 and the audited consolidated financial statements and Management Discussion and Analysis for the year ended December 31, 2012. The interim consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS"). There have been no significant changes to the critical estimates disclosed in the Company's audited financial statements for the year ended December 31, 2012. All figures provided herein and in the interim 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, and Crew's forecasts in respect of production and cash flow for 2013 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; 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. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6:1, utilizing a 6:1 conversion may be misleading as an indication of value.

Oil Classification

The Princess, Alberta property, which is an area that produces crude oil and associated liquids (ranging from 200 to 260 API), has historically been classified as medium oil by Crew's previous independent reserve evaluators. Effective December 31, 2012, Crew's reserves attributable to its Princess property have been classified by Crew's independent reserve evaluator as heavy oil to accord with definitions contained in the Canadian Oil and Gas Evaluation Handbook, specifically the guidelines related to heavy oil designations contained in the royalty regulations for the Province of Alberta. We have presented Princess and other oil production and revenue separately from our Lloydminster heavy oil in this MD&A for greater clarity as they have historically been classified separately as medium or conventional oil and most volumes would be classified as light and medium oil were it not for the specific royalty regime existing in the province of Alberta.

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 and decommissioning obligation expenditures. 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:

	Three months ended		Six months ended	
($ thousands)	**June 30, 2013**	June 30, 2012	**June 30, 2013**	June 30, 2012
Cash provided by operating activities	**44,486**	49,557	**70,401**	115,783
Decommissioning obligation expenditures	**355**	371	**2,135**	550
Change in non-cash working capital	**3,246**	2,099	**9,739**	(16,249)
Funds from operations	**48,087**	52,027	**82,275**	100,084

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. The calculation of Crew's netbacks can be seen 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)	**June 30, 2013**	December 31, 2012
Current assets	**53,530**	46,405
Current liabilities	**(94,143)**	(102,097)
Fair value of financial instruments	**12,626**	7,170
Working capital deficit	**(27,987)**	(48,522)

($ thousands)	**June 30, 2013**	December 31, 2012
Bank loan	**(287,687)**	(242,834)
Working capital deficit	**(27,987)**	(48,522)
Net debt	**(315,674)**	(291,356)

RESULTS OF OPERATIONS

Production

	Three months ended June 30, 2013					Three months ended June 30, 2012				
	Princess & Other Oil (bbl/d)	Lloydminster Oil (bbl/d)	Ngl (bbl/d)	Nat. gas (mcf/d)	Total (boe/d)	Princess & Other Oil (bbl/d)	Lloydminster Oil (bbl/d)	Ngl (bbl/d)	Nat. gas (mcf/d)	Total (boe/d)
Alberta	**4,433**	**6**	**1,759**	**38,535**	**12,621**	5,726	9	1,345	39,391	13,645
British Columbia	**128**	**–**	**1,326**	**42,067**	**8,465**	214	–	1,464	39,841	8,318
Saskatchewan	**–**	**5,975**	**–**	**291**	**6,023**	–	6,031	–	1,187	6,229
Total	**4,561**	**5,981**	**3,085**	**80,893**	**27,109**	5,940	6,040	2,809	80,419	28,192

In the second quarter of 2013, production decreased 4% compared to the same period in 2012 as a result of declines in Princess, Alberta oil production and the sale of the Company's Kobes, British Columbia area production which produced approximately 845 boe per day in the second quarter of 2012. The Princess oil declines were the result of reduced capital spending. In addition, during the second quarter, unplanned third party facility outages affected natural gas and associated liquids production by approximately 650 boe per day in the Company's Deep Basin area in Alberta. These decreases were partially offset by increased natural gas and associated natural gas liquids production during the quarter in the Septimus, British Columbia area due to a successful drilling program.

	Six months ended June 30, 2013					Six months ended June 30, 2012				
	Princess & Other Oil (bbl/d)	Lloydminster Oil (bbl/d)	Ngl (bbl/d)	Nat. gas (mcf/d)	Total (boe/d)	Princess & Other Oil (bbl/d)	Lloydminster Oil (bbl/d)	Ngl (bbl/d)	Nat. gas (mcf/d)	Total (boe/d)
Alberta	**4,596**	**6**	**1,805**	**38,768**	**12,868**	6,000	8	1,628	43,114	14,822
British Columbia	**152**	**–**	**1,230**	**39,077**	**7,895**	355	–	1,329	39,223	8,221
Saskatchewan	**–**	**5,706**	**–**	**414**	**5,775**	–	6,093	–	900	6,243
Total	**4,748**	**5,712**	**3,035**	**78,259**	**26,538**	6,355	6,101	2,957	83,237	29,286

Production for the first six months of 2013 has decreased over the same period in 2012 as a result of decreased Princess oil production due to reduced capital spending, the disposition of production in the Kobes area, unplanned third party facility outages in the Deep Basin area as well as declines in Lloydminster oil production due to reduced pressure in the Waseca formation at Low Lake.

Revenue

	Three months ended		Six months ended	
	June 30, 2013	June 30, 2012	**June 30, 2013**	June 30, 2012
Revenue *($ thousands)*				
Princess and other oil	**31,070**	38,063	**59,659**	88,027
Lloydminster oil	**36,735**	32,402	**61,517**	72,237
Natural gas liquids	**14,642**	14,386	**29,262**	29,375
Natural gas	**28,346**	15,095	**51,622**	33,382
Total	**110,793**	99,946	**202,060**	223,021
Crew average prices				
Princess and other oil ($/bbl)	**74.85**	70.41	**69.43**	76.11
Lloydminster oil ($/bbl)	**67.50**	58.95	**59.50**	65.05
Natural gas liquids ($/bbl)	**52.16**	56.27	**53.27**	54.58
Natural gas ($/mcf)	**3.85**	2.06	**3.64**	2.20
Oil equivalent ($/boe)	**44.91**	38.96	**42.07**	41.84
Benchmark pricing				
Conv. and heavy oil – WCS (Cdn $/bbl)	**76.78**	71.29	**69.87**	76.44
Oil and ngl – Cdn$ WTI (Cdn $/bbl)	**96.43**	94.32	**95.81**	98.68
Natural Gas – AECO C daily index (Cdn $/mcf)	**3.59**	1.93	**3.41**	2.06

Crew's second quarter 2013 revenue increased 11% compared to the second quarter of 2012 as a result of the 15% increase in realized commodity pricing partially offset by a 4% decrease in production. During the second quarter of 2013, the Company's Princess oil price increased 6% which was comparable to an 8% increase in the Company's Western Canadian Select ("WCS") benchmark price. The Company's Lloydminster oil price increased 15% compared to the 8% increase in the second quarter 2013 WCS benchmark compared to 2012 due to the Company successfully marketing its physical heavy crude at periods during the quarter when WCS differentials were narrower than the average market trade for the quarter. The Company's ngl price decreased 7% as compared with a 2% increase in the Cdn$ West Texas Intermediate ("WTI") benchmark price due to increased production of lower valued ethane in the Deep Basin area in the second quarter of 2013 as compared with the same period in 2012. During the second quarter, the Company's natural gas price increased 87% over the same period in 2012 which was equivalent with the increase in the AECO benchmark price.

For the first six months of 2013, the Company's realized Princess and Lloydminster oil prices decreased 9% over the same period in 2012 which was equivalent to the decrease in the Company's WCS benchmark. Crew's realized ngl price decreased 2% over the same period in 2012 which was comparable to the decrease in the Cdn$ WTI benchmark price. For the first six months of 2013, the Company's natural gas price increased 65% as compared to a 66% increase in the AECO benchmark price.

Royalties

	Three months ended		Six months ended	
($ thousands, except per boe)	**June 30, 2013**	June 30, 2012	**June 30, 2013**	June 30, 2012
Royalties	**21,014**	22,729	**38,339**	53,554
Per boe	**8.52**	8.86	**7.98**	10.05
Percentage of revenue	**19.0%**	22.7%	**19.0%**	24.0%

Royalties as a percentage of revenue decreased in the second quarter and first six months of 2013 compared to the same periods in 2012 as a result of the decreased revenue from the Princess and Lloydminster areas which attract a higher effective royalty rate as compared to the corporate average royalty rate. In addition, increased revenue at Septimus, which currently attracts a lower effective royalty rate, and additional gas cost allowance received in the second quarter have also decreased the Company's corporate average royalty rate. Crew continues to forecast an annual 2013 royalty rate of between 20% and 23% as existing Deep Basin and Septimus wells come off royalty holidays.

Financial Instruments

Commodities

The Company enters into derivative and medium to long-term physical risk management contracts in order to reduce volatility in financial results, to protect acquisition economics and to ensure a certain level of cash flow to fund planned capital projects. Crew's strategy focuses on the use of puts, costless collars, swaps and fixed price contracts to limit exposure to fluctuations in commodity prices, interest rates and foreign exchange rates while allowing for participation in commodity price increases. The Company's financial derivative trading activities are conducted pursuant to the Company's Risk Management Policy approved by the Board of Directors. In 2013, these contracts had the following impact on the consolidated statements of income and comprehensive income:

	Three months ended		Six months ended	
($ thousands)	**June 30, 2013**	June 30, 2012	**June 30, 2013**	June 30, 2012
Realized gain (loss) on financial instruments	**(4,286)**	15,239	**(5,566)**	16,621
Unrealized gain (loss) on financial instruments	**7,984**	29,140	**(6,735)**	26,403

As at June 30, 2013, the Company held derivative commodity contracts as follows:

Subject of Contract	Notional Quantity	Remaining Term	Reference	Average Strike Price	Contract Traded	Fair Value ($000s)
Oil	4,500 bbl/day	July 1, 2013 – December 31, 2013	CDN$ WTI	$91.20	Swap	(8,063)
Oil	750 bbl/day	July 1, 2013 – December 31, 2013	CDN$ WTI	$85.00 – $95.00	Collar(1)	(887)
Oil	250 bbl/day	July 1, 2013 – December 31, 2013	CDN$ WTI	$85.00 – $100.00	Collar(2)	(41)
Oil	2,000 bbl/day	July 1, 2013 – September 30, 2013	CDN$ WCS – WTI diff	($21.93)	Swap	(969)
Oil	2,500 bbl/day	July 1, 2013 – December 31, 2013	CDN$ WCS – WTI diff	($22.58)	Swap	(1,343)
Oil	500 bbl/day	October 1, 2013 – December 31, 2013	CDN$ WCS – WTI diff	($22.50)	Swap	37
Gas	2,500 gj/day	July 1, 2013 – October 31, 2013	ACEO C Monthly Index	$2.93	Swap	(11)
Gas	5,000 gj/day	July 1, 2013 – October 31, 2013	ACEO C Monthly Index	$3.39 – $4.00	Collar(3)	277
Gas	5,000 gj/day	July 1, 2013 – December 31, 2013	ACEO C Monthly Index	$2.65 – $3.50	Collar	(20)
Gas	35,000 gj/day	July 1, 2013 – December 31, 2013	AECO C Monthly Index	$3.03	Swap	(328)
Oil	2,500 bbl/day	January 1, 2014 – December 31, 2014	CDN$ WTI	$95.81	Swap	241
Oil	250 bbl/day	January 1, 2014 – December 31, 2014	CDN$ WTI	$92.20	Call(4)	(662)
Oil	500 bbl/day	January 1, 2014 – December 31, 2014	CDN$ WTI	$96.05	Call	(1,110)
Oil	1,000 bbl/day	January 1, 2014 – December 31, 2014	US$ WTI	$92.40	Call	(2,421)
Oil	1,000 bbl/day	January 1, 2014 – December 31, 2014	CDN$ WCS – WTI diff	($22.75)	Swap	(144)
Gas	17,500 gj/day	January 1, 2014 – December 31, 2014	AECO C Monthly Index	$3.58	Swap	1,597
Gas	5,000 gj/day	January 1, 2014 – December 31, 2014	AECO C Monthly Index	$4.00	Swaption(3)	(58)
Total						**(13,905)**

(1) The referenced contract is a fade-in Collar whereby the price is fixed at $95/bbl unless the market price falls below $85/bbl in which case the price received will be $85/bbl.

(2) The referenced contract is a fade-in Collar whereby the price is fixed at $100/bbl unless the market price falls below $85/bbl in which case the price received will be $85/bbl.

(3) The July to October 2013 Collar includes a $3.39 Put that was enhanced by the sale of the 2014 Swaption which gives the counterparties a one-time election to commit Crew to a 2014 Swap at $4.00 per GJ.

(4) This is a structured Call which is only triggered if the average CDN$ WTI trades above $100 per bbl for a given month during the term.

Subsequent to June 30, 2013, the Company entered into the following derivative contracts:

Subject of Contract	Volume	Term	Reference	Strike Price	Option Traded
Oil	1,250 bbl/day	August 1, 2013 – December 31, 2013	CDN$ WTI	$105.19	Swap
Oil	1,250 bbl/day	August 1, 2013 – December 31, 2013	CDN$ WCS – WTI diff	($22.93)	Swap
Oil	500 bbl/day	January 1, 2014 – December 31, 2014	CDN$ WTI	$85.00 – $100.00	Call (1)

(1) The referenced contract is a fade-in collar whereby the price is fixed at $85/bbl unless the market price rises above $85/bbl in which case the price received will be $100/bbl. Should the market price rise above $100/bbl the price received is still $100/bbl.

Operating Costs

	Three months ended		Six months ended	
($ thousands, except per boe)	**June 30, 2013**	June 30, 2012	**June 30, 2013**	June 30, 2012
Operating costs	**26,541**	29,044	**54,651**	62,622
Per boe	**10.76**	11.32	**11.38**	11.75

In the second quarter and first six months of 2013, the Company's operating costs per unit decreased over the same periods in 2012 due to the decline in higher cost Princess and Lloydminster oil production combined with increased lower cost production in the Septimus area. The Company continues to forecast annual operating costs to average $11.00 to $11.50.

Transportation Costs

($ thousands, except per boe)	Three months ended June 30, 2013	Three months ended June 30, 2012	Six months ended June 30, 2013	Six months ended June 30, 2012
Transportation costs	**3,115**	3,569	**6,043**	7,357
Per boe	**1.26**	1.39	**1.26**	1.38

The Company realized lower second quarter and first half 2013 transportation costs and costs per unit as compared to the same periods in 2012 due to a decrease in clean oil trucking in the Princess area as a result of the addition of a clean oil sales pipeline added in the second quarter of 2012 and the sale of the Kobes area higher cost production which attracted a higher transportation charge as compared to the corporate average cost. The Company continues to forecast transportation costs to range between $1.25 and $1.50 per boe for 2013.

Operating Netbacks

($/boe)	Three months ended June 30, 2013	Three months ended June 30, 2012	Six months ended June 30, 2013	Six months ended June 30, 2012
Revenue	**44.91**	38.96	**42.07**	41.84
Realized commodity hedging gain/(loss)	**(1.74)**	5.94	**(1.16)**	3.12
Royalties	**(8.52)**	(8.86)	**(7.98)**	(10.05)
Operating costs	**(10.76)**	(11.32)	**(11.38)**	(11.75)
Transportation costs	**(1.26)**	(1.39)	**(1.26)**	(1.38)
Operating netbacks	**22.63**	23.33	**20.29**	21.78

The hedging gain realized in the second quarter of 2012 was significantly impacted by a one-time realization of a $12.1 million gain from the unwinding of 2013 oil hedges.

General and Administrative Costs

($ thousands, except per boe)	Three months ended June 30, 2013	Three months ended June 30, 2012	Six months ended June 30, 2013	Six months ended June 30, 2012
Gross costs	**7,435**	7,576	**14,322**	15,856
Operator's recoveries	**(146)**	(633)	**(264)**	(941)
Capitalized costs	**(2,525)**	(2,635)	**(4,650)**	(5,336)
General and administrative expenses	**4,764**	4,308	**9,408**	9,579
Per boe	**1.93**	1.68	**1.96**	1.80

During the second quarter of 2013, increased general and administrative costs after recoveries were the result of decreased capital projects involving industry partners which resulted in reduced operator recoveries. Per boe costs increased in the second quarter as compared with the same period in 2012 due to decreased production combined with the decreased operator recoveries. For the first half of 2013, lower gross general and administrative costs were the result of reduced staffing costs as a result of a decline in activity levels during the latter half of 2012 and the first quarter of 2013. The Company continues to expect general and administrative costs to average between $1.70 and $1.90 per boe for 2013 with higher amounts incurred in the first half of the year due to the payment of one time annual costs during this period combined with forecasted higher production levels during the remainder of the year.

Finance Expenses

	Three months ended		Six months ended	
($ thousands, except per boe)	**June 30, 2013**	June 30, 2012	**June 30, 2013**	June 30, 2012
Interest on bank debt	**2,986**	3,508	**5,778**	6,446
Accretion of the decommissioning obligation	**667**	678	**1,327**	1,310
Total finance expense	**3,653**	4,186	**7,105**	7,756
Average debt level	**292,184**	348,816	**276,073**	308,236
Effective interest rate on bank debt	**4.1%**	4.0%	**4.2%**	4.2%
Interest on bank debt per boe	**1.21**	1.37	**1.20**	1.21

In the second quarter and first six months of 2013, lower average debt levels due to the disposition of the Kobes property in the fourth quarter of 2012 resulted in lower interest costs as compared with the same period in 2012. The effective interest rate on the Company's bank debt slightly increased in the second quarter of 2013 as compared with the same period in 2012 due to increased standby fees on the Company's unutilized portion of its borrowings. The Company expects its effective interest rate on bank debt will average approximately 4.0% to 4.5% in 2013.

Share-Based Compensation

	Three months ended		Six months ended	
($ thousands)	**June 30, 2013**	June 30, 2012	**June 30, 2013**	June 30, 2012
Gross costs	**2,631**	4,638	**3,717**	9,545
Capitalized costs	**(1,339)**	(2,356)	**(1,895)**	(4,829)
Total share-based compensation	**1,292**	2,282	**1,822**	4,716

The Company's share-based compensation expense has decreased in the second quarter and first six months of 2013 compared with the same periods in 2012 due to a decrease in the number of options outstanding, a lower average fair value on new and existing options outstanding and an increased amount of forfeitures during the first quarter of 2013. The decrease in the number of options outstanding is a result of the voluntary surrender of 2.3 million stock options in the fourth quarter of 2012 for which the share based compensation expense on these options was accelerated in 2012. During the second quarter, the Company issued restricted and performance awards in which the fair value, for the purposes of share-based compensation expense, is determined at the date of grant using the closing price of the common shares and, for performance awards, an estimated payout multiplier. The expense for the restricted and performance awards is included in share-based compensation for the quarter.

Depletion and Depreciation

	Three months ended		Six months ended	
($ thousands, except per boe)	**June 30, 2013**	June 30, 2012	**June 30, 2013**	June 30, 2012
Depletion and depreciation	**46,351**	48,624	**94,730**	99,139
Per boe	**18.79**	18.95	**19.72**	18.60

Total depletion and depreciation costs per boe have slightly decreased in the second quarter of 2013 as compared with the same period in 2012 due to a decreased depletable cost base as a result of the Company's write-down of certain assets at December 31, 2012. For the first six months of 2013, depletion costs per boe increased due to reduced production levels combined with the expiry of non-core undeveloped land which was recorded as additional depletion in the first quarter of 2013.

Deferred Income Taxes

In the second quarter and first six months of 2013, the provision for deferred income taxes was an expense of $2.2 million and a recovery of $5.1 million, respectively, compared to an expense of $9.0 million and $7.2 million, respectively, for the same periods in 2012. The change was due to higher pre-tax earnings in 2012 and an increase in the Company's effective tax rate during the second quarter of 2013 due to the province of British Columbia increasing its provincial tax rate from 10% to 11%.

Cash and Funds from Operations and Net Income

($ thousands, except per share amounts)	Three months ended June 30, 2013	Three months ended June 30, 2012	Six months ended June 30, 2013	Six months ended June 30, 2012
Cash provided by operating activities	**44,486**	49,557	**70,401**	115,783
Funds from operations	**48,087**	52,027	**82,775**	100,084
Per share – basic	**0.40**	0.43	**0.68**	0.83
– diluted	**0.40**	0.43	**0.68**	0.83
Net income (loss)	**2,008**	24,107	**(20,039)**	17,677
Per share – basic	**0.02**	0.20	**(0.16)**	0.15
– diluted	**0.02**	0.20	**(0.16)**	0.15

The decrease in second quarter and first six months cash provided by operating activities and funds from operations was the result of decreased production and a realized loss from the Company's risk management program as compared to significant gain for the same periods in 2012. The second quarter and first six months of 2013 decrease in net income was the result of a decrease in the unrealized gain on the Company's risk management program.

Capital Expenditures, Acquisitions and Dispositions

During the second quarter, the Company drilled a total of three (3.0 net) wells in the Septimus area resulting in three (3.0 net) natural gas wells. In addition, the Company completed six (6.0 net) wells and recompleted 19 (18.0 net) wells in the quarter. In June, the Company also closed the disposition of approximately 140 boe per day of non-core production in central Alberta for approximately $5.1 million. Total net capital expenditures are detailed below:

($ thousands)	Three months ended June 30, 2013	Three months ended June 30, 2012	Six months ended June 30, 2013	Six months ended June 30, 2012
Land	**980**	1,270	**3,548**	3,701
Seismic	**(538)**	992	**2,666**	3,976
Drilling, completions and recompletions	**23,718**	13,757	**72,585**	103,603
Facilities, equipment and pipelines	**3,283**	11,691	**11,564**	41,735
Other	**2,905**	2,722	**5,237**	6,160
Total exploration and development	**30,348**	30,432	**95,600**	159,175
Property acquisitions (dispositions)	**(5,717)**	(4,290)	**8,946**	(4,290)
Total	**24,631**	26,142	**104,546**	154,885

LIQUIDITY AND CAPITAL RESOURCES

Capital Funding

The Company has a credit facility with a syndicate of lending banks (the "Syndicate"). The credit facility includes 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, 2014. If not extended, the Facility will cease to revolve, the margins thereunder will increase by 0.50 percent and all outstanding balances under the Facility will become repayable in one year from the extension date. The available lending limits of the Facility are reviewed semi-annually and are based on the Syndicate's interpretation of the Company's reserves and future commodity prices. There can be no assurance that the amount of the available Facility will not be adjusted at the next scheduled borrowing base review on or before October 31, 2013. At June 30, 2013, the Company had drawings of $287.7 million on the Facility and had issued letters of credit totaling $12.1 million.

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 deficiency includes accounts receivable less accounts payable and accrued liabilities. The Company maintains sufficient unused bank credit lines to satisfy working capital deficiencies. At June 30, 2013, the Company's working capital deficiency totaled $28.0 million which, when combined with the drawings on its bank line, represented 73% of its bank facility at June 30, 2013.

Share Capital

Crew is authorized to issue an unlimited number of Common Shares. As at August 9, 2013, Crew had 121,634,844 Common Shares and options to acquire 7,977,485 Common Shares of the Company issued and outstanding.

At the Company's annual and special meeting held on May 24, 2012, the shareholders of the Company approved the adoption of a Restricted and Performance Award Incentive Plan ("RPAP") which authorizes the Board of Directors to grant restricted awards ("RAs") and performance awards ("PAs") to directors, officers, employees, consultants or other service providers of Crew and its affiliates.

Subject to terms and conditions of the RPAP, each RA and PA entitles the holder to an award value to be typically paid as to one-third on each of the first, second and third anniversaries of the date of grant. In the case of PAs, the award value is adjusted for a payout multiplier which can range from 0.0 to 2.0 and is dependent on the performance of the Company relative to pre-defined corporate performance measures for a particular period. On the vesting dates, the Company has the option of settling the award value in cash or Common Shares of the Company.

As at August 9, 2013 there were 285,675 restricted awards and 306,875 performance awards 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 June 30, 2013, the Company's ratio of net debt to annualized funds from operations was 1.64 to 1 (December 31, 2012 – 1.55 to 1). The Company plans to continue its strategy of divesting of non-core properties and will adjust its annual capital expenditure program if necessary or may consider an alternative form of financing in order to maintain the integrity of its financial position

($ thousands, except ratio)	**June 30, 2013**	December 31, 2012
Working capital deficit	**(27,987)**	(48,522)
Bank loan	**(287,687)**	(242,834)
Net debt	**(315,674)**	(291,356)
Funds from operations for the three months ended June 30, 2013	**48,087**	47,110
Annualized	**192,348**	188,440
Net debt to annualized funds from operations ratio	**1.64**	1.55

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	2013	2014	2015	2016	2017	Thereafter
Bank loan [(1)]	287,687	–	–	287,687	–	–	–
Operating leases	8,598	1,116	2,363	2,494	2,625	–	–
Firm transportation agreements	23,546	1,687	3,980	4,245	4,085	2,559	6,990
Firm processing agreement	62,547	4,230	8,926	8,961	8,783	7,740	23,907
Total	382,378	7,033	15,269	303,387	15,493	10,299	30,897

(1) Based on the existing terms of the Company's bank facility the first possible repayment date may come in 2015. 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 five year lease of office space.

The transportation agreements include a commitment to a third party to transport natural gas from a gas processing facility in the Septimus area to the Alliance pipeline system as well as firm service obligations for Alberta and British Columbia natural gas transportation.

The firm processing agreements include a commitment to process natural gas through a third party owned gas processing facility in the Septimus area until 2021. Crew has 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 repurchases a 50% interest on January 1, 2014 for approximately $21 million, the remaining commitment would be reduced by approximately $27 million.

GUIDANCE

Crew is maintaining annual guidance to average 27,500 to 28,500 boe per day, exploration and development capital budget at $219 million as well as exit guidance of 29,000 to 30,000 boe per day as production is forecasted to steadily increase through the remainder of the year. Funds from operations was markedly improved over the first quarter as a result of higher production and higher realized product prices. Funds from operations increased to $48.1 million or $0.40 per share up 43% from $0.28 per share in the first quarter. Crew maintained its capital discipline in the second quarter spending $30.3 million on exploration and development activities, 13% less than budgeted while reducing net debt by $22.5 million to 1.6x annualized second quarter funds from operations.

The Company will continue to divest of non-core assets to fund production growth in its core areas as well as actively engage in asset swaps to further concentrate our asset base. Crew's capital program will be funded by funds from operations, long-term debt and minor asset dispositions.

Oil prices have continued to strengthen as the WTI/Brent and WTI/WCS differentials have narrowed significantly over the first half of the year resulting in much improved price realizations. This has been partially offset by an approximate $0.50 per mcf reduction in realized natural gas prices. We are currently forecasting realized oil prices to be approximately $6 per bbl higher and natural gas prices to be $0.50 per mcf lower in the third quarter. When combined with higher forecasted production, funds from operations is expected to be strong in the third quarter.

ADDITIONAL DISCLOSURES

Quarterly Analysis

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

($ thousands, except per share amounts)	**June 30 2013**	Mar. 31 2013	Dec. 31 2012	Sept. 30 2012	June 30 2012	Mar. 31 2012	Dec. 31 2011	Sept. 30 2011
Total daily production (boe/d)	**27,109**	25,961	27,027	26,281	28,192	30,380	30,034	27,510
Exploration and development expenditures	**30,348**	65,252	55,173	44,443	30,432	128,743	108,854	138,671
Property acquisitions/ (dispositions)	**(5,717)**	14,663	(86,395)	(5,872)	(4,290)	–	(13,203)	–
Average wellhead price ($/boe)	**44.91**	39.06	41.21	38.16	38.96	44.52	51.41	45.33
Petroleum and natural gas sales	**110,793**	91,267	102,473	92,269	99,946	123,075	142,063	114,719
Cash provided by operations	**44,486**	25,917	50,873	46,935	49,557	66,226	39,969	54,095
Funds from operations	**48,087**	34,188	47,110	39,410	52,027	48,057	64,841	54,260
Per share – basic	**0.40**	0.28	0.39	0.33	0.43	0.40	0.54	0.45
– diluted	**0.40**	0.28	0.39	0.33	0.43	0.40	0.54	0.45
Net income (loss)	**2,008**	(22,047)	21,812	(17,947)	24,107	(6,430)	(148,529)	12,232
Per share – basic	**0.02**	(0.18)	0.18	(0.15)	0.20	(0.05)	(1.24)	0.10
– diluted	**0.02**	(0.18)	0.18	(0.15)	0.20	(0.05)	(1.24)	0.10

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. The Company reduced capital expenditures beginning in the second quarter of 2012 in order to maintain financial strength during a period of commodity price volatility. This impacted production as new production additions were not sufficient to replace corporate declines and dispositions during this period.
- Production was negatively impacted by scheduled and unscheduled third party facility shutdowns in the second quarter of 2012 and the first and second quarters of 2013. The Company also shut-in approximately 1,200 boe per day of uneconomic natural gas production in the second quarter of 2012 and some of this production remained shut-in through the second quarter of 2013.
- 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. The Company also monetized certain 2012 WTI to WCS differential hedges in the first quarter of 2012 and certain 2013 WTI hedges in the second quarter of 2012 resulting in realized gains of $3.7 million and $12.1 million, respectively.
- From the fourth quarter of 2011 to the second quarter of 2013, the Company has sold assets for proceeds of approximately $137 million. These dispositions in central Alberta and northeast British Columbia resulted in gains on sale of assets of $7.4 million, $3.5 million, $3.6 million and $70.8 million in the fourth quarter of 2011 and the second, third and fourth quarters of 2012, respectively. In addition, a loss of $3.6 million was recorded for the disposition in the second quarter of 2013.
- The Company incurred an impairment charge of $122.8 million on certain CGUs in the fourth quarter of 2012 which was offset by the reversal of $93.6 million of impairment charges taken on certain CGUs in 2011. In the fourth quarter of 2011, the Company recorded an impairment charge of $181.9 million on certain CGUs.

Future Accounting Pronouncements

On January 1, 2013, the Company adopted new standards with respect to consolidations (IFRS 10), joint arrangements (IFRS 11), disclosure of interest in other entities (IFRS 12), fair value measurements (IFRRS 13) and amendments to financial instruments disclosures (IFRS 7). The adoption of these standards had no impact on the amounts recorded in the consolidated financial statements as at January 1, 2013 or on the comparative periods.

The Company has reviewed the following new accounting pronouncement that has been issued but is not yet effective and determined that the following may have an impact on the Company's financial statements:

(a) IFRS-9 Financial Instruments:

As of January 1, 2015, the Company will be required to adopt IFRS-9 Financial Instruments, which is the result of the first phase of the IASB project to replace IAS-39 Financial Instruments: Recognition and Measurement. The new standard replaces the current multiple classification and measurement models for financial assets and liabilities with a single model that has two classification categories: amortized cost and fair value. Portions of the standard remain in development and the full impact of the standard on the Company's financial statements will not be known until the project is complete

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 April 1, 2013 and ended on June 30, 2013 that has materially affected, or is reasonably likely to materially affect, the Company's internal controls over financial reporting. No material changes in the Company's internal controls over financial reporting were identified during such period that have materially affected, or are reasonably likely to materially affect, the Company's internal controls over financial reporting.

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

Dated as of August 9, 2013

CONDENSED INTERIM CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

(unaudited) (thousands)	**June 30, 2013**	December 31, 2012
ASSETS		
Current Assets:		
Accounts receivable	**$ 53,530**	$ 46,405
Exploration and evaluation assets (note 3)	**59,647**	60,651
Property, plant and equipment (note 4)	**1,740,692**	1,726,746
	$ 1,853,869	$ 1,833,802
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities:		
Accounts payable and accrued liabilities	**$ 81,517**	$ 94,927
Fair value of financial instruments (note 8)	**12,626**	7,170
	94,143	102,097
Fair value of financial instruments (note 8)	**1,279**	–
Bank loan (note 5)	**287,687**	242,834
Decommissioning obligations (note 6)	**112,019**	108,787
Deferred tax liability	**191,412**	196,521
Shareholders' Equity		
Share capital (note 7)	**1,275,906**	1,275,777
Contributed surplus (note 7)	**57,711**	54,035
Deficit	**(166,288)**	(146,249)
	1,167,329	1,183,563
Commitments (note 9)		
	$ 1,853,869	$ 1,833,802

See accompanying notes to the condensed interim consolidated financial statements.

CONDENSED INTERIM CONSOLIDATED STATEMENTS OF INCOME (LOSS) AND COMPREHENSIVE INCOME (LOSS)

	Three months ended		Six months ended	
(unaudited) (thousands, except per share amounts)	**June 30, 2013**	June 30, 2012	**June 30, 2013**	June 30, 2012
Revenue				
Petroleum and natural gas sales	**$ 110,793**	$ 99,946	**$ 202,060**	$ 223,021
Royalties	**(21,014)**	(22,729)	**(38,339)**	(53,554)
Realized gain (loss) on financial instruments (note 8)	**(4,286)**	15,239	**(5,566)**	16,621
Unrealized gain (loss) on financial instruments (note 8)	**7,984**	29,140	**(6,735)**	26,403
	93,477	121,596	**151,420**	212,491
Expenses				
Operating	**26,541**	29,044	**54,651**	62,622
Transportation	**3,115**	3,569	**6,043**	7,357
General and administrative	**4,764**	4,308	**9,408**	9,579
Share-based compensation	**1,292**	2,282	**1,822**	4,716
Depletion and depreciation	**46,351**	48,624	**94,730**	99,139
	82,063	87,827	**166,654**	183,413
Income (loss) from operations	**11,414**	33,769	**(15,234)**	29,078
Financing	**(3,653)**	(4,186)	**(7,105)**	(7,756)
Gain (loss) on divestitures	**(3,584)**	3,530	**(2,809)**	3,530
Income (loss) before income taxes	**4,177**	33,113	**(25,148)**	24,852
Deferred tax expense (recovery)	**2,169**	9,006	**(5,109)**	7,175
Net and comprehensive income (loss)	**$ 2,008**	$ 24,107	**$ (20,039)**	$ 17,677
Net income (loss) per share (note 7)				
Basic	**$ 0.02**	$ 0.20	**$ (0.16)**	$ 0.15
Diluted	**$ 0.02**	$ 0.20	**$ (0.16)**	$ 0.15

See accompanying notes to the condensed interim consolidated financial statements.

CONDENSED INTERIM CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

(unaudited) (thousands)	Number of shares	Share capital	Contributed surplus	Deficit	Total Shareholders' equity
Balance January 1, 2013	121,620	$ 1,275,777	$ 54,035	$ (146,249)	$ 1,183,563
Net loss for the period	–	–	–	(20,039)	(20,039)
Share-based compensation expensed	–	–	1,822	–	1,822
Share-based compensation capitalized	–	–	1,895	–	1,895
Transfer of share-based compensation on exercises	–	41	(41)	–	–
Issued on exercise of options	16	88	–	–	88
Balance June 30, 2013	**121,636**	**$ 1,275,906**	**$ 57,711**	**$ (166,288)**	**$ 1,167,329**

	Number of shares	Share capital	Contributed surplus	Deficit	Total Shareholders' equity
Balance January 1, 2012	119,993	$ 1,261,884	$ 36,089	$ (167,791)	$ 1,130,182
Net income for the period	–	–	–	17,677	17,677
Share-based compensation expensed	–	–	4,716	–	4,716
Share-based compensation capitalized	–	–	4,829	–	4,829
Transfer of share-based compensation on exercises	–	2,297	(2,297)	–	–
Issued on exercise of options	837	5,675	–	–	5,675
Balance June 30, 2012	120,830	$ 1,269,856	$ 43,337	$ (150,114)	$ 1,163,079

See accompanying notes to the condensed interim consolidated financial statements.

CONDENSED INTERIM CONSOLIDATED STATEMENTS OF CASH FLOWS

	Three months ended		Six months ended	
(unaudited) (thousands)	**June 30, 2013**	June 30, 2012	**June 30, 2013**	June 30, 2012
Cash provided by (used in):				
Operating activities:				
Net income (loss)	**$ 2,008**	$ 24,107	**$ (20,039)**	$ 17,677
Adjustments:				
Depletion and depreciation	**46,351**	48,624	**94,730**	99,139
Financing expenses	**3,653**	4,186	**7,105**	7,756
Interest expense	**(2,986)**	(3,508)	**(5,778)**	(6,446)
Share-based compensation	**1,292**	2,282	**1,822**	4,716
Deferred tax expense (recovery)	**2,169**	9,006	**(5,109)**	7,175
Unrealized (gain) loss on financial instruments	**(7,984)**	(29,140)	**6,735**	(26,403)
Loss (gain) on divestitures	**3,584**	(3,530)	**2,809**	(3,530)
Decommissioning obligations settled	**(355)**	(371)	**(2,135)**	(550)
Change in non-cash working capital	**(3,246)**	(2,099)	**(9,739)**	16,249
	44,486	49,557	**70,401**	115,783
Financing activities:				
Increase (decrease) in bank loan	**(835)**	40,557	**44,853**	130,034
Proceeds from exercise of share options	**88**	259	**88**	5,675
	(747)	40,816	**44,941**	135,709
Investing activities:				
Exploration and evaluation asset expenditures	**–**	–	**–**	(2,477)
Property, plant and equipment expenditures	**(30,348)**	(30,432)	**(95,600)**	(156,698)
Property acquisitions	**–**	–	**(20,032)**	–
Property divestitures	**5,717**	4,290	**11,086**	4,290
Change in non-cash working capital	**(19,108)**	(64,231)	**(10,796)**	(96,607)
	(43,739)	(90,373)	**(115,342)**	(251,492)
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 condensed interim consolidated financial statements.

NOTES TO THE CONDENSED INTERIM CONSOLIDATED FINANCIAL STATEMENTS

For the three and six months ended June 30, 2013 and 2012

(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, in the provinces of Alberta, British Columbia and Saskatchewan. The condensed interim consolidated financial statements (the "financial statements") of the Company as at June 30, 2013 and for the three and six months ended June 30, 2013 and 2012 are comprised of the Company and its wholly owned subsidiary, Crew Oil and Gas Inc., which are both incorporated in Canada and three partnerships, Crew Energy Partnership, Crew Conventional Partnership and Crew Heavy Oil Partnership which are registered in Canada. The Company conducts many of its activities jointly with others; these financial statements reflect only the Company's proportionate interest in such activities. Crew's principal place of business is located at Suite 800, 250 – 5th Street SW, Calgary, Alberta, Canada, T2P 0R4.

2. BASIS OF PREPARATION:

These financial statements have been prepared in accordance with IAS 34 – Interim Financial Reporting of the International Financial Reporting Standards ("IFRS"). The financial statements use the accounting policies which the Company applied in its annual consolidated financial statements for the year ended December 31, 2012, except as noted below. The financial statements do not include certain disclosures that are normally required to be included in annual consolidated financial statements which have been condensed or omitted.

On January 1, 2013, the Company adopted new standards with respect to consolidations (IFRS 10), joint arrangements (IFRS 11), disclosure of interests in other entities (IFRS 12), fair value measurements (IFRS 13) and amendments to financial instruments disclosures (IFRS 7). The adoption of these standards had no impact on the amounts recorded in the consolidated financial statements as at January 1, 2013 or on the comparative periods.

The condensed interim consolidated financial statements were authorized for issue by the Board of Directors on August 9, 2013.

3. EXPLORATION AND EVALUATION ASSETS:

Cost or deemed cost	Total
Balance, January 1, 2012	$ 56,197
Additions	7,821
Transfer to property, plant and equipment	(3,367)
Balance, December 31, 2012	$ 60,651
Transfer to property, plant and equipment	(1,004)
Balance, June 30, 2013	**$ 59,647**

Exploration and evaluation (E&E) 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 E&E assets during the period.

4. PROPERTY, PLANT AND EQUIPMENT:

Cost or deemed cost	Total
Balance, January 1, 2012	$ 2,148,714
Additions	250,970
Transfer from exploration and evaluation assets	3,367
Acquisitions	22,178
Divestitures	(43,837)
Change in decommissioning obligations	4,882
Capitalized share-based compensation	11,168
Balance, December 31, 2012	$ 2,397,442
Additions	95,600
Transfer from exploration and evaluation assets	1,004
Acquisitions	20,032
Divestitures	(19,765)
Change in decommissioning obligations	6,688
Capitalized share-based compensation	1,895
Balance, June 30, 2013	**$ 2,502,896**

Accumulated depletion and depreciation	Total
Balance, January 1, 2012	$ 441,309
Depletion and depreciation expense	202,604
Divestitures	(2,471)
Impairment	29,254
Balance, December 31, 2012	$ 670,696
Depletion and depreciation expense	94,730
Divestitures	(3,222)
Balance, June 30, 2013	**$ 762,204**

Net book value	Total
Balance, December 31, 2012	$ 1,726,746
Balance, June 30, 2013	**$ 1,740,692**

The calculation of depletion for the period ended June 30, 2013 included estimated future development costs of $690.6 million (December 31, 2012 - $731.1 million) associated with the development of the Company's proved plus probable reserves and excluded salvage value of $91.4 million (December 31, 2012 - $91.5 million) and undeveloped land of $178.4 million (December 31, 2012 - $165.8 million) related to development acreage.

5. BANK LOAN:

The Company's bank facility consists of 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, 2014. 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 from the extension date. The available lending limits of the Facility are reviewed semi-annually and are based on the bank syndicate's interpretation of the Company's reserves and future commodity prices. There can be no assurance that the amount of the available Facility will not be adjusted at the next scheduled borrowing base review on or before October 31, 2013.

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 June 30, 2013, 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 June 30, 2013, the Company had issued letters of credit totaling $12.1 million (December 31, 2012 - $10.3 million). The effective interest rate on the Company's borrowings under its bank facility for the period ended June 30, 2013 was 4.1% (2012 – 4.0%).

6. DECOMMISSIONING OBLIGATIONS:

	Six Months Ended June 30, 2013	Year ended December 31, 2012
Decommissioning obligations, beginning of period	**$ 108,787**	$ 104,836
Obligations incurred	**6,688**	8,254
Obligations settled	**(2,135)**	(2,460)
Obligations divested	**(2,648)**	(1,148)
Change in estimated future cash outflows	**–**	(3,372)
Accretion of decommissioning liabilities	**1,327**	2,677
Decommissioning obligations, end of period	**$ 112,019**	$ 108,787

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 $112.0 million as at June 30, 2013 (December 31, 2012 - $108.8 million) based on an undiscounted total future liability of $114.5 million (December 31, 2012 - $113.4 million). These payments are expected to be made over the next 25 years with the majority of costs to be incurred between 2015 and 2036. The discount factor, being the risk-free rate related to the liability, is 2.55% (December 31, 2012 – 2.55%).

7. SHARE CAPITAL:

At June 30, 2013, the Company was authorized to issue an unlimited number of common shares with the holders of common shares entitled to one vote per share.

In 2012, the Company received approval for the commencement of a Normal Course Issuer Bid from the Toronto Stock Exchange ("TSX"). Under the bid, the Company was able to purchase for cancellation up to 6,038,492 of its Common Shares, representing approximately 5% of the public float of issued and outstanding shares. Purchases under the bid were to be made between May 14, 2012 and May 13, 2013. As at June 30, 2013, the bid has expired without any repurchases.

Share based payments:

Stock option program:

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, 2013	6,420	$ 9.94
Granted	2,245	$ 7.08
Exercised	(16)	$ 5.65
Forfeited	(618)	$ 10.69
Balance at June 30, 2013	**8,031**	**$ 9.09**
Exercisable at June 30, 2013	**2,887**	**$ 11.63**

The following table summarizes information about the stock options outstanding at June 30, 2013:

Range of exercise prices	Outstanding at June 30, 2013	Weighted average remaining life (years)	Weighted average exercise price	Exercisable at June 30, 2013	Weighted average exercise price
$5.16 to $7.01	2,794	3.0	$ 5.78	774	$ 5.64
$7.02 to $9.94	2,030	3.7	$ 7.22	29	$ 9.16
$9.95 to $14.63	1,427	2.4	$ 11.18	490	$ 11.26
$14.64 to $18.29	1,780	0.8	$ 14.74	1,594	$ 14.70
	8,031	2.6	$ 9.09	2,887	$ 11.63

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

	Three months ended		Six months ended	
Assumptions	**June 30, 2013**	June 30, 2012	**June 30, 2013**	June 30, 2012
Risk free interest rate (%)	**1.2**	1.4	**1.2**	1.4
Expected life (years)	**4.0**	4.0	**4.0**	4.0
Expected volatility (%)	**47**	61	**47**	61
Forfeiture rate (%)	**16.2**	16.4	**16.2**	16.6
Weighted average fair value of options	**$ 2.68**	$ 2.67	**$ 2.68**	$ 3.15

Restricted and Performance Award Incentive Plan:

At the Company's annual and special meeting held on May 24, 2012, the shareholders of the Company approved the adoption of a Restricted and Performance Award Incentive Plan ("RPAP") which authorizes the Board of Directors to grant restricted awards ("RAs") and performance awards ("PAs") to directors, officers, employees, consultants or other service providers of Crew and its affiliates.

Subject to terms and conditions of the RPAP, each RA and PA entitles the holder to an award value to be typically paid as to one-third on each of the first, second and third anniversaries of the date of grant. For the purpose of calculating share-based compensation, the fair value of each award is determined at the grant date using the closing price of the common shares. An estimated forfeiture rate of 5% was used to value all awards granted for the three and six month period ended June 30, 2013. The weighted average fair value of awards granted for the three and six months ended June 30, 2013 is $7.08. In the case of PAs, the award value is adjusted for a payout multiplier which can range from 0.0 to 2.0 and is dependent on the performance of the Company relative to pre-defined corporate performance measures for a particular period. On the vesting dates, the Company has the option of settling the award value in cash or common shares of the Company.

The number of restricted and performance awards outstanding are as follows:

	Number of restricted awards	Number of performance awards
Balance January 1, 2013	–	–
Granted	298	322
Forfeited	(15)	(14)
Balance at June 30, 2013	**283**	**308**

Per share amounts:

Per share amounts have been calculated on the weighted average number of shares outstanding. The weighted average shares outstanding for the three month period ended June 30, 2013 was 121,627,000 (2012 – 120,811,000) and for the six month period ended June 30, 2013, the weighted average number of shares outstanding was 121,623,000 (2012 – 120,737,000).

In computing the diluted per share amounts for the three month period ended June 30, 2013, 27,000 (2012 – 148,000) shares were added to the weighted average Common Shares outstanding to account for the dilution of stock options and restricted and performance awards and for the six month period ended June 30, 2013, nil (2012 – 407,000) shares were added to the weighted average Common Shares for the dilution. There were 8,031,000 (2012 – 6,793,000) stock options and 527,000 (2012 – nil) restricted and performance awards that were not included in the diluted per share calculation because they were anti-dilutive.

8. FINANCIAL RISK 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.

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. These instruments are considered level two under the fair value hierarchy. 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 date of the statement of financial position, using the remaining contracted oil and natural gas volumes and a risk-free interest rate (based on published government rates).

At June 30, 2013 the Company held derivative contracts as follows:

Subject of Contract	Notional Quantity	Remaining Term	Reference	Average Strike Price	Contract Traded	Fair Value ($000s)
Oil	4,500 bbl/day	July 1, 2013 – December 31, 2013	CDN$ WTI	$91.20	Swap	(8,063)
Oil	750 bbl/day	July 1, 2013 – December 31, 2013	CDN$ WTI	$85.00 – $95.00	Collar[(1)]	(887)
Oil	250 bbl/day	July 1, 2013 – December 31, 2013	CDN$ WTI	$85.00 – $100.00	Collar[(2)]	(41)
Oil	2,000 bbl/day	July 1, 2013 – September 30, 2013	CDN$ WCS – WTI diff	$(21.93)	Swap	(969)
Oil	2,500 bbl/day	July 1, 2013 – December 31, 2013	CDN$ WCS – WTI diff	$(22.58)	Swap	(1,343)
Oil	500 bbl/day	October 1, 2013 – December 31, 2013	CDN$ WCS – WTI diff	$(22.50)	Swap	37
Gas	2,500 gj/day	July 1, 2013 – October 31, 2013	ACEO C Monthly Index	$2.93	Swap	(11)
Gas	5,000 gj/day	July 1, 2013 – October 31, 2013	ACEO C Monthly Index	$3.39 – $4.00	Collar[(3)]	277
Gas	5,000 gj/day	July 1, 2013 – December 31, 2013	ACEO C Monthly Index	$2.65 – $3.50	Collar	(20)
Gas	35,000 gj/day	July 1, 2013 – December 31, 2013	AECO C Monthly Index	$3.03	Swap	(328)
Oil	2,500 bbl/day	January 1, 2014 – December 31, 2014	CDN$ WTI	$95.81	Swap	241
Oil	250 bbl/day	January 1, 2014 – December 31, 2014	CDN$ WTI	$92.20	Call[(4)]	(662)
Oil	500 bbl/day	January 1, 2014 – December 31, 2014	CDN$ WTI	$96.05	Call	(1,110)
Oil	1,000 bbl/day	January 1, 2014 – December 31, 2014	US$ WTI	$92.40	Call	(2,421)
Oil	1,000 bbl/day	January 1, 2014 – December 31, 2014	CDN$ WCS – WTI diff	$(22.75)	Swap	(144)
Gas	17,500 gj/day	January 1, 2014 – December 31, 2014	AECO C Monthly Index	$3.58	Swap	1,597
Gas	5,000 gj/day	January 1, 2014 – December 31, 2014	AECO C Monthly Index	$4.00	Swaption[(3)]	(58)
Total						(13,905)

(1) The referenced contract is a fade-in Collar whereby the price is fixed at $95/bbl unless the market price falls below $85/bbl in which case the price received will be $85/bbl.

(2) The referenced contract is a fade-in Collar whereby the price is fixed at $100/bbl unless the market price falls below $85/bbl in which case the price received will be $85/bbl.

(3) The July to October 2013 Collar includes a $3.39 Put that was enhanced by the sale of the 2014 Swaption which gives the counterparties a one-time election to commit Crew to a 2014 Swap at $4.00 per GJ.

(4) This is a structured Call which is only triggered if the average CDN$ WTI trades above $100 per bbl for a given month during the term.

As at June 30, 2013, a 10% decrease in the market price used to calculate unrealized gains and losses for the contracts above would result in a $17.6 million increase in income.

Subsequent to June 30, 2013, the Company entered into the following derivative contracts:

Subject of Contract	Volume	Term	Reference	Strike Price	Option Traded
Oil	1,250 bbl/day	August 1, 2013 – December 31, 2013	CDN$ WTI	$105.19	Swap
Oil	1,250 bbl/day	August 1, 2013 – December 31, 2013	CDN$ WCS – WTI diff	$(22.93)	Swap
Oil	500 bbl/day	January 1, 2014 – December 31, 2014	CDN$ WTI	$85.00 –$100.00	Collar[1]

(1) The referenced contract is a fade-in Collar whereby the price is fixed at $85/bbl unless the market price rises above $85/bbl in which case the price received will be $100/bbl. Should the market price rise above $100/bbl, the price received is still $100/bbl.

(b) Capital management:

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

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

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

The Company monitors this ratio and endeavours to maintain it at or below 2.0 to 1.0 in a normalized commodity price environment. This ratio may increase at certain times as a result of acquisitions or low commodity prices. As shown below, as at June 30, 2013 the Company's ratio of net debt to annualized cash flow was 1.64 to 1 (December 31, 2012 – 1.55 to 1). There were no changes in the Company's approach to capital management during the period.

	June 30, 2013	December 31, 2012
Net debt:		
Accounts receivable	**$ 53,530**	$ 46,405
Accounts payable and accrued liabilities	**(81,517)**	(94,927)
Working capital deficiency	**$ (27,987)**	$ (48,522)
Bank loan	**(287,687)**	(242,834)
Net debt	**$ (315,674)**	$ (291,356)
Annualized funds from operations:		
Cash provided by operating activities	**$ 44,486**	$ 50,873
Decommissioning obligations settled	**355**	1,160
Change in non-cash working capital	**3,246**	(4,923)
Funds from operations	**48,087**	47,110
Annualized	**$ 192,348**	$ 188,440
Net debt to annualized funds from operations	**1.64**	1.55

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.

9. COMMITMENTS:

($ thousands)	Total	2013	2014	2015	2016	2017	Thereafter
Operating leases	8,598	1,116	2,363	2,494	2,625	–	–
Firm transportation agreements	23,546	1,687	3,980	4,245	4,085	2,559	6,990
Firm processing agreement	62,547	4,230	8,926	8,961	8,783	7,740	23,907
Total	94,691	7,033	15,269	15,700	15,493	10,299	30,897

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

The transportation agreements include a commitment to a third party to transport natural gas from a gas processing facility in the Septimus area to the Alliance pipeline system as well as firm service obligations for Alberta and British Columbia natural gas transportation.

The firm processing agreements include a commitment to process natural gas through a third party owned gas processing facility in the Septimus area until 2021. Crew has 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 $20 million, the remaining commitment would be reduced by approximately $27 million.

CORPORATE INFORMATION

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Union Bank

Bank of Montreal

Bank of Nova Scotia

Alberta Treasury Branches

National Bank of Canada

JPMorgan Chase Bank

LEGAL COUNSEL

Burnet, Duckworth & Palmer LLP

RESERVE ENGINEERS

Sproule Associates Ltd.

TRANSFER AGENT

Valiant Trust Company

EXCHANGE LISTING

Toronto Stock Exchange
Stock Symbol: **CR**

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Independent Director

Jeffery E. Errico
Independent Director

Dennis L. Nerland
Independent Director

Dale O. Shwed
President, Crew Energy Inc.

David G. Smith
Independent Director

OFFICERS

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Secretary Partner, Burnet, Duckworth & Palmer LLP

ABBREVIATIONS

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

TSX: CR

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