interim report

Q2

2017

second quarter
ending June 30, 2017

Crew Energy Inc. (TSX: CR) ("Crew" or the "Company") is pleased to announce our operating and financial results for the three and six month periods ended June 30, 2017.

Q2 HIGHLIGHTS

- Production for the quarter averaged 20,468 boe per day, reflecting the impact of several planned and unplanned third party pipeline and facility outages which affected our core northeast British Columbia ("NE BC") operating areas by approximately 1,500 boe per day for the quarter. With the resumption of service, our current production is at a restricted average of approximately 24,500 boe per day.

- Funds from operations totaled $21.4 million in the second quarter, a 33% increase over the same period in 2016 ($0.14 per fully diluted share), largely due to improved pricing and offset by higher royalties and a decrease in realized hedging gains.

- Improved product pricing year over year combined with a continued focus on cost reductions contributed to operating netbacks (including hedging) of $15.93 per boe, a 38% improvement over the same period in 2016.

- Net exploration and development expenditures totaled $36.7 million for the quarter, slightly above previous forecasts of $25 to $35 million, reflecting Crew's ability to restart three drilling rigs and two frac spreads sooner than anticipated after break up.

- Crew drilled six (6.0 net) Montney wells and completed nine (9.0 net) wells at our liquids-rich Greater Septimus area during the second quarter, and combined with early third quarter activity, have resulted in an inventory of 17 drilled and uncompleted wells and eight wells in various stages of completion and tie-in.

- Five wells on an infill pad at Septimus, which was originally developed between 2009 and 2012 with low well density spacing and dated completion practices, were completed during the second quarter. After one week of production, the wells were flowing at a combined rate of 32.6 mmcf per day at an average flowing casing pressure of 1,550 psi.

- Ongoing site work to double the capacity of our West Septimus facility to 120 mmcf per day continued during the quarter and remains on schedule, with a target on-stream date in fourth quarter, 2017.

- A successful $49.1 million disposition of non-core assets in the Goose area of NE BC further strengthened our financial position, with no impact on production or assigned reserves, and contributed to Crew's strong balance sheet at the end of the second quarter, which includes $28.1 million in cash and an undrawn $235 million bank facility.

FINANCIAL & OPERATING HIGHLIGHTS

FINANCIAL ($ thousands, except per share amounts)	**Three months ended June 30, 2017**	Three months ended June 30, 2016	**Six months ended June 30, 2017**	Six months ended June 30, 2016
Petroleum and natural gas sales	**48,886**	36,232	**106,184**	72,575
Funds from operations(1)	**21,353**	16,048	**49,072**	27,762
Per share - basic	**0.14**	0.11	**0.33**	0.20
- diluted	**0.14**	0.11	**0.32**	0.19
Net income /(loss)	**21,880**	(16,815)	**29,936**	(23,610)
Per share - basic	**0.15**	(0.12)	**0.20**	(0.17)
- diluted	**0.14**	(0.12)	**0.20**	(0.17)
Exploration and Development expenditures	**36,656**	15,096	**111,820**	32,859
Property acquisitions (net of dispositions)	**(45,701)**	16	**(46,053)**	972
Net capital expenditures	**(9,045)**	15,112	**65,767**	33,831

Capital Structure ($ thousands)	**As at June 30, 2017**	As at Dec. 31, 2016
Working capital (surplus)/deficiency(2)	**(18,831)**	10,006
Bank loan	**-**	88,036
	(18,831)	98,042
Senior Unsecured Notes	**293,296**	147,329
Total Net Debt	**274,465**	245,371
Current Debt Capacity(3)	**535,000**	385,000
Common Shares Outstanding (thousands)	**148,910**	146,812

Notes:

(1) Funds from operations is calculated as cash provided by operating activities, adding the change in non-cash working capital, decommissioning obligation expenditures and accretion of deferred financing costs. Funds from operations is used to analyze the Company's operating performance and leverage. Funds from operations does not have a standardized measure prescribed by International Financial Reporting Standards and therefore may not be comparable with the calculations of similar measures for other companies. See "Non-IFRS Measures" contained within Crew's MD&A.

(2) Working capital (surplus) / deficiency includes cash and cash equivalents plus accounts receivable less accounts payable and accrued liabilities.

(3) Current Debt Capacity reflects the bank facility of $235 million plus $300 million in senior unsecured notes outstanding.

Operations	**Three months ended June 30, 2017**	Three months ended June 30, 2016	**Six months ended June 30, 2017**	Six months ended June 30, 2016
Daily production				
Light crude oil (bbl/d)	**499**	285	**514**	294
Heavy crude oil (bbl/d)	**1,778**	2,362	**1,817**	2,580
Natural gas liquids (bbl/d)	**2,886**	3,015	**3,123**	3,187
Natural gas (mcf/d)	**91,828**	97,726	**98,321**	100,975
Total (boe/d @ 6:1)	**20,468**	21,950	**21,841**	22,890
Average prices (1)				
Light crude oil ($/bbl)	**58.14**	48.33	**58.96**	42.67
Heavy crude oil ($/bbl)	**45.05**	37.47	**43.98**	28.24
Natural gas liquids ($/bbl)	**38.66**	35.12	**42.43**	30.29
Natural gas ($/mcf)	**3.45**	1.94	**3.50**	2.15
Oil equivalent ($/boe)	**26.25**	18.14	**26.86**	17.42

Notes:

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

	Three months ended June 30, 2017	Three months ended June 30, 2016	**Six months ended June 30, 2017**	Six months ended June 30, 2016
Netback ($/boe)				
Revenue	**26.25**	18.14	**26.86**	17.42
Royalties	**(2.06)**	(1.02)	**(2.12)**	(0.95)
Realized commodity hedging gain	**0.64**	2.83	**0.10**	2.51
Operating costs	**(6.15)**	(6.04)	**(5.74)**	(6.25)
Transportation costs	**(2.75)**	(2.38)	**(2.51)**	(2.44)
Operating netback (1)	**15.93**	11.53	**16.59**	10.29
G&A	**(1.52)**	(1.28)	**(1.51)**	(1.53)
Interest on long-term debt	**(2.93)**	(2.22)	**(2.66)**	(2.10)
Funds from operations	**11.48**	8.03	**12.42**	6.66
Drilling Activity				
Gross wells	**7**	1	**22**	5
Working interest wells	**7.0**	1.0	**22.0**	5.0
Success rate, net wells (%)	**100%**	100%	**95%**	100%

Notes:

(1) 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. See "Non-IFRS Measures" contained within Crew's MD&A.

OVERVIEW

The second quarter of 2017 presented several challenges as exceptionally wet weather conditions in NE BC led to our three drilling rigs being shut down through break up and several extended planned and unplanned third party facility and pipeline outages impacted production. Despite these challenges, we continued to execute our strategy with the majority of our efforts directed to the West Septimus facility expansion, as well as late quarter drilling and completion activity at Greater Septimus. The facility expansion to 120 mmcf per day is currently on schedule and we anticipate the plant will be on-stream in the fourth quarter of 2017. We also strengthened our balance sheet with a non-core asset disposition of $49.1 million, which had no impact on production or reserves, and supports ongoing financial flexibility to withstand longer-term uncertainty in commodity prices.

We achieved second quarter production volumes of 20,468 boe per day, which is the mid-point of our original quarterly guidance of 20,000 to 21,000 boe per day, and demonstrates the benefits of Crew's infrastructure network, infield logistics and marketing strategy. The Company's connectivity to multiple pipelines proved beneficial as NE BC operators were subject to numerous scheduled and unscheduled third party plant and pipeline outages in June which restricted product movement to sales points. Crew's access to egress, coupled with our active marketing strategy, enabled the Company to successfully divert a portion of our volumes and mitigate some of the market access issues.

FINANCIAL

Funds from operations in the second quarter of 2017 totaled $21.4 million, a 33% increase over the same period in 2016 reflecting improved commodity prices partially offset by lower realized hedging gains. Netbacks during the quarter were impacted by higher per unit costs than realized in recent quarters. This was the result of fixed costs, including take-or-pay transportation and processing charges that were incurred while production was shut-in due to third party outages. In the third quarter of 2017, the Company's costs per unit are expected to return to levels consistent with those realized in previous quarters.

Realized commodity prices improved across the board compared to those received in the second quarter of 2016. The Company's realized prices for its liquids products continued to reflect a stronger world oil market bolstered in the first half of 2017 by OPEC production curtailments. Crew's light crude, heavy crude and natural gas liquids prices in the second quarter of 2017 realized a 20%, 20% and 10% increase, respectively, over the same period in 2016. Crew's realized second quarter natural gas prices increased

78% compared to the second quarter of 2016. This is consistent with the increase in natural gas prices across North America which benefited from supportive weather in the latter half of 2016 as well as natural gas supply reductions stemming from lower industry investment in natural gas drilling.

Second quarter 2017 exploration and development expenditures totaled $36.7 million, at the high end of our guidance as improved weather conditions in late May enabled Crew to accelerate work. The majority of our capital was directed to drilling and completions activities, including drilling six (6.0 net) and completing nine (9.0 net) Montney wells, drilling one (1.0 net) and completing two (2.0 net) heavy oil wells and recompleting five (4.5 net) heavy oil wells at Lloydminster. Work continued on the expansion of our West Septimus facility from 60 mmcf per day to 120 mmcf per day during the quarter. The Company confirmed the participation of one of our working interest partners in the West Septimus facility expansion, who will participate for 72% of the costs. As forecasted, net second quarter facility expenditures reflect the recovery of costs incurred in prior quarters due to our partner's participation in the expansion. The Company also acquired 11.9 sections of surface rights at Groundbirch for the planned construction of a gas plant and associated future Montney well development for $3.8 million.

As a result of the disposition of the non-core Goose asset for $49.1 million, Crew's total net debt at the end of the quarter was $274.5 million, which includes cash on our balance sheet, a working capital surplus and our new $300 million ($293.3 million net of deferred financing costs) 6.5% senior unsecured notes that have a seven year term with repayment due in March of 2024.

During the quarter the Company commenced a Normal Course Issuer Bid ("NCIB"). Under the NCIB, Crew may purchase for cancellation, from time to time as the Company considers advisable, up to a maximum of 7.5 million common shares. Crew purchased, cancelled and removed from share capital a total of 924,100 common shares during the second quarter at a total cost of $3.3 million for an average price of $3.51 per share.

TRANSPORTATION, MARKETING & HEDGING

Crew's natural gas sales portfolio mix for the second quarter was consistent with the previous quarter allocation with approximately 45% to Chicago City Gate, 26% to AECO, 19% to Alliance ATP and 10% to Station 2, and is expected to remain consistent through Q3. This diversity of markets will help to mitigate the impact of discounted Canadian pricing that is expected to occur throughout the summer as a result of various maintenance outages planned on the three major Canadian egress pipeline systems.

As part of our longer term growth strategy, Crew will continue to plan for processing and transportation diversification for natural gas from our Greater Septimus and Groundbirch areas. In April of 2018, we have secured 60 mmcf per day of firm service capacity on the TransCanada pipeline system ("TCPL"), uniquely positioning Crew with access to triple-connectivity to all three major pipeline systems and optimal market diversification. In mid-2019, we have also secured an additional 60 mmcf per day of firm capacity on the TCPL system.

The Company's marketing team continues to monitor commodities futures markets with the view to adding to the hedge position when pricing is conducive to maintaining attractive economics. For the balance of 2017, Crew's total natural gas hedged position is approximately 50% of our forecast 2017 gas sales at a transportation-adjusted equivalent price of $2.92 per gj, which when adjusting for the higher heat content of Crew's gas, equates to $3.62 per mcf. For liquids, we have approximately 50% of our 2017 light oil and natural gas liquids sales hedged at an average price of CDN$68.17 per bbl.

OPERATIONS

NE BC Montney – Greater Septimus Overview

During the second quarter, Crew invested $31.2 million in drilling and completions at Greater Septimus, and was able to resume field activities earlier than anticipated. Crew restarted our three drilling rigs in early June, which resulted in the drilling of five (5.0 net) Montney wells at Greater Septimus before the end of the quarter. Although we experienced completion delays through most of the first half of 2017, we were able to access two frac spreads and successfully completed nine (9.0 net) Montney wells at Greater

Septimus. Combined with early third quarter activity, the completion backlog that resulted from wet field conditions and service shortages earlier in the year has been eliminated.

Crew has incurred net expenditures of $11 million for the expansion of our West Septimus facility from 60 to 120 mmcf per day. Progress continues with the delivery of major equipment currently underway. In conjunction with the West Septimus facility buildout and expansion, Crew's drilling and completions focus has been directed to this area over the past 12 to 18 months. During this time, we have evolved our completions from 20 to 30 stages with a sand loading of 0.5 to 0.8 tonnes per metre to 30 to 46 stages with 1.0 to 2.0 tonnes per metre. Four key wells that were completed late in the quarter at our West Septimus 15-9 pad were brought on production in July and were producing approximately 28.0 mmcf per day in aggregate after two weeks of flow. This initial result is very positive for Crew's western and southern Greater Septimus acreage, and we will provide further updates on these wells in our third quarter release.

Crew has many areas within our original Septimus field that were developed up to eight years ago with low well density spacing and dated completion practices. This presents an excellent opportunity to assess the potential for incremental recovery associated with improving technology while enhancing rates of return through lower well costs and our ability to use existing infrastructure. During the second quarter, we completed five wells at a Septimus pad. These wells were interspersed among wells that were originally completed from 2009 to 2012 and have benefitted from the enhanced completion technology, demonstrating a 52% improvement in the cumulative volume relative to the earlier wells over the same flow period with 34% higher average flowing pressures. After one week of production, the wells were flowing at a combined rate of 32.6 mmcf per day at an average flowing casing pressure of 1,550 psi. We will continue to evaluate the long term productivity of these wells for potential application of further infill drilling in areas that were thought to be partially depleted.

Greater Septimus

Production & Drilling	**Q2 2017**	**Q1 2017**	**Q4 2016**	**Q3 2016**	**Q2 2016**
Average daily production (boe/d)	15,558	17,440	17,307	18,592	17,131
Wells drilled (gross / net)	5 / 5.0	10 / 10.0	8 / 7.7	8 / 7.0	-
Wells completed (gross / net)	9 / 9.0	3 / 3.0	5 / 4.0	7 / 7.0	7 / 6.3

Operating Netback ($ per boe)	**Q2 2017**	**Q1 2017**	**Q4 2016**	**Q3 2016**	**Q2 2016**
Revenue	24.51	26.49	25.10	20.56	16.06
Royalties	(1.57)	(1.66)	(1.47)	(0.94)	(0.69)
Realized commodity hedge gain / (loss)	0.77	(0.41)	(0.39)	1.11	3.24
Operating costs	(4.10)	(3.34)	(3.34)	(3.61)	(4.02)
Transportation costs	(2.03)	(1.67)	(1.68)	(1.59)	(1.97)
Operating netback	17.58	19.41	18.22	15.53	12.62

Our Greater Septimus operations were impacted during the second quarter by a combination of planned and unplanned outages on third party systems. An unplanned force majeure outage on the Alliance pipeline caused Crew's Montney production (approximately 18,000 boe per day) to be shut-in for four days. In addition, a planned 21 day outage on the Enbridge system was extended to 40 days which impacted approximately 2,500 boe per day for the last 26 days of the second quarter and two weeks into the third quarter. The combined impact of these outages was a reduction of Crew's average second quarter production by approximately 1,500 boe per day. Our current corporate production is at a restricted average of approximately 24,500 boe per day, approximately 20% higher than our second quarter average. The Company is currently restricting flow in NE BC as a result of unfavourable pricing caused by pipeline restrictions in Alberta and forest fires in BC.

NE BC Montney – Groundbirch overview

Crew has drilled two delineation wells at Groundbirch, one in the first quarter and one in the second quarter, targeting two specific stratigraphic intervals within the Upper Montney that were not tested in the original two wells drilled in the area in 2014. These wells are being completed and we expect to have test results by our third quarter release in early November. We continue to be encouraged by the production performance and high natural gas liquids rates from the first two wells drilled in the area, particularly the initial condensate ratios of 25 to 35 bbls per mmcf.

NE BC Montney – Tower overview

Crew's Montney Tower area continues to represent a significant future development opportunity for the Company and has torque to crude oil prices. Our Tower oil production was 105% higher than the second quarter of 2016 and declined slightly through the second quarter to 481 bbls per day compared to 493 bbls per day in the previous quarter, as a number of wells were shut in awaiting the installation of gas lift. Infrastructure to accommodate gas lift is being installed at Tower and is expected to result in production improvements once fully implemented. The Company is currently installing the final pipeline segment and would expect the system to be operational in the third quarter.

Lloydminster, AB/SK overview

At Lloydminster, we drilled our second dual lateral horizontal oil well at the Company's Swimming area and completed both wells during the second quarter. The wells were placed on production in June and are each currently producing approximately 100 bbls per day. We also recompleted five (4.5 net) oil wells during the period. Crew intends to continue to invest minor amounts of capital in order to maintain the asset value of our Lloydminster heavy oil property as part of our ongoing disposition process.

OUTLOOK

Crew will continue to strategically develop and delineate our greater than 16 Billion boe of Total Petroleum Initially In Place ("TPIIP") resource on over 280,000 net acres of Montney rights in NE BC. We are solely focused on the efficient and cost effective execution of our capital program which is currently in full gear. Since the beginning of 2017, Crew has had up to three drilling rigs running with two rigs currently in operation and one to two frac spreads operating when required. Our West Septimus plant expansion to take productive capacity to 120 mmcf per day from its current 60 mmcf per day is on budget and on schedule. The majority of the components are on site and a full complement of personnel are completing the installation. At our current pace of drilling, Crew will add four new wells per month to our inventory. This elevated level of activity has led to a current inventory of 17 drilled and uncompleted wells and eight wells in various stages of completion and tie-in.

With the successful disposition of our Goose asset for $49.1 million during the second quarter, and our recent $300 million high yield note placement, Crew has successfully managed our balance sheet with $28.1 million of available cash at the end of the second quarter and an undrawn $235 million credit facility. These actions have aligned our long term growth plans with our capital structure, affording Crew the financial flexibility to execute our capital program.

Our Septimus line loop will be completed this year at a projected cost of $13 million. After taking into account this expenditure combined with the capital required to maintain the plant at or near capacity with six wells, Septimus is expected to generate free cash flow in 2017 as it did in 2016. Our business model is simple: replicate what we have accomplished at Septimus five additional times over the next three years providing commodity prices are supportive. We expect West Septimus to provide free cash flow in 2019 based on initial forecasts.

A key component of Crew's ability to optimize our free cash flow for the long term is the strategic location of our asset base providing access to the three major export pipelines in Canada. We have plans to invest approximately $55 million through 2018 to install 43 kilometers of interconnecting pipelines that will complete our physical connection to these export pipelines, and will allow for movement of natural gas and natural gas liquids between our operating areas completing the first phase of Crew's vision of a diverse marketing platform. The combination of a physical connection, access to greater and flexible downstream market options, our ongoing commitment to improving capital efficiencies and a demonstrated willingness to take advantage of value creating opportunities within our large land base will ensure Crew has the optimum flexibility to manage through the current commodity cycle.

Our guidance for 2017 remains unchanged with average production of 24,000 to 26,000 boe per day and a forecast year end exit rate over 31,000 boe per day. Crew is currently focused on proceeding with the infrastructure build-out and the drilling of our wells in inventory to support our growth plan as these key elements require the longest lead time. We expect third quarter production of 24,500 to 26,500 which reflects the loss of 410 boe per day for the quarter from the extension of the McMahon gas plant turnaround for 14 days into July, and fourth quarter production of 29,500 to 31,500 boe per day. Crew is currently monitoring projected activity and pricing levels for the first quarter of 2018 and will flex our activity levels and capital as appropriate to mitigate service supply constraints and cost inflation experienced in the first quarter of 2017.

We would like to thank our employees and Board of Directors for their commitment to Crew, and our shareholders for their ongoing support.

A summary of Crew's operational and financial highlights are as follows:

2017 average production(1)	24,000 – 26,000 boe/d
2017 exit production(1)	>31,000 boe/d
Total proved + probable reserves(2)	324 MMboe
Total proved + probable BT NPV10(2)	$2 billion
Resource TPIIP(3)	112.2 TCFE
Montney potential drilling locations(4)	5,782
2017 capital program(1)	$200 MM
Net debt(5)	$274.5 MM
Exit 2017 net debt / funds from operations(1)	2.1 x
Basic shares outstanding(5)	148.9 MM
Tax pools(5)	~$1 billion

(1) Forecast. See "Forward Looking Information and Statements".
(2) Reserves included herein are stated on a company gross basis (working interest before deduction of royalties without including any royalty interests). Information presented herein in respect of reserves and related information is based on our independent reserves evaluation (the "Sproule Report") for the year ended December 31, 2016 prepared by Sproule Associates Limited ("Sproule") details of which were provided in our press release issued on February 9, 2017 and are contained in our Annual Information Form filed on SEDAR.
(3) As per Crew's independent Resource Evaluation as at December 31, 2016 prepared by Sproule in accordance with the NI 51-101 and current COGE Handbook guidelines, the details of which were provided in our press release issued on May 8, 2017.
(4) Estimated potential drilling locations are the total number of risked Contingent (2,071) and Prospective (3,355) resource locations as identified in Crew's year end independent Resource Evaluation, plus the 2P booked locations (356) as identified in the Sproule Report, both of which were prepared in accordance with the COGE Handbook provisions and NI 51-101.
(5) As at June 30, 2017.

Cautionary Statements

Information Regarding Disclosure on Oil and Gas Reserves, Resources and Operational Information

All amounts in this report are stated in Canadian dollars unless otherwise specified. Throughout this report, the terms Boe (barrels of oil equivalent) and Mmboe (millions of barrels of oil equivalent), are used. Such terms when used in isolation, may be misleading. Where applicable, natural gas has been converted to barrels of oil equivalent ("BOE") based on 6 Mcf:1 BOE and oil and liquids have been converted to natural gas equivalent on the basis of 1 bbl:6 mcfe. The BOE rate is based on an energy equivalent conversion method primarily applicable at the burner tip, and given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different than the energy equivalency of the 6:1 conversion ratio, utilizing the 6:1 conversion ratio may be misleading as an indication of value. The BOE rate is based on an energy equivalent conversion method primarily applicable at the burner tip and does not represent a value equivalent at the wellhead. In accordance with Canadian practice, production volumes and *revenues are reported on a company gross basis, before deduction of Crown and other royalties and without including any royalty interest, unless otherwise stated. Unless otherwise specified, all reserves volumes in this report (and all information derived therefrom) are based on "company gross reserves" using forecast prices and costs. Our oil and gas reserves statement for the year-ended December 31, 2016 includes complete disclosure of our oil and gas reserves and other oil and gas information in accordance with NI 51-101, and is contained within our Annual Information Form which is available on our SEDAR profile at www.sedar.com.*

This report contains metrics commonly used in the oil and natural gas industry, such as "funds from operations" and "operating netback". Such terms do not have a standardized meaning and may not be comparable to similar measures presented by other companies, and therefore should not be used to make such comparisons. These metrics do not have standardized meanings and may not be comparable to similar measures presented by other companies. As such, they should not be used to make comparisons. Management uses these oil and gas metrics for its own performance measurements and to provide shareholders with measures to compare Crew's performance over time, however, such measures are not reliable indicators of Crew's future performance and future performance may not compare to the performance in previous periods.

*This report contains references to estimates of oil and gas classified as Total Petroleum Initially In Place ("**TPIIP**") in Crew's Montney region in northeast 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 December 31, 2016, prepared for Crew in accordance with the Canadian Oil & Gas Evaluation Handbook, complete details of which evaluation were set forth in Crew's previously disseminated press release dated May 8, 2017 (the "**Resource Report Press Release**"). Such resource estimates are broken into the requisite categories and are subject to a number of cautionary statements, assumptions, risks, positive and negative factors relative to the estimates and contingencies, all of which details are set forth in the Resource Report Press Release, all of which is incorporated by reference herein.*

Forward-Looking Information and Statements

This report contains certain forward–looking information and statements within the meaning of applicable securities laws. The use of any of the words "expect", "anticipate", "continue", "estimate", "may", "will", "project", "should", "believe", "plans", "intends" "forecast" and similar expressions are intended to identify forward-looking information or statements. In particular, but without limiting the foregoing, this report contains forward-looking information and statements pertaining to the following: the volume and product mix of Crew's oil and gas production; production estimates including Q3, Q4 and annual 2017 forecast average production and 2017 exit rate; the volumes and estimated value of Crew's resources and undeveloped land; 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; year end forecasted debt to funds from operations ratio; anticipated reductions in operating costs, well costs and G&A expenditures and potential to improve ultimate recoveries and initial production rates; 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; our expectations regarding free cash flow generation at Greater Septimus and the timing thereof; the potential value of our undeveloped land base; the amount and timing of capital projects including infrastructure, pipeline and facility expansions, commissioning and the timing and anticipated impact thereof; 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 and the adequacy of cash flow to fund its planned expenditures; 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.

The forward-looking information and statements included in this report are not guarantees of future performance and should not be unduly relied upon. Such information and statements, including the assumptions made in respect thereof, involve known and *unknown risks, uncertainties and other factors that may cause actual results or events to defer materially from those anticipated in such forward-looking information or statements including, without limitation: changes in commodity prices; 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 report and Crew's Annual Information Form).*

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

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.

MANAGEMENT'S DISCUSSION AND ANALYSIS

ABOUT CREW

Crew Energy Inc. ("Crew" or the "Company") is a growth-oriented oil and natural gas producer, committed to pursuing sustainable per share growth through a balanced mix of financially responsible exploration and development complemented by strategic acquisitions. The Company's operations are primarily focused in the vast Montney resource, situated in northeast British Columbia, and include a large contiguous land base. Crew's liquids-rich Septimus and West Septimus areas ("Greater Septimus") along with Groundbirch and the light oil area at Tower offer significant development potential over the long-term. The Company has access to diversified markets with operated infrastructure and increasing liquids production. Crew's common shares are listed for trading on the Toronto Stock Exchange ("TSX") under the symbol "CR".

ADVISORIES

Management's discussion and analysis ("MD&A") is the explanation of the financial performance for the period covered by the financial statements along with an analysis of the financial position of the Company. Comments relate to and should be read in conjunction with the unaudited condensed interim consolidated financial statements of the Company for the three and six month periods ended June 30, 2017 and 2016. The unaudited condensed 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, 2016. All figures provided herein and in the June 30, 2017 unaudited condensed interim consolidated financial statements are reported in Canadian dollars ("CDN"). This MD&A is dated August 2, 2017.

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 completion and tie-in of wells, facility and pipeline construction, expansion, commissioning and the timing thereof, capital expenditures, including the Company's current 2017 capital budget, timing of capital expenditures and methods of financing capital expenditures and the ability to fund financial liabilities, production estimates including annual, third and fourth quarter 2017 average and 2017 exit forecasts, expected commodity mix and prices, future operating costs, future transportation costs, expected royalty rates, expected general and administrative expenses, expected interest rates, debt levels, funds from operations and the timing of and impact of implementing accounting policies, the closing of the disposition of non-core assets, estimates regarding undeveloped land position and estimated future drilling, recompletion or reactivation locations and anticipated impact of potential future transactions 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; changes in the Company's banking facility; field production rates and decline rates; the ability to reduce operating costs; the ability to replace and expand oil and natural gas reserves through acquisition, development or exploration; the timing and costs of pipeline, storage and facility construction and expansion; the ability of the Company to secure adequate product transportation; future petroleum and natural gas prices; currency, exchange and interest rates; the regulatory framework regarding royalties, taxes and environmental matters in the jurisdictions in which the Company operates; and Crew's ability to successfully market its petroleum and natural gas products. Readers are cautioned that the foregoing list of factors is not exhaustive. Additional information on these and other factors that could affect the Company's operations and financial results are included in reports on file with Canadian securities regulatory authorities and may be accessed through the SEDAR website (www.sedar.com) or at the Company's website (www.crewenergy.com). Furthermore, the forward looking statements contained in this document are made as at the date of this document and the Company does not undertake any obligation to update publicly or to revise any of the included forward looking statements, whether as a result of new information, future events or otherwise, except as may be required by applicable securities laws.

Conversions

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

Throughout this MD&A, Crew has used the 6:1 boe measure which is the approximate energy equivalency of the two commodities at the burner tip. Boe does not represent a value equivalency at the wellhead nor at the plant gate which is where Crew sells its production volumes and therefore may be a misleading measure, particularly if used in isolation. 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.

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 but is commonly used in the oil and gas industry. It represents cash provided by operating activities before decommissioning obligations settled, changes in operating non-cash working capital and accretion of deferred financing costs. The Company considers it a key measure as it demonstrates the ability of the Company's continuing operations to generate the cash flow necessary to fund future growth through capital investment and to service and repay debt. Funds from operations should not be considered as an alternative to, or more meaningful than, cash provided by operating activities as determined in accordance with IFRS as an indicator of the Company's performance. Crew's determination of funds from operations may not be comparable to that reported by other companies. Crew also presents funds from operations per share whereby per share amounts are calculated using weighted average shares outstanding consistent with the calculation of income per share. The following table reconciles Crew's cash provided by operating activities to funds from operations:

($ thousands)	**Three months ended June 30, 2017**	Three months ended June 30, 2016	**Six months ended June 30, 2017**	Six months ended June 30, 2016
Cash provided by operating activities	**31,359**	12,047	**58,548**	31,638
Decommissioning obligations (recovered) settled	**(22)**	(33)	**356**	386
Change in operating non-cash working capital	**(9,734)**	4,209	**(9,375)**	(3,912)
Accretion of deferred financing costs	**(250)**	(175)	**(457)**	(350)
Funds from operations	**21,353**	16,048	**49,072**	27,762

Debt to EBITDA

The Company uses the terms debt to EBITDA and secured debt to EBITDA which are used in reference to the financial covenants prescribed by the Company's bank facility. Under the bank facility, debt includes drawings on the bank facility and the Company's senior unsecured notes, while secured debt refers only to drawings on the bank facility. EBITDA is defined by the credit agreement as earnings before interest, taxes, depreciation and amortization, unrealized gains or losses on financial instruments, share-based compensation, all other non-cash items and EBITDA from disposed properties and acquisitions for the most recent twelve month period. Other non-cash items include impairment, gains or losses on divestitures and the premium on flow-through shares for the most recent twelve month period.

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 related derivative financial instruments less royalties, operating costs and transportation costs calculated on a boe basis. Management considers operating netback an important measure to evaluate its operational performance as it demonstrates its field level profitability relative to current commodity prices. The calculation of Crew's netbacks can be seen below in the Operating Netbacks section.

Working Capital and Net Debt

The Company closely monitors its capital structure with a goal of maintaining a strong financial position in order to fund current operations and 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, 2017**	December 31, 2016
Current assets	**85,113**	39,588
Current liabilities	**(59,443)**	(68,494)
Derivative financial instruments	**(6,839)**	18,900
Working capital surplus (deficiency)	**18,831**	(10,006)

($ thousands)	**June 30, 2017**	December 31, 2016
Bank loan	**-**	(88,036)
Senior unsecured notes	**(293,296)**	(147,329)
Working capital surplus (deficiency)	**18,831**	(10,006)
Net debt	**(274,465)**	(245,371)

RESULTS OF OPERATIONS

Production

	Three months ended June 30, 2017				Three months ended June 30, 2016			
	Oil (bbl/d)	**Ngl (bbl/d)**	**Nat. gas (mcf/d)**	**Total (boe/d)**	Oil (bbl/d)	Ngl (bbl/d)	Nat. gas (mcf/d)	Total (boe/d)
Northeast British Columbia	**499**	**2,886**	**91,796**	**18,684**	285	3,015	97,399	19,533
Lloydminster	**1,778**	**-**	**32**	**1,784**	2,362	-	327	2,417
Total	**2,277**	**2,886**	**91,828**	**20,468**	2,647	3,015	97,726	21,950

Production for the second quarter of 2017 decreased 7% over the same period in 2016 as a result of planned and unplanned third party facility and pipeline outages which negatively impacted northeast British Columbia production by approximately 1,500 boe per day. In addition, a prolonged and exceptionally wet spring break up extending from mid-April through May forced the unplanned shut down of the Company's drilling and completion operations, delaying the planned start-up of new production.

Production was also negatively impacted due to a decline in Lloydminster heavy oil production as the Company continues to direct the majority of its investment capital to higher rate of return projects in northeast British Columbia.

	Six months ended June 30, 2017				Six months ended June 30, 2016			
	Oil (bbl/d)	**Ngl (bbl/d)**	**Nat. gas (mcf/d)**	**Total (boe/d)**	Oil (bbl/d)	Ngl (bbl/d)	Nat. gas (mcf/d)	Total (boe/d)
Northeast British Columbia	**514**	**3,123**	**98,281**	**20,017**	294	3,187	100,685	20,262
Lloydminster	**1,817**	**-**	**40**	**1,824**	2,580	-	290	2,628
Total	**2,331**	**3,123**	**98,321**	**21,841**	2,874	3,187	100,975	22,890

In the first six months of 2017, production decreased 5% over the same period in 2016 as a result of the aforementioned second quarter third party facility and pipeline outages and an extended spring break up impacting field operations. At Lloydminster, heavy oil production declined as the Company continues to direct the majority of its investment capital to higher rate of return projects in northeast British Columbia. This was partially offset by increased oil production at Tower, British Columbia from a successful completion program and an acquisition of approximately 800 boe per day of non-Montney natural gas production in the Company's other northeast British Columbia properties ("Other NE BC") late in the fourth quarter of 2016.

Revenue

	Three months ended June 30, 2017	Three months ended June 30, 2016	**Six months ended June 30, 2017**	Six months ended June 30, 2016
Revenue ($ thousands)				
Light crude oil	**2,641**	1,254	**5,489**	2,282
Heavy crude oil	**7,290**	8,055	**14,465**	13,263
Natural gas liquids	**10,153**	9,637	**23,988**	17,571
Natural gas	**28,802**	17,286	**62,242**	39,459
Total	**48,886**	36,232	**106,184**	72,575
Crew average prices				
Light crude oil ($/bbl)	**58.14**	48.33	**58.96**	42.67
Heavy crude oil ($/bbl)	**45.05**	37.47	**43.98**	28.24
Natural gas liquids ($/bbl)	**38.66**	35.12	**42.43**	30.29
Natural gas ($/mcf)	**3.45**	1.94	**3.50**	2.15
Oil equivalent ($/boe)	**26.25**	18.14	**26.86**	17.42
Benchmark pricing				
Light crude oil – Cdn$ WTI (Cdn $/bbl)	**64.95**	58.76	**66.81**	52.32
Heavy crude oil – WCS (Cdn $/bbl)	**49.96**	41.61	**49.72**	34.11
Natural gas liquids – Condensate @ Edmonton (Cdn $/bbl)	**65.17**	56.89	**67.17**	52.08
Natural Gas:				
AECO 5A daily index (Cdn $/mcf)	**2.78**	1.40	**2.74**	1.62
Chicago City Gate at ATP (Cdn $/mcf)	**3.19**	1.98	**3.20**	2.02
Alliance 5A (Cdn $/mcf)	**2.93**	1.77	**3.01**	1.87

In the second quarter of 2017, the Company's revenue increased 35% as compared to the same period in 2016 as a result of a 45% increase in realized commodity pricing, partially offset by a decline in production. Crew's realized light crude oil price increased 20% as compared to the same period in 2016, which was higher than the 11% increase in the Company's Cdn$ West Texas Intermediate ("WTI") benchmark for the same period last year. This higher realized price is a result of the Company securing sales contracts when differentials between the WTI price and Canadian Light crude price were narrower than the same period last year. Crew's second quarter heavy oil price increased 20%, which was consistent with the 20% increase in the Company's Western Canadian Select ("WCS") benchmark. The Company's second quarter realized natural gas liquids ("ngl") price increased 10% over the same period in 2016 as compared to the 15% increase in the Condensate at Edmonton benchmark price. The increase in realized ngl price was lower in the second quarter of 2017 than the increase in the benchmark as a result of an increase in lower value propane and butane production relative to the other liquids in the ngl stream as compared to the same period in 2016. During the second quarter, Crew's realized natural gas price increased 78% over the same period in 2016 which is directionally consistent with the 71% increase in the Company's natural gas sales portfolio weighted benchmark price. The Company's second quarter natural gas price continued to benefit from the high heat content of its Montney natural gas which averaged approximately 19% hotter than the natural gas standard heat content.

The Company's second quarter natural gas sales portfolio was consistent with the first quarter of 2017 and is based approximately on the following reference prices:

	Q2 2017	Q2 2016
Chicago City Gate at ATP	**45%**	40%
AECO	**26%**	22%
Alliance 5A	**19%**	30%
Station 2	**10%**	4%
Sumas	**-**	4%
Total	**100%**	100%

The Company's revenue for the first half of 2017 increased 46% over same period in 2016 as a result of the 54% increase in realized commodity pricing partially offset by the 5% decline in production. The Company's realized light oil price increased 38% which was greater than the 28% increase in the Company's WTI benchmark as a result of the Company's ability to secure sales contracts when differentials between the WTI price and Canadian Light crude price were narrower than the same period in 2016. Crew's heavy oil price for the first half of 2017 increased 56% which was higher than the 46% increase in the Company's WCS benchmark, as a result of the Company securing short term sales contracts when WCS differentials were narrower than the average market trade for the same period in 2016. In the first six months of 2017, the Company's realized ngl price increased 40% as compared to the 29% increase in the Condensate at Edmonton benchmark price as a result of higher realized pricing for propane and butane production in the ngl stream as compared to the same period last year. The Company's natural gas price increased 63% over the first half of 2016 which is consistent with the Company's natural gas sales portfolio weighted benchmark price increase of 62%.

Royalties

($ thousands, except per boe)	**Three months ended June 30, 2017**	Three months ended June 30, 2016	**Six months ended June 30, 2017**	Six months ended June 30, 2016
Royalties	**3,836**	2,039	**8,393**	3,938
Per boe	**2.06**	1.02	**2.12**	0.95
Percentage of revenue	**7.8%**	5.6%	**7.9%**	5.4%

For the second quarter and first half of 2017, royalties and royalties as a percentage of revenue increased over the same periods in 2016 as a result of the increase in realized commodity pricing, with production attracting higher royalty rates from price sensitive royalty calculations, and the addition of acquired Other NE BC production which yields higher royalty rates. The increased natural gas royalty rates were partially offset by declines in heavy oil production which have higher royalty rates relative to the corporate average. The Company continues to expect its royalties as a percentage of revenue to average between 6% and 8% in 2017.

Derivative Financial Instruments

Commodities

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

These contracts had the following impact on the condensed interim consolidated statements of income (loss) and comprehensive income (loss):

($ thousands)	**Three months ended June 30, 2017**	Three months ended June 30, 2016	**Six months ended June 30, 2017**	Six months ended June 30, 2016
Realized gain on derivative financial instruments	**1,192**	5,661	**377**	10,459
Per boe	**0.64**	2.83	**0.10**	2.51
Unrealized gain (loss) on financial instruments	**6,941**	(15,501)	**26,816**	(8,297)

At June 30, 2017, the Company held derivative commodity contracts as follows:

Subject of Contract	Notional Quantity	Term	Reference	Strike Price	Option Traded	Fair Value ($000s)
Gas	2,500 gj/day	July 1, 2017 – October 31, 2017	AECO C Daily Index	$2.55	Swap	80
Gas	22,500 mmbtu/day	July 1, 2017 – December 31, 2017	Chicago Citygate	$3.88	Swap	308
Oil	1,750 bbl/day	July 1, 2017 – December 31, 2017	CDN$ WTI	$68.02	Swap	2,408
Gas	22,500 gj/day	July 1, 2017 – December 31, 2017	AECO C Monthly Index	$2.83	Swap	1,759
Gas	10,000 gj/day	July 1, 2017 – December 31, 2017	AECO C Daily Index	$3.08	Swap	1,397
Gas	5,000 mmbtu/day	July 1, 2017 – December 31, 2018	Chicago Citygate	$4.23	Swap	1,424
Gas	5,000 gj/day	January 1, 2018 – December 31, 2018	AECO C Monthly Index	$3.00	Call	(257)
Gas	2,500 gj/day	January 1, 2018 – December 31, 2018	AECO C Daily Index	$2.62	Swap	174
Gas	5,000 mmbtu/day	January 1, 2018 – December 31, 2018	US$ Nymex Henry Hub	$3.05	Swap	133
Total						7,426

Operating Costs

($ thousands, except per boe)	**Three months ended June 30, 2017**	Three months ended June 30, 2016	**Six months ended June 30, 2017**	Six months ended June 30, 2016
Operating costs	**11,463**	12,072	**22,706**	26,051
Per boe	**6.15**	6.04	**5.74**	6.25

For the second quarter of 2017, operating costs per boe increased as compared to the same period in 2016 as a result of the aforementioned third party facility and pipeline outages reducing production, while fixed costs remained constant increasing operating costs per boe. This was partially offset by the decrease in higher cost Lloydminster production. For the first half of 2017, operating costs per boe decreased 8% over the same period last year as the Company continues to bring on lower cost northeast British Columbia production, combined with the decrease in higher cost Lloydminster production. The Company continues to forecast its 2017 operating costs to average between $5.50 and $6.00 per boe.

Transportation Costs

($ thousands, except per boe)	**Three months ended June 30, 2017**	Three months ended June 30, 2016	**Six months ended June 30, 2017**	Six months ended June 30, 2016
Transportation costs	**5,123**	4,750	**9,907**	10,184
Per boe	**2.75**	2.38	**2.51**	2.44

In the second quarter and first half of 2017, the Company's transportation costs per boe increased as compared to the same periods in 2016 as a result of increased production in Other NE BC which attracts higher transportation costs per boe as compared to the corporate average. In addition, the aforementioned lower natural gas production resulting from third party facility and pipeline outages resulted in unutilized fixed facility and pipeline usage demand charges. This negatively impacted transportation costs by approximately $0.22 per boe for the second quarter and $0.10 per boe for the first six months of 2017. With an increase in forecasted Greater Septimus production in the second half of 2017, the Company continues to forecast transportation costs per boe to range between $2.25 and $2.50 for 2017.

Operating Netbacks

($/boe)	**Greater Septimus**	**Lloydminster Heavy Oil**	**Other NE BC**	**Three months ended June 30, 2017**	Three months ended June 30, 2016
Revenue	**24.51**	**44.97**	**24.23**	**26.25**	18.14
Royalties	**(1.57)**	**(5.10)**	**(2.76)**	**(2.06)**	(1.02)
Realized commodity hedging gain/(loss)	**0.77**	**(1.25)**	**1.06**	**0.64**	2.83
Operating costs	**(4.10)**	**(20.03)**	**(8.47)**	**(6.15)**	(6.04)
Transportation costs	**(2.03)**	**(0.94)**	**(7.37)**	**(2.75)**	(2.38)
Operating netbacks	**17.58**	**17.65**	**6.69**	**15.93**	11.53
Production (boe/d)	**15,558**	**1,784**	**3,126**	**20,468**	21,950

($/boe)	**Greater Septimus**	**Lloydminster Heavy Oil**	**Other NE BC**	**Six months ended June 30, 2017**	Six months ended June 30, 2016
Revenue	**25.55**	**43.88**	**24.19**	**26.86**	17.42
Royalties	**(1.62)**	**(5.47)**	**(2.76)**	**(2.12)**	(0.95)
Realized commodity hedging gain/(loss)	**0.15**	**(0.67)**	**0.25**	**0.10**	2.51
Operating costs	**(3.70)**	**(21.31)**	**(7.27)**	**(5.74)**	(6.25)
Transportation costs	**(1.84)**	**(0.96)**	**(6.43)**	**(2.51)**	(2.44)
Operating netbacks	**18.54**	**15.47**	**7.98**	**16.59**	10.29
Production (boe/d)	**16,494**	**1,824**	**3,523**	**21,841**	22,890

For the second quarter and first half of 2017, the Company's operating netbacks increased over the same period in 2016 as a result of a significant increase in realized pricing, partially offset by increased royalties and decreased realized gains on commodity hedging.

General and Administrative Costs

($ thousands, except per boe)	**Three months ended June 30, 2017**	Three months ended June 30, 2016	**Six months ended June 30, 2017**	Six months ended June 30, 2016
Gross costs	**4,469**	4,099	**9,446**	9,529
Operator's recoveries	**(35)**	(92)	**(209)**	(101)
Capitalized costs	**(1,593)**	(1,461)	**(3,250)**	(3,065)
General and administrative expenses	**2,841**	2,546	**5,987**	6,363
Per boe	**1.52**	1.28	**1.51**	1.53

Gross and net general and administrative ("G&A") costs have increased in the three months ended June 30, 2017 as compared to the same period in 2016, due to an increase in compensation costs. For the first half of 2017, the adjusted office rent costs from the renewed five year lease term contributed to a slight decrease in gross and net G&A as compared to the same period in 2016. G&A costs per boe were also impacted by the aforementioned decline in production related to third party facility and pipeline outages. Crew forecasts G&A costs per boe to average between $1.25 and $1.50 in 2017 with higher forecasted production lowering G&A per boe in the second half of 2017.

Share-Based Compensation

($ thousands)	**Three months ended June 30, 2017**	Three months ended June 30, 2016	**Six months ended June 30, 2017**	Six months ended June 30, 2016
Gross costs	**3,837**	3,607	**9,950**	8,792
Capitalized costs	**(1,830)**	(1,677)	**(4,789)**	(4,011)
Total share-based compensation	**2,007**	1,930	**5,161**	4,781

Share-based compensation expense for the three and six months ended June 30, 2017 increased as compared to the same periods in 2016, due to additional compensation expense recorded as a result of a higher fair value of awards granted in the current year as compared to the same period in 2016.

Depletion and Depreciation

($ thousands, except per boe)	**Three months ended June 30, 2017**	Three months ended June 30, 2016	**Six months ended June 30, 2017**	Six months ended June 30, 2016
Depletion and depreciation	**16,393**	20,478	**36,103**	45,426
Per boe	**8.80**	10.25	**9.13**	10.90

In the second quarter and first half of 2017, depletion and depreciation costs decreased by 20% and 21%, respectively, and costs per boe decreased by 14% and 16%, respectively, as compared to the same periods in 2016. These decreases were due to increased 2016 year end proved plus probable reserve bookings at Greater Septimus, where depletion rates are substantially lower than the corporate average. Additionally, lower depletion was recognized on the Lloydminster cash-generating unit ("CGU") due to an impairment write down in the fourth quarter of 2016 which reduced the CGU's net book value.

Impairment

At June 30, 2017, due to the continuing decline in the heavy oil price environment, reduced future heavy oil development plans and the prevailing heavy oil transaction market, the Company tested its Lloydminster CGU for impairment. It was determined that the carrying value of the Lloydminster heavy oil CGU exceeded its fair value and a $16.7 million impairment charge was recorded. There were no indicators of impairment for the Company's northeast British Columbia CGU and therefore an impairment test was not performed.

Gain on Divesture of Property

During the second quarter of 2017, the Company disposed of non-core assets in northeast British Columbia for cash proceeds of $49.1 million. The disposed assets had a net book value of $11.4 million and associated decommissioning obligations of $0.2 million, resulting in a gain of $37.9 million on closing of the disposition.

Finance Expenses

($ thousands, except per boe)	**Three months ended June 30, 2017**	Three months ended June 30, 2016	**Six months ended June 30, 2017**	Six months ended June 30, 2016
Interest on bank loan	**350**	1,131	**1,316**	2,156
Interest on senior notes	**4,862**	3,132	**8,723**	6,230
Accretion of deferred financing charges	**250**	175	**457**	350
Accretion of the decommissioning obligation	**479**	436	**953**	869
Premium paid on redemption of 2020 Notes	**-**	-	**6,282**	-
Deferred financing costs expensed on 2020 Notes	**-**	-	**2,510**	-
Total finance expense	**5,941**	4,874	**20,241**	9,605
Average debt level	**300,000**	249,128	**285,040**	239,013
Average drawings on bank loan	**-**	99,128	**36,422**	89,013
Average senior unsecured notes outstanding	**300,000**	150,000	**248,619**	150,000
Effective interest rate on senior notes	**6.5%**	8.4%	**7.1%**	8.4%
Effective interest rate on long-term debt	**7.3%**	6.9%	**7.4%**	7.1%
Interest on long-term debt per boe	**2.93**	2.22	**2.66**	2.10

The Company's average corporate debt level increased in the three and six months ended June 30, 2017 as compared to the same periods in 2016, due to the March 14, 2017 issuance of $300 million of 6.5% senior unsecured notes (the "2024 Notes") as described below in the Capital Funding section. Proceeds from the 2024 Notes were used to redeem the $150 million of 8.375% senior unsecured notes (the "2020 Notes") and repay the drawings on the bank loan. As a result, the effective interest rate on the Company's senior notes decreased for both the three and six months ended June 30, 2017 as compared to the same periods in 2016, and the Company's effective interest rate on long term debt increased for the three months ended June 30, 2017 due to an increase in standby fees as the Company was undrawn on its bank facility throughout the second quarter of 2017. The effective interest rate on long term debt for the six months ended June 30, 2017 is consistent with the same period in the prior year as the effect of increased standby fees was offset by a decrease in the interest rate on the Company's senior notes. Crew forecasts the effective interest rate on its long-term debt to average between 6.5% and 7.5% for 2017.

Deferred Income Taxes

In the second quarter and first half of 2017, the provision for deferred tax expense was $8.7 million and $16.5 million, respectively, as compared to the deferred tax recovery of $5.4 million and $7.2 million, respectively, in the same periods in 2016. These differences are a result of increased income before taxes from the significant gain on disposition of non-core assets in the second quarter of 2017, combined with the large unrealized loss on financial instruments recorded in the second quarter of 2016.

Cash, Funds from Operations and Net Income (Loss)

($ thousands, except per share amounts)	**Three months ended June 30, 2017**	Three months ended June 30, 2016	**Six months ended June 30, 2017**	Six months ended June 30, 2016
Cash provided by operating activities	**31,359**	12,047	**58,548**	31,638
Funds from operations	**21,353**	16,048	**49,072**	27,762
Per share - basic	**0.14**	0.11	**0.33**	0.20
- diluted	**0.14**	0.11	**0.32**	0.19
Net Income (loss)	**21,880**	(16,815)	**29,936**	(23,610)
Per share - basic	**0.15**	(0.12)	**0.20**	(0.17)
- diluted	**0.14**	(0.12)	**0.20**	(0.17)

The increase in cash provided by operating activities and funds from operations in the second quarter and the first half of 2017 was a result of a significant increase in realized commodity prices partially offset by an increase in royalties and a decrease in realized hedging gains. The increase in net income in the second quarter and first half of 2017 as compared to the same period in 2016 is a result of the increase in the Company's revenue combined with the gain on disposition of non-core properties in the second quarter of 2017, coupled with unrealized gains on 2017 hedging compared to the same period last year where the Company realized hedging losses.

Capital Expenditures, Property Acquisitions and Dispositions

In the second quarter of 2017, the Company drilled six (6.0 net) natural gas wells in northeast British Columbia and one (1.0 net) oil well in Lloydminster. Crew completed nine (9.0 net) wells in northeast British Columbia and two (2.0 net) oil wells in Lloydminster, and also recompleted five (4.5 net) oil wells in Lloydminster.

The Company continued with the 120 mmcf per day expansion of the West Septimus facility, spending $4.2 million in the second quarter and also incurred $9.0 million on other miscellaneous infrastructure projects in northeast British Columbia. The Company confirmed the participation of one of its working interest partners in the West Septimus facility expansion, who will participate for 72% of the costs. Net second quarter facility expenditures reflect the recovery of costs incurred in prior quarters due to the partner's participation in the expansion.

During the second quarter of 2017, the Company completed the disposition of non-core assets in northeast British Columbia for cash proceeds of $49.1 million. The assets included undeveloped land of approximately 18,400 net acres, with no assigned reserves or current production associated therewith. The Company also acquired 11.9 sections of surface rights at Groundbirch for the planned construction of a gas plant and associated future Montney well development for $3.8 million.

Total net capital expenditures are detailed below:

($ thousands)	**Three months ended June 30, 2017**	Three months ended June 30, 2016	**Six months ended June 30, 2017**	Six months ended June 30, 2016
Land	**820**	676	**1,690**	1,295
Seismic	**222**	222	**482**	399
Drilling and completions	**37,842**	10,587	**90,910**	24,376
Facilities, equipment and pipelines	**(3,880)**	2,072	**15,087**	3,537
Other	**1,652**	1,539	**3,651**	3,252
Total exploration and development	**36,656**	15,096	**111,820**	32,859
Property (dispositions) acquisitions	**(45,701)**	16	**(46,053)**	972
Total	**(9,045)**	15,112	**65,767**	33,831

LIQUIDITY AND CAPITAL RESOURCES

Capital Funding

As at June 30, 2017, the Company's bank facility consists of a revolving line of credit of $210 million and an operating line of credit of $25 million (the "Facility"). The Facility revolves for a 364 day period and will be subject to its next 364 day extension by June 6, 2018. 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 (the "Borrowing Base") are reviewed semi-annually and are based on the bank syndicate's interpretation of the Company's reserves and future commodity prices. The credit agreement requires the Company to maintain a debt to EBITDA ratio of 4:1 and a secured debt to EBITDA ratio of 3:1 at the end of each fiscal quarter. Debt consists of the Company's bank loan and senior unsecured notes while secured debt consists of the Company's bank loan. At June 30, 2017, these ratios were 2.5:1 and 0.0:1, respectively. EBITDA is a non-GAAP measure and is defined in the credit agreement as earnings before interest, taxes, depreciation and amortization, unrealized gains or losses on financial instruments, share-based compensation, all other non-cash items and EBITDA from disposed properties and acquisitions for the most recent twelve month period. Other non-cash items include impairment, gains or losses on divestitures, premium on flow-through shares and unrealized gains or losses on marketable securities for the most recent twelve month period. 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, 2017. The Facility is secured by a floating charge debenture and a general securities agreement on the assets of the Company.

On March 14, 2017, the Company issued $300 million of 6.5% senior unsecured notes, due March 14, 2024 (the "2024 Notes"). The 2024 Notes are guaranteed, jointly and severally, on an unsecured basis, by each of the Company's current and future restricted subsidiaries. Interest on the 2024 Notes accrues at the rate of 6.5% per year and is payable semi-annually. At June 30, 2017, the carrying value of the 2024 Notes was net of deferred financing costs of $6.7 million.

Prior to March 14, 2020, the Company may redeem, on any one or more occasions, up to 35% of the aggregate principal amount of the 2024 Notes, with the cash proceeds from certain equity issues, at a redemption price of 106.5%, plus accrued and unpaid interest. In addition, at any time prior to March 14, 2020, the Company may redeem, on any one or more occasions, all or part of the 2024 Notes at a price equal to par, plus a "make-whole" premium and any accrued and unpaid interest. At any time on or after March 14, 2020, the Company may redeem, on any one or more occasions, all or part of the 2024 Notes at the redemption prices set forth below, plus any accrued and unpaid interest:

Year[(1)]	Percentage
2020	103.250%
2021	102.145%
2022	101.040%
2023 and thereafter	100.000%

(1) For the 12 month period beginning on March 14 of each year.

Upon the occurrence of a change of control, the Company will be required to offer to repurchase each holder's notes at a price equal to not less than 101% of the principal amount, plus any accrued and unpaid interest.

In connection with the issuance of the 2024 Notes, on March 23, 2017 the Company redeemed all of the previously issued and outstanding $150 million of 8.375% senior unsecured notes, due October 21, 2020 (the "2020 Notes") at a redemption price of $1,041.88 per $1,000 of principal amount, plus accrued and unpaid interest. A redemption premium of $6.3 million and unamortized deferred financing costs of $2.5 million were recorded in financing expense as a result of the 2020 Notes redemption.

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

Working Capital

The capital intensive nature of Crew's activities generally results in the Company carrying a working capital deficit; however, in the second quarter of 2017, the Company carried a working capital surplus of $18.8 million. Working capital includes cash and cash equivalents and accounts receivable less accounts payable and accrued liabilities. Included in working capital surplus is $28.1 million of cash and a receivable of $8.3 million for a government grant credit earned through the completion of the construction of the Pine River pipeline. The collection of the grant is realized through the reduction of future royalties payable to the British Columbia government. In addition, the working capital surplus includes a receivable of $24.4 million relating to the partner's share of the West Septimus facility expansion costs which is expected to be collected in the fourth quarter of 2017.

The Company ensures that sufficient drawings are available from its Facility to satisfy working capital requirements. At June 30, 2017, the Company had a working capital surplus of $18.8 million and as a result, there were no drawings on the Facility.

Share Capital

On May 25, 2017, the Company commenced a normal course issuer bid (the "NCIB"), under which the Company may purchase for cancellation up to a maximum of 7,491,368 common shares of the Company. The NCIB will terminate on May 24, 2018 or such earlier time as the maximum number of common shares are purchased pursuant to the NCIB or the NCIB is terminated at the option of the Company. For the six months ended June 30, 2017, 924,100 common shares for a total cost of $3.3 million were purchased, cancelled and removed from share capital.

In 2016, the Company closed a non-brokered private placement offering of 1,845,100 common shares at a price of $8.13 per share for gross proceeds of $15.0 million. The shares were issued on a flow-through basis, with an issuance premium to the common share trading value at the time of issuance of $1.4 million. Pursuant to the provisions of the Income Tax Act (Canada) and the terms of the offering, the Company committed to renounce to the subscribers Canadian Development Expenses incurred by the Company of $7.5 million by each of January 31, 2017 and March 31, 2017. The Company renounced the Canadian Development Expenses such that the full proceeds were deductible against the subscribers' income in 2017. The Company has incurred the entire $15.0 million in qualifying expenditures under this flow-through share offering during the first quarter of 2017.

Crew is authorized to issue an unlimited number of common shares. As at August 2, 2017, there were 148,909,620 common shares issued and outstanding and options to acquire 25,800 common shares. In addition, there were 1,770,683 restricted awards and 2,596,508 performance awards outstanding under the Company's long-term incentive program.

Capital Structure

The Company considers its capital structure to include working capital, long-term debt (including the bank loan and senior unsecured notes) 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 ongoing basis in order to maintain the flexibility needed to achieve the Company's long-term objectives. To manage its 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 long-term debt and net working capital, divided by annualized funds from operations for the most recent quarter.

The Company monitors this ratio and endeavors to maintain it at or below 2.0 to 1.0. During periods of increased capital expenditures, acquisitions or during extended periods of low commodity prices, this ratio will increase. As shown below, as at June 30, 2017, the Company's ratio of net debt to annualized funds from operations was 3.21 to 1 (December 31, 2016 – 2.20 to 1). With the Company's $235 million Facility undrawn and extended until June 2018, along with the long-term 2024 Notes, the Company's financial position is strong. If the Company feels it is necessary to improve its financial position, it will consider divesting of non-core properties, will further adjust its annual capital expenditure program or may consider other forms of financing.

($ thousands, except ratio)	**June 30, 2017**	December 31, 2016
Working capital surplus (deficiency)	**18,831**	(10,006)
Bank loan	**-**	(88,036)
Senior unsecured notes	**(293,296)**	(147,329)
Net debt	**(274,465)**	(245,371)
Quarterly funds from operations	**21,353**	27,879
Annualized	**85,412**	111,516
Net debt to annualized funds from operations ratio	**3.21**	2.20

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	2017	2018	2019	2020	2021	Thereafter
Senior unsecured notes (note 1)	300,000	-	-	-	-	-	300,000
Operating leases	4,504	587	1,175	1,175	1,175	392	-
Capital commitments	6,764	6,764	-	-	-	-	-
Firm transportation agreements	125,703	16,210	31,972	29,687	26,456	3,517	17,861
Firm processing agreements	90,334	6,398	12,691	12,691	11,390	7,449	39,715
Total	**527,305**	**29,959**	**45,838**	**43,553**	**39,021**	**11,358**	**357,576**

Note 1 – Matures on March 14, 2024.

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

Capital commitments includes the Company's share of the estimated remaining cost for the expansion of the West Septimus natural gas processing facility.

Firm transportation agreements include commitments to third parties to transport natural gas and natural gas liquids from gas processing facilities in northeast British Columbia.

Firm processing agreements include commitments to process natural gas through the Septimus complex gas processing facilities in northeast British Columbia.

GUIDANCE

The Company's guidance for 2017 remains unchanged with average production of 24,000 to 26,000 boe per day and a forecast year end exit rate over 31,000 boe per day. Crew is currently focused on proceeding with the infrastructure buildout and the drilling of an inventory of wells in support of its growth plan as these key elements require the longest lead time. Crew expects third quarter average production of 24,500 to 26,500 and fourth quarter average production of 29,500 to 31,500 boe per day. The Company is currently monitoring projected activity and pricing levels for the first quarter of 2018 and will flex our well completion schedule and capital as appropriate to mitigate the service supply constraints and cost inflation experienced in the first quarter of 2017.

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 2017**	Mar. 31 2017	Dec. 31 2016	Sep. 30 2016	June 30 2016	Mar. 31 2016	Dec. 31 2015	Sep. 30 2015
Total daily production (boe/d)	**20,468**	23,231	22,380	23,211	21,950	23,832	20,706	16,773
Exploration and development expenditures	**36,656**	75,164	37,612	37,731	15,096	17,763	42,067	58,565
Property (dispositions)/acquisitions	**(45,701)**	(352)	3,099	(98)	16	956	(36,644)	(50,281)
Average wellhead price ($/boe)	**26.25**	27.40	26.74	22.05	18.14	16.76	18.13	22.54
Petroleum and natural gas sales	**48,886**	57,298	55,051	47,093	36,232	36,343	34,532	34,784
Cash provided by operations	**31,359**	27,189	19,900	25,940	12,047	19,591	12,373	22,091
Funds from operations	**21,353**	27,719	27,879	23,033	16,048	11,714	19,601	17,273
Per share – basic	**0.14**	0.19	0.19	0.16	0.11	0.08	0.14	0.12
– diluted	**0.14**	0.18	0.19	0.16	0.11	0.08	0.14	0.12
Net income (loss)	**21,880**	8,056	(40,030)	(1,286)	(16,815)	(6,795)	(8,167)	(18,179)
Per share – basic	**0.15**	0.05	(0.28)	(0.01)	(0.12)	(0.05)	(0.06)	(0.13)
– diluted	**0.14**	0.05	(0.28)	(0.01)	(0.12)	(0.05)	(0.06)	(0.13)

Over the past eight quarters, the Company has invested the majority of its capital expenditures in northeastern British Columbia, increasing production by 44% in these areas over that time period. In the fourth quarter of 2015 and into the first half of 2016, commodity prices significantly declined forcing the Company to decrease capital expenditures in the first half of 2016. As prices began their recovery in the latter part of 2016, the Company subsequently increased its capital expenditures at Greater Septimus and Tower. Despite the conservative first half of 2016 capital program, the Company's 2016 production remained fairly stable throughout the year with limited planned growth. In the latter part of 2016 and into 2017, as commodity prices strengthened, the Company has expanded its capital program and infrastructure spending in order to prepare for projected growth late in 2017.

The significant fluctuations in commodity prices have impacted cash provided by operations, funds from operations and net income (loss). Crew has reduced the financial impact of volatile commodity prices by entering into derivative and physical risk management contracts which can cause significant fluctuations in income due to unrealized gains and losses recognized on a quarterly basis. The Company has also attempted to mitigate the lower price environment by reducing its controllable costs. Over the past two years, low commodity prices have also led to the assessment and realization of impairment of the carrying value of the Lloydminster CGU. From 2015 to 2017, the Company has incurred impairment charges of $55.4 million, $44.4 million and $16.7 million, respectively. These charges have been partially offset by gains on the sale of certain properties in 2015 and 2017. In the first half of 2017, the Company's production declined as a result of significant third party facility outages and an extended spring break up which has shifted planned investment and projected growth to the second half of year. The Company has increased its infrastructure spending to facilitate this growth and continues to monetize non-core properties where the Company realized a $37.9 million gain on the divesture in the second quarter of 2017.

New Accounting Pronouncements

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

a) IFRS 15 Revenue from Contracts with Customers:

As of January 1, 2018, the Company will be required to adopt IFRS 15 Revenue from Contracts with Customers. The new standard replaces IAS 11 Construction Contracts; IAS 18 Revenue, IFRIC 13 Customer Loyalty Programmes, IFRIC 15 Agreements for the Construction of Real Estate, IFRIC 18 Transfers of Assets from Customers and SIC 31 Revenue-Barter Transactions Involving Advertising Services. The new standard dictates the recognition and measurement requirements for reporting the nature, amount, timing and uncertainty of revenue resulting from an entity's contracts with customers. The Company is currently in the process of identifying and reviewing underlying revenue contracts with customers to determine the impact, if any, that the adoption of IFRS 15 will have on its financial statements, including enhanced disclosures of disaggregation of revenue.

b) IFRS 9 Financial Instruments:

As of January 1, 2018, 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. In addition, updates have also been applied surrounding hedge accounting requirements which are now more aligned with an entity's risk management activities. The Company does not currently apply hedge accounting to its financial instruments contracts and does not currently intend to apply hedge accounting to any of its financial instrument contracts upon adoption of IFRS 9.

c) IFRS 16 Leases:

As of January 1, 2019, the Company will be required to adopt IFRS 16 Leases, which will replace IFRS 17 Leases. For lessees applying the new standard, a single recognition and measurement model for leases would apply, with required recognition of assets and liabilities for most leases. Crew is still determining the impact that the adoption of this standard will have on its financial statements.

Disclosure Controls and Procedures and Internal Controls over Financial Reporting

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

The Company's CEO and CFO have designed, or caused to be designed under their supervision, internal controls over financial reporting to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. The Company is required to disclose herein any change in the Company's internal controls over financial reporting that occurred during the period beginning on April 1, 2017 and ended on June 30, 2017 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 2, 2017

CONDENSED INTERIM CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

(unaudited) (thousands)	**June 30, 2017**	December 31, 2016
Assets		
Current Assets:		
Cash and cash equivalents	**$ 28,080**	$ -
Accounts receivable	**50,194**	39,588
Derivative financial instruments (note 8)	**6,839**	-
	85,113	39,588
Derivative financial instruments (note 8)	**715**	-
Property, plant and equipment (note 3)	**1,255,279**	1,199,452
	$ 1,341,107	$ 1,239,040
Liabilities and Shareholders' Equity		
Current Liabilities:		
Accounts payable and accrued liabilities	**$ 59,443**	$ 49,594
Derivative financial instruments (note 8)	**-**	18,900
	59,443	68,494
Derivative financial instruments (note 8)	**128**	490
Bank loan (note 4)	**-**	88,036
Senior unsecured notes (note 5)	**293,296**	147,329
Decommissioning obligations (note 6)	**86,296**	85,859
Deferred premium on flow-through shares (note 7)	**-**	1,419
Deferred tax liability	**43,620**	25,724
Shareholders' Equity		
Share capital (note 7)	**1,455,816**	1,442,284
Contributed surplus	**68,127**	74,960
Deficit	**(665,619)**	(695,555)
	858,324	821,689
Commitments (note 10)		
	$ 1,341,107	$ 1,239,040

See accompanying notes to the condensed interim consolidated financial statements.

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

(unaudited) (thousands, except per share amounts)	**Three months ended June 30, 2017**	Three months ended June 30, 2016	**Six months ended June 30, 2017**	Six months ended June 30, 2016
Revenue				
Petroleum and natural gas sales	**$ 48,886**	$ 36,232	**$ 106,184**	$ 72,575
Royalties	**(3,836)**	(2,039)	**(8,393)**	(3,938)
Realized gain on derivative financial instruments (note 8)	**1,192**	5,661	**377**	10,459
Unrealized gain (loss) on derivative financial instruments (note 8)	**6,941**	(15,501)	**26,816**	(8,297)
	53,183	24,353	**124,984**	70,799
Expenses				
Operating	**11,463**	12,072	**22,706**	26,051
Transportation	**5,123**	4,750	**9,907**	10,184
General and administrative	**2,841**	2,546	**5,987**	6,363
Share-based compensation	**2,007**	1,930	**5,161**	4,781
Depletion and depreciation (note 3)	**16,393**	20,478	**36,103**	45,426
	37,827	41,776	**79,864**	92,805
Income (loss) from operations	**15,356**	(17,423)	**45,120**	(22,006)
Financing (note 9)	**5,941**	4,874	**20,241**	9,605
Gain on marketable securities	**-**	(77)	**-**	(955)
Impairment on property, plant and equipment (note 3)	**16,710**	-	**16,710**	-
(Gain) loss on divestiture of property, plant and equipment (note 3)	**(37,898)**	-	**(38,244)**	130
Income (loss) before income taxes	**30,603**	(22,220)	**46,413**	(30,786)
Deferred tax expense (recovery)	**8,723**	(5,405)	**16,477**	(7,176)
Net income (loss) and comprehensive income (loss)	**$ 21,880**	$ (16,815)	**$ 29,936**	$ (23,610)
Net income (loss) per share (note 7)				
Basic	**$ 0.15**	$ (0.12)	**$ 0.20**	$ (0.17)
Diluted	**$ 0.14**	$ (0.12)	**$ 0.20**	$ (0.17)

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, 2017	146,812	$ 1,442,284	$ 74,960	$ (695,555)	$ 821,689
Net income for the period	-	-	-	29,936	29,936
Share-based compensation expensed	-	-	5,161	-	5,161
Share-based compensation capitalized	-	-	4,789	-	4,789
Issued on vesting of share awards	3,022	16,783	(16,783)	-	-
Shares purchased and cancelled (note 7)	(924)	(3,251)	-	-	(3,251)
Balance, June 30, 2017	**148,910**	**$ 1,455,816**	**$ 68,127**	**$ (665,619)**	**$ 858,324**

(unaudited) (thousands)	Number of shares	Share capital	Contributed surplus	Deficit	Total Shareholders' equity
Balance, January 1, 2016	141,067	$ 1,398,698	$ 77,627	$ (630,629)	$ 845,696
Net loss for the period	-	-	-	(23,610)	(23,610)
Share-based compensation expensed	-	-	4,781	-	4,781
Share-based compensation capitalized	-	-	4,011	-	4,011
Issued on vesting of share awards	1,647	12,522	(12,522)	-	-
Balance, June 30, 2016	**142,714**	**$ 1,411,220**	**$ 73,897**	**$ (654,239)**	**$ 830,878**

See accompanying notes to the condensed interim consolidated financial statements.

CONDENSED INTERIM CONSOLIDATED STATEMENTS OF CASH FLOWS

(unaudited) (thousands)	**Three months ended June 30, 2017**	Three months ended June 30, 2016	**Six months ended June 30, 2017**	Six months ended June 30, 2016
Cash provided by (used in):				
Operating activities:				
Net income (loss)	**$ 21,880**	$ (16,815)	**$ 29,936**	$ (23,610)
Adjustments:				
Unrealized (gain) loss on derivative financial instruments	**(6,941)**	15,501	**(26,816)**	8,297
Share-based compensation	**2,007**	1,930	**5,161**	4,781
Depletion and depreciation	**16,393**	20,478	**36,103**	45,426
Financing expenses (note 9)	**5,941**	4,874	**20,241**	9,605
Interest expense (note 9)	**(5,212)**	(4,263)	**(10,039)**	(8,386)
Impairment on property, plant and equipment (note 3)	**16,710**	-	**16,710**	-
Gain on marketable securities	**-**	(77)	**-**	(955)
(Gain) loss on divestiture of property, plant and equipment (note 3)	**(37,898)**	-	**(38,244)**	130
Deferred tax expense (recovery)	**8,723**	(5,405)	**16,477**	(7,176)
Decommissioning obligations recovered (settled)	**22**	33	**(356)**	(386)
Change in non-cash working capital	**9,734**	(4,209)	**9,375**	3,912
	31,359	12,047	**58,548**	31,638
Financing activities:				
(Decrease) increase in bank loan	**-**	(922)	**(88,036)**	16,206
Issuance of senior notes, net of financing costs (note 5)	**-**	-	**293,000**	-
Redemption of senior notes (note 5)	**-**	-	**(156,282)**	-
Shares purchased and cancelled (note 7)	**(3,251)**	-	**(3,251)**	-
	(3,251)	(922)	**45,431**	16,206
Investing activities:				
Property, plant and equipment expenditures	**(36,656)**	(15,096)	**(111,820)**	(32,859)
Property acquisitions	**(3,812)**	(16)	**(3,820)**	(1,066)
Property dispositions (note 3)	**49,513**	-	**49,873**	94
Proceeds from disposition of marketable securities	**-**	2,115	**-**	2,115
Change in non-cash working capital	**(32,551)**	1,872	**(10,132)**	(16,128)
	(23,506)	(11,125)	**(75,899)**	(47,844)
Change in cash and cash equivalents	**4,602**	-	**28,080**	-
Cash and cash equivalents, beginning of period	**23,478**	-	**-**	-
Cash and cash equivalents, end of period	**$ 28,080**	$ -	**$ 28,080**	$ -

See accompanying notes to the condensed interim consolidated financial statements.

NOTES TO CONDENSED INTERIM CONSOLIDATED FINANCIAL STATEMENTS

For the three and six months ended June 30, 2017 and 2016

(Unaudited) (Tabular amounts in thousands)

1. Reporting entity:

Crew Energy Inc. ("Crew" or the "Company") is an oil and gas exploration, development and production company based in Calgary, Alberta, Canada. Crew conducts its operations in the Western Canadian Sedimentary basin, primarily in the provinces of British Columbia, Saskatchewan and Alberta. The condensed interim consolidated financial statements (the "financial statements") of the Company are comprised of the accounts of Crew and its wholly owned subsidiary, Crew Oil and Gas Inc., which is incorporated in Canada, and two partnerships, Crew Energy Partnership and Crew Heavy Oil Partnership. 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, 2016. 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. These financial statements are presented in Canadian dollars ("CDN"), which is the functional currency of the Company, its subsidiary and partnerships.

The condensed interim consolidated financial statements were authorized for issuance by Crew's Board of Directors on August 2, 2017.

3. Property, plant and equipment:

Cost or deemed cost		Total
Balance, January 1, 2016	$	2,061,858
Additions		108,202
Acquisitions		4,097
Divestitures		(254)
Change in decommissioning obligations		(320)
Capitalized share-based compensation		7,696
Balance, December 31, 2016	$	2,181,279
Additions		111,820
Acquisitions		3,820
Divestitures		(12,202)
Change in decommissioning obligations		383
Capitalized share-based compensation		4,789
Balance, June 30, 2017	**$**	**2,289,889**

Accumulated depletion and depreciation		Total
Balance, January 1, 2016	$	851,992
Depletion and depreciation expense		85,403
Impairment (net)		44,432
Balance, December 31, 2016	$	981,827
Depletion and depreciation expense		36,103
Divestitures		(30)
Impairment		16,710
Balance, June 30, 2017	**$**	**1,034,610**

Net book value		Total
Balance, June 30, 2017	**$**	**1,255,279**
Balance, December 31, 2016	$	1,199,452

The calculation of depletion for the three months ended June 30, 2017 included estimated future development costs of $1,553.7 million (December 31, 2016 - $1,603.2 million) associated with the development of the Company's proved plus probable reserves and excludes salvage value of $68.3 million (December 31, 2016 - $67.3 million) and undeveloped land of $170.7 million (December 31, 2016 - $182.3 million) related to future development acreage with no associated reserves.

At June 30, 2017, due to the continuing decline in the heavy oil price environment, reduced future heavy oil development plans and the prevailing heavy oil transaction market, the Company tested its Lloydminster cash generating unit ("CGU") for impairment. It was determined that the carrying value of the Lloydminster heavy oil CGU exceeded its fair value and a $16.7 million impairment charge was recorded. There were no indicators of impairment for the Company's northeast British Columbia CGU and therefore an impairment test was not performed.

During the quarter, the Company disposed of non-core assets in northeast British Columbia for cash proceeds of $49.1 million. The assets consisted of undeveloped land and had a net book value of $11.4 million and associated decommissioning obligations of $0.2 million, resulting in a gain of $37.9 million on closing of the disposition.

4. Bank loan:

As at June 30, 2017, the Company's bank facility consists of a revolving line of credit of $210 million and an operating line of credit of $25 million (the "Facility"). The Facility revolves for a 364 day period and will be subject to its next 364 day extension by June 6, 2018. 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 (the "Borrowing Base") are reviewed semi-annually and are based on the bank syndicate's interpretation of the Company's reserves and future commodity prices. The credit agreement requires the Company to maintain a debt to EBITDA ratio of 4:1 and a secured debt to EBITDA ratio of 3:1 at the end of each fiscal quarter. Debt consists of the Company's bank loan and senior unsecured notes while secured debt consists of the Company's bank loan. At June 30, 2017, these ratios were 2.5:1 and 0.0:1, respectively. EBITDA is a non-GAAP measure and is defined in the credit agreement as earnings before interest, taxes, depreciation and amortization, unrealized gains or losses on financial instruments, share-based compensation, all other non-cash items and EBITDA from disposed properties and acquisitions for the most recent twelve month period. Other non-cash items include impairment, gains or losses on divestitures, premium on flow-through shares and unrealized gains or losses on marketable securities for the most recent twelve month period. 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, 2017. The Facility is secured by a floating charge debenture and a general securities agreement on the assets of the Company.

Advances under the Facility are available by way of prime rate loans with interest rates between 0.50 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 1.50 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 0.375 percent to 0.875 percent depending upon the debt to EBITDA ratio. As at June 30, 2017, the Company's applicable pricing included a 0.50 percent margin on prime lending, a 1.50 percent stamping fee and margin on bankers' acceptances and LIBOR loans along with a 0.375 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, 2017, the Company had issued letters of credit totaling $8.2 million (December 31, 2016 - $13.6 million). The effective interest rate on the Company's borrowings under its Facility for the six months ended June 30, 2017 was 7.3% (December 31, 2016 – 4.8%), which includes standby fees on the undrawn amounts of the Facility.

5. Senior unsecured notes:

On March 14, 2017, the Company issued $300 million of 6.5% senior unsecured notes, due March 14, 2024 (the "2024 Notes"). The 2024 Notes are guaranteed, jointly and severally, on an unsecured basis, by each of the Company's current and future restricted subsidiaries. Interest on the 2024 Notes accrues at the rate of 6.5% per year and is payable semi-annually. At June 30, 2017, the carrying value of the 2024 Notes was net of deferred financing costs of $6.7 million.

Prior to March 14, 2020, the Company may redeem, on any one or more occasions, up to 35% of the aggregate principal amount of the 2024 Notes, with the cash proceeds from certain equity issues, at a redemption price of 106.5%, plus accrued and unpaid interest. In addition, at any time prior to March 14, 2020, the Company may redeem, on any one or more occasions, all or part of the 2024 Notes at a price equal to par, plus a "make-whole" premium and any accrued and unpaid interest. At any time on or after March 14, 2020, the Company may redeem, on any one or more occasions, all or part of the 2024 Notes at the redemption prices set forth below, plus any accrued and unpaid interest:

Year(1)	Percentage
2020	103.250%
2021	102.145%
2022	101.040%
2023 and thereafter	100.000%

(1) For the 12 month period beginning on March 14 of each year.

Upon the occurrence of a change of control, the Company will be required to offer to repurchase each holder's notes at a price equal to not less than 101% of the principal amount, plus any accrued and unpaid interest.

In connection with the issuance of the 2024 Notes, on March 23, 2017 the Company redeemed all of the previously issued and outstanding $150 million of 8.375% senior unsecured notes, due October 21, 2020 (the "2020 Notes") at a redemption price of $1,041.88 per $1,000 of principal amount, plus accrued and unpaid interest. A redemption premium of $6.3 million and unamortized deferred financing costs of $2.5 million were recorded in financing expense as a result of the 2020 Notes redemption (Financing – note 9).

6. Decommissioning obligations:

	Six months ended June 30, 2017	Year ended December 31, 2016
Decommissioning obligations, beginning of period	**$ 85,859**	$ 85,822
Obligations incurred	**1,977**	1,344
Obligations acquired	**-**	4,061
Obligations settled	**(356)**	(1,411)
Obligations divested	**(543)**	-
Change in estimated future cash outflows	**(1,594)**	(5,725)
Accretion of decommissioning obligations	**953**	1,768
Decommissioning obligations, end of period	**$ 86,296**	$ 85,859

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 $86.3 million as at June 30, 2017 (December 31, 2016 - $85.9 million) based on an inflation adjusted undiscounted total future liability of $114.3 million (December 31, 2016 - $113.4 million). These payments are expected to be made over the next 40 years, with the majority of costs to be incurred between 2020 and 2035. The inflation rate applied to the liability is 2% (December 31, 2016 – 2%). The discount factor, being the risk-free rate related to the liability, is 2.21% (December 31, 2016 –

2.21%). The $1.6 million (December 31, 2016 - $5.7 million) change in estimated future cash outflows for the six months ended June 30, 2017 is a result of a change in future estimated undiscounted abandonment costs.

7. Share capital:

At June 30, 2017, the Company was authorized to issue an unlimited number of common shares with the holders of common shares entitled to one vote per share.

On May 25, 2017, the Company commenced a normal course issuer bid (the "NCIB"), under which the Company may purchase for cancellation up to a maximum of 7,491,368 common shares of the Company. The NCIB will terminate on May 24, 2018 or such earlier time as the maximum number of common shares are purchased pursuant to the NCIB or the NCIB is terminated at the option of the Company. For the six months ended June 30, 2017, 924,100 common shares for a total cost of $3.3 million were purchased, cancelled and removed from share capital.

In 2016, the Company closed a non-brokered private placement offering of 1,845,100 common shares at a price of $8.13 per share for gross proceeds of $15.0 million. The shares were issued on a flow-through basis, with an issuance premium to the common share trading value at the time of issuance of $1.4 million. Pursuant to the provisions of the Income Tax Act (Canada) and the terms of the offering, the Company committed to renounce to the subscribers Canadian Development Expenses incurred by the Company of $7.5 million by each of January 31, 2017 and March 31, 2017. The Company renounced the Canadian Development Expenses such that the full proceeds were deductible against the subscribers' income in 2017. The Company incurred the entire $15.0 million in qualifying expenditures under this flow-through share offering during the first quarter of 2017.

Share based payments:

The Company had a stock option program that entitles officers, directors, employees and certain consultants to purchase shares in the Company. Options were granted at the market price of the shares at the date of grant, have a four year term and vested over three years. The Company elected not to seek shareholder approval for the requisite three-year renewal of its option program at its 2014 annual meeting and, as a result, is no longer eligible to issue new options without shareholder approval. Previously issued options will remain outstanding until exercised or their expiry.

The following table summarizes stock options outstanding as at June 30, 2017, all of which are exercisable:

	Number of options	Weighted average remaining life (years)	Weighted average exercise price
Balance, January 1, 2017	1,430	0.3	$ 7.08
Forfeited	(3)	-	7.17
Expired	(1,401)	-	7.10
Balance, June 30, 2017	**26**	**0.3**	**$ 5.70**

Restricted and Performance Award Incentive Plan:

The Company has 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. 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. Through the vesting of 728,000 restricted awards and 1,147,000 performance awards, when taking into account the earned multipliers for performance awards, 3,022,000 common shares of the Company were issued for the six months ended June 30, 2017.

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

	Number of RAs	Number of PAs
Balance, January 1, 2017	1,699	2,537
Granted	896	1,306
Vested	(728)	(1,147)
Forfeited	(72)	(63)
Balance, June 30, 2017	**1,795**	**2,633**

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, 2017 was 149,469,000 (June 30, 2016 – 142,524,000) and for the six month period ended June 30, 2017, the weighted average number of shares outstanding was 148,152,000 (June 30, 2016 – 141,797,000).

In computing diluted earnings per share for the three month period ended June 30, 2017, 2,051,000 (June 30, 2016 – nil) 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, 2017, 3,001,000 (June 30, 2016 – nil) shares were added to the weighted average common shares for the dilution. For the three month period ended June 30, 2017, there were 26,000 (June 30, 2016 – 3,366,000) stock options and 2,515,000 (June 30, 2016 – 4,439,000) restricted and performance awards that were not included in the diluted earnings per share calculation because they were anti-dilutive. For the six month period ended June 30, 2017, there were 26,000 (June 30, 2016 – 3,366,000) stock options and 2,883,000 (June 30, 2016 – 4,439,000) restricted and performance awards that were not included in the diluted earnings per share calculation because they were anti-dilutive.

8. Financial risk management:

Derivative contracts:

It is the Company's policy to economically hedge a portion of its oil and natural gas revenues 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, 2017, the Company held derivative commodity contracts as follows:

Subject of Contract	Notional Quantity	Term	Reference	Strike Price	Option Traded	Fair Value ($000s)
Gas	2,500 gj/day	July 1, 2017 – October 31, 2017	AECO C Daily Index	$2.55	Swap	80
Gas	22,500 mmbtu/day	July 1, 2017 – December 31, 2017	Chicago Citygate	$3.88	Swap	308
Oil	1,750 bbl/day	July 1, 2017 – December 31, 2017	CDN$ WTI	$68.02	Swap	2,408
Gas	22,500 gj/day	July 1, 2017 – December 31, 2017	AECO C Monthly Index	$2.83	Swap	1,759
Gas	10,000 gj/day	July 1, 2017 – December 31, 2017	AECO C Daily Index	$3.08	Swap	1,397
Gas	5,000 mmbtu/day	July 1, 2017 – December 31, 2018	Chicago Citygate	$4.23	Swap	1,424
Gas	5,000 gj/day	January 1, 2018 – December 31, 2018	AECO C Monthly Index	$3.00	Call	(257)
Gas	2,500 gj/day	January 1, 2018 – December 31, 2018	AECO C Daily Index	$2.62	Swap	174
Gas	5,000 mmbtu/day	January 1, 2018 – December 31, 2018	US$ Nymex Henry Hub	$3.05	Swap	133
Total						7,426

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, long-term debt (including the bank loan and senior unsecured notes) 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 ongoing basis in order to maintain the flexibility needed to achieve the Company's long-term objectives. To manage its 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 long-term 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. During periods of increased capital expenditures, acquisitions or during extended periods of low commodity prices, this ratio will increase. As shown below, as at June 30, 2017, the Company's ratio of net debt to annualized funds from operations was 3.21 to 1 (December 31, 2016 – 2.20 to 1). With the Company's $235 million Facility undrawn and extended until June 2018, along with the recently issued long-term 2024 Notes, the Company's financial position is strong. If the Company feels it is necessary to improve its financial position, it will consider divesting of non-core properties, will further adjust its annual capital expenditure program or may consider other forms of financing.

		June 30, 2017		December 31, 2016
Net debt:				
Cash and cash equivalents	$	**28,080**	$	-
Accounts receivable		**50,194**		39,588
Accounts payable and accrued liabilities		**(59,443)**		(49,594)
Working capital surplus (deficiency)	$	**18,831**	$	(10,006)
Bank loan		**-**		(88,036)
Senior unsecured notes		**(293,296)**		(147,329)
Net debt	$	**(274,465)**	$	(245,371)
Quarterly Annualized funds from operations:				
Cash provided by operating activities	$	**31,359**	$	19,900
Decommissioning obligations (settled) recovered		**(22)**		763
Change in non-cash working capital		**(9,734)**		7,394
Accretion of deferred financing charges		**(250)**		(178)
Quarterly Funds from operations	$	**21,353**	$	27,879
Annualized	$	**85,412**	$	111,516
Net debt to annualized funds from operations		**3.21**		2.20

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 (Bank loan – note 4).

9. Financing:

	Three months ended June 30, 2017	Three months ended June 30, 2016	Six months ended June 30, 2017	Six months ended June 30, 2016
Interest expense	**$ 5,212**	$ 4,263	**$ 10,039**	$ 8,386
Accretion of deferred financing costs	**250**	175	**457**	350
Accretion of decommissioning obligations	**479**	436	**953**	869
Premium paid on redemption of 2020 Notes (note 5)	**-**	-	**6,282**	-
Deferred financing costs expensed on 2020 Notes (note 5)	**-**	-	**2,510**	-
	$ 5,941	$ 4,874	**$ 20,241**	$ 9,605

10. Commitments:

	Total	2017	2018	2019	2020	2021	Thereafter
Operating leases	$ 4,504	$ 587	$ 1,175	$ 1,175	$ 1,175	$ 392	$ -
Capital Commitments	6,764	6,764	-	-	-	-	-
Firm transportation agreements	125,703	16,210	31,972	29,687	26,456	3,517	17,861
Firm processing agreements	90,334	6,398	12,691	12,691	11,390	7,449	39,715
Total	**$ 227,305**	**$ 29,959**	**$ 45,838**	**$ 43,553**	**$ 39,021**	**$ 11,358**	**$ 57,576**

Operating leases include the Company's commitment to a third party for the five year lease of office space.

Capital commitments includes the Company's share of the estimated remaining cost for the expansion of the West Septimus natural gas processing facility.

Firm transportation agreements include commitments to third parties to transport natural gas and natural gas liquids from gas processing facilities in northeast British Columbia.

Firm processing agreements include commitments to process natural gas through the Septimus complex gas processing facilities in northeast British Columbia.

DIRECTORS & OFFICERS

OFFICERS

Dale O. Shwed
President and Chief Executive Officer

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

Rob Morgan, P.Eng.
Senior Vice President and Chief Operating Officer

Ken Truscott
Senior Vice President, Business Development and Land

Jamie L. Bowman
Vice President, Marketing

Kurtis Fischer
Vice President, Business Development

Shawn A. Van Spankeren, CPA, CMA
Vice President, Finance and Administration

BOARD OF DIRECTORS

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Chairman Independent Director

Jeffery E. Errico,
Lead Director Independent Director

Dennis L. Nerland
Independent Director

Dale O. Shwed
President, Crew Energy Inc.

David G. Smith
Independent Director

Corporate Secretary

Michael D. Sandrelli
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
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