interim report

Q2 2018

second quarter
ending June 30, 2018

crew energy inc.

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, 2018.

HIGHLIGHTS

- **Production Ahead of Forecast:** At 23,583 boe per day in Q2, average production volumes were 15% above the Q2 2017 average and 3% above the upper end of our quarterly guidance of 22,000 to 23,000 boe per day. First half production averaged 24,754 boe per day, positioning Crew to meet our 2018 guidance of 23,500 to 24,500 boe per day. Greater Septimus production of 18,953 boe per day was 22% higher than the 15,558 boe per day produced in Q2 2017.

- **Growing Montney Condensate Volumes Into Higher Pricing:** Q2 condensate volumes of 2,304 barrels ("bbls") per day were 49% higher compared to Q2 2017 as Crew benefited from a 38% increase in realized condensate pricing in the quarter, averaging $82.73 per barrel, compared to $59.90 per bbl in Q2 2017 and $73.82 per bbl compared to the previous quarter.

- **Diverse Marketing Strategy Leads to Price Outperformance:** Q2 average realized natural gas price of $2.23 per mcf outperformed the AECO 5A benchmark by 89%, driven by Crew's high heat content natural gas and exposure to diversified sales hubs and gas markets.

- **Strong Performance from Heavy Oil Operations:** Q2 heavy oil volumes averaged 1,930 bbls per day, a 9% increase over the same period of 2017 and a 10% increase over Q1 2018, despite limited capital investment over the past 24 months.

- **Adjusted Funds Flow ("AFF") Reflects Higher Volumes and Strong Liquids Prices:** Q2 AFF totaled $21.8 million or $0.14 per fully diluted share, in line with the same period in 2017, reflecting an increased weighting to higher-value liquids production, higher volumes and improved liquids pricing, offset by lower realized natural gas prices and a realized hedging loss.

- **Modest Spending with Strong Capital Efficiencies:** Net exploration and development expenditures in Q2 were $12.5 million, with activity directed to the completion of two (1.6 net) natural gas wells at our liquids-rich Greater Septimus area and the recompletion of ten (9.5 net) heavy oil wells in Lloydminster.

FINANCIAL & OPERATING HIGHLIGHTS

FINANCIAL ($ thousands, except per share amounts)	**Three months ended June 30, 2018**	Three months ended June 30, 2017	**Six months ended June 30, 2018**	Six months ended June 30, 2017
Petroleum and natural gas sales	**54,040**	48,886	**113,467**	106,184
Adjusted Funds Flow[(1)]	**21,804**	21,353	**48,177**	49,072
Per share - basic	**0.14**	0.14	**0.32**	0.33
- diluted	**0.14**	0.14	**0.32**	0.32
Net (loss) / income	**(9,181)**	21,880	**(5,033)**	29,936
Per share - basic	**(0.06)**	0.15	**(0.03)**	0.20
- diluted	**(0.06)**	0.14	**(0.03)**	0.20
Exploration and Development expenditures	**12,468**	36,656	**46,389**	111,820
Property acquisitions (net of dispositions)	**17**	(45,701)	**(9,990)**	(46,053)
Net capital expenditures	**12,485**	(9,045)	**36,399**	65,767

Capital Structure ($ thousands)	**As at June 30, 2018**	As at Dec. 31, 2017
Working capital (surplus) / deficiency[(2)]	**(19,954)**	29,143
Bank loan	**54,803**	21,977
	34,849	51,120
Senior Unsecured Notes	**294,380**	293,862
Total Net Debt	**329,229**	344,982
Current Debt Capacity[(3)]	**535,000**	535,000
Common Shares Outstanding (thousands)	**151,708**	149,328

Notes:

(1) Adjusted funds flow 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. Adjusted funds flow is used to analyze the Company's operating performance and leverage. Adjusted funds flow 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, 2018**	Three months ended June 30, 2017	**Six months ended June 30, 2018**	Six months ended June 30, 2017
Daily production				
Light crude oil (bbl/d)	**261**	499	**288**	514
Heavy crude oil (bbl/d)	**1,930**	1,778	**1,839**	1,817
Condensate (bbl/d)	**2,304**	1,550	**2,500**	1,731
Other natural gas liquids (bbl/d)	**1,710**	1,336	**1,751**	1,392
Natural gas (mcf/d)	**104,269**	91,828	**110,257**	98,321
Total (boe/d @ 6:1)	**23,583**	20,468	**24,754**	21,841
Average prices [(1)]				
Light crude oil ($/bbl)	**75.72**	58.14	**71.62**	58.96
Heavy crude oil ($/bbl)	**55.65**	45.05	**46.41**	43.98
Condensate ($/bbl)	**82.73**	59.90	**77.95**	61.94
Other natural gas liquids ($/bbl)	**25.63**	14.03	**25.21**	18.19
Natural gas ($/mcf)	**2.23**	3.45	**2.56**	3.50
Oil equivalent ($/boe)	**25.18**	26.25	**25.32**	26.86

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, 2018	Three months ended June 30, 2017	**Six months ended June 30, 2018**	Six months ended June 30, 2017
Netback ($/boe)				
Revenue	**25.18**	26.25	**25.32**	26.86
Royalties	**(1.83)**	(2.06)	**(1.77)**	(2.12)
Realized commodity (loss) / gain	**(1.23)**	0.64	**(1.07)**	0.10
Marketing income (1)	**0.28**	-	**0.28**	-
Net operating costs(2)	**(6.56)**	(6.15)	**(6.42)**	(5.74)
Transportation costs	**(1.78)**	(2.75)	**(1.95)**	(2.51)
Operating netback (3)	**14.06**	15.93	**14.39**	16.59
G&A	**(1.23)**	(1.52)	**(1.31)**	(1.51)
Other income	**-**	-	**0.22**	-
Financing costs on long-term debt	**(2.67)**	(2.93)	**(2.55)**	(2.66)
Adjusted funds flow	**10.16**	11.48	**10.75**	12.42
Drilling Activity				
Gross wells	**0**	7	**0**	22
Working interest wells	**0.0**	7.0	**0.0**	22.0
Success rate, net wells (%)	**-**	100%	**-**	95%

Notes:

(1) Marketing income was recognized from the monetization of forward physical sales contracts offset by the cost of committed natural gas transportation that was not available during the period.

(2) Net operating costs are calculated as gross operating costs less processing revenue.

(3) Operating netback equals petroleum and natural gas sales including realized hedging gains and losses on commodity contracts less royalties, operating costs and transportation costs calculated on a boe basis. Operating netback and adjusted funds flow 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.

FINANCIAL OVERVIEW

Strong Second Quarter Production

- Q2 2018 volumes of 23,583 boe per day exceeded the upper range of our quarterly guidance and were 15% higher than the same period in 2017, reflecting limited break-up related downtime, management of natural gas volumes within a volatile Canadian pricing environment and a 9% increase in Lloydminster production stemming from successful recompletions during the first half of 2018.

- Greater Septimus production averaged 18,953 boe per day, a 22% increase over the same period in 2017 and a 7% decline from Q1 2018 as the Company managed production through the low Q2 natural gas price environment.

- Second quarter natural gas production was curtailed to firm processing and transportation commitments and the Company's firm natural gas sales arrangements in order to avoid the extremely low spot Canadian natural gas prices that were realized during certain days throughout the quarter.

Adjusted Funds Flow Continued to Exceed Net Capital Expenditures

- AFF in Q2 2018 totaled $21.8 million ($0.14 per diluted share) and exceeded Crew's net capital expenditures for the second consecutive period, while remaining consistent with absolute and per share AFF generated in Q2 2017. Stronger realized pricing for crude oil, condensate and other natural gas liquids ("ngl") year-over-year contributed to AFF, however the decline in natural gas prices offset the liquids price gain. AFF declined 17% compared to Q1 2018 due to a 22% decline in realized natural gas prices and lower production.

- Q2 2018 revenue grew 11% over Q2 2017 due to higher production from liquids-weighted areas complemented by realized liquids prices that were 64% stronger, on average, relative to the same period in 2017.

- Q2 2018 liquids revenue comprised 61% of Crew's total revenue, a marked increase over the 50% and 41% in Q1 2018 and Q2 2017, respectively; a reflection of Crew's focus on liquids and condensate-rich targets in West Septimus, complemented by stronger liquids pricing.

- Corporate operating netbacks of $14.06 per boe were 12% and 4% lower than Q2 2017 and Q1 2018, respectively, reflecting the impact of lower natural gas prices, realized losses on the Company's risk management program, and higher net operating costs. This was partially offset by marketing income derived from strategic marketing initiatives, combined with lower royalties and transportation costs.

- Corporate cash costs per boe were consistent with Q1 2018 and declined 9% over Q2 2017, as lower royalties, transportation, general and administrative and financing costs were offset by higher net operating costs. Compared with Q2 2017 and Q1 2018, higher net operating costs in the current quarter stemmed from increased fixed processing fees at the expanded West Septimus facility, higher volumes from Lloydminster, where operating costs are higher relative to the corporate average, and lower third-party processing revenue.

Rising Liquids Prices Helped Offset Weak Natural Gas Prices

- Average realized price per boe in Q2 2018 was $25.18, a 4% decline from Q2 2017 and 1% lower than Q1 2018. Liquids prices in Q2 2018 increased 36% to $58.40 per boe over Q2 2017, and were 16% higher than Q1 2018, offset by realized natural gas prices that were 35% and 22% lower compared to Q2 2017 and Q1 2018, respectively.

- Global crude oil prices continued to rise through Q2 2018, fueled by shrinking world crude inventories brought on by increasing world demand and concerns over supply interruptions resulting from U.S.-led trade embargos against Iran and political unrest in Venezuela and Libya. Late in the quarter, the Organization of Petroleum Exporting Countries ("OPEC") authorized an output increase that was lower than market expectations which further contributed to rising crude oil benchmark prices.

- Canadian dollar denominated West Texas Intermediate ("WTI") oil benchmark increased 35% in Q2 2018 compared to Q2 2017 and increased 10% over Q1 2018. This increase supported an increase in Crew's average Q2 2018 liquids prices of 39% and 16% compared to Q2 2017 and Q1 2018, respectively.

- Crew's diversified marketing portfolio and higher heat content natural gas (higher liquids content) resulted in Crew's gas price outperforming the Canadian benchmark by 89%. Canadian natural gas prices continued to be volatile as bottlenecks in our natural gas pipeline egress system has limited access to markets outside of Canada. This was enhanced in Q2 2018 as maintenance on TransCanada Pipeline infrastructure further limited movement of gas outside of Western Canada and into local storage facilities. This decrease in demand resulted in the benchmark AECO 5A price averaging $1.18 per mcf, a drop of 58% over Q2 2017, and a drop of 43% over Q1 2018. Crew's Q2 2018 natural gas sales price averaged $2.23 per mcf, a 35% decrease over Q2 2017 and 22% lower than Q1 2018.

Modest Capital Expenditure Reflects Value Preservation

- Q2 2018 exploration and development expenditures totaled $12.5 million. Of the total, $6.8 million, or 54%, was directed to activities related to drilling and completions, $2.9 million to well site development, facilities and pipelines and $2.8 million to land, seismic and other miscellaneous items.

- Activity in the quarter included the completion and tie-in of two (1.6 net) liquids-rich natural gas wells in West Septimus and the recompletion of ten (9.5 net) heavy oil wells in Lloydminster.

Declining Net Debt and Continued Balance Sheet Strength

- Net debt declined to $329.2 million at the end of Q2 2018. Crew's debt is largely termed-out, with $300 million of term debt that has no financial covenants and no repayment required until 2024.

TRANSPORTATION, MARKETING & HEDGING

- **Natural Gas Pricing Exposure**: Approximately 37% Chicago City Gate, 24% AECO 5A, 15% AECO 7A, 17% Alliance ATP, 4% Sumas and 3% Station 2 through Q2 2018 and forecast through Q3 2018. This market diversification resulted in Crew's realized natural gas sales price exceeding the Canadian AECO 5A benchmark by 89%.

- **Clear Value Focus**: In Q1 2018, Crew took steps to monetize the inherent value in our Dawn and Malin market exposure for Q2 and Q3, 2018. As a result, we recognized $1.5 million of marketing revenue in Q2, with an equivalent amount expected to be recognized in Q3 2018.

- **New Natural Gas Sales Exposure**: Construction on the strategic pipeline from the West Septimus facility through our Groundbirch acreage connecting into the existing TCPL Saturn meter station is anticipated to be finalized by the end of Q3. This will complete Crew's goal of accessing all three major export pipelines in BC, allowing the Company to benefit from additional natural gas sales exposure, including Nymex, which complements our long-standing market diversification strategy.

Natural Gas & Liquids Hedging

- Approximately 23% of budgeted 2018 natural gas volumes are hedged at an average of $2.50 per GJ or approximately $2.64 per mcf which increases to approximately $3.10 per mcf after adjusting for Crew's heat conversion.
- Through 2018, 2,750 bbls per day of WTI is hedged at a minimum average price of C$72.57 per bbl, 750 bbls per day of Western Canadian Select ("WCS") for the second half of 2018 at an average price of C$56.62 per bbl and 400 bbls per day of OPIS Conway propane hedged at US$0.7863 per gallon or US$33.03 per bbl.

- Crew's 2019 risk management program currently has 1,625 barrels per day of WTI hedged at an average price of C$73.72 per barrel and 250 barrels per day of WCS for the first half of 2019 at an average price of C$52.10 per bbl. As a result of the weak forward pricing for natural gas, we have elected to hedge cautiously with 7,500 mmbtu per day of Chicago City Gate gas at C$3.19 per mmbtu and 2,500 mmbtu per day of Dawn gas at C$3.30 per mmbtu.

OPERATIONS & AREA OVERVIEW

- During Q2, Crew flowed back a total of eight wells, including all six that were completed by the end of Q1 2018, and two wells completed during Q2. These wells targeted three distinct stratigraphic intervals in the Upper Montney and are being flow-restricted in order to optimize condensate recoveries. Over the first 30 days on production, these eight wells averaged sales of 4.0 mmcf per day of gas and 220 bbls per day of ngl (64% condensate) at an average flowing casing pressure of 1,765 psi. Based on the successful test spacing of this program, a future development spacing of 15 wells per section in the Upper Montney is supported in this area.

- Early in Q3 2018, Crew commenced drilling a five well pad in the ultra-condensate rich ("UCR") Montney area with lateral lengths that are 30-50% longer than previous wells. We plan to utilize a revised cased-hole plug and perf completion design expected to optimize condensate recovery.

- Crew now has over 70 mmcf per day of excess natural gas processing capacity to accommodate future growth. After completion of the Groundbirch to Saturn meter station pipeline later in Q3, the Company will have access to all three export pipelines in northeast BC.

Greater Septimus

Production & Drilling	Q2 2018	Q1 2018	Q4 2017	Q3 2017	Q2 2017
Average daily production (boe/d)	**18,953**	20,467	20,193	18,154	15,558
Wells drilled (gross / net)	**-**	-	5 / 3.9	13 / 12.3	5 / 5.0
Wells completed (gross / net)	**2 / 1.6**	9 / 7.7	3 / 3.0	14 / 14.0	9 / 9.0

Operating Netback ($ per boe)	**Q2 2018**	**Q1 2018**	**Q4 2017**	**Q3 2017**	**Q2 2017**
Revenue	**22.70**	25.40	24.43	20.05	24.51
Royalties	**(1.35)**	(1.50)	(1.19)	(0.89)	(1.57)
Realized commodity hedge (loss) / gain	**(1.32)**	(1.01)	1.74	2.97	0.77
Marketing income	**0.34**	0.37	-	-	-
Net operating costs(1)	**(4.71)**	(4.45)	(3.67)	(3.38)	(4.10)
Transportation costs	**(1.40)**	(1.51)	(1.51)	(1.65)	(2.03)
Operating netback(2)	**14.26**	17.30	19.80	17.10	17.58

Notes:

(1) Net operating costs are calculated as gross operating costs less processing revenue.

(2) Operating netback equals petroleum and natural gas sales including realized hedging gains and losses on commodity contracts less royalties, operating costs and transportation costs calculated on a boe basis. Operating netback and adjusted funds flow 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.

Other NE BC Montney

- **Tower:** Production in the Tower area averaged 875 boe per day in Q2 2018. Crew continues to evaluate the relative economics of Tower development as well as the encouraging early results from our peers in the Lower Montney. Production rates and gas condensate ratios from nearby wells have generally exceeded those of the Upper Montney in the area. Crew plans to reinitiate drilling in this area in 2019.

- **Attachie:** Crew owns 97 sections of land in this area with approximately 45 sections in the liquids-rich hydrocarbon window. An offsetting operator has been actively testing wells with condensate rates of over 1,000 bbls per day. Crew plans on drilling one well in this area in 2019 to retain land.

- **Oak / Flatrock:** Crew has over 60 sections of land in this area where drilling activity is gaining momentum for liquids-rich gas. We will continue to monitor well results and consider this an asset Crew could monetize.

- **Inga:** Crew has eight sections of Montney rights in this area, which is prospective for highly liquids-rich gas. Montney rights have recently sold for approximately $4,000 to $6,000 per acre in close proximity to our lands.

AB / SK Heavy Oil - Lloydminster

- An effective $1.4 million recompletion program was executed at Lloydminster in Q2 2018, resulting in average production volumes of 1,930 bbls per day, a 9% increase over the same period in 2017 and a 10% increase over the prior quarter. Rising oil prices and narrowing differentials contributed to strong Lloydminster operating netbacks of $26.48 per boe.

- Over the past three years, Crew has successfully disposed of $61 million of assets at Lloydminster with less than 200 boe per day of associated production. Despite a rigorous sales process, the lack of available capital funding for companies in the Canadian energy market has resulted in two potential buyers failing to close on acquisitions for the balance of our heavy oil operations. At current commodity prices, Crew plans on maintaining production in this area and expects this property to continue generating free cash flow that can be deployed to our Montney operations until a reasonable valuation for the asset can be realized through a successful disposition.

OUTLOOK

Second Half 2018 Operations Focused on Condensate Growth

- Crew has benefited from stronger liquids production and pricing which supports continued development of our liquids and condensate-rich area at West Septimus. Our condensate operating netbacks in Q2 were over $70 per barrel illustrating our low-cost structure and premium realized price for this commodity.

- The remainder of our 2018 capital spending will be focused on our UCR area with a total of five wells at West Septimus. Three of these wells are expected to be completed in 2018 and two in 2019, with plans to implement additional water handling at West Septimus to further enhance our produced water recycling program.

2018 Guidance Remains on Target

- Q3 2018 capital expenditures are expected to be $25 to $30 million, with forecast production expected to average 23,000 to 24,000 boe per day, which reflects additional planned maintenance on the TCPL system and continued management of natural gas volumes during summer price volatility. The Company continues to forecast annual capital expenditures will approximate adjusted funds flow for 2018.

- Crew's diversified marketing strategy affords optionality to reduce exposure to those markets with pricing that remains below our returns threshold and the Company will continue adjusting production levels to generate optimal returns.

- Production year-to-date has exceeded Crew's original forecast and averaged 24,754 boe per day, positioning the Company to meet our annual guidance of 23,500 to 24,500 boe per day.

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

Cautionary Statements

Information Regarding Disclosure on Oil and Gas and Operational Information

This report contains metrics commonly used in the oil and natural gas industry, such as "adjusted funds flow" and "operating netbacks". These terms are not defined in IFRS and do not have standardized meanings or standardized methods of calculation and therefore may not be comparable to similar measures presented by other companies, and therefore should not be used to make such comparisons. Such metrics have been included herein to provide readers with additional information to evaluate the Company's performance, however such metrics should not be unduly relied upon. Management uses oil and gas metrics for its own performance measurements and to provide shareholders with measures to compare Crew's operations over time. Readers are cautioned that the information provided by these metrics, or that can be derived from the metrics presented in this report, should not be relied upon for investment or other purposes. See "Non-IFRS Measures" contained within Crew's MD&A for applicable calculations and reconciliations.

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 estimated volumes, including shut-ins, and product mix of Crew's oil and gas production; production estimates including Q3 and 2018 average production forecasts; commodity price expectations including Crew's estimates of natural gas pricing exposure; Crew's commodity risk management programs; marketing, transportation and natural gas egress plans; future liquidity and financial capacity; future results from operations and operating metrics; potential for lower costs and efficiencies going forward; future development, exploration, acquisition and disposition activities (including drilling, completion and infrastructure plans and methodology and associated timing and cost estimates); the amount and timing of capital projects; Q3 and 2018 capital expenditure and operational plans; and Crew's 2018 budget and methods of funding our capital program.

In addition, 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: that Crew will continue to conduct its operations in a manner consistent with past operations; results from drilling and development activities consistent with past operations; the quality of the reservoirs in which Crew operates and continued performance from existing wells; the continued and timely development of infrastructure in areas of new production; the accuracy of the estimates of Crew's reserve volumes; certain commodity price and other cost assumptions; continued availability of debt and equity financing and cash flow to fund Crew's current and future plans and expenditures; the impact of increasing competition; the general stability of the economic and political environment in which Crew operates; the general continuance of current industry conditions; the timely receipt of any required regulatory approvals; the ability of Crew to obtain qualified staff, equipment and services in a timely and cost efficient manner; drilling results; the ability of the operator of the projects in which Crew has an interest in to operate the field in a safe, efficient and effective manner; the ability of Crew to obtain financing on acceptable terms; field production rates and decline rates; the ability to replace and expand oil and natural gas reserves through acquisition, development and exploration; the timing and cost of pipeline, storage and facility construction and expansion and the ability of Crew to secure adequate product transportation; future *commodity prices; currency, exchange and interest rates; regulatory framework regarding royalties, taxes and environmental matters in the jurisdictions in which Crew operates; and the ability of Crew to successfully market its oil and natural gas products.*

The forward-looking information and statements included in this report are not guarantees of future performance and should not be unduly relied upon. Such information and statements, including the assumptions made in respect thereof, involve known and unknown risks, uncertainties and other factors that may cause actual results or events to defer materially from those anticipated in such forward-looking information or statements including, without limitation: changes in commodity prices; changes in the demand for or supply of Crew's products, the early stage of development of some of the evaluated areas and zones the potential for variation in the quality of the Montney formation; 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 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, particularly those short in duration, may not necessarily be indicative of long term performance or of ultimate recovery.

BOE equivalent

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

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 in British Columbia offer significant development potential over the long-term. The Company has access to diversified markets with operated infrastructure and access to multiple pipeline egress options. 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, 2018 and 2017. 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, 2017. All figures provided herein and in the June 30, 2018 unaudited condensed interim consolidated financial statements are reported in Canadian dollars ("CDN"). This MD&A is dated August 1, 2018.

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 2018 capital budget including anticipated third quarter and 2018 capital expenditures, timing of capital expenditures and methods of financing capital expenditures and the ability to fund financial liabilities, production estimates including third quarter and 2018 average forecasts, expected commodity mix and prices, future net operating costs, future transportation costs, expected royalty rates, expected general and administrative expenses, expected interest rates and other financing charges, debt levels, funds from operations, adjusted funds flow and the timing of and impact of implementing accounting policies, estimates regarding undeveloped land position and estimated future drilling, recompletion or reactivation locations and anticipated impact 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 net 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 and Adjusted Funds Flow

One of the benchmarks Crew uses to evaluate its performance is funds from operations and adjusted funds flow. Funds from operations and adjusted funds flow are measures not defined in IFRS but are commonly used in the oil and gas industry. Funds from operations represents cash provided by operating activities before changes in operating non-cash working capital and accretion of deferred financing costs. Adjusted funds flow represents funds from operations before decommissioning obligations settled. The Company considers these metrics as key measures that demonstrate 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 and adjusted funds flow 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 and adjusted funds flow may not be comparable to that reported by other companies. Crew also presents adjusted funds flow 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 and adjusted funds flow:

($ thousands)	**Three months ended June 30, 2018**	Three months ended June 30, 2017	**Six months ended June 30, 2018**	Six months ended June 30, 2017
Cash provided by operating activities	**31,304**	31,359	**47,189**	58,548
Change in operating non-cash working capital	**(9,463)**	(9,734)	**693**	(9,375)
Accretion of deferred financing costs	**(259)**	(250)	**(518)**	(457)
Funds from operations	**21,582**	21,375	**47,364**	48,716
Decommissioning obligations settled (recovered)	**222**	(22)	**813**	356
Adjusted funds flow	**21,804**	21,353	**48,177**	49,072

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 petroleum and natural gas sales including realized gains and losses on commodity related derivative financial instruments less royalties, marketing revenue, net 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, 2018**	December 31, 2017
Current assets	**55,845**	42,596
Current liabilities	**(50,070)**	(71,392)
Derivative financial instruments	**14,179**	(347)
Working capital surplus (deficiency)	**19,954**	(29,143)

($ thousands)	**June 30, 2018**	December 31, 2017
Bank loan	**(54,803)**	(21,977)
Senior unsecured notes	**(294,380)**	(293,862)
Working capital surplus (deficiency)	**19,954**	(29,143)
Net debt	**(329,229)**	(344,982)

RESULTS OF OPERATIONS

Production

	Three months ended June 30, 2018					Three months ended June 30, 2017				
	Oil (bbl/d)	**Condensate (bbl/d)**	**Other Ngl (bbl/d)**	**Nat. gas (mcf/d)**	**Total (boe/d)**	Oil (bbl/d)	Condensate (bbl/d)	Other Ngl (bbl/d)	Nat. gas (mcf/d)	Total (boe/d)
NE BC	**261**	**2,304**	**1,710**	**104,269**	**21,653**	499	1,550	1,336	91,796	18,684
Lloydminster	**1,930**	**-**	**-**	**-**	**1,930**	1,778	-	-	32	1,784
Total	**2,191**	**2,304**	**1,710**	**104,269**	**23,583**	2,277	1,550	1,336	91,828	20,468

In the second quarter of 2018, production increased 15% over the same period in 2017, as a result of an active and successful drilling and completion program at the condensate-rich area of West Septimus in northeast British Columbia (“NE BC”) over the previous 12 months. In addition, and as a result of stronger netbacks as benchmark crude oil prices continue to improve, the Company successfully executed an effective recompletion program in Lloydminster, where production increased over the same period in 2017. These production increases were partially offset by a decline in light oil production in the Tower area of NE BC.

	Six months ended June 30, 2018					Six months ended June 30, 2017				
	Oil (bbl/d)	**Condensate (bbl/d)**	**Other Ngl (bbl/d)**	**Nat. gas (mcf/d)**	**Total (boe/d)**	Oil (bbl/d)	Condensate (bbl/d)	Other Ngl (bbl/d)	Nat. gas (mcf/d)	Total (boe/d)
NE BC	**288**	**2,500**	**1,751**	**110,254**	**22,914**	514	1,731	1,392	98,281	20,017
Lloydminster	**1,839**	**-**	**-**	**3**	**1,840**	1,817	-	-	40	1,824
Total	**2,127**	**2,500**	**1,751**	**110,257**	**24,754**	2,331	1,731	1,392	98,321	21,841

For the first half of 2018, production increased 13% as compared to the same period in 2017, as a result of the aforementioned successful drilling and completion program focused on condensate-rich wells at West Septimus in NE BC, where the Company continues to direct the majority of its capital investment. This increase in production coincided with the expansion of the West Septimus gas facility, which doubled the facility’s processing capacity to 120 mmcf per day in the fourth quarter of 2017. This production increase was partially offset by a decline in light oil production in the Tower area of NE BC.

Petroleum and Natural Gas Sales

	Three months ended June 30, 2018	Three months ended June 30, 2017	**Six months ended June 30, 2018**	Six months ended June 30, 2017
Petroleum and natural gas sales ($ thousands)				
Light crude oil	**1,796**	2,641	**3,735**	5,489
Heavy crude oil	**9,776**	7,290	**15,450**	14,465
Condensate	**17,343**	8,447	**35,276**	19,407
Other natural gas liquids	**3,989**	1,706	**7,992**	4,581
Natural gas	**21,136**	28,802	**51,014**	62,242
Total	**54,040**	48,886	**113,467**	106,184
Crew average prices				
Light crude oil ($/bbl)	**75.72**	58.14	**71.62**	58.96
Heavy crude oil ($/bbl)	**55.65**	45.05	**46.41**	43.98
Condensate ($/bbl)	**82.73**	59.90	**77.95**	61.94
Other natural gas liquids ($/bbl)	**25.63**	14.03	**25.21**	18.19
Natural gas ($/mcf)	**2.23**	3.45	**2.56**	3.50
Oil equivalent ($/boe)	**25.18**	26.25	**25.32**	26.86
Benchmark pricing				
Light crude oil – Cdn$ WTI (Cdn $/bbl)	**87.64**	64.95	**83.58**	66.81
Heavy crude oil – WCS (Cdn $/bbl)	**62.96**	49.96	**56.00**	49.72
Condensate – Condensate @ Edmonton (Cdn $/bbl)	**88.78**	65.17	**84.30**	67.17
Natural Gas:				
AECO 5A daily index (Cdn $/mcf)	**1.18**	2.78	**1.63**	2.74
AECO 7A monthly index (Cdn $/mcf)	**1.03**	2.77	**1.44**	2.86
Chicago City Gate at ATP (Cdn $/mcf)	**2.73**	3.19	**2.87**	3.20
Alliance 5A (Cdn $/mcf)	**1.54**	2.93	**2.05**	3.01

In the second quarter 2018, the Company's revenue increased 11% as compared to the same period in 2017, as a result of the increase in production in NE BC and Lloydminster, coupled with an increase in crude oil, condensate and other natural gas liquids pricing, partially offset by a decline in natural gas pricing. The Company's realized light crude oil price increased 30% which was lower than the 35% increase in the Company's Cdn$ West Texas Intermediate ("WTI") benchmark for the same period last year. The lower realized price is a result of the Company securing sales contracts when the differentials between WTI and Canadian light crude price were wider than sales contracts realized during the same period last year. Crew's second quarter heavy crude price increased 24%, which is comparable with the 26% increase in the Company's Western Canadian Select ("WCS") benchmark. The Company's second quarter realized condensate price increased 38% over the same period in 2017 which was comparable to the 36% increase in the Condensate at Edmonton benchmark price. Other natural gas liquids ("ngl") realized price increased 83% in the second quarter, due to an increase in propane and butane pricing as compared to the same period in 2017. Crew's realized natural gas price decreased 35% in the second quarter of 2018 which is consistent with the 39% decrease in the Company's natural gas sales portfolio weighted benchmark price. The Company's natural gas price benefits from the high heat content of its Montney natural gas, reflective of the presence of larger amounts of propane and butane in the gas stream, which yields approximately 20% more value than the standard heat conversion used in the Company's benchmark pricing.

The Company's second quarter 2018 natural gas sales portfolio is based approximately on the following reference prices:

	Q2 2018	Q2 2017
Chicago City Gate at ATP	**37%**	45%
AECO 5A	**24%**	9%
AECO 7A	**15%**	17%
Alliance 5A	**17%**	19%
Station 2	**3%**	10%
Sumas	**4%**	-
Total	**100%**	100%

Note: the Company realized $1.5 million of additional revenue during the second quarter of 2018 as a result of the monetization of its Dawn and Malin market exposure. See Marketing Income section below.

The Company's revenue for the first half of 2018 increased 7% over same period in 2017 as a result of the 13% increase in production, partially offset by the 6% decrease in realized wellhead pricing. The Company's realized light crude price increased 21% which was consistent the 25% increase in the Company's WTI benchmark. Crew's heavy crude price for the first half of 2018 increased 6% which was lower than the 13% increase in the Company's WCS benchmark, as a result of the Company securing short term sales contracts at weaker spot pricing to manage inventory levels, coupled with an increase in blending costs as compared to the same period last year. In the first six months of 2018, the Company's realized condensate price increased 26%, which was consistent with the 26% increase in the Condensate at Edmonton benchmark price for the same period last year. Other ngl realized price increased 39% in the first half of 2018, due to an increase in propane and butane pricing as compared to the same period in 2017. The Company's natural gas price decreased 27% over the first half of 2017, which is consistent with the Company's natural gas sales portfolio weighted benchmark price decrease of 27%.

Royalties

($ thousands, except per boe)	**Three months ended June 30, 2018**	Three months ended June 30, 2017	**Six months ended June 30, 2018**	Six months ended June 30, 2017
Royalties	**3,919**	3,836	**7,926**	8,393
Per boe	**1.83**	2.06	**1.77**	2.12
Percentage of petroleum and natural gas sales	**7.3%**	7.8%	**7.0%**	7.9%

For the second quarter and first half of 2018, royalties per boe and as a percentage of revenue decreased over the same period in 2017 predominantly due to a significant decline in realized natural gas prices. In addition, increased production at West Septimus, which attracts lower royalties due to new deep well gas royalty credit programs, further contributed to the decrease in royalties per boe and as a percentage of revenue. The Company expects its royalties as a percentage of revenue to average between 6% and 8% in 2018, slightly higher than previously forecasted due to higher forecasted 2018 heavy oil and condensate prices, which attract higher royalty rates.

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 (loss) income and comprehensive (loss) income:

($ thousands)	**Three months ended June 30, 2018**	Three months ended June 30, 2017	**Six months ended June 30, 2018**	Six months ended June 30, 2017
Realized (loss) gain on derivative financial instruments	**(2,632)**	1,192	**(4,809)**	377
Per boe	**(1.23)**	0.64	**(1.07)**	0.10
Unrealized (loss) gain on financial instruments	**(13,906)**	6,941	**(18,554)**	26,816

At June 30, 2018, the Company held derivative commodity contracts as follows:

Subject of Contract	Notional Quantity	Term	Reference	Strike Price	Option Traded	Fair Value
Gas	2,500 mmbtu/day	July 1, 2018 – October 31, 2018	Chicago Citygate	$3.06/mmbtu	Swap	$ (158)
Gas	5,000 gj/day	July 1, 2018 – December 31, 2018	AECO C Monthly Index	$3.00/gj	Call	(3)
Gas	2,500 gj/day	July 1, 2018 – December 31, 2018	AECO C Daily Index	$2.62/gj	Swap	465
Gas	20,000 mmbtu/day	July 1, 2018 – December 31, 2018	Chicago Citygate	$3.61/mmbtu	Swap	(99)
Gas	5,000 mmbtu/day	July 1, 2018 – December 31, 2018	US$ Nymex Henry Hub	$3.05 US/mmbtu	Swap	107
Gas	7,500 mmbtu/day	January 1, 2019 – December 31, 2019	Chicago Citygate	$3.19/mmbtu	Swap	(487)
Gas	2,500 mmbtu/day	January 1, 2019 – December 31, 2019	Dawn Daily Index	$3.30/mmbtu	Swap	(99)
Propane	400 bbl/day	July 1, 2018 – December 31, 2018	US$ Conway OPIS	$0.79 US/gal	Swap	32
Oil	2,250 bbl/day	July 1, 2018 – December 31, 2018	CDN$ WTI	$72.92/bbl	Swap	(8,158)
Oil	250 bbl/day	July 1, 2018 – December 31, 2018	CDN$ WTI	$60.00 - $69.65/bbl	Collar(1)	(1,061)
Oil	250 bbl/day	July 1, 2018 – December 31, 2018	CDN$ WTI	$69.00 - $74.25/bbl	Collar(2)	(854)
Oil	750 bbl/day	July 1, 2018 – December 31, 2018	CDN$ WCS	$56.62/bbl	Swap	(836)
Oil	250 bbl/day	January 1, 2019 – June 30, 2019	CDN$ WTI	$83.80/bbl	Swap	(153)
Oil	250 bbl/day	January 1, 2019 – June 30, 2019	CDN$ WCS	$52.10/bbl	Swap	(217)
Oil	1,500 bbl/day	January 1, 2019 – December 31, 2019	CDN$ WTI	$72.88/bbl	Swap	(6,686)
Total						**$ (18,207)**

(1) The referenced contract is a costless collar whereby the Company receives $60.00/bbl when the market price is below $60.00/bbl, and receives $69.65/bbl when the market price is above $69.65/bbl.

(2) The referenced contract is a costless collar whereby the Company receives $69.00/bbl when the market price is below $69.00/bbl, and receives $74.25/bbl when the market price is above $74.25/bbl.

Marketing Income

($ thousands, except per boe)	**Three months ended June 30, 2018**	Three months ended June 30, 2017	**Six months ended June 30, 2018**	Six months ended June 30, 2017
Marketing revenue	**1,519**	-	**2,198**	-
Less: marketing expense	**(925)**	-	**(925)**	-
Marketing income	**594**	-	**1,273**	
Per boe	**0.28**	-	**0.28**	-

In the second quarter of 2018 and first half of 2018, the Company recognized $1.5 million and $2.2 million, respectively, of marketing revenue related to the monetization of the Company's exposure to the Dawn and Malin natural gas markets. Marketing expense reflects the cost of firm transportation commitments on TransCanada's NGTL natural gas pipeline system that is currently not physically accessible. This natural gas transportation is not expected to be accessible to the Company until the fourth quarter of 2018, upon the completion of our West Septimus to Saturn pipeline project.

Net Operating Costs

($ thousands, except per boe)	**Three months ended June 30, 2018**	Three months ended June 30, 2017	**Six months ended June 30, 2018**	Six months ended June 30, 2017
Operating costs	**14,982**	12,460	**30,561**	24,991
Less: processing revenue	**(896)**	(997)	**(1,788)**	(2,285)
Net operating costs	**14,086**	11,463	**28,773**	22,706
Per boe	**6.56**	6.15	**6.42**	5.74

In the second quarter and first half of 2018, net operating costs per boe increased as compared to the same periods in 2017 as a result of increased processing fees from the facility expansion at West Septimus and increased production in Lloydminster, which yields higher operating costs when compared to the corporate average. In addition, net operating costs were impacted by the decrease in third party volumes resulting in lower processing revenue for the second quarter and first half of 2018, as compared to the same periods in 2017. These increases in net operating costs per boe were partially offset by a decline in higher net operating costs per boe production in Tower. The Company continues to forecast 2018 net operating costs to average between $6.50 and $6.75 per boe.

Transportation Costs

($ thousands, except per boe)	**Three months ended June 30, 2018**	Three months ended June 30, 2017	**Six months ended June 30, 2018**	Six months ended June 30, 2017
Transportation costs	**3,826**	5,123	**8,759**	9,907
Per boe	**1.78**	2.75	**1.95**	2.51

During the second quarter and first half of 2018, transportation costs per boe decreased as compared to the same periods in 2017, as a result of increased production in West Septimus and Lloydminster, which yield lower transportation costs per boe when compared to the corporate average. Additionally, transportation costs per boe were higher in the second quarter and first half of 2017 as a result of third party facility and pipeline outages resulting in unutilized fees in the second quarter and first half of 2017. The Company continues to forecast transportation costs per boe to average between $2.40 and $2.65 for 2018. Increased 2018 second half costs are reflective of the forecasted fourth quarter addition of third party charges for the Company's partially owned West Septimus to Saturn pipeline that is expected to be commissioned in the fourth quarter of 2018, combined with the cost of the TransCanada NGTL fees that are currently recorded as a marketing expense.

Operating Netbacks

($/boe)	**Greater Septimus**	**Lloydminster Heavy Oil**	**Other NE BC**	**Three months ended June 30, 2018**	Three months ended June 30, 2017
Petroleum and natural gas sales	**22.70**	**55.64**	**20.79**	**25.18**	26.25
Royalties	**(1.35)**	**(7.14)**	**(1.33)**	**(1.83)**	(2.06)
Realized commodity hedging (loss) gain	**(1.32)**	**-**	**(1.47)**	**(1.23)**	0.64
Marketing income	**0.34**	**-**	**-**	**0.28**	-
Net operating costs	**(4.71)**	**(21.07)**	**(9.18)**	**(6.56)**	(6.15)
Transportation costs	**(1.40)**	**(0.95)**	**(5.07)**	**(1.78)**	(2.75)
Operating netbacks	**14.26**	**26.48**	**3.74**	**14.06**	15.93
Production (boe/d)	**18,953**	**1,930**	**2,700**	**23,583**	20,468

($/boe)	**Greater Septimus**	**Lloydminster Heavy Oil**	**Other NE BC**	**Six months ended June 30, 2018**	Six months ended June 30, 2017
Petroleum and natural gas sales	**24.10**	**46.40**	**20.78**	**25.32**	26.86
Royalties	**(1.43)**	**(6.05)**	**(1.39)**	**(1.77)**	(2.12)
Realized commodity hedging (loss) gain	**(1.16)**	**-**	**(1.13)**	**(1.07)**	0.10
Marketing income	**0.36**	**-**	**-**	**0.28**	-
Net operating costs	**(4.58)**	**(22.24)**	**(8.71)**	**(6.42)**	(5.74)
Transportation costs	**(1.46)**	**(0.98)**	**(5.58)**	**(1.95)**	(2.51)
Operating netbacks	**15.83**	**17.13**	**3.97**	**14.39**	16.59
Production (boe/d)	**19,705**	**1,840**	**3,209**	**24,754**	21,841

For the second quarter and first half of 2018, the Company's operating netbacks decreased over the same periods in 2017, as a result of a decrease in realized pricing in the Greater Septimus and Other NE BC, realized hedging losses and higher net operating costs, partially offset by decreased royalties and transportation costs, and marketing income recognized.

General and Administrative Costs

($ thousands, except per boe)	**Three months ended June 30, 2018**	Three months ended June 30, 2017	**Six months ended June 30, 2018**	Six months ended June 30, 2017
Gross costs	**4,529**	4,469	**9,369**	9,446
Operator's recoveries	**(416)**	(35)	**(456)**	(209)
Capitalized costs	**(1,484)**	(1,593)	**(3,040)**	(3,250)
General and administrative expenses	**2,629**	2,841	**5,873**	5,987
Per boe	**1.23**	1.52	**1.31**	1.51

Gross general and administrative ("G&A") costs have increased in the second quarter of 2018 as compared to the same period in 2017, due to higher office rent costs. For the six months ended June 30, 2018, gross G&A costs decreased due to lower compensation costs as a result of reduced staffing levels and a reduction in reserve evaluator fees, partially offset by an increase in office rent costs. The decrease in net G&A costs in the second quarter of 2018 and for the six months ended June 30, 2018 is a result of an increase in third party operator recoveries, as compared to the same periods in 2017. The decrease in net G&A costs per boe is due to an increase in production in both the second quarter of 2018 and the six months ended June 30, 2018, as compared to the same periods in 2017. Crew continues to forecast G&A costs per boe to average between $1.25 and $1.50 in 2018.

Other Income

($ thousands, except per boe)	**Three months ended June 30, 2018**	Three months ended June 30, 2017	**Six months ended June 30, 2018**	Six months ended June 30, 2017
Other	**-**	-	**1,000**	-
Per boe	**-**	-	**0.22**	-

In the first half of 2018, the Company recognized $1.0 million for the receipt of a non-refundable deposit from a third party for a non-core property disposition that failed to close.

Share-Based Compensation

($ thousands)	**Three months ended June 30, 2018**	Three months ended June 30, 2017	**Six months ended June 30, 2018**	Six months ended June 30, 2017
Gross costs	**3,702**	3,837	**5,843**	9,950
Capitalized costs	**(1,755)**	(1,830)	**(2,791)**	(4,789)
Total share-based compensation	**1,947**	2,007	**3,052**	5,161

In the second quarter of 2018 and six months ended June 30, 2018, the Company's share-based compensation expense decreased as compared to the same periods in 2017, as a result of the departure of a Company executive and a lower performance multiplier applied to certain performance awards, as compared to the same periods in 2017.

Depletion and Depreciation

($ thousands, except per boe)	**Three months ended June 30, 2018**	Three months ended June 30, 2017	**Six months ended June 30, 2018**	Six months ended June 30, 2017
Depletion and depreciation	**18,252**	16,393	**40,699**	36,103
Per boe	**8.50**	8.80	**9.08**	9.13

In the second quarter and first half of 2018, depletion and depreciation costs increased as a result of increased production and land expiries when compared to the same periods in 2017. In the second quarter and first half of 2018, depletion and depreciation per boe decreased as a result of increased production in the Greater Septimus area which yields a lower depletion rate when compared to the corporate average.

Gain on Divesture of Property

During the first quarter of 2018, the Company disposed of non-core assets for cash proceeds of $10.0 million. The assets consisted of petroleum and natural gas properties and undeveloped land with a net book value of $0.9 million and associated decommissioning obligations of $0.4 million, resulting in a gain of $9.5 million on closing of the disposition.

Finance Expenses

($ thousands, except per boe)	**Three months ended June 30, 2018**	Three months ended June 30, 2017	**Six months ended June 30, 2018**	Six months ended June 30, 2017
Interest on bank loan and other	**617**	350	**1,235**	1,316
Interest on senior notes	**4,862**	4,862	**9,670**	8,723
Accretion of deferred financing charges	**259**	250	**518**	457
Accretion of the decommissioning obligation	**488**	479	**979**	953
Premium paid on redemption of 2020 Notes	**-**	-	**-**	6,282
Deferred financing costs expensed on 2020 Notes	**-**	-	**-**	2,510
Total finance expense	**6,226**	5,941	**12,402**	20,241
Average debt level	**349,948**	300,000	**340,302**	285,040
Average drawings on bank loan	**49,948**	-	**40,302**	36,422
Average senior unsecured notes outstanding	**300,000**	300,000	**300,000**	248,619
Effective interest rate on senior unsecured notes	**6.5%**	6.5%	**6.5%**	7.1%
Effective interest rate on long-term debt	**6.1%**	7.3%	**6.2%**	7.4%
Financing costs on long-term debt per boe	**2.67**	2.93	**2.55**	2.66

The Company's average corporate debt level increased in both the second quarter of 2018 and for the six months ended June 30, 2018 as compared to the same periods in 2017, as a result of increased capital expenditures in 2017 focused on the West Septimus facility expansion and the drilling and completion of wells associated with the planed start-up of the expanded facility. These expenditures were partially funded with the first quarter 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 total long-term debt decreased in the second quarter of 2018 as compared to the same period in 2017, and the effective interest rate on the Company's senior notes and total long-term debt decreased for the six months ended June 30, 2018 as compared to the same period in 2017. Crew forecasts the effective interest rate on its long-term debt to average between 6.0% and 6.5% in 2018.

Deferred Income Taxes

In the second quarter and first half of 2018, the provision for deferred tax recovery was $3.6 million and $0.5 million, respectively, as compared to deferred tax expense of $8.7 million and $16.5 million, respectively, for the same periods in 2017. The change from an expense to a recovery is predominantly due to net income in 2017 as a result of a significant gain on property disposition and losses incurred on the Company's risk management program in the first half of 2018, partially offset by impairment recorded in the second quarter of 2017.

Cash, Funds from Operations and Net Income (Loss)

($ thousands, except per share amounts)		**Three months ended June 30, 2018**	Three months ended June 30, 2017	**Six months ended June 30, 2018**	Six months ended June 30, 2017
Cash provided by operating activities		**31,304**	31,359	**47,189**	58,548
Adjusted funds flow		**21,804**	21,353	**48,177**	49,072
Per share	- basic	**0.14**	0.14	**0.32**	0.33
	- diluted	**0.14**	0.14	**0.32**	0.32
Net (loss) income		**(9,181)**	21,880	**(5,033)**	29,936
Per share	- basic	**(0.06)**	0.15	**(0.03)**	0.20
	- diluted	**(0.06)**	0.14	**(0.03)**	0.20

The decrease in cash provided by operating activities in the first half of 2018 was a result of a change in operating non-cash working capital in the first half of 2017. Net income decreased for the second quarter and first half of 2018 when compared to the same periods in 2017, as a result of a material gain on disposition, and realized and unrealized gains on derivative financial instruments, partially offset by impairment recorded in 2017.

Capital Expenditures, Property Acquisitions and Dispositions

($ thousands)	**Three months ended June 30, 2018**	Three months ended June 30, 2017	**Six months ended June 30, 2018**	Six months ended June 30, 2017
Land	**781**	820	**1,871**	1,690
Seismic	**363**	222	**658**	482
Drilling and completions	**6,835**	37,842	**25,500**	90,910
Facilities, equipment and pipelines	**2,918**	(3,880)	**14,891**	15,087
Other	**1,571**	1,652	**3,469**	3,651
Total exploration and development	**12,468**	36,656	**46,389**	111,820
Net property acquisitions/(dispositions)	**17**	(45,701)	**(9,990)**	(46,053)
Total	**12,485**	(9,045)	**36,399**	65,767

In the second quarter of 2018, the Company spent a total of $12.5 million on exploration and development expenditures, focused on the continued development of our Montney assets at West Septimus. During the quarter, $6.8 million was spent on drilling and completion activities, including the completion of two (1.6 net) liquids-rich natural gas wells in NE BC and recompletion of ten (9.5 net) heavy oil wells in Lloydminster, $2.9 million on Montney well site development, facilities and pipelines and $2.8 million on land, seismic and other miscellaneous items.

The Company's Board of Directors have approved an exploration and development budget for 2018 of $80 to $85 million.

During the first quarter of 2018, the Company disposed of certain Lloydminster properties for cash proceeds of $10.0 million. The assets included 190 acres of developed non-producing land and 692 acres of undeveloped land.

LIQUIDITY AND CAPITAL RESOURCES

Working Capital

The capital intensive nature of Crew's activities generally results in the Company carrying a working capital deficiency, however at the end of the second quarter of 2018, the Company carried a working capital surplus of $20.0 million. Working capital includes cash and cash equivalents and accounts receivable less accounts payable and accrued liabilities. Included in the working capital surplus is a receivable of $5.9 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.

The Company ensures that sufficient drawings are available from its Facility to satisfy working capital requirements. At June 30, 2018, the Company's working capital surplus of $20.0 million, when combined with the drawings on its bank loan, represented drawings of 15% on its $235 million Facility described below.

Capital Funding

Bank Loan

As at June 30, 2018, 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 5, 2019. 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. 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, 2018. The Facility is secured by a floating charge debenture and a general securities agreement on the assets of the Company.

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.

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, non-core asset dispositions and equity financings as needed. As the majority of our on-going capital expenditure program is directed to the further growth of reserves and production volumes, Crew is readily able to adjust its budgeted capital expenditures should the need arise.

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 was terminated on May 24, 2018. Subject to the terms of this NCIB, for the year ended December 31, 2017, 924,100 common shares for a total cost of $3.3 million were purchased, cancelled and removed from share capital. The Company did not purchase any common shares for cancellation under the NCIB for the six months ended June 30, 2018.

Crew is authorized to issue an unlimited number of common shares. As at August 1, 2018, there were 151,707,869 common shares of the Company issued and outstanding. In addition, there were 3,433,813 restricted awards and 4,487,105 performance awards outstanding.

Related-Party and Off-Balance-Sheet Transactions

Crew was not involved in any off-balance-sheet transactions or related party transactions during the quarter ended June 30, 2018.

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 through commodity contracts, issue new equity, issue new debt or repay existing debt through asset sales.

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

The Company monitors this ratio and endeavours to maintain it near or below 2.0 to 1.0. During periods of increased capital expenditures, acquisitions or during periods of low commodity prices, this ratio will increase over the Company's target. As shown below, as at June 30, 2018, the Company's ratio of net debt to annualized adjusted funds flow was 3.8 to 1 (December 31, 2017 – 2.5 to 1). As commodity prices remain volatile, including the recent decline in Canadian natural gas pricing, Crew plans to limit capital expenditures to approximate adjusted funds flow. With only 23% drawn on the Company's $235 million Facility and the senior unsecured notes termed out to 2024, the Company's financial position remains strong. The Company will continue to monitor this ratio and if necessary, 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, 2018**	December 31, 2017
Working capital surplus (deficiency)	**19,954**	(29,143)
Bank loan	**(54,803)**	(21,977)
Senior unsecured notes	**(294,380)**	(293,862)
Net debt	**(329,229)**	(344,982)
Quarterly adjusted funds flow	**21,804**	34,087
Annualized	**87,216**	136,348
Net debt to annualized adjusted funds flow	**3.8**	2.5

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	2018	2019	2020	2021	2022	Thereafter
Bank loan (note 1)	54,803	-	54,803	-	-	-	-
Senior unsecured notes (note 2)	300,000	-	-	-	-	-	300,000
Operating leases	3,329	587	1,175	1,175	392	-	-
Capital commitments	4,228	4,228	-	-	-	-	-
Firm transportation agreements	258,680	21,291	49,315	48,587	26,299	25,705	87,483
Firm processing agreements	122,404	9,185	18,221	16,776	12,354	12,354	53,514
Total	**743,444**	**35,291**	**123,514**	**66,538**	**39,045**	**38,059**	**440,997**

Note 1 – Based on the existing terms of the Company's Facility, the first possible repayment date may come in 2019. However, it is expected that the Facility will be extended and no repayment will be required in the near term.

Note 2 – 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 include the Company's share of the estimated remaining cost for the construction of the pipeline connecting the West Septimus facility to the TransCanada Pipeline Saturn meter station.

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

Crew's 2018 capital expenditure budget is planned to approximate adjusted funds flow and is currently Board approved at $80 to $85 million. Our Q3 2018 capital expenditures are expected to range from $25 to $30 million, with forecast production expected to average 23,000 to 24,000 boe per day. The Company will continue to manage natural gas production by shutting-in uneconomic wells during times of extreme low pricing. Production year-to-date has met or exceeded the Company's original forecasts. This performance is expected to support the upper end of the Company's annual guidance of 23,500 to 24,500 boe per day.

ADDITIONAL DISCLOSURES

Quarterly Analysis

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

($ thousands, except per share amounts)	**June 30 2018**	Mar. 31 2018	Dec. 31 2017	Sep. 30 2017	June 30 2017	Mar. 31 2017	Dec. 31 2016	Sep. 30 2016
Total daily production (boe/d)	**23,583**	25,939	25,270	23,251	20,468	23,231	22,380	23,211
Exploration and development expenditures	**12,468**	33,921	36,413	90,069	36,656	75,164	37,612	37,731
Net property acquisitions/(dispositions)	**17**	(10,007)	(1,709)	(144)	(45,701)	(352)	3,099	(98)
Average wellhead price ($/boe)	**25.18**	25.46	25.87	22.36	26.25	27.40	26.74	22.05
Petroleum and natural gas sales	**54,040**	59,427	60,146	47,824	48,886	57,298	55,051	47,093
Cash provided by operations	**31,304**	15,885	43,484	15,258	31,359	27,189	19,900	25,940
Adjusted funds flow	**21,804**	26,373	34,087	24,970	21,353	27,719	27,879	23,033
Per share – basic	**0.14**	0.18	0.23	0.17	0.14	0.19	0.19	0.16
– diluted	**0.14**	0.17	0.22	0.17	0.14	0.18	0.19	0.16
Net (loss) income	**(9,181)**	4,148	2,342	2,127	21,880	8,056	(40,030)	(1,286)
Per share – basic	**(0.06)**	0.03	0.02	0.01	0.15	0.05	(0.28)	(0.01)
– diluted	**(0.06)**	0.03	0.02	0.01	0.14	0.05	(0.28)	(0.01)

Over the past eight quarters, the Company continued to invest the majority of its capital expenditures in northeastern British Columbia, including the completion of the West Septimus facility expansion in the fourth quarter of 2017, resulting in significant production growth and infrastructure development in the area. Average wellhead pricing began to recover in the latter part of 2016, prompting the Company to increase its capital expenditures at Greater Septimus and Tower. Commodity pricing continued to strengthen in the latter part of 2016 and stabilize in early 2017, where the Company further expanded it capital program and infrastructure spending to allow for the growth realized in the second half of 2017. Late in the third quarter of 2017 through the first half of 2018, natural gas prices decreased significantly below amounts received in the previous few years. This decrease will impact 2018 petroleum and natural gas sales and the associated cash provided by operations and adjusted funds flow. As a result, the Company has reduced its planned capital spending in 2018 as compared to 2017, which will impact production levels as the year proceeds.

For the last two years, significant fluctuations in commodity prices have impacted cash provided by operations, adjusted funds flow and net income (loss). The Company 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. Crew has also attempted to mitigate the lower price environment by reducing its controllable costs and achieve operational efficiencies. 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. In the fourth quarter of 2016 and the second quarter of 2017, the Company incurred impairment charges of $44.4 million and $16.7 million, respectively. In the second quarter of 2017, the Company realized a $37.9 million gain on divesture as it continues to monetize non-core properties to fund future growth.

New Accounting Pronouncements

The Company has reviewed the following new and revised accounting pronouncements that have been issued and has determined that the following impact on the Company's financial statements:

a) IFRS 9 Financial Instruments:

   On January 1, 2018, the Company adopted IFRS 9 Financial Instruments. IFRS 9 introduces new requirements for the classification and measurement of financial assets, amends the requirements related to hedge accounting, and introduces a forward-looking expected loss impairment model. As a result of adopting IFRS 9, certain financial assets were reclassified from fair value through profit and loss to assets at amortized cost. The change in classification category did not result in an adjustment to the carrying amount of the related assets and the adoption of this standard has not had a material impact on the Company's financial statements.

b) IFRS 15 Revenue from Contracts with Customers:

   On January 1, 2018, the Company adopted IFRS 15 Revenue from Contracts with Customers. The new standard replaces IAS 18 Revenue, IAS 11 Construction Contracts and related interpretations. IFRS 15 dictates the recognition and measurement requirements for reporting the nature, amount, timing and uncertainty of revenue resulting from an entity's contracts with customers using a single principles based, five step model. The Company used the cumulative effect method to adopt the new standard. There was no adjustment to opening retained earnings as at January 1, 2018 based on the Company's assessment of revenue contracts not yet completed as at January 1, 2018.

c) IFRS 16 Leases:

   As of January 1, 2019, the Company will be required to adopt IFRS 16 Leases, which will replace IAS 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. As of June 30, 2018, Crew is in the process of identifying and gathering contracts impacted by the new standard. Although the impact is still being determined, it is expected that adoption of IFRS 16 will have a material impact on the Company's consolidated 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, 2018 and ended on June 30, 2018 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 1, 2018

CONDENSED INTERIM CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

(unaudited) (thousands)	**June 30, 2018**	December 31, 2017
Assets		
Current Assets:		
Accounts receivable	**$ 55,845**	$ 40,930
Derivative financial instruments (note 4)	**-**	1,666
	55,845	42,596
Other long-term assets	**-**	4,788
Property, plant and equipment (note 5)	**1,346,832**	1,340,736
	$ 1,402,677	$ 1,388,120
Liabilities and Shareholders' Equity		
Current Liabilities:		
Accounts payable and accrued liabilities	**$ 35,891**	$ 70,073
Derivative financial instruments (note 4)	**14,179**	1,319
	50,070	71,392
Derivative financial instruments (note 4)	**4,028**	-
Bank loan (note 6)	**54,803**	21,977
Senior unsecured notes (note 7)	**294,380**	293,862
Decommissioning obligations (note 8)	**86,593**	88,368
Deferred tax liability	**41,863**	42,427
Shareholders' Equity		
Share capital (note 9)	**1,468,852**	1,458,086
Contributed surplus	**68,271**	73,158
Deficit	**(666,183)**	(661,150)
	870,940	870,094
Commitments (note 12)		
	$ 1,402,677	$ 1,388,120

See accompanying notes to the condensed interim consolidated financial statements.

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

(unaudited) (thousands, except per share amounts)	**Three months ended June 30, 2018**	Three months ended June 30, 2017	**Six months ended June 30, 2018**	Six months ended June 30, 2017
Revenue				
Petroleum and natural gas sales (note 10)	**$ 54,040**	$ 48,886	**$ 113,467**	$ 106,184
Royalties	**(3,919)**	(3,836)	**(7,926)**	(8,393)
Realized (loss) gain on derivative financial instruments (note 4)	**(2,632)**	1,192	**(4,809)**	377
Unrealized (loss) gain on derivative financial instruments (note 4)	**(13,906)**	6,941	**(18,554)**	26,816
Other revenue (note 10)	**2,415**	997	**4,986**	2,285
	35,998	54,180	**87,164**	127,269
Expenses				
Operating	**14,982**	12,460	**30,561**	24,991
Transportation	**3,826**	5,123	**8,759**	9,907
Marketing	**925**	-	**925**	-
General and administrative	**2,629**	2,841	**5,873**	5,987
Share-based compensation	**1,947**	2,007	**3,052**	5,161
Depletion and depreciation (note 5)	**18,252**	16,393	**40,699**	36,103
	42,561	38,824	**89,869**	82,149
(Loss) income from operations	**(6,563)**	15,356	**(2,705)**	45,120
Financing (note 11)	**6,226**	5,941	**12,402**	20,241
Impairment on property, plant and equipment	**-**	16,710	**-**	16,710
Gain on divestiture of property, plant and equipment (note 5)	**-**	(37,898)	**(9,546)**	(38,244)
(Loss) income before income taxes	**(12,789)**	30,603	**(5,561)**	46,413
Deferred tax (recovery) expense	**(3,608)**	8,723	**(528)**	16,477
Net (loss) income and comprehensive (loss) income	**$ (9,181)**	$ 21,880	**$ (5,033)**	$ 29,936
Net (loss) income per share (note 9)				
Basic	**$ (0.06)**	$ 0.15	**$ (0.03)**	$ 0.20
Diluted	**$ (0.06)**	$ 0.14	**$ (0.03)**	$ 0.20

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, 2018	149,328	$ 1,458,086	$ 73,158	$ (661,150)	$ 870,094
Net loss for the period	-	-	-	(5,033)	(5,033)
Share-based compensation expensed	-	-	3,052	-	3,052
Share-based compensation capitalized	-	-	2,791	-	2,791
Issued on vesting of share awards	2,380	10,766	(10,766)	-	-
Tax deduction on excess value of share awards	-	-	36	-	36
Balance, June 30, 2018	**151,708**	**$ 1,468,852**	**$ 68,271**	**$ (666,183)**	**$ 870,940**

(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 9)	(924)	(3,251)	-	-	(3,251)
Balance, June 30, 2017	**148,910**	**$ 1,455,816**	**$ 68,127**	**$ (665,619)**	**$ 858,324**

See accompanying notes to the condensed interim consolidated financial statements.

CONDENSED INTERIM CONSOLIDATED STATEMENTS OF CASH FLOWS

(unaudited) (thousands)	**Three months ended June 30, 2018**	Three months ended June 30, 2017	**Six months ended June 30, 2018**	Six months ended June 30, 2017
Cash provided by (used in):				
Operating activities:				
Net (loss) income	**$ (9,181)**	$ 21,880	**$ (5,033)**	$ 29,936
Adjustments:				
Unrealized loss (gain) on derivative financial instruments (note 4)	**13,906**	(6,941)	**18,554**	(26,816)
Share-based compensation	**1,947**	2,007	**3,052**	5,161
Depletion and depreciation (note 5)	**18,252**	16,393	**40,699**	36,103
Financing expenses (note 11)	**6,226**	5,941	**12,402**	20,241
Interest expense (note 11)	**(5,479)**	(5,212)	**(10,905)**	(10,039)
Impairment on property, plant and equipment	**-**	16,710	**-**	16,710
Gain on divestiture of property, plant and equipment (note 5)	**-**	(37,898)	**(9,546)**	(38,244)
Deferred tax (recovery) expense	**(3,608)**	8,723	**(528)**	16,477
Decommissioning obligations (settled) recovered (note 8)	**(222)**	22	**(813)**	(356)
Change in non-cash working capital	**9,463**	9,734	**(693)**	9,375
	31,304	31,359	**47,189**	58,548
Financing activities:				
Increase (decrease) in bank loan	**7,274**	-	**32,826**	(88,036)
Issuance of senior notes, net of financing costs (note 7)	**-**	-	**-**	293,000
Redemption of senior notes (note 7)	**-**	-	**-**	(156,282)
Shares purchased and cancelled (note 9)	**-**	(3,251)	**-**	(3,251)
	7,274	(3,251)	**32,826**	45,431
Investing activities:				
Property, plant and equipment expenditures (note 5)	**(12,468)**	(36,656)	**(45,048)**	(111,820)
Property acquisitions (note 5)	**(17)**	(3,812)	**(17)**	(3,820)
Property dispositions (note 5)	**-**	49,513	**10,007**	49,873
Change in non-cash working capital	**(26,093)**	(32,551)	**(44,957)**	(10,132)
	(38,578)	(23,506)	**(80,015)**	(75,899)
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, 2018 and 2017

(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, 2017, with the exception of the changes in accounting policies described below. The financial statements do not include certain disclosures that are normally required to be included in annual consolidated financial statements which have been condensed or omitted. 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 1, 2018.

Certain prior year amounts have been reclassified to conform to current presentation.

3. Change in accounting policies:

(i) Adoption of IFRS 9 – Financial Instruments:

On January 1, 2018, the Company adopted IFRS 9 Financial Instruments. IFRS 9 introduces new requirements for the classification and measurement of financial assets, amends the requirements related to hedge accounting, and introduces a forward-looking expected loss impairment model. As a result of adopting IFRS 9, certain financial assets were reclassified from fair value through profit and loss to assets at amortized cost. The change in classification category did not result in an adjustment to the carrying amount of the related assets and the adoption of this standard has not had a material impact on the Company's financial statements.

(ii) Adoption of IFRS 15 – Revenue from Contracts with Customers:

On January 1, 2018, the Company adopted IFRS 15 Revenue from Contracts with Customers. The new standard replaces IAS 18 Revenue, IAS 11 Construction Contracts and related interpretations. IFRS 15 dictates the recognition and measurement requirements for reporting the nature, amount, timing and uncertainty of revenue resulting from an entity's contracts with customers using a single principles based, five step model. The Company used the cumulative effect method to adopt the new standard. There was no adjustment to opening retained earnings as at January 1, 2018 based on the Company's assessment of revenue contracts not yet completed as at January 1, 2018.

The additional disclosures required by IFRS 15, including those required for the cumulative effect method, are disclosed in note 10.

Revenue recognition:

Revenue from the sale of crude oil, natural gas, condensate and natural gas liquids is recorded when control of the product is transferred to the buyer based on the consideration specified in the contracts with customers. This usually occurs when the product is physically transferred at the delivery point agreed upon in the contract and legal title to the product passes to the customer.

The Company evaluates its arrangements with third parties and partners to determine if the Company acts as the principal or as an agent. In making this evaluation, the Company considers if it obtains control of the product delivered or services provided, which is indicated by the Company having the primary responsibility for the delivery of the product or rendering of the service, having the ability to establish prices or having inventory risk. If the Company acts in the capacity of an agent rather than as a principal in a transaction, then the revenue is recognized on a net-basis, only reflecting the fee, if any, realized by the Company from the transaction.

Fees charged to other entities for use of pipelines and facilities owned by the Company are evaluated by management to determine if these originate from contracts with customers or from incidental or collaborative arrangements. Fees charged to other entities that are from contracts with customers are recognized in revenue when the related services are provided.

4. 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. 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, 2018, the Company held derivative commodity contracts as follows:

Subject of Contract	Notional Quantity	Term	Reference	Strike Price	Option Traded	Fair Value
Gas	2,500 mmbtu/day	July 1, 2018 – October 31, 2018	Chicago Citygate	$3.06/mmbtu	Swap	$ (158)
Gas	5,000 gj/day	July 1, 2018 – December 31, 2018	AECO C Monthly Index	$3.00/gj	Call	(3)
Gas	2,500 gj/day	July 1, 2018 – December 31, 2018	AECO C Daily Index	$2.62/gj	Swap	465
Gas	20,000 mmbtu/day	July 1, 2018 – December 31, 2018	Chicago Citygate	$3.61/mmbtu	Swap	(99)
Gas	5,000 mmbtu/day	July 1, 2018 – December 31, 2018	US$ Nymex Henry Hub	$3.05 US/mmbtu	Swap	107
Gas	7,500 mmbtu/day	January 1, 2019 – December 31, 2019	Chicago Citygate	$3.19/mmbtu	Swap	(487)
Gas	2,500 mmbtu/day	January 1, 2019 – December 31, 2019	Dawn Daily Index	$3.30/mmbtu	Swap	(99)
Propane	400 bbl/day	July 1, 2018 – December 31, 2018	US$ Conway OPIS	$0.79 US/gal	Swap	32
Oil	2,250 bbl/day	July 1, 2018 – December 31, 2018	CDN$ WTI	$72.92/bbl	Swap	(8,158)
Oil	250 bbl/day	July 1, 2018 – December 31, 2018	CDN$ WTI	$60.00 - $69.65/bbl	Collar(1)	(1,061)
Oil	250 bbl/day	July 1, 2018 – December 31, 2018	CDN$ WTI	$69.00 - $74.25/bbl	Collar(2)	(854)
Oil	750 bbl/day	July 1, 2018 – December 31, 2018	CDN$ WCS	$56.62/bbl	Swap	(836)
Oil	250 bbl/day	January 1, 2019 – June 30, 2019	CDN$ WTI	$83.80/bbl	Swap	(153)
Oil	250 bbl/day	January 1, 2019 – June 30, 2019	CDN$ WCS	$52.10/bbl	Swap	(217)
Oil	1,500 bbl/day	January 1, 2019 – December 31, 2019	CDN$ WTI	$72.88/bbl	Swap	(6,686)
Total						**$ (18,207)**

(3) The referenced contract is a costless collar whereby the Company receives $60.00/bbl when the market price is below $60.00/bbl, and receives $69.65/bbl when the market price is above $69.65/bbl.

(4) The referenced contract is a costless collar whereby the Company receives $69.00/bbl when the market price is below $69.00/bbl, and receives $74.25/bbl when the market price is above $74.25/bbl.

Capital management:

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 through commodity contracts, issue new equity, issue new debt or repay existing debt through asset sales.

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

The Company monitors this ratio and endeavours to maintain it near or below 2.0 to 1.0. During periods of increased capital expenditures, acquisitions or during periods of low commodity prices, this ratio will increase over the Company's target. As shown below, as at June 30, 2018, the Company's ratio of net debt to annualized adjusted funds flow was 3.8 to 1 (December 31, 2017 – 2.5 to 1). As commodity prices remain volatile, including the recent decline in Canadian natural gas pricing, Crew plans to limit capital expenditures to approximate adjusted funds flow. With only 23% drawn on the Company's $235 million

Facility and the senior unsecured notes termed out to 2024, the Company's financial position remains strong. The Company will continue to monitor this ratio and if necessary, 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, 2018		December 31, 2017
Net debt:				
Accounts receivable	**$**	**55,845**	$	40,930
Accounts payable and accrued liabilities		**(35,891)**		(70,073)
Working capital surplus (deficiency)	**$**	**19,954**	$	(29,143)
Bank loan		**(54,803)**		(21,977)
Senior unsecured notes		**(294,380)**		(293,862)
Net debt	**$**	**(329,229)**	$	(344,982)
Quarterly annualized adjusted funds flow:				
Cash provided by operating activities	**$**	**31,304**	$	43,484
Decommissioning obligations settled		**222**		29
Change in non-cash working capital		**(9,463)**		(9,165)
Accretion of deferred financing charges		**(259)**		(261)
Quarterly adjusted funds flow	**$**	**21,804**	$	34,087
Annualized	**$**	**87,216**	$	136,348
Net debt to annualized adjusted funds flow		**3.8**		2.5

Neither the Company nor any of its subsidiaries are subject to externally imposed capital requirements. The Facility is 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 6).

5. Property, plant and equipment:

Cost or deemed cost		Total
Balance, January 1, 2017	$	2,181,279
Additions		238,302
Acquisitions		6,827
Divestitures		(22,626)
Change in decommissioning obligations		2,853
Capitalized share-based compensation		7,690
Balance, December 31, 2017	$	2,414,325
Additions		46,389
Acquisitions		17
Divestitures		(875)
Change in decommissioning obligations		(1,527)
Capitalized share-based compensation		2,791
Balance, June 30, 2018	**$**	**2,461,120**

Accumulated depletion and depreciation		Total
Balance, January 1, 2017	$	981,827
Depletion and depreciation expense		75,131
Divestitures		(79)
Impairment		16,710
Balance, December 31, 2017	$	1,073,589
Depletion and depreciation expense		40,699
Balance, June 30, 2018	**$**	**1,114,288**

Net book value		Total
Balance, June 30, 2018	**$**	**1,346,832**
Balance, December 31, 2017	$	1,340,736

Included in property, plant and equipment additions for the six months ended June 30, 2018 is $1.3 million of pipe inventory transferred from other long-term assets upon the construction of the West Septimus to the TransCanada Pipeline Saturn meter station pipeline.

The calculation of depletion for the three months ended June 30, 2018 included estimated future development costs of $1,742.6 million (December 31, 2017 - $1,764.2 million) associated with the development of the Company's proved plus probable reserves and excludes salvage value of $69.6 million (December 31, 2017 - $70.0 million) and undeveloped land of $158.7 million (December 31, 2017 - $161.6 million) related to future development acreage with no associated reserves.

During the first quarter of 2018, the Company disposed of non-core assets for cash proceeds of $10.0 million. The assets consisted of petroleum and natural gas properties and undeveloped land with a net book value of $0.9 million and associated decommissioning obligations of $0.4 million, resulting in a gain of $9.5 million on closing of the disposition.

There were no indicators of impairment for the Company's cash-generating units ("CGU") as at June 30, 2018, and therefore an impairment test was not performed.

6. Bank loan:

As at June 30, 2018, 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 5, 2019. 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. 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, 2018. 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, 2018, 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, 2018, the Company had issued letters of credit totaling $30.5 million (December 31, 2017 – $7.7 million).

7. 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, 2018, the carrying value of the 2024 Notes was net of deferred financing costs of $5.6 million (December 31, 2017 – $6.1 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 11).

8. Decommissioning obligations:

	Six months ended June 30, 2018	Year ended December 31, 2017
Decommissioning obligations, beginning of period	**$ 88,368**	$ 85,859
Obligations incurred	**174**	4,557
Obligations settled	**(813)**	(513)
Obligations divested	**(414)**	(1,765)
Change in estimated future cash outflows	**(1,701)**	(1,704)
Accretion of decommissioning obligations	**979**	1,934
Decommissioning obligations, end of period	**$ 86,593**	$ 88,368

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 $86.6 million as at June 30, 2018 (December 31, 2017 – $88.4 million) based on an inflation adjusted undiscounted total future liability of $115.7 million (December 31, 2017 – $118.9 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, 2017 – 2%). The discount factor, being the risk-free rate related to the liability, is 2.22% (December 31, 2017 – 2.22%). The $1.7 million (December 31, 2017 – $1.7 million) change in estimated future cash outflows for the six months ended June 30, 2018 is a result of a change in future estimated undiscounted abandonment costs.

9. Share capital:

At June 30, 2018, 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 was terminated on May 24, 2018. Subject to the terms of this NCIB, for the year ended December 31, 2017, 924,100 common shares for a total cost of $3.3 million were purchased, cancelled and removed from share capital. The Company did not purchase any common shares for cancellation under the NCIB for the six months ended June 30, 2018.

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. Since the inception of the RPAP, the Company has settled all awards through the issuance of common shares from treasury. For RAs and PAs granted subsequent to May 21, 2018, the Company currently intends to settle the award value with common shares purchased on the secondary market as the Company no longer has the ability, in the absence of shareholder approval being obtained, to settle the award values associated with such awards with common shares issued from treasury. Through the vesting of 723,000 RAs and 980,000 PAs, when taking into account the earned multipliers for PAs, 2,380,000 common shares of the Company were issued for the six months ended June 30, 2018.

The number of RAs and PAs outstanding are as follows:

	Number of RAs	Number of PAs
Balance, January 1, 2018	1,616	2,221
Granted	2,604	3,406
Vested	(723)	(980)
Forfeited	(63)	(160)
Balance, June 30, 2018	**3,434**	**4,487**

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, 2018 was 151,548,000 (June 30, 2017 – 149,469,000) and for the six month period ended June 30, 2018, the weighted average number of shares outstanding was 150,451,000 (June 30, 2017 – 148,152,000).

In computing diluted earnings per share for the three month period ended June 30, 2018, nil (June 30, 2017 – 2,051,000) shares were added to the weighted average common shares outstanding to account for the dilution of RAs and PAs, and for the six month period ended June 30, 2018, nil (June 30, 2017 – 3,001,000) shares were added to the weighted average common shares for the dilution. For the three month period ended June 30, 2018, there were 7,921,000 (June 30, 2017 – 2,515,000) RAs and PAs that were not included in the diluted earnings per share calculation because they were anti-dilutive. For the six month period ended June 30, 2018, there were 7,921,000 (June 30, 2017 – 2,883,000) RAs and PAs that were not included in the diluted earnings per share calculation because they were anti-dilutive.

10. Revenue:

Petroleum and natural gas sales:

Crew sells its production pursuant to fixed or variable-price contracts. The transaction price for variable priced contracts is based on the commodity price, adjusted for quality, location or other factors, whereby each component of the pricing formula can be either fixed or variable, depending on the contract terms. Under the contracts, the Company is required to deliver a fixed or variable volume of crude oil, condensate, natural gas or natural gas liquids to the customer. Revenue is recognized when a unit of production is delivered to the customer. The amount of revenue recognized is based on the agreed transaction price, whereby any variability in revenue relates specifically to the Company's efforts to transfer production, and therefore the resulting revenue is allocated to the production delivered in the period during which the variability occurs. As a result, none of the variable revenue is considered constrained.

Crude oil, condensate and natural gas liquids are sold under contracts of varying terms of up to one year. The majority of the Company's natural gas is sold on multi-year contracts. Revenues are typically collected on the 25th day of the month following production.

The following table summarizes the Company's petroleum and natural gas sales, all of which are from revenue with contracts with customers:

	Three months ended June 30, 2018	Three months ended June 30, 2017	**Six months ended June 30, 2018**	Six months ended June 30, 2017
Light crude oil	**$ 1,796**	$ 2,641	**$ 3,735**	$ 5,489
Heavy crude oil	**9,776**	7,290	**15,450**	14,465
Condensate	**17,343**	8,447	**35,276**	19,407
Other natural gas liquids	**3,989**	1,706	**7,992**	4,581
Natural gas	**21,136**	28,802	**51,014**	62,242
	$ 54,040	$ 48,886	**$ 113,467**	$ 106,184

The adoption of IFRS 15 resulted in the Company evaluating its arrangement with third parties and partners to determine if the Company is the principal or agent. Based on the focus of control of the specified good or service, the Company identified arrangements for processing services where the Company is considered the principal and not a result of collaborative arrangements with partners in jointly owned assets. As a result of this change, the Company has reclassified $1.8 million for the six months ended June 30, 2018 from operating expenses to processing revenue included in other revenue.

Other revenue:

The following table summarizes the Company's other revenue:

	Three months ended June 30, 2018	Three months ended June 30, 2017	**Six months ended June 30, 2018**	Six months ended June 30, 2017
Marketing revenue	**$ 1,519**	$ -	**$ 2,198**	$ -
Processing revenue	**896**	997	**1,788**	2,285
Other	**-**	-	**1,000**	-
	$ 2,415	$ 997	**$ 4,986**	$ 2,285

11. Financing:

	Three months ended June 30, 2018	Three months ended June 30, 2017	**Six months ended June 30, 2018**	Six months ended June 30, 2017
Interest expense	**$ 5,479**	$ 5,212	**$ 10,905**	$ 10,039
Accretion of deferred financing costs	**259**	250	**518**	457
Accretion of decommissioning obligations	**488**	479	**979**	953
Premium paid on redemption of 2020 Notes (note 7)	**-**	-	**-**	6,282
Deferred financing costs expensed on 2020 Notes (note 7)	**-**	-	**-**	2,510
	$ 6,226	$ 5,941	**$ 12,402**	$ 20,241

12. Commitments:

	Total	2018	2019	2020	2021	2022	Thereafter
Operating leases	$ 3,329	$ 587	$ 1,175	$ 1,175	$ 392	$ -	$ -
Capital commitments	4,228	4,228	-	-	-	-	-
Firm transportation agreements	258,680	21,291	49,315	48,587	26,299	25,705	87,483
Firm processing agreements	122,404	9,185	18,221	16,776	12,354	12,354	53,514
Total	**$ 388,641**	**$ 35,291**	**$ 68,711**	**$ 66,538**	**$ 39,045**	**$ 38,059**	**$140,997**

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

Capital commitments include the Company's share of the estimated remaining cost for the construction of the pipeline connecting the West Septimus facility to the TransCanada Pipeline Saturn meter station.

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

James Taylor
Chief Operating Officer

Jamie L. Bowman
Vice President, Marketing & Originations

Kurtis Fischer
Vice President, Planning & Development

Paul Dever
Vice President, Government & Stakeholder Relations

Kevin G. Evers
Vice President, Geosciences

Mark Miller
Vice President, Land & Negotiations

BOARD OF DIRECTORS

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Chairman Independent Director

Jeffery E. Errico,
Lead Director Independent Director

Dennis L. Nerland
Independent Director

Karen A. Nielsen
Independent Director

Ryan A. Shay
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