interim report

Q1

2018

first quarter ending March 31, 2018

Crew Energy Inc. (TSX: CR) ("Crew" or the "Company") is pleased to announce our operating and financial results for the three month period ended March 31, 2018.

HIGHLIGHTS

- **Production Growth in Q1 2018:** At 25,939 boe per day, average volumes were 12% higher than Q1 2017 reflecting Crew's program focused on completion of condensate-rich wells at West Septimus in northeast British Columbia ("NE BC").

- **Increased Montney Condensate Production:** Crew's continued focus on condensate-rich opportunities at West Septimus resulted in Montney condensate production increasing 41% to average 2,699 bbls per day and other natural gas liquids increasing 24% to average 1,792 bbls per day relative to Q1 2017. Realized prices in Q1 2018 for condensate and other natural gas liquids were stronger relative to Q1 2017, averaging $73.82 per bbl and $24.81 per bbl, respectively.

- **Robust Greater Septimus Netbacks Support Adjusted Funds Flow:** Corporate operating netbacks averaged $14.70 per boe in Q1 2018, while Greater Septimus operating netbacks were 18% higher averaging $17.30 per boe. Adjusted Funds Flow ("AFF") of $26.4 million ($0.17 per diluted share) was 5% lower than Q1 2017, with higher production and stronger condensate and other natural gas liquids pricing offset by lower realized natural gas and heavy oil pricing.

- **Capital Activity Focused on Completion of Condensate-Rich Wells:** Net capital expenditures totaled $23.9 million ($33.9 million before dispositions), directed to the completion of nine (7.7 net) previously-drilled wells at West Septimus and the recompletion of 11 (10.5 net) heavy oil wells in Lloydminster. Three of the nine West Septimus wells were brought on production during Q1 with the remaining six wells expected to be brought on in late Q2 or early Q3. The Company also completed the majority of the construction of 83 km of line pipe from the West Septimus facility through Groundbirch to the Saturn meter station.

- **Balance Sheet Strength Maintained:** Net debt declined $6.7 million from year end 2017 to $338.3 million, including $300 million of term debt that has no repayment required until 2024. Crew completed our annual bank review maintaining the borrowing base of our syndicated credit facility at $235 million supported by our strong 2017 proved developed producing reserve additions. The Company also closed a $10.0 million cash disposition of certain assets within the Lloydminster area comprised of 882 acres of land with no associated production.

FINANCIAL & OPERATING HIGHLIGHTS

FINANCIAL ($ thousands, except per share amounts)	Three months ended Mar. 31, 2018	Three months ended Mar. 31, 2017
Petroleum and natural gas sales	**59,427**	57,298
Adjusted Funds Flow[1]	**26,373**	27,719
Per share - basic	**0.18**	0.19
- diluted	**0.17**	0.18
Net income	**4,148**	8,056
Per share - basic	**0.03**	0.05
- diluted	**0.03**	0.05
Exploration and Development expenditures	**33,921**	75,164
Property acquisitions (net of dispositions)	**(10,007)**	(352)
Net capital expenditures	**23,914**	74,812

Capital Structure ($ thousands)	As at Mar. 31, 2018	As at Dec. 31, 2017
Working capital (surplus) deficiency[2]	**(3,324)**	29,143
Bank loan	**47,529**	21,977
	44,205	51,120
Senior Unsecured Notes	**294,121**	293,862
Total Net Debt	**338,326**	344,982
Common Shares Outstanding (thousands)	**149,346**	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.

Operations	Three months ended Mar. 31, 2018	Three months ended Mar. 31, 2017
Daily production		
Light crude oil (bbl/d)	**316**	530
Heavy crude oil (bbl/d)	**1,747**	1,857
Condensate (bbl/d)	**2,699**	1,915
Other natural gas liquids (bbl/d)	**1,792**	1,448
Natural gas (mcf/d)	**116,312**	104,887
Total (boe/d @ 6:1)	**25,939**	23,231
Average prices [1]		
Light crude oil ($/bbl)	**68.20**	59.74
Heavy crude oil ($/bbl)	**36.09**	42.93
Condensate ($/bbl)	**73.82**	63.61
Natural gas liquids ($/bbl)	**24.81**	22.06
Natural gas ($/mcf)	**2.85**	3.54
Oil equivalent ($/boe)	**25.46**	27.40

Notes:

(1) Average prices do not include gains and losses on financial instruments.

	Three months ended Mar. 31, 2018	Three months ended Mar. 31, 2017
Netback ($/boe)		
Petroleum and natural gas sales	**25.46**	27.40
Royalties	**(1.72)**	(2.18)
Realized commodity hedging loss	**(0.93)**	(0.39)
Marketing revenue (1)	**0.29**	-
Net operating costs	**(6.29)**	(5.38)
Transportation costs	**(2.11)**	(2.29)
Operating netback (2)	**14.70**	17.16
G&A	**(1.39)**	(1.50)
Other income	**0.43**	-
Financing costs on long-term debt	**(2.44)**	(2.41)
Adjusted funds flow	**11.30**	13.25
Drilling Activity		
Gross wells	**0**	15
Working interest wells	**0.0**	15.0
Success rate, net wells (%)	**-**	93%

Notes:

(1) Marketing revenue was recognized from the monetization of forward physical sales contracts in the period.

(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" within Crew's MD&A.

FINANCIAL OVERVIEW

Higher Production from West Septimus

- Q1 2018 production of 25,939 boe per day is a 12% increase over the first quarter of 2017 and 3% higher than the previous quarter and reflects continued strong results at West Septimus, with only three of the nine wells completed during Q1 2018 brought on stream through permanent facilities and two (1.6 net) wells that were flow-tested over an extended period.
- The Company continues to manage natural gas production given weak prices realized at delivery points in Canada. In particular, legacy dry gas production, processed and transported through third party facilities, has been limited during times when realized prices at Station II have fallen below $1.50 per GJ.
- Planned maintenance programs by all Canadian pipeline operators during Q2 2018 have impacted Canadian natural gas prices. As such, Crew has budgeted to leave six of the West Septimus wells completed during the first quarter shut-in through most of Q2. The Company currently plans to bring the wells on stream later in the year when prices are expected to recover.

Adjusted Funds Flow Exceeds Net Capital Expenditures

- Q1 2018 AFF totaled $26.4 million ($0.17 per diluted share), exceeding net capital expenditures during the period. AFF was 5% lower (6% on a diluted per share basis) relative to Q1 2017, and 23% lower on an absolute and per share basis compared to Q4 2017, as higher production volumes were offset by lower realized natural gas and heavy oil pricing.
- Petroleum and natural gas sales in Q1 2018 increased 4% over Q1 2017 as a result of higher production volumes, in particular higher condensate production, and improved pricing for light oil, condensate and other natural gas liquids prices. This was partially offset by lower heavy oil and natural gas prices and higher cash costs.
- Cash costs per boe have increased 1% over Q1 2017 as lower royalties and general and administrative costs were offset by an increase in operating costs. Operating costs have increased over the first and fourth quarter of 2017 with a full quarter of fixed costs associated with the expanded West Septimus facility realized in Q1 2018. The expanded West Septimus facility provides Crew with the processing capacity to increase corporate production by over 50% from current levels, including the handling of an additional 5,000 barrels per day of incremental liquids production.

Greater Septimus Netbacks Remain Robust

- Greater Septimus operating netbacks were $17.30 per boe in Q1 2018, 18% higher than Crew's corporate operating netback of $14.70 per boe. Year over year netbacks at Greater Septimus reflect lower realized natural gas pricing and an increase in unit operating costs at the recently expanded West Septimus gas processing facility, offset by an increase in condensate production, higher prices for condensate and NGLs and lower royalties.

Strong Liquids Pricing Partially Offset Weak Natural Gas Prices

- Q1 2018 commodity prices averaged $25.46 per boe, a 7% decline over Q1 2017 and a 2% decline over the previous quarter.
- Realized total liquids prices increased 9% to $50.09 per boe compared to Q1 2017, a decrease of 7% over Q4 2017. Crew's liquids pricing in the first quarter benefited from increased condensate production relative to other, lower valued liquids and stronger condensate pricing, offset by weaker pricing for the Company's heavy oil sales. A stronger West Texas Intermediate ("WTI") benchmark price, which increased 13% quarter over quarter and 16% compared to Q1 2017, benefited Crew's light oil and condensate pricing. The WTI increase was supported by tightening world oil markets and geopolitical tensions that continue to build between several nations.
- Conversely, Canadian heavy oil prices represented by the Western Canadian Select benchmark were 11% lower quarter over quarter and 1% lower compared to Q1 2017. Canadian heavy oil prices were negatively impacted by limited export transportation options out of western Canada and high inventory levels caused by a major export pipeline outage in the fourth quarter of 2017.
- Realized natural gas prices decreased 19% to $2.85 per mcf compared to Q1 2017, while increasing 8% over Q4 2017. Natural gas prices year over year have been impacted by increasing natural gas production throughout North America. The oversupplied market situation has been amplified in Canada as bottlenecks in our natural gas pipeline system have limited the delivery of Canadian production to markets outside of western Canada. This has significantly widened the differential between western Canadian benchmark prices and those outside of this region. Crew's diversified marketing portfolio, which had 42% exposure to Chicago City Gate prices in the first quarter, contributed to Crew outperforming the AECO 5A benchmark price by 37%.

Capital Expenditures Focused at West Septimus

- Q1 2018 exploration and development expenditures of $33.9 million ($23.9 million net of the impact of dispositions) included the completion of nine (7.7 net) liquids-rich wells in West Septimus, of which three were tied-in during the quarter.
- During the first quarter, Crew closed a $10.0 million cash disposition of certain assets in the Lloydminster area comprised of 882 acres of land, directing the proceeds to offset a portion of the first quarter capital program.

Balance Sheet Strength and Financial Flexibility Remain a Priority

- Balance sheet strength and ongoing financial flexibility were strengthened with net debt declining to $338.3 million, including $300 million of term debt with no financial covenants and no repayment required until 2024.
- Crew exited the period 20% drawn on our $235 million bank facility. The Company's bank syndicate recently completed its annual review extending the facility for an additional one-year term and maintaining the borrowing base at $235 million, supported by our strong 2017 proved developed producing reserve additions.

TRANSPORTATION, MARKETING & HEDGING

- **Natural Gas Pricing Exposure**: Approximately 40% Chicago City Gate, 19% AECO, 16% Alliance ATP, 13% Dawn, 8% Malin and 4% Sumas through the second and third quarters of 2018.
- **Crystalizing Value:** During Q1 the Company elected to monetize the value inherent in our Dawn and Malin market exposure for Q2 and Q3 of 2018. As a result, the Company realized $0.7 million of marketing revenue in Q1 related to the monetization of 50% of Crew's Q2 and Q3 Malin exposure. An additional amount of approximately $3.0 million of marketing revenue will be recognized over Q2 and Q3 related to the monetization of the remaining Malin and Crew's Dawn exposure for those periods.
- **New Natural Gas Sales Exposure**: Commencing in Q4 2018, the Company will benefit from additional natural gas sales exposure that complements our long-standing market diversification strategy and offers access to further natural gas delivery points, including Nymex.

Natural Gas & Liquids Hedging

- Approximately 24% 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 are hedged at a minimum average price of C$72.57 per bbl, 500 bbls per day of Western Canadian Select for the second half of 2018 at an average price of C$57.90 per bbl and 400 bbls per day of OPIS Conway propane hedged at US$0.7863 per gallon or US$33.03 per bbl.
- The Company has started adding to our 2019 risk management program with 1,500 barrels per day of WTI hedged at an average price of C$72.88 per barrel. As a result of the weak forward pricing for natural gas, the Company has only hedged 2,500 mmbtu per day of Chicago City Gate gas at C$3.16 per mmbtu.

OPERATIONS & AREA OVERVIEW

NE BC Montney - Greater Septimus

- Three (3.0 net) wells were placed on production at rates that were disclosed in Crew's February 8, 2018 press release. Six (4.7 net) new wells situated within the West Septimus core area were completed in the quarter with limited flow data. To facilitate water management, two of the six wells were flow tested for an extended period and produced at an average rate of 7.4 mmcf per day and 325 bbls per day of NGLs (55% condensate) after ten days of post-frac flow at an average flowing casing pressure of 2,258 psi over the last six hours of the test, equating to an average per well sales rate of 1,473 boe per day. Crew expects to have additional flow data from these wells in our Q2 2018 press release in August. The cost for the six wells averaged approximately $4.3 million per well.
- In the first quarter of 2018, Crew completed the majority of the construction of strategic line pipe infrastructure from the West Septimus facility through our Groundbirch acreage connecting into the existing TCPL Saturn meter station and expects the project to be finalized by the end of the third quarter. This will complete Crew's goal of accessing all three major export pipelines in BC.
- Crew continuously evaluates the drilling and completion evolution in the ultra-condensate rich ("UCR") Montney reservoirs across Western Canada and has developed a next generation plan for the development of this highly prospective area. Immediately after spring breakup we plan to begin drilling the next four well pad in the UCR area at lengths that are 30-50% longer and we intend to utilize a revised cased-hole plug and perf completion design which is expected to improve condensate recovery.

Greater Septimus Operational Statistics

Production & Drilling	Q1 2018	Q4 2017	Q3 2017	Q2 2017	Q1 2017
Average daily production (boe/d)	20,467	20,193	18,154	15,558	17,440
Wells drilled (gross / net)	-	5 / 3.9	13 / 12.3	5 / 5.0	10 / 10.0
Wells completed (gross / net)	9 / 7.7	3 / 3.0	14 / 14.0	9 / 9.0	3 / 3.0

Operating Netback[(1)] ($ per boe)	Q1 2018	Q4 2017	Q3 2017	Q2 2017	Q1 2017
Revenue	25.40	24.43	20.05	24.51	26.49
Royalties	(1.50)	(1.19)	(0.89)	(1.57)	(1.66)
% basis	5.9%	4.9%	4.4%	6.4%	6.3%
Realized commodity hedge (loss) / gain	(1.01)	1.74	2.97	0.77	(0.41)
Marketing Income	0.37	-	-	-	-
Operating costs	(4.45)	(3.67)	(3.38)	(4.10)	(3.34)
Transportation costs	(1.51)	(1.51)	(1.65)	(2.03)	(1.67)
Operating netback	17.30	19.80	17.10	17.58	19.41

Notes:

(1) Operating netback equals petroleum and natural gas sales including realized hedging gains and losses on commodity contracts less royalties, operating costs and transportation costs calculated on a boe basis. Operating netback 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" within Crew's MD&A.

NE BC Montney - Tower

- Production in the Tower area averaged 1,065 boe per day in Q1 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.
- A strategic partner completed construction of a water handling facility at Tower during Q1 2018, and Crew is a priority customer. In light of reduced operating costs associated with improved water handling coupled with the strength in oil prices, Tower's economics represent an attractive option for continued investment.

AB / SK Heavy Oil - Lloydminster

- Crew's previously announced sales process in respect of our Lloydminster asset is ongoing, while netbacks in the area continue to improve as benchmark crude oil prices have increased and differentials have narrowed. During the first quarter, the Company divested of 882 acres of land at Lloydminster with no associated production and approximately $0.4 million of abandonment and reclamation obligations for cash proceeds of $10.0 million.
- Despite limited capital investment, average production in the area was 1,748 boe per day during the first quarter, representing a 3% decline over the previous quarter. Activities included the recompletion of 11 (10.5 net) oil wells for total capital cost of $0.5 million.

OUTLOOK

Execution of Fully Funded Budget Remains on Track

- Crew's Q2 capital expenditures are expected to be approximately $12 to $15 million, reflecting reduced activity and restricted access typically associated with spring breakup. The capital expenditure budget has been maintained at $80 to 85 million (gross) or net $70 to 75 million after the impact of the Q1 disposition.

Annual Production on Budget with Second Quarter Forecast Reflecting Broader Market Conditions

- Pipeline restrictions in Canada continue to plague the industry and have resulted in lower benchmark prices. Several third-party pipeline maintenance activities are scheduled in Alberta and BC during Q2 2018, leading to interruptible export and storage service restrictions that are currently being reflected in very low Western Canadian natural gas prices for May and June.
- In light of weak pricing, Crew plans to shut-in volumes to preserve value. However, with our diversified marketing strategy, the Company maintains optionality to reduce exposure to markets that do not offer economic pricing and we will continue to closely monitor natural gas market dynamics and adjust production levels to generate optimal returns.
- Currently, Crew has six (4.7 net) completed wells and four (3.6 net) drilled uncompleted wells to bring on production when prices are supportive. In addition, following spring breakup, the Company will commence drilling a four well pad in the UCR area. Based on activity levels through spring break-up, the impact of shutting-in volumes and electing to defer producing the six wells completed in the first quarter, Q2 production is expected to average 22,000 to 23,000 boe per day, which is in-line with our original budget and supportive of Crew's annual forecast average production of 23,500 to 24,500 boe per day.

We thank our employees, contractors and directors for their commitment and dedication through the current market conditions, and we thank all of our shareholders and bondholders for their continued support of Crew.

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 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.

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 Q2 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; the potential sale of our heavy oil assets; Q2 and 2018 capital expenditure and operational plans and priorities; 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 month period ended March 31, 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 March 31, 2018 unaudited condensed interim consolidated financial statements are reported in Canadian dollars ("CDN"). This MD&A is dated May 10, 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 second quarter expenditures, timing of capital expenditures and methods of financing capital expenditures and the ability to fund financial liabilities, production estimates including second 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 March 31, 2018**	Three months ended March 31, 2017
Cash provided by operating activities	**15,885**	27,189
Change in operating non-cash working capital	**10,156**	359
Accretion of deferred financing costs	**(259)**	(207)
Funds from operations	**25,782**	27,341
Decommissioning obligations settled	**591**	378
Adjusted funds flow	**26,373**	27,719

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)	**March 31, 2018**	December 31, 2017
Current assets	**45,672**	42,596
Current liabilities	**(45,803)**	(71,392)
Derivative financial instruments	**3,455**	(347)
Working capital surplus (deficiency)	**3,324**	(29,143)

($ thousands)	**March 31, 2018**	December 31, 2017
Bank loan	**(47,529)**	(21,977)
Senior unsecured notes	**(294,121)**	(293,862)
Working capital surplus (deficiency)	**3,324**	(29,143)
Net debt	**(338,326)**	(344,982)

RESULTS OF OPERATIONS

Production

	Three months ended March 31, 2018					Three months ended March 31, 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	**316**	**2,699**	**1,792**	**116,306**	**24,191**	530	1,915	1,448	104,838	21,366
Lloydminster	**1,747**	**-**	**-**	**6**	**1,748**	1,857	-	-	49	1,865
Total	**2,063**	**2,699**	**1,792**	**116,312**	**25,939**	2,387	1,915	1,448	104,887	23,231

Production for the first quarter of 2018 increased 12% as compared to the same period in 2017, as a result of an active drilling and completion program in northeast British Columbia, focusing on the condensate-rich wells at West Septimus. Increased West Septimus production coincided with the fourth quarter 2017 completion of the West Septimus facility expansion, doubling the facility's processing capacity to 120 mmcf per day in the fourth quarter of 2017. This production increase was partially offset by decreased heavy oil production at Lloydminster, where the Company continues to redirect its investment capital to higher rate of return projects within its Montney liquid-rich natural gas assets in northeast British Columbia.

Petroleum and Natural Gas Sales

	Three months ended March 31, 2018	Three months ended March 31, 2017
Petroleum and natural gas sales ($ thousands)		
Light crude oil	**1,939**	2,848
Heavy crude oil	**5,674**	7,175
Condensate	**17,933**	10,960
Other natural gas liquids	**4,003**	2,875
Natural gas	**29,878**	33,440
Total	**59,427**	57,298
Crew average prices		
Light crude oil ($/bbl)	**68.20**	59.74
Heavy crude oil ($/bbl)	**36.09**	42.93
Condensate ($/bbl)	**73.82**	63.61
Other natural gas liquids ($/bbl)	**24.81**	22.06
Natural gas ($/mcf)	**2.85**	3.54
Oil equivalent ($/boe)	**25.46**	27.40
Benchmark pricing		
Light crude oil – Cdn$ WTI (Cdn $/bbl)	**79.53**	68.66
Heavy crude oil – WCS (Cdn $/bbl)	**49.03**	49.47
Natural gas liquids – Condensate @ Edmonton (Cdn $/bbl)	**79.83**	69.18
Natural Gas:		
AECO 5A daily index (Cdn $/mcf)	**2.08**	2.69
AECO 7A monthly index (Cdn $/mcf)	**1.85**	2.94
Chicago City Gate at ATP (Cdn $/mcf)	**3.01**	3.22
Alliance 5A (Cdn $/mcf)	**2.56**	3.09

The Company's first quarter 2018 revenue increased 4% as compared to the same period in 2017, as a result of the increase in production in northeast British Columbia coupled with an increase in light oil, condensate and other natural gas liquids pricing, partially offset by a decline in heavy oil and natural gas pricing.

The Company's realized light crude oil price increased 14% which was comparable to the 16% increase in the Company's Cdn$ West Texas Intermediate ("WTI") benchmark for the same period last year. Crew's first quarter heavy oil price decreased 16%, which was greater than the 1% decrease in the Company's Western Canadian Select ("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. The Company's first quarter realized condensate price increased 16% over the same period in 2017 which was comparable to the 15% increase in the Condensate at Edmonton benchmark price. Other natural gas liquids ("ngl") realized price increased 12% in the first quarter, due to an increase in propane pricing as compared to the same period in 2017. Crew's realized natural gas price decreased 19% in the first quarter of 2018 which is consistent with the 16% 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 first quarter 2018 natural gas sales portfolio is based approximately on the following reference prices:

	Q1 2018	Q1 2017
Chicago City Gate at ATP	**42%**	45%
AECO 5A	**12%**	12%
AECO 7A	**13%**	14%
Alliance 5A	**24%**	19%
Station 2	**9%**	10%
Total	**100%**	100%

Royalties

($ thousands, except per boe)	**Three months ended March 31, 2018**	Three months ended March 31, 2017
Royalties	**4,007**	4,557
Per boe	**1.72**	2.18
Percentage of Petroleum and natural gas sales	**6.7%**	8.0%

For the first quarter of 2018, royalties and royalties as a percentage of revenue decreased over the same period in 2017 as a result of new production at West Septimus, which attracts lower royalties due to new well deep gas royalty credit programs. In addition, declines in higher royalty rate heavy oil sales at Lloydminster decreased the corporate royalty rate. The Company continues to expect its royalties as a percentage of revenue to average between 5% and 7% in 2018.

Derivative Financial Instruments

Commodities

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

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

($ thousands)	**Three months ended March 31, 2018**	Three months ended March 31, 2017
Realized loss on derivative financial instruments	**(2,177)**	(815)
Per boe	**(0.93)**	(0.39)
Unrealized (loss) gain on financial instruments	**(4,648)**	19,875

At March 31, 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	April 1, 2018 – October 31, 2018	Chicago Citygate	$3.06/mmbtu	Swap	$ (41)
Gas	5,000 gj/day	April 1, 2018 – December 31, 2018	AECO C Monthly Index	$3.00/gj	Call	(9)
Gas	2,500 gj/day	April 1, 2018 – December 31, 2018	AECO C Daily Index	$2.62/gj	Swap	871
Gas	20,000 mmbtu/day	April 1, 2018 – December 31, 2018	Chicago Citygate	$3.61/mmbtu	Swap	2,034
Gas	5,000 mmbtu/day	April 1, 2018 – December 31, 2018	US$ Nymex Henry Hub	$3.05 US/mmbtu	Swap	351
Gas	2,500 mmbtu/day	January 1, 2019 – December 31, 2019	Chicago Citygate	$3.16/mmbtu	Swap	(5)
Propane	400 bbl/day	April 1, 2018 – December 31, 2018	US$ Conway OPIS	$0.79 US/gal	Swap	561
Oil	2,250 bbl/day	April 1, 2018 – December 31, 2018	CDN$ WTI	$72.92/bbl	Swap	(5,148)
Oil	250 bbl/day	April 1, 2018 – December 31, 2018	CDN$ WTI	$60.00 - $69.65/bbl	Collar(1)	(844)
Oil	250 bbl/day	April 1, 2018 – December 31, 2018	CDN$ WTI	$69.00 - $74.25/bbl	Collar(2)	(539)
Oil	1,250 bbl/day	January 1, 2019 – December 31, 2019	CDN$ WTI	$71.56/bbl	Swap	(1,532)
Total						**$ (4,301)**

(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.

Subsequent to March 31, 2018, the Company entered into the following derivative commodity contracts:

Subject of Contract	Notional Quantity	Term	Reference	Strike Price	Option Traded
Oil	500 bbl/day	July 1, 2018 – December 31, 2018	CDN$ WCS	$57.90/bbl	Swap
Oil	250 bbl/day	January 1, 2019 – December 31, 2019	CDN$ WTI	$79.50/bbl	Swap

Marketing Revenue

($ thousands, except per boe)	**Three months ended March 31, 2018**	Three months ended March 31, 2017
Marketing revenue	**679**	-
Per boe	**0.29**	-

In the first quarter of 2018, the Company recognized $0.7 million as marketing revenue, relating to the monetization of certain natural gas sale contracts.

Net Operating Costs

($ thousands, except per boe)	**Three months ended March 31, 2018**	Three months ended March 31, 2017
Operating costs	**15,579**	12,531
Less: processing revenue	**(892)**	(1,288)
Net operating costs	**14,687**	11,243
Per boe	**6.29**	5.38

For the first quarter of 2018, net operating costs per boe increased 17% as compared to the same period in 2017, as a result of increased processing fees from the facility expansion at West Septimus, and higher water handling costs at Tower. In addition, third party volume decreased resulting in lower processing revenue as compared to the same period in 2017. These increases in costs were partially offset by decreased heavy oil production at Lloydminster which yield higher operating costs as compared to the corporate average. The Company is forecasting 2018 net operating costs to average between $6.50 and $6.75 per boe, an increase over the first quarter, as the Company is expecting lower production volume during the second and third quarters due to natural gas volumes being shut-in due to projected weak pricing.

Transportation Costs

($ thousands, except per boe)	**Three months ended March 31, 2018**	Three months ended March 31, 2017
Transportation costs	**4,933**	4,784
Per boe	**2.11**	2.29

In the first quarter of 2018, the Company's transportation costs per boe decreased as compared to the same period in 2017 as a result of increased production in West Septimus which yields lower transportation costs per boe. This was partially offset by a reduction in heavy oil and Tower oil production which attracts lower transportation costs than the corporate average as compared to the same period last year. The Company is forecasting transportation costs per boe to average between $2.40 and $2.65 for 2018, an increase over the first quarter, as the Company is expecting lower production volume during the second and third quarters due to natural gas volumes being shut-in due to projected weak pricing. Additionally, the Company will add additional natural gas egress in the fourth quarter of 2018, which will provide access to higher priced natural gas delivery points but at a higher transportation delivery cost per unit.

Operating Netbacks

($/boe)	Greater Septimus	Lloydminster Heavy Oil	Other NE BC	Three months ended March 31, 2018	Three months ended March 31, 2017
Petroleum and natural gas sales	**25.40**	**36.08**	**20.78**	**25.46**	27.40
Royalties	**(1.50)**	**(4.83)**	**(1.44)**	**(1.72)**	(2.18)
Realized commodity hedging loss	**(1.01)**	**-**	**(0.95)**	**(0.93)**	(0.39)
Marketing revenue	**0.37**	**-**	**-**	**0.29**	-
Net operating costs	**(4.45)**	**(23.55)**	**(8.36)**	**(6.29)**	(5.38)
Transportation costs	**(1.51)**	**(1.01)**	**(5.96)**	**(2.11)**	(2.29)
Operating netbacks	**17.30**	**6.69**	**4.07**	**14.70**	17.16
Production (boe/d)	**20,467**	**1,748**	**3,724**	**25,939**	23,231

For the first quarter of 2018, the Company's operating netbacks decreased over the same period in 2017 as a result of a decrease in realized pricing, higher operating costs and realized hedging losses, partially offset by marketing revenue recognized in the quarter and decreased royalties and transportation costs.

General and Administrative Costs

($ thousands, except per boe)	Three months ended March 31, 2018	Three months ended March 31, 2017
Gross costs	**4,840**	4,977
Operator's recoveries	**(40)**	(174)
Capitalized costs	**(1,556)**	(1,657)
General and administrative expenses	**3,244**	3,146
Per boe	**1.39**	1.50

Gross general and administrative ("G&A") costs have decreased in the first quarter of 2018 as compared to the same period in 2017, due to lower compensation costs as a result of reduced staffing levels and a reduction in reserve evaluator fees. The increase in net G&A costs in the first quarter of 2018 is a result of a decrease in third party operator recoveries, as compared to the same period in 2017. The decrease in net G&A costs per boe is due to an increase in production in the first quarter of 2018, as compared to the same period in 2017. Crew forecasts G&A costs per boe to average between $1.25 and $1.50 in 2018.

Other Income

($ thousands, except per boe)	Three months ended March 31, 2018	Three months ended March 31, 2017
Other	**1,000**	-
Per boe	**0.43**	-

In the first quarter of 2018, the Company recognized $1.0 million as income, representing 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 March 31, 2018**	Three months ended March 31, 2017
Gross costs	**2,141**	6,113
Capitalized costs	**(1,036)**	(2,959)
Total share-based compensation	**1,105**	3,154

In the first quarter of 2018, the Company's share-based compensation expense decreased as compared to the same period 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 period in 2017.

Depletion and Depreciation

($ thousands, except per boe)	**Three months ended March 31, 2018**	Three months ended March 31, 2017
Depletion and depreciation	**22,447**	19,710
Per boe	**9.62**	9.43

Depletion and depreciation costs increased 14% when compared to the same period in 2017 as a result of the increased production in the Greater Septimus area and higher land expiries in the quarter. In the first quarter of 2018, depletion and depreciation per boe increased as a result of increased land expiries in the other NE BC and Lloydminster areas which was partially offset by increased production and increased reserve bookings in the Greater Septimus area, where depletion rates are lower than 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 March 31, 2018**	Three months ended March 31, 2017
Interest on bank loan and other	**618**	966
Interest on senior notes	**4,808**	3,861
Accretion of deferred financing charges	**259**	207
Accretion of the decommissioning obligation	**491**	474
Premium paid on redemption of 2020 Notes	**-**	6,282
Deferred financing costs expensed on 2020 Notes	**-**	2,510
Total finance expense	**6,176**	14,300
Average debt level	**330,550**	269,914
Average drawings on bank loan	**30,550**	73,248
Average senior unsecured notes outstanding	**300,000**	196,666
Effective interest rate on senior unsecured notes	**6.5%**	8.0%
Effective interest rate on long-term debt	**6.3%**	7.6%
Financing costs on long-term debt per boe	**2.44**	2.41

The Company's average corporate debt level increased in the first quarter of 2018 as compared to the same period in 2017, due to increased capital expenditures incurred over the previous twelve months, predominantly in the third quarter of 2017. In addition, during the first quarter of 2017, the Company issued $300 million of 6.5% senior unsecured notes (the "2024 Notes") as described below in the Capital Funding section. Proceeds from the 2024 Notes were used to redeem the $150 million of 8.375% senior unsecured notes (the "2020 Notes") and repay the drawings on the bank loan. As a result, the effective interest rate on the Company's senior notes and total long-term debt decreased in the first quarter of 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 first quarter of 2018, the provision for deferred tax expense was $3.1 million, as compared to $7.8 million for the same period in 2017. The decrease in deferred tax expense is predominantly due to flow-through shares being renounced in 2017 and higher income due to an unrealized hedging gain in the first quarter of 2017.

Cash, Funds from Operations and Net Income (Loss)

($ thousands, except per share amounts)		**Three months ended March 31, 2018**	Three months ended March 31, 2017
Cash provided by operating activities		**15,885**	27,189
Adjusted funds flow		**26,373**	27,719
Per share	- basic	**0.18**	0.19
	- diluted	**0.17**	0.18
Net Income		**4,148**	8,056
Per share	- basic	**0.03**	0.05
	- diluted	**0.03**	0.05

The decrease in cash provided by operating activities in the first quarter of 2018 was a result of a significant change in operating non-cash working capital, mainly due to the semi-annual interest payment on the Company's senior unsecured notes. Adjusted funds flow in the first quarter of 2018 slightly decreased as compared to the same period in 2017 due to a decrease in netbacks, partially offset by the increase in production. The decrease in net income for the first quarter of 2018 is a result of a significant unrealized hedging gain in the first quarter of 2017, partially offset by higher financing expenses due to the redemption and issuance of senior notes in 2017 and a higher gain on disposition during the first quarter of 2018.

Capital Expenditures, Property Acquisitions and Dispositions

($ thousands)	**Three months ended March 31, 2018**	Three months ended March 31, 2017
Land	**1,090**	870
Seismic	**295**	260
Drilling and completions	**18,665**	53,068
Facilities, equipment and pipelines	**11,973**	18,967
Other	**1,898**	1,999
Total exploration and development	**33,921**	75,164
Net property dispositions	**(10,007)**	(352)
Total	**23,914**	74,812

In the first quarter of 2018, the Company completed nine (7.7 net) natural gas wells in northeast British Columbia, and recompleted eleven (10.5 net) heavy oil wells in Lloydminster. The Company spent a total of $33.9 million on exploration and development expenditures. The majority of this amount was spent on the continued development of our Montney assets at West Septimus. During the quarter, $18.7 million was spent on drilling and completion activities, $12.0 million on well site development, facilities and pipelines and $3.3 million on land, seismic and other miscellaneous items, including a net $8.3 million on the on-going construction of the Company's West Septimus to TransCanada Pipeline meter station connection. During the quarter, the Company entered into an agreement with an infrastructure partner who will participate in the building of this pipeline as a 72% partner.

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

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 in the first quarter of 2018, the Company carried a working capital surplus of $3.3 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 March 31, 2018, the Company's working capital surplus of $3.3 million, when combined with the drawings on its bank loan, represented drawings of 19% on its $235 million Facility described below.

Capital Funding

Bank Loan

As at March 31, 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 will terminate on May 24, 2018 or such earlier time as the maximum number of common shares are purchased pursuant to the NCIB or the NCIB is terminated at the option of the Company. 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 three months ended March 31, 2018.

Crew is authorized to issue an unlimited number of common shares. As at May 10, 2018, there were 151,707,869 common shares of the Company issued and outstanding. In addition, there were 3,356,693 restricted awards and 4,487,470 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 March 31, 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 March 31, 2018, the Company's ratio of net debt to annualized adjusted funds flow was 3.2 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 20% drawn on the Company's reconfirmed $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)	**March 31, 2018**	December 31, 2017
Working capital surplus (deficiency)	**3,324**	(29,143)
Bank loan	**(47,529)**	(21,977)
Senior unsecured notes	**(294,121)**	(293,862)
Net debt	**(338,326)**	(344,982)
Quarterly adjusted funds flow	**26,373**	34,087
Annualized	**105,492**	136,348
Net debt to annualized adjusted funds flow	**3.2**	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)	47,529	-	47,529	-	-	-	-
Senior unsecured notes (note 2)	300,000	-	-	-	-	-	300,000
Operating leases	3,623	881	1,175	1,175	392	-	-
Capital commitments	4,032	4,032	-	-	-	-	-
Firm transportation agreements	258,825	30,890	47,893	47,039	24,072	23,896	85,035
Firm processing agreements	126,947	13,728	18,221	16,776	12,354	12,354	53,514
Total	**740,956**	**49,531**	**114,818**	**64,990**	**36,818**	**36,250**	**438,549**

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 has planned second quarter capital expenditures of approximately $12 to $15 million, reflect the reduced activity and restricted access typically associated with spring breakup. The second quarter capital expenditure plans are part of the Company's planned annual capital budget, currently set at between $80 million and $85 million. Based on reduced activity levels, the impact of shutting-in volumes and electing to defer tying-in of the six wells completed in the first quarter, second quarter production is expected to average between 22,000 and 23,000 boe per day, in-line with our original budget and supporting our annual forecast average production 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)	**Mar. 31 2018**	Dec. 31 2017	Sep. 30 2017	June 30 2017	Mar. 31 2017	Dec. 31 2016	Sep. 30 2016	June 30 2016
Total daily production (boe/d)	**25,939**	25,270	23,251	20,468	23,231	22,380	23,211	21,950
Exploration and development expenditures	**33,921**	36,413	90,069	36,656	75,164	37,612	37,731	15,096
Net property (dispositions)/acquisitions	**(10,007)**	(1,709)	(144)	(45,701)	(352)	3,099	(98)	16
Average wellhead price ($/boe)	**25.46**	25.87	22.36	26.25	27.40	26.74	22.05	18.14
Petroleum and natural gas sales	**59,427**	60,146	47,824	48,886	57,298	55,051	47,093	36,232
Cash provided by operations	**15,885**	43,484	15,258	31,359	27,189	19,900	25,940	12,047
Adjusted funds flow	**26,373**	34,087	24,970	21,353	27,719	27,879	23,033	16,048
Per share – basic	**0.18**	0.23	0.17	0.14	0.19	0.19	0.16	0.11
– diluted	**0.17**	0.22	0.17	0.14	0.18	0.19	0.16	0.11
Net income (loss)	**4,148**	2,342	2,127	21,880	8,056	(40,030)	(1,286)	(16,815)
Per share – basic	**0.03**	0.02	0.01	0.15	0.05	(0.28)	(0.01)	(0.12)
– diluted	**0.03**	0.02	0.01	0.14	0.05	(0.28)	(0.01)	(0.12)

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 quarter of 2018, natural gas prices decreased significantly below amounts received in the previous few years. This decrease will have an impact on 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, 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 March 31, 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 January 1, 2018 and ended on March 31, 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 May 10, 2018

CONDENSED INTERIM CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

(unaudited) (thousands)	**March 31, 2018**	December 31, 2017
Assets		
Current Assets:		
Accounts receivable	**$ 45,672**	$ 40,930
Derivative financial instruments (note 4)	**-**	1,666
	45,672	42,596
Other long-term assets	**-**	4,788
Property, plant and equipment (note 5)	**1,350,847**	1,340,736
	$ 1,396,519	$ 1,388,120
Liabilities and Shareholders' Equity		
Current Liabilities:		
Accounts payable and accrued liabilities	**$ 42,348**	$ 70,073
Derivative financial instruments (note 4)	**3,455**	1,319
	45,803	71,392
Derivative financial instruments (note 4)	**846**	-
Bank loan (note 6)	**47,529**	21,977
Senior unsecured notes (note 7)	**294,121**	293,862
Decommissioning obligations (note 8)	**86,330**	88,368
Deferred tax liability	**45,480**	42,427
Shareholders' Equity		
Share capital (note 9)	**1,458,170**	1,458,086
Contributed surplus	**75,242**	73,158
Deficit	**(657,002)**	(661,150)
	876,410	870,094
Subsequent event (note 4)		
Commitments (note 12)		
	$ 1,396,519	$ 1,388,120

See accompanying notes to the condensed interim consolidated financial statements.

CONDENSED INTERIM CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME

(unaudited) (thousands, except per share amounts)		**Three months ended March 31, 2018**		Three months ended March 31, 2017
Revenue				
Petroleum and natural gas sales (note 10)	**$**	**59,427**	$	57,298
Royalties		**(4,007)**		(4,557)
Realized loss on derivative financial instruments (note 4)		**(2,177)**		(815)
Unrealized (loss) gain on derivative financial instruments (note 4)		**(4,648)**		19,875
Other revenue (note 10)		**2,571**		1,288
		51,166		73,089
Expenses				
Operating		**15,579**		12,531
Transportation		**4,933**		4,784
General and administrative		**3,244**		3,146
Share-based compensation		**1,105**		3,154
Depletion and depreciation (note 5)		**22,447**		19,710
		47,308		43,325
Income from operations		**3,858**		29,764
Financing (note 11)		**6,176**		14,300
Gain on divestiture of property, plant and equipment (note 5)		**(9,546)**		(346)
Income before income taxes		**7,228**		15,810
Deferred tax expense		**3,080**		7,754
Net income and comprehensive income	**$**	**4,148**	$	8,056
Net income per share (note 9)				
Basic	**$**	**0.03**	$	0.05
Diluted	**$**	**0.03**	$	0.05

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 income for the period	-	-	-	4,148	4,148
Share-based compensation expensed	-	-	1,105	-	1,105
Share-based compensation capitalized	-	-	1,036	-	1,036
Issued on vesting of share awards	18	84	(84)	-	-
Tax deduction on excess value of share awards	-	-	27	-	27
Balance, March 31, 2018	**149,346**	**$ 1,458,170**	**$ 75,242**	**$ (657,002)**	**$ 876,410**

(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	-	-	-	8,056	8,056
Share-based compensation expensed	-	-	3,154	-	3,154
Share-based compensation capitalized	-	-	2,959	-	2,959
Issued on vesting of share awards	315	1,246	(1,246)	-	-
Balance, March 31, 2017	**147,127**	**$ 1,443,530**	**$ 79,827**	**$ (687,499)**	**$ 835,858**

See accompanying notes to the condensed interim consolidated financial statements.

CONDENSED INTERIM CONSOLIDATED STATEMENTS OF CASH FLOWS

(unaudited) (thousands)	**Three months ended March 31, 2018**	Three months ended March 31, 2017
Cash provided by (used in):		
Operating activities:		
Net income	**$ 4,148**	$ 8,056
Adjustments:		
Unrealized loss (gain) on derivative financial instruments (note 4)	**4,648**	(19,875)
Share-based compensation	**1,105**	3,154
Depletion and depreciation	**22,447**	19,710
Financing expenses (note 11)	**6,176**	14,300
Interest expense (note 11)	**(5,426)**	(4,827)
Gain on divestiture of property, plant and equipment (note 5)	**(9,546)**	(346)
Deferred tax expense	**3,080**	7,754
Decommissioning obligations settled (note 8)	**(591)**	(378)
Change in non-cash working capital	**(10,156)**	(359)
	15,885	27,189
Financing activities:		
Increase (decrease) in bank loan	**25,552**	(88,036)
Issuance of senior notes, net of financing costs (note 7)	**-**	293,000
Redemption of senior notes (note 7)	**-**	(156,282)
	25,552	48,682
Investing activities:		
Property, plant and equipment expenditures	**(32,580)**	(75,164)
Property acquisitions	**-**	(8)
Property dispositions (note 5)	**10,007**	360
Change in non-cash working capital	**(18,864)**	22,419
	(41,437)	(52,393)
Change in cash and cash equivalents	**-**	23,478
Cash and cash equivalents, beginning of period	**-**	-
Cash and cash equivalents, end of period	**$ -**	$ 23,478

See accompanying notes to the condensed interim consolidated financial statements.

NOTES TO CONDENSED INTERIM CONSOLIDATED FINANCIAL STATEMENTS

For the three months ended March 31, 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 May 10, 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 March 31, 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	April 1, 2018 – October 31, 2018	Chicago Citygate	$3.06/mmbtu	Swap	$ (41)
Gas	5,000 gj/day	April 1, 2018 – December 31, 2018	AECO C Monthly Index	$3.00/gj	Call	(9)
Gas	2,500 gj/day	April 1, 2018 – December 31, 2018	AECO C Daily Index	$2.62/gj	Swap	871
Gas	20,000 mmbtu/day	April 1, 2018 – December 31, 2018	Chicago Citygate	$3.61/mmbtu	Swap	2,034
Gas	5,000 mmbtu/day	April 1, 2018 – December 31, 2018	US$ Nymex Henry Hub	$3.05 US/mmbtu	Swap	351
Gas	2,500 mmbtu/day	January 1, 2019 – December 31, 2019	Chicago Citygate	$3.16/mmbtu	Swap	(5)
Propane	400 bbl/day	April 1, 2018 – December 31, 2018	US$ Conway OPIS	$0.79 US/gal	Swap	561
Oil	2,250 bbl/day	April 1, 2018 – December 31, 2018	CDN$ WTI	$72.92/bbl	Swap	(5,148)
Oil	250 bbl/day	April 1, 2018 – December 31, 2018	CDN$ WTI	$60.00 - $69.65/bbl	Collar(1)	(844)
Oil	250 bbl/day	April 1, 2018 – December 31, 2018	CDN$ WTI	$69.00 - $74.25/bbl	Collar(2)	(539)
Oil	1,250 bbl/day	January 1, 2019 – December 31, 2019	CDN$ WTI	$71.56/bbl	Swap	(1,532)
Total						**$ (4,301)**

(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.

Subsequent to March 31, 2018, the Company entered into the following derivative commodity contracts:

Subject of Contract	Notional Quantity	Term	Reference	Strike Price	Option Traded
Oil	500 bbl/day	July 1, 2018 – December 31, 2018	CDN$ WCS	$57.90/bbl	Swap
Oil	250 bbl/day	January 1, 2019 – December 31, 2019	CDN$ WTI	$79.50/bbl	Swap

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 March 31, 2018, the Company's ratio of net debt to annualized adjusted funds flow was 3.2 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 20% drawn on the Company's reconfirmed $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.

		March 31, 2018		December 31, 2017
Net debt:				
Accounts receivable	**$**	**45,672**	$	40,930
Accounts payable and accrued liabilities		**(42,348)**		(70,073)
Working capital surplus (deficiency)	**$**	**3,324**	$	(29,143)
Bank loan		**(47,529)**		(21,977)
Senior unsecured notes		**(294,121)**		(293,862)
Net debt	**$**	**(338,326)**	$	(344,982)
Quarterly annualized adjusted funds flow:				
Cash provided by operating activities	**$**	**15,885**	$	43,484
Decommissioning obligations settled		**591**		29
Change in non-cash working capital		**10,156**		(9,165)
Accretion of deferred financing charges		**(259)**		(261)
Quarterly adjusted funds flow	**$**	**26,373**	$	34,087
Annualized	**$**	**105,492**	$	136,348
Net debt to annualized adjusted funds flow		**3.2**		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		33,921
Divestitures		(875)
Change in decommissioning obligations		(1,524)
Capitalized share-based compensation		1,036
Balance, March 31, 2018	**$**	**2,446,883**

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		22,447
Balance, March 31, 2018	**$**	**1,096,036**

Net book value		Total
Balance, March 31, 2018	**$**	**1,350,847**
Balance, December 31, 2017	$	1,340,736

Included in property, plant and equipment additions for the three months ended March 31, 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 March 31, 2018 included estimated future development costs of $1,746.2 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 $159.1 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 March 31, 2018, and therefore an impairment test was not performed.

6. Bank loan:

As at March 31, 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 March 31, 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 March 31, 2018, the Company had issued letters of credit totaling $7.7 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 March 31, 2018, the carrying value of the 2024 Notes was net of deferred financing costs of $5.9 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:

	Three months ended March 31, 2018	Year ended December 31, 2017
Decommissioning obligations, beginning of period	**$ 88,368**	$ 85,859
Obligations incurred	**177**	4,557
Obligations settled	**(591)**	(513)
Obligations divested	**(414)**	(1,765)
Change in estimated future cash outflows	**(1,701)**	(1,704)
Accretion of decommissioning obligations	**491**	1,934
Decommissioning obligations, end of period	**$ 86,330**	$ 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 $86.3 million as at March 31, 2018 (December 31, 2017 – $88.4 million) based on an inflation adjusted undiscounted total future liability of $115.9 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 three months ended March 31, 2018 is a result of a change in future estimated undiscounted abandonment costs.

9. Share capital:

At March 31, 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 will terminate on May 24, 2018 or such earlier time as the maximum number of common shares are purchased pursuant to the NCIB or the NCIB is terminated at the option of the Company. 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 three months ended March 31, 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. Through the vesting of 10,000 restricted awards and 4,000 performance awards, when taking into account the earned multipliers for performance awards, 18,000 common shares of the Company were issued for the three months ended March 31, 2018.

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

	Number of RAs	Number of PAs
Balance, January 1, 2018	1,616	2,221
Granted	60	180
Vested	(10)	(4)
Forfeited	(63)	(160)
Balance, March 31, 2018	**1,603**	**2,237**

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 March 31, 2018 was 149,341,000 (March 31, 2017 – 146,820,000).

In computing diluted earnings per share for the three month period ended March 31, 2018, 1,747,000 (March 31, 2017 – 4,440,000) shares were added to the weighted average common shares outstanding to account for the dilution of restricted and performance awards. There were 2,329,000 (March 31, 2017 – 14,000) restricted and performance awards 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 March 31, 2018	Three months ended March 31, 2017
Light crude oil	**$ 1,939**	$ 2,848
Heavy crude oil	**5,674**	7,175
Condensate	**17,933**	10,960
Other natural gas liquids	**4,003**	2,875
Natural gas	**29,878**	33,440
	$ 59,427	$ 57,298

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 $0.9 million from operating expenses to processing income as other revenue.

Other revenue:

The following table summarizes the Company's other revenue:

	Three months ended March 31, 2018	Three months ended March 31, 2017
Processing revenue	**$ 892**	$ 1,288
Marketing revenue	**679**	-
Other	**1,000**	-
	$ 2,571	$ 1,288

During the period ended March 31, 2018, the Company realized $1.0 million as revenue, representing the receipt of a non-refundable deposit from a third party for a non-core property disposition that failed to close.

11. Financing:

	Three months ended March 31, 2018	Three months ended March 31, 2017
Interest expense	**$ 5,426**	$ 4,827
Accretion of deferred financing costs	**259**	207
Accretion of decommissioning obligations	**491**	474
Premium paid on redemption of 2020 Notes (note 7)	**-**	6,282
Deferred financing costs expensed on 2020 Notes (note 7)	**-**	2,510
	$ 6,176	$ 14,300

12. Commitments:

	Total	2018	2019	2020	2021	2022	Thereafter
Operating leases	$ 3,623	$ 881	$ 1,175	$ 1,175	$ 392	$ -	$ -
Capital commitments	4,032	4,032	-	-	-	-	-
Firm transportation agreements	258,825	30,890	47,893	47,039	24,072	23,896	85,035
Firm processing agreements	126,947	13,728	18,221	16,776	12,354	12,354	53,514
Total	**$ 393,427**	**$ 49,531**	**$ 67,289**	**$ 64,990**	**$ 36,818**	**$ 36,250**	**$138,549**

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

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Chairman Independent Director

Jeffery E. Errico,
Lead Director Independent Director

Dennis L. Nerland
Independent Director

Dale O. Shwed
President, Crew Energy Inc.

David G. Smith
Independent Director

Corporate Secretary

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

ABBREVIATIONS

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