Interim Report

Q1 2019 first quarter ending March 31, 2019

crew energy inc.

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, 2019.

HIGHLIGHTS

- **Production of 23,222 boe per day:** Volumes were 4% higher than the previous quarter supported by stronger Greater Septimus production of 19,535 boe per day that was 6% higher than the previous quarter due to robust production from newly completed Ultra Condensate Rich ("UCR") wells.

- **Stable Adjusted Funds Flow ("AFF"):** Q1 AFF totaled $25.8 million or $0.17 per fully diluted share, compared to Q4 2018 AFF of $23.7 million or $0.16 per fully diluted share, reflecting increased liquids production, including condensate growth and stronger overall liquids pricing.

- **Continued Focus on Montney Condensate Growth:** Q1 condensate volumes averaged 2,617 bbls per day, an increase of 7% over Q4 2018. Total liquids represented 28% of average quarterly volumes and contributed 44% to Crew's petroleum and natural gas sales for the quarter.

- **Strong UCR Well Results from 15-20 Pad:** Early results from four "B" zone wells and one "C" zone well on our 15-20 pad at Greater Septimus continue to support further development and capital allocation in the UCR area. After 45 days of production, the four "B" zone wells produced an average of 1,211 boe per day comprised of 3,336 mcf per day of sales gas, 538 bbls per day of condensate and 117 bbls per day of propane and butane.

- **Positive Early Results from 4-21 Pad in UCR Transition Zone:** After 20 days of flow back, the six (6.0 net) "B" zone wells were producing at restricted rates averaging 1,374 boe per day comprised of 4,830 mcf per day of sales gas, 400 bbls per day of condensate and 169 bbls per day of propane and butane at an average flowing casing pressure of approximately 8,900 kPa.

- **Strong Operational Execution with Capital Spending Below Guidance:** Exploration and development capital expenditures in the quarter totaled $55.2 million, lower than our forecast guidance of between $60 and $70 million. Crew drilled seven (7.0 net) and completed eight (8.0 net) wells in our UCR area at West Septimus and recompleted six (6.0 net) heavy oil wells at Lloydminster. After incorporating $17.5 million in proceeds from a disposition and minor acquisition during the period, net capital expenditures were $39.3 million.

- **Longest Laterals Drilled in Company History:** Four extended reach horizontal ("ERH") UCR wells were drilled in Q1 with lateral lengths over 3,000 metres and per lateral metre drilling costs that were 35% lower than costs realized in 2017.

- **Realized Natural Gas Prices Again Outperformed Benchmark:** Q1 average realized natural gas prices of $3.45 per mcf were 21% higher than Q1 2018 and outperformed the AECO 5A benchmark of $2.62 per mcf by 32%, driven by Crew's high heat content natural gas and exposure to diversified sales hubs and markets.

- **Financial Flexibility Maintained:** Quarter end net debt of $361.5 million includes $300 million of term debt due in 2024 with no financial maintenance covenants and 17% drawn on the Company's $235 million credit facility (excluding working capital deficiency).

FINANCIAL & OPERATING HIGHLIGHTS

FINANCIAL ($ thousands, except per share amounts)	**Three months ended Mar. 31, 2019**	Three months ended Mar. 31, 2018
Petroleum and natural gas sales	**55,451**	59,427
Adjusted Funds Flow(1)	**25,771**	26,373
Per share - basic	**0.17**	0.18
- diluted	**0.17**	0.17
Net income	**6,186**	4,148
Per share - basic	**0.04**	0.03
- diluted	**0.04**	0.03
Exploration and Development expenditures	**55,241**	33,921
Property acquisitions (net of dispositions)	**(15,924)**	(10,007)
Net capital expenditures	**39,317**	23,914

Capital Structure ($ thousands)	**As at Mar. 31, 2019**	As at Dec. 31, 2018
Working capital deficiency (surplus)(2)	**26,283**	(11,984)
Bank loan	**40,065**	59,904
	66,348	47,920
Senior Unsecured Notes	**295,130**	294,885
Total Net Debt	**361,478**	342,805
Current Debt Capacity(3)	**535,000**	535,000
Common Shares Outstanding (thousands)	**150,554**	151,730

Notes:

(1) AFF 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 on the senior unsecured notes. AFF does not have a standardized measure prescribed by International Financial Reporting Standards, ("IFRS") 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 for details including reasons for use and a reconciliation of AFF to its most closely related IFRS measure.

(2) Working capital deficiency / (surplus) includes cash and cash equivalents plus accounts receivable less accounts payable and accrued liabilities. See "Non-IFRS Measures" contained within Crew's MD&A.

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

Operations	**Three months ended Mar. 31, 2019**	Three months ended Mar. 31, 2018
Daily production		
Light crude oil (bbl/d)	**226**	316
Heavy crude oil (bbl/d)	**1,608**	1,747
Condensate (bbl/d)	**2,617**	2,699
Other natural gas liquids (bbl/d)	**2,014**	1,792
Natural gas (mcf/d)	**100,542**	116,312
Total (boe/d @ 6:1)	**23,222**	25,939
Average prices (1)		
Light crude oil ($/bbl)	**61.04**	68.20
Heavy crude oil ($/bbl)	**44.25**	36.09
Condensate ($/bbl)	**62.17**	73.82
Other natural gas liquids ($/bbl)	**10.89**	24.81
Natural gas ($/mcf)	**3.45**	2.85
Oil equivalent ($/boe)	**26.53**	25.46

Notes:

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

	Three months ended Mar. 31, 2019	Three months ended Mar. 31, 2018
Netback ($/boe)		
Petroleum and natural gas sales	**26.53**	25.46
Royalties	**(1.85)**	(1.72)
Realized commodity hedging loss	**(0.88)**	(0.93)
Marketing income(1)	**1.40**	0.29
Net operating costs(2)	**(6.25)**	(6.29)
Transportation costs	**(2.26)**	(2.11)
Operating netback (3)	**16.69**	14.70
General & administrative ("G&A")	**(1.51)**	(1.39)
Other income	**-**	0.43
Financing costs on long-term debt	**(2.86)**	(2.44)
Adjusted funds flow	**12.32**	11.30
Drilling Activity		
Gross wells	**7**	0
Working interest wells	**7.0**	0.0
Success rate, net wells (%)	**100%**	-

Notes:

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

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

(3) Operating netback equals petroleum and natural gas sales including realized hedging gains and losses on commodity contracts, marketing income, less royalties, net 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 IFRS and therefore may not be comparable with the calculations of similar measures for other companies. See "Non-IFRS Measures" contained within Crew's MD&A.

FINANCIAL OVERVIEW

Production Above Guidance

- Volumes for the quarter averaged 23,222 boe per day, above our projected volume range for the period of 22,000 to 23,000 boe per day, as a result of strong early performance from the eight West Septimus UCR wells completed during the quarter.
- Greater Septimus production averaged 19,535 boe per day in Q1 2019, an increase of 6% over the 18,447 boe per day in Q4 2018.
- Production for the quarter was impacted by several wells at West Septimus being shut-in for the majority of January and February to accommodate the completion of the final two wells on the 15-20 pad and six wells on the 4-21 pad. Production was also negatively impacted due to the 17 day unplanned shut down of the McMahon gas plant which processes the Company's non-Montney gas in northeast British Columbia.
- The addition of the eight newly completed wells described above showed strong results in March, which helped to offset lower production volumes in January and February.

Pricing Environment Impacts Revenue

- First quarter 2019 petroleum and natural gas sales increased 9% over the previous quarter as a result of higher quarter-over-quarter liquids production, led by a 7% increase in condensate production. First quarter revenue was also bolstered by stronger liquids pricing, which reflects higher prices for condensate and heavy crude oil offset by weaker natural gas and natural gas liquids ("ngl") pricing.
- Liquids prices for the quarter benefited from the Alberta Government's mandated oil production curtailment that took 325,000 bbls per day of Alberta supply out of the market, effective January 1, 2019. Despite slightly

weaker benchmark pricing for Canadian dollar denominated WTI, which declined 6% compared to the fourth quarter of 2018, pricing for Western Canadian Select ("WCS") and Canadian condensate delivered at Edmonton increased 126% and 13% respectively, over the prior quarter.

- Crew's realized natural gas price decreased by 9% compared to the previous quarter, as the Company's weighting of natural gas sold into the US Chicago and NYMEX markets increased from 55% to 61% in Q1 2019 compared to Q4 2018, while the prices received for delivering into those markets declined 18% and 13%, respectively.
- Marketing income for the quarter increased to $2.9 million or $1.40 per boe from $2.1 million or $1.03 per boe in Q4 2018 and reflects the net revenue received for monetarization of the Company's Dawn transport contract and Malin sales contract, offset by unutilized demand charges for natural gas pipeline capacity that was not accessed until March 2019.

Liquids Production and Prices Improve AFF

- Crew's AFF in Q1 2019 totaled $25.8 million ($0.17 per diluted share), an increase of 9% over the prior quarter, attributable to higher liquids production and pricing, combined with higher marketing income. These were partially offset by higher net operating and transportation costs and a larger hedging loss. Crew's AFF declined 2% compared to the same period in 2018, mainly due to lower production.

- Corporate operating netbacks in Q1 2019 averaged $16.69 per boe, a 14% improvement over the same period in 2018 and 5% over the prior quarter. Improvements relative to Q1 2018 and Q4 2018 reflect a higher liquids weighting, stronger commodity pricing and higher marketing income, offset by higher cash costs and relative to Q4 2018, an increased hedging loss.

- Cash costs and cash costs per boe increased in Q1 2019 compared to the prior quarter, mainly due to increased royalties, net operating and transportation costs, offset by lower G&A costs. Relative to Q1 2018, cash costs declined due to lower overall production while on a per boe basis, cash costs increased due to higher royalties and transportation costs, offset by lower net operating and G&A costs.

- Net operating cost and net operating costs per boe in the first quarter increased over the previous quarter as a result of the re-activation of higher cost heavy crude oil production that had been shut-in during Q4 2018 due to extremely low WCS pricing. Additionally, extremely cold weather experienced in Western Canada early in 2019 contributed to higher first quarter net operating costs.

- With higher natural gas production from the Greater Septimus area in Q1 2019 relative to Q4 2018, Crew moved more volumes to higher priced markets which incur a higher per unit cost. This resulted in increased transportation costs in the first quarter of 2019 relative to the prior quarter.

Q1 Capital Expenditures Below Guidance

- Q1 2019 net capital expenditures totaled $39.3 million, including $55.2 million in exploration and development expenditures and $17.5 million of gross proceeds related to the sale of non-core land with no associated reserves or production, which was partially offset by a tuck-in acquisition for approximately $1.6 million.

- Approximately $49.0 million of our Q1 capital was allocated to drilling and completion activities, with $3.4 million spent on Montney well site development, facilities and pipelines and $2.8 million directed to land, seismic and other miscellaneous items.

- In the first quarter of 2019, Crew drilled seven (7.0 net) and completed eight (8.0 net) wells in our UCR area at West Septimus and recompleted six (6.0 net) heavy crude oil wells at Lloydminster.

Net Debt Reflects Modest Draws on Bank Facility and Working Capital Deficiency

- March 31, 2019 net debt of $361.5 million was 5% higher than year end 2018 due to the Company's 2019 capital expenditure program being weighted to higher first quarter spending. Annual capital spending is forecast to approximate AFF resulting in minimal expected change to year over year net debt.

- The Company's debt is comprised of $300 million of term debt with no financial maintenance covenants or repayment required until 2024, as well as a $235 million credit facility that was 28% drawn after adjusting for a working capital deficiency of approximately $26.3 million at quarter end.

TRANSPORTATION, MARKETING & HEDGING

Diversified Market Access Provides Strategic Benefit

- Crew strategically chose to monetize the inherent value in our Dawn and Malin market exposure in Q1 2019, realizing marketing income of $3.3 million. The Company has further elected to monetize the value inherent in these contracts for Q2 2019 and will recognize approximately $2.5 million of associated marketing income for the second quarter.

- For 2019, our average natural gas sales exposure is currently expected to be approximately 54% to Chicago, 17% to NYMEX, 7% to Dawn, 8% to Alliance ATP, 5% to Malin, 4% to Station 2 and 5% to AECO 5A.

- During Q1 2019, Crew began shipping natural gas through the Company's new West Septimus to TCPL Saturn meter station sales pipeline system. This allowed Crew to benefit from the spike in AECO pricing that occurred during the quarter due to the extreme cold weather experienced across Western Canada.

Natural Gas & Liquids Hedging

- Crew's natural gas hedges currently include:
  - 25,000 mmbtu per day of Chicago gas at C$3.53 per mmbtu
  - 7,500 mmbtu per day of Dawn gas at C$3.55 per mmbtu
  - 10,000 mmbtu per day of NYMEX gas at US$2.95 per mmbtu

- For liquids, Crew has the following hedges in place:
  - 1,874 bbls per day of WTI at an average price of C$75.99 per bbl for 2019
  - 500 bbls per day of WCS for the first half of 2019 at an average price of C$52.93 per bbl
  - 250 bbls per day of WCS for Q4 2019 at C$56.20 per bbl
  - 250 bbls per day of WCS differential at C$25.75 per bbl for the first half of 2019
  - 500 bbls per day of WCS differential at C$25.23 per bbl for the second half of 2019
  - 250 bbls per day of differentials at US$12.25 per bbl for Q2 2019
  - 250 bbls per day of differentials at US$17.25 per bbl for Q3 2019

OPERATIONS & AREA OVERVIEW

NE BC Montney - Greater Septimus

- Development drilling continued in the UCR region at West Septimus with five wells rig released in Q1. Four of the wells were ERH wells with lateral lengths over 3,000 metres. Progressive changes to fluid systems, drill bits, and downhole assemblies has enabled a 35% reduction in the cost per lateral metre drilled relative to the same costs incurred in 2017.

- As Crew's focus continues to be directed largely to our West Septimus area, reduced capital and activity levels at Septimus have allowed the Company to better understand our base decline profile, which is forecast to be moving towards 12%, enhancing the sustainability of our business model.

- The final two wells on our 15-20 UCR pad at Greater Septimus and all six wells on our 4-21 pad were completed during Q1 2019. Two completions on the 4-21 pad were accelerated into Q1 to minimize downtime and offset the impact of inter-well communication. Early results indicate this strategy was effective as the 15-20 wells have returned to similar productivity levels that were realized prior to the offset completion operations. Cost efficiencies were also captured by simultaneously executing all six of the 4-21 well completions.
- Better than forecasted production rates indicate well design enhancements, are effectively delivering positive results. Early results from wells on our 15-20 pad at Greater Septimus continue to support further development and capital allocation in the UCR area, and after 45 days of production, demonstrated the following:
  - Four "B" zone wells produced average sales of 1,211 boe per day comprised of 3,336 mcf per day of gas, 538 bbls per day of condensate and 117 bbls per day of propane and butane.
  - After 45 days of production, one "C" zone delineation well confirmed increasing condensate/gas ratios ("CGR") trending east over our acreage, and produced an average of 923 boe per day comprised of 3,969 mcf per day gas, 162 bbls per day condensate and 99 bbls per day of propane and butane, which represents approximately three times the CGR relative to a "C" zone well drilled 1,000 metres to the west.

- Early results from Crew's 4-21 pad in the UCR transition zone are also encouraging. After 20 days of flow back, the six (6.0 net) "B" zone wells were producing at restricted rates averaging 1,374 boe per day of sales, comprised of 4,830 mcf per day of gas, 400 bbls per day of condensate and 169 bbls per day of propane and butane at an average flowing casing pressure of approximately 8,900 kPa.

Greater Septimus

Production & Drilling	**Q1 2019**	Q4 2018	Q3 2018	Q2 2018	Q1 2018
Average daily production (boe/d)	**19,535**	18,447	19,240	18,953	20,467
Wells drilled (gross / net)	**7 (7.0)**	6 (6.0)	4 / 4.0	-	-
Wells completed (gross / net)	**8 (8.0)**	3 (3.0)	0 / 0	2 / 1.6	9 / 7.7

Operating Netback ($ per boe)	**Q1 2019**	Q4 2018	Q3 2018	Q2 2018	Q1 2018
Revenue	**25.61**	26.53	22.83	22.70	25.40
Royalties	**(1.56)**	(1.58)	(1.15)	(1.35)	(1.50)
Realized commodity hedge loss	**(0.74)**	(1.79)	(2.01)	(1.32)	(1.01)
Marketing income (1)	**1.66**	1.23	0.34	0.34	0.37
Net operating costs(2)	**(4.65)**	(4.51)	(4.61)	(4.71)	(4.45)
Transportation costs	**(1.73)**	(1.35)	(1.22)	(1.40)	(1.51)
Operating netback(3)	**18.59**	18.53	14.18	14.26	17.30

Notes:

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

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

(3) Operating netback equals petroleum and natural gas sales including realized hedging gains and losses on commodity contracts, marking income, less royalties, net operating costs and transportation costs calculated on a boe basis. Operating netback does not have a standardized measure prescribed by IFRS and therefore may not be comparable with the calculations of similar measures for other companies. See "Non-IFRS Measures" contained within Crew's MD&A.

Other NE BC Montney

- **Tower:** Production at Tower averaged 787 boe per day in Q1 2019. Crew continues to evaluate the relative economics of Tower development as well as encouraging nearby Lower Montney well results.
- **Monias**: One horizontal Montney delineation well was drilled in Q1 in the Monias area, located approximately 18 km to the northwest of our West Septimus UCR core area.
- **Attachie:** Of Crew's 97 sections of land in this area, approximately 45 sections are situated within the liquids-rich hydrocarbon window. Given the positive results generated by offsetting operators, a lease retention well was drilled in January.
- **Oak / Flatrock:** Drilling activity is gaining momentum for liquids-rich gas in this area where Crew has over 60 sections of land. We will continue to monitor industry activity and offsetting well results from this area.

AB / SK Heavy Oil - Lloydminster

- Q1 heavy oil activity at Lloydminster included the recompletion of six (6.0 net) heavy oil wells, resulting in average production volumes of 1,614 boe per day for the quarter. Production volumes were approximately 8% lower than Q1 2018 due to minimal capital investment in 2018 and shutting in lower margin production in Q4 2018 in response to extremely wide differentials.

- WCS pricing differentials contracted significantly in the first quarter with Q1 2019 operating netbacks at Lloydminster averaging $13.48 per boe in the period.

- Crew plans on drilling three (3.0 net) multi-lateral horizontal wells in this area in 2019 should prices be supportive.

OUTLOOK

Value Creation Strategy Intact

- Crew has assembled an attractive land base with over 280,000 net acres of highly prospective Montney rights in northeast B.C., with proved plus probable reserves of over 401 million boe assigned by Crew's independent reserves evaluator at year end 2018 on only 13% of our Upper Montney lands and less than 1% of our Lower Montney lands[1].

- Our strategic investment in infrastructure has resulted in Crew having the capacity to produce over 40,000 boe per day through existing facilities, which can significantly reduce future on-stream costs. We remain committed to high grading our portfolio of assets to enhance shareholder value while preserving the material upside in our vast resource base.

Increasing Condensate Production and Margin Expansion

- Crew's focus will continue to reflect our ongoing goal of increasing condensate in our production mix, which is expected to contribute to further improvements in realized pricing and operating netbacks. Under current strip pricing, the UCR wells being drilled by Crew are expected to generate robust internal rates of return ("IRR") of over 70% with over $6.0 million per well of before tax net present value discounted at 10% (NPV10)[1]. With over 135 potential drilling opportunities[2] at Crew's current pace of development, this represents over ten years of highly economic future growth.

Balancing Capital Expenditures with AFF

- Crew is committed to capital discipline with a 2019 capital expenditure budget that is forecast to range between $95 and $105 million and designed to approximate annual AFF. This budget has been structured to support the Company's ability to effectively manage our balance sheet and retain the flexibility to produce average volumes of 22,000 to 23,000 boe per day, while increasing our exposure to higher valued condensate. Net proceeds from the sale of non-core assets in Q1 2019 of $15.9 million were used to reduce net debt, strengthening our financial position.

- Our Q2 2019 production is expected to range between 22,000 and 23,000 boe per day on capital expenditures between $12 and $18 million, although Crew's productive capacity is higher. The quarterly forecast reflects the Company's planned deferral of dry gas production which is exposed to spot gas prices in Western Canada which are currently very low. Our Q2 activity will largely be directed to continued Montney development, including the equip and tie-in of eight (8.0 net) UCR wells and the workover and recompletion of heavy oil wells which are attracting a wellhead oil price of over C$65 per bbl based on current oil prices.

- Based on our first half capital program, Crew anticipates directing approximately $28 to $32 million to the second half program, which anticipates two net Montney completions, drilling three multi-lateral heavy oil wells and other minor expenditures.

We thank our employees and directors for their commitment and dedication to the success of Crew, and we thank all of our shareholders and bondholders for their patience and continued support in this challenging operating environment.

[1,2] See "Information Regarding Disclosure on Oil and Gas Reserves, Operational Information and Non-IFRS Measures".

Cautionary Statements

Information Regarding Disclosure on Oil and Gas Reserves, Operational Information and Non-IFRS Measures

*Unless otherwise specified, all reserves volumes and associated net present values of future net revenue for the Company's reserves disclosed in this report are based on "company gross reserves" using forecast prices and costs and are derived from the Company's independent reserves evaluation prepared by Sproule Associates Ltd. ("**Sproule**") with an effective date of December 31, 2018 (the "**Sproule Report**"). The recovery and reserve estimates provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. It should not be assumed that the estimates of net present value of future net revenues presented herein represent the fair market value of the reserves. Actual reserves may be greater than or less than the estimates provided. In relation to the disclosure of estimates for individual wells or properties, such estimates may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation. Estimates provided in respect of NPV10 before tax for Crew's UCR wells at West Septimus are based on Sproule's year-end 2018 type wells for West Septimus. The Company's oil and gas reserves statement for the year ended December 31, 2018 includes complete disclosure of our oil and gas reserves and other oil and gas information prepared in accordance with NI 51-101 and the COGE Handbook, and is contained within our Annual Information Form which is available on our SEDAR profile at www.sedar.com.*

This report discloses "potential drilling opportunities" in the Company's Greater Septimus area of operations which are comprised of: (i) proved locations; (ii) probable locations; and (iii) unbooked locations. Proved locations and probable locations are derived from the Sproule Report and account for drilling inventory that have associated proved and/or probable reserves assigned by Sproule. Unbooked locations are internally identified potential drilling opportunities based on the Company's prospective acreage and an assumption as to the number of wells that can be drilled per section based on industry practice and internal review. Unbooked locations do not have reserves or resources attributed to them and are not estimates of drilling locations which have been evaluated by a qualified reserves evaluator performed in accordance with the COGE Handbook. Of the 135 total potential drilling opportunities identified herein, 29 are proved locations, 53 are probable locations and 53 are unbooked locations. Unbooked locations have been identified by management as an estimation of our multi-year drilling activities based on evaluation of applicable geologic, seismic, engineering, production and reserves information. There is no certainty that the Company will drill any of these potential drilling opportunities and if drilled there is no certainty that such locations will result in additional oil and gas reserves, resources or production. The drilling locations on which we actually drill wells will ultimately depend upon the availability of capital, regulatory approvals, seasonal restrictions, oil and natural gas prices, costs, actual drilling results, additional reservoir information that is obtained and other factors. While certain of the unbooked drilling opportunities identified have been derisked by drilling existing wells in relative close proximity to such unbooked drilling locations, other unbooked drilling locations are further away from existing wells where management has less information about the characteristics of the reservoir and therefore there is more uncertainty whether wells will be drilled in such locations and if drilled there is more uncertainty that such wells will result in additional oil and gas reserves, resources or production.

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

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: as to the execution of Crew's business plan including guidance as to its capital expenditure plans for Q2 and the second half of 2019; as to plans to internally fund its capital program with funds flow generated from Crew's existing business; as to plans to internally fund capital in 2019 with adjusted funds flow; as to the Company's ongoing goal of increasing the overall weighting of condensate in its production mix and associated improvements in realized pricing and operating netbacks for 2019 and beyond; as to estimates of net present value and expectations that the Company's UCR wells will generate internal rates of return of over 70%; as to the Company's estimates that its UCR wells will pay out in approximately 12 – 18 months at current prices; the estimated volumes, including shut-ins, and product mix of Crew's oil and gas production; production estimates including Q2 and 2019 average production targets; Crew's forecast *base decline profile moving towards 12%; commodity price expectations including Crew's estimates of natural gas pricing exposure; Crew's commodity risk management programs including plans for additional hedging in 2019; marketing and transportation 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 associated timing and cost estimates); the amount and timing of capital projects; management's assessment of potential drilling opportunities representing over ten years of economic growth; and future production capacity and corresponding potential for reduced on-stream costs.*

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.

Crew 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".

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 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, 2019 and 2018. 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, 2018. All figures provided herein and in the March 31, 2019 unaudited condensed interim consolidated financial statements are reported in Canadian dollars ("CDN"). This MD&A is dated May 2, 2019.

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 2019 capital budget encompassing anticipated 2019 net capital expenditures (after dispositions), timing of capital expenditures and methods of financing capital expenditures and the ability to fund financial liabilities, production estimates including second quarter and annual 2019 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, forecasted 2019 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, the potential for further property divestures and the 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 maintain production at current levels and fund future growth through capital investment and to service and repay debt. Management believes that such measures provide an insightful assessment of the Company's operations on a continuing basis by eliminating certain non-cash charges and actual settlements of decommissioning obligations, the timing of which is discretionary. 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, 2019**	Three months ended March 31, 2018
Cash provided by operating activities	**10,533**	15,885
Change in operating non-cash working capital	**13,719**	10,156
Accretion of deferred financing costs	**(245)**	(259)
Funds from operations	**24,007**	25,782
Decommissioning obligations settled	**1,764**	591
Adjusted funds flow	**25,771**	26,373

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, marketing income, less royalties, 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 in the section entitled "Operating Netbacks" of this MD&A.

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, 2019**	December 31, 2018
Current assets	**38,792**	78,904
Current liabilities	**(67,573)**	(58,538)
Derivative financial instruments	**2,498**	(8,382)
Working capital (deficiency) surplus	**(26,283)**	11,984

($ thousands)	**March 31, 2019**	December 31, 2018
Bank loan	**(40,065)**	(59,904)
Senior unsecured notes	**(295,130)**	(294,885)
Working capital (deficiency) surplus	**(26,283)**	11,984
Net debt	**(361,478)**	(342,805)

RESULTS OF OPERATIONS

Production

	Three months ended March 31, 2019					Three months ended March 31, 2018				
	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	**226**	**2,617**	**2,014**	**100,505**	**21,608**	316	2,699	1,792	116,306	24,191
Lloydminster	**1,608**	**-**	**-**	**37**	**1,614**	1,747	-	-	6	1,748
Total	**1,834**	**2,617**	**2,014**	**100,542**	**23,222**	2,063	2,699	1,792	116,312	25,939

During the first quarter of 2019, production decreased 10% over the same period in 2018 as a result of the 59% decline in drilling and completion capital expenditures in 2018 as compared to 2017. In addition, the Company shut-in several wells during January and February as a result of completion operations at West Septimus in northeast British Columbia ("NE BC"). Additionally, production in the Lloydminster area decreased as the Company continues to focus capital investment on the liquids rich West Septimus area. These amounts were partially offset by strong production towards the end of the first quarter from new wells drilled and completed at West Septimus in the fourth quarter of 2018 and the first quarter of 2019.

Petroleum and Natural Gas Sales

	Three months ended March 31, 2019	Three months ended March 31, 2018
Petroleum and natural gas sales ($ thousands)		
Light crude oil	**1,240**	1,939
Heavy crude oil	**6,404**	5,674
Other natural gas liquids	**1,974**	4,003
Condensate	**14,642**	17,933
Natural gas	**31,191**	29,878
Total	**55,451**	59,427
Crew average prices		
Light crude oil ($/bbl)	**61.04**	68.20
Heavy crude oil ($/bbl)	**44.25**	36.09
Other natural gas liquids ($/bbl)	**10.89**	24.81
Condensate ($/bbl)	**62.17**	73.82
Natural gas ($/mcf)	**3.45**	2.85
Oil equivalent ($/boe)	**26.53**	25.46
Benchmark pricing		
Light crude oil – Cdn$ WTI (Cdn $/bbl)	**72.98**	79.53
Heavy crude oil – WCS (Cdn $/bbl)	**56.89**	49.03
Condensate – Condensate @ Edmonton (Cdn $/bbl)	**67.84**	79.83
Natural Gas:		
AECO 5A daily index (Cdn $/mcf)	**2.62**	2.08
AECO 7A monthly index (Cdn $/mcf)	**2.15**	1.85
Alliance 5A (Cdn $/mcf)	**2.77**	2.56
Chicago City Gate at ATP (Cdn $/mcf)	**3.37**	3.01
Henry Hub Close (Cdn $/mcf)	**4.19**	2.56

In the first quarter of 2019, the Company's petroleum and natural gas sales decreased 7% as compared to the same period in 2018, as a result of the 10% decrease in production, coupled with a decrease in light crude oil, condensate and other natural gas liquids pricing, partially offset by an increase in heavy crude oil and natural gas pricing. The Company's realized light crude oil price decreased 10%, which approximated the 8% decrease in the Company's Cdn$ West Texas Intermediate ("WTI") benchmark price from the same period last year. Crew's first quarter heavy crude oil price increased 23%, which is greater than the 16% increase in the Company's WCS benchmark, as a result of the Company entering into short term sales contracts at stronger spot pricing, coupled with a decrease in diluent blending costs of heavy crude oil as compared to the same period last year. The Company's first quarter realized condensate price decreased 16% over the same period in 2018, which approximated the 15% decrease in the Condensate at Edmonton benchmark price. Other natural gas liquids ("ngl") realized price decreased 56% in the first quarter, due to a decrease in propane and butane pricing as compared to the same period in 2018. Crew's realized natural gas price increased by 21% in the first quarter of 2019, which is directionally consistent with the 27% increase 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 2019 natural gas sales portfolio was based approximately on the following reference prices:

	Q1 2019	Q1 2018
AECO 5A	**9%**	12%
AECO 7A	**-**	13%
Alliance 5A	**28%**	24%
Chicago City Gate at ATP	**46%**	42%
Henry Hub	**15%**	-
Station 2	**2%**	9%
Total	**100%**	100%

Royalties

($ thousands, except per boe)	**Three months ended March 31, 2019**	Three months ended March 31, 2018
Royalties	**3,864**	4,007
Per boe	**1.85**	1.72
Percentage of petroleum and natural gas sales	**7.0%**	6.7%

For the first quarter of 2019, royalties per boe and as a percentage of petroleum and natural gas sales increased over the same period in 2018, predominantly due to an increase in heavy crude oil and natural gas pricing that attracted higher royalty rates. The Company expects its royalties as a percentage of revenue to average between 6% and 8% in 2019, an increase from the previous estimate of 5% to 7%, due to higher estimated liquids pricing resulting in increased royalty rates.

Derivative Financial Instruments

Commodities

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

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

($ thousands)	**Three months ended March 31, 2019**	Three months ended March 31, 2018
Realized loss on derivative financial instruments	**(1,837)**	(2,177)
Per boe	**(0.88)**	(0.93)
Unrealized loss on financial instruments	**(10,880)**	(4,648)

At March 31, 2019, 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, 2019 – October 31, 2019	CDN$ Chicago Citygate	$3.44/mmbtu	Swap	$ 21
Gas	2,500 mmbtu/day	April 1, 2019 – October 31, 2019	CDN$ Dawn Daily Index	$3.52/mmbtu	Swap	44
Gas	2,500 mmbtu/day	April 1, 2019 – October 31, 2019	US$ Nymex Henry Hub	$2.85/mmbtu	Swap	56
Gas	22,500 mmbtu/day	April 1, 2019 – December 31, 2019	CDN$ Chicago Citygate	$3.54/mmbtu	Swap	215
Gas	5,000 mmbtu/day	April 1, 2019 – December 31, 2019	CDN$ Dawn Daily Index	$3.56/mmbtu	Swap	36
Gas	7,500 mmbtu/day	April 1, 2019 – December 31, 2019	US$ Nymex Henry Hub	$2.98/mmbtu	Swap	570
Oil	250 bbl/day	April 1, 2019 – June 30, 2019	CDN$ WTI	$83.80/bbl	Swap	76
Oil	500 bbl/day	April 1, 2019 – June 30, 2019	CDN$ WCS	$52.93/bbl	Swap	(649)
Oil	250 bbl/day	April 1, 2019 – June 30, 2019	CDN$ WCS – WTI Differential	($25.75)/bbl	Swap	(283)
Oil	250 bbl/day	April 1, 2019 – June 30, 2019	US$ WCS – WTI Differential	($12.25)/bbl	Swap	(53)
Oil	250 bbl/day	July 1, 2019 – September 30, 2019	US$ WCS – WTI Differential	($17.25)/bbl	Swap	(52)
Oil	1,750 bbl/day	April 1, 2019 – December 31, 2019	CDN$ WTI	$75.44/bbl	Swap	(2,325)
Oil	500 bbl/day	April 1, 2019 – December 31, 2019	CDN$ WCS – WTI Differential	($25.23)/bbl	Swap	(154)
Total						**$ (2,498)**

Subsequent to March 31, 2019, the Company entered into the following derivative commodity contracts:

Subject of Contract	Notional Quantity	Term	Reference	Strike Price	Option Traded
Oil	250 bbl/day	October 1, 2019 – December 31, 2019	CDN$ WCS	$56.20/bbl	Swap
Oil	750 bbl/day	January 1, 2020 – December 31, 2020	CDN$ WTI	$79.12/bbl	Swap

Marketing Income

($ thousands, except per boe)	**Three months ended March 31, 2019**	Three months ended March 31, 2018
Marketing revenue	**3,340**	679
Less: marketing expense	**(414)**	-
Marketing income	**2,926**	679
Per boe	**1.40**	0.29

In the first quarter of 2019, the Company recognized $3.3 million of marketing revenue related to the monetization of the Company's exposure to the Dawn and Malin natural gas markets. Marketing expense reflects the cost of firm transportation commitments on TransCanada's natural gas pipeline system that was not operational until later in the first quarter of 2019.

Net Operating Costs

($ thousands, except per boe)	**Three months ended March 31, 2019**	Three months ended March 31, 2018
Operating costs	**13,955**	15,579
Less: processing revenue	**(900)**	(892)
Net operating costs	**13,055**	14,687
Per boe	**6.25**	6.29

During the first quarter of 2019, net operating costs and net operating costs per boe decreased as compared to the same period in 2018 as a result of a decline in Tower and Lloydminster production, which yield higher operating costs per unit. The net operating costs per boe were also positively impacted by a slight increase in processing revenue from third parties, despite a decrease in production. These decreases were partially offset by an increase in net operating costs per boe in Greater Septimus as a result of the aforementioned shut-in volumes. The Company forecasts 2019 operating costs to average between $6.25 and $6.50 per boe, an increase compared to our previous estimate as a result of higher first quarter costs due to extreme cold weather and the early addition of higher cost heavy oil production that had been previously shut-in due to low pricing.

Transportation Costs

($ thousands, except per boe)	**Three months ended March 31, 2019**	Three months ended March 31, 2018
Transportation costs	**4,717**	4,933
Per boe	**2.26**	2.11

First quarter 2019 transportation costs decreased compared to the first quarter of 2018, as a result of lower Other NE BC production that is transported and processed through the higher cost McMahon gas processing complex. Transportation costs per boe increased in the first quarter compared to the first quarter of 2018 as a result of the late first quarter commissioning of the pipeline system connecting the West Septimus processing facility to the TransCanada Saturn meter station. This line is partially owned by a third party resulting in additional transportation costs. The Company forecasts 2019 transportation costs to average between $3.50 and $3.75 per boe, with second half costs increasing with the addition of new TransCanada service in June 2019.

Operating Netbacks

($/boe)	**Greater Septimus**	**Lloydminster Heavy Oil**	**Other NE BC**	**Three months ended March 31, 2019**	Three months ended March 31, 2018
Petroleum and natural gas sales	**25.61**	**44.15**	**21.47**	**26.53**	25.46
Royalties	**(1.56)**	**(5.20)**	**(2.01)**	**(1.85)**	(1.72)
Realized commodity hedging loss	**(0.74)**	**(2.56)**	**(0.86)**	**(0.88)**	(0.93)
Marketing income	**1.66**	**-**	**-**	**1.40**	0.29
Net operating costs	**(4.65)**	**(21.89)**	**(9.08)**	**(6.25)**	(6.29)
Transportation costs	**(1.73)**	**(1.02)**	**(8.19)**	**(2.26)**	(2.11)
Operating netbacks	**18.59**	**13.48**	**1.33**	**16.69**	14.70
Production (boe/d)	**19,535**	**1,614**	**2,073**	**23,222**	25,939

For the first quarter of 2019, the Company's operating netbacks increased over the same period in 2018, as a result of higher wellhead pricing and an increase in marketing income, partially offset by higher royalties and transportation costs.

General and Administrative Costs

($ thousands, except per boe)	**Three months ended March 31, 2019**	Three months ended March 31, 2018
Gross costs	**4,715**	4,840
Operator's recoveries	**(23)**	(40)
Capitalized costs	**(1,546)**	(1,556)
General and administrative expenses	**3,146**	3,244
Per boe	**1.51**	1.39

Gross and net general and administrative ("G&A") costs decreased in the first quarter of 2019 as compared to the same period in 2018, mainly due to the impact from the adoption of IFRS 16, where the Company's head office lease is no longer charged to G&A. The increase in net G&A costs per boe in the first quarter of 2019 is due to the decrease in production as compared to the same period in 2018, partially offset by the aforementioned impact from the adoption of IFRS 16. Crew forecasts G&A costs per boe to average between $1.40 and $1.65 in 2019.

Other Income

($ thousands, except per boe)	**Three months ended March 31, 2019**	Three months ended March 31, 2018
Other	**-**	1,000
Per boe	**-**	0.43

In the first quarter of 2019, the Company did not recognize any other income, whereas in the first quarter of 2018, the Company recognized $1.0 million for the receipt of non-refundable deposits from third parties for a non-core property disposition that failed to close.

Share-Based Compensation

($ thousands)	**Three months ended March 31, 2019**	Three months ended March 31, 2018
Gross costs	**3,514**	2,141
Capitalized costs	**(1,680)**	(1,036)
Total share-based compensation	**1,834**	1,105

In the first quarter of 2019, the Company's total share-based compensation expense increased as compared to the same period in 2018, due to lower than normal share-based compensation expense in the first quarter of 2018 as a result of the departure of a Company executive.

Depletion and Depreciation

($ thousands, except per boe)	**Three months ended March 31, 2019**	Three months ended March 31, 2018
Depletion and depreciation	**19,828**	22,447
Per boe	**9.49**	9.62

Depletion and depreciation costs per boe for the first quarter of 2019 were consistent with the same period in 2018. The first quarter of 2019 had fewer land expiries when compared to the same period in 2018, offset by an increase in future development costs associated with additional liquids reserves bookings and the addition of depreciation on right-of-use assets, which was the result of the adoption of IFRS 16 in the first quarter of 2019.

Gain on Divesture of Property

During the first quarter of 2019, the Company disposed of non-core land with no associated production or assigned reserves, for gross proceeds of $17.5 million. The land consisted of petroleum and natural gas properties and undeveloped land with a net book value of $0.7 million, resulting in a gain of $16.8 million on closing of the disposition.

Finance Expenses

($ thousands, except per boe)	**Three months ended March 31, 2019**	Three months ended March 31, 2018
Interest on bank loan and other	**934**	618
Interest on senior notes	**4,808**	4,808
Accretion of deferred financing charges	**245**	259
Accretion of the decommissioning obligation	**479**	491
Total finance expense	**6,466**	6,176
Average long-term debt level	**357,127**	330,550
Average drawings on bank loan	**57,127**	30,550
Average senior unsecured notes outstanding	**300,000**	300,000
Effective interest rate on senior unsecured notes	**6.5%**	6.5%
Effective interest rate on long-term debt	**6.1%**	6.3%
Financing costs on long-term debt per boe	**2.86**	2.44

The Company's total finance expense and average corporate debt level increased in the first quarter of 2019 as compared to the same period in 2018, as a result of increased joint venture accounts receivable related to a capital project that was collected towards the end of the first quarter of 2019 and was funded by increased drawings on the bank loan. As a result of the increased drawings on the Company's bank loan, the effective interest rate on the Company's long-term debt was lower in the first quarter of 2019 as compared to the same period in 2018, as a greater proportion of the Company's outstanding long-term debt was in the form of a bank loan, which attracts a lower interest rate. Crew forecasts the effective interest rate on its long-term debt to average between 6.0% and 6.5% in 2019.

Deferred Income Taxes

In the first quarter of 2019, the provision for deferred tax expense was $3.4 million, compared to a deferred tax expense of $3.1 million for the same period in 2018. The increase in the deferred tax expense was predominantly due to higher net income realized in 2019, as a result of gains on property dispositions.

Cash, Funds from Operations and Net Income

($ thousands, except per share amounts)		**Three months ended March 31, 2019**	Three months ended March 31, 2018
Cash provided by operating activities		**10,533**	15,885
Adjusted funds flow		**25,771**	26,373
Per share	- basic	**0.17**	0.18
	- diluted	**0.17**	0.17
Net income		**6,186**	4,148
Per share	- basic	**0.04**	0.03
	- diluted	**0.04**	0.03

In the first quarter of 2019, cash provided by operating activities and adjusted funds flow decreased due to a decrease in revenue resulting from less production, which was partially offset by higher marketing revenue and lower cash expenses when compared to the same period in 2018. Net income increased in the first quarter of 2019 when compared to the same period in 2018, as a result of higher gains on property dispositions, offset by a decrease in revenue and greater losses from the 2019 hedging program.

Capital Expenditures, Property Acquisitions and Dispositions

($ thousands)	**Three months ended March 31, 2019**	Three months ended March 31, 2018
Land	**722**	1,090
Seismic	**303**	295
Drilling and completions	**49,041**	18,665
Facilities, equipment and pipelines	**3,368**	11,973
Other	**1,807**	1,898
Total exploration and development	**55,241**	33,921
Net property dispositions	**(15,924)**	(10,007)
Total	**39,317**	23,914

In the first quarter of 2019, the Company spent a total of $55.2 million on exploration and development expenditures, focused on the continued development of our Montney assets at West Septimus. During the quarter, $49.0 million was spent on drilling and completion activities, including the drilling of seven (7.0 net) and the completion of eight (8.0 net) ultra condensate-rich natural gas wells in NE BC and the recompletion of six (6.0 net) heavy oil wells in Lloydminster. The Company spent $3.4 million on well sites, facilities and pipelines and $2.8 million on land, seismic and other miscellaneous items.

The Company's Board of Directors have approved a net capital expenditure budget for 2019 of $95 to $105 million.

LIQUIDITY AND CAPITAL RESOURCES

Working Capital

The capital intensive nature of Crew's activities generally results in the Company carrying a working capital deficiency. Working capital includes cash and cash equivalents and accounts receivable less accounts payable and accrued liabilities. Included in the working capital deficiency is a receivable of $8.9 million for a Government of British Columbia infrastructure credit earned through the completion of a pipeline connecting the West Septimus processing facility to the TransCanada Saturn meter station. The collection of the credits is realized through the reduction of future royalties payable.

The Company ensures that sufficient drawings are available from its Facility to satisfy working capital requirements. At March 31, 2019, the Company's working capital deficiency of $26.3 million, when combined with the drawings on its bank loan, represented drawings of 28% on its $235 million Facility described below.

Capital Funding

Bank Loan

As at March 31, 2019, 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 June 5, 2019. 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.

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

Share Capital

Crew is authorized to issue an unlimited number of common shares. As at May 2, 2019, there were 156,209,401 common shares of the Company issued and outstanding, which includes 1,755,544 of shares held in trust for the potential future settlement of awards issued under the Company's Restricted and Performance Award Incentive Plan. In addition, there were 3,724,001 restricted awards and 4,227,649 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, 2019.

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 low commodity prices, this ratio will increase over the Company's target. As shown below, as at March 31, 2019, the Company's ratio of net debt to annualized adjusted funds flow was 3.5 to 1 (December 31, 2018 – 3.6 to 1). In the current depressed and volatile commodity environment, Crew plans to limit capital expenditures to approximate adjusted funds flow. With only 17% drawn on the Company's $235 million Facility and the senior unsecured notes termed out to 2024, the Company's financial position remains strong. The Company will continue to monitor this ratio, and if necessary, it will consider divesting of non-core properties, will further adjust its annual capital expenditure program or may consider other forms of financing to further strengthen its financial position.

($ thousands, except ratio)	March 31, 2019	December 31, 2018
Working capital (deficiency) surplus	**(26,283)**	11,984
Bank loan	**(40,065)**	(59,904)
Senior unsecured notes	**(295,130)**	(294,885)
Net debt	**(361,478)**	(342,805)
Quarterly adjusted funds flow	**25,771**	23,712
Annualized	**103,084**	94,848
Net debt to annualized adjusted funds flow	**3.5**	3.6

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. 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	2019	2020	2021	2022	2023	Thereafter
Bank loan (note 1)	40,065	-	40,065	-	-	-	-
Senior unsecured notes (note 2)	300,000	-	-	-	-	-	300,000
Lease obligations	2,447	880	1,175	392	-	-	-
Firm transportation agreements	273,536	38,370	53,809	31,800	31,201	27,215	91,141
Firm processing agreements	107,844	13,286	16,337	12,354	12,354	12,354	41,159
Total	**723,892**	**52,536**	**111,386**	**44,546**	**43,555**	**39,569**	**432,300**

Note 1 – Based on the existing terms of the Company's Facility, the first possible repayment date may come in 2020. 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.

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

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 Greater Septimus complex gas processing facilities in northeast British Columbia.

GUIDANCE

Crew will continue to focus on its ongoing goal of increasing the weighting of condensate in its production mix, which is expected to contribute to further improvements in realized pricing and operating netbacks. The Company is also committed to capital discipline with a 2019 capital expenditure budget that is forecast to range between $95 and $105 million, and designed to approximate annual adjusted funds flow. This budget has been structured to support the Company's ability to effectively manage its balance sheet and retain the flexibility to produce average volumes of 22,000 to 23,000 boe per day, while increasing its exposure to higher valued condensate.

The Company's Q2 2019 production is expected to range between 22,000 and 23,000 boe per day, despite the Company's productive capability being higher, as the Company plans to defer production of drier gas exposed to the current low gas prices in Western Canada. Capital expenditures are forecast to range between $12 and $18 million. Second quarter activity will largely be directed to continued Montney development, including the equipping and tie-in of eight (8.0 net) ultra condensate-rich wells and the workover of heavy crude oil wells, which are attracting a wellhead oil price of over $65 CDN per bbl based on current crude oil prices.

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 2019**	Dec. 31 2018	Sep. 30 2018	June 30 2018	Mar. 31 2018	Dec. 31 2017	Sep. 30 2017	June 30 2017
Total daily production (boe/d)	**23,222**	22,383	23,680	23,583	25,939	25,270	23,251	20,468
Exploration and development expenditures	**55,241**	33,174	23,656	12,468	33,921	36,413	90,069	36,656
Net property (dispositions)/ acquisitions	**(15,924)**	175	9	17	(10,007)	(1,709)	(144)	(45,701)
Average wellhead price ($/boe)	**26.53**	24.69	24.82	25.18	25.46	25.87	22.36	26.25
Petroleum and natural gas sales	**55,451**	50,838	54,080	54,040	59,427	60,146	47,824	48,886
Cash provided by operations	**10,533**	22,878	19,095	31,304	15,885	43,484	15,258	31,359
Adjusted funds flow	**25,771**	23,712	20,107	21,804	26,373	34,087	24,970	21,353
Per share – basic	**0.17**	0.16	0.13	0.14	0.18	0.23	0.17	0.14
– diluted	**0.17**	0.16	0.13	0.14	0.17	0.22	0.17	0.14
Net income (loss)	**6,186**	18,771	(939)	(9,181)	4,148	2,342	2,127	21,880
Per share – basic	**0.04**	0.12	(0.01)	(0.06)	0.03	0.02	0.01	0.15
– diluted	**0.04**	0.12	(0.01)	(0.06)	0.03	0.02	0.01	0.14

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 stabilized in early 2017, prompting the Company to further expand its capital program and infrastructure spending to allow for the growth realized in the second half of 2017 and early 2018. Beginning in the third quarter of 2017 and extending throughout 2018 and into the first quarter of 2019, the Canadian oil and gas industry has experienced volatile commodity prices with significant declines in Canadian natural gas prices and quarter to quarter volatility in the price of Canadian crude oil, condensate and natural gas liquids.

The significant fluctuations in commodity prices have impacted cash provided by operating activities, 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. Despite these efforts, cash flow from operations used to fund the Company's capital program has been impacted.

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) Adoption of IFRS 16 – Leases:

On January 1, 2019, the Company adopted IFRS 16 Leases, which replaces IAS 17 Leases and IFRIC 4 Determining Whether an Arrangement Contains a Lease. IFRS 16 uses a single lease accounting model for lessees, which requires the Company to recognize a right-of-use asset and lease liability on the statement of financial position, for all contracts that contain a lease.

The Company adopted IFRS 16 using the modified retrospective approach, and therefore comparative information has not been restated and continues to be reported under IAS 17 and IFRIC 4. The cumulative effect of initially applying the standard was recognized through $2.6 million in right-of-use assets (included in "Property, plant and equipment") and $2.6 million in lease obligations, split between the current portion of $1.1 million included in "Accounts payable and accrued liabilities", and the long term portion of $1.5 million included in "Lease obligations". The weighted average incremental borrowing rate used to calculate the lease obligation at adoption was 4.5%. The right-of-use asset and lease obligation relates primarily to the Company's head office lease in Calgary.

The Company applied the following practical expedients as permitted under the standard. Some of these expedients are on a lease-by-lease basis and others are applicable by class of underlying assets:

- Maintain classification of contracts previously identified as leases under IAS 17 and IFRIC 4;
- Account for leases with a remaining term of less than 12 months at January 1, 2019 as short-term leases;
- Account for lease payments as an expense and not recognize a right-of-use asset if the underlying asset is of a lower dollar value;
- Apply a single discount rate to a portfolio of leases with similar characteristics; and
- Recognize lease liabilities at the present value of the remaining lease payments, discounted using the interest rate implicit in the lease or the Company's incremental borrowing rate as at January 1, 2019. The associated right-of-use assets will be measured at the amount equal to the lease liability on the date of transition, with no impact to opening retained earnings (deficit).

As at December 31, 2018, the Company had operating lease commitments of $2.7 million, which would have resulted in a discounted lease obligation of $2.6 million. At January 1, 2019, the Company recognized a current and non-current lease obligation of $2.6 million.

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, 2019 and ended on March 31, 2019 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 2, 2019

CONDENSED INTERIM CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

(unaudited) (thousands)	**March 31, 2019**	December 31, 2018
Assets		
Current Assets:		
Accounts receivable	**$ 38,256**	$ 70,522
Derivative financial instruments (note 4)	**536**	8,382
	38,792	78,904
Property, plant and equipment (note 5)	**1,414,918**	1,373,019
	$ 1,453,710	$ 1,451,923
Liabilities and Shareholders' Equity		
Current Liabilities:		
Accounts payable and accrued liabilities	**$ 64,539**	$ 58,538
Derivative financial instruments (note 4)	**3,034**	-
	67,573	58,538
Bank loan (note 6)	**40,065**	59,904
Senior unsecured notes (note 7)	**295,130**	294,885
Lease obligations (note 8)	**1,244**	-
Decommissioning obligations (note 9)	**89,497**	89,448
Deferred tax liability	**56,151**	52,798
Shareholders' Equity		
Share capital (note 10)	**1,468,313**	1,468,986
Contributed surplus	**77,902**	75,715
Deficit	**(642,165)**	(648,351)
	904,050	896,350
Subsequent event (note 4)		
Commitments (note 13)		
	$ 1,453,710	$ 1,451,923

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, 2019**		Three months ended March 31, 2018
Revenue				
Petroleum and natural gas sales (note 11)	**$**	**55,451**	$	59,427
Royalties		**(3,864)**		(4,007)
Realized loss on derivative financial instruments		**(1,837)**		(2,177)
Unrealized loss on derivative financial instruments		**(10,880)**		(4,648)
Other revenue (note 11)		**4,240**		2,571
		43,110		51,166
Expenses				
Operating		**13,955**		15,579
Transportation		**4,717**		4,933
Marketing		**414**		-
General and administrative		**3,146**		3,244
Share-based compensation		**1,834**		1,105
Depletion and depreciation (note 5)		**19,828**		22,447
		43,894		47,308
(Loss) income from operations		**(784)**		3,858
Financing (note 12)		**6,466**		6,176
Gain on divestiture of property, plant and equipment (note 5)		**(16,789)**		(9,546)
Income before income taxes		**9,539**		7,228
Deferred tax expense		**3,353**		3,080
Net income and comprehensive income	**$**	**6,186**	$	4,148
Net income per share (note 10)				
Basic	**$**	**0.04**	$	0.03
Diluted	**$**	**0.04**	$	0.03

See accompanying notes to the condensed interim consolidated financial statements.

CONDENSED INTERIM CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

(unaudited) (thousands)	Number of shares, net of shares in trust	Share capital	Contributed surplus	Deficit	Total Shareholders' equity
Balance, January 1, 2019	151,730	$ 1,468,986	$ 75,715	$ (648,351)	$ 896,350
Net income for the period	-	-	-	6,186	6,186
Share-based compensation expensed	-	-	1,834	-	1,834
Share-based compensation capitalized	-	-	1,680	-	1,680
Issued on vesting of share awards	580	1,327	(1,327)	-	-
Change in shares held in trust (note 10)	(1,756)	(2,000)	-	-	(2,000)
Balance, March 31, 2019	**150,554**	**$ 1,468,313**	**$ 77,902**	**$ (642,165)**	**$ 904,050**

(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**

See accompanying notes to the condensed interim consolidated financial statements.

CONDENSED INTERIM CONSOLIDATED STATEMENTS OF CASH FLOWS

(unaudited) (thousands)	**Three months ended March 31, 2019**	Three months ended March 31, 2018
Cash provided by (used in):		
Operating activities:		
Net income	**$ 6,186**	$ 4,148
Adjustments:		
Unrealized loss on derivative financial instruments	**10,880**	4,648
Share-based compensation	**1,834**	1,105
Depletion and depreciation (note 5)	**19,828**	22,447
Financing expenses (note 12)	**6,466**	6,176
Interest expense (note 12)	**(5,742)**	(5,426)
Gain on divestiture of property, plant and equipment (note 5)	**(16,789)**	(9,546)
Deferred tax expense	**3,353**	3,080
Decommissioning obligations settled (note 9)	**(1,764)**	(591)
Change in non-cash working capital	**(13,719)**	(10,156)
	10,533	15,885
Financing activities:		
(Decrease) increase in bank loan	**(19,839)**	25,552
Payments on lease obligations (note 8)	**(268)**	-
Shares purchased and held in trust (note 10)	**(2,000)**	-
	(22,107)	25,552
Investing activities:		
Property, plant and equipment expenditures (note 5)	**(55,241)**	(32,580)
Property acquisitions	**(1,576)**	-
Property dispositions (note 5)	**17,500**	10,007
Change in non-cash working capital	**50,891**	(18,864)
	11,574	(41,437)
Change in cash and cash equivalents	**-**	-
Cash and cash equivalents, beginning of period	**-**	-
Cash and cash equivalents, end of period	**$ -**	$ -

See accompanying notes to the condensed interim consolidated financial statements.

NOTES TO CONDENSED INTERIM CONSOLIDATED FINANCIAL STATEMENTS

For the three months ended March 31, 2019 and 2018

(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 Canada 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, 2018, 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 financial statements were authorized for issuance by Crew's Board of Directors on May 2, 2019.

3. Change in accounting policies:

(i) Adoption of IFRS 16 – Leases:

On January 1, 2019, the Company adopted IFRS 16 Leases, which replaces IAS 17 Leases and IFRIC 4 Determining Whether an Arrangement Contains a Lease. IFRS 16 uses a single lease accounting model for lessees, which requires the Company to recognize a right-of-use asset and lease liability on the statement of financial position, for all contracts that contain a lease.

The Company adopted IFRS 16 using the modified retrospective approach, and therefore comparative information has not been restated and continues to be reported under IAS 17 and IFRIC 4. The cumulative effect of initially applying the standard was recognized through $2.6 million in right-of-use assets (included in "Property, plant and equipment") and $2.6 million in lease obligations, split between the current portion of $1.1 million included in "Accounts payable and accrued liabilities", and the long term portion of $1.5 million included in "Lease obligations". The weighted average incremental borrowing rate used to calculate the lease obligation at adoption was 4.5%. The right-of-use asset and lease obligation relates primarily to the Company's head office lease in Calgary.

The Company applied the following practical expedients as permitted under the standard. Some of these expedients are on a lease-by-lease basis and others are applicable by class of underlying assets:

- Maintain classification of contracts previously identified as leases under IAS 17 and IFRIC 4;
- Account for leases with a remaining term of less than 12 months at January 1, 2019 as short-term leases;
- Account for lease payments as an expense and not recognize a right-of-use asset if the underlying asset is of a lower dollar value;
- Apply a single discount rate to a portfolio of leases with similar characteristics; and
- Recognize lease liabilities at the present value of the remaining lease payments, discounted using the interest rate implicit in the lease or the Company's incremental borrowing rate as at January 1, 2019. The associated

right-of-use assets will be measured at the amount equal to the lease liability on the date of transition, with no impact to opening retained earnings (deficit).

As at December 31, 2018, the Company had operating lease commitments of $2.7 million, which would have resulted in a discounted lease obligation of $2.6 million. At January 1, 2019, the Company recognized a current and non-current lease obligation of $2.6 million.

As a result of the adoption of IFRS 16 Leases, the Company has revised its accounting policy for leases as follows:

Contracts where the Company obtains the right to control the use of an identified asset in exchange for consideration are determined to contain a lease. At commencement, a right-of-use asset is initially measured at cost, which comprises the initial amount of the lease liability, less any lease incentives received. The right-of-use asset is depreciated on a straight-line basis over the lease term. The corresponding lease liability is equal to the present value of the future lease payments. Interest expense is recognized on the lease obligations using the effective interest rate method. These payments are applied against the lease liability.

The Company is required to make judgements and assumptions on incremental borrowing rates and lease terms. The carrying balance of the right-of-use assets, lease obligations, interest and depreciation expense may differ due to changes in market conditions and expected lease terms. Incremental borrowing rates are based on the Company's borrowing rate at the commencement date of the lease, the security of the asset and market conditions. Leases terms are based on management's assumptions of future market conditions and operational decisions.

4. Financial risk management:

Derivative contracts:

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

The fair value of options and costless collars is based on option models that use published information with respect to volatility, prices and interest rates. 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, 2019, 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, 2019 – October 31, 2019	CDN$ Chicago Citygate	$3.44/mmbtu	Swap	$ 21
Gas	2,500 mmbtu/day	April 1, 2019 – October 31, 2019	CDN$ Dawn Daily Index	$3.52/mmbtu	Swap	44
Gas	2,500 mmbtu/day	April 1, 2019 – October 31, 2019	US$ Nymex Henry Hub	$2.85/mmbtu	Swap	56
Gas	22,500 mmbtu/day	April 1, 2019 – December 31, 2019	CDN$ Chicago Citygate	$3.54/mmbtu	Swap	215
Gas	5,000 mmbtu/day	April 1, 2019 – December 31, 2019	CDN$ Dawn Daily Index	$3.56/mmbtu	Swap	36
Gas	7,500 mmbtu/day	April 1, 2019 – December 31, 2019	US$ Nymex Henry Hub	$2.98/mmbtu	Swap	570
Oil	250 bbl/day	April 1, 2019 – June 30, 2019	CDN$ WTI	$83.80/bbl	Swap	76
Oil	500 bbl/day	April 1, 2019 – June 30, 2019	CDN$ WCS	$52.93/bbl	Swap	(649)
Oil	250 bbl/day	April 1, 2019 – June 30, 2019	CDN$ WCS – WTI Differential	($25.75)/bbl	Swap	(283)
Oil	250 bbl/day	April 1, 2019 – June 30, 2019	US$ WCS – WTI Differential	($12.25)/bbl	Swap	(53)
Oil	250 bbl/day	July 1, 2019 – September 30, 2019	US$ WCS – WTI Differential	($17.25)/bbl	Swap	(52)
Oil	1,750 bbl/day	April 1, 2019 – December 31, 2019	CDN$ WTI	$75.44/bbl	Swap	(2,325)
Oil	500 bbl/day	April 1, 2019 – December 31, 2019	CDN$ WCS – WTI Differential	($25.23)/bbl	Swap	(154)
Total						**$ (2,498)**

Subsequent to March 31, 2019, the Company entered into the following derivative commodity contracts:

Subject of Contract	Notional Quantity	Term	Reference	Strike Price	Option Traded
Oil	250 bbl/day	October 1, 2019 – December 31, 2019	CDN$ WCS	$56.20/bbl	Swap
Oil	750 bbl/day	January 1, 2020 – December 31, 2020	CDN$ WTI	$79.12/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 at or below 2.0 to 1.0. During periods of increased capital expenditures, acquisitions or low commodity prices, this ratio will increase over the Company's target. As shown below, as at March 31, 2019, the Company's ratio of net debt to annualized adjusted funds flow was 3.5 to 1 (December 31, 2018 – 3.6 to 1). In the current depressed and volatile commodity price environment, Crew plans to limit capital expenditures to approximate adjusted funds flow. With only 17% drawn on the Company's $235 million Facility and the senior unsecured notes termed out to 2024, the Company's financial position remains strong. The Company will continue to monitor this ratio and, if necessary, it will consider divesting of non-core properties, will further adjust its annual capital expenditure program or may consider other forms of financing to further strengthen its financial position.

		March 31, 2019		December 31, 2018
Net debt:				
Accounts receivable	**$**	**38,256**	$	70,522
Accounts payable and accrued liabilities		**(64,539)**		(58,538)
Working capital (deficiency) surplus	**$**	**(26,283)**	$	11,984
Bank loan		**(40,065)**		(59,904)
Senior unsecured notes		**(295,130)**		(294,885)
Net debt	**$**	**(361,478)**	$	(342,805)
Quarterly annualized adjusted funds flow:				
Cash provided by operating activities	**$**	**10,533**	$	22,878
Change in non-cash working capital		**13,719**		843
Accretion of deferred financing charges		**(245)**		(246)
Decommissioning obligations settled		**1,764**		237
Quarterly adjusted funds flow	**$**	**25,771**	$	23,712
Annualized	**$**	**103,084**	$	94,848
Net debt to annualized adjusted funds flow		**3.5**		3.6

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		Total
Balance, January 1, 2018	$	2,414,325
Additions		103,219
Acquisitions		201
Divestitures		(875)
Change in decommissioning obligations		730
Capitalized share-based compensation		6,381
Balance, December 31, 2018	$	2,523,981
Additions		55,241
Acquisitions		1,576
Increase in right-of-use assets		2,607
Divestitures		(913)
Change in decommissioning obligations		1,334
Capitalized share-based compensation		1,680
Balance, March 31, 2019	**$**	**2,585,506**

Accumulated depletion and depreciation		Total
Balance, January 1, 2018	$	1,073,589
Depletion and depreciation expense		77,373
Balance, December 31, 2018	$	1,150,962
Depletion and depreciation expense		19,828
Divestitures		(202)
Balance, March 31, 2019	**$**	**1,170,588**

Net book value		Total
Balance, March 31, 2019	**$**	**1,414,918**
Balance, December 31, 2018	$	1,373,019

The calculation of depletion and depreciation expense for the three months ended March 31, 2019 included estimated future development costs of $1,861.6 million (December 31, 2018 - $1,894.4 million) associated with the development of the Company's proved plus probable reserves and excludes salvage value of $70.9 million (December 31, 2018 - $70.5 million) and undeveloped land of $156.6 million (December 31, 2018 - $159.3 million) related to future development acreage with no associated reserves.

Included in depletion and depreciation expense for the three months ended March 31, 2019, is $0.3 million related to the right-of-use asset for the Company's head office lease. As at March 31, 2019, the net book value of this right-of-use asset is $2.3 million.

During the first quarter of 2019, the Company disposed of non-core land with no associated production or assigned reserves, for gross proceeds of $17.5 million. The land consisted of petroleum and natural gas properties and undeveloped land with a net book value of $0.7 million, resulting in a gain of $16.8 million on closing of the disposition.

There were no indicators of impairment for the Company's cash-generating units ("CGU") as at March 31, 2019, and therefore an impairment test was not performed.

6. Bank loan:

As at March 31, 2019, 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 June 5, 2019. 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 0.338 percent to 0.788 percent depending upon the debt to EBITDA ratio. As at March 31, 2019, 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 0.338 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, 2019 the Company had issued letters of credit totaling $21.8 million (December 31, 2018 - $20.9 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.

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.

At March 31, 2019, the carrying value of the 2024 Notes was net of deferred financing costs of $4.9 million (December 31, 2018 – $5.1 million).

8. Lease obligations:

		As at March 31, 2019
Less than 1 year	**$**	**1,175**
1 – 3 years		**1,272**
Total undiscounted future lease payments	**$**	**2,447**
Future interest payments		**(107)**
Change in estimated future cash outflows	**$**	**2,340**
Current portion of lease obligations, included in accounts payable and accrued liabilities		**(1,096)**
Long-term portion of lease obligations	**$**	**1,244**

		Three months ended March 31, 2019
Principal payments	**$**	**268**
Interest payments		**26**
Total cash outflow	**$**	**294**

The Company's total undiscounted future lease payments of $2.4 million equate to future operating lease obligations and exclude commitments for firm transportation and processing agreements, as disclosed in note 13, as they do not meet the definition of a lease as a result of the Company's inability to receive substantially all of the asset's economic benefits.

9. Decommissioning obligations:

		Three months ended March 31, 2019		Year ended December 31, 2018
Decommissioning obligations, beginning of period	**$**	**89,448**	$	88,368
Obligations incurred		**702**		1,523
Obligations settled		**(1,764)**		(1,194)
Obligations divested		**-**		(414)
Change in estimated future cash outflows		**632**		(793)
Accretion of decommissioning obligations		**479**		1,958
Decommissioning obligations, end of period	**$**	**89,497**	$	89,448

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 $89.5 million as at March 31, 2019 (December 31, 2018 – $89.4 million) based on an inflation adjusted undiscounted total future liability of $117.8 million (December 31, 2018 – $117.8 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, 2018 – 2%). The discount factor, being the risk-free rate related to the liability, is 2.13% (December 31, 2018 – 2.13%). The $0.6 million (December 31, 2018 – $0.8 million) change in estimated future cash outflows for the three months ended March 31, 2019 is a result of a change in future estimated undiscounted abandonment costs.

10. Share capital:

At March 31, 2019, the Company was authorized to issue an unlimited number of common shares with the holders of common shares entitled to one vote per share.

Restricted and performance award incentive plan:

The Company has a Restricted and Performance Award Incentive Plan ("RPAP") which authorizes the Board of Directors to grant restricted awards ("RAs") and performance awards ("PAs") to directors, officers, employees, consultants or other service providers of Crew and its affiliates.

Subject to terms and conditions of the RPAP, each RA and PA entitles the holder to an award value to be typically paid as to one-third on each of the first, second and third anniversaries of the date of grant. For the purpose of calculating share-based compensation, the fair value of each award is determined at the grant date using the closing price of the common shares. In the case of PAs, the award value is adjusted for a payout multiplier which can range from 0.0 to 2.0 and is dependent on the performance of the Company relative to pre-defined corporate performance measures for a particular period. On the vesting dates, the Company has the option of settling the award value in cash or common shares of the Company. Since the inception of the RPAP, the Company has settled all awards through the issuance of common shares from treasury.

Subsequent to May 21, 2018, being the third anniversary from the date the Company last obtained approval from shareholders for the continued issuance of common shares from treasury under the RPAP, the Company is no longer eligible to issue common shares from treasury to settle the award value of any newly granted RAs and PAs. The Company remains eligible to settle the award value for any such grants either in cash or in common shares acquired by an independent trustee in the open market for such purposes. Common shares acquired in the open market are held in trust for the potential future settlement of award values and are netted out of share capital, including the cumulative purchase cost, until they are distributed for future settlements. For the three months ended March 31, 2019, the trustee purchased and holds at March 31, 2019, 1,756,000 common shares with a total cost of $2.0 million.

Through the vesting of 131,000 RAs and 299,000 PAs, when taking into account the earned multipliers for PAs, 580,000 common shares of the Company were issued for the three months ended March 31, 2019.

The number of RAs and PAs outstanding are as follows:

	Number of RAs	Number of PAs
Balance, January 1, 2019	3,437	4,495
Granted	18	18
Vested	(131)	(299)
Forfeited	(124)	(292)
Balance, March 31, 2019	**3,200**	**3,922**

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, 2019 was 151,688,000 (March 31, 2018 – 149,341,000).

In computing diluted earnings per share for the three month period ended March 31, 2019, 1,570,000 (March 31, 2018 – 1,747,000) shares were added to the weighted average common shares outstanding to account for the dilution of RAs and PAs. For the three month period ended March 31, 2019, there were 6,788,000 (March 31, 2018 – 2,329,000) RAs and PAs that were not included in the diluted earnings per share calculation because they were anti-dilutive.

11. 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 revenue from contracts with customers:

	Three months ended March 31, 2019	Three months ended March 31, 2018
Light crude oil	**$ 1,240**	$ 1,939
Heavy crude oil	**6,404**	5,674
Other natural gas liquids	**1,974**	4,003
Condensate	**14,642**	17,933
Natural gas	**31,191**	29,878
	$ 55,451	$ 59,427

Other revenue:

The following table summarizes the Company's other revenue:

	Three months ended March 31, 2019	Three months ended March 31, 2018
Marketing revenue	**$ 3,340**	$ 679
Processing revenue	**900**	892
Other	**-**	1,000
	$ 4,240	$ 2,571

12. Financing:

	Three months ended March 31, 2019	Three months ended March 31, 2018
Interest expense	**$ 5,742**	$ 5,426
Accretion of deferred financing costs	**245**	259
Accretion of decommissioning obligations	**479**	491
	$ 6,466	$ 6,176

13. Commitments:

	Total	2019	2020	2021	2022	2023	Thereafter
Firm transportation agreements	$ 273,536	$ 38,370	$ 53,809	$ 31,800	$ 31,201	$ 27,215	$ 91,141
Firm processing agreements	107,844	13,286	16,337	12,354	12,354	12,354	41,159
Total	**$ 381,380**	**$ 51,656**	**$ 70,146**	**$ 44,154**	**$ 43,555**	**$ 39,569**	**$132,300**

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 Greater 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
Executive Vice President and Chief Financial Officer

James Taylor
Chief Operating Officer

Jamie L. Bowman
Senior Vice President, Marketing & Originations

Kurtis Fischer
Vice President, Business 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

Karen A. Nielsen
Independent Director

Ryan A. Shay, CPA, CA
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

crew energy inc.