Interim Report

Q3 2019

third quarter ending September 30, 2019

crew energy inc.

Crew Energy Inc. (TSX: CR) ("Crew of the "Company) is pleased to announce our operating and financial results for the three and nine month periods ended September 30, 2019.

HIGHLIGHTS

- **Average Production of 22,824 boe per day with 29% Liquids:** Liquids volumes increased to 29% of production for both Q3/19 and year-to-date 2019, compared to 25% in Q3/18, representing a 16% increase. Liquids made up 58% of Crew's total petroleum and natural gas sales in the quarter, while oil and condensate volumes were 67% of the Company's total liquids.

- **Ultra Condensate-Rich ("UCR") Montney Growth Drives 24% Growth in Condensate Volumes:** Condensate production for the quarter grew 24% to 2,575 bbls per day from 2,077 bbls per day in Q3/18, and year-to-date increased 18% to 2,773 bbls per day, reflecting the success of Crew's strategy to focus our production growth volumes on higher-value condensate.

- **Adjusted Funds Flow ("AFF") Reflects Pricing Environment:** Q3/19 AFF totaled $16.7 million or $0.11 per fully diluted share, while year-to-date, Crew generated AFF of $65.0 million or $0.43 per diluted share. Relative to the same periods in 2018, significantly weaker commodity pricing offset the benefit of higher condensate production.

- **New Completions Outperform:** The four "B" zone wells at the 15-20 pad have produced 282,000 bbls of condensate in the first 210 days of production averaging 839 boe per day[1] (40 % condensate), while five "B" zone wells at the 4-21 pad have produced 201,600 bbls of condensate over the first 180 days averaging 896 boe per day (25% condensate). Better than expected performance from these wells has enabled Crew to achieve forecasted Q3/19 production volumes while shutting-in dry gas production in the quarter due to low pricing.

- **Support for Long-Term Sustainability:** With base production decline rates below 15% at Septimus and area operating netbacks that exceed maintenance capital, Crew is well positioned to support our sustainability by replicating this trend at West Septimus, where decline rates are estimated at approximately 18%.

- **Financial Liquidity Remains Strong:** Ending Q3/19 net debt of $356.1 million remains in-line with $353.4 million at June 30 2019, and is comprised of $300 million of senior notes which have no financial maintenance covenants and are termed out until 2024. The Company's syndicate of lenders have completed their fall 2019 review and re-confirmed the bank facility's borrowing base at $235 million, with Crew 26% drawn at September 30th.

- **Capital Plans Outlined Through First Half 2020:** Crew remains committed to balancing our capital expenditures with AFF to retain financial flexibility. To capitalize on strong gas prices anticipated this winter, the Company plans to invest a total of $54 million in Q4/19 (55%), Q1/20 (30%) and Q2/20 (15%), which compares to $102 million invested in the comparable periods the prior year. Shifting the timing of this capital is expected to enable Crew to secure lower rates for services, significantly improve economics, enhance per well rates of return, and produce an average of 22,000 to 23,000 boe per day in the first half of 2020 while maintaining liquidity levels.

[1] Total volumes at the 15-20 and 4-21 pad are estimated from average gas and condensate shrinkage, process recovery and the exclusion of low volume days during cleanup.

FINANCIAL & OPERATING HIGHLIGHTS:

FINANCIAL ($ thousands, except per share amounts)	**Three months ended Sept 30, 2019**	Three months ended Sept 30, 2018	**Nine months ended Sept 30, 2019**	Nine months ended Sept 30, 2018
Petroleum and natural gas sales	**41,597**	54,080	**148,591**	167,547
Adjusted Funds Flow(1)	**16,664**	20,107	**64,948**	68,284
Per share - basic	**0.11**	0.13	**0.43**	0.45
- diluted	**0.11**	0.13	**0.43**	0.45
Net (loss) income	**(3,255)**	(939)	**18,306**	(5,972)
Per share - basic	**(0.02)**	(0.01)	**0.12**	(0.04)
- diluted	**(0.02)**	(0.01)	**0.12**	(0.04)
Exploration and Development expenditures	**18,466**	23,656	**87,704**	70,045
Property acquisitions (net of dispositions)	**7**	9	**(19,166)**	(9,981)
Net capital expenditures	**18,473**	23,665	**68,538**	60,064

Capital Structure ($ thousands)	**As at Sept 30, 2019**	As at Dec. 31, 2018
Working capital deficiency (surplus)(2)	**3,571**	(11,984)
Bank loan	**56,864**	59,904
	60,435	47,920
Senior Unsecured Notes	**295,622**	294,885
Total Net Debt(2)	**356,057**	342,805
Current Debt Capacity(3)	**535,000**	535,000
Common Shares Outstanding (thousands)	**151,482**	151,730

Notes:

(1) Non-IFRS Measure. 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) Non-IFRS Measure. 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 Sept 30, 2019**	Three months ended Sept 30, 2018	**Nine months ended Sept 30, 2019**	Nine months ended Sept 30, 2018
Daily production				
Light crude oil (bbl/d)	**233**	269	**205**	282
Heavy crude oil (bbl/d)	**1,627**	1,819	**1,653**	1,832
Condensate (bbl/d)	**2,575**	2,077	**2,773**	2,358
Ngl (bbl/d)	**2,148**	1,711	**2,071**	1,738
Natural gas (mcf/d)	**97,443**	106,821	**97,608**	109,099
Total (boe/d @ 6:1)	**22,824**	23,680	**22,970**	24,393
Average prices(1)				
Light crude oil ($/bbl)	**63.81**	78.25	**63.39**	73.75
Heavy crude oil ($/bbl)	**52.86**	51.03	**52.58**	47.96
Ngl ($/bbl)	**0.57**	28.15	**6.16**	26.19
Condensate ($/bbl)	**62.19**	81.45	**64.73**	78.99
Natural gas ($/mcf)	**1.95**	2.40	**2.58**	2.51
Oil equivalent ($/boe)	**19.81**	24.82	**23.70**	25.16

Notes:

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

	Three months ended Sept 30, 2019	Three months ended Sept 30, 2018	**Nine months ended Sept 30, 2019**	Nine months ended Sept 30, 2018
Netback ($/boe)				
Petroleum and natural gas sales	**19.81**	24.82	**23.70**	25.16
Royalties	**(1.49)**	(1.73)	**(1.70)**	(1.76)
Realized commodity hedging gain (loss)	**1.38**	(2.09)	**0.12**	(1.40)
Marketing income(1)	**1.33**	0.25	**1.32**	0.27
Net operating costs(2)	**(5.94)**	(6.21)	**(6.06)**	(6.35)
Transportation costs	**(2.80)**	(1.62)	**(2.69)**	(1.85)
Operating netback(3)	**12.29**	13.42	**14.69**	14.07
General & administrative ("G&A")	**(1.36)**	(1.39)	**(1.42)**	(1.34)
Other income	**-**	-	**-**	0.15
Financing costs on long-term debt	**(2.99)**	(2.81)	**(2.90)**	(2.64)
Adjusted funds flow(3)	**7.94**	9.22	**10.37**	10.24
Drilling Activity				
Gross wells	**0**	6	**8**	6
Working interest wells	**0.0**	6.0	**8.0**	6.0
Success rate, net wells (%)	**N/A**	100%	**100%**	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) Non-IFRS Measure. 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

Shifting Production Gains to Condensate

- Production of 22,824 boe per day for the quarter was in line with the previous quarter and 4% lower than the same period in 2018 on exploration and development capital spending of $18.5 million. Third quarter forecasted production was not impacted by the shut-in of dry gas caused by lower prices due to the production outperformance of our UCR pads that were completed earlier in the year.

- Condensate production averaged 2,575 bbls per day, an increase of 24% compared to Q3/18, and represented 11% of Crew's total volumes for the period. Condensate contributed 35% to Crew's total sales in Q3/19, compared with 29% in Q3/18 and 38% in Q2/19. Liquids production averaged 29% of corporate volumes, although petroleum and natural gas sales were negatively impacted due to weakened liquids pricing.

- Greater Septimus production averaged 19,648 boe per day in Q3/19, an increase of 2% over 19,240 boe per day in Q3/18 and on par with Q2/19 volumes. Year-to-date area production averaged 19,593 boe per day, on par with the same period in 2018, and reflective of the Company's focus on prudent development of the higher value UCR area.

Commodity Prices Having an Impact

- AFF in Q3/19 was $16.7 million ($0.11 per diluted share) and for the first nine months of the year totaled $65.0 million ($0.43 per diluted share). Weaker petroleum and natural gas sales through both periods, partially offset by improved hedging gains, marketing income and lower net operating costs, has contributed to modest declines in both absolute and per share AFF in 2019.

- Quarter-over-quarter AFF was 26% lower, primarily attributable to weaker petroleum and natural gas sales. This was partially offset by an increase in hedging gains, lower royalties, transportation and net operating costs.

- Petroleum and natural gas sales for Q3/19 and for the first nine months of the year decreased 23% and 11%, respectively, relative to the same periods in 2018, mainly due to lower realized commodity prices in 2019 relative to the same periods in 2018. Q3/19 petroleum and natural gas sales decreased 19% compared to Q2/19, primarily the result of a 20% decline in realized commodity prices.

- The price for West Texas Intermediate ("WTI") denominated in Canadian dollars, Crew's benchmark price for light oil and condensate, decreased 7% sequentially from Q2/19 and 18% over Q3/18, mainly the result of a global oversupply of crude oil due to increased U.S. shale oil production.

- Crew's realized combined light crude oil and condensate price decreased 8% and 23% in the quarter, compared to the prior quarter and Q3/18 respectively, consistent with the decline in WTI benchmark pricing over the same periods.

- Crew's heavy oil benchmark Western Canada Select ("WCS") decreased 11% in Q3/19 compared to Q2/19 and declined 5% as compared to Q3/18 mainly the result of declining global crude prices. The year-over-year heavy oil price decline was moderated, as compared to WTI declines, by the Alberta Government's oil curtailment program, which has strengthened Canadian crude oil prices in 2019 compared to 2018.

- Crew's Q3 2019 heavy crude oil realized price decreased 12% compared to Q2/19 and increased 4% compared to Q3/18. The quarter-over-quarter decrease is consistent with the WCS benchmark change. Crew's year-over-year change, as compared to WCS, was enhanced by lower diluent blending costs realized in 2019.

- The realized price for Crew's ngl production was 92% lower than the previous quarter, and decreased 98% compared to Q3/18, primarily due to a decrease in realized propane and butane pricing in North America. Crew's ngl pricing includes embedded cost to process the ngl product out of the Company's gas stream. During the third quarter, revenue earned from the sale of the extracted ngl product was only slightly above the cost of the extraction due to the low realized prices.

- Crew's realized natural gas price for Q3/19 was 17% lower than the previous quarter and 19% lower than Q3/18, which is consistent with the decline in all of the Company's benchmark natural gas prices over the last year. Natural gas prices across North America have continued to decline as a result of persistent production growth in the U.S.

- Marketing income for the quarter was $2.8 million or $1.33 per boe compared to $2.6 million or $1.23 per boe in Q2/19, and $0.6 million or $0.25 per boe in Q3/18, reflecting the monetization of the Company's Dawn transport contract and Malin sales contract.

Net Operating Costs Continue Trending Lower

- Corporate operating netbacks in Q3/19 averaged $12.29 per boe, a decline of 18% sequentially from Q2/19, reflective of a 20% decline in realized commodity prices per boe, partially offset by a larger hedging gain and lower operating costs per boe. Compared to Q3/18, operating netbacks declined 8%.

- Cash costs per boe for Q3 decreased 3% relative to Q2/19, attributable mainly to lower royalties and transportation costs per boe. Cash costs per boe in Q3/19 increased 6% relative to Q3/18 predominantly due to higher transportation costs associated with transportation access to new natural gas markets, partially offset by lower royalties and operating costs per boe.

- With a focus on optimizing field operations to increase the efficiency of the Company's operations, Crew's per boe net operating costs decreased 4% in Q3/19 compared to Q3/18 and by 5% for the nine months ended September 30, 2019 relative to the same period in 2018.

- As part of the ongoing expansion to diversify market opportunities for our natural gas production, transportation costs in Q3/19 and the first nine months of 2019 increased relative to the corresponding periods in 2018, but declined 6% relative to Q2/19. The year-over-year increase is due to the addition of fees associated with the new sales pipeline between West Septimus and TC Energy's Saturn meter station.

Q3 Capital Expenditures In-Line with Guidance

- Exploration and development capital expenditures remained in line with guidance at $18.5 million in Q3/19 and $68.5 million (net of $19.2 million of net acquisition and disposition proceeds) year-to-date in 2019. The majority of Crew's net capital investments in Q3 and year-to-date 2019 were directed to development within the Company's UCR area.

- Approximately $12.4 million of Crew's Q3 capital was allocated to drilling and completion activities largely focused in our UCR area, including a partial completion at Crew's 3-32 pad, completion of the 14-34 well, incremental water handling infrastructure and pipeline installation. Of our total capital, $3.4 million was directed to Montney well site development, facilities and pipelines with $2.7 million for land, seismic and other miscellaneous expenditures.

Ongoing Commitment to Balance Sheet Strength

- Net debt of $356.1 million was stable relative to the $353.4 million of net debt at the end of Q2/19.

- Crew'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 26% drawn when combined with the working capital deficiency of approximately $3.6 million at quarter end.

- The Company's syndicate of lenders have completed their fall 2019 review and re-confirmed the bank facility's borrowing base at $235 million.

TRANSPORTATION, MARKETING & HEDGING

Active Marketing Program Underpins Strategy

- Crew elected to monetize the Company's Dawn market access for the remainder of 2019 and all of 2020 and its Malin market exposure for the remainder of 2019, realizing marketing income in Q3/19 of $2.8 million and a total of $8.3 million for the nine months ended September 30, 2019.

- For the fourth quarter of 2019, Crew's average natural gas sales exposure is currently forecast to be weighted approximately 53% to Chicago, 17% to NYMEX, 16% to Alliance ATP, 7% to Station 2 and 7% to AECO 5A.

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 for 2019
  - 7,500 mmbtu per day of Dawn gas at C$3.55 per mmbtu for 2019
  - 10,000 mmbtu per day of NYMEX gas at US$2.95 per mmbtu for 2019
  - 12,500 mmbtu per day of Chicago gas at C$3.32 per mmbtu for 2020
  - 2,500 mmbtu per day of NYMEX gas at US$2.48 per mmbtu for 2020

- For liquids, Crew has the following hedges in place:
  - 1,937 bbls per day of WTI at an average price of C$76.17 per bbl for 2019
  - 250 bbls per day of WCS for Q4 2019 at C$56.20 per bbl
  - 250 bbls per day of WCS for Q4 2019 at C$55.75 per bbl
  - 500 bbls per day of WCS differential at C$25.23 per bbl for the second half of 2019
  - 1,127 bbls per day of WTI at an average price of C$77.41 per bbl for 2020
  - 250 bbls per day of WCS differential at US$17.25 per bbl for first half 2020
  - 250 bbls per day of WCS for first half 2020 at C$52.00 per bbl

OPERATIONS & AREA OVERVIEW

NE BC Montney - Greater Septimus

- During Q3/19, Crew completed the toe of one extended reach horizontal ("ERH") well with a total lateral length of 3,050 metres drilled to the northwest on the 3-32 pad in the UCR area at West Septimus. This was a partial completion of approximately 25% of the well to confirm flow and liquids characteristics which proved to be similar to other UCR wells in the area.

- Results to date from wells on our 15-20 pad in the UCR area at Greater Septimus have remained strong and are averaging above the 4.6 BCF of gas and 296,500 bbls of condensate assigned to proved plus probable UCR ERH type wells by Crew's independent reserves evaluator at year end 2018. The four "B" zone wells produced average sales of 839 boe per day, comprised of 40% condensate and 12% ngl, over the first 210 days on production[2].

- At Crew's 4-21 pad in the UCR transition zone, results have also exceeded management's initial expectations. The wells have produced average sales of 896 boe per day over the first 180 days on production, including 25% condensate and 13% ngl, despite being restricted for the first two months on production[2].

- As a result of the outperformance of these condensate-rich wells at Greater Septimus, Crew has been able to optimize our commodity mix. During Q3 we were able to meet forecast production guidance while shutting in dry gas due to low prices.

Greater Septimus

Production & Drilling	**Q3 2019**	Q2 2019	Q1 2019	Q4 2018	Q3 2018
Average daily production (boe/d)	**19,648**	19,594	19,535	18,447	19,240
Wells drilled (gross / net)	**-**	1 / 1.0	6 / 6.0	6 / 6.0	4 / 4.0
Wells completed (gross / net)	**1 / 1.0**	-	8 / 8.0	3 / 3.0	-

Operating Netback ($ per boe)	**Q3 2019**	Q2 2019	Q1 2019	Q4 2018	Q3 2018
Revenue	**17.38**	22.20	25.61	26.53	22.83
Royalties	**(1.04)**	(1.27)	(1.56)	(1.58)	(1.15)
Realized commodity hedge gain (loss)	**1.78**	0.28	(0.74)	(1.79)	(2.01)
Marketing income (1)	**1.55**	1.43	1.66	1.23	0.34
Net operating costs(2)	**(4.41)**	(4.46)	(4.65)	(4.51)	(4.61)
Transportation costs	**(2.62)**	(2.81)	(1.73)	(1.35)	(1.22)
Operating netback(3)	**12.64**	15.37	18.59	18.53	14.18

Notes:
(1) Marketing income was recognized from the monetization of forward physical sales contracts offset by the cost of committed natural gas transportation.
(2) Net operating costs are calculated as gross operating costs less processing revenue.
(3) Non-IFRS Measure. 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:** After being shut-in for offsetting completion operations for most of Q2/19, volumes at Tower in Q3/19 returned to similar productivity levels realized prior to the shut-in. Crew continues to evaluate the relative economics of Tower development as well as reviewing encouraging nearby Lower Montney well results.

[2] Total volumes at the 15-20 and 4-21 pad are estimated from average gas and condensate shrinkage, process recovery and the exclusion of low volume days during cleanup.

- **Monias:** Activity at Monias during Q3 was directed to the completion of one horizontal Montney delineation well that is currently being tested and evaluated.

- **Attachie:** Of Crew's 90 net sections of land in this area, approximately 44 net 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 of 2019 and another is planned in 2020, which is expected to conclude the lease preservation program in this area.

- **Oak / Flatrock:** In this liquids-rich gas area, Crew has more than 60 (52 net) sections of land, and the Company plans to continue monitoring industry activity and offsetting well results which have been encouraging.

AB / SK Heavy Oil - Lloydminster

- During Q3, activity at Lloydminster included the recompletion of eight (8.0 net) heavy crude oil wells which contributed to average production of 1,627 bbls per day of heavy crude oil, 5% lower than the prior quarter and 10% lower relative to Q3/18, reflecting limited capital investment in the area.

- Relative to Q3/18, Crew's realized heavy crude oil price increased 4% due to the lower cost of diluent needed to blend with the heavy crude oil, while the WCS benchmark price decreased 5% in the period. This price improvement contributed to Q3 operating netbacks at Lloydminster which averaged $17.56 per boe. To maximize profitability, Crew will continue to evaluate forward pricing for WCS for the purposes of optimizing execution timing of a one to three well multilateral horizontal drilling program.

OUTLOOK

Value Creation and Value Preservation Intact

- Crew's strategy of maximizing value over volume growth has led to the successful realization of increased margins through replacement of natural gas volumes with condensate production growth.

- The Company's emphasis on UCR drilling along with our goal of improving margins is proving successful. Condensate volumes in Q3 increased 24% year-over-year while Crew's average condensate price of $62.19 per bbl was materially higher than the average corporate realized price per boe of $19.81. Ngl prices continued to be very weak, averaging only $0.57 per bbl in Q3/19 versus $28.15 per bbl in Q3/18.

Sustainability Continues to Improve

- At Septimus, Crew is successfully generating an operating netback that exceeds maintenance capital requirements for the area. As a result of Crew's investment in the area, production declines for Septimus are under 15%, representing similar performance attributes to a tight conventional reservoir. The Company has estimated the base decline rate in the West Septimus area to now be approximately 18%, further improving the sustainability of our entire Montney production base.

- Crew plans to replicate the development success and free cash flow generation realized first at Septimus and now at West Septimus within our UCR area, which has over 135 potential drilling opportunities[3], representing over ten years of highly economic future growth at Crew's current pace of development.

Capital Expenditures to Approximate AFF through First Half 2020

- Responding to advantageous Q4/19 operational and cost efficiencies, as well as favorable winter commodity prices, Crew's Board of Directors have approved a re-allocated capital expenditure budget of $54 million for the next three quarters, including Q4/19, Q1/20 and Q2/20. Crew anticipates investing approximately $28 to $32 million in Q4/19, $14 to $18 million in Q1/20 and $6 to $10 million in Q2/20, to generate average production of 22,000 and 23,000 boe per day through this period. For comparative purposes, over the same nine month period in Q4/18 and the first half of 2019, Crew invested $102 million. The Company continues to prioritize financial flexibility and as a result, if this level of capital spending does not approximate AFF, Crew would further refine its capital spending plans to align with its goal of

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

maintaining current debt levels. The Company plans on releasing its full year 2020 capital investment budget and production guidance in Q1/20.

- Four drilled but uncompleted wells on our 3-32 pad were originally planned for completion in Q1/20 and are now planned to be completed in Q4/19, consistent with our revised capital allocation timing. Crew has been able to secure the required services to complete this operation at compelling rates, allowing the Company to achieve more with lower capital while producing at higher rates into a period with forward curve commodity prices that are expected to be over 40% higher on average than the forward curve for Q2 and Q3/20. Our analysis indicates that completing these wells in Q4/19 rather than Q1/20 can enhance individual well rates of return and meaningfully impact 2020 AFF.

- Crew's net 2019 capital expenditure budget is expected to range between $95 and $100 million (exploration and development spending of between $114 and $119 million). Average volumes are forecast to be between 22,500 to 23,000 boe per day, with a steady focus on increasing the weighting of higher valued condensate and oil within Crew's production portfolio.

- For Q4 2019, production is expected to average between 22,000 and 22,500 boe per day on capital expenditures of between $28 and $32 million. Quarterly volume forecasts incorporate the Company's planned deferral of dry gas production that is exposed to weak Station 2 gas prices and the shut-in of production for offsetting completion operations. Activity during Q4/19 will focus on the completion and equipping of four UCR ERH Montney wells and water-handling initiatives.

Diversified Market Access and Positioned for Low-Cost Growth

- With access to differentiated sales points in North America, three major export pipelines and close proximity to the Coastal Gas Link Pipeline, Crew's land base is ideally located to move gas to advantageously-priced markets in addition to having the potential to significantly reduce transportation costs as a supply source for LNG.

- Crew's continuous investment in infrastructure has positioned the Company with capacity to produce over 40,000 boe per day, providing future growth opportunities at reduced costs.

Innovation Leads to Improved Safety and Reduced Emissions

- Crew's relentless pursuit to continuously improve has led to a 52% reduction in gas plant flaring intensity from 2015 to 2018. The Company has also transitioned to testing new wells directly into pipelines which has led to a reduction in flaring of over 85% from 2017, equivalent to removing 120 passenger vehicles from the road annually.

- Over 95% recycled water was used during our completion operations in 2018, significantly reducing the amount of fresh water used.

- By building pipelines to pad sites prior to drilling, Crew is able to fuel our drilling operations with natural gas rather than diesel, thereby reducing CO_2 emissions by 20% and saving approximately $80,000 per well. By using the same pipeline, the Company can deliver water for fracturing operations to the pad site. In our last 11 well completions, this practice resulted in 1,286 truckloads being removed from the road and saving the Company $275,000, while also significantly reducing the risk of vehicular accidents.

We thank our employees and directors for their commitment and dedication to the success of Crew, particularly in light of insiders now constituting 10 of the top 20 shareholders of the Company. We would also like to thank all of our shareholders and bondholders for their patience and support in this challenging environment.

Cautionary Statements

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

*Unless otherwise specified, all reserves volumes 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. 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. 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 deficiency (surplus)" 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 Q4 and the first half of 2020 and the potential refinement of those plans; as to plans to internally fund capital in 2019 and 2020 with adjusted funds flow and to maintain net debt at current levels; 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; the estimated volumes, including shut-ins, and product mix of Crew's oil and gas production; production estimates including Q4, annual 2019 and first half of 2020 average production guidance; Crew's currently estimated base decline profile of approximately 18% at West Septimus; commodity price expectations including the potential for materially higher natural gas prices this winter and Crew's estimates of natural gas pricing exposure and market allocation; Crew's commodity risk management programs; marketing and transportation plans; future liquidity *and financial capacity; future results from operations and operating metrics; potential for lower on-stream 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; the Company's potential to capitalize on an LNG project; and future production capability 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 Greater Septimus area features an Ultra Condensate-Rich ("UCR") zone, which offers significant development and value creation 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 and nine month periods ended September 30, 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 September 30, 2019 unaudited condensed interim consolidated financial statements are reported in Canadian dollars ("CDN"). This MD&A is dated November 1, 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 fourth quarter 2019, annual 2019 and first half 2020 capital budget encompassing anticipated 2019 net capital expenditures (after dispositions) and first and second quarter 2020 capital expenditures, timing of capital expenditures and methods of financing capital expenditures and the ability to fund financial liabilities, production estimates including fourth 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 and expected debt levels, funds from operations and the timing of and impact of implementing accounting policies, expectations in regards to the Company's credit facilities, 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 crude oil, condensate, other natural gas liquids ("ngl") 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 the 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 Sept. 30, 2019**	Three months ended Sept. 30, 2018	**Nine months ended Sept. 30, 2019**	Nine months ended Sept. 30, 2018
Cash provided by operating activities	**8,877**	19,095	**60,289**	66,284
Change in operating non-cash working capital	**7,272**	1,127	**2,018**	1,820
Accretion of deferred financing costs	**(246)**	(259)	**(737)**	(777)
Funds from operations	**15,903**	19,963	**61,570**	67,327
Decommissioning obligations settled	**761**	144	**3,378**	957
Adjusted funds flow	**16,664**	20,107	**64,948**	68,284

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)	**September 30, 2019**	December 31, 2018
Current assets	**30,956**	78,904
Current liabilities	**(28,337)**	(58,538)
Derivative financial instruments	**(6,190)**	(8,382)
Working capital (deficiency) surplus	**(3,571)**	11,984

($ thousands)	**September 30, 2019**	December 31, 2018
Bank loan	**(56,864)**	(59,904)
Senior unsecured notes	**(295,622)**	(294,885)
Working capital (deficiency) surplus	**(3,571)**	11,984
Net debt	**(356,057)**	(342,805)

RESULTS OF OPERATIONS

Production

	Three months ended September 30, 2019					Three months ended September 30, 2018				
	Oil (bbl/d)	**Condensate (bbl/d)**	**Ngl (bbl/d)**	**Nat. gas (mcf/d)**	**Total (boe/d)**	Oil (bbl/d)	Condensate (bbl/d)	Ngl (bbl/d)	Nat. gas (mcf/d)	Total (boe/d)
NE BC	**233**	**2,575**	**2,148**	**97,372**	**21,185**	269	2,077	1,711	106,821	21,861
Lloydminster	**1,627**	**-**	**-**	**71**	**1,639**	1,819	-	-	-	1,819
Total	**1,860**	**2,575**	**2,148**	**97,443**	**22,824**	2,088	2,077	1,711	106,821	23,680

During the third quarter of 2019, production decreased 4% over the same period in 2018 as a result of a third party processing facility outage and voluntary shut-ins of natural gas wells, with lower liquids content, in northeast British Columbia ("NE BC") due to low natural gas pricing. This was coupled with a decline in production in the Lloydminster area stemming from natural declines and limited capital investment. The decline was partially offset by increased condensate and ngl production in the liquids-rich West Septimus area where the Company completed new wells in the first quarter of 2019.

	Nine months ended September 30, 2019					Nine months ended September 30, 2018				
	Oil (bbl/d)	**Condensate (bbl/d)**	**Ngl (bbl/d)**	**Nat. gas (mcf/d)**	**Total (boe/d)**	Oil (bbl/d)	Condensate (bbl/d)	Ngl (bbl/d)	Nat. gas (mcf/d)	Total (boe/d)
NE BC	**205**	**2,773**	**2,071**	**97,556**	**21,308**	282	2,358	1,738	109,099	22,561
Lloydminster	**1,653**	**-**	**-**	**52**	**1,662**	1,832	-	-	-	1,832
Total	**1,858**	**2,773**	**2,071**	**97,608**	**22,970**	2,114	2,358	1,738	109,099	24,393

For the first nine months of 2019, production decreased 6% as compared to the same period in 2018, as a result of production declines, voluntary shut-ins of natural gas wells, pipeline outages in the second quarter of 2019 and the aforementioned third party facility outage in NE BC. These declines were partially offset by new production added from condensate-rich wells completed in West Septimus in the first quarter of 2019.

Petroleum and Natural Gas Sales

	Three months ended Sept. 30, 2019	Three months ended Sept. 30, 2018	**Nine months ended Sept. 30, 2019**	Nine months ended Sept. 30, 2018
Petroleum and natural gas sales ($ thousands)				
Light crude oil	**1,368**	1,935	**3,544**	5,670
Heavy crude oil	**7,911**	8,538	**23,719**	23,988
Natural gas liquids	**112**	4,430	**3,484**	12,422
Condensate	**14,734**	15,563	**48,999**	50,839
Natural gas	**17,472**	23,614	**68,845**	74,628
Total	**41,597**	54,080	**148,591**	167,547
Crew average prices				
Light crude oil ($/bbl)	**63.81**	78.25	**63.39**	73.75
Heavy crude oil ($/bbl)	**52.86**	51.03	**52.58**	47.96
Natural gas liquids ($/bbl)	**0.57**	28.15	**6.16**	26.19
Condensate ($/bbl)	**62.19**	81.45	**64.73**	78.99
Natural gas ($/mcf)	**1.95**	2.40	**2.58**	2.51
Oil equivalent ($/boe)	**19.81**	24.82	**23.70**	25.16
Benchmark pricing				
Light crude oil – Cdn$ WTI (Cdn $/bbl)	**74.55**	90.85	**75.85**	86.01
Heavy crude oil – WCS (Cdn $/bbl)	**58.45**	61.81	**60.33**	57.93
Condensate – Condensate @ Edmonton (Cdn $/bbl)	**68.49**	87.49	**70.36**	85.36
Natural Gas:				
AECO 5A daily index (Cdn $/mcf)	**0.91**	1.19	**1.52**	1.48
AECO 7A monthly index (Cdn $/mcf)	**1.04**	1.35	**1.39**	1.41
Alliance 5A (Cdn $/mcf)	**0.99**	1.87	**1.67**	1.99
Chicago City Gate at ATP (Cdn $/mcf)	**2.02**	2.92	**2.58**	2.88
Henry Hub Close (Cdn $/mcf)	**2.94**	3.80	**3.55**	3.73

In the third quarter of 2019, the Company's petroleum and natural gas sales decreased 23% as compared to the same period in 2018, as a result of the 4% decrease in production, coupled with realized wellhead pricing during the quarter.

The Company's realized light crude oil price decreased 18%, which is consistent with the 18% decrease in the Company's Cdn$ West Texas Intermediate ("WTI") benchmark price from the same period last year. Crew's third quarter heavy crude oil price increased 4%, which trended opposite to the 5% decrease in the Company's WCS benchmark, a result of a decrease in the cost of diluent purchased to blend with the heavy crude oil as compared to the same period last year. The ngl realized price decreased 98% in the third quarter as compared to the same period in 2018 due to a decrease in component pricing, in particular a large decline in realized propane and butane pricing. Crew's ngl pricing includes embedded cost to process the ngl product out of the Company's gas stream, which occurs after the custody transfer point. The cost of processing cannot exceed the price of the extracted product. During the third quarter, the revenue earned from the sale of the extracted ngl product was only slightly above the cost of the extraction due to low product pricing. The Company's third quarter realized condensate price decreased 24% over the same period in 2018, which approximated the 22% decrease in the Condensate at Edmonton benchmark price.

Crew's realized natural gas price decreased 19% in the third quarter of 2019, which is lower than the 5% decrease in the Company's natural gas sales portfolio weighted benchmark price. The variance was the result of Crew's gas sold at Chicago City Gate and Henry Hub prices being physically sold at the Alliance Trading Pool in Canada, where it is bought by third parties at a Chicago City Gate or Henry Hub market price less a fixed cost to transport the product to the end market. As the fixed cost is embedded in the price, the impact of a fluctuating price, as compared to benchmark pricing, is enhanced.

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 third quarter 2019 natural gas sales portfolio was based approximately on the following reference prices:

	Q3 2019	Q3 2018
AECO 5A	**6%**	23%
AECO 7A	**-**	14%
Alliance 5A	**20%**	19%
Chicago City Gate at ATP	**56%**	36%
Henry Hub	**16%**	-
Station 2	**2%**	4%
Sumas	**-**	4%
Total	**100%**	100%

The Company's revenue for the first nine months of 2019 decreased 11% over same period in 2018, as a result of the 6% decrease in production combined with a 6% decline in realized wellhead pricing.

The Company's realized light crude oil price decreased 14%, which approximated the 12% decrease in the Company's WTI benchmark. Crew's heavy crude oil price for the first nine months of 2019 increased 10%, which is higher than the 4% increase in the Company's WCS benchmark, as a result of a decrease in the cost of diluent purchased to blend with the heavy crude oil as compared to the same period last year. In the first nine months of 2019, the Company's ngl realized price decreased 76% over the same period in 2018, due to the aforementioned decreases in component pricing at the Company's primary pricing point. The Company's realized condensate price decreased 18%, which was consistent with the 18% decrease in the Condensate at Edmonton benchmark price for the same period last year.

The Company's natural gas price increased 3% over the first nine months of 2018, which is lower than the Company's natural gas sales portfolio weighted benchmark price increase of 14%, due to the aforementioned fixed transportation costs embedded in the price received for a portion of the Company's natural gas sales.

Royalties

($ thousands, except per boe)	**Three months ended Sept. 30, 2019**	Three months ended Sept. 30, 2018	**Nine months ended Sept. 30, 2019**	Nine months ended Sept. 30, 2018
Royalties	**3,126**	3,764	**10,682**	11,690
Per boe	**1.49**	1.73	**1.70**	1.76
Percentage of petroleum and natural gas sales	**7.5%**	7.0%	**7.2%**	7.0%

For the third quarter and first nine months of 2019, royalties and royalties per boe decreased over the same period in 2018, predominantly due to a decrease in realized wellhead pricing, coupled with a decline in Lloydminster heavy crude oil production, which yields a higher royalty rate than the corporate average. Royalties as a percentage of petroleum and natural gas sales increased in both the third quarter and first nine months of 2019, as a result of a prior period adjustment related to the Company's NE BC royalty assessments. The Company expects its royalties as a percentage of revenue to average between 6% and 8% in 2019.

Derivative Financial Instruments

Commodities

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

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

($ thousands)	**Three months ended Sept. 30, 2019**	Three months ended Sept. 30, 2018	**Nine months ended Sept. 30, 2019**	Nine months ended Sept. 30, 2018
Realized gain (loss) on derivative financial instruments	**2,893**	(4,545)	**731**	(9,354)
Per boe	**1.38**	(2.09)	**0.12**	(1.40)
Unrealized gain (loss) on financial instruments	**579**	1,133	**(1,123)**	(17,421)

At September 30, 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	October 1, 2019 – October 31, 2019	CDN$ Chicago Citygate	$3.44/mmbtu	Swap	$ 51
Gas	2,500 mmbtu/day	October 1, 2019 – October 31, 2019	CDN$ Dawn Daily Index	$3.52/mmbtu	Swap	77
Gas	2,500 mmbtu/day	October 1, 2019 – October 31, 2019	US$ Nymex Henry Hub	$2.85/mmbtu	Swap	103
Gas	22,500 mmbtu/day	October 1, 2019 – December 31, 2019	CDN$ Chicago Citygate	$3.54/mmbtu	Swap	1,083
Gas	5,000 mmbtu/day	October 1, 2019 – December 31, 2019	CDN$ Dawn Daily Index	$3.56/mmbtu	Swap	296
Gas	7,500 mmbtu/day	October 1, 2019 – December 31, 2019	US$ Nymex Henry Hub	$2.98/mmbtu	Swap	410
Gas	7,500 mmbtu/day	January 1, 2020 – December 31, 2020	CDN$ Chicago Citygate	$3.40/mmbtu	Swap	815
Oil	2,000 bbl/day	October 1, 2019 – December 31, 2019	CDN$ WTI	$76.19/bbl	Swap	904
Oil	500 bbl/day	October 1, 2019 – December 31, 2019	CDN$ WCS – WTI Differential	($25.23)/bbl	Swap	(373)
Oil	500 bbl/day	October 1, 2019 – December 31, 2019	CDN$ WCS	$55.98/bbl	Swap	82
Oil	250 bbl/day	January 1, 2020 – June 30, 2020	CDN$ WTI	$75.50/bbl	Swap	292
Oil	250 bbl/day	January 1, 2020 – June 30, 2020	USD$ WCS – WTI Differential	($17.25)/bbl	Swap	(99)
Oil	250 bbl/day	January 1, 2020 – June 30, 2020	CDN$ WCS	$52.00/bbl	Swap	154
Oil	1,000 bbl/day	January 1, 2020 – December 31, 2020	CDN$ WTI	$77.65/bbl	Swap	3,464
Total						**$ 7,259**

Subsequent to September 30, 2019, the Company entered into the following commodity contracts:

Subject of Contract	Notional Quantity	Term	Reference	Strike Price	Option Traded
Gas	5,000 mmbtu/day	January 1, 2020 – December 31, 2020	CDN$ Chicago Citygate	$3.20/mmbtu	Swap
Gas	2,500 mmbtu/day	January 1, 2020 – December 31, 2020	US$ Nymex Henry Hub	$2.48/mmbtu	Swap

Marketing Income

($ thousands, except per boe)	**Three months ended Sept. 30, 2019**	Three months ended Sept. 30, 2018	**Nine months ended Sept. 30, 2019**	Nine months ended Sept. 30, 2018
Marketing revenue	**2,797**	1,689	**8,690**	3,887
Marketing expense	**-**	(1,137)	**(414)**	(2,062)
Marketing income	**2,797**	552	**8,276**	1,825
Per boe	**1.33**	0.25	**1.32**	0.27

In the third quarter and first nine months of 2019, the Company recognized $2.8 million and $8.3 million, respectively, of marketing income 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 TC Energy's (formerly TransCanada Pipeline) natural gas pipeline system that was not accessible until later in the first quarter of 2019.

Net Operating Costs

($ thousands, except per boe)	**Three months ended Sept. 30, 2019**	Three months ended Sept. 30, 2018	**Nine months ended Sept. 30, 2019**	Nine months ended Sept. 30, 2018
Operating costs	**13,232**	14,770	**40,472**	45,331
Processing revenue	**(756)**	(1,241)	**(2,450)**	(3,029)
Net operating costs	**12,476**	13,529	**38,022**	42,302
Per boe	**5.94**	6.21	**6.06**	6.35

During the third quarter and first nine months of 2019, net operating costs and net operating costs per boe decreased as compared to the same periods in 2018, as a result of efforts by the Company to optimize field operations and reduce costs across all operating areas, coupled with volume declines in Tower and Lloydminster production, which yield higher operating costs per boe. The Company is forecasting 2019 net operating costs to average between $6.00 and $6.25 per boe.

Transportation Costs

($ thousands, except per boe)	**Three months ended Sept. 30, 2019**	Three months ended Sept. 30, 2018	**Nine months ended Sept. 30, 2019**	Nine months ended Sept. 30, 2018
Transportation costs	**5,876**	3,529	**16,861**	12,288
Per boe	**2.80**	1.62	**2.69**	1.85

During the third quarter and first nine months of 2019, transportation costs increased compared to the same periods in 2018, as a result of the Company's new West Septimus to TC Energy's Saturn meter station natural gas sales pipeline system, which came on-line late in the first quarter of 2019, increasing the Company's exposure to diversified markets. The Company continues to forecast 2019 transportation costs to average between $2.75 and $3.00 per boe.

Operating Netbacks

($/boe)	Greater Septimus	Lloydminster Heavy Oil	Other NE BC	Three months ended Sept. 30, 2019	Three months ended Sept. 30, 2018
Petroleum and natural gas sales	**17.38**	**52.50**	**16.05**	**19.81**	24.82
Royalties	**(1.04)**	**(7.86)**	**(0.41)**	**(1.49)**	(1.73)
Realized commodity hedging gain (loss)	**1.78**	**(3.94)**	**1.87**	**1.38**	(2.09)
Marketing income	**1.55**	**-**	**-**	**1.33**	0.25
Net operating costs	**(4.41)**	**(22.53)**	**(7.74)**	**(5.94)**	(6.21)
Transportation costs	**(2.62)**	**(0.61)**	**(7.40)**	**(2.80)**	(1.62)
Operating netbacks	**12.64**	**17.56**	**2.37**	**12.29**	13.42
Production (boe/d)	**19,648**	**1,639**	**1,537**	**22,824**	23,680

($/boe)	Greater Septimus	Lloydminster Heavy Oil	Other NE BC	Nine months ended Sept. 30, 2019	Nine months ended Sept. 30, 2018
Petroleum and natural gas sales	**21.69**	**52.34**	**18.85**	**23.70**	25.16
Royalties	**(1.29)**	**(7.23)**	**(1.11)**	**(1.70)**	(1.76)
Realized commodity hedging gain (loss)	**0.44**	**(4.11)**	**0.48**	**0.12**	(1.40)
Marketing income	**1.55**	**-**	**-**	**1.32**	0.27
Net operating costs	**(4.51)**	**(21.60)**	**(8.78)**	**(6.06)**	(6.35)
Transportation costs	**(2.39)**	**(0.60)**	**(8.12)**	**(2.69)**	(1.85)
Operating netbacks	**15.49**	**18.80**	**1.32**	**14.69**	14.07
Production (boe/d)	**19,593**	**1,662**	**1,715**	**22,970**	24,393

For the third quarter of 2019, the Company's operating netback decreased 8% over the same period in 2018, as a result of decreases in wellhead pricing and increased transportation costs, partially offset by reductions in royalties, hedging gains, net operating costs and increased marketing income. For the first nine months of 2019, the Company's operating netbacks increased 4% over the same period in 2018, as a result of increases in marketing income and hedging gains, lower net operating costs and royalties, partially offset by reductions in wellhead pricing and higher transportation costs.

General and Administrative Cost

($ thousands, except per boe)	Three months ended Sept. 30, 2019	Three months ended Sept. 30, 2018	Nine months ended Sept. 30, 2019	Nine months ended Sept. 30, 2018
Gross costs	**4,396**	4,648	**13,526**	14,017
Operator's recoveries	**(16)**	(196)	**(53)**	(652)
Capitalized costs	**(1,526)**	(1,422)	**(4,575)**	(4,462)
General and administrative expenses	**2,854**	3,030	**8,898**	8,903
Per boe	**1.36**	1.39	**1.42**	1.34

Gross and net general and administrative ("G&A") costs decreased in both the third quarter of 2019 and nine months ended September 30, 2019 as compared to the same periods in 2018, mainly due to the impact from the adoption of IFRS 16, where a portion of the Company's head office lease is no longer charged to G&A, partially offset by a decrease in operator's recoveries as a result of reduced capital spending on partnered wells. The decrease in G&A costs per boe in the third quarter of 2019 is mainly due to the aforementioned impact from the adoption of IFRS 16, partially offset by a decrease in production as compared to the same period in 2018. The increase in G&A costs per boe in the nine months ended September 30, 2019 is mainly due to a decrease in production and operator's recoveries 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.

Share-Based Compensation

($ thousands)	**Three months ended Sept. 30, 2019**	Three months ended Sept. 30, 2018	**Nine months ended Sept. 30, 2019**	Nine months ended Sept. 30, 2018
Gross costs	**2,189**	4,184	**8,050**	10,027
Capitalized costs	**(1,042)**	(1,975)	**(3,839)**	(4,766)
Total share-based compensation	**1,147**	2,209	**4,211**	5,261

In the third quarter of 2019 and nine months ended September 30, 2019, the Company's total share-based compensation expense decreased as compared to the same periods in 2018, mainly due to the lower value of share-based compensation granted in 2019 as compared to 2018.

Depletion and Depreciation

($ thousands, except per boe)	**Three months ended Sept. 30, 2019**	Three months ended Sept. 30, 2018	**Nine months ended Sept. 30, 2019**	Nine months ended Sept. 30, 2018
Depletion and depreciation	**19,308**	18,215	**57,420**	58,914
Per boe	**9.20**	8.36	**9.16**	8.85

Depletion and depreciation costs per boe increased in both the third quarter of 2019 and nine months ended September 30, 2019 as compared to the same periods in 2018, due to an increase in future development costs associated with additional liquids reserves bookings at the end of 2018 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. In addition, for the third quarter of 2019, the Company had higher land expiries as compared to the same period in 2018, which contributed to the increase in depletion and depreciation costs and depletion and depreciation costs per boe.

Finance Expenses

($ thousands, except per boe)	**Three months ended Sept. 30, 2019**	Three months ended Sept. 30, 2018	**Nine months ended Sept. 30, 2019**	Nine months ended Sept. 30, 2018
Interest on bank loan and other	**1,123**	954	**2,858**	2,189
Interest on senior notes	**4,915**	4,915	**14,585**	14,585
Accretion of deferred financing charges	**246**	259	**737**	777
Accretion of the decommissioning obligation	**466**	488	**1,439**	1,467
Total finance expense	**6,750**	6,616	**19,619**	19,018
Average long-term debt level	**352,128**	349,948	**351,022**	343,659
Average drawings on bank loan	**52,128**	49,948	**51,022**	43,659
Average senior unsecured notes outstanding	**300,000**	300,000	**300,000**	300,000
Effective interest rate on senior unsecured notes	**6.5%**	6.5%	**6.5%**	6.5%
Effective interest rate on long-term debt	**6.1%**	6.1%	**6.1%**	6.1%
Financing costs on long-term debt per boe	**2.99**	2.81	**2.90**	2.64

Average corporate debt levels and the associated interest charges have remained relatively consistent year-over-year, as the Company has limited net capital expenditures to approximate adjusted funds flow over the past several quarters. Crew forecasts the effective interest rate on its long-term debt to average between 6.0% and 6.5% in 2019.

Gain on Divesture of Property

During the second quarter of 2019, the Company disposed of non-core land with no associated production or assigned reserves, for gross proceeds of $3.3 million. The land consisted of petroleum and natural gas properties and undeveloped land with a net book value of $0.2 million, resulting in a gain of $3.1 million on closing of the disposition.

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.

Deferred Income Taxes

In the third quarter and first nine months of 2019, the provision for deferred tax was a recovery of $0.4 million and an expense of $2.3 million, respectively, compared to deferred tax expenses of $1.3 million and $0.7 million for the same periods in 2018. The deferred income tax recovery in the third quarter of 2019 is due to a net loss realized in the third quarter of 2019, primarily the result of lower petroleum and natural gas sales as compared to the third quarter of 2018. The increase of the deferred tax expense in the first nine months of 2019 as compared to the prior period in 2018 was the result of net income the period, resulting from a significant gain on property dispositions.

Cash, Funds from Operations and Net (Loss) Income

($ thousands, except per share amounts)		**Three months ended Sept. 30, 2019**	Three months ended Sept. 30, 2018	**Nine months ended Sept. 30, 2019**	Nine months ended Sept. 30, 2018
Cash provided by operating activities		**8,877**	19,095	**60,289**	66,284
Adjusted funds flow		**16,664**	20,107	**64,948**	68,284
Per share	- basic	**0.11**	0.13	**0.43**	0.45
	- diluted	**0.11**	0.13	**0.43**	0.45
Net (loss) income		**(3,255)**	(939)	**18,306**	(5,972)
Per share	- basic	**(0.02)**	(0.01)	**0.12**	(0.04)
	- diluted	**(0.02)**	(0.01)	**0.12**	(0.04)

In the third quarter of 2019 and nine months ended September 30, 2019, cash provided by operating activities and adjusted funds flow decreased predominantly due to lower petroleum and natural gas sales, and increased transportation costs as compared to the same periods in 2018. Cash provided by operating activities was further decreased by a negative change in non-cash working capital. Realized gains on derivative financial instruments partially offset the impact of lower prices in the third quarter of 2019 and nine months ended September 30, 2019, as compared to the same periods in 2018.

Capital Expenditures, Property Acquisitions and Dispositions

($ thousands)	**Three months ended Sept. 30, 2019**	Three months ended Sept. 30, 2018	**Nine months ended Sept. 30, 2019**	Nine months ended Sept. 30, 2018
Land	**856**	857	**2,421**	2,728
Seismic	**275**	93	**929**	751
Drilling and completions	**12,397**	13,195	**69,202**	38,695
Facilities, equipment and pipelines	**3,383**	8,019	**10,093**	22,910
Other	**1,555**	1,492	**5,059**	4,961
Total exploration and development	**18,466**	23,656	**87,704**	70,045
Net property acquisitions (dispositions)	**7**	9	**(19,166)**	(9,981)
Total	**18,473**	23,665	**68,538**	60,064

In the third quarter of 2019, the Company spent a total of $18.5 million on exploration and development expenditures, focused on the continued development of its Montney assets at West Septimus. During the quarter, $12.4 million was spent on drilling and completion activities, including the completion of one (1.0 net) well in the Monias area. The Company spent $3.4 million on well sites, facilities and pipelines and $2.7 million on land, seismic and other miscellaneous items.

The Company's Board of Directors has approved a revised exploration and development capital expenditure budget for 2019, combined with planned capital spending for the first half of 2020. The revised 2019 plan increases the 2019 exploration budget to $114 to $119 million, combined with a modest exploration and development spending plan for the first half of 2020, totalling $20 to $28 million (see Guidance section below for further details).

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 $7.6 million for a Government of British Columbia infrastructure credit earned through the completion of a pipeline connecting the West Septimus processing facility to the TC Energy 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 on its Facility to satisfy working capital requirements. At September 30, 2019, the Company's working capital deficiency of $3.6 million, when combined with the drawings on its bank loan, represented drawings of 26% on its $235 million Facility described below.

Capital Funding

Bank Loan

As at September 30, 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 4, 2020. 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. Subsequent to September 30, 2019, the Facility was reviewed and the Borrowing Base was confirmed at the existing levels. 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 November 1, 2019, there were 156,239,499 common shares of the Company issued and outstanding, which includes 4,738,496 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 3,658,072 restricted awards and 4,198,947 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 September 30, 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 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 September 30, 2019, the Company's ratio of net debt to annualized adjusted funds flow was 5.3 to 1 (December 31, 2018 – 3.6 to 1). In the current depressed and volatile commodity price environment, Crew plans to limit net capital expenditures to approximate adjusted funds flow. With only 24% drawn on the Company's $235 million Facility and the senior unsecured notes termed out to 2024, the Company's financial position remains manageable. The Company will continue to monitor this ratio and, if necessary, it will consider divesting of non-core assets, will further adjust its annual capital expenditure program or may consider other forms of financing to strengthen its financial position.

($ thousands, except ratio)	**September 30, 2019**	December 31, 2018
Working capital (deficiency) surplus (note 1)	**(3,571)**	11,984
Bank loan	**(56,864)**	(59,904)
Senior unsecured notes	**(295,622)**	(294,885)
Net debt (note 1)	**(356,057)**	(342,805)
Quarterly adjusted funds flow (note 1)	**16,664**	23,712
Annualized	**66,656**	94,848
Net debt to annualized adjusted funds flow (note 1)	**5.3**	3.6

Note 1 – Non-IFRS measures. See "Advisories – Non-IFRS Measures".

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)	56,864	-	56,864	-	-	-	-
Senior unsecured notes (note 2)	300,000	-	-	-	-	-	300,000
Lease obligations	3,672	290	290	244	-	-	2,848
Firm transportation agreements	241,189	11,806	46,826	31,596	30,982	26,961	93,018
Firm processing agreements	99,003	4,445	16,337	12,354	12,354	12,354	41,159
Total	**700,728**	**16,541**	**120,317**	**44,194**	**43,336**	**39,315**	**437,025**

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 relate primarily to the Company's commitment to a third party for the lease of office space.

Firm transportation agreements include commitments to third parties to transport condensate, ngl and natural gas 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

In order to respond to advantageous fourth quarter 2019 operational and cost efficiencies, as well as favorable winter commodity prices, the Company's Board of Directors has approved a re-allocated capital expenditure budget of $54 million covering the next three quarters, including fourth quarter 2019, first quarter 2020 and second quarter 2020. The Company anticipates investing approximately $28 to $32 million in the fourth quarter of 2019, $14 to $18 million in the first quarter of 2020 and $6 to $10 million in the second quarter of 2020. For comparative purposes, over the same nine month period in the fourth quarter of 2018 and the first half of 2019, Crew invested $102 million. The Company's net 2019 capital expenditure budget is now expected to range between $95 and $100 million after dispositions (exploration and development spending of between $114 and $119 million). The Company continues to prioritize financial flexibility and as a result, if this level of capital spending does not approximate adjusted funds flow, the Company would further refine its capital spending plans to align with our goal of maintaining current debt levels.

For the fourth quarter of 2019, production volumes are expected to average between 22,000 and 22,500 boe per day on planned capital expenditures between $28 and $32 million. Average 2019 annual production volumes are forecast between 22,500 to 23,000 boe per day, with a steady focus on increasing the weighting of higher valued condensate and liquids within Crew's production portfolio.

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)	**Sep. 30 2019**	June 30 2019	Mar. 31 2019	Dec. 31 2018	Sep. 30 2018	June 30 2018	Mar. 31 2018	Dec. 31 2017
Total daily production (boe/d)	**22,824**	22,865	23,222	22,383	23,680	23,583	25,939	25,270
Exploration and development expenditures	**18,466**	13,997	55,241	33,174	23,656	12,468	33,921	36,413
Net property acquisitions/ (dispositions)	**7**	(3,249)	(15,924)	175	9	17	(10,007)	(1,709)
Average wellhead price ($/boe)	**19.81**	24.77	26.53	24.69	24.82	25.18	25.46	25.87
Petroleum and natural gas sales	**41,597**	51,543	55,451	50,838	54,080	54,040	59,427	60,146
Cash provided by operations	**8,877**	40,879	10,533	22,878	19,095	31,304	15,885	43,484
Adjusted funds flow (note 1)	**16,664**	22,513	25,771	23,712	20,107	21,804	26,373	34,087
Per share – basic	**0.11**	0.15	0.17	0.16	0.13	0.14	0.18	0.23
– diluted	**0.11**	0.15	0.17	0.16	0.13	0.14	0.17	0.22
Net (loss) income	**(3,255)**	15,375	6,186	18,771	(939)	(9,181)	4,148	2,342
Per share – basic	**(0.02)**	0.10	0.04	0.12	(0.01)	(0.06)	0.03	0.02
– diluted	**(0.02)**	0.10	0.04	0.12	(0.01)	(0.06)	0.03	0.02

Note 1 – Non-IFRS measures. See "Advisories – Non-IFRS Measures".

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 production growth and infrastructure development in the area. The Company reduced capital spending in 2018 and 2019 as compared to 2017, due to weakening Canadian natural gas prices over the past three years. As a result, the Company's net capital expenditures, after proceeds from acquisitions and dispositions, have approximated cash flow over this period, effectively maintaining production at a consistent level.

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 assets and lease obligations relate 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 July 1, 2019 and ended on September 30, 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 November 1, 2019

CONDENSED INTERIM CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

(unaudited) (thousands)	**September 30, 2019**	December 31, 2018
Assets		
Current Assets:		
Accounts receivable	**$ 24,766**	$ 70,522
Derivative financial instruments (note 4)	**6,190**	8,382
	30,956	78,904
Derivative financial instruments (note 4)	**1,069**	-
Property, plant and equipment (note 5)	**1,417,052**	1,373,019
	$ 1,449,077	$ 1,451,923
Liabilities and Shareholders' Equity		
Current Liabilities:		
Accounts payable and accrued liabilities	**$ 28,337**	$ 58,538
Bank loan (note 6)	**56,864**	59,904
Senior unsecured notes (note 7)	**295,622**	294,885
Lease obligations (note 8)	**2,683**	-
Decommissioning obligations (note 9)	**92,765**	89,448
Deferred tax liability	**55,100**	52,798
Shareholders' Equity		
Share capital (note 10)	**1,478,143**	1,468,986
Contributed surplus	**69,608**	75,715
Deficit	**(630,045)**	(648,351)
	917,706	896,350
Subsequent event (note 4)		
Commitments (note 13)		
	$ 1,449,077	$ 1,451,923

See accompanying notes to the condensed interim consolidated financial statements.

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

(unaudited) (thousands, except per share amounts)	**Three months ended Sept. 30, 2019**	Three months ended Sept. 30, 2018	**Nine months ended Sept. 30, 2019**	Nine months ended Sept. 30, 2018
Revenue				
Petroleum and natural gas sales (note 11)	**$ 41,597**	$ 54,080	**$ 148,591**	$ 167,547
Royalties	**(3,126)**	(3,764)	**(10,682)**	(11,690)
Realized gain (loss) on derivative financial instruments	**2,893**	(4,545)	**731**	(9,354)
Unrealized gain (loss) on derivative financial instruments	**579**	1,133	**(1,123)**	(17,421)
Other revenue (note 11)	**3,553**	2,930	**11,140**	7,916
	45,496	49,834	**148,657**	136,998
Expenses				
Operating	**13,232**	14,770	**40,472**	45,331
Transportation	**5,876**	3,529	**16,861**	12,288
Marketing	**-**	1,137	**414**	2,062
General and administrative	**2,854**	3,030	**8,898**	8,903
Share-based compensation	**1,147**	2,209	**4,211**	5,261
Depletion and depreciation (note 5)	**19,308**	18,215	**57,420**	58,914
	42,417	42,890	**128,276**	132,759
Income from operations	**3,079**	6,944	**20,381**	4,239
Financing (note 12)	**6,750**	6,616	**19,619**	19,018
Gain on divestiture of property, plant and equipment (note 5)	**-**	-	**(19,846)**	(9,546)
(Loss) income before income taxes	**(3,671)**	328	**20,608**	(5,233)
Deferred tax (recovery) expense	**(416)**	1,267	**2,302**	739
Net (loss) income and comprehensive (loss) income	**$ (3,255)**	$ (939)	**$ 18,306**	$ (5,972)
Net (loss) income per share (note 10)				
Basic	**$ (0.02)**	$ (0.01)	**$ 0.12**	$ (0.04)
Diluted	**$ (0.02)**	$ (0.01)	**$ 0.12**	$ (0.04)

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	-	-	-	18,306	18,306
Share-based compensation expensed	-	-	4,211	-	4,211
Share-based compensation capitalized	-	-	3,839	-	3,839
Issued from treasury on vesting of share awards	4,509	14,096	(14,096)	-	-
Released from trust on vesting of share awards	26	61	(61)	-	-
Purchase of shares held in trust (note 10)	(4,783)	(5,000)	-	-	(5,000)
Balance, September 30, 2019	**151,482**	**$ 1,478,143**	**$ 69,608**	**$ (630,045)**	**$ 917,706**

(unaudited) (thousands)	Number of shares	Share capital	Contributed surplus	Deficit	Total Shareholders' equity
Balance, January 1, 2018	149,328	$ 1,458,086	$ 73,158	$ (661,150)	$ 870,094
Net loss for the period	-	-	-	(5,972)	(5,972)
Share-based compensation expensed	-	-	5,261	-	5,261
Share-based compensation capitalized	-	-	4,766	-	4,766
Issued on vesting of share awards	2,402	10,900	(10,900)	-	-
Tax deduction on excess value of share awards	-	-	9	-	9
Balance, September 30, 2018	**151,730**	**$ 1,468,986**	**$ 72,294**	**$ (667,122)**	**$ 874,158**

See accompanying notes to the condensed interim consolidated financial statements.

CONDENSED INTERIM CONSOLIDATED STATEMENTS OF CASH FLOWS

(unaudited) (thousands)	**Three months ended Sept. 30, 2019**	Three months ended Sept. 30, 2018	**Nine months ended Sept. 30, 2019**	Nine months ended Sept. 30, 2018
Cash provided by (used in):				
Operating activities:				
Net (loss) income	**$ (3,255)**	$ (939)	**$ 18,306**	$ (5,972)
Adjustments:				
Unrealized (gain) loss on derivative financial instruments	**(579)**	(1,133)	**1,123**	17,421
Share-based compensation	**1,147**	2,209	**4,211**	5,261
Depletion and depreciation (note 5)	**19,308**	18,215	**57,420**	58,914
Financing expenses (note 12)	**6,750**	6,616	**19,619**	19,018
Interest expense (note 12)	**(6,045)**	(5,869)	**(17,450)**	(16,774)
Gain on divestiture of property, plant and equipment (note 5)	**-**	-	**(19,846)**	(9,546)
Deferred tax (recovery) expense	**(416)**	1,267	**2,302**	739
Decommissioning obligations settled (note 9)	**(761)**	(144)	**(3,378)**	(957)
Change in non-cash working capital	**(7,272)**	(1,127)	**(2,018)**	(1,820)
	8,877	19,095	**60,289**	66,284
Financing activities:				
Increase (decrease) in bank loan	**8,466**	(5,486)	**(3,040)**	27,340
Payments on lease obligations (note 8)	**(272)**	-	**(809)**	-
Shares purchased and held in trust (note 10)	**(421)**	-	**(5,000)**	-
	7,773	(5,486)	**(8,849)**	27,340
Investing activities:				
Property, plant and equipment expenditures (note 5)	**(18,466)**	(23,656)	**(87,704)**	(68,704)
Property acquisitions (note 5)	**(7)**	(9)	**(1,583)**	(26)
Property dispositions (note 5)	**-**	-	**20,749**	10,007
Change in non-cash working capital	**1,823**	10,056	**17,098**	(34,901)
	(16,650)	(13,609)	**(51,440)**	(93,624)
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 and nine months ended September 30, 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 November 1, 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 assets and lease obligations relate 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.

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. Lease 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 September 30, 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	October 1, 2019 – October 31, 2019	CDN$ Chicago Citygate	$3.44/mmbtu	Swap	$ 51
Gas	2,500 mmbtu/day	October 1, 2019 – October 31, 2019	CDN$ Dawn Daily Index	$3.52/mmbtu	Swap	77
Gas	2,500 mmbtu/day	October 1, 2019 – October 31, 2019	US$ Nymex Henry Hub	$2.85/mmbtu	Swap	103
Gas	22,500 mmbtu/day	October 1, 2019 – December 31, 2019	CDN$ Chicago Citygate	$3.54/mmbtu	Swap	1,083
Gas	5,000 mmbtu/day	October 1, 2019 – December 31, 2019	CDN$ Dawn Daily Index	$3.56/mmbtu	Swap	296
Gas	7,500 mmbtu/day	October 1, 2019 – December 31, 2019	US$ Nymex Henry Hub	$2.98/mmbtu	Swap	410
Gas	7,500 mmbtu/day	January 1, 2020 – December 31, 2020	CDN$ Chicago Citygate	$3.40/mmbtu	Swap	815
Oil	2,000 bbl/day	October 1, 2019 – December 31, 2019	CDN$ WTI	$76.19/bbl	Swap	904
Oil	500 bbl/day	October 1, 2019 – December 31, 2019	CDN$ WCS – WTI Differential	($25.23)/bbl	Swap	(373)
Oil	500 bbl/day	October 1, 2019 – December 31, 2019	CDN$ WCS	$55.98/bbl	Swap	82
Oil	250 bbl/day	January 1, 2020 – June 30, 2020	CDN$ WTI	$75.50/bbl	Swap	292
Oil	250 bbl/day	January 1, 2020 – June 30, 2020	USD$ WCS – WTI Differential	($17.25)/bbl	Swap	(99)
Oil	250 bbl/day	January 1, 2020 – June 30, 2020	CDN$ WCS	$52.00/bbl	Swap	154
Oil	1,000 bbl/day	January 1, 2020 – December 31, 2020	CDN$ WTI	$77.65/bbl	Swap	3,464
Total						**$ 7,259**

Subsequent to September 30, 2019, the Company entered into the following commodity contracts:

Subject of Contract	Notional Quantity	Term	Reference	Strike Price	Option Traded
Gas	5,000 mmbtu/day	January 1, 2020 – December 31, 2020	CDN$ Chicago Citygate	$3.20/mmbtu	Swap
Gas	2,500 mmbtu/day	January 1, 2020 – December 31, 2020	US$ Nymex Henry Hub	$2.48/mmbtu	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 September 30, 2019, the Company's ratio of net debt to annualized adjusted funds flow was 5.3 to 1 (December 31, 2018 – 3.6 to 1). In the current depressed and volatile commodity price environment, Crew plans to limit net capital expenditures to approximate adjusted funds flow. With only 24% drawn on the Company's $235 million Facility and the senior unsecured notes termed out to 2024, the Company's financial position remains manageable. The Company will continue to monitor this ratio and, if necessary, it will consider divesting of non-core assets, will further adjust its annual capital expenditure program or may consider other forms of financing to strengthen its financial position.

		September 30, 2019		December 31, 2018
Net debt:				
Accounts receivable	**$**	**24,766**	$	70,522
Accounts payable and accrued liabilities		**(28,337)**		(58,538)
Working capital (deficiency) surplus	**$**	**(3,571)**	$	11,984
Bank loan		**(56,864)**		(59,904)
Senior unsecured notes		**(295,622)**		(294,885)
Net debt	**$**	**(356,057)**	$	(342,805)
Quarterly annualized adjusted funds flow:				
Cash provided by operating activities	**$**	**8,877**	$	22,878
Change in non-cash working capital		**7,272**		843
Accretion of deferred financing charges		**(246)**		(246)
Decommissioning obligations settled		**761**		237
Quarterly adjusted funds flow	**$**	**16,664**	$	23,712
Annualized	**$**	**66,656**	$	94,848
Net debt to annualized adjusted funds flow		**5.3**		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		87,704
Acquisitions		1,583
Increase in right-of-use assets		3,974
Divestitures		(1,212)
Change in decommissioning obligations		5,256
Capitalized share-based compensation		3,839
Balance, September 30, 2019	**$**	**2,625,125**

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		57,420
Divestitures		(309)
Balance, September 30, 2019	**$**	**1,208,073**

Net book value		Total
Balance, September 30, 2019	**$**	**1,417,052**
Balance, December 31, 2018	$	1,373,019

The calculation of depletion and depreciation expense for the nine months ended September 30, 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 $155.8 million (December 31, 2018 - $159.3 million) related to future development acreage with no associated reserves.

Included in depletion and depreciation expense for the nine months ended September 30, 2019, is $0.8 million related to the right-of-use assets for the Company's leases. As at September 30, 2019, the net book value of these right-of-use assets is $3.1 million.

During the second quarter of 2019, the Company disposed of non-core land with no associated production or assigned reserves, for gross proceeds of $3.3 million. The land consisted of petroleum and natural gas properties and undeveloped land with a net book value of $0.2 million, resulting in a gain of $3.1 million on closing of the disposition.

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 September 30, 2019, and therefore an impairment test was not performed.

6. Bank loan:

As at September 30, 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 4, 2020. 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. Subsequent to September 30, 2019, the Facility was reviewed and the Borrowing Base was confirmed at the existing levels. 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 September 30, 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 September 30, 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 September 30, 2019, the carrying value of the 2024 Notes was net of deferred financing costs of $4.4 million (December 31, 2018 – $5.1 million).

8. Lease obligations:

		As at September 30, 2019
Less than 1 year	$	**580**
1 – 3 years		**61**
After 3 years		**3,031**
Total undiscounted future lease payments	$	**3,672**
Future interest payments		**(514)**
Change in estimated future cash outflows	$	**3,158**
Current portion of lease obligations, included in accounts payable and accrued liabilities		**(475)**
Long-term portion of lease obligations	$	**2,683**

		Nine months ended September 30, 2019
Principal payments	$	**809**
Interest payments		**72**
Total cash outflow	$	**881**

The Company's total undiscounted future lease payments of $3.7 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 the Company does not control the asset or receive substantially all of the asset's economic benefits.

9. Decommissioning obligations:

		Nine months ended September 30, 2019		Year ended December 31, 2018
Decommissioning obligations, beginning of period	$	**89,448**	$	88,368
Obligations incurred		**3,047**		1,523
Obligations settled		**(3,378)**		(1,194)
Obligations divested		**-**		(414)
Change in estimated future cash outflows		**2,209**		(793)
Accretion of decommissioning obligations		**1,439**		1,958
Decommissioning obligations, end of period	$	**92,765**	$	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 $92.8 million as at September 30, 2019 (December 31, 2018 – $89.4 million) based on an inflation adjusted undiscounted total future liability of $119.2 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 2022 and 2037. 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% (December 31, 2018 – 2.13%). The $2.2 million (December 31, 2018 – $0.8 million) change in estimated future cash outflows for the nine months ended September 30, 2019 is a result of a change in future estimated undiscounted abandonment costs and a change in the discount factor.

10. Share capital:

At September 30, 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.

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 nine months ended September 30, 2019, the trustee purchased 4,783,000 common shares for a total cost of $5.0 million and as at September 30, 2019, holds 4,757,000 common shares in trust.

Upon the vesting of 1,430,000 RAs and 2,021,000 PAs, when taking into account the earned multipliers for PAs, 4,509,000 common shares of the Company were issued from treasury and 26,000 common shares were released from trust in settlement of such awards for the nine months ended September 30, 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	1,825	2,050
Vested	(1,430)	(2,021)
Forfeited	(166)	(318)
Balance, September 30, 2019	**3,666**	**4,206**

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 September 30, 2019 was 151,655,000 (September 30, 2018 – 151,726,000) and for the nine month period ended September 30, 2019, the weighted average number of shares outstanding was 152,021,000 (September 30, 2018 – 150,881,000).

In computing diluted earnings per share for the three month period ended September 30, 2019, nil (September 30, 2018 – nil) shares were added to the weighted average common shares outstanding to account for the dilution of RAs and PAs, and for the nine month period ended September 30, 2019, 153,000 (September 30, 2018 – nil) shares were added to the weighted average common shares for the dilution. For the three month period ended September 30, 2019, there were 7,872,000 (September 30, 2018 – 7,891,000) RAs and PAs that were not included in the diluted earnings per share calculation because they were anti-dilutive. For the nine month period ended September 30, 2019, there were 4,724,000 (September 30, 2018 – 7,891,000) 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, other natural gas liquids ("ngl") or natural gas 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 ngl 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 Sept. 30, 2019	Three months ended Sept. 30, 2018	**Nine months ended Sept. 30, 2019**	Nine months ended Sept. 30, 2018
Light crude oil	**$ 1,368**	$ 1,935	**$ 3,544**	$ 5,670
Heavy crude oil	**7,911**	8,538	**23,719**	23,988
Natural gas liquids	**112**	4,430	**3,484**	12,422
Condensate	**14,734**	15,563	**48,999**	50,839
Natural gas	**17,472**	23,614	**68,845**	74,628
	$ 41,597	$ 54,080	**$ 148,591**	$ 167,547

Other revenue:

The following table summarizes the Company's other revenue:

	Three months ended Sept. 30, 2019	Three months ended Sept. 30, 2018	**Nine months ended Sept. 30, 2019**	Nine months ended Sept. 30, 2018
Marketing revenue	**$ 2,797**	$ 1,689	**$ 8,690**	$ 3,887
Processing revenue	**756**	1,241	**2,450**	3,029
Other	**-**	-	**-**	1,000
	$ 3,553	$ 2,930	**$ 11,140**	$ 7,916

12. Financing:

	Three months ended Sept. 30, 2019	Three months ended Sept. 30, 2018	**Nine months ended Sept. 30, 2019**	Nine months ended Sept. 30, 2018
Interest expense	**$ 6,045**	$ 5,869	**$ 17,450**	$ 16,774
Gain on lease modification	**(7)**	-	**(7)**	-
Accretion of deferred financing costs	**246**	259	**737**	777
Accretion of decommissioning obligations	**466**	488	**1,439**	1,467
	$ 6,750	$ 6,616	**$ 19,619**	$ 19,018

13. Commitments:

	Total	2019	2020	2021	2022	2023	Thereafter
Firm transportation agreements	$ 241,189	$ 11,806	$ 46,826	$ 31,596	$ 30,982	$ 26,961	$ 93,018
Firm processing agreements	99,003	4,445	16,337	12,354	12,354	12,354	41,159
Total	**$ 340,192**	**$ 16,251**	**$ 63,163**	**$ 43,950**	**$ 43,336**	**$ 39,315**	**$134,177**

Firm transportation agreements include commitments to third parties to transport condensate, ngl and natural gas 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

BOARD OF DIRECTORS

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Chairman Independent Director

Jeffery E. Errico,
Lead Director Independent Director

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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