interim report Q3 2017

third quarter ending September 30, 2017

crew energy inc.

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

Q3 HIGHLIGHTS

- Funds from operations totaled $25.0 million ($0.17 per fully diluted share) in the third quarter, a 21% per share improvement over the second quarter of 2017, despite a 27% decrease in natural gas prices. All-in cash costs of $13.44 per boe were 13% lower than the second quarter of 2017 which helped to offset the impact of lower natural gas prices.

- Production for the quarter averaged 23,251 boe per day, reflecting the Company's decision to hold back approximately 2,600 boe per day of Northeast British Columbia ("NE BC") natural gas sales volumes that were exposed to weak Canadian spot pricing. Current production is 28,000 boe per day which is forecasted to ramp up to 31,000 boe per day by year end once the West Septimus plant expansion is complete.

- Crew drilled 13 (12.3 net) Montney wells and completed 16 (16.0 net) wells in NE BC during the third quarter, including 14 (14.0 net) wells at our liquids-rich Greater Septimus area, which will result in an inventory of 13 (11.2 net) drilled and uncompleted wells ("DUCs") and three (3.0 net) wells in various stages of completion and tie-in by the end of 2017.

- During the third quarter, Crew completed three ultra condensate-rich wells and after a ten day flow back period were on production at an average per well rate of 1,445 boe per day, comprised of 4.3 mmcf per day of raw gas with 824 bbls per day of wellhead condensate for an average condensate-gas ratio of 192 bbls per mmcf.

- Crew completed two wells in the transition zone between the liquids-rich and ultra condensate-rich areas of West Septimus which, after a ten-day flow back period, were producing at an average per well rate of 1,340 boe per day, comprised of 5.6 mmcf per day of raw gas and 420 bbls per day of condensate for an average condensate-gas ratio of 75 bbls per mmcf.

- Operationally, Crew was very active in the third quarter with capital expenditures of $89.9 million. This accelerated program, aided by exceptional weather conditions, allowed the Company to advance completion operations while natural gas prices were low in advance of the new gas contract year that starts on November 1st. The majority of Crew's completion operations were conducted in the third and early fourth quarters where producing wells were shut-in proximal to completion operations which impacted production but had less effect on funds from operations due to low prices.

- Expansion of the West Septimus facility to 120 mmcf per day continued during the quarter with total costs tracking under budget. Final tie-in work was completed during a twelve day shut-down of the plant early in the fourth quarter in preparation for an anticipated on-stream timeframe in mid-November.

- Crew's financial flexibility continued through the end of the third quarter, with $339.5 million in net debt which includes $300 million of senior notes due 2024, and $31.7 million drawn on our $235 million bank facility, leaving the facility 87% undrawn.

FINANCIAL & OPERATING HIGHLIGHTS

FINANCIAL ($ thousands, except per share amounts)	**Three months ended Sept. 30, 2017**	Three months ended Sept. 30, 2016	**Nine months ended Sept. 30, 2017**	Nine months ended Sept. 30, 2016
Petroleum and natural gas sales	**47,824**	47,093	**154,008**	119,668
Funds from operations(1)	**24,970**	23,033	**74,042**	50,795
Per share - basic	**0.17**	0.16	**0.50**	0.36
- diluted	**0.17**	0.16	**0.49**	0.35
Net income /(loss)	**2,127**	(1,286)	**32,063**	(24,986)
Per share - basic	**0.01**	(0.01)	**0.22**	(0.17)
- diluted	**0.01**	(0.01)	**0.21**	(0.17)
Exploration and Development expenditures	**90,069**	37,731	**201,889**	70,590
Property acquisitions (net of dispositions)	**(144)**	(98)	**(46,197)**	874
Net capital expenditures	**89,925**	37,633	**155,692**	71,464

Capital Structure ($ thousands)	**As at Sept. 30, 2017**	As at Dec. 31, 2016
Working capital deficiency(2)	**14,306**	10,006
Bank loan	**31,696**	88,036
	46,002	98,042
Senior Unsecured Notes	**293,546**	147,329
Total Net Debt	**339,548**	245,371
Current Debt Capacity(3)	**535,000**	385,000
Common Shares Outstanding (thousands)	**148,956**	146,812

Notes:

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

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

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

Operations	**Three months ended Sept. 30, 2017**	Three months ended Sept. 30, 2016	**Nine months ended Sept. 30, 2017**	Nine months ended Sept. 30, 2016
Daily production				
Light crude oil (bbl/d)	**553**	210	**528**	266
Heavy crude oil (bbl/d)	**1,902**	2,489	**1,846**	2,550
Condensate (bbl/d)	**2,102**	2,013	**1,856**	1,920
Other ngl (bbl/d)	**1,686**	1,603	**1,491**	1,411
Natural gas (mcf/d)	**102,046**	101,378	**99,577**	101,110
Total (boe/d @ 6:1)	**23,251**	23,211	**22,317**	22,999
Average prices (1)				
Light crude oil ($/bbl)	**52.47**	50.28	**56.66**	44.69
Heavy crude oil ($/bbl)	**43.91**	36.88	**43.95**	31.07
Condensate ($/bbl)	**52.71**	44.98	**58.41**	46.32
Other natural gas liquids ($/bbl)	**23.71**	6.49	**20.29**	6.43
Natural gas ($/mcf)	**2.51**	3.04	**3.16**	2.45
Oil equivalent ($/boe)	**22.36**	22.05	**25.28**	18.99

Notes:

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

	Three months ended Sept. 30, 2017	Three months ended Sept. 30, 2016	**Nine months ended Sept. 30, 2017**	Nine months ended Sept. 30, 2016
Netback ($/boe)				
Revenue	**22.36**	22.05	**25.28**	18.99
Royalties	**(1.43)**	(1.28)	**(1.88)**	(1.06)
Realized commodity hedging gain	**2.76**	0.99	**1.03**	1.99
Operating costs	**(5.86)**	(5.66)	**(5.78)**	(6.05)
Transportation costs	**(2.18)**	(2.02)	**(2.39)**	(2.30)
Operating netback (1)	**15.65**	14.08	**16.26**	11.57
G&A	**(1.29)**	(1.25)	**(1.43)**	(1.43)
Interest on long-term debt	**(2.68)**	(2.05)	**(2.67)**	(2.08)
Funds from operations	**11.68**	10.78	**12.16**	8.06
Drilling Activity				
Gross wells	**13**	8	**35**	13
Working interest wells	**12.3**	7.0	**34.3**	12.0
Success rate, net wells (%)	**100%**	100%	**97%**	100%

Notes:

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

OVERVIEW

The third quarter of 2017 was an active period operationally for Crew, as we moved towards the completion of our West Septimus facility expansion to 120 mmcf per day and put greater emphasis on the development of our ultra liquids-rich area at Greater Septimus. Crew's accelerated drilling and completions program, which began late in the second quarter, continued into the third quarter as we were able to capitalize on exceptionally dry summer weather leading to operational efficiencies. Work continued in the third quarter on the expansion of our West Septimus facility, with final tie-in work completed during a shut-down of the plant in October. On November 1st, with the start of the new gas contract year, Crew had 28,000 boe per day of production on-line, approximately 1,500 boe per day of production shut-in due to low regional gas prices in NE BC and over 3,000 boe per day expected to be brought on-line following the commissioning of our West Septimus facility expansion. A total of $89.9 million was invested during the quarter largely directed to liquids-rich drilling and completions activities coupled with our major infrastructure projects.

Crew's third quarter production averaged 23,251 boe per day, which was an increase of 14% over the previous quarter. Production during the period was impacted by the Company's decision to limit NE BC natural gas sales volumes exposed to extremely weak spot Canadian pricing, as we elected to produce only those volumes processed and transported under firm contracts and previously dedicated to markets with prices significantly above Canadian spot prices. The impact of this decision was a reduction in third quarter production of approximately 2,600 boe per day resulting in quarterly volumes below previous guidance of 24,500 to 26,500 boe per day. Although production was affected, Crew's funds from operations were positively impacted by approximately $1 million, while preserving approximately 230,000 boe of production. These production volumes continued to be shut-in through October awaiting improved Canadian spot natural gas pricing.

Crew anticipates that challenges experienced in the first quarter of 2017 related to services procurement and cost escalation will be encountered again in the first quarter of 2018. To mitigate these challenges and take advantage of the favourable operating environment, Crew has elected to proceed with certain planned first quarter 2018 activity in the fourth quarter of 2017 resulting in an increase in our 2017 exploration and development capital budget to $235 million. This $35 million expansion to the capital program is forecasted to approximate fourth quarter funds from operations and will afford optimized capital and operating efficiencies, allowing for maximum flexibility to achieve our strategic goal of having physical connection to the three major pipelines in NE BC and at the same time provide a range of growth options for 2018 and beyond as commodity prices allow. The Company has not formally approved a 2018 budget and intends to release the 2018 budget in mid-December, 2017. Crew anticipates that the Company will target a capital budget that is driven by funds from operations through the end of 2018.

FINANCIAL

Funds from operations in the third quarter of 2017 totaled $25.0 million or $0.17 per share, a 21% increase over the previous quarter and 6% over the same period in 2016 on a per share basis. The quarter over quarter increase was reflective of higher production volumes, increased hedging gains and lower overall costs partially offset by lower natural gas prices. The year over year increase in funds from operations reflects higher realized liquids pricing, which was offset by a decrease in natural gas pricing and hedging gains.

The Company's third quarter liquids sales, including light oil, heavy oil and natural gas liquids, benefited from higher overall North American crude prices supported by OPEC's production curtailments relative to the same period in 2016. Compared to the second quarter of 2017, prices for Crew's third quarter liquids sales were impacted by a stronger Canadian dollar which negatively affected the price for the Company's production sold in Canadian markets. Natural gas prices in Canada weakened throughout the third quarter as planned and unplanned pipeline maintenance projects resulted in significant bottlenecks in the Western Canadian natural gas transportation system further weakening prices in an already oversupplied market. Compared to the second quarter of 2017, Crew's realized natural gas price declined 27% in the third quarter and 17% relative to the same period in 2016. The Company's realized natural gas prices reflect the strength of our portfolio marketing approach given the Canadian natural gas benchmark AECO daily spot price declined 48% quarter over quarter and 38% year over year.

Capital expenditures totaled $89.9 million for the quarter, reflecting several contributing factors. These factors include favorable weather conditions which allowed the Company to complete more projects in Q3 in a lower price cycle, an increased focus on condensate-rich wells that require higher sand loading, and ongoing infrastructure projects including the West Septimus facility expansion, the West Septimus to Saturn pipeline project and the installation of a pipeline to debottleneck the gathering system in the Septimus area. The Company directed $65.3 million or 73% of its capital expenditures to our drilling and completions program in NE BC. In addition, Crew invested $22.3 million for infrastructure, including pipeline expenditures required to tie-in new production to the Company's gas facilities and for improvements to roads and leases at West Septimus to allow for improved access.

The Company's accelerated 2017 capital program will be funded through funds from operations, the proceeds of the $300 million, 6.5% senior unsecured notes (the "2024 Notes") issued in the first quarter of 2017 and the $49 million of proceeds from the Company's second quarter property disposition. Crew's net debt at the end of the third quarter was $339.5 million with $31.7 million drawn on our $235 million credit facility. This amount, along with the Company's working capital deficiency of $14.3 million represents a draw of 20% on the facility. With a seven year term and attractive coupon on our 2024 Notes, coupled with significant room on our credit facility, Crew has maintained a strong financial position with flexibility moving into 2018.

TRANSPORTATION, MARKETING & HEDGING

Crew's natural gas sales portfolio mix for the third quarter was consistent with the previous quarter and allocated approximately 39% to Chicago City Gate, 28% to AECO, 26% to Alliance ATP and 7% to Station 2. Our portfolio was also enhanced by natural gas contracts sold at higher monthly index prices, physical fixed differential contracts and our natural gas hedge portfolio. Commencing November 1, 2017, in anticipation of the increased throughput associated with the West Septimus facility expansion start-up, the sales mix is expected to change to 39% Chicago City Gate, 35% to AECO, 19% to Alliance ATP and 7% to Station 2.

Starting in April of 2018, Crew will have 60 mmcf per day of firm service capacity on TransCanada Pipeline's ("TCPL") Nova line, followed by another 60 mmcf per day currently planned for June of 2019. As such, by April 2018, Crew plans to have connectivity to all three major export pipeline systems, a unique position for Montney producers, and one that affords the Company significant flexibility and access to diverse markets. In conjunction with this expanded transportation option, Crew has broadened its market diversity with added exposure to alternative Canadian and US natural gas markets.

Crew will continue to plan for processing and transportation diversification for natural gas from our Greater Septimus and Groundbirch areas as part of our longer term, Septimus 5X growth strategy. This strategy is designed to replicate the free cash flow currently being generated by our 60 mmcf per day facility at Septimus a total of five times across our asset base over the next number of years, depending on commodity prices. As our 120 mmcf per day West Septimus expansion nears completion and becomes the third component of this Septimus 5X strategy, Crew's next growth phase will shift to the Company's strategic Groundbirch acreage, where we have secured significant optionality regarding the development and infrastructure build-out in this area, described below in the 'NE BC Montney – Groundbirch Overview' section.

The Company's marketing team continues to monitor commodity futures markets with the view to adding to the hedge position when pricing is conducive to maintaining attractive economics. For the balance of 2017, Crew's total natural gas hedged position is 69,000 gj per day at a transportation-adjusted equivalent price of $2.92 per gj, which when adjusting for the higher heat content of Crew's gas, equates to $3.62 per mcf. For liquids, we have 1,750 bbl per day hedged at an average West Texas Intermediate ("WTI") price of CDN$68.02 per bbl. Forward pricing into 2018 has been weak throughout the past two quarters, and has not met thresholds at which the Company was willing to lock in hedges. Hedges in place for 2018 include 13,000 gj per day of natural gas at an average price of $2.71 per gj, or $3.36 per mcf adjusted for heat content, and 500 bbls per day of liquids hedged at an average WTI price of $62.64 per bbl. We continue to closely monitor 2018 oil and natural gas prices with the intention to add commodity price protection for up to 50% of our planned 2018 production.

OPERATIONS

NE BC Montney - Greater Septimus Overview

Throughout the third quarter, Crew maintained high activity levels focused in Greater Septimus with 88% of our $90 million expenditures directed to the area, including $58 million for drilling and completions and $19.5 million for infrastructure, including the expansion of our West Septimus facility to 120 mmcf per day of processing capacity, the installation of a pipeline to debottleneck the gathering system in the Septimus area and initial work on the pipeline connection from West Septimus to the TCPL Saturn meter station. During the quarter, we drilled 13 (12.3 net) wells and completed 14 (14.0 net) wells at Greater Septimus, of which seven and four, respectively, were in our ultra-condensate rich area. Greater Septimus production for the quarter averaged 18,154 boe per day, an increase of 17% over the previous quarter and consistent with the same period in 2016.

Crew's two initial ultra condensate-rich wells have performed exceptionally, with the first well paying out in nine months, and have been on production for 326 and 211 days, respectively. Crew has embarked on a more aggressive plan for the development of the ultra condensate-rich area as a key source of feedstock for the West Septimus plant expansion. The higher liquids weighting offers significant economic benefit even after the impact of a 10 to 15% industry cost increase that has brought total average well costs with higher intensity completions to between $4.8 and $5.0 million. Crew expects to have completed and tied-in ten ultra liquids-rich wells at West Septimus by the end of 2017, compared to two at the end of 2016. Crew intends on developing the Company's large inventory of ultra condensate-rich drilling locations over the next several years.

During the third quarter, Crew continued to delineate West Septimus and completed three ultra condensate-rich wells. After a ten day flow back period, these wells were on production at an average per well rate of 1,445 boe per day comprised of 824 bbls per day of condensate and 4.3 mmcf per day of raw gas for a condensate-gas ratio of 192 bbls per mmcf. A fourth well that was also completed in an exploratory stratigraphic interval in the area continues to flow back high volumes of frac fluid, and after 180 hours, flowed 4.4 mmcf per day and 106 bbls per day of condensate over a 24 hour period. Crew also completed two wells in the transition zone between the liquids-rich and ultra condensate-rich areas at West Septimus which, after ten days, were producing at an average 1,340 boe per day, including 420 bbls per day of wellhead condensate and 5.6 mmcf per day of raw gas for an average condensate-gas ratio of 75 bbls per mmcf. All of these wells are in the process of being tied-in to the expanded West Septimus gas plant. A six well pad was drilled in the ultra condensate-rich area with three wells scheduled to be completed in the fourth quarter, and the remaining three scheduled for completion in the first quarter of 2018.

Work continued in the third quarter on the expansion of our West Septimus facility, with final tie-in work completed during a shut-down of the plant in October. Crew anticipates starting up the expanded capacity in mid-November with the total cost expected to come in under the $63 million budget. With the high degree of volatility in current gas pricing, Crew will focus on maximizing liquids production while meeting current firm gas transportation arrangements and will bring on excess volumes as commodity prices warrant.

Greater Septimus Operational Statistics

Production & Drilling	Q3 2017	Q2 2017	Q1 2017	Q4 2016	Q3 2016
Average daily production (boe/d)	18,154	15,558	17,440	17,307	18,592
Wells drilled (gross / net)	13 / 12.3	5 / 5.0	10 / 10.0	8 / 7.7	8 / 7.0
Wells completed (gross / net)	14 / 14.0	9 / 9.0	3 / 3.0	5 / 4.0	7 / 7.0

Operating Netback ($ per boe)	Q3 2017	Q2 2017	Q1 2017	Q4 2016	Q3 2016
Revenue	20.05	24.51	26.49	25.10	20.56
Royalties	(0.89)	(1.57)	(1.66)	(1.47)	(0.94)
% basis	4.4%	6.4%	6.3%	5.9%	4.6%
Realized commodity hedge gain / (loss)	2.97	0.77	(0.41)	(0.39)	1.11
Operating costs	(3.38)	(4.10)	(3.34)	(3.34)	(3.61)
Transportation costs	(1.65)	(2.03)	(1.67)	(1.68)	(1.59)
Operating netback	17.10	17.58	19.41	18.22	15.53

NE BC Montney – Groundbirch Overview

Crew completed two (2.0 net) delineation wells at Groundbirch in the third quarter, both of which targeted two distinct stratigraphic intervals within the Upper Montney that had not been tested in the original two wells drilled in the area in 2014. After five days of flow back, these wells were flowing an average of 5.1 mmcf per day of gas and 108 bbls per day of condensate at an average flowing casing pressure of 1,407 psi, a pressure that was more than double the original two wells. To further test their productivity, the wells were produced through a third party facility at an IP30 restricted rate of 3.1 mmcf per day with condensate recovery of 23 bbls per mmcf.

Crew has a current engineering design for a 120 mmcf per day facility at Groundbirch and has selected pad sites for the first phase of drilling which would initially fill the facility. Fortunately, by proceeding with the installation of strategic pipeline infrastructure from the West Septimus facility through our Groundbirch acreage and connecting into the existing TCPL Saturn meter station, Crew will have the flexibility to meet the majority of our transportation commitments through 2019 without the need for additional processing capacity at Groundbirch. Crew's plan to proceed with our plant at Groundbirch is currently deferred given the superior economics of our ultra-condensate rich program and a priority to lower expenses and increase margins through full optimization of facilities. Our Septimus 5X growth strategy has been developed to provide maximum flexibility and optionality for the Company to respond to drilling results and broader market conditions in the development of our world-class asset base, demonstrated by the Groundbirch decision.

NE BC Montney – Tower Overview

Crew's Montney Tower area continues to represent a significant future development opportunity for the Company and offers high torque to crude oil prices. Gas lift infrastructure was successfully installed through the second and early third quarters and is now operational. As a result, our overall production at Tower averaged 1,475 boe per day in the third quarter, including 524 bbls of oil per day.

Lloydminster, AB/SK Overview

Crew produced an average of 1,907 boe per day at Lloydminster in the third quarter with minor amounts of workover capital expended. The Company remains committed to divesting the Lloydminster assets to further focus efforts on our Montney acreage and plans to continue investing minor amounts of capital in order to maintain the value inherent in these assets as part of the ongoing disposition process.

OUTLOOK

Crew has continued to focus on profitability through cost control and margin expansion by pursuing the highest value projects amidst ongoing volatility in commodity prices. We elected to shut-in 2,600 boe per day during the period which resulted in approximately $1 million of incremental funds from operations, attributable to not producing gas at low spot prices and avoiding delivery of gas into higher-cost interruptible transportation service. With little relief forecast for natural gas prices at Station 2, Crew intends to keep this production shut-in awaiting a gas price recovery. Positively, the Canadian dollar has continued to lose value against its U.S. counterpart and oil prices have trended up through the latter half of October as supply/demand fundamentals are becoming balanced setting up for a possible recovery.

Our commitment to cost control continued through the third quarter, with Greater Septimus operating expenses being reduced to $3.38 per boe, 6% lower than the same period in 2016 and 18% lower than the second quarter of 2017. Although industry inflation combined with Crew's higher intensity completions have increased per well capital costs by 10 to 15% in 2017, these increases have been largely offset by higher productivity and increased condensate-gas ratios. By focusing on ultra condensate-rich development at West Septimus, maintaining our low cost structure and electing to shut-in production that does not meet corporate netback hurdles, Crew anticipates continued improvement in our margins going forward.

For the past several years, Crew has been focused on the execution of our long-term Montney growth strategy and has successfully achieved the first phase: capturing a sizeable resource. Crew now owns over 280,000 net acres of Montney rights in NE BC with an independently assigned resource of over 16 billion boe of Total Petroleum Initially in Place ("TPIIP"). We have accumulated this world-class asset for a net cost of approximately $80 million or $285 per acre. Phase two of our plan is centered on proving the production and economic viability of each of our areas, including Tower, Greater Septimus, Groundbirch and Attachie. To date, Crew and other industry participants have successfully drilled, completed and tested wells in all of these areas proving the economic merits of each.

Phase three of our long-term plan is the build-out and control of processing and transportation infrastructure, expanding on the over 180 mmcf per day of processing capacity established to date at Septimus, West Septimus and Tower. Currently, Crew is connected to two major export pipeline systems and expects to complete a major pipeline project in 2018 to install approximately 83 kilometres of line pipe from West Septimus to the TCPL Saturn meter station, which will achieve our goal of having access to all three major export pipeline systems in Canada.

The fourth and final phase of our long-term plan is to generate free funds from operations across each of Septimus, West Septimus and Groundbirch, which we have achieved at Septimus. Encouraged by the results to date, Crew's focus continues to be on the Company's exciting new condensate-rich development at West Septimus, which is targeted to be the next area to generate free funds from operations. With the Company's recent success and heightened drive to increase the liquids component of our portfolio, efforts to grow the lower liquids yielding gas has been replaced with an emphasis on the ultra condensate-rich areas of our asset base. Given the continued volatility in the commodities, particularly natural gas, we believe the optimal strategy is to maintain our focus on cost control, margin expansion and growth in funds from operations per share, rather than growing natural gas production in an over-supplied market.

Crew began diversifying natural gas sales markets three years ago and will continue to do so, having predominantly outperformed the natural gas benchmarks since the end of 2015. In addition, we will seek opportunities to high-grade or monetize assets similar to the successful transactions we have undertaken in the past to raise funds to initially strengthen the balance sheet and then to invest in the Montney. The Company's balance sheet remains strong with 20% drawn on our $235 million bank facility.

Crew's fourth quarter 2017 production estimate reflects the continued shut-in of previously mentioned NE BC production due to low regional natural gas prices and the shut-down of the West Septimus gas plant for tie-in of the expansion resulting in the deferral of approximately 7,500 boe per day of production in October. On November 1st with the start of the new gas contract year, production rose to 28,000 boe per day with over 3,000 boe per day awaiting commissioning of the West Septimus plant and 1,500 boe per day shut in due to pricing. Crew expects to average 26,000 to 27,000 boe per day in the fourth quarter with an exit rate of approximately 31,000 boe per day and anticipates entering 2018 with 13 (11.2 net) drilled but uncompleted wells in the Montney.

Our focus on increasing the Company's condensate weighting is not necessarily a unique strategy in the current environment. However, Crew's large inventory of tier one, ultra condensate-rich drilling locations, wells that are highly productive with the potential to payout in less than one year, operating expenses at Greater Septimus under $3.50 per boe and per well capital costs of $4.8 to $5.0 million, the Company is in an excellent position to provide profitable growth for many years to come from this exciting new development.

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

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

2017 average production(1)	23,000 – 24,000 boe/d
2017 exit production(1)	31,000 boe/d
Total proved + probable reserves(2)	324 MMboe
Total proved + probable BT NPV10(2)	$2 billion
Montney potential drilling locations(3)	~5,465
2017 capital program(1)	$235 MM
Net debt(4)	$339.5 MM
Exit 2017 net debt / funds from operations(1)	2.5 – 2.9x
Basic shares outstanding(4)	149.0 MM
Tax pools(4)	~$1.1 billion

(1) Forecast. See "Forward Looking Information and Statements".
(2) Reserves included herein are stated on a company gross basis (working interest before deduction of royalties without including any royalty interests). Information presented herein in respect of reserves and related information is based on our independent reserves evaluation (the "Sproule Report") for the year ended December 31, 2016 prepared by Sproule Associates Limited ("Sproule") details of which were provided in our press release issued on February 9, 2017 and are contained in our Annual Information Form filed on SEDAR.
(3) Estimated potential drilling locations are the total number of risked Contingent (1,953) and Prospective (3,160) resource locations as identified in Crew's year-end independent Resource Evaluation, plus the 2P booked locations (356) as identified in the Sproule Report, both of which were prepared in accordance with the COGE Handbook provisions and NI 51-101.
(4) As at Sept. 30, 2017.

Cautionary Statements

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

All amounts in this report are stated in Canadian dollars unless otherwise specified. Throughout this report, the terms Boe (barrels of oil equivalent) and Mmboe (millions of barrels of oil equivalent), are used. Such terms when used in isolation, may be misleading. Where applicable, natural gas has been converted to barrels of oil equivalent ("BOE") based on 6 Mcf:1 BOE and oil and liquids have been converted to natural gas equivalent on the basis of 1 bbl:6 mcfe. The BOE rate is based on an energy equivalent conversion method primarily applicable at the burner tip, and given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different than the energy equivalency of the 6:1 conversion ratio, utilizing the 6:1 conversion ratio may be misleading as an indication of value. The BOE rate is based on an energy equivalent conversion method primarily applicable at the burner tip and does not represent a value equivalent at the wellhead. In accordance with Canadian practice, production volumes and revenues are reported on a company gross basis, before deduction of Crown and other royalties and without including any royalty interest, unless otherwise stated. Unless otherwise specified, all reserves volumes in this report (and all information derived therefrom) are based on "company gross reserves" using forecast prices and costs. It should not be assumed that the estimates of future net revenues presented herein represent the fair market value of Crew's reserves. There is no assurance that the forecast prices and cost assumptions will be attained and variances could be material and there is no guarantee that the estimated reserves will be recovered. Our oil and gas reserves statement for the year-ended December 31, 2016 includes complete disclosure of our oil and gas reserves and other oil and gas information in accordance with NI 51-101, and is contained within our Annual Information Form which is available on our SEDAR profile at www.sedar.com.

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

*This report contains references to estimates of oil and gas classified as Total Petroleum Initially In Place ("**TPIIP**") in Crew's Montney region in northeast British Columbia which are not, and should not, be confused with, oil and gas reserves. Such estimates are based upon an independent resource evaluation effective as at December 31, 2016, prepared for Crew in accordance with the Canadian Oil & Gas Evaluation Handbook, complete details of which evaluation were set forth in Crew's previously disseminated news release dated May 8, 2017 (the "**Resource Report News Release**"). Such resource estimates are broken into the requisite categories and are subject to a number of cautionary statements, assumptions, risks, positive and negative factors relative to the estimates and contingencies, all of which details are set forth in the Resource Report News Release, all of which is incorporated by reference herein.*

Forward-Looking Information and Statements

This report contains certain forward–looking information and statements within the meaning of applicable securities laws. The use of any of the words "expect", "anticipate", "continue", "estimate", "may", "will", "project", "should", "believe", "plans", "intends" "forecast" and similar expressions are intended to identify forward-looking information or statements. In particular, but without limiting the foregoing, this report contains forward-looking information and statements pertaining to the following: estimates of the volume and product mix of Crew's oil and gas production and expectations in respect thereof; production estimates including Q4 and annual 2017 forecast average production and 2017 exit rate; the volumes and estimated value of Crew's resources and reserves; future oil and natural gas prices and Crew's commodity risk management programs; future liquidity and financial capacity; future results from operations and operating metrics; year-end forecasted debt to funds from operations ratio; potential to improve operating costs, well costs and G&A expenditures and potential to improve ultimate recoveries and initial production rates; future costs, expenses and royalty rates; transportation commitments; future interest costs; the exchange rate between the $US and $Cdn; future development, exploration, acquisition and development activities and related capital expenditures and the timing thereof; the number of wells to be drilled, completed and tied-in and the timing thereof; our long-term plan regarding free cash flow generation at West Septimus and Groundbirch and the timing thereof; the number of potential drilling locations and the potential value associated with our undeveloped land base; the amount and timing of capital projects including infrastructure, pipeline and facility expansions, commissioning and the timing and anticipated impact thereof; service capacity and pipeline connectivity expectations; the total future capital associated with development of reserves and resources; our 2017 budget and preliminary expectations in respect of our 2018 budget and methods of funding our capital program, including possible non-core asset divestitures and asset swaps.

In this report, reference is made to the Company's long-term plan and potential Montney growth scenario, more particularly referred to herein as our "Septimus 5X Growth Strategy" and associated information including phases comprising the same. Such information reflects internal projections used by management for the purposes of making capital investment decisions and for internal long-term planning and budget preparation. This information is based upon a variety of assumptions that may prove to be incorrect and, accordingly, long-term projections and targets are not intended to reflect estimates or forecasts of metrics that may actually be achieved. Accordingly, undue reliance should not be placed on the same.

Forward-looking statements or information are based on a number of material factors, expectations or assumptions of Crew which have been used to develop such statements and information but which may prove to be incorrect. Although Crew believes that the expectations reflected in such forward-looking statements or information are reasonable, undue reliance should not be placed on forward-looking statements because Crew can give no assurance that such expectations will prove to be correct. In addition to other factors and assumptions which may be identified herein, assumptions have been made regarding, among other things: the impact of increasing competition; the general stability of the economic and political environment in which Crew operates; the timely receipt of any required regulatory approvals; the ability of Crew to obtain qualified staff, equipment and services in a timely and cost efficient manner; drilling results; the ability of the operator of the projects in which Crew has an interest in to operate the field in a safe, efficient and effective manner; the ability of Crew to obtain financing on acceptable terms and the adequacy of cash flow to fund its planned expenditures; field production rates and decline rates; the ability to replace and expand oil and natural gas reserves through acquisition, development and exploration; the timing and cost of pipeline, storage and facility construction and expansion and the ability of Crew to secure adequate product transportation; future commodity prices; currency, exchange and interest rates; regulatory framework regarding royalties, taxes and environmental matters in the jurisdictions in which Crew operates; the ability of Crew to successfully market its oil and natural gas products.

The forward-looking information and statements included in this report are not guarantees of future performance and should not be unduly relied upon. Such information and statements, including the assumptions made in respect thereof, involve known and unknown risks, uncertainties and other factors that may cause actual results or events to defer materially from those anticipated in such forward-looking information or statements including, without limitation: changes in commodity prices; the potential for variation in the quality of the Montney formation; changes in the demand for or supply of Crew's products; unanticipated operating results or production declines; changes in tax or environmental laws, royalty rates or other regulatory matters; changes in development plans of Crew or by third party operators of Crew's properties, increased debt levels or debt service requirements; inaccurate estimation of Crew's oil and gas reserve and resource volumes; limited, unfavourable or a lack of access to capital markets; increased costs; a lack of adequate insurance coverage; the impact of competitors; and certain other risks detailed from time-to-time in Crew's public disclosure documents (including, without limitation, those risks identified in this report and Crew's Annual Information Form).

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

Test Results and Initial Production Rates

A pressure transient analysis or well-test interpretation has not been carried out and thus certain of the test results provided herein should be considered to be preliminary until such analysis or interpretation has been completed. Test results and initial production rates disclosed herein, particularly those short in duration, may not necessarily be indicative of long term performance or of ultimate recovery.

MANAGEMENT'S DISCUSSION AND ANALYSIS

ABOUT CREW

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

ADVISORIES

Management's discussion and analysis ("MD&A") is the explanation of the financial performance for the period covered by the financial statements along with an analysis of the financial position of the Company. Comments relate to and should be read in conjunction with the unaudited condensed interim consolidated financial statements of the Company for the three and nine month periods ended September 30, 2017 and 2016. The unaudited condensed interim consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS"). There have been no significant changes to the critical estimates disclosed in the Company's audited financial statements for the year ended December 31, 2016. All figures provided herein and in the September 30, 2017 unaudited condensed interim consolidated financial statements are reported in Canadian dollars ("CDN"). This MD&A is dated November 2, 2017.

Forward Looking Statements

This MD&A contains forward looking statements. Management's assessment of future plans and operations, drilling plans and the timing thereof, plans for the completion and tie-in of wells, facility and pipeline construction, expansion, commissioning and the timing thereof, capital expenditures, including the Company's current 2017 capital budget, timing of capital expenditures and methods of financing capital expenditures and the ability to fund financial liabilities, production estimates including annual, fourth quarter 2017 average and 2017 exit forecasts, expected commodity mix and prices, future operating costs, future transportation costs, expected royalty rates, expected general and administrative expenses, expected interest rates, debt levels, expectations regarding the Company's Borrowing Base under its credit Facility, funds from operations and the timing of and impact of implementing accounting policies, estimates regarding undeveloped land position and estimated future drilling, recompletion or reactivation locations and anticipated impact of potential future transactions may constitute forward looking statements under applicable securities laws and necessarily involve risks including, without limitation, risks associated with oil and gas exploration, development, exploitation, production, marketing and transportation, loss of markets, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other producers, inability to retain drilling rigs and other services, incorrect assessment of the value of acquisitions, failure to realize the anticipated benefits of acquisitions, the inability to fully realize the benefits of acquisitions, delays resulting from or inability to obtain required regulatory approvals and inability to access sufficient capital from internal and external sources. As a consequence, the Company's actual results may differ materially from those expressed in, or implied by, the forward looking statements. Forward looking statements or information are based on a number of factors and assumptions which have been used to develop such statements and information but which may prove to be incorrect. Although Crew believes that the expectations reflected in such forward looking statements or information are reasonable, undue reliance should not be placed on forward looking statements because the Company can give no assurance that such expectations will prove to be correct. In addition to other factors and assumptions which may be identified in this document and other documents filed by the Company, assumptions have been made regarding, among other things: the impact of increasing competition; the general stability of the economic and political environment in which Crew operates; the ability of the Company to obtain qualified staff, equipment and services in a timely and cost efficient manner; drilling results; the ability of the operator of the projects which the Company has an interest in to operate the field in a safe, efficient and effective manner; Crew's ability to obtain financing on acceptable terms; changes in the Company's banking facility; field production rates and decline rates; the ability to reduce operating costs; the ability to replace and expand oil and natural gas reserves through acquisition, development or exploration; the timing and costs of pipeline, storage and facility construction and expansion; the ability of the Company to secure adequate product transportation; future petroleum and natural gas prices; currency, exchange and interest rates; the regulatory framework regarding royalties, taxes and environmental matters in the jurisdictions in which the Company operates; and Crew's ability to successfully market its petroleum and natural gas products. Readers are cautioned that the foregoing list of factors is not exhaustive. Additional information on these and other factors that could affect the Company's operations and financial results are included in reports on file with Canadian securities regulatory authorities and may be accessed through the SEDAR website (www.sedar.com) or at the Company's website (www.crewenergy.com). Furthermore, the forward looking statements contained in this document are made as at the date of this document and the Company does not undertake any obligation to update publicly or to revise any of the included forward looking statements, whether as a result of new information, future events or otherwise, except as may be required by applicable securities laws.

Conversions

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

Throughout this MD&A, Crew has used the 6:1 boe measure which is the approximate energy equivalency of the two commodities at the burner tip. Boe does not represent a value equivalency at the wellhead nor at the plant gate which is where Crew sells its production volumes and therefore may be a misleading measure, particularly if used in isolation. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6:1, utilizing a 6:1 conversion may be misleading as an indication of value.

Non-IFRS Measures

Funds from Operations

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

($ thousands)	**Three months ended Sept. 30, 2017**	Three months ended Sept. 30, 2016	**Nine months ended Sept. 30, 2017**	Nine months ended Sept. 30, 2016
Cash provided by operating activities	**15,258**	25,940	**73,806**	57,578
Decommissioning obligations settled	**128**	262	**484**	648
Change in operating non-cash working capital	**9,834**	(3,047)	**459**	(6,959)
Accretion of deferred financing costs	**(250)**	(122)	**(707)**	(472)
Funds from operations	**24,970**	23,033	**74,042**	50,795

Debt to EBITDA

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

Operating Netback

Management uses certain industry benchmarks such as operating netback to analyze financial and operating performance. This benchmark as presented does not have any standardized meaning prescribed by IFRS, and therefore may not be comparable with the calculation of similar measures for other entities. Operating netback equals total petroleum and natural gas sales including realized gains and losses on commodity related derivative financial instruments less royalties, operating costs and transportation costs calculated on a boe basis. Management considers operating netback an important measure to evaluate its operational performance as it demonstrates its field level profitability relative to current commodity prices. The calculation of Crew's netbacks can be seen below in the Operating Netbacks section.

Working Capital and Net Debt

The Company closely monitors its capital structure with a goal of maintaining a strong financial position in order to fund current operations and the future growth of the Company. Crew monitors working capital and net debt as part of its capital structure. Working capital and net debt do not have a standardized meaning prescribed by IFRS, and therefore may not be comparable with the calculation of similar measures for other entities. The following tables outline Crew's calculation of working capital and net debt:

($ thousands)	**September 30, 2017**	December 31, 2016
Current assets	**69,606**	39,588
Current liabilities	**(78,507)**	(68,494)
Derivative financial instruments	**(5,405)**	18,900
Working capital deficiency	**(14,306)**	(10,006)

($ thousands)	**September 30, 2017**	December 31, 2016
Bank loan	**(31,696)**	(88,036)
Senior unsecured notes	**(293,546)**	(147,329)
Working capital deficiency	**(14,306)**	(10,006)
Net debt	**(339,548)**	(245,371)

RESULTS OF OPERATIONS

Production

	Three months ended September 30, 2017					Three months ended September 30, 2016				
	Oil (bbl/d)	**Condensate (bbl/d)**	**Other Ngl (bbl/d)**	**Nat. gas (mcf/d)**	**Total (boe/d)**	Oil (bbl/d)	Condensate (bbl/d)	Other Ngl (bbl/d)	Nat. gas (mcf/d)	Total (boe/d)
NE BC	**553**	**2,102**	**1,686**	**102,019**	**21,344**	210	2,013	1,603	101,324	20,713
Lloydminster	**1,902**	**-**	**-**	**27**	**1,907**	2,489	-	-	54	2,498
Total	**2,455**	**2,102**	**1,686**	**102,046**	**23,251**	2,699	2,013	1,603	101,378	23,211

Production for the third quarter of 2017 was consistent with the same period in 2016 as a result of increased light oil and associated natural gas production at Tower, offset by decreased heavy oil production at Lloydminster. Northeast British Columbia production during the third quarter of 2017 was impacted by the Company's decision to limit third quarter natural gas sales volumes exposed to weak spot Canadian pricing, favouring to produce those volumes processed and transported under firm contracts and previously dedicated to markets at prices significantly above Canadian spot prices. The Company's Northeast British Columbia production for the quarter was impacted by approximately 2,600 boe per day as a result of this strategy. With the completion of the Company's expanded processing facility at West Septimus and improved pricing expected in November 2017, the Company plans to increase production through the last two months of 2017 towards its forecast corporate exit rate of 31,000 boe per day.

	Nine months ended September 30, 2017					Nine months ended September 30, 2016				
	Oil (bbl/d)	**Condensate (bbl/d)**	**Other Ngl (bbl/d)**	**Nat. gas (mcf/d)**	**Total (boe/d)**	Oil (bbl/d)	Condensate (bbl/d)	Other Ngl (bbl/d)	Nat. gas (mcf/d)	Total (boe/d)
NE BC	**528**	**1,856**	**1,491**	**99,541**	**20,465**	266	1,920	1,411	100,900	20,414
Lloydminster	**1,846**	**-**	**-**	**36**	**1,852**	2,550	-	-	210	2,585
Total	**2,374**	**1,856**	**1,491**	**99,577**	**22,317**	2,816	1,920	1,411	101,110	22,999

For the first nine months of 2017, production decreased 3% over the same period in 2016 as a result of heavy oil production declines at Lloydminster, as the Company continues to direct the majority of its investment capital to higher rate of return projects in northeast British Columbia. In addition, in the second and third quarters of 2017, there were several extended planned and unplanned third party facility and pipeline outages, coupled with the aforementioned shut-in natural gas volumes which negatively affected production in the Company's British Columbia properties. This was partially offset by increased oil production at Tower from a successful completion program during the first six months of 2017 and an acquisition of non-Montney natural gas production in other northeast British Columbia properties ("Other NE BC") late in the fourth quarter of 2016.

Revenue

	Three months ended Sept. 30, 2017	Three months ended Sept. 30, 2016	**Nine months ended Sept. 30, 2017**	Nine months ended Sept. 30, 2016
Revenue ($ thousands)				
Light crude oil	**2,671**	970	**8,160**	3,252
Heavy crude oil	**7,683**	8,446	**22,148**	21,709
Condensate	**10,192**	8,329	**29,600**	24,372
Other natural gas liquids	**3,679**	957	**8,259**	2,485
Natural gas	**23,599**	28,391	**85,841**	67,850
Total	**47,824**	47,093	**154,008**	119,668
Crew average prices				
Light crude oil ($/bbl)	**52.47**	50.28	**56.66**	44.69
Heavy crude oil ($/bbl)	**43.91**	36.88	**43.95**	31.07
Condensate ($/bbl)	**52.71**	44.98	**58.41**	46.32
Other natural gas liquids ($/bbl)	**23.71**	6.49	**20.29**	6.43
Natural gas ($/mcf)	**2.51**	3.04	**3.16**	2.45
Oil equivalent ($/boe)	**22.36**	22.05	**25.28**	18.99
Benchmark pricing				
Light crude oil – Cdn$ WTI (Cdn $/bbl)	**60.35**	58.65	**64.65**	54.43
Heavy crude oil – WCS (Cdn $/bbl)	**47.90**	41.02	**49.11**	36.41
Natural gas liquids – Condensate @ Edmonton (Cdn $/bbl)	**59.72**	56.23	**64.69**	53.46
Natural Gas:				
AECO 5A daily index (Cdn $/mcf)	**1.45**	2.32	**2.31**	1.85
Chicago City Gate at ATP (Cdn $/mcf)	**2.84**	2.91	**3.08**	2.32
Alliance 5A (Cdn $/mcf)	**1.27**	2.54	**2.43**	2.09

In the third quarter of 2017, the Company's revenue increased 2% as compared to the same period in 2016 as a result of the increase in realized liquids pricing, partially offset by a decrease in natural gas pricing. The Company's realized light crude oil price increased 4% which was comparable to the 3% increase in the Company's Cdn$ West Texas Intermediate ("WTI") benchmark for the same period last year. Crew's third quarter heavy oil price increased 19%, which was consistent with the 17% increase in the Company's Western Canadian Select ("WCS") benchmark. The Company's third quarter realized condensate price increased 17% over the same period in 2016 as compared to the 6% increase in the Condensate at Edmonton benchmark price, as a result of lower pipeline tariffs and quality differentials. Other natural gas liquids ("ngl") realized price increased significantly in the third quarter, due to the increase in propane pricing as compared to the same period in 2016. Crew's realized natural gas price decreased 17% in the third quarter of 2017 as compared to the 26% decrease in the Company's natural gas sales portfolio weighted benchmark price as the Company benefited from the selling of a portion of its gas sales at monthly index prices rather than the lower monthly spot prices. The Company's natural gas price benefits from the high heat content of its Montney natural gas which yields approximately 20% more value than the standard heat conversion used in the Company's benchmark pricing.

The Company's third quarter 2017 natural gas sales portfolio is based approximately on the following reference prices:

	Q3 2017	Q3 2016
Chicago City Gate at ATP	**39%**	40%
AECO	**28%**	22%
Alliance 5A	**26%**	30%
Station 2(1)	**7%**	4%
Sumas	**-**	4%
Total	**100%**	100%

(1) The Company secured fixed short term sales contracts that were greater than the average price realized during the quarter.

The Company's revenue for the first nine months of 2017 increased 29% over same period in 2016 as a result of the 33% increase in realized commodity pricing partially offset by the 3% decline in production. The Company's realized light oil price increased 27% which was greater than the 19% increase in the Company's WTI benchmark as a result of the Company's ability to secure sales contracts when differentials between the WTI price and Canadian light crude price were narrower than in the first nine months of 2016. The Company's heavy oil price increased 41% as compared to the 35% increase in the Company's WCS benchmark for the first nine months of 2017, as a result of the Company securing short term sales contracts when WCS differentials were narrower than the average market trade for the same period in 2016. The Company's third quarter realized condensate price increased 26% over the same period in 2016 as compared to the 21% increase in the Condensate at Edmonton benchmark price, as a result of the aforementioned lower pipeline tariffs and quality differentials applied against the Company's condensate sales. Other ngl realized price increased significantly in the first nine months of 2017, due to the increase in propane pricing as compared to the same period in 2016. The Company's natural gas price increased 29% over the same period in 2016 which is consistent with the Company's natural gas sales portfolio weighted benchmark price increase of 25%.

Royalties

($ thousands, except per boe)	**Three months ended Sept. 30, 2017**	Three months ended Sept. 30, 2016	**Nine months ended Sept. 30, 2017**	Nine months ended Sept. 30, 2016
Royalties	**3,067**	2,724	**11,460**	6,662
Per boe	**1.43**	1.28	**1.88**	1.06
Percentage of revenue	**6.4%**	5.8%	**7.4%**	5.6%

For the third quarter of 2017, royalties and royalties as a percentage of revenue increased over the same periods in 2016 as a result of the increase in oil production at Tower, which attracts higher royalty rates as compared to the corporate average, coupled with higher realized oil and ngl pricing which realizes higher royalty rates. The increased Tower royalties were partially offset by new production at Greater Septimus, which attracts lower royalties due to new well deep gas royalty credit programs. In addition, declines in higher royalty rate heavy oil production at Lloydminster partially offset the increased corporate royalty rates. For the first nine months of 2017, royalties and royalties as a percentage of revenue increased as a result of the 33% increase in realized commodity pricing and increased production from Tower. This was partially offset by declines in Lloydminster production, which attracts higher royalty rates, and new production from Greater Septimus that yield lower royalty rates as compared to the corporate average. The Company continues to expect its royalties as a percentage of revenue to average between 6% and 8% in 2017.

Derivative Financial Instruments

Commodities

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

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

($ thousands)	**Three months ended Sept. 30, 2017**	Three months ended Sept. 30, 2016	**Nine months ended Sept. 30, 2017**	Nine months ended Sept. 30, 2016
Realized gain on derivative financial instruments	**5,910**	2,112	**6,287**	12,571
Per boe	**2.76**	0.99	**1.03**	1.99
Unrealized (loss) gain on financial instruments	**(1,341)**	(763)	**25,475**	(9,060)

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

Subject of Contract	Notional Quantity	Term	Reference	Strike Price	Option Traded	Fair Value
Gas	2,500 gj/day	October 1, 2017 – October 31, 2017	AECO C Daily Index	$2.55	Swap	$ 129
Gas	22,500 mmbtu/day	October 1, 2017 – December 31, 2017	Chicago Citygate	$3.88	Swap	439
Oil	1,750 bbl/day	October 1, 2017 – December 31, 2017	CDN$ WTI	$68.02	Swap	516
Gas	22,500 gj/day	October 1, 2017 – December 31, 2017	AECO C Monthly Index	$2.83	Swap	1,732
Gas	10,000 gj/day	October 1, 2017 – December 31, 2017	AECO C Daily Index	$3.08	Swap	1,419
Gas	5,000 mmbtu/day	October 1, 2017 – December 31, 2018	Chicago Citygate	$4.23	Swap	1,497
Gas	5,000 gj/day	January 1, 2018 – December 31, 2018	AECO C Monthly Index	$3.00	Call	(107)
Gas	2,500 gj/day	January 1, 2018 – December 31, 2018	AECO C Daily Index	$2.62	Swap	394
Gas	5,000 mmbtu/day	January 1, 2018 – December 31, 2018	US$ Nymex Henry Hub	$3.05	Swap	8
Oil	250 bbl/day	January 1, 2018 – December 31, 2018	CDN$ WTI	$65.27	Swap	58
Oil	250 bbl/day	January 1, 2018 – December 31, 2018	CDN$ WTI	$60.00 - $69.65	Collar(1)	-
Total						**$ 6,085**

(1) The referenced contract is a costless collar whereby the Company receives $60/bbl when the market price is below $60/bbl, and receives $69.65/bbl when the market price is above $69.65/bbl.

Subsequent to September 30, 2017, the Company entered into the following derivative commodity contracts:

Subject of Contract	Notional Quantity	Term	Reference	Strike Price	Option Traded
Oil	250 bbl/day	January 1, 2018 – December 31, 2018	CDN$ WTI	$69.00	Swap

Operating Costs

($ thousands, except per boe)	**Three months ended Sept. 30, 2017**	Three months ended Sept. 30, 2016	**Nine months ended Sept. 30, 2017**	Nine months ended Sept. 30, 2016
Operating costs	**12,530**	12,076	**35,236**	38,127
Per boe	**5.86**	5.66	**5.78**	6.05

For the third quarter of 2017, operating costs per boe increased 4% as compared to the same period in 2016 as a result of the aforementioned increase in Tower light oil production which yields higher operating costs per boe as compared to the corporate average, partially offset by a decrease in higher cost Lloydminster production. For the first nine months of 2017, operating costs per boe decreased 4% over the same period last year as the Company continues to realize efficiencies at Greater Septimus where operating costs have decreased 11% in the first nine months of 2017, as compared to the same period in 2016. In addition, decreased higher cost heavy oil production lowered corporate operating costs per boe which was partially offset by increased higher cost Tower light oil production. The Company continues to forecast its 2017 operating costs to average between $5.50 and $6.00 per boe.

Transportation Costs

($ thousands, except per boe)	**Three months ended Sept. 30, 2017**	Three months ended Sept. 30, 2016	**Nine months ended Sept. 30, 2017**	Nine months ended Sept. 30, 2016
Transportation costs	**4,672**	4,320	**14,579**	14,504
Per boe	**2.18**	2.02	**2.39**	2.30

In the third quarter and first nine months of 2017, the Company's transportation costs per boe increased as compared to the same periods in 2016 as a result of increased production in Other NE BC which attracts higher transportation costs per boe, combined with lower production from Lloydminster where transportation costs per boe are lower as compared to the corporate average. In addition, the aforementioned extended facility and pipeline outages negatively impacted Other NE BC transportation costs per unit as the Company incurred unutilized fixed facility and pipeline demand charges during the second and third quarters of 2017. The Company continues to forecast transportation costs per boe to range between $2.25 and $2.50 for 2017.

Operating Netbacks

($/boe)	**Greater Septimus**	**Lloydminster Heavy Oil**	**Other NE BC**	**Three months ended Sept. 30, 2017**	Three months ended Sept. 30, 2016
Revenue	**20.05**	**43.82**	**22.66**	**22.36**	22.05
Royalties	**(0.89)**	**(5.58)**	**(2.03)**	**(1.43)**	(1.28)
Realized commodity hedging gain	**2.97**	**0.01**	**3.21**	**2.76**	0.99
Operating costs	**(3.38)**	**(22.58)**	**(9.97)**	**(5.86)**	(5.66)
Transportation costs	**(1.65)**	**(0.92)**	**(5.96)**	**(2.18)**	(2.02)
Operating netbacks	**17.10**	**14.75**	**7.91**	**15.65**	14.08
Production (boe/d)	**18,154**	**1,906**	**3,191**	**23,251**	23,211

($/boe)	**Greater Septimus**	**Lloydminster Heavy Oil**	**Other NE BC**	**Nine months ended Sept. 30, 2017**	Nine months ended Sept. 30, 2016
Revenue	**23.58**	**43.86**	**23.71**	**25.28**	18.99
Royalties	**(1.36)**	**(5.51)**	**(2.53)**	**(1.88)**	(1.06)
Realized commodity hedging gain/(loss)	**1.14**	**(0.44)**	**1.31**	**1.03**	1.99
Operating costs	**(3.58)**	**(21.75)**	**(8.12)**	**(5.78)**	(6.05)
Transportation costs	**(1.77)**	**(0.94)**	**(6.28)**	**(2.39)**	(2.30)
Operating netbacks	**18.01**	**15.22**	**8.09**	**16.26**	11.57
Production (boe/d)	**17,053**	**1,852**	**3,412**	**22,317**	22,999

For the third quarter of 2017, the Company's operating netbacks increased 11% over the same period in 2016 as a result of an increase in realized pricing and realized hedging gains, partially offset by increased royalties and transportation costs. For the first nine months of 2017, the Company's operating netbacks increased 41% over the same period in 2016 as a result of a significant increase in realized pricing and lower operating costs, partially offset by a decrease in realized hedging gains and increased royalties.

General and Administrative Costs

($ thousands, except per boe)	**Three months ended Sept. 30, 2017**	Three months ended Sept. 30, 2016	**Nine months ended Sept. 30, 2017**	Nine months ended Sept. 30, 2016
Gross costs	**4,193**	4,357	**13,639**	13,886
Operator's recoveries	**(105)**	(86)	**(314)**	(187)
Capitalized costs	**(1,334)**	(1,600)	**(4,584)**	(4,665)
General and administrative expenses	**2,754**	2,671	**8,741**	9,034
Per boe	**1.29**	1.25	**1.43**	1.43

Gross general and administrative ("G&A") costs have decreased in the three months ended September 30, 2017 as compared to the same period in 2016, due to a decrease in compensation costs as a result of reduced staffing levels, partially offset by the adjusted office rent costs from the renewed five year lease term. The decrease in compensation costs resulted in a decrease in capitalized costs, which contributed to the slight increase in net G&A as compared to the same period in 2016. For the first nine months of 2017, gross and net G&A costs decreased as compared to the same period in 2016, due to the aforementioned decrease in compensation costs. Crew continues to forecast G&A costs per boe to average between $1.25 and $1.50 in 2017.

Share-Based Compensation

($ thousands)	**Three months ended Sept. 30, 2017**	Three months ended Sept. 30, 2016	**Nine months ended Sept. 30, 2017**	Nine months ended Sept. 30, 2016
Gross costs	**4,108**	3,964	**14,058**	12,756
Capitalized costs	**(1,886)**	(1,883)	**(6,675)**	(5,894)
Total share-based compensation	**2,222**	2,081	**7,383**	6,862

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

Depletion and Depreciation

($ thousands, except per boe)	**Three months ended Sept. 30, 2017**	Three months ended Sept. 30, 2016	**Nine months ended Sept. 30, 2017**	Nine months ended Sept. 30, 2016
Depletion and depreciation	**19,408**	21,054	**55,511**	66,480
Per boe	**9.07**	9.86	**9.11**	10.55

Depletion and depreciation costs decreased in the three and nine month periods ended September 30, 2017 by 8% and 16%, respectively, and costs per boe decreased by 8% and 14%, respectively, as compared to the same periods in 2016. These decreases were due to increased 2016 year end proved plus probable reserve bookings at Greater Septimus, where depletion rates are substantially lower than the corporate average. Additionally, lower depletion was recognized on the Lloydminster cash-generating unit ("CGU") due to an impairment write down in the second quarter of 2017 and fourth quarter of 2016 which reduced the CGU's net book value.

Impairment

In the second quarter of 2017, due to the continuing decline in the heavy oil price environment, reduced future heavy oil development plans and the prevailing heavy oil transaction market, the Company tested its Lloydminster CGU for impairment. It was determined that the carrying value of the Lloydminster heavy oil CGU exceeded its fair value and a $16.7 million impairment charge was recorded.

There were no indicators of impairment for the Company's CGUs as at September 30, 2017, and therefore an impairment test was not performed.

Gain on Divesture of Property

During the third quarter of 2017, the Company entered into a swap of petroleum and natural gas properties and undeveloped land with a total net book value of $1.1 million and associated decommissioning obligations of $0.1 million for land with a fair value of $3.0 million and $0.1 million cash, resulting in a gain of $2.1 million.

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

Finance Expenses

($ thousands, except per boe)	**Three months ended Sept. 30, 2017**	Three months ended Sept. 30, 2016	**Nine months ended Sept. 30, 2017**	Nine months ended Sept. 30, 2016
Interest on bank loan and other	**576**	1,093	**1,892**	3,249
Interest on senior notes	**4,915**	3,166	**13,638**	9,396
Accretion of deferred financing charges	**250**	122	**707**	472
Accretion of the decommissioning obligation	**482**	438	**1,435**	1,307
Premium paid on redemption of 2020 Notes	**-**	-	**6,282**	-
Deferred financing costs expensed on 2020 Notes	**-**	-	**2,510**	-
Total finance expense	**6,223**	4,819	**26,464**	14,424
Average debt level	**302,702**	239,193	**290,992**	239,073
Average drawings on bank loan	**2,702**	89,193	**25,058**	89,073
Average senior unsecured notes outstanding	**300,000**	150,000	**265,934**	150,000
Effective interest rate on senior unsecured notes	**6.5%**	8.4%	**6.9%**	8.4%
Effective interest rate on long-term debt	**6.5%**	6.4%	**6.5%**	6.4%
Financing costs on long-term debt per boe	**2.68**	2.05	**2.67**	2.08

The Company's average corporate debt level increased in the three and nine months ended September 30, 2017 as compared to the same periods in 2016, due to increased capital expenditures in 2017 which have been heavily weighted to the first and third quarters of 2017. In addition, during the first quarter of 2017, the Company issued $300 million of 6.5% senior unsecured notes (the "2024 Notes") as described below in the Capital Funding section. Proceeds from the 2024 Notes were used to redeem the $150 million of 8.375% senior unsecured notes (the "2020 Notes") and repay the drawings on the bank loan. As a result, the effective interest rate on the Company's senior notes decreased for the three and nine months periods ended September 30, 2017 as compared to the same periods in 2016. In addition, the Company's corporate effective interest rate increased in 2017 due to an increase in standby fees as the Company was undrawn on its bank facility throughout the second quarter and majority of the third quarter of 2017. Crew forecasts the effective interest rate on its long-term debt to average approximately 6.5% for 2017.

Deferred Income Taxes

In the third quarter and first nine months of 2017, the provision for deferred tax expense was $1.5 million and $18.0 million, respectively, as compared to the deferred tax recovery of nil and $7.2 million, respectively, in the same periods in 2016. The increase in deferred tax expense is a result of increased income before taxes from the gain on disposition of non-core assets in the second and third quarters of 2017.

Cash, Funds from Operations and Net Income (Loss)

($ thousands, except per share amounts)		**Three months ended Sept. 30, 2017**	Three months ended Sept. 30, 2016	**Nine months ended Sept. 30, 2017**	Nine months ended Sept. 30, 2016
Cash provided by operating activities		**15,258**	25,940	**73,806**	57,578
Funds from operations		**24,970**	23,033	**74,042**	50,795
Per share	- basic	**0.17**	0.16	**0.50**	0.36
	- diluted	**0.17**	0.16	**0.49**	0.35
Net Income (loss)		**2,127**	(1,286)	**32,063**	(24,896)
Per share	- basic	**0.01**	(0.01)	**0.22**	(0.17)
	- diluted	**0.01**	(0.01)	**0.21**	(0.17)

The decrease in cash provided by operating activities in the third quarter of 2017 was a result of a significant increase in operating non-cash working capital. Funds from operations in the third quarter of 2017 increased as compared to the same period in 2016 due to an increase in realized pricing and realized hedging gains, partially offset by increased royalties and transportation costs. The increase in net income for the third quarter and first nine months of 2017 is a result of the gain on disposition of properties in the second and third quarters of 2017, as compared to the same period last year. For the first nine months of 2017, cash provided from operating activities and funds from operations increased as a result of a significant increase in realized pricing and lower operating costs, partially offset by a decrease in realized hedging gains and increased royalties and transportation costs.

Capital Expenditures, Property Acquisitions and Dispositions

In the third quarter of 2017, the Company drilled thirteen (12.3 net) natural gas wells in northeast British Columbia. Crew also completed sixteen (16.0 net) wells in northeast British Columbia, and recompleted nine (8.6 net) oil wells in Lloydminster.

The Company focused on executing its drilling and completions program in northeast British Columbia in the third quarter of 2017, spending $65.3 million or 73% of its capital expenditures. In addition, Crew continued to expand its infrastructure in northeast British Columbia, spending $22.3 million on wellsites, facilities and pipelines, which included $3.0 million on the West Septimus facility expansion where the Company owns 28% of the facility. The majority of the remaining capital expenditures related to pipeline infrastructure expenditures to tie-in new production to the Company's gas facilities.

Total net capital expenditures are detailed below:

($ thousands)	**Three months ended Sept. 30, 2017**	Three months ended Sept. 30, 2016	**Nine months ended Sept. 30, 2017**	Nine months ended Sept. 30, 2016
Land	**796**	1,100	**2,486**	2,395
Seismic	**232**	179	**714**	578
Drilling and completions	**65,349**	30,284	**156,259**	54,660
Facilities, equipment and pipelines	**22,328**	4,526	**37,415**	8,063
Other	**1,364**	1,642	**5,015**	4,894
Total exploration and development	**90,069**	37,731	**201,889**	70,590
Property (dispositions) acquisitions	**(144)**	(98)	**(46,197)**	874
Total	**89,925**	37,633	**155,692**	71,464

LIQUIDITY AND CAPITAL RESOURCES

Capital Funding

As at September 30, 2017, the Company's bank facility consists of a revolving line of credit of $210 million and an operating line of credit of $25 million (the "Facility"). The Facility revolves for a 364 day period and will be subject to its next 364 day extension by June 6, 2018. If not extended, the Facility will cease to revolve, the margins thereunder will increase by 0.50 per cent and all outstanding advances thereunder will become repayable in one year from the extension date. The available lending limits of the Facility (the "Borrowing Base") are reviewed semi-annually and are based on the bank syndicate's interpretation of the Company's reserves and future commodity prices. Subsequent to September 30, 2017, the Facility was reviewed, and based on discussions with the Company's lenders, it is expected that the Borrowing Base will be confirmed at the same levels. The credit agreement requires the Company to maintain a debt to EBITDA ratio of 4:1 and a secured debt to EBITDA ratio of 3:1 at the end of each fiscal quarter. Debt consists of the Company's bank loan and senior unsecured notes, while secured debt consists of the Company's bank loan. At September 30, 2017, these ratios were 2.7:1 and 0.3:1, respectively. EBITDA is a non-GAAP measure and is defined in the credit agreement as earnings before interest, taxes, depreciation and amortization, unrealized gains or losses on financial instruments, share-based compensation, all other non-cash items and EBITDA from disposed properties and acquisitions for the most recent twelve month period. Other non-cash items include impairment, gains or losses on divestitures and the premium on flow-through shares for the most recent twelve month period. There can be no assurance that the amount of the available Facility will not be adjusted at the next scheduled Borrowing Base review on or before June 6, 2018. The Facility is secured by a floating charge debenture and a general securities agreement on the assets of the Company.

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

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

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

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

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

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

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

Working Capital

The capital intensive nature of Crew's activities generally results in the Company carrying a working capital deficit. Working capital includes cash and cash equivalents and accounts receivable, less accounts payable and accrued liabilities. Included in working capital deficiency is a receivable of $8.1 million for a government grant credit earned through the completion of the construction of the Pine River pipeline. The collection of the grant is realized through the reduction of future royalties payable to the British Columbia government. In addition, the working capital deficiency includes a receivable of $31.5 million relating to the partner's share of the West Septimus facility expansion costs which is expected to be collected in the fourth quarter of 2017.

The Company ensures that sufficient drawings are available from its Facility to satisfy working capital requirements. At September 30, 2017, the Company had a working capital deficiency of $14.3 million, which, when combined with its bank loan, represented 20% of the Facility.

Share Capital

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

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

Expenses such that the full proceeds were deductible against the subscribers' income in 2017. The Company has incurred the entire $15.0 million in qualifying expenditures under this flow-through share offering during the first quarter of 2017.

Crew is authorized to issue an unlimited number of common shares. As at November 2, 2017, there were 148,955,853 common shares issued and outstanding and options to acquire 25,800 common shares. In addition, there were 1,762,168 restricted awards and 2,583,629 performance awards outstanding under the Company's long-term incentive program.

Capital Structure

The Company considers its capital structure to include working capital, long-term debt (including the bank loan and senior unsecured notes) and shareholders' equity. Crew's primary capital management objective is to maintain a strong financial position in order to continue to fund the future growth of the Company. Crew monitors its capital structure and makes adjustments on an ongoing basis in order to maintain the flexibility needed to achieve the Company's long-term objectives. To manage its capital structure, the Company may adjust capital spending, hedge future revenue and costs, issue new equity, issue new debt or repay existing debt through non-core asset sales.

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

The Company monitors this ratio and endeavours to maintain it at approximately 2.0 to 1.0 or lower. Since early 2015, a period of extended low commodity prices has negatively impacted quarterly funds from operations and increased this ratio. In addition, in order to accommodate future production growth, the Company has incurred incremental capital to expand its infrastructure in core areas which has increased its debt levels. As this upfront capital expenditure on infrastructure allows for increase future production leading to higher funds from operations, the Company expects this ratio to decrease from current levels. As shown below, as at September 30, 2017, the Company's ratio of net debt to annualized funds from operations was 3.40 to 1 (December 31, 2016 – 2.20 to 1). With the Company's recently confirmed $235 million Facility and the 2024 Notes, the Company's financial position is strong. If the Company feels it is necessary to improve its financial position, it will consider divesting of non-core properties, will further adjust its annual capital expenditure program or may consider other forms of financing.

($ thousands, except ratio)	**September 30, 2017**	December 31, 2016
Working capital deficiency	**(14,306)**	(10,006)
Bank loan	**(31,696)**	(88,036)
Senior unsecured notes	**(293,546)**	(147,329)
Net debt	**(339,548)**	(245,371)
Quarterly funds from operations	**24,970**	27,879
Annualized	**99,880**	111,516
Net debt to annualized funds from operations ratio	**3.40**	2.20

Contractual Obligations

Throughout the course of its ongoing business, the Company enters into various contractual obligations such as credit agreements, purchase of services, royalty agreements, operating agreements, processing agreements, right of way agreements and lease obligations for office space and automotive equipment. All such contractual obligations reflect market conditions prevailing at the time of contract and none are with related parties. The Company believes it has adequate sources of capital to fund all contractual obligations as they come due. The following table lists the Company's obligations with a fixed term.

($ thousands)	Total	2017	2018	2019	2020	2021	Thereafter
Bank loan (note 1)	31,696	-	-	31,696	-	-	-
Senior unsecured notes (note 2)	300,000	-	-	-	-	-	300,000
Operating leases	4,211	294	1,175	1,175	1,175	392	-
Capital commitments	3,764	3,764	-	-	-	-	-
Firm transportation agreements	168,162	8,109	36,580	35,958	32,728	9,789	44,998
Firm processing agreements	87,249	3,208	12,729	12,729	11,419	7,449	39,715
Total	**595,082**	**15,375**	**50,484**	**81,558**	**45,322**	**17,630**	**384,713**

Note 1 – Based on the existing terms of the Company's Facility, the first possible repayment date may come in 2019. However, it is expected that the Facility will be extended and no repayment will be required in the near term.
Note 2 – Matures on March 14, 2024.

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

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

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

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

GUIDANCE

With the Company's focus on condensate production and profitability exhibited in the third quarter, our fourth quarter 2017 production guidance has been adjusted to reflect the continuation of sub-economic non-Montney production being shut in, and a concentration on drilling for higher valued condensate volumes and lower natural gas volumes. As such, production in the fourth quarter is anticipated to range between 26,000 and 27,000 boe per day with exit production at approximately 31,000 boe per day.

ADDITIONAL DISCLOSURES

Quarterly Analysis

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

($ thousands, except per share amounts)	**Sep. 30 2017**	June 30 2017	Mar. 31 2017	Dec. 31 2016	Sep. 30 2016	June 30 2016	Mar. 31 2016	Dec. 31 2015
Total daily production (boe/d)	**23,251**	20,468	23,231	22,380	23,211	21,950	23,832	20,706
Exploration and development expenditures	**90,069**	36,656	75,164	37,612	37,731	15,096	17,763	42,067
Property (dispositions)/acquisitions	**(144)**	(45,701)	(352)	3,099	(98)	16	956	(36,644)
Average wellhead price ($/boe)	**22.36**	26.25	27.40	26.74	22.05	18.14	16.76	18.13
Petroleum and natural gas sales	**47,824**	48,886	57,298	55,051	47,093	36,232	36,343	34,532
Cash provided by operations	**15,258**	31,359	27,189	19,900	25,940	12,047	19,591	12,373
Funds from operations	**24,970**	21,353	27,719	27,879	23,033	16,048	11,714	19,601
Per share – basic	**0.17**	0.14	0.19	0.19	0.16	0.11	0.08	0.14
– diluted	**0.17**	0.14	0.18	0.19	0.16	0.11	0.08	0.14
Net income (loss)	**2,127**	21,880	8,056	(40,030)	(1,286)	(16,815)	(6,795)	(8,167)
Per share – basic	**0.01**	0.15	0.05	(0.28)	(0.01)	(0.12)	(0.05)	(0.06)
– diluted	**0.01**	0.14	0.05	(0.28)	(0.01)	(0.12)	(0.05)	(0.06)

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

The significant fluctuations in commodity prices have impacted cash provided by operations, funds from operations and net income (loss). Crew has reduced the financial impact of volatile commodity prices by entering into derivative and physical risk management contracts which can cause significant fluctuations in income due to unrealized gains and losses recognized on a quarterly basis. The Company has also attempted to mitigate the lower price environment by reducing its controllable costs. Over the past two years, low commodity prices have also led to the assessment and realization of impairment of the carrying value of the Lloydminster CGU. In 2015, 2016 and 2017, the Company has incurred impairment charges of $55.4 million, $44.4 million and $16.7 million, respectively. These charges have been partially offset by gains on the sale of certain properties in 2015 and 2017. In the second quarter of 2017, the Company's production declined as a result of significant third party facility outages and an extended spring break up which has shifted planned investment and projected growth to the second half of year. The Company has increased its infrastructure spending to facilitate this growth and continues to monetize non-core properties where the Company realized a $37.9 million gain on the divesture in the second quarter of 2017.

New Accounting Pronouncements

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

a) IFRS 15 Revenue from Contracts with Customers:

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

b) IFRS 9 Financial Instruments:

As of January 1, 2018, the Company will be required to adopt IFRS 9 Financial Instruments, which is the result of the first phase of the IASB project to replace IAS 39 Financial Instruments: Recognition and Measurement. The new standard replaces the current multiple classification and measurement models for financial assets and liabilities with a single model that has two classification categories: amortized cost and fair value. In addition, updates have also been applied surrounding hedge accounting requirements which are now more aligned with an entity's risk management activities. The Company does not currently apply hedge accounting to its financial instruments contracts and does not currently intend to apply hedge accounting to any of its financial instrument contracts upon adoption of IFRS 9.

c) IFRS 16 Leases:

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

Disclosure Controls and Procedures and Internal Controls over Financial Reporting

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

The Company's CEO and CFO have designed, or caused to be designed under their supervision, internal controls over financial reporting to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. The Company is required to disclose herein any change in the Company's internal controls over financial reporting that occurred during the period beginning on July 1, 2017 and ended on September 30, 2017 that has materially affected, or is reasonably likely to materially affect, the Company's internal controls over financial reporting. No material changes in the Company's internal controls over financial reporting were identified during such period that have materially affected, or are reasonably likely to materially affect, the Company's internal controls over financial reporting.

It should be noted that a control system, including the Company's disclosure and internal controls and procedures, no matter how well conceived, can provide only reasonable, but not absolute assurance that the objectives of the control system will be met and it should not be expected that the disclosure and internal controls and procedures will prevent all errors or fraud.

Dated as of November 2, 2017

CONDENSED INTERIM CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

(unaudited) (thousands)	**September 30, 2017**	December 31, 2016
Assets		
Current Assets:		
Accounts receivable	**$ 64,201**	$ 39,588
Derivative financial instruments (note 8)	**5,405**	-
	69,606	39,588
Derivative financial instruments (note 8)	**680**	-
Property, plant and equipment (note 3)	**1,331,053**	1,199,452
	$ 1,401,339	$ 1,239,040
Liabilities and Shareholders' Equity		
Current Liabilities:		
Accounts payable and accrued liabilities	**$ 78,507**	$ 49,594
Derivative financial instruments (note 8)	**-**	18,900
	78,507	68,494
Derivative financial instruments (note 8)	**-**	490
Bank loan (note 4)	**31,696**	88,036
Senior unsecured notes (note 5)	**293,546**	147,329
Decommissioning obligations (note 6)	**87,898**	85,859
Deferred premium on flow-through shares (note 7)	**-**	1,419
Deferred tax liability	**45,133**	25,724
Shareholders' Equity		
Share capital (note 7)	**1,456,149**	1,442,284
Contributed surplus	**71,902**	74,960
Deficit	**(663,492)**	(695,555)
	864,559	821,689
Subsequent events (note 4,8)		
Commitments (note 10)		
	$ 1,401,339	$ 1,239,040

See accompanying notes to the condensed interim consolidated financial statements.

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

(unaudited) (thousands, except per share amounts)	**Three months ended Sept. 30, 2017**	Three months ended Sept. 30, 2016	**Nine months ended Sept. 30, 2017**	Nine months ended Sept. 30, 2016
Revenue				
Petroleum and natural gas sales	**$ 47,824**	$ 47,093	**$ 154,008**	$ 119,668
Royalties	**(3,067)**	(2,724)	**(11,460)**	(6,662)
Realized gain on derivative financial instruments (note 8)	**5,910**	2,112	**6,287**	12,571
Unrealized (loss) gain on derivative financial instruments (note 8)	**(1,341)**	(763)	**25,475**	(9,060)
	49,326	45,718	**174,310**	116,517
Expenses				
Operating	**12,530**	12,076	**35,236**	38,127
Transportation	**4,672**	4,320	**14,579**	14,504
General and administrative	**2,754**	2,671	**8,741**	9,034
Share-based compensation	**2,222**	2,081	**7,383**	6,862
Depletion and depreciation (note 3)	**19,408**	21,054	**55,511**	66,480
	41,586	42,202	**121,450**	135,007
Income (loss) from operations	**7,740**	3,516	**52,860**	(18,490)
Financing (note 9)	**6,223**	4,819	**26,464**	14,424
Gain on marketable securities	**-**	-	**-**	(955)
Impairment on property, plant and equipment (note 3)	**-**	-	**16,710**	-
(Gain) loss on divestiture of property, plant and equipment (note 3)	**(2,123)**	-	**(40,367)**	130
Income (loss) before income taxes	**3,640**	(1,303)	**50,053**	(32,089)
Deferred tax expense (recovery)	**1,513**	(17)	**17,990**	(7,193)
Net income (loss) and comprehensive income (loss)	**$ 2,127**	$ (1,286)	**$ 32,063**	$ (24,896)
Net income (loss) per share (note 7)				
Basic	**$ 0.01**	$ (0.01)	**$ 0.22**	$ (0.17)
Diluted	**$ 0.01**	$ (0.01)	**$ 0.21**	$ (0.17)

See accompanying notes to the condensed interim consolidated financial statements.

CONDENSED INTERIM CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

(unaudited) (thousands)	Number of shares	Share capital	Contributed surplus	Deficit	Total Shareholders' equity
Balance, January 1, 2017	146,812	$ 1,442,284	$ 74,960	$ (695,555)	$ 821,689
Net income for the period	-	-	-	32,063	32,063
Share-based compensation expensed	-	-	7,383	-	7,383
Share-based compensation capitalized	-	-	6,675	-	6,675
Issued on vesting of share awards	3,068	17,116	(17,116)	-	-
Shares purchased and cancelled (note 7)	(924)	(3,251)	-	-	(3,251)
Balance, September 30, 2017	**148,956**	**$ 1,456,149**	**$ 71,902**	**$ (663,492)**	**$ 864,559**

(unaudited) (thousands)	Number of shares	Share capital	Contributed surplus	Deficit	Total Shareholders' equity
Balance, January 1, 2016	141,067	$ 1,398,698	$ 77,627	$ (630,629)	$ 845,696
Net loss for the period	-	-	-	(24,896)	(24,896)
Share-based compensation expensed	-	-	6,862	-	6,862
Share-based compensation capitalized	-	-	5,894	-	5,894
Transfer to share capital for exercised options	-	4,793	(4,793)	-	-
Issued on exercise of options	1,794	10,131	-	-	10,131
Issued on vesting of share awards	1,677	12,797	(12,797)	-	-
Balance, September 30, 2016	**144,538**	**$ 1,426,419**	**$ 72,793**	**$ (655,525)**	**$ 843,687**

See accompanying notes to the condensed interim consolidated financial statements.

CONDENSED INTERIM CONSOLIDATED STATEMENTS OF CASH FLOWS

(unaudited) (thousands)	**Three months ended Sept. 30, 2017**	Three months ended Sept. 30, 2016	**Nine months ended Sept. 30, 2017**	Nine months ended Sept. 30, 2016
Cash provided by (used in):				
Operating activities:				
Net income (loss)	**$ 2,127**	$ (1,286)	**$ 32,063**	$ (24,896)
Adjustments:				
Unrealized loss (gain) on derivative financial instruments	**1,341**	763	**(25,475)**	9,060
Share-based compensation	**2,222**	2,081	**7,383**	6,862
Depletion and depreciation	**19,408**	21,054	**55,511**	66,480
Financing expenses (note 9)	**6,223**	4,819	**26,464**	14,424
Interest expense (note 9)	**(5,491)**	(4,259)	**(15,530)**	(12,645)
Gain on marketable securities	**-**	-	**-**	(955)
Impairment on property, plant and equipment (note 3)	**-**	-	**16,710**	-
(Gain) loss on divestiture of property, plant and equipment (note 3)	**(2,123)**	-	**(40,367)**	130
Deferred tax expense (recovery)	**1,513**	(17)	**17,990**	(7,193)
Decommissioning obligations settled	**(128)**	(262)	**(484)**	(648)
Change in non-cash working capital	**(9,834)**	3,047	**(459)**	6,959
	15,258	25,940	**73,806**	57,578
Financing activities:				
Increase (decrease) in bank loan	**31,696**	(14,799)	**(56,340)**	1,407
Proceeds from exercise of options	**-**	10,131	**-**	10,131
Issuance of senior notes, net of financing costs (note 5)	**-**	-	**293,000**	-
Redemption of senior notes (note 5)	**-**	-	**(156,282)**	-
Shares purchased and cancelled (note 7)	**-**	-	**(3,251)**	-
	31,696	(4,668)	**77,127**	11,538
Investing activities:				
Property, plant and equipment expenditures	**(90,069)**	(37,731)	**(201,889)**	(70,590)
Property acquisitions	**(6)**	88	**(3,826)**	(978)
Property dispositions (note 3)	**150**	10	**50,023**	104
Proceeds from disposition of marketable securities	**-**	-	**-**	2,115
Change in non-cash working capital	**14,891**	16,361	**4,759**	233
	(75,034)	(21,272)	**(150,933)**	(69,116)
Change in cash and cash equivalents	**(28,080)**	-	**-**	-
Cash and cash equivalents, beginning of period	**28,080**	-	**-**	-
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, 2017 and 2016

(Unaudited) (Tabular amounts in thousands)

1. Reporting entity:

Crew Energy Inc. ("Crew" or the "Company") is an oil and gas exploration, development and production company based in Calgary, Alberta, Canada. Crew conducts its operations in the Western Canadian Sedimentary basin, primarily in the provinces of British Columbia, Saskatchewan and Alberta. The condensed interim consolidated financial statements (the "financial statements") of the Company are comprised of the accounts of Crew and its wholly owned subsidiary, Crew Oil and Gas Inc., which is incorporated in Canada, and two partnerships, Crew Energy Partnership and Crew Heavy Oil Partnership. Crew's principal place of business is located at Suite 800, 250 – 5th Street SW, Calgary, Alberta, Canada, T2P 0R4.

2. Basis of preparation:

These financial statements have been prepared in accordance with IAS 34 – Interim Financial Reporting of the International Financial Reporting Standards ("IFRS"). The financial statements use the accounting policies which the Company applied in its annual consolidated financial statements for the year ended December 31, 2016. The financial statements do not include certain disclosures that are normally required to be included in annual consolidated financial statements which have been condensed or omitted. These financial statements are presented in Canadian dollars ("CDN"), which is the functional currency of the Company, its subsidiary and partnerships.

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

3. Property, plant and equipment:

Cost or deemed cost	Total
Balance, January 1, 2016	$ 2,061,858
Additions	108,202
Acquisitions	4,097
Divestitures	(254)
Change in decommissioning obligations	(320)
Capitalized share-based compensation	7,696
Balance, December 31, 2016	$ 2,181,279
Additions	201,889
Acquisitions	6,826
Divestitures	(13,337)
Change in decommissioning obligations	1,690
Capitalized share-based compensation	6,675
Balance, September 30, 2017	**$ 2,385,022**

Accumulated depletion and depreciation	Total
Balance, January 1, 2016	$ 851,992
Depletion and depreciation expense	85,403
Impairment (net)	44,432
Balance, December 31, 2016	$ 981,827
Depletion and depreciation expense	55,511
Divestitures	(79)
Impairment	16,710
Balance, September 30, 2017	**$ 1,053,969**

Net book value	Total
Balance, September 30, 2017	**$ 1,331,053**
Balance, December 31, 2016	$ 1,199,452

The calculation of depletion for the three months ended September 30, 2017 included estimated future development costs of $1,473.2 million (December 31, 2016 - $1,603.2 million) associated with the development of the Company's proved plus probable reserves and excludes salvage value of $69.1 million (December 31, 2016 - $67.3 million) and undeveloped land of $170.9 million (December 31, 2016 - $182.3 million) related to future development acreage with no associated reserves.

During the third quarter of 2017, the Company entered into a swap of petroleum and natural gas properties and undeveloped land with a total net book value of $1.1 million and associated decommissioning obligations of $0.1 million for land with a fair value of $3.0 million and $0.1 million cash, resulting in a gain of $2.1 million.

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

In the second quarter of 2017, due to the continuing decline in the heavy oil price environment, reduced future heavy oil development plans and the prevailing heavy oil transaction market, the Company tested its Lloydminster cash generating unit ("CGU") for impairment. It was determined that the carrying value of the Lloydminster heavy oil CGU exceeded its fair value and a $16.7 million impairment charge was recorded.

There were no indicators of impairment for the Company's CGUs as at September 30, 2017, and therefore an impairment test was not performed.

4. Bank loan:

As at September 30, 2017, the Company's bank facility consists of a revolving line of credit of $210 million and an operating line of credit of $25 million (the "Facility"). The Facility revolves for a 364 day period and will be subject to its next 364 day extension by June 6, 2018. If not extended, the Facility will cease to revolve, the margins thereunder will increase by 0.50 per cent and all outstanding advances thereunder will become repayable in one year from the extension date. The available lending limits of the Facility (the "Borrowing Base") are reviewed semi-annually and are based on the bank syndicate's interpretation of the Company's reserves and future commodity prices. Subsequent to September 30, 2017, the Facility was reviewed, and based on discussions with the Company's lenders, it is expected that the Borrowing Base will be confirmed at the same levels. The credit agreement requires the Company to maintain a debt to EBITDA ratio of 4:1 and a secured debt to EBITDA ratio of 3:1 at the end of each fiscal quarter. Debt consists of the Company's bank loan and senior unsecured notes, while secured debt consists of the Company's bank loan. At September 30, 2017, these ratios were 2.7:1 and 0.3:1, respectively. EBITDA is a non-GAAP measure and is defined in the credit agreement as earnings before interest, taxes, depreciation and amortization, unrealized gains or losses on financial instruments, share-based compensation, all other non-cash items and EBITDA from disposed properties and acquisitions for the most recent twelve month period. Other non-cash items include impairment, gains or losses on divestitures and the premium on flow-through shares for the most recent twelve month period. There can be no assurance that the amount of the available Facility will not be adjusted at the next scheduled Borrowing Base review on or before June 6, 2018. The Facility is secured by a floating charge debenture and a general securities agreement on the assets of the Company.

Advances under the Facility are available by way of prime rate loans with interest rates between 0.50 percent and 2.50 percent over the bank's prime lending rate and bankers' acceptances and LIBOR loans, which are subject to stamping fees and margins ranging from 1.50 percent to 3.50 percent depending upon the debt to EBITDA ratio of the Company calculated at the Company's previous quarter end. Standby fees are charged on the undrawn Facility at rates ranging from 0.375 percent to 0.875 percent depending upon the debt to EBITDA ratio. As at September 30, 2017, the Company's applicable pricing included a 0.50 percent margin on prime lending, a 1.50 percent stamping fee and margin on bankers' acceptances and LIBOR loans along with a 0.375 percent per annum standby fee on the portion of the Facility that is not drawn. Borrowing margins and fees are reviewed annually as part of the bank syndicate's annual renewal.

At September 30, 2017, the Company had issued letters of credit totaling $8.2 million (December 31, 2016 - $13.6 million). The effective interest rate on the Company's borrowings under its Facility for the nine months ended September 30, 2017 was 3.3% (December 31, 2016 – 4.8%), which includes standby fees on the undrawn amounts of the Facility.

5. Senior unsecured notes:

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

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

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

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

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

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

6. Decommissioning obligations:

	Nine months ended September 30, 2017	Year ended December 31, 2016
Decommissioning obligations, beginning of period	**$ 85,859**	$ 85,822
Obligations incurred	**3,284**	1,344
Obligations acquired	**-**	4,061
Obligations settled	**(484)**	(1,411)
Obligations divested	**(602)**	-
Change in estimated future cash outflows	**(1,594)**	(5,725)
Accretion of decommissioning obligations	**1,435**	1,768
Decommissioning obligations, end of period	**$ 87,898**	$ 85,859

The Company's decommissioning obligations result from its ownership interest in oil and natural gas assets including well sites and facilities. The total decommissioning obligation is estimated based on the Company's net ownership interest in all wells and facilities, estimated costs to reclaim and abandon these wells and facilities and the estimated timing of the costs to be incurred in future years. The Company has estimated the net present value of the decommissioning obligations to be $87.9 million as at September 30, 2017 (December 31, 2016 - $85.9 million) based on an inflation adjusted undiscounted total future liability of $116.9 million (December 31, 2016 - $113.4 million). These payments are expected to be made over the next 40 years, with the majority of costs to be incurred between 2020 and 2035. The inflation rate applied to the liability is 2% (December 31, 2016 – 2%). The discount factor, being the risk-free rate related to the liability, is 2.21% (December 31, 2016 – 2.21%). The $1.6 million (December 31, 2016 - $5.7 million) change in estimated future cash outflows for the nine months ended September 30, 2017 is a result of a change in future estimated undiscounted abandonment costs.

7. Share capital:

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

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

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

Stock Option Plan:

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

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

	Number of options	Weighted average remaining life (years)	Weighted average exercise price
Balance, January 1, 2017	1,430	0.3	$ 7.08
Forfeited	(3)	-	7.17
Expired	(1,401)	-	7.10
Balance, September 30, 2017	**26**	**0.1**	**$ 5.70**

Restricted and Performance Award Incentive Plan:

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

Subject to terms and conditions of the RPAP, each RA and PA entitles the holder to an award value to be typically paid as to one-third on each of the first, second and third anniversaries of the date of grant. For the purpose of calculating share-based compensation, the fair value of each award is determined at the grant date using the closing price of the common shares. In the case of PAs, the award value is adjusted for a payout multiplier which can range from 0.0 to 2.0 and is dependent on the performance of the Company relative to pre-defined corporate performance measures for a particular period. On the vesting dates, the Company has the option of settling the award value in cash or common shares of the Company. Through the vesting of 743,000 restricted awards and 1,162,000 performance awards, when taking into account the earned multipliers for performance awards, 3,068,000 common shares of the Company were issued for the nine months ended September 30, 2017.

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

	Number of RAs	Number of PAs
Balance, January 1, 2017	1,699	2,537
Granted	902	1,309
Vested	(743)	(1,162)
Forfeited	(96)	(100)
Balance, September 30, 2017	**1,762**	**2,584**

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, 2017 was 148,928,000 (September 30, 2016 – 143,621,000) and for the nine month period ended September 30, 2017, the weighted average number of shares outstanding was 148,413,000 (September 30, 2016 – 142,409,000).

In computing diluted earnings per share for the three month period ended September 30, 2017, 2,117,000 (September 30, 2016 – nil) shares were added to the weighted average common shares outstanding to account for the dilution of stock options and restricted and performance awards, and for the nine month period ended September 30, 2017, 2,551,000 (September 30, 2016 – nil) shares were added to the weighted average common shares for the dilution. For the three month period ended September 30, 2017, there were 26,000 (September 30, 2016 – 1,539,000) stock options and 2,474,000 (September 30, 2016 – 4,464,000) restricted and performance awards that were not included in the diluted earnings per share calculation because they were anti-dilutive. For the nine month period ended September 30, 2017, there were 26,000 (September 30, 2016 – 1,539,000) stock options and 2,493,000 (September 30, 2016 – 4,464,000) restricted and performance awards that were not included in the diluted earnings per share calculation because they were anti-dilutive.

8. Financial risk management:

Derivative contracts:

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

The fair value of options and costless collars is based on option models that use published information with respect to volatility, prices and interest rates. These instruments are considered level two under the fair value hierarchy. The fair value of forward contracts and swaps is determined by discounting the difference between the contracted prices and published forward price curves as at the date of the statement of financial position, using the remaining contracted oil and natural gas volumes and a risk-free interest rate (based on published government rates).

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

Subject of Contract	Notional Quantity	Term	Reference	Strike Price	Option Traded	Fair Value
Gas	2,500 gj/day	October 1, 2017 – October 31, 2017	AECO C Daily Index	$2.55	Swap	$ 129
Gas	22,500 mmbtu/day	October 1, 2017 – December 31, 2017	Chicago Citygate	$3.88	Swap	439
Oil	1,750 bbl/day	October 1, 2017 – December 31, 2017	CDN$ WTI	$68.02	Swap	516
Gas	22,500 gj/day	October 1, 2017 – December 31, 2017	AECO C Monthly Index	$2.83	Swap	1,732
Gas	10,000 gj/day	October 1, 2017 – December 31, 2017	AECO C Daily Index	$3.08	Swap	1,419
Gas	5,000 mmbtu/day	October 1, 2017 – December 31, 2018	Chicago Citygate	$4.23	Swap	1,497
Gas	5,000 gj/day	January 1, 2018 – December 31, 2018	AECO C Monthly Index	$3.00	Call	(107)
Gas	2,500 gj/day	January 1, 2018 – December 31, 2018	AECO C Daily Index	$2.62	Swap	394
Gas	5,000 mmbtu/day	January 1, 2018 – December 31, 2018	US$ Nymex Henry Hub	$3.05	Swap	8
Oil	250 bbl/day	January 1, 2018 – December 31, 2018	CDN$ WTI	$65.27	Swap	58
Oil	250 bbl/day	January 1, 2018 – December 31, 2018	CDN$ WTI	$60.00 - $69.65	Collar[1]	-
Total						**$ 6,085**

(2) The referenced contract is a costless collar whereby the Company receives $60/bbl when the market price is below $60/bbl, and receives $69.65/bbl when the market price is above $69.65/bbl.

Subsequent to September 30, 2017, the Company entered into the following derivative commodity contracts:

Subject of Contract	Notional Quantity	Term	Reference	Strike Price	Option Traded
Oil	250 bbl/day	January 1, 2018 – December 31, 2018	CDN$ WTI	$69.00	Swap

Capital management:

The Company's objective when managing capital is to maintain a strong financial position and flexible capital structure which will allow it to execute on its capital expenditure program, including expenditures on oil and gas activities which may or may not be successful. Therefore, the Company monitors the level of risk incurred in its capital expenditures to balance the proportion of debt and equity in its capital structure.

The Company considers its capital structure to include working capital, long-term debt (including the bank loan and senior unsecured notes) and shareholders' equity. Crew monitors its capital structure and makes adjustments on an ongoing basis in order to maintain the flexibility needed to achieve the Company's long-term objectives. To manage its capital structure, the Company may adjust capital spending, hedge future revenue and costs, issue new equity, issue new debt or repay existing debt through non-core asset sales.

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

The Company monitors this ratio and endeavours to maintain it at approximately 2.0 to 1.0 or lower. Since early 2015, a period of extended low commodity prices has negatively impacted quarterly funds from operations and increased this ratio. In addition, in order to accommodate future production growth, the Company has incurred incremental capital to expand its infrastructure in core areas which has increased its debt levels. As this upfront capital expenditure on infrastructure allows for increased future production leading to higher funds from operations, the Company expects this ratio to decrease from current levels. As shown below, as at September 30, 2017, the Company's ratio of net debt to annualized funds from operations was 3.40 to 1 (December 31, 2016 – 2.20 to 1). With the Company's recently confirmed $235 million Facility and the 2024 Notes, the Company's financial position is strong. If the Company feels it is necessary to improve its financial position, it will consider divesting of non-core properties, will further adjust its annual capital expenditure program or may consider other forms of financing.

		September 30, 2017		December 31, 2016
Net debt:				
Accounts receivable	**$**	**64,201**	$	39,588
Accounts payable and accrued liabilities		**(78,507)**		(49,594)
Working capital deficiency	**$**	**(14,306)**	$	(10,006)
Bank loan		**(31,696)**		(88,036)
Senior unsecured notes		**(293,546)**		(147,329)
Net debt	**$**	**(339,548)**	$	(245,371)
Quarterly annualized funds from operations:				
Cash provided by operating activities	**$**	**15,258**	$	19,900
Decommissioning obligations settled		**128**		763
Change in non-cash working capital		**9,834**		7,394
Accretion of deferred financing charges		**(250)**		(178)
Quarterly funds from operations	**$**	**24,970**	$	27,879
Annualized	**$**	**99,880**	$	111,516
Net debt to annualized funds from operations		**3.40**		2.20

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 4).

9. Financing:

		Three months ended Sept. 30, 2017		Three months ended Sept. 30, 2016		**Nine months ended Sept. 30, 2017**		Nine months ended Sept. 30, 2016
Interest expense	**$**	**5,491**	$	4,259	**$**	**15,530**	$	12,645
Accretion of deferred financing costs		**250**		122		**707**		472
Accretion of decommissioning obligations		**482**		438		**1,435**		1,307
Premium paid on redemption of 2020 Notes (note 5)		**-**		-		**6,282**		-
Deferred financing costs expensed on 2020 Notes (note 5)		**-**		-		**2,510**		-
	$	**6,223**	$	4,819	**$**	**26,464**	$	14,424

10. Commitments:

	Total	2017	2018	2019	2020	2021	Thereafter
Operating leases	$ 4,211	$ 294	$ 1,175	$ 1,175	$ 1,175	$ 392	$ -
Capital commitments	3,764	3,764	-	-	-	-	-
Firm transportation agreements	168,162	8,109	36,580	35,958	32,728	9,789	44,998
Firm processing agreements	87,249	3,208	12,729	12,729	11,419	7,449	39,715
Total	**$ 263,386**	**$ 15,375**	**$ 50,484**	**$ 49,862**	**$ 45,322**	**$ 17,630**	**$ 84,713**

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

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

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

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

DIRECTORS & OFFICERS

OFFICERS

Dale O. Shwed
President and Chief Executive Officer

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

Ken Truscott
Senior Vice President, Business Development and Land

Jamie L. Bowman
Vice President, Marketing

Kurtis Fischer
Vice President, Business Development

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

BOARD OF DIRECTORS

John A. Brussa,
Chairman Independent Director

Jeffery E. Errico,
Lead Director Independent Director

Dennis L. Nerland
Independent Director

Dale O. Shwed
President, Crew Energy Inc.

David G. Smith
Independent Director

Corporate Secretary

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

ABBREVIATIONS

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