interim report Q1 2017

first quarter ending March 31, 2017

crew energy inc.

Crew Energy Inc. (TSX: CR) ("Crew" or the "Company") is pleased to provide our operating and financial results for the three month period ended March 31, 2017, along with an updated independent Montney Resource Evaluation.

FIRST QUARTER HIGHLIGHTS

- Production for the quarter averaged 23,231 boe per day, 4% higher than the previous quarter primarily attributable to an 8% increase in liquids-rich natural gas production from northeast British Columbia ("NE BC").
- Funds from operations totaled $27.7 million in the first quarter, more than double the same period in 2016, and increased 125% on a per share basis to $0.18 per share from $0.08 per share in Q1 2016.
- Benchmark prices increased for all products resulting in stronger revenues, while our continued focus on cost control contributed to operating netbacks that averaged $17.16 per boe compared to $9.13 per boe in the first quarter of 2016.
- At our liquids-rich Septimus and West Septimus ("Greater Septimus") area, operating costs were 25% lower than Q1 2016 at $3.34 per boe while transportation costs were 24% lower at $1.67 per boe, contributing to an operating netback of $19.41 per boe.
- Crew closed a $300 million senior debt financing in March, 2017 and exited the quarter undrawn on our re-confirmed $235 million bank credit facility, affording the Company ample financial flexibility to execute on our longer-term, Montney-focused development strategy.
- In NE BC, drilled 11 wells and completed five wells, and at Lloydminster, drilled four wells and completed two wells, and currently have an inventory of 20 drilled and uncompleted wells, 18 of which are in Greater Septimus and Groundbirch.
- Continued the advancement of Crew's Montney development plan with site work on the West Septimus facility expansion to 120 mmcf per day and the acquisition of 10 contiguous sections of surface rights that will accommodate the planned Groundbirch facility and the drilling of a minimum of 150 wells.
- Subsequent to the end of the quarter, we entered into an Agreement of Purchase and Sale for the disposition of non-core assets in the Goose area of NE BC comprised of approximately 18,400 net acres of undeveloped land with no production or assigned reserves for $49 million (subject to certain closing adjustments and costs). The transaction is expected to close prior to the end of the second quarter, subject to customary closing conditions.
- Updated Crew's independent Montney Resource Evaluation which reflected a 2% increase to the risked Best Estimate Economic Contingent Resource ("ECR") assessment to 9.2 TCFE and a modest increase to the Total Petroleum Initially In Place ("TPIIP") estimate to 112.2 TCFE (prior to the Goose disposition). Continued annual increases in our resource estimate demonstrates the value in Crew's ongoing Montney-focused drilling and development strategy to realize significant long-term value through reserves additions from this massive resource.

FINANCIAL & OPERATING HIGHLIGHTS

FINANCIAL ($ thousands, except per share amounts)	**Three months ended March 31, 2017**	Three months ended March 31, 2016
Petroleum and natural gas sales	**57,298**	36,343
Funds from operations[1]	**27,719**	11,714
Per share - basic	**0.19**	0.08
- diluted	**0.18**	0.08
Net income /(loss)	**8,056**	(6,795)
Per share - basic	**0.05**	(0.05)
- diluted	**0.05**	(0.05)
Exploration and Development expenditures	**75,164**	17,763
Property acquisitions (net of dispositions)	**(352)**	956
Net capital expenditures	**74,812**	18,719

Capital Structure ($ thousands)	**As at March 31, 2017**	As at Dec. 31, 2016
Working capital deficiency[2]	**8,588**	10,006
Bank loan	**-**	88,036
	8,588	98,042
Senior Unsecured Notes	**293,046**	147,329
Total Net Debt	**301,634**	245,371
Current Debt Capacity[3]	**535,000**	385,000
Common Shares Outstanding (thousands)	**147,127**	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 newly approved bank facility of $235 million plus $300 million in senior unsecured notes outstanding.

Operations	**Three months ended March 31, 2017**	Three months ended March 31, 2016
Daily production		
Light crude oil (bbl/d)	**530**	303
Heavy crude oil (bbl/d)	**1,857**	2,799
Natural gas liquids (bbl/d)	**3,363**	3,359
Natural gas (mcf/d)	**104,887**	104,224
Total (boe/d @ 6:1)	**23,231**	23,832
Average prices [1]		
Light crude oil ($/bbl)	**59.74**	37.34
Heavy crude oil ($/bbl)	**42.93**	20.45
Natural gas liquids ($/bbl)	**45.71**	25.95
Natural gas ($/mcf)	**3.54**	2.34
Oil equivalent ($/boe)	**27.40**	16.76

Notes:

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

	Three months ended March 31, 2017	Three months ended March 31, 2016
Netback ($/boe)		
Revenue	**27.40**	16.76
Realized commodity hedging gain/(loss)	**(0.39)**	2.21
Royalties	**(2.18)**	(0.88)
Operating costs	**(5.38)**	(6.45)
Transportation costs	**(2.29)**	(2.51)
Operating netback (1)	**17.16**	9.13
G&A	**(1.50)**	(1.76)
Interest on long-term debt	**(2.41)**	(1.98)
Funds from operations	**13.25**	5.39
Drilling Activity		
Gross wells	**15**	4
Working interest wells	**15.0**	4.0
Success rate, net wells (%)	**93%**	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

During the first three months of 2017, activity levels increased across the Western Canadian Sedimentary Basin in response to frozen ground conditions and an improved commodity price environment. This resulted in a tight supply-demand dynamic for field services, particularly reservoir stimulation. Crew was able to complete five of a planned ten wells in the quarter and as a result underspent our forecasted first quarter budget by deferring these operations until after spring break up. Our production of 23,231 boe per day was at the lower end of our guidance range for the quarter and is reflective of these service delays. Work on the expansion of our West Septimus facility to double throughput capacity continued in the quarter, and is currently ahead of schedule, with commissioning of the expanded facility currently planned for the fourth quarter of 2017.

We continued to move forward on Crew's long term growth plan by successfully closing a $300 million senior note financing, which has a 6.5% coupon and a term through March, 2024. This financing has positioned Crew with $535 million of total credit capacity and enhances our ability to manage through continued commodity price volatility for an extended period. Upon the closing of this financing, we repaid the balance on our $235 million credit facility, resulting in an undrawn bank facility, and after the end of the quarter, the credit facility was approved for extension at the same level. Subsequent to quarter end, we entered into an agreement to dispose of our non-core Goose property in NE BC for proceeds of approximately $49 million. Upon closing, which is expected prior to the end of the second quarter, we will have monetized a portion of our asset base that was not within Crew's long-term development horizon.

MONTNEY RESOURCE EVALUATION UPDATE

Crew is pleased to report the results of its annual updated independent Montney resource evaluation conducted by Sproule Associates Ltd. ("Sproule") on our principal NE BC Montney lands including Septimus, West Septimus, Groundbirch / Monias, Attachie and Tower as well as other minor NE BC Montney lands, effective December 31, 2016 (the "Resource Evaluation"). Sproule performed detailed mapping across the evaluated areas which included section by section estimates of reservoir parameters, such as pressure, temperature, porosity, and water saturation, which make up the TPIIP determination. At 112.2 TCFE, Crew's TPIIP estimate provides the Company with significant opportunities to continue increasing the current ECR estimates plus add reserves with further drilling. Crew's risked best estimate ECR on natural gas increased 3% to 7.7 Tcf, natural gas liquids ("ngl") risked best estimate ECR was 1% higher at 227 million barrels, while our crude oil risked best estimate ECR decreased by 2 million bbls to 21 million bbls. All numbers referenced from the Resource Evaluation are prior to the pending disposition of Crew's Goose asset.

The updated Resource Evaluation demonstrates the significant potential of our lands, offering multiple years of future running room and significant value creation opportunities. Although the play remains in its early stages of development, with new and enhanced drilling and completions techniques, Crew and other area operators continue to further delineate and de-risk the potential of this massive play and demonstrate results from the Montney that continue to improve.

FINANCIAL

Crew's first quarter funds from operations of $27.7 million was consistent with the previous quarter but 137% higher than the first quarter of 2016, reflecting stronger year over year commodity prices, and operating and transportation costs that were 17% and 9% lower, respectively. We continue to see compelling returns from Greater Septimus, where our first quarter operating netback from the area was $19.41 per boe compared to $17.16 per boe corporately, reflecting the strong economics and returns generated in our core Montney operating areas.

Crew's realized light oil price improved by 60% in the first quarter of 2017 over the first quarter of 2016, while our heavy oil price increased 110% and our ngl prices were 76% higher than the same period in 2016. Improved first quarter oil and ngl prices were the result of improved world oil prices prompted by OPEC's (Organization of Petroleum Exporting Countries) decision to limit production in the first half of 2017 in order to reduce global inventories. This action stabilized world oil prices late in 2016 resulting in a 50% improvement in Crew's Canadian dollar denominated WTI benchmark price. Higher oil prices also supported stronger demand and pricing for the condensate, propane and butane that make up Crew's ngl mix. Crew's realized natural gas price increased 51% over Q1 of 2016 as a result of stronger North American natural gas prices. Natural gas prices were supported by lower supply related to reduced capital investment and lower inventories resulting from warmer 2016 summer weather, liquefied natural gas exports from the U.S. gulf coast and increased U.S. exports to Mexico.

First quarter 2017 capital expenditures totaled $75 million which included the drilling of eleven Montney wells and four heavy oil wells. Operations during the quarter also included the completion of five Montney wells and two heavy oil wells. Drilling and completion expenditures for the quarter were $10 million lower than budgeted as a lack of available completion services restricted the first quarter program to five of a planned ten Montney completions. During the quarter we also continued with the expansion of our West Septimus facility from 60 mmcf per day to 120 mmcf per day. Major equipment fabrication was ahead of schedule resulting in $14.1 million charged to the expansion which represents an additional $5 million of capital accrual towards the project in the quarter.

Consistent with our efforts to maintain a strong balance sheet, control costs, and ensure liquidity to execute our strategy, on May 1, 2017 Crew entered into a new arrangement resulting in the replacement of one of the partners in our Septimus Gas Processing Complex (comprised of the Septimus and West Septimus facilities). This new arrangement will not impact Crew's current 28% ownership or operatorship of the complex, while the other remaining partner retains a 22% ownership and the new partner a 50% ownership. This change to the arrangement will save the Company approximately $1 million per year on processing costs associated with the current complex further reducing overall Greater Septimus operating costs. As part of this arrangement, the new partner has agreed to fund 50% of the current West Septimus facility expansion. Crew has retained the option to buy both partners' interest in these facilities at future dates.

On March 14, 2017, Crew closed an offering of $300 million aggregate principal amount of 6.5% senior unsecured notes due March 14, 2024. Proceeds from the note offering were partially used to redeem Crew's $150 million, 8.375% senior unsecured notes due 2020, with the excess proceeds used to repay indebtedness under our credit facility and for the continued development of our Montney assets. Successful completion of this offering enhances Crew's liquidity and financial flexibility. Total net debt at the end of the quarter was $301.6 million, including working capital deficiency and our new $300 million ($293.0 million net of deferred financing costs) 6.5% senior unsecured notes that have a seven year term with repayment due in March of 2024. The Company also recently completed our annual bank facility review with the facility renewed at the same level of $235 million. The pending disposition of our non-core Goose asset will further contribute to our flexibility and add cash to our balance sheet.

TRANSPORTATION, MARKETING & HEDGING

Crew's realized natural gas price has outperformed the benchmark indices for the last six quarters, which demonstrates the value of our active marketing and hedging program, diversified sales markets as well as the 19% higher heat content of our natural gas over industry standards. One of the many advantages of our Montney land base is that we are situated with access to all three major export pipeline systems which provides substantial market and operational optionality. During the first quarter, our natural gas sales portfolio was allocated 45% to Chicago City Gate, 26% to AECO, 19% to Alliance ATP and 10% to Station 2. Crew will continue to plan for processing and transportation diversification that is timed to coincide with our longer term growth strategy, and afford us the ability to access new markets. Our transportation arrangement on the Spectra pipeline increased from 13 mmcf per day to 30 mmcf per day effective April 1, 2017. In the second quarter of 2018, we also secured 60 mmcf per day of capacity on the TransCanada pipeline system ("TCPL"), affording improved market diversity for natural gas from our Greater Septimus and Groundbirch areas. In mid-2019, we have also secured an additional 60 mmcf per day of firm capacity on the TCPL system.

In the interests of managing our commodity price risk and exposure, Crew continued to systematically add 2017 and 2018 hedges during the first quarter. For the balance of 2017, Crew's total natural gas hedged position is approximately 50% of our forecast 2017 gas sales 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 approximately 50% of our 2017 light oil and natural gas liquids sales hedged at an average price of CDN$68.17 per bbl.

OPERATIONS

NE BC Montney – Greater Septimus Overview

During the first quarter, Crew continued to focus on drilling and completions activities primarily at our Greater Septimus area, while advancing our West Septimus facility expansion. We directed the majority of our first quarter capital to Greater Septimus, including $14.1 million allocated to the doubling of our West Septimus processing facility from 60 mmcf per day to 120 mmcf per day. In addition, Crew drilled ten (10.0 net) Montney wells and completed three (3.0 net) Montney wells of our budgeted eight well Greater Septimus completions program in the quarter.

Crew continued to see efficiency improvements in the first quarter as the first five wells drilled off the 4-22 pad achieved a record low average 12.6 drilling days per well at an average well cost of $1.5 million, contributing to strong capital efficiencies and supporting returns. Following up on the success of our first two ultra condensate-rich wells, we spud the first well on a six well pad directly offsetting the 7-30 wells which continue to exceed expectations.

Late in 2016, industry activity increased significantly in NE BC, particularly the demand for reservoir stimulation services. All industry participants, including Crew, have been subject to scheduling challenges with service companies. The delays Crew experienced with completions in turn delayed new production volumes coming on-stream in the quarter. These delays reduced capital expenditures for completions by approximately $10 million in Q1 relative to our budget, which were partially offset by the West Septimus facility expansion running ahead of schedule.

Crew's geographic location in the Montney has typically provided year round access to conduct our drilling and completions operations, or at worst, resulted in modest delays during spring break-up. For the first time in Crew's operational history in the Montney, we were forced to completely shut down these activities in the middle of April. This year's spring break up was a 'perfect storm' of an initial spring thaw, complicated by a significant period of cool, snowy weather which led to extremely poor road conditions and resultant road bans. Given the circumstances, and an emphasis on prioritizing our capital efficiencies, Crew has adjusted our operational plan to incorporate an extended spring break-up period during which no drilling or completions activity will be undertaken until June. Crew currently has three drilling rigs sitting on Crew leases, a significant inventory of 18 wells drilled and uncompleted in NE BC and has made arrangements to secure necessary equipment and services to complete the wells once access to our well sites is available.

Greater Septimus

Production & Drilling	**Q1 2017**	**Q4 2016**	**Q3 2016**	**Q2 2016**	**Q1 2016**
Average Daily Production (boe/d)	17,440	17,307	18,592	17,131	18,149
Wells drilled (gross / net)	10 / 10.0	8 / 7.7	8 / 7.0	-	4 / 4.0
Wells completed	3	5	7	7	3

Operating Netback ($ per boe)	**Q1 2017**	**Q4 2016**	**Q3 2016**	**Q2 2016**	**Q1 2016**
Revenue	26.49	25.10	20.56	16.06	16.69
Royalties	(1.66)	(1.47)	(0.94)	(0.69)	(0.79)
Realized commodity hedge (loss)/gain	(0.41)	(0.39)	1.11	3.24	1.34
Operating costs	(3.34)	(3.34)	(3.61)	(4.02)	(4.43)
Transportation costs	(1.67)	(1.68)	(1.59)	(1.97)	(2.21)
Operating netback	19.41	18.22	15.53	12.62	10.60

First quarter production at Greater Septimus averaged 17,440 boe per day, representing approximately 76% of the Company's total production volumes. Greater Septimus operating netbacks of $19.41 per boe were the highest in the past five quarters, due to increased revenue, and supported by low operating costs of $3.34 per boe and $1.67 per boe transportation costs, which have been kept stable despite inflationary pressures as industry activity levels increase.

Crew's ultra condensate-rich area is the Company's new focus for development at Greater Septimus. Results from area wells at the 7-30 pad are compelling in the current environment, including C7-30 which has produced 70,000 bbls of condensate in 220 days on production with an average condensate gas ratio ("CGR") of 187 bbls per mmcf, and B7-30 which has produced 40,000 bbls of condensate over 165 days with an average CGR of 133 bbls per mmcf.

Three new well completions at Septimus in late 2016 have resulted in record well performance at an all-in average well cost of $3.8 million. Over a 123 day period, the wells each produced 0.8 bcf of natural gas with a well head condensate yield of 19 bbls per mmcf and have continued to produce at a current average rate of 4.7 mmcf per day per well.

NE BC Montney – Groundbirch overview

Crew spud the first of two delineation wells at Groundbirch that will employ the latest completion technology as part of further delineating our significant Groundbirch resource (which represents 18.7 TCFE of TPIIP in our Resource Evaluation) and in preparation for development drilling in 2018 as part of our long-term growth plan. The Company also acquired ownership of 10 sections of surface rights at Groundbirch on which we have planned the construction of a gas plant and associated Montney development of a minimum of 150 wells. Ownership is expected to reduce surface lease costs, improve access and timing of operations, provide access to a major rail line for potential trans-load capability in addition to providing access to proprietary gravel for lease and road maintenance and construction.

NE BC Montney – Tower overview

Crew's Montney Tower area continues to represent significant future development opportunity for the Company as crude oil prices strengthen. We realized increased oil production at Tower in Q1 as a result of successfully completing two light oil wells in the fourth quarter of 2016 and two light oil wells in the first quarter of 2017. These four wells were drilled in 2014 prior to the collapse in oil prices, and were designed to be completed using plug and perf technology, which has been the predominant completion technique within the light oil window of the Montney relative to the then available open-hole completion technology. The first two wells have been on production for 60 and 80 days at average rates of 365 and 600 boe per day, with 53% and 64% liquids, respectively. The second two wells were completed late in the first quarter and achieved average rates of 445 and 520 boe per day, with 55% and 58% liquids over 35 and 60 days, respectively. In both sets of wells, the stronger of the two was placed in Crew's "Upper B" interval of the upper Montney while the other two wells tested the deeper Montney "C" stratigraphic interval of the upper Montney. All four wells presently flow without the aid of artificial lift. Crew has also undertaken the first stage of facility modifications to install gas lift which we believe will allow us to further optimize fluid production rates from these wells.

Lloydminster, AB/SK overview

At Lloydminster, Crew drilled four (4.0 net) oil wells including two dual-leg horizontal wells, completed two (2.0 net) wells and recompleted four (3.5 net) oil wells in the quarter. Production at our Lloydminster heavy oil property averaged 1,865 boe per day in the first quarter of 2017 which reflects minimal impact from the drilling and completion operations, and is part of the Company's plan to maintain heavy oil production in the range of 2,000 boe per day. The two completions were vertical wells in the Swimming area (Sparky formation) and the Wildmere area (Colony formation). The wells were placed on production in early March and by mid-April were producing at a combined average rate of 220 bbls of oil per day. Crew's two dual leg horizontal wells also located in the Swimming area are expected to be completed when road ban restrictions are removed.

OUTLOOK

Crew has assembled a sizeable and uniquely situated land base of 474 net sections (prior to the impact of the pending Goose disposition) which offers exposure to condensate-rich natural gas and light oil. The intrinsic value of Crew's acreage coupled with owned and operated facilities and infrastructure, firm transportation arrangements, a diversified marketing strategy, a strong balance sheet and a returns-focused strategy provide the foundation for long-term profitable growth and value creation. Under our current plan, we expect to exit 2017 in a strong financial position with an estimated debt to annualized fourth quarter 2017 funds from operations ratio of 1.5 times. Given these strengths, we believe our share price does not always reflect the underlying value of Crew's assets and as such, the Company intends to apply to implement a normal course issuer bid ("NCIB") through the facilities of the Toronto Stock Exchange (the "TSX") and alternative Canadian trading platforms, pursuant to which Crew would have the ability to repurchase, from time to time, our outstanding shares for cancellation. This NCIB is expected to commence later in May following application being made to, and approved by, the TSX and will terminate one year later.

Exiting the first quarter, Crew has an inventory of 18 drilled but uncompleted wells that we intend to complete in order to bring on new volumes, and will continue to time our completions to ensure new volumes come on-stream with the commissioning of our West Septimus facility expansion. In the interests of creating value for our shareholders, we remain focused on return-on-capital in the development of our assets. Crew's activity levels can be scaled back in a weak market to preserve our valuable reserves. We believe in the potential of our Montney assets, and are excited by the results from the ultra condensate-rich area which offers attractive economics in the current environment. Additional improvements in well results will be pursued through enhanced completions, while striving to improve operational efficiencies. With stronger financial liquidity, proceeds from the pending sale of Goose and the $300 million note offering, we are well positioned to continue executing our Montney focused strategy over the near and longer-term.

We have revised our capital planning based on the previously referenced delays, with our projected second quarter capital program reduced by approximately $30 million to between $25 and $35 million. Production additions will be heavily weighted to the fourth quarter, concurrent with the commissioning of our West Septimus plant expansion. Also, during the second quarter of 2017, the third-party McMahon gas processing facility will be shut down for an estimated 21 days, which will impact Crew's volumes by approximately 900 boe per day in the second quarter. This shut down, combined with the production delays caused by the extended spring break-up, results in second quarter 2017 production estimates of approximately 20,000 to 21,000 boe per day. We anticipate that Q3 and Q4 2017 production will average between 24,500 to 26,500 boe per day, and 29,500 to 31,500 boe per day, respectively, spending approximately $100 million in the last half of 2017. Accordingly, our 2017 annual production guidance is reduced by 4% to 24,000 to 26,000 boe per day, with a positive impact to our forecast 2017 exit rate, which is increasing to over 31,000 boe per day while our $200 million capital budget remains unchanged.

We are very pleased to have secured additional financial flexibility, and have a high-quality asset base that only continues to improve with time and technology. We would like to thank our employees and Board of Directors for their commitment to Crew, and our shareholders for their ongoing support through ongoing market challenges.

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

2017 Average production(1)	24,000 – 26,000 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
Resource TPIIP(3)	112.2 TCFE
Montney potential drilling locations(4)	5,782
2017 Capital program(1)	$200 MM
Net debt(5)	$301.6 MM
Exit 2017 net debt / funds from operations(1)	~1.5x
Basic shares outstanding(5)	147.1 MM
Tax pools(5)	~$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 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.
(3) As per the Resource Evaluation as at December 31, 2016 prepared by Sproule in accordance with the NI 51-101 and current COGE Handbook guidelines
(4) Potential drilling locations are the total number of risked Contingent (2,071) and Prospective (3,355) resource locations as identified in Crew's year end independent Resource Evaluation, plus the 2P booked locations (356) as identified in the independent reserves evaluation for the year ended December 31, 2016, both of which were prepared in accordance with the COGE Handbook provisions and NI 51-101
(5) As at March 31, 2017

DECEMBER 31, 2016 RESOURCE EVALUATION

The following discussion in "Crew Northeast British Columbia Montney Resource Evaluation" is subject to a number of cautionary statements, assumptions and risks as set forth therein. See "Information Regarding Disclosure on Oil and Gas Reserves, Resources and Operational Information" at the end of this release for additional cautionary language, explanations and discussion, and see "Forward-looking Information and Statements" for a statement of principal assumptions and risks that may apply. See also "Definitions of Oil and Gas Resources and Reserves" in this report. The discussion includes reference to TPIIP, DPIIP and ECR as per the Resource Evaluation as at December 31, 2016, prepared in accordance with the NI 51-101 and current COGE Handbook guidelines. Unless otherwise indicated in this report, all references to ECR and prospective volumes are Best Estimate ECR and Best Estimate prospective volumes, respectively. All information referenced in the Resource Evaluation is prior to the pending disposition of Crew's Goose area, expected to close in the second quarter of 2017.

In accordance with NI 51-101 Crew's contingent resources have been subclassified into specified project maturity subclasses. Those that apply to Crew's resources include "development pending", "development on hold", and "development not viable". Sproule considers the 'development pending' and 'development on hold' project maturity subclasses to be economic and are therefore included in ECR. The economic status of the 'development not viable' project maturity subclass is undetermined and is therefore not included in the ECR reported. The "development not viable" sub-classification represented less than 2% of the sum of all three sub-classifications on a BOE basis, and accordingly, has not been considered to be material for reporting purposes. Crew does not have any resources within the "development unclarified" subclass.

CREW NORTHEAST BRITISH COLUMBIA MONTNEY RESOURCE EVALUATION

The Montney formation in NE BC has been identified as a world-class unconventional resource play with the potential for significant volumes of recoverable resources. The area includes dry gas, liquids-rich gas and light oil development opportunities, with Crew having access to all three hydrocarbon windows. It is one of the largest and lowest cost liquids-rich natural gas resource plays in North America and Crew's land base comprises 300,000 net acres, ideally situated in some of the most prospective parts of the play, with good access to infrastructure and multiple egress options.

Sproule was engaged to conduct an updated independent Montney resource evaluation of Crew's principal lands in the NE BC Montney region including Septimus, West Septimus, Groundbirch/Monias, Attachie, Tower and other minor NE BC Montney lands (the "Evaluated Areas") effective as of December 31, 2016, and based on Sproule's forecast price deck as at December 31, 2016 (the "Resource Evaluation"). The Resource Evaluation highlights the development potential on the Company's undeveloped land base providing Crew with significant opportunities to progress conversion of Resource to ECR and ultimately to increased reserve bookings over time. Further, the diversity of Crew's NE BC Montney assets with exposure to liquids-rich gas, crude oil and dry natural gas allows us to effectively navigate through commodity price cycles.

TPIIP for the natural gas-bearing lands in the Evaluated Areas remains unchanged relative to year end 2015 at 64.3 Tcf. Natural gas ECR was evaluated on an unrisked and risked basis in the Resource Evaluation and was subdivided into the Maturity Subclasses of 'development pending' and 'development on hold'. The risked 'development pending' natural gas ECR totaled 7.3 Tcf and the risked 'development on hold' ECR totaled 0.43 Tcf, which includes 104 bcf of 'development pending' natural gas and 26 bcf of 'development on hold' natural gas on Crew's oil-bearing lands.

The ECR of our ngl was also evaluated on an unrisked and risked basis in the Resource Evaluation and was subdivided into the Maturity Subclasses of 'development pending' and 'development on hold'. The risked 'development pending' ngl ECR totaled 211 MMbbl and risked 'development on hold' ngl ECR totaled 16 MMbbl which includes 3 mmbbls of 'development pending' ngl and 1 mmbbls of 'development on hold' ngl on Crew's oil-bearing lands.

On the oil-bearing Montney lands, TPIIP increased 1% to 7,979 MMbbl and DPIIP increased 2% to 1,647 MMbbl. Oil ECR was evaluated on an unrisked and risked basis in the Resource Evaluation and was subdivided into the Maturity Subclasses of 'development pending' and 'development on hold'. The risked 'development pending' oil ECR totaled 17 MMbbl and risked 'development on hold' oil ECR totaled 4 MMbbl.

Risking of the contingent resources included a quantitative assessment of the contingencies applicable to the project including evaluation drilling, corporate commitment and timing of production and development. Risking of the prospective resources included a quantitative assessment of these same factors, as well as a quantitative assessment of the chance of discovery.

The following tables summarize the results of the Resource Evaluation along with comparatives to the December 31, 2015 evaluation using the resource categories set out in the COGE Handbook on a "best estimate" case.

	Dec. 31, 2016	Dec. 31, 2015	% Change
Conventional Natural Gas Resource Categories (1)(2)(3)(4)(5)(6)	**Tcf**	Tcf	
Total Petroleum Initially In Place (TPIIP)	**64.3**	64.3	**0**
Discovered Petroleum Initially In Place (DPIIP)	**35.2**	35.2	**0**
Undiscovered Petroleum Initially In Place (UPIIP)	**29.1**	29.1	**0**

Notes:

(1) TPIIP, DPIIP and UPIIP have been estimated using a one percent porosity cut-off in the Resource Evaluation, which means that essentially all gas bearing rock has been incorporated into the calculations.
(2) All volumes in table are Company gross and raw gas volumes.
(3) Sproule's analysis identified four intervals in the Montney consisting of one interval in the Upper Montney and three intervals in the Lower Montney.
(4) Crew's acreage was divided into five (5) areas in the "gas window".
(5) There is uncertainty that it will be commercially viable to produce any portion of the resources.
(6) There is no certainty that any portion of the resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resources.

Light & Medium Crude Oil Resource Categories [1][2][3][4][5][6][7]	**Dec. 31, 2016**	Dec. 31, 2015	% Change
	Mmbbls	Mmbbls	
Total Petroleum Initially In Place (TPIIP)	**7,979**	7,895	1
Discovered Petroleum Initially In Place (DPIIP)	**1,647**	1,613	2
Undiscovered Petroleum Initially In Place (UPIIP)	**6,332**	6,282	1

Notes:

(1) TPIIP, DPIIP and UPIIP have been estimated using a one percent porosity cut-off in the Resource Evaluation, which means that essentially all oil bearing rock has been incorporated into the calculations.
(2) All volumes in table are Company gross.
(3) The oil volumes are quoted as Stock Tank Barrels ("STB").
(4) Sproule's analysis identified four intervals in the Montney consisting of one interval in the Upper Montney and three intervals in the Lower Montney.
(5) Crew's acreage was divided into five (5) areas in the "oil window".
(6) There is uncertainty that it will be commercially viable to produce any portion of the resources.
(7) There is no certainty that any portion of the resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resources.

2016 Reserves and Risked and Unrisked ECR[1][2][3][6][7][8]	Chance of Development	Best Estimate Unrisked	**Best Estimate Risked**
Conventional Natural gas (Bcf)			
Reserves [3]	100%	1,426	**1,426**
Development Pending ECR	87%	8,388	**7,298**
Development on Hold ECR	85%	500	**425**
NGL (Mmbbls) [4][5]			
Reserves [3]	100%	59	**59**
Development Pending ECR	88%	240	**211**
Development on Hold ECR	84%	19	**16**
Light & Medium Crude Oil (Mmbbls)			
Reserves [3]	100%	12	**12**
Development Pending ECR	89%	19	**17**
Development on Hold ECR	80%	5	**4**

Notes:

(1) All DPIIP other than cumulative production, reserves, and ECR has been categorized as unrecoverable at this time. A portion of the Unrecoverable DPIIP may in the future be determined to be recoverable and reclassified as contingent resources or reserves as additional technical studies are performed, commercial circumstances change or technological developments occur; the remaining portion may never be recovered due to the physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks.
(2) All volumes in table are company gross and sales volumes. Reserves and development pending volumes include economic cutoff.
(3) For reserves, the volumes are proved plus probable reserves as at December 31, 2016.
(4) The liquid yields are based on average yield over the producing life of the property.
(5) Liquid yields are unique to each area. They are estimated based on gas composition of gas samples in the area and expected plant recoveries.
(6) There is no certainty that it will be commercially viable to produce any of the resources.
(7) All ECR are risked for the chance of development. For ECR, the chance of development is defined as the probability of a project being commercially viable. In quantifying the chance of development, contingencies that were assessed quantitatively to be less than one in the risking calculation included evaluation drilling, corporate commitment and timing of production and development. The chance of development is multiplied by the unrisked resource volume estimate, which yields the risked volume estimate. As many of these factors have a wide range of uncertainty and are difficult to quantify, the chance of development is an uncertain value that should be used with caution.
(8) The economic status of the 'development not viable' project maturity subclass is deemed to be undetermined and is therefore not included in the ECR reported, representing, on a risked basis, 125 bcf of conventional natural gas, 2 mmbbls of ngl and 3 mmbbls of light and medium crude oil.

An estimate of risked Net Present Value ("NPV") of future net revenue of the development pending contingent resources subclass only is preliminary in nature and is provided to assist the reader in reaching an opinion on the merit and likelihood of Crew proceeding with the required investment. It includes contingent resources that are considered too uncertain with respect to chance of development and cannot be classified as reserves until the contingencies are lifted. There is uncertainty that the risked NPV of future net revenue will be realized. The other subclasses of resources are not included in this NPV and therefore this is not reflective of the value of the resource base.

Before-Tax NPV(1) 2016 Risked ECR Development Pending[(2)]	($ millions)
Undiscounted	26,539
Discounted at 5%	6,447
Discounted at 10%	1,997
Discounted at 15%	693
Discounted at 20%	217

Notes

(1) Based on the Resource Evaluation and Sproule's forecast pricing at December 31, 2016 which is set forth in Crew's press release dated February 9, 2017.
(2) Risk in the above table is the chance of development. ECR are discovered resources by definition.
(3) There is uncertainty that it will be commercially viable to produce any portion of the resources.

The estimated cost to fully develop and bring on commercial production of the 'development pending' contingent resources for all three product types is approximately $11.2 billion (or approximately $3.0 billion discounted at 10%). The forecasted timeline to bring these resources onto production is between two and 17 years utilizing the same technology in horizontal drilling and multi-stage fracturing that Crew has already proven to be effective in the Montney formation in NE BC.

Prospective Resources [(1)(2)(3)(4)(5)(6)(7)]	Chance of Commerciality	Best Estimate Unrisked	**Best Estimate Risked**
Conventional Natural Gas (Tcf)	66%	10,311	**6,774**
NGL (MMbbl)	66%	327	**215**
Light & Medium Crude Oil (MMbbl)	66%	149	**98**

Notes:

(1) All UPIIP other than prospective resources has been categorized as unrecoverable at this time.
(2) All volumes in table are company gross and sales volumes.
(3) The liquid yields are based on average yield over the producing life of the property.
(4) Liquid yields are unique to each area. They are estimated based on gas composition of gas samples in the area and expected plant recoveries.
(5) There is no certainty that any portion of the resources will be discovered. If discovered there is no certainty that it will be commercially viable to produce any of the resources.
(6) Prospective resources are risked for the chance of discovery and the chance of development. For prospective resources, the chance of development multiplied by the chance of discovery is defined as the probability of a project being commercially viable. In quantifying the chance of commerciality, factors that were assessed quantitatively to be less than one in the risking calculation included evaluation drilling, corporate commitment and timing of production and development, along with the overall chance of discovery. The chance of commerciality is multiplied by the unrisked prospective resource volume estimate, which yields the risked volume estimate. As many of these factors have a wide range of uncertainty and are difficult to quantify, the chance of commerciality is an uncertain value that should be used with caution.
(7) All prospective resources are subclassified as either the 'prospect' or 'lead' project maturity subclass.

Resource volumes are estimated using volumetric calculations of the in-place quantities, combined with performance from analog reservoirs. The currently producing assets of Crew and other industry parties in the Montney area of NE BC are used as performance analogs for ECR within Crew's areas of operations. The evaluation of ECR is based on an independent third party evaluation that assumes all of Crew's ECR will be recovered using horizontal multi-stage hydraulic fracturing and multi-well pad drilling, which are established technologies.

Based upon the foregoing analysis and resource information, coupled with Crew's expertise in the NE BC Montney, we anticipate that significant additional reserves will be developed in the future as we achieve continued drilling success on that portion of our Montney acreage which is currently undeveloped. Key positive factors considered in the Resource Evaluation estimates which support Crew's view that significant additional resources will be recovered include completions enhancements; improved economic conditions; historic drilling success and recoveries on the more fully-developed Montney acreage; abundant well log and production test data; the presence of analogue wells in the area; improving average initial productivity trends; and the application of increased drilling densities. Continuous development through multi-year exploration and development programs and significant levels of future capital expenditures are required in order for additional resources to be recovered in the future.

Our ability to recover additional resources is subject to numerous risks and the key negative factors include minimal well data from the Montney formation in certain intervals; a lack of long-term production history in the Montney; potential for variations in the quality of the Montney formation where minimal well data currently exists; access to capital that would enable us to continue development; low commodity prices which could impact economics; the future performance of wells; regulatory approvals or surface restrictions; lack of infrastructure in certain areas; access to required services at the appropriate cost; overall industry cost structures; and the continued efficacy of fracture stimulation technologies and application. In order for ECR to be converted into reserves, Crew's management and technical teams must continue to assess commercial production rates, devise firm development plans that incorporate timing, infrastructure and capital commitments. Confirmation of commercial productivity is generally required before the Company can prepare firm development plans and commit required capital for the development of the ECR. With continued development and delineation, some resources currently classified as ECR are expected to be reclassified as Reserves.

A key contingency that prevents the classification of ECR as Reserves is the additional drilling, completions and testing required to confirm viable commercial rates. Sproule assigned ECR beyond those areas which were assigned Reserves but which were within three miles of existing wells, or production tests. Further, a lack of infrastructure in the Evaluated Areas which is required to develop the resources, such as gas gathering, processing and natural gas liquids separation facilities, further impedes the reclassification of ECR to Reserves. In addition to these factors, and the general operational risks facing the oil and gas industry, there are several technical and non-technical contingencies that need to be overcome in order to reclassify ECR to Reserves. These include evaluation drilling, corporate commitment and timing of production and development of the ECR.

There is no certainty that any portion of the prospective resources will be discovered. There is uncertainty that it will be commercially viable to produce any portion of the prospective (if discovered) or contingent resources.

Definitions of Oil and Gas Resources and Reserves

Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, based on the analysis of drilling, geological, geophysical and engineering data; the use of established technology; and specified economic conditions, which are generally accepted as being reasonable. Reserves are classified according to the degree of certainty associated with the estimates as follows:

> **Proved Reserves** are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.
>
> **Probable Reserves** are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

Cumulative Production is the cumulative quantity of petroleum that has been recovered at a given date.

Resources encompasses all petroleum quantities that originally existed on or within the earth's crust in naturally occurring accumulations, including Discovered and Undiscovered (recoverable and unrecoverable) plus quantities already produced. "Total resources" is equivalent to "Total Petroleum Initially-In-Place". Resources are classified in the following categories:

> **Total Petroleum Initially-In-Place ("TPIIP")** is that quantity of petroleum that is estimated to exist originally in naturally occurring accumulations. It includes that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations, prior to production, plus those estimated quantities in accumulations yet to be discovered.
>
> **Discovered Petroleum Initially-In-Place ("DPIIP")** is that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production. The recoverable portion of discovered petroleum initially in place includes production, reserves, and contingent resources; the remainder is unrecoverable.
>
> **Contingent Resources** are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development but which are not currently considered to be commercially recoverable due to one or more contingencies.

Economic Contingent Resources ("ECR") are those contingent resources which are currently economically recoverable.

Project Maturity Subclass Development Pending is defined as a contingent resource that has been assigned a high chance of development and the resolution of final conditions for development are being actively pursued.

Project Maturity Subclass Development On Hold is defined as a contingent resource that has been assigned a reasonable chance of development, but there are major non-technical contingencies to be resolved that are usually beyond the control of the operator.

Project Maturity Subclass Development Unclarified is defined as a contingent resource that requires further appraisal to clarify the potential for development and has been assigned a lower chance of development until contingencies can be clearly defined.

Project Maturity Subclass Development not Viable is defined as a contingent resource where no further data acquisition or evaluation is currently planned and hence there is a low chance of development.

Undiscovered Petroleum Initially-In-Place ("UPIIP") is that quantity of petroleum that is estimated, on a given date, to be contained in accumulations yet to be discovered. The recoverable portion of undiscovered petroleum initially in place is referred to as "prospective resources" and the remainder as "unrecoverable."

Prospective Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective resources have both an associated chance of discovery and a chance of development.

Unrecoverable is that portion of DPIIP and UPIIP quantities which is estimated, as of a given date, not to be recoverable by future development projects. A portion of these quantities may become recoverable in the future as commercial circumstances change or technological developments occur; the remaining portion may never be recovered due to the physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks.

Uncertainty Ranges are described by the Canadian Oil and Gas Evaluation Handbook as low, best, and high estimates for reserves and resources. The **Best Estimate** is considered to be the best estimate of the quantity that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. If probabilistic methods are used, there should be at least a 50 percent probability (P50) that the quantities actually recovered will equal or exceed the best estimate.

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), Mmboe (millions of barrels of oil equivalent), and Tcfe (trillion cubic feet of gas 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. 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 "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 TPIIP, DPIIP, UPIIP and ECR in the Montney region in NE BC which are not, and should not be confused with, oil and gas reserves. See "Definitions of Oil and Gas Resources and Reserves".

Projects have not been defined to develop the resources in the Evaluated Areas as at the evaluation date. Such projects, in the case of the Montney resource development, have historically been developed sequentially over a number of drilling seasons and are subject to annual budget constraints, Crew's policy of orderly development on a staged basis, the timing of the growth of third party infrastructure, the short and long-term view of Crew on oil and gas prices, the results of exploration and development activities of Crew and others in the area and possible infrastructure capacity constraints. As with any resource estimates, the evaluation will change over time as new information becomes available.

Crew's belief that it will establish significant additional reserves over time with the conversion of DPIIP and prospective resource into contingent resource, contingent resource into probable reserves and probable reserves into proved reserves is a forward looking statement and is based on certain assumptions and is subject to certain risks, as discussed below under the heading "Forward Looking Information and Statements".

<u>Cautionary Statements</u>

Forward-Looking Information and Statements

This report contains certain forward–looking information and statements within the meaning of applicable securities laws. The use of any of the words "expect", "anticipate", "continue", "estimate", "may", "will", "project", "should", "believe", "plans", "intends" "forecast" and similar expressions are intended to identify forward-looking information or statements. In particular, but without limiting the foregoing, this report contains forward-looking information and statements pertaining to the following: the volume and product mix of Crew's oil and gas production; production estimates including Q2, Q3, Q4 and annual 2017 forecast average production and 2017 exit rate; anticipated closing of the Goose asset disposition and the timing thereof; the volumes and estimated value of Crew's resources and undeveloped land; the recognition of significant resources under the heading "Crew Northeast British Columbia Montney Resource Evaluation"; 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; anticipated reductions in operating costs, well costs and G&A expenditures and potential to improve ultimate recoveries and initial production rates; future costs, expenses and royalty rates; 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; the potential value of our undeveloped land base; the amount and timing of capital projects including facility expansions, commissioning and the timing thereof; the total future capital associated with development of reserves and resources; methods of funding our capital program, including possible non-core asset divestitures and asset swaps; and our intention to apply to the TSX to implement a normal course issuer bid and the timing thereof.

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. There are a number of assumptions associated with the potential of resource volumes and development of the Evaluated Areas including the quality of the Montney reservoir, future drilling programs and the funding thereof, continued performance from existing wells and performance of new wells, the growth of infrastructure, well density per section, and recovery factors and development necessarily involves known and unknown risks and uncertainties, including those identified in this report.*

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 may not necessarily be indicative of long term performance or of ultimate recovery.

BOE equivalent

Barrel of oil equivalents or BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 mcf: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different than the energy equivalency of 6:1, utilizing a 6:1 conversion basis may be misleading as an indication of value.

Crew Energy Inc. is a dynamic, growth-oriented exploration and production company, focused on increasing long-term production, reserves and cash flow per share through the development of our world-class Montney resource. Crew is based in Calgary, Alberta and our shares are traded on The Toronto Stock Exchange under the trading symbol "CR".

MANAGEMENT'S DISCUSSION AND ANALYSIS

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 for Crew Energy Inc. ("Crew" or the "Company"). Comments relate to and should be read in conjunction with the unaudited condensed interim consolidated financial statements of the Company for the three month period ended March 31, 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 March 31, 2017 unaudited condensed interim consolidated financial statements are reported in Canadian dollars. This MD&A is dated May 8, 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 2017 capital budget, timing of capital expenditures and methods of financing capital expenditures and the ability to fund financial liabilities, production estimates including 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, funds from operations and the timing of and impact of implementing accounting policies, the closing of the disposition of non-core assets, 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 March 31, 2017**	Three months ended March 31, 2016
Cash provided by operating activities	**27,189**	19,591
Decommissioning obligations settled	**378**	419
Change in operating non-cash working capital	**359**	(8,121)
Accretion of deferred financing costs	**(207)**	(175)
Funds from operations	**27,719**	11,714

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, the premium on flow-through shares and unrealized gains or losses on marketable securities 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)	**March 31, 2017**	December 31, 2016
Current assets	**56,156**	39,588
Current liabilities	**(64,492)**	(68,494)
Derivative financial instruments	**(252)**	18,900
Working capital deficit	**(8,588)**	(10,006)

($ thousands)	**March 31, 2017**	December 31, 2016
Bank loan	**-**	(88,036)
Senior unsecured notes	**(293,046)**	(147,329)
Working capital deficit	**(8,588)**	(10,006)
Net debt	**(301,634)**	(245,371)

RESULTS OF OPERATIONS

Production

	Three months ended March 31, 2017				Three months ended March 31, 2016			
	Oil (bbl/d)	**Ngl (bbl/d)**	**Nat. gas (mcf/d)**	**Total (boe/d)**	Oil (bbl/d)	Ngl (bbl/d)	Nat. gas (mcf/d)	Total (boe/d)
Northeast British Columbia	**530**	**3,363**	**104,838**	**21,366**	303	3,359	103,973	20,991
Lloydminster	**1,857**	**-**	**49**	**1,865**	2,799	-	251	2,841
Total	**2,387**	**3,363**	**104,887**	**23,231**	3,102	3,359	104,224	23,832

Production for the first quarter of 2017 decreased 3% over the same period in 2016 due to a decline in Lloydminster heavy oil production as the Company continues to direct its investment capital to higher rate of return projects in northeast British Columbia. This was partially offset by increased oil production at Tower, British Columbia as a result of successfully completing two light oil wells in the fourth quarter of 2016 and two wells in the first quarter of 2017, in addition to the acquisition of approximately 800 boe per day of non-Montney natural gas production in other northeast British Columbia ("Other NE BC") late in the fourth quarter of 2016.

Revenue

	Three months ended March 31, 2017	Three months ended March 31, 2016
Revenue ($ thousands)		
Light crude oil	**2,848**	1,027
Heavy crude oil	**7,175**	5,208
Natural gas liquids	**13,835**	7,934
Natural gas	**33,440**	22,174
Total	**57,298**	36,343
Crew average prices		
Light crude oil ($/bbl)	**59.74**	37.34
Heavy crude oil ($/bbl)	**42.93**	20.45
Natural gas liquids ($/bbl)	**45.71**	25.95
Natural gas ($/mcf)	**3.54**	2.34
Oil equivalent ($/boe)	**27.40**	16.76
Benchmark pricing		
Light crude oil – Cdn$ WTI (Cdn $/bbl)	**68.66**	45.88
Heavy crude oil – WCS (Cdn $/bbl)	**49.47**	26.61
Natural gas liquids – Condensate @ Edmonton (Cdn $/bbl)	**69.18**	47.27
Natural Gas:		
AECO 5A daily index (Cdn $/mcf)	**2.69**	1.83
Chicago City Gate at ATP (Cdn $/mcf)	**3.22**	2.07
Alliance 5A (Cdn $/mcf)	**3.09**	1.96

In the first quarter of 2017, the Company's revenue increased 58% as compared to the same period in 2016 as a result of a 63% increase in realized commodity pricing, partially offset by the slight decline in production. Crew's realized light crude oil price increased 60% as compared to the same period last year, which was greater than the 50% increase in the Company's Cdn$ West Texas Intermediate ("WTI") benchmark for the same period last year. This increase is a result of the Company securing sales contracts when differentials between the WTI price and Canadian Light crude price were narrower than the same period last year. The Company's first quarter heavy oil price increased 110%, which was greater than the 86% increase in the Company's Western Canadian Select ("WCS") benchmark as a result of the Company securing short term sales contracts when WCS differentials were narrower than the average market trade for the quarter. Crew's first quarter realized natural gas liquids ("ngl") price increased 76% over the same period in 2016 as compared to the 46% increase in the Condensate at Edmonton benchmark price, as the realized price for propane and butane was significantly higher during the quarter as compared to the same period in 2016. Crew's realized natural gas price increased 51% over the same quarter in 2016 as a result of the significant increase in the Company's primary sales markets for its natural gas. The Company's Alliance 5A and Chicago City Gate at ATP benchmark increased 58% and 56%, respectively, while the AECO 5A benchmark increased 47%. The Company's natural gas price is further enhanced by the high heat content of its Montney natural gas which averaged approximately 19% hotter than the Alliance standard heat content in the first quarter.

The Company's first quarter natural gas sales portfolio was based on the following reference prices:

	Three months ended March 31, 2017	Three months ended March 31, 2016
Chicago City Gate at ATP	**45%**	40%
AECO	**26%**	35%
Alliance 5A	**19%**	15%
Station 2	**10%**	10%
	100%	100%

Royalties

($ thousands, except per boe)	**Three months ended March 31, 2017**	Three months ended March 31, 2016
Royalties	**4,557**	1,899
Per boe	**2.18**	0.88
Percentage of revenue	**8.0%**	5.2%

In the first quarter of 2017, royalties and royalties as a percentage of revenue increased over the same period in 2016 as a result of the significant increase in realized commodity pricing which attracts higher royalty rates from price sensitive royalty calculations. The increased natural gas royalty rates were partially offset by declines in heavy oil production which yield a higher royalty rate relative 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 March 31, 2017**	Three months ended March 31, 2016
Realized (loss) / gain on derivative financial instruments	**(815)**	4,798
Per boe	**(0.39)**	2.21
Unrealized gain on financial instruments	**19,875**	7,204

At March 31, 2017, the Company held derivative commodity contracts as follows:

Subject of Contract	Notional Quantity	Term	Reference	Strike Price	Option Traded	Fair Value ($000s)
Oil	1,000 bbl/day	April 1, 2017 – June 30, 2017	CDN$ WTI	$68.94	Swap	88
Oil	500 bbl/day	April 1, 2017 – June 30, 2017	CDN$ WCS – WTI Diff	($19.40)	Swap	(110)
Gas	2,500 gj/day	April 1, 2017 – October 31, 2017	AECO C Daily Index	$2.55	Swap	(45)
Gas	22,500 mmbtu/day	April 1, 2017 – December 31, 2017	Chicago Citygate	$3.88	Swap	(1,907)
Oil	1,750 bbl/day	April 1, 2017 – December 31, 2017	CDN$ WTI	$68.02	Swap	(270)
Oil	250 bbl/day	July 1, 2017 – December 31, 2017	CDN$ WTI	$71.00	Call Swaption(1)	(103)
Gas	22,500 gj/day	April 1, 2017 – December 31, 2017	AECO C Monthly Index	$2.83	Swap	1,004
Gas	10,000 gj/day	April 1, 2017 – December 31, 2017	AECO C Daily Index	$3.08	Swap	1,187
Gas	5,000 mmbtu/day	April 1, 2017 – December 31, 2018	Chicago Citygate	$4.23	Swap	856
Gas	5,000 gj/day	January 1, 2018 – December 31, 2018	AECO C Monthly Index	$3.00	Call	(365)
Gas	2,500 gj/day	January 1, 2018 – December 31, 2018	AECO C Daily Index	$2.62	Swap	109
Gas	5,000 mmbtu/day	January 1, 2018 – December 31, 2018	US$ Nymex Henry Hub	$3.05	Swap	41
Total						485

(1) The referenced contract is a European call swaption, which the counterparty will accept or decline by June 30, 2017.

Operating Costs

($ thousands, except per boe)	**Three months ended March 31, 2017**	Three months ended March 31, 2016
Operating costs	**11,243**	13,979
Per boe	**5.38**	6.45

For the first quarter of 2017, operating costs and operating costs per boe decreased as compared to the same period in 2016 as a result of increased lower cost production in northeast British Columbia, combined with the decrease in higher cost Lloydminster production. In addition, the Company continues to reduce its operating costs per boe at Septimus and West Septimus ("Greater Septimus"), where increased efficiencies have decreased costs by 25% over the same period in 2016 to average $3.34 per boe in the first quarter of 2017. 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 March 31, 2017**	Three months ended March 31, 2016
Transportation costs	**4,784**	5,434
Per boe	**2.29**	2.51

In the first quarter of 2017, the Company's transportation costs and transportation costs per boe decreased as compared to the same period in 2016 as the Company completed the construction of the Pine River sales gas and condensate pipeline connecting the Greater Septimus facilities in the second quarter of 2016, significantly reducing the trucking of condensate from the West Septimus facility. This was partially offset by increased production in other non-Montney northeast British Columbia properties, which attract higher transportation costs per boe as compared to the corporate average. 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 March 31, 2017**	Three months ended March 31, 2016
Revenue	**26.49**	**42.81**	**24.16**	**27.40**	16.76
Royalties	**(1.66)**	**(5.84)**	**(2.76)**	**(2.18)**	(0.88)
Realized commodity hedging (loss)/gain	**(0.41)**	**(0.12)**	**(0.43)**	**(0.39)**	2.21
Operating costs	**(3.34)**	**(22.54)**	**(6.30)**	**(5.38)**	(6.45)
Transportation costs	**(1.67)**	**(0.98)**	**(5.67)**	**(2.29)**	(2.51)
Operating netbacks	**19.41**	**13.33**	**9.00**	**17.16**	9.13
Production (boe/d)	**17,440**	**1,865**	**3,926**	**23,231**	23,832

For the first quarter of 2017, the Company's operating netbacks increased over the same period in 2016 as a result of a significant increase in revenue and a reduction in operating costs, partially offset by an increase in royalties and a loss realized on commodity hedging.

General and Administrative Costs

($ thousands, except per boe)	**Three months ended March 31, 2017**	Three months ended March 31, 2016
Gross costs	**4,977**	5,429
Operator's recoveries	**(174)**	(9)
Capitalized costs	**(1,657)**	(1,603)
General and administrative expenses	**3,146**	3,817
Per boe	**1.50**	1.76

Gross and net general and administrative ("G&A") costs have decreased in the first quarter of 2017 as compared to the same period in 2016, due to the start of a new office lease in the second quarter of 2016, which significantly reduced office rent costs for the first year of the five year lease term. In addition to lower rent costs, decreased compensation costs and increased operator's recoveries contributed to a further reduction in net G&A costs per boe in the first quarter as compared to the same period in 2016. Crew forecasts G&A costs per boe to average between $1.25 and $1.50 in 2017.

Share-Based Compensation

($ thousands)	**Three months ended March 31, 2017**	Three months ended March 31, 2016
Gross costs	**6,113**	5,184
Capitalized costs	**(2,959)**	(2,333)
Total share-based compensation	**3,154**	2,851

Share-based compensation expense increased in the first quarter of 2017 as compared to the same period in 2016, due to additional compensation expense recorded as a result of an increase in the previously estimated performance multiplier applied to certain outstanding performance awards, recognizing the Company's positive operational performance in 2016.

Depletion and Depreciation

($ thousands, except per boe)	**Three months ended March 31, 2017**	Three months ended March 31, 2016
Depletion and depreciation	**19,710**	24,948
Per boe	**9.43**	11.50

Depletion and depreciation costs and costs per boe decreased in the first quarter of 2017 by 21% and 18%, respectively, when compared to the same period 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 fourth quarter of 2016 which reduced the CGU's net book value and a decrease in the higher depletion rate Lloydminster production as compared to the same period in 2016.

Finance Expenses

($ thousands, except per boe)	**Three months ended March 31, 2017**	Three months ended March 31, 2016
Interest on bank loan	**966**	1,025
Interest on senior notes	**3,861**	3,098
Accretion of deferred financing charges	**207**	175
Accretion of the decommissioning obligation	**474**	433
Premium paid on redemption of 2020 Notes	**6,282**	-
Deferred financing costs expensed on 2020 Notes	**2,510**	-
Total finance expense	**14,300**	4,731
Average debt level	**269,914**	228,897
Average drawings on bank loan	**73,248**	78,897
Average senior unsecured notes outstanding	**196,666**	150,000
Effective interest rate on bank loan	**5.3%**	5.2%
Effective interest rate on senior notes	**8.0%**	8.4%
Effective interest rate on long-term debt	**7.6%**	7.2%
Interest on long-term debt per boe	**2.41**	1.98

The Company's average corporate debt level increased in the first quarter of 2017 as compared to the same period in 2016, due to an increase in capital expenditures in 2017 combined with the March 14, 2017 issuance of $300 million of 6.5% senior unsecured notes (the "2024 Notes") and subsequent March 23, 2017 redemption of all of the previously issued and outstanding $150 million of 8.375% senior unsecured notes (the "2020 Notes"), as described below in the Capital Funding section. Proceeds from the 2024 Notes were used to redeem the 2020 Notes and repay the drawings on the bank loan. As a result, the effective interest rate on the Company's bank loan increased slightly in the first quarter of 2017 as compared to the same period in 2016, due to increased standby fees as a result of a decrease in the average drawings on the Company's bank facility. Crew forecasts the effective interest rate on its long-term debt to average between 6.5% and 7.5% for 2017.

Deferred Income Taxes

In the first quarter of 2017, the provision for deferred tax expense was $7.8 million as compared to the deferred tax recovery of $1.8 million in the same period in 2016. This increase is a result of increased income before taxes combined with the Company incurring and renouncing its qualifying Canadian Development Expenses under its flow-through share offering as described in the Share Capital section below.

Cash, Funds from Operations and Net Income

($ thousands, except per share amounts)		**Three months ended March 31, 2017**	Three months ended March 31, 2016
Cash provided by operating activities		**27,189**	19,591
Funds from operations		**27,719**	11,714
Per share	- basic	**0.19**	0.08
	- diluted	**0.18**	0.08
Net Income (loss)		**8,056**	(6,795)
Per share	- basic	**0.05**	(0.05)
	- diluted	**0.05**	(0.05)

The increase in cash provided by operating activities and funds from operations in the first quarter of 2017 was a result of a significant increase in realized commodity prices, combined with lower operating and transportation costs incurred during the quarter. The increase in net income in the first quarter of 2017 as compared to the same period in 2016 is a result of the increase in the Company's revenue and unrealized gain on derivative financial instruments, partially offset by an increase in financing costs relating to the redemption of the 2020 Notes and an increase in deferred tax expense for the period.

Capital Expenditures, Property Acquisitions and Dispositions

In the first quarter of 2017, the Company drilled eleven (11.0 net) natural gas wells in northeast British Columbia and four (4.0 net) oil wells in Lloydminster. Crew completed five (5.0 net) wells in northeast British Columbia and two (2.0 net) oil wells in Lloydminster, and also recompleted four (3.5 net) oil wells in Lloydminster. During the quarter, approximately $69.2 million was spent in northeast British Columbia which included approximately $14.1 million to double the processing capacity at the West Septimus facility to approximately 120 mmcf per day which is currently expected to be completed in the fourth quarter of 2017.

Subsequent to March 31, 2017, the Company entered into an agreement to dispose of non-core assets in northeast British Columbia for cash consideration of approximately $49 million, subject to certain closing adjustments and costs. The assets consist of undeveloped land of approximately 18,400 net acres, with no booked reserves or current production associated therewith. Closing of the transaction is expected to occur in the second quarter of 2017, subject to satisfaction of customary closing conditions.

Total net capital expenditures are detailed below:

($ thousands)	**Three months ended March 31, 2017**	Three months ended March 31, 2016
Land	**870**	619
Seismic	**260**	177
Drilling and completions	**53,068**	13,789
Facilities, equipment and pipelines	**18,967**	1,465
Other	**1,999**	1,713
Total exploration and development	**75,164**	17,763
Property (dispositions) acquisitions	**(352)**	956
Total	**74,812**	18,719

The Company's Board of Directors has approved a $200 million exploration and development budget for 2017.

LIQUIDITY AND CAPITAL RESOURCES

Capital Funding

The Company's bank facility has recently been reconfirmed at $235 million, and now 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. 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 debt and senior unsecured notes while secured debt consists of the Company's bank debt. At March 31, 2017, these ratios were 2.6:1 and 0.0:1, 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, premium on flow-through shares and unrealized gains or losses on marketable securities 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 October 31, 2017. 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 are guaranteed, jointly and severally, on an unsecured basis, by each of the Company's current and future restricted subsidiaries. Interest on the 2024 Notes accrues at the rate of 6.5% per year and is payable semi-annually. At March 31, 2017, the carrying value of the 2024 Notes was net of deferred financing costs of $7.0 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 costs as a result of the 2020 Notes redemption.

The Company will continue to fund its on-going operations from a combination of cash flow, debt, non-core asset dispositions and additional equity financings as needed. As the majority of the Company's on-going capital expenditure program is directed to the further growth of reserves and production volumes, 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 the working capital deficit is an accounts receivable of $8.3 million for a government incentive credit earned through the completion of the construction of the Pine River pipeline. The collection of the grant is realized through the reduction of future royalties payable to the British Columbia government.

The Company ensures that sufficient drawings are available from its Facility to satisfy working capital deficiencies. At March 31, 2017, the Company's working capital deficiency totaled $8.6 million, which when combined with the drawings on its Facility, represented 4% of its Facility at March 31, 2017.

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. At March 31, 2017, the Company has incurred the entire $15.0 million in qualifying expenditures under this flow-through share offering.

Crew is authorized to issue an unlimited number of common shares. As at May 8, 2017, there were 149,827,371 common shares and options to acquire 46,500 common shares of the Company issued and outstanding. In addition, there were 1,829,295 restricted awards and 2,682,315 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 or below 2.0 to 1.0. During periods of increased capital expenditures, acquisitions or during periods of low commodity prices, this ratio will increase over short-term periods. As shown below, as at March 31, 2017, the Company's ratio of net debt to annualized funds from operations was 2.72 to 1 (December 31, 2016 – 2.20 to 1). With the Company's Facility undrawn, recently confirmed at $235 million and extended until June 2018, along with the recently issued long-term 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)	**March 31, 2017**	December 31, 2016
Working capital deficit	**(8,588)**	(10,006)
Bank loan	**-**	(88,036)
Senior unsecured notes	**(293,046)**	(147,329)
Net debt	**(301,634)**	(245,371)
Quarterly funds from operations	**27,719**	27,879
Annualized	**110,876**	111,516
Net debt to annualized funds from operations ratio	**2.72**	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
Senior unsecured notes (note 1)	300,000	-	-	-	-	-	300,000
Operating leases	4,700	783	1,175	1,175	1,175	392	-
Capital commitments	14,359	14,359	-	-	-	-	-
Firm transportation agreements	131,778	23,517	30,311	29,739	26,509	3,570	18,132
Firm processing agreements	93,017	9,585	12,637	12,637	11,336	7,395	39,427
Total	**543,854**	**48,244**	**44,123**	**43,551**	**39,020**	**11,357**	**357,559**

Note 1 – 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 expansion costs of the Septimus complex 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

Exiting the first quarter, Crew has an inventory of 18 drilled but uncompleted wells. As a result of deferred first quarter completions and extended road bans due to wet weather in northeastern British Columbia, the Company expects second quarter drilling and completion capital expenditures to be reduced, which will impact budgeted second quarter production volumes. Due to the deferral of capital expenditures, the Company's 2017 annual production guidance has been reduced by 4% to 24,000 to 26,000 boe per day based on a $200 million capital budget with the 2017 production exit rate expected at over 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)	**Mar. 31 2017**	Dec. 31 2016	Sep. 30 2016	June 30 2016	Mar. 31 2016	Dec. 31 2015	Sep. 30 2015	June 30 2015
Total daily production (boe/d)	**23,231**	22,380	23,211	21,950	23,832	20,706	16,773	17,656
Exploration and development expenditures	**75,164**	37,612	37,731	15,096	17,763	42,067	58,565	54,694
Property acquisitions/(dispositions)	**(352)**	3,099	(98)	16	956	(36,644)	(50,281)	1,226
Average wellhead price ($/boe)	**27.40**	26.74	22.05	18.14	16.76	18.13	22.54	27.81
Petroleum and natural gas sales	**57,298**	55,051	47,093	36,232	36,343	34,532	34,784	44,678
Cash provided by operations	**27,189**	19,900	25,940	12,047	19,591	12,373	22,091	23,013
Funds from operations	**27,719**	27,879	23,033	16,048	11,714	19,601	17,273	24,769
Per share – basic	**0.19**	0.19	0.16	0.11	0.08	0.14	0.12	0.18
– diluted	**0.18**	0.19	0.16	0.11	0.08	0.14	0.12	0.18
Net income (loss)	**8,056**	(40,030)	(1,286)	(16,815)	(6,795)	(8,167)	(18,179)	(13,239)
Per share – basic	**0.05**	(0.28)	(0.01)	(0.12)	(0.05)	(0.06)	(0.13)	(0.09)
– diluted	**0.05**	(0.28)	(0.01)	(0.12)	(0.05)	(0.06)	(0.13)	(0.09)

Beginning in 2014, Crew embarked on a plan to refocus the Company towards its Montney assets in northeast British Columbia. In 2015, the Company invested the majority of its capital expenditures in Greater Septimus and Tower, increasing production by 57% from the first quarter of 2015 to the fourth quarter of 2016. 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 net income (loss) 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. In 2015 and into 2016, low commodity prices have also led to the assessment and realization of impairment of the carrying value of the Lloydminster CGU. In 2015, the Company incurred $55.4 million in impairment charges and in 2016, the Company also incurred $44.4 million of impairment charges. These losses have been partially offset by gains on the sale of certain properties in 2015.

Disclosure Controls and Procedures and Internal Controls over Financial Reporting

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

The Company's CEO and CFO have designed, or caused to be designed under their supervision, internal controls over financial reporting to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. The Company is required to disclose herein any change in the Company's internal controls over financial reporting that occurred during the period beginning on January 1, 2017 and ended on March 31, 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 May 8, 2017

CONDENSED INTERIM CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

(unaudited) (thousands)	**March 31, 2017**	December 31, 2016
Assets		
Current Assets:		
Cash and cash equivalents	**$ 23,478**	$ -
Accounts receivable	**31,523**	39,588
Derivative financial instruments (note 8)	**1,155**	-
	56,156	39,588
Derivative financial instruments (note 8)	**507**	-
Property, plant and equipment (note 3)	**1,257,297**	1,199,452
	$ 1,313,960	$ 1,239,040
Liabilities and Shareholders' Equity		
Current Liabilities:		
Accounts payable and accrued liabilities	**$ 63,589**	$ 49,594
Derivative financial instruments (note 8)	**903**	18,900
	64,492	68,494
Derivative financial instruments (note 8)	**274**	490
Bank loan (note 4)	**-**	88,036
Senior unsecured notes (note 5)	**293,046**	147,329
Decommissioning obligations (note 6)	**85,393**	85,859
Deferred premium on flow-through shares (note 7)	**-**	1,419
Deferred tax liability	**34,897**	25,724
Shareholders' Equity		
Share capital (note 7)	**1,443,530**	1,442,284
Contributed surplus	**79,827**	74,960
Deficit	**(687,499)**	(695,555)
	835,858	821,689
Subsequent events (note 11)		
Commitments (note 10)		
	$ 1,313,960	$ 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 March 31, 2017**		Three months ended March 31, 2016
Revenue				
Petroleum and natural gas sales	**$**	**57,298**	$	36,343
Royalties		**(4,557)**		(1,899)
Realized (loss) gain on derivative financial instruments (note 8)		**(815)**		4,798
Unrealized gain on derivative financial instruments (note 8)		**19,875**		7,204
		71,801		46,446
Expenses				
Operating		**11,243**		13,979
Transportation		**4,784**		5,434
General and administrative		**3,146**		3,817
Share-based compensation		**3,154**		2,851
Depletion and depreciation		**19,710**		24,948
		42,037		51,029
Income (loss) from operations		**29,764**		(4,583)
Financing (note 9)		**14,300**		4,731
Unrealized gain on marketable securities		**-**		(878)
(Gain) loss on divestiture of property, plant and equipment		**(346)**		130
Income (loss) before income taxes		**15,810**		(8,566)
Deferred tax (expense) recovery		**(7,754)**		1,771
Net income (loss) and comprehensive income (loss)	**$**	**8,056**	$	(6,795)
Net income (loss) per share (note 7)				
Basic	**$**	**0.05**	$	(0.05)
Diluted	**$**	**0.05**	$	(0.05)

See accompanying notes to the condensed interim consolidated financial statements.

CONDENSED INTERIM CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

(unaudited) (thousands)	Number of shares	Share capital	Contributed surplus	Deficit	Total Shareholders' equity
Balance, January 1, 2017	146,812	$ 1,442,284	$ 74,960	$ (695,555)	$ 821,689
Net income for the period	-	-	-	8,056	8,056
Share-based compensation expensed	-	-	3,154	-	3,154
Share-based compensation capitalized	-	-	2,959	-	2,959
Issued on vesting of share awards	315	1,246	(1,246)	-	-
Balance, March 31, 2017	**147,127**	**$ 1,443,530**	**$ 79,827**	**$ (687,499)**	**$ 835,858**

(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	-	-	-	(6,795)	(6,795)
Share-based compensation expensed	-	-	2,851	-	2,851
Share-based compensation capitalized	-	-	2,333	-	2,333
Issued on vesting of share awards	6	53	(53)	-	-
Balance, March 31, 2016	**141,073**	**$ 1,398,751**	**$ 82,758**	**$ (637,424)**	**$ 844,085**

See accompanying notes to the condensed interim consolidated financial statements.

CONDENSED INTERIM CONSOLIDATED STATEMENTS OF CASH FLOWS

(unaudited) (thousands)		**Three months ended March 31, 2017**		Three months ended March 31, 2016
Cash provided by (used in):				
Operating activities:				
Net income (loss)	**$**	**8,056**	$	(6,795)
Adjustments:				
Unrealized gain on derivative financial instruments		**(19,875)**		(7,204)
Share-based compensation		**3,154**		2,851
Depletion and depreciation		**19,710**		24,948
Financing expenses (note 9)		**14,300**		4,731
Interest expense (note 9)		**(4,827)**		(4,123)
Unrealized gain on marketable securities		**-**		(878)
(Gain) loss on divestiture of property, plant and equipment		**(346)**		130
Deferred tax expense (recovery)		**7,754**		(1,771)
Decommissioning obligations settled		**(378)**		(419)
Change in non-cash working capital		**(359)**		8,121
		27,189		19,591
Financing activities:				
(Decrease) increase in bank loan		**(88,036)**		17,128
Issuance of senior notes, net of financing costs (note 5)		**293,000**		-
Redemption of senior notes (note 5)		**(156,282)**		-
		48,682		17,128
Investing activities:				
Property, plant and equipment expenditures		**(75,164)**		(17,763)
Property acquisitions		**(8)**		(1,050)
Property dispositions		**360**		94
Change in non-cash working capital		**22,419**		(18,000)
		(52,393)		(36,719)
Change in cash and cash equivalents		**23,478**		-
Cash and cash equivalents, beginning of period		**-**		-
Cash and cash equivalents, end of period	**$**	**23,478**	$	-

See accompanying notes to the condensed interim consolidated financial statements.

NOTES TO CONDENSED INTERIM CONSOLIDATED FINANCIAL STATEMENTS

For the three months ended March 31, 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 May 8, 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		75,164
Acquisitions		8
Divestitures		(378)
Change in decommissioning obligations		(198)
Capitalized share-based compensation		2,959
Balance, March 31, 2017	**$**	**2,258,834**

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		19,710
Balance, March 31, 2017	**$**	**1,001,537**

Net book value		Total
Balance, March 31, 2017	**$**	**1,257,297**
Balance, December 31, 2016	$	1,199,452

The calculation of depletion for the three months ended March 31, 2017 included estimated future development costs of $1,573.3 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 $67.9 million (December 31, 2016 - $67.3 million) and undeveloped land of $179.9 million (December 31, 2016 - $182.3 million) related to future development acreage, with no associated reserves.

4. Bank loan:

The Company's bank facility has recently been reconfirmed at $235 million, and now 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. 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 debt and senior unsecured notes while secured debt consists of the Company's bank debt. At March 31, 2017, these ratios were 2.6:1 and 0.0:1, 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, premium on flow-through shares and unrealized gains or losses on marketable securities 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 October 31, 2017. The Facility is secured by a floating charge debenture and a general securities agreement on the assets of the Company.

Advances under the Facility are available by way of prime rate loans with interest rates between 0.50 percent and 2.50 percent over the bank's prime lending rate and bankers' acceptances and LIBOR loans, which are subject to stamping fees and margins ranging from 1.50 percent to 3.50 percent depending upon the debt to EBITDA ratio of the Company calculated at the Company's previous quarter end. Standby fees are charged on the undrawn Facility at rates ranging from 0.375 percent to 0.875 percent depending upon the debt to EBITDA ratio. As at March 31, 2017, the Company's applicable pricing included a 1.00 percent margin on prime lending, a 2.00 percent stamping fee and margin on bankers' acceptances and LIBOR loans along with a 0.50 percent per annum standby fee on the portion of the Facility that is not drawn. Borrowing margins and fees are reviewed annually as part of the bank syndicate's annual renewal.

At March 31, 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 three months ended March 31, 2017 was 5.3% (December 31, 2016 – 4.8%).

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 March 31, 2017, the carrying value of the 2024 Notes was net of deferred financing costs of $7.0 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 costs as a result of the 2020 Notes redemption (Financing – note 9).

6. Decommissioning obligations:

	Three months ended March 31, 2017	Year ended December 31, 2016
Decommissioning obligations, beginning of period	**$ 85,859**	$ 85,822
Obligations incurred	**1,396**	1,344
Obligations acquired	**-**	4,061
Obligations settled	**(378)**	(1,411)
Obligations divested	**(364)**	-
Change in estimated future cash outflows	**(1,594)**	(5,725)
Accretion of decommissioning obligations	**474**	1,768
Decommissioning obligations, end of period	**$ 85,393**	$ 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 $85.4 million as at March 31, 2017 (December 31, 2016 - $85.9 million) based on an inflation adjusted undiscounted total future liability of $113.3 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 three months ended March 31, 2017 is a result of a change in future estimated undiscounted abandonment costs.

7. Share capital:

At March 31, 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.

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. At March 31, 2017, the Company has incurred the entire $15.0 million in qualifying expenditures under this flow-through share offering.

Share based payments:

The Company had a stock option program that entitles 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, have 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 number and weighted average exercise prices of stock options are as follows:

	Number of options	Weighted average exercise price
Balance, January 1, 2017	1,430	$ 7.08
Forfeited	(3)	7.17
Balance, March 31, 2017	**1,427**	**$ 7.08**

The following table summarizes information about the stock options outstanding at March 31, 2017:

Range of exercise prices	Outstanding at March 31, 2017	Weighted average remaining life (years)	Weighted average exercise price	Exercisable at March 31, 2017	Weighted average exercise price
$ 5.58 to $ 5.65	24	0.5	$ 5.58	24	$ 5.58
$ 5.66 to $ 7.16	156	0.1	6.58	156	6.58
$ 7.17 to $ 7.25	1,247	0.1	7.17	1,247	7.17
	1,427	**0.1**	**$ 7.08**	**1,427**	**$ 7.08**

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 59,000 restricted awards and 128,000 performance awards, when taking into account the earned multipliers for performance awards, 315,000 common shares of the Company were issued for the three months ended March 31, 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	6	5
Vested	(59)	(128)
Forfeited	(10)	(3)
Balance, March 31, 2017	**1,636**	**2,411**

Per share amounts:

Per share amounts have been calculated on the weighted average number of shares outstanding. The weighted average shares outstanding for the three month period ended March 31, 2017 was 146,820,000 (March 31, 2016 – 141,071,000).

In computing diluted earnings per share for the three month period ended March 31, 2017, 4,440,000 (March 31, 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. There were 1,406,000 (March 31, 2016 – 3,653,000) stock options and 14,000 (March 31, 2016 – 2,575,000) 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 March 31, 2017, the Company held derivative commodity contracts as follows:

Subject of Contract	Notional Quantity	Term	Reference	Strike Price	Option Traded	Fair Value ($000s)
Oil	1,000 bbl/day	April 1, 2017 – June 30, 2017	CDN$ WTI	$68.94	Swap	88
Oil	500 bbl/day	April 1, 2017 – June 30, 2017	CDN$ WCS – WTI Diff	($19.40)	Swap	(110)
Gas	2,500 gj/day	April 1, 2017 – October 31, 2017	AECO C Daily Index	$2.55	Swap	(45)
Gas	22,500 mmbtu/day	April 1, 2017 – December 31, 2017	Chicago Citygate	$3.88	Swap	(1,907)
Oil	1,750 bbl/day	April 1, 2017 – December 31, 2017	CDN$ WTI	$68.02	Swap	(270)
Oil	250 bbl/day	July 1, 2017 – December 31, 2017	CDN$ WTI	$71.00	Call Swaption(1)	(103)
Gas	22,500 gj/day	April 1, 2017 – December 31, 2017	AECO C Monthly Index	$2.83	Swap	1,004
Gas	10,000 gj/day	April 1, 2017 – December 31, 2017	AECO C Daily Index	$3.08	Swap	1,187
Gas	5,000 mmbtu/day	April 1, 2017 – December 31, 2018	Chicago Citygate	$4.23	Swap	856
Gas	5,000 gj/day	January 1, 2018 – December 31, 2018	AECO C Monthly Index	$3.00	Call	(365)
Gas	2,500 gj/day	January 1, 2018 – December 31, 2018	AECO C Daily Index	$2.62	Swap	109
Gas	5,000 mmbtu/day	January 1, 2018 – December 31, 2018	US$ Nymex Henry Hub	$3.05	Swap	41
Total						485

(1) The referenced contract is a European call swaption, which the counterparty will accept or decline by June 30, 2017.

Capital management:

The Company's objective when managing capital is to maintain a flexible capital structure which will allow it to execute on its capital expenditure program, which includes 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'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 or below 2.0 to 1.0. During periods of increased capital expenditures, acquisitions or during periods of low commodity prices, this ratio will increase over short-term periods. As shown below, as at March 31, 2017, the Company's ratio of net debt to annualized funds from operations was 2.72 to 1 (December 31, 2016 – 2.20 to 1). With the Company's Facility undrawn, recently confirmed at $235 million and extended until June 2018, along with the recently issued long-term 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.

		March 31, 2017		December 31, 2016
Net debt:				
Cash and cash equivalents	**$**	**23,478**	$	-
Accounts receivable		**31,523**		39,588
Accounts payable and accrued liabilities		**(63,589)**		(49,594)
Working capital deficiency	**$**	**(8,588)**	$	(10,006)
Bank loan		**-**		(88,036)
Senior unsecured notes		**(293,046)**		(147,329)
Net debt	**$**	**(301,634)**	$	(245,371)
Quarterly Annualized funds from operations:				
Cash provided by operating activities	**$**	**27,189**	$	19,900
Decommissioning obligations settled		**378**		763
Change in non-cash working capital		**359**		7,394
Accretion of deferred financing charges		**(207)**		(178)
Quarterly Funds from operations	**$**	**27,719**	$	27,879
Annualized	**$**	**110,876**	$	111,516
Net debt to annualized funds from operations		**2.72**		2.20

Neither the Company nor any of its subsidiaries are subject to externally imposed capital requirements. The credit facilities are 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 March 31, 2017	Three months ended March 31, 2016
Interest expense	$ 4,827	$ 4,123
Accretion of deferred financing costs	207	175
Accretion of decommissioning obligations	474	433
Premium paid on redemption of 2020 Notes (note 5)	6,282	-
Deferred financing costs expensed on 2020 Notes (note 5)	2,510	-
	$ 14,300	$ 4,731

10. Commitments:

	Total	2017	2018	2019	2020	2021	Thereafter
Operating leases	$ 4,700	$ 783	$ 1,175	$ 1,175	$ 1,175	$ 392	$ -
Capital Commitments	14,359	14,359	-	-	-	-	-
Firm transportation agreements	131,778	23,517	30,311	29,739	26,509	3,570	18,132
Firm processing agreements	93,017	9,585	12,637	12,637	11,336	7,395	39,427
Total	**$ 243,854**	**$ 48,244**	**$ 44,123**	**$ 43,551**	**$ 39,020**	**$ 11,357**	**$57,559**

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

Capital commitments includes commitments related to the expansion of the Septimus complex 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.

11. Subsequent event:

Subsequent to March 31, 2017, the Company entered into an agreement to dispose of non-core assets in northeast British Columbia for cash consideration of approximately $49 million, subject to certain closing adjustments and costs. The assets consist of undeveloped land of approximately 18,400 net acres, with no booked reserves or current production associated therewith. Closing of the transaction is expected to occur in the second quarter of 2017, subject to satisfaction of customary closing conditions.

DIRECTORS & OFFICERS

OFFICERS

Dale O. Shwed
President and Chief Executive Officer

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

Rob Morgan, P.Eng.
Senior Vice President and Chief Operating 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