crew energy inc.

2020 ANNUAL REPORT

THE **BEST VIEWS** COME AFTER
THE **HARDEST CLIMBS**

ABOUT CREW

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

CORPORATE INFORMATION

AUDITORS
KPMG LLP

LEGAL COUNSEL
Burnet, Duckworth & Palmer LL

RESERVE ENGINEERS
Sproule Associates Ltd.

TRANSFER AGENT
Odyssey Trust Company

BANKERS
Toronto-Dominion Bank
Alberta Treasury Branches
National Bank of Canada
Bank of Nova Scotia
JPMorgan Chase Bank
Business Development Bank of Canada

INVESTOR CONTACT

INVESTOR RELATIONS
Crew Energy Inc.
Phone: (403) 266-2088
Email: investor@crewenergy.com
Web: www.crewenergy.com

EXCHANGE LISTING
TSX: CR

HEAD OFFICE

Suite 800, 250 - 5th Street S.W.
Calgary, Alberta
Canada T2P 0R4
Phone: (403) 266-2088

CREW ENERGY INC. 2020 ANNUAL REPORT

Crew Energy Inc. (TSX: CR) ("Crew" or the "Company") today announced our operating and financial results for the three and twelve month periods ended December 31, 2020. Crew's full audited consolidated Financial Statements, as well as Management's Discussion and Analysis ("MD&A") for the three and twelve month periods ended December 31, 2020 are available on Crew's website and filed on SEDAR at www.sedar.com.

While 2020 proved to be one of the most challenging years in recent memory for commodities and energy companies due to the economic fallout caused by the COVID-19 pandemic, Crew remained focused on the Company's long-term sustainability. In December, we announced a strategic asset development plan for 2021 and 2022 designed to increase the pace of development of our world-class Montney resource, capturing value from stronger commodity pricing while optimizing production and infrastructure utilization, enhancing margins and ultimately improving leverage metrics. As a result, we anticipate generating meaningful Free Adjusted Funds Flow[1] targeting a range of $35 to $65 million[2] in 2022, depending on commodity prices.

2020 OPERATING & FINANCIAL HIGHLIGHTS

- **21,955 boe per day**[3] (131.7 mmcfe per day) average annual production in 2020, 4% lower than 2019 on 24% less capital invested, reflecting the quality of Crew's asset base and low base decline rate. Q4/20 production averaged 21,666 boe per day[3], 7% higher than Q3/20.
- **$41.2 million of Adjusted Funds Flow (AFF")**[1] ($0.27 per fully diluted share) in 2020, with $15.6 million ($0.10 per fully diluted share) generated in Q4/20, 82% higher than Q3/20 due to stronger commodity pricing and lower operating costs.
- **8% lower net operating costs**[1] in Q4/20 over Q3/20, averaging $5.30 per boe, while 2020 net operating costs of $5.61 were 5% lower than 2019. General and administrative ("G&A") costs declined 28% to $1.01 per boe in 2020.
- **$28.1 million** ($86.3 million gross) net capital expenditures[1] in 2020**,** 48% of which was invested during Q4/20, marking the start of Crew's two-year asset development plan.
- **15.0 net wells** were drilled in 2020, including 12.0 net natural gas wells, 2.0 net heavy oil wells and 1.0 net disposal well, while 10.0 net wells were completed (including 7.0 net natural gas wells) at Crew's Septimus and West Septimus areas ("Greater Septimus"), primarily in Q4/20. In Q1/21, Crew drilled and cased the longest well in our history, drilled to a total depth of over 20,000 feet in under 11 days at West Septimus.
- **7.0 net wells** were drilled, completed, equipped and tied-in on our 9-5 pad at Greater Septimus in 2020, with per well costs 12% lower than originally budgeted, averaging an estimated $5 million.
- **Continued positive performance** from the 9-5, seven well pad, with average IP60 production sales rates per well of 1,500 boe per day (21% condensate and ngl's) with flowing metrics of approximately $3,300 per boe[4].
- **Over 50% of forecast 2021 natural gas production is hedged** at an average price of $3.08 per mcf, reflecting the success of our marketing activities in 2020.
- **Record low** Proved Developed Producing ("PDP") F&D costs[5] of $6.83 per boe and FD&A costs[5] of $2.00 per boe in 2020, resulting in recycle ratios[5] of 1.8x and 6.1x, respectively.

---

1 Non-IFRS measure that does not have any standardized meaning under IFRS and therefore may not be comparable to similar measures presented for other entities. See "Advisories - Non-IFRS Measures".
2 See table in the Advisories for key budget and underlying material assumptions related to the two-year development plan and associated guidance.
3 See table in the Advisories for production breakdown by product type as defined in NI 51-101.
4 Amounts exclude a short cleanup period after 20% of load fracturing fluid is recovered. Volumes include 7.1 mmcfd of sales gas, 176 bbl/d of condensate and 140 bbl/d of ngls. See "Advisories - Test Results and Initial Production ("IP") Rates".
5 "Finding, Development and Acquisitions costs" or "FD&A costs", "Finding and Development costs" or "F&D costs" and "recycle ratio" do not have standardized meanings and therefore may not be comparable to similar measures presented for other entities. See "Advisories - Information Regarding Disclosure on Oil and Gas Reserves and Operational Information".

- **12.0 MMboe of PDP reserves added** in 2020, prior to accounting for production, bringing the total to 67.1 MMboe at year-end, a 6% increase over 2019.
- **$357.2 million of year-end net debt**[6], with no near-term maturities or repayment requirements on the $300 million of senior notes termed out until 2024, and 24% drawn on our $150 million credit facility which was reconfirmed until June 2021.

FINANCIAL & OPERATING HIGHLIGHTS

FINANCIAL ($ thousands, except per share amounts)	**Three months ended Dec. 31, 2020**	Three months ended Dec. 31, 2019	**Year ended Dec. 31, 2020**	Year ended Dec. 31, 2019
Petroleum and natural gas sales	**42,604**	44,941	**137,931**	193,532
Adjusted funds flow (1)	**15,568**	16,086	**41,150**	81,034
Per share - basic	**0.10**	0.11	**0.27**	0.53
- diluted	**0.10**	0.11	**0.27**	0.53
Net income / (loss)	**34,668**	(6,235)	**(203,180)**	12,071
Per share - basic	**0.23**	(0.04)	**(1.34)**	0.08
- diluted	**0.22**	(0.04)	**(1.34)**	0.08
Exploration and development expenditures	**41,007**	26,390	**86,260**	114,094
Property acquisitions (net of dispositions)	**(23,219)**	82	**(58,150)**	(19,084)
Net capital expenditures	**17,788**	26,472	**28,110**	95,010

Capital structure ($ thousands)	**As at Dec. 31, 2020**	As at Dec. 31, 2019
Working capital deficiency (surplus) (1)	**24,361**	(149)
Bank loan	**35,994**	52,136
	60,355	51,987
Senior Unsecured Notes	**296,851**	295,868
Total net debt (1)	**357,206**	347,855
Common shares outstanding (thousands)	**151,182**	151,534

Notes:

(1) Non-IFRS measure that does not have any standardized meaning under IFRS and therefore may not be comparable to similar measures presented for other entities. See "Advisories - Non-IFRS Measures".

[6] Non-IFRS measure that does not have any standardized meaning under IFRS and therefore may not be comparable to similar measures presented for other entities. See "Advisories - Non-IFRS Measures".

Operations	**Three months ended Dec. 31, 2020**	Three months ended Dec. 31, 2019	**Year ended Dec. 31, 2020**	Year ended Dec. 31, 2019
Daily production				
Light crude oil (bbl/d)[1]	**182**	251	**187**	216
Heavy crude oil (bbl/d)	**1,281**	1,600	**1,362**	1,639
Natural gas liquids ("ngl")[2] (bbl/d)	**1,953**	2,011	**2,070**	2,056
Condensate (bbl/d)	**2,121**	2,455	**2,583**	2,693
Natural gas (mcf/d)	**96,771**	96,776	**94,519**	97,398
Total (boe/d @ 6:1)	**21,666**	22,446	**21,955**	22,837
Average prices [3]				
Light crude oil ($/bbl)	**47.38**	62.85	**39.97**	63.24
Heavy crude oil ($/bbl)	**38.79**	44.76	**28.86**	50.65
Natural gas liquids ($/bbl)	**13.20**	8.66	**9.01**	6.78
Condensate ($/bbl)	**47.68**	63.29	**42.99**	64.40
Natural gas ($/mcf)	**2.87**	2.36	**2.12**	2.53
Oil equivalent ($/boe)	**21.37**	21.76	**17.17**	23.22

Notes:
(1) The Company does not have any medium crude oil as defined by NI 51-101.
(2) Throughout this report, natural gas liquids ("ngl") comprise all natural gas liquids as defined in National Instrument 51-101, Standards of Disclosure for Oil and Gas Activities ("NI 51-101"), other than condensate, which is disclosed separately, and natural gas means conventional natural gas by NI 51-101 product type.
(3) Average prices are before deduction of transportation costs and do not include realized gains and losses on derivative financial instruments.

	Three months ended Dec. 31, 2020	Three months ended Dec. 31, 2019	**Year ended Dec. 31, 2020**	Year ended Dec. 31, 2019
Netback ($/boe)				
Petroleum and natural gas sales	**21.37**	21.76	**17.17**	23.22
Royalties	**(0.99)**	(1.97)	**(0.81)**	(1.77)
Realized commodity hedging gain	**1.27**	0.78	**2.06**	0.28
Marketing (loss) income[1]	**(0.04)**	(0.02)	**(0.11)**	0.99
Net operating costs[2][3]	**(5.30)**	(5.51)	**(5.61)**	(5.93)
Transportation costs	**(4.23)**	(2.88)	**(3.67)**	(2.74)
Operating netback[3]	**12.08**	12.16	**9.03**	14.05
G&A	**(1.30)**	(1.33)	**(1.01)**	(1.40)
Financing costs on long-term debt	**(2.97)**	(3.06)	**(2.90)**	(2.94)
Adjusted funds flow[3]	**7.81**	7.77	**5.12**	9.71
Drilling activity				
Gross wells			**15**	8
Working interest wells			**15**	8
Success rate, net wells (%)			**100%**	100%

Notes:
(1) Marketing income was recognized from the monetization of forward natural gas sales contracts offset by the cost of committed natural gas transportation that was not available during the period.
(2) Net operating costs are calculated as gross operating costs less processing revenue.
(3) Non-IFRS measure that does not have any standardized meaning under IFRS and therefore may not be comparable to similar measures presented for other entities. See "Advisories - Non-IFRS Measures".

SUSTAINABILITY AND ESG INITIATIVES

Underpinning Crew's long-term strategy is our unwavering commitment to safely and responsibly operating in the communities in which we work, while focussing on our environmental, social and governance ("ESG") initiatives. The Company expects the release of our inaugural ESG report to stakeholders by mid-2021, meanwhile, we continue to advance our sustainability goals:

- In the summer of 2021, Crew plans to install a waste heat recovery system at our West Septimus facility, which is expected to reduce emissions and increase condensate stabilization capacity. The system is expected to reduce total greenhouse gas emissions from the facility by approximately 10-15% and increase condensate stabilization capacity by 20% to around 5,000 bbls per day. Crew gratefully acknowledges assistance from the Province of British Columbia for their support of this project.
- Crew is the first Canadian energy producer to receive regulatory approval from the B.C. Oil and Gas Commission for the installation and operation of a next-generation, spoolable surface pipeline for produced water transfer, confirming Crew's commitment to improving efficiencies and reducing emissions. The pipeline allows for the safe and environmentally responsible transportation of produced water, dramatically reducing the trucking of water in Crew’s area of operations while significantly reducing emissions. As a result of this pipeline, 5,940 two-way truckloads were removed from the road during the completion of the 3-32 pad in Q1 2021, which is the equivalent distance of three trips around the globe. In addition to the CO_2 emission reductions, removing vehicles from the road also significantly reduces the risk of accidents and spills, further contributing to improved safety and environmental performance.
- We are proud of Crew’s safety record, which in 2020 featured no lost time injuries for a second consecutive year. In 2020, the Company had only two recordable injuries across our employee and contractor workforce.
- Crew successfully participated in the provincially funded dormant well programs and initiated abandonment and reclamation activities on 79 wells in 2020.
- Through 2020, Crew’s regulatory compliance remained on par with 2019 as we achieved a 95% compliance rating, with 220 regulatory inspections across the three provinces in which we operate.
- Crew has established a new committee, constituted with members of our Board of Directors, which has a specific focus on our ESG initiatives.

OPERATIONS & AREA OVERVIEW

NE BC Montney - Greater Septimus

Production & Drilling	**Q4 2020**	Q3 2020	Q2 2020	Q1 2020	Q4 2019
Average daily production (boe/d)(1)	**18,089**	17,119	18,565	19,894	18,720
Wells drilled (gross / net)	**6 / 6.0**	6 / 6.0	0	1 / 1.0	0
Wells completed (gross / net)	**7 / 7.0**	0	1 / 1.0	0	4 / 4.0

Note:
(1) See table in the Advisories for production breakdown by product type as defined in NI 51-101.

Operating Netback ($ per boe)	**Q4 2020**	Q3 2020	Q2 2020	Q1 2020	Q4 2019
Petroleum and natural gas sales	**20.41**	15.73	11.97	17.61	20.13
Royalties	**(0.89)**	(0.42)	(0.36)	(0.86)	(1.76)
Realized commodity hedge gain	**1.45**	2.18	3.06	1.44	0.90
Marketing income(1)	**(0.05)**	(0.33)	(0.31)	0.13	(0.02)
Net operating costs(2)(3)	**(4.33)**	(4.71)	(4.81)	(4.52)	(3.99)
Transportation costs	**(4.33)**	(3.86)	(3.37)	(2.99)	(2.61)
Operating netback(3)	**12.26**	8.59	6.18	10.81	12.65

Notes:
(1) Marketing income was recognized from the monetization of forward physical sales contracts offset by the cost of committed natural gas transportation that was not available during the period.
(2) Net operating costs are calculated as gross operating costs less processing revenue.
(3) Non-IFRS measure that does not have any standardized meaning under IFRS and therefore may not be comparable to similar measures presented for other entities. See "Advisories - Non-IFRS Measures".

- The seven wells on Crew's 9-5 pad at Greater Septimus were drilled, completed, equipped and tied-in with all wells currently flowing through permanent facilities. The estimated per well costs at this pad averaged $5 million, 12% lower than the original $5.7 million budgeted. Average per well sales production over the first 60 days was approximately 1,500 boe per day (21% condensate and ngl's) with a flowing IP60 efficiency of approximately $3,300 per boe[7].
- From the 9-5 pad, over 120,000 m^3 of produced water has been transferred through above ground lines, saving approximately $550,000 while reducing emissions by removing trucks from the road.
- At Crew's 3-32 pad, five wells were drilled in Q4/20 and six wells were completed in Q1/21, with encouraging initial condensate rates. Production from the 3-32 pad is expected to start in Q2/21.
- Drilling of our seven-well, 1-8 pad began in Q4 and has incorporated the longest wells drilled in the Company's history. As part of our drive to improve returns, and our ongoing ESG strategy, these ultra-extended reach horizontal wells will reduce future development capital and minimize surface footprint by eliminating the number of wells required to effectively deplete the reservoir while reducing the need for additional pipelines. Following the finalization of the 1-8 pad, the associated drilling rig is scheduled to move to our 4-14 pad, targeting gas and condensate in our ultra-condensate rich area at Greater Septimus.

Other NE BC Montney

- During Q4/20 we initiated the drilling of a three well tenure retention pad in Groundbirch which has recently been rig released. The drilling rig has since moved to Attachie to drill the final lease retention well in that area, which was originally planned to be drilled in Q3/21 and will conclude the Company's tenure retention program at Attachie.

7 Amounts exclude a short cleanup period after 20% of load fracturing fluid is recovered. Volumes include 7.1 mmcfd of sales gas, 176 bbl/d of condensate and 140 bbl/d of ngls. See "Advisories - Test Results and Initial Production ("IP") Rates".

OUTLOOK

Crew continues to look forward and plan for the future, which we believe to be bright for natural gas. Despite the last six years being challenging for natural gas producers, we have learned to do more with less which has also led to a period of cost cutting and under-investment. We strongly believe that natural gas is and will continue to be an important source of energy as the world transitions to more socially responsible and cleaner energy. With society requiring more environmentally-friendly energy sources, the underlying fundamentals are constructive for natural gas with demand projected to grow by 33% from 2019 to 2050, rivalling the growth of renewables as reported by the Energy Information Administration[8]. With this important backdrop as support, and as previously announced, Crew developed our strategic asset development plan to enhance long-term sustainability and create meaningful value.

Progress on our Two-Year Plan

Crew's pivotal two-year plan, designed to expand margins and significantly improve leverage metrics by efficiently matching production volumes with infrastructure and transportation commitments, has been successfully initiated.

- **Production Growth** – Q1/21 production is expected to average between 25,500 and 26,500 boe per day[9], representing a 20% increase at the midpoint over Q4/20 production while also accounting for wells shut-in for offsetting completion operations as the Company ramps up activity.
- **Optimizing Commitments** - Increasing Q1/21 natural gas production has resulted in Crew increasing the utilization of our committed transportation by over 30% as compared to Q4/20. Further improvements are anticipated as production increases throughout the year and the Company's committed transportation decreases by over 20% in Q4/21 which is expected to reduce transportation expenses by over $9 million annually.
- **Enhanced Hedging Program** – Crew currently has over 50% of forecast 2021 natural gas production is hedged at an average price of $2.48 per Gigajoule ("GJ") (or $3.08 per thousand cubic feet ("mcf") calculated using Crew's heat content factor). In addition, approximately 35% of targeted natural gas production for 2022 is hedged at an average price of $2.46 per GJ (or $3.05 per mcf using Crew's heat content factor).
- **Reduced Costs -** Crew's plan to reduce unit costs by over 25% is largely based on increasing production volumes into existing infrastructure, as over 50% of the Company's expenses are fixed. As production increases, per unit costs associated with operating, transportation, general and administrative and interest expenses are expected to decline from $13.19 per boe in 2020 to approximately $10.00 per boe in 2022.
- **Q1 2021 Capital Expenditures** are expected to range between $50 and $53 million, a slight increase over initial projections as the Company was able to access and drill a lease expiry well in Q1/21 that was originally planned for Q3/21.
- **Full Year 2021 Guidance** remains unchanged, with plans to invest between $120 and $145 million of capital over the year, resulting in average annual production of 26,000 to 28,000 boe per day[9] and an exit rate of over 30,000 boe per day[9].

The Board, management and our Crew team all remain excited and focussed on the efficient execution of the Company's business plan. We have identified numerous opportunities within our portfolio to further expand margins, develop additional value and foster profitable growth while participating in the energy transition. With low average costs to find reserves leading to robust recycle ratios, and excellent market access, we are poised to capture additional value from our world-class Montney resource. Crew retains the financial flexibility and expertise to execute on our plans, with ample liquidity and the optionality to raise funds through asset transactions as needed. We commend the hard work of Crew's employees, contractors and directors whose commitment and dedication are critical to our ongoing success and thank all shareholders and bondholders for your ongoing support.

---

[8] Source: U.S. Energy Information Administration: Annual Energy Outlook 2020

[9] See table in the Advisories for production breakdown by product type as defined in NI 51-101.

ADVISORIES

Information Regarding Disclosure on Oil and Gas Reserves and Operational Information

All amounts in this report are stated in Canadian dollars unless otherwise specified. All reserves information in this report is derived from our independent reserves evaluation effective December 31, 2020, the details of which were announced in our February 8, 2021 press release (the "Reserves Press Release"). Our oil and gas reserves statement for the year ended December 31, 2020, which will include complete disclosure of our oil and gas reserves and other oil and gas information in accordance with NI 51-101, will be contained within our Annual Information Form which will be available on our SEDAR profile at www.sedar.com on or before March 31, 2021. The recovery and reserve estimates contained herein are estimates only and there is no guarantee that the estimated reserves will be recovered. In relation to the disclosure of estimates for individual properties or subsets thereof, such estimates may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.

This report contains metrics commonly used in the oil and natural gas industry, such as "recycle ratio", "finding and development costs" and "finding, development and acquisition costs". Each of these metrics are determined by Crew as specifically set forth in the Capital Program Efficiency tables contained in our Reserves Press Release. These terms do not have standardized meanings or standardized methods of calculation and therefore may not be comparable to similar measures presented by other companies, and therefore should not be used to make such comparisons. Such metrics have been included to provide readers with additional information to evaluate the Company's performance however, such metrics are not reliable indicators of future performance and therefore should not be unduly relied upon for investment or other purposes. Recycle Ratio is calculated as operating netback per boe divided by F&D costs on a per boe basis. Management uses these metrics for its own performance measurements and to provide readers with measures to compare Crew's performance over time.

Both F&D and FD&A costs take into account reserves revisions during the year on a per boe basis. The aggregate of the costs incurred in the financial year and changes during that year in estimated FDC may not reflect total F&D costs related to reserves additions for that year. Finding and development costs both including and excluding acquisitions and dispositions have been presented in this report because acquisitions and dispositions can have a significant impact on our ongoing reserves replacement costs and excluding these amounts could result in an inaccurate portrayal of our cost structure.

Non-IFRS Measures

Certain financial measures referred to in this report, such as adjusted funds flow or AFF, free adjusted funds flow, EBITDA, operating netback, net capital expenditures, net debt, net operating costs and working capital deficiency and are not prescribed by IFRS. Crew uses these measures to help evaluate its financial and operating performance as well as its liquidity and leverage. These non-IFRS financial measures do not have any standardized meaning prescribed by IFRS and therefore may not be comparable to similar measures presented by other issuers.

"Adjusted funds flow" or "AFF", presented herein is equivalent to cash flow provided by operating activities, which is an IFRS measure, adding the change in non-cash working capital, decommissioning obligation expenditures, excluding grants, and accretion of deferred financing costs on the senior unsecured notes. The Company considers this metric as a key measure that demonstrate the ability of the Company's continuing operations to generate the cash flow necessary to maintain production at current levels and fund future growth through capital investment and to service and repay debt. Crew also presents AFF per share in this presentation whereby per share amounts are calculated using fully diluted shares outstanding.

"Free AFF" is calculated by taking adjusted funds flow and subtracting capital expenditures, excluding acquisitions and dispositions. Management believes that free adjusted funds flow provides a useful measure to determine Crew's ability to improve sustainability and to manage the long-term value of the business.

"EBITDA" is calculated as consolidated net income (loss) before interest and financing expenses, income taxes, depletion, depreciation and amortization, adjusted for certain non-cash, extraordinary and non-recurring items primarily relating to unrealized gains and losses on financial instruments and impairment losses. Crew utilizes EBITDA as a measure of operational performance and cash flow generating capability. EBITDA impacts the level and extent of funding for capital projects investments. This measure is consistent with the EBITDA formula prescribed under the Company's Credit Facility and allows Crew and others to assess its ability to fund financing expenses, net debt reductions and other obligations.

"Operating Netbacks" equals petroleum and natural gas sales including realized gains and losses on commodity related derivative financial instruments, marketing income, less royalties, net operating costs and transportation costs calculated on a boe basis.

Management considers operating netback an important measure to evaluate its operational performance as it demonstrates its field level profitability relative to current commodity prices. The calculation of Crew's netbacks can be seen under "Operating Netbacks" within the Company's most recently filed MD&A."

"Net Capital Expenditures" equals exploration and development expenditures plus property acquisitions or less property dispositions.

"Net Debt" is defined as outstanding long-term debt and net working capital.

"Net Operating Costs" equals gross operating costs less processing revenue.

"Working Capital Surplus (Deficiency)" equals current assets less current liabilities and derivative financial instruments.

Please refer to Crew's most recently filed MD&A for additional information relating to Non-IFRS measures including a reconciliation of AFF to its most closely related IFRS measure. The MD&A can be accessed either on Crew's website at www.crewenergy.com or under the Company's profile on www.sedar.com.

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 ability to execute on its two-year development plan as described herein; as to our plan to optimize production and infrastructure utilization, enhance margins, increase AFF, free AFF and improve leverage metrics; our 2021 capital budget range and associated drilling and completion plans and guidance; preliminary capital plans and targets for 2022; production estimates including forecast Q1 and 2021 annual average and exit production volumes and targets for 2022; commodity price expectations including Crew's estimates of natural gas pricing exposure; Crew's commodity risk management programs and future hedging opportunities; marketing and transportation and processing plans and requirements; estimates of processing capacity and requirements; future liquidity and financial capacity; future results from operations and operating and leverage metrics; anticipated reductions in expenses and associated estimates including forecast unit costs in 2022; strong capital efficiencies and enhanced returns going forward; anticipated reductions in transportation commitments and costs; estimated maintenance capital requirements; the potential impact of COVID-19 as well as government programs associated with COVID-19; world supply and demand projections and anticipated reductions in industry spending as a result, and long-term impact on pricing; future development, exploration, acquisition and disposition activities (including drilling and completion plans, anticipated on-stream dates and associated timing and cost estimates); infrastructure investment plans; the successful implementation of our ESG initiatives including the anticipated release of Crew's inaugural ESG report in 2021; the amount and timing of capital projects; and anticipated improvement in our long-term sustainability including the expected positive attributes discussed herein attributable to our two-year development plan.

The internal projections, expectations, or beliefs underlying our Board approved 2021 capital budget and associated guidance, as well as management's preliminary estimates and targets in respect of plans for 2022 and beyond, are subject to change in light of the impact of the COVID-19 pandemic, and any related actions taken by businesses and governments, ongoing results, prevailing economic circumstances, commodity prices, and industry conditions and regulations. Crew's financial outlook and guidance provides shareholders with relevant information on management's expectations for results of operations, excluding any potential acquisitions or dispositions, for such time periods based upon the key assumptions outlined herein. In this report reference is made to the Company's longer range 2022 and beyond internal plan and associated economic model. Such information reflects internal targets used by management for the purposes of making capital investment decisions and for internal long-range planning and budget preparation. Readers are cautioned that events or circumstances could cause capital plans and associated results to differ materially from those predicted and Crew's guidance for 2021 and beyond may not be appropriate for other purposes. Accordingly, undue reliance should not be placed on same.

In addition, forward-looking statements or information are based on a number of material factors, expectations or assumptions of Crew which have been used to develop such statements and information but which may prove to be incorrect. Although Crew believes that the expectations reflected in such forward-looking statements or information are reasonable, undue reliance should not be placed on forward-looking statements because Crew can give no assurance that such expectations will prove to be correct. In addition to other factors and assumptions which may be identified herein, assumptions have been made regarding, among other things: that Crew will continue to conduct its operations in a manner consistent with past operations; results from drilling and development *activities consistent with past operations; the quality of the reservoirs in which Crew operates and continued performance from existing wells; the continued and timely development of infrastructure in areas of new production; the accuracy of the estimates of Crew's reserve volumes; certain commodity price and other cost assumptions; continued availability of debt and equity financing and cash flow to fund Crew's current and future plans and expenditures; the impact of increasing competition; the general stability of the economic and political environment in which Crew operates; the general continuance of current industry conditions; the timely receipt of any required regulatory approvals; the ability of Crew to obtain qualified staff, equipment and services in a timely and cost efficient manner; drilling results; the ability of the operator of the projects in which Crew has an interest in to operate the field in a safe, efficient and effective manner; the ability of Crew to obtain financing on acceptable terms; field production rates and decline rates; the ability to replace and expand oil and natural gas reserves through acquisition, development and exploration; the timing and cost of pipeline, storage and facility construction and expansion and the ability of Crew to secure adequate product transportation; future commodity prices; currency, exchange and interest rates; regulatory framework regarding royalties, taxes and environmental matters in the jurisdictions in which Crew operates; and the ability of Crew to successfully market its oil and natural gas products.*

The forward-looking information and statements included in this report are not guarantees of future performance and should not be unduly relied upon. Such information and statements, including the assumptions made in respect thereof, involve known and unknown risks, uncertainties and other factors that may cause actual results or events to defer materially from those anticipated in such forward-looking information or statements including, without limitation: the continuing and uncertain impact of COVID-19; changes in commodity prices; changes in the demand for or supply of Crew's products, the early stage of development of some of the evaluated areas and zones the potential for variation in the quality of the Montney formation; interruptions, unanticipated operating results or production declines; changes in tax or environmental laws, royalty rates; climate change regulations, or other regulatory matters; changes in development plans of Crew or by third party operators of Crew's properties, increased debt levels or debt service requirements; inaccurate estimation of Crew's oil and gas reserve volumes; limited, unfavourable or a lack of access to capital markets; increased costs; a lack of adequate insurance coverage; the impact of competitors; and certain other risks detailed from time-to-time in Crew's public disclosure documents (including, without limitation, those risks identified in this report and Crew's Annual Information Form).

This report contains future-oriented financial information and financial outlook information (collectively, "FOFI") about Crew's prospective capital expenditures, all of which are subject to the same assumptions, risk factors, limitations, and qualifications as set forth in the above paragraphs. The actual results of operations of Crew and the resulting financial results will likely vary from the amounts set forth in this report and such variation may be material. Crew and its management believe that the FOFI has been prepared on a reasonable basis, reflecting management's best estimates and judgments. However, because this information is subjective and subject to numerous risks, it should not be relied on as necessarily indicative of future results. Except as required by applicable securities laws, Crew undertakes no obligation to update such FOFI. FOFI contained in this report was made as of the date of this report and was provided for the purpose of providing further information about Crew's anticipated future business operations. Readers are cautioned that the FOFI contained in this report should not be used for purposes other than for which it is disclosed herein.

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.

Key Budget and Underlying Material Assumptions

	2021	2022
Capital Expenditures ($MM)	120-145	70-95
Annual Average Production (boe/d)	26,000 – 28,000	31,000 – 33,000
Adjusted Funds Flow ($MM)	85-105	120-150
EBITDA ($MM)	111-130	144-173
Oil price (WTI)($US per bbl)	$45.20	$44.60
Natural gas price (AECO 5A) ($C per mcf)	$2.60	$2.50
Natural gas price (NYMEX) ($US per mmbtu)	$2.80	$2.70
Natural gas price (Crew est. wellhead) ($C per mcf)	$3.00	$2.90
WCS price ($C per bbl)	$42.00	$40.00
Foreign exchange ($US/$CAD)	$0.77	$0.77
Royalties	4-6%	4-6%
Net operating costs ($ per boe)	$4.75-$5.25	$4.25-$4.75
Transportation ($ per boe)	$3.00-$3.50	$2.25-$2.75
G&A ($ per boe)	$0.90-$1.10	$0.80-$1.00
Interest rate – bank debt	6.0%	6.0%
Interest rate – high yield	6.5%	6.5%

Notes:

[1] Reflects a pricing premium given Crew's higher heat content gas

Supplemental Information Regarding Product Types

The following is intended to provide the product type composition for each of the boe/d production figures provided herein, where not already disclosed within tables above:

Corporate Production Volume Breakdown

	Crude Oil[1]	Natural gas liquids[3]	Condensate	Conventional Natural gas	Total (boe/d)
2020 Q4 Average	1,463	1,953	2,121	96,771	21,666
2020 Annual Average	1,549	2,070	2,583	94,519	21,955
2021 Q1 Average[2]	5%	9%	9%	77%	25,500-26,500
2021 Annual Average[2]	4%	10%	11%	75%	26,000-28,000
2021 Exit Average[2]	3%	9%	16%	72%	>30,000
2022 Annual Average[2]	3%	10%	12%	75%	31,000-33,000

Greater Septimus Production Volume Breakdown

	Crude Oil[1]	Natural gas liquids[3]	Condensate	Conventional Natural gas	Total (boe/d)
Q4/20	0%	10%	12%	78%	18,089
Q3/20	0%	11%	13%	76%	17,119
Q2/20	0%	11%	14%	75%	18,565
Q1/20	0%	11%	17%	72%	19,894
Q4/19	0%	10%	13%	77%	18,720

Notes:

[1] *Crude oil is comprised primarily of Heavy crude oil, with an immaterial portion of Light and Medium crude oil.*

[2] *With respect to forward looking production guidance, given the potential for variability in actual product type results, the issuer approximates percentages for budget planning purposes based on management's reasonable assumptions including, without limitation, historical well results.*

[3] *Excludes condensate volumes which have been reported separately.*

Test Results and Initial Production ("IP") Rates

A pressure transient analysis or well-test interpretation has not been carried out and thus certain of the test results provided herein should be considered to be preliminary until such analysis or interpretation has been completed. Test results and initial production rates disclosed herein, particularly those short in duration, may not necessarily be indicative of long term performance or of ultimate recovery. Sales gas used herein reflects natural gas sales based on historical gas processing shrinkage and condensate and ngl yields.

BOE, MMCFE and TCFE Conversions

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

TCFe of gas is defined as Trillion Cubic Feet Equivalent, and MMCFe of gas is defined as Million Cubic Feet Equivalent. Both terms have been applied using the oil equivalent conversion ratio of six thousand cubic feet of natural gas (6 mcf) to one barrel of oil (1 bbl). TCFe and MMCFe amounts may be misleading, particularly if used in isolation.

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

Financial statements and Management's Discussion and Analysis for the three and twelve month periods ended December 31, 2020 and 2019 are filed on SEDAR at www.sedar.com and are available on the Company's website at www.crewenergy.com.

YEAR END 2020

Management's Discussion and Analysis

&

Consolidated Financial Statements

MANAGEMENT'S DISCUSSION AND ANALYSIS

ABOUT CREW

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

BASIS OF PRESENTATION

Management's discussion and analysis ("MD&A") is the explanation of the financial performance for the period covered by the consolidated financial statements along with an analysis of the financial position of the Company. Comments relate to and should be read in conjunction with the audited consolidated financial statements of the Company for the year ended December 31, 2020 and 2019. The consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS"). All figures provided herein and in the December 31, 2020 audited consolidated financial statements are reported in Canadian dollars ("CDN"). This MD&A is dated March 11, 2021.

FINANCIAL HIGHLIGHTS

Financial ($ thousands, except per share amounts)	**Three months ended December 31, 2020**	Three months ended December 31, 2019	**Year ended December 31, 2020**	Year ended December 31, 2019
Petroleum and natural gas sales	**42,604**	44,941	**137,931**	193,532
Adjusted funds flow(1)	**15,568**	16,086	**41,150**	81,034
Per share -basic	**0.10**	0.11	**0.27**	0.53
-diluted	**0.10**	0.11	**0.27**	0.53
Net income (loss)	**34,668**	(6,235)	**(203,180)**	12,071
Per share -basic	**0.23**	(0.04)	**(1.34)**	0.08
-diluted	**0.22**	(0.04)	**(1.34)**	0.08
Exploration and development expenditures	**41,007**	26,390	**86,260**	114,094
Property acquisitions (net of dispositions)	**(23,219)**	82	**(58,150)**	(19,084)
Net capital expenditures	**17,788**	26,472	**28,110**	95,010

Capital structure ($ thousands)	**As at December 31, 2020**	As at December 31, 2019
Working capital deficiency (surplus)(1)	**24,361**	(149)
Bank loan	**35,994**	52,136
	60,355	51,987
Senior unsecured notes	**296,851**	295,868
Net debt(1)	**357,206**	347,855
Common shares outstanding (thousands)	**151,182**	151,534

OPERATING HIGHLIGHTS

Operations	**Three months ended December 31, 2020**	Three months ended December 31, 2019	**Year ended December 31, 2020**	Year ended December 31, 2019
Daily production(1)				
Light crude oil (bbl/d)	**182**	251	**187**	216
Heavy crude oil (bbl/d)	**1,281**	1,600	**1,362**	1,639
Natural gas liquids (bbl/d)	**1,953**	2,011	**2,070**	2,056
Condensate (bbl/d)	**2,121**	2,455	**2,583**	2,693
Natural gas (mcf/d)	**96,771**	96,776	**94,519**	97,398
Oil equivalent (boe/d @ 6:1)	**21,666**	22,446	**21,955**	22,837
Average prices(2)				
Light crude oil ($/bbl)	**47.38**	62.85	**39.97**	63.24
Heavy crude oil ($/bbl)	**38.79**	44.76	**28.86**	50.65
Natural gas liquids ($/bbl)	**13.20**	8.66	**9.01**	6.78
Condensate ($/bbl)	**47.68**	63.29	**42.99**	64.40
Natural gas ($/mcf)	**2.87**	2.36	**2.12**	2.53
Oil equivalent ($/boe)	**21.37**	21.76	**17.17**	23.22
Netback ($/boe)				
Operating netback(3)	**12.08**	12.16	**9.03**	14.05
G&A	**(1.30)**	(1.33)	**(1.01)**	(1.40)
Financing costs on long-term debt	**(2.97)**	(3.06)	**(2.90)**	(2.94)
Funds from operations per boe(3)	**7.81**	7.77	**5.12**	9.71
Drilling activity				
Gross wells	**5**	0	**15**	8
Working interest wells	**5**	0	**15**	8
Success rate, net wells	**100%**	-	**100%**	100%

Notes:

(1) Throughout this MD&A, light crude oil refers to light and medium crude oil product type as defined by National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities ("NI 51-101"). Condensate is a natural gas liquid as defined by NI 51-101. Throughout this MD&A, references to other natural gas liquids or ngls comprise all natural gas liquids as defined by NI 51-101 other than condensate, which is disclosed separately. Throughout this MD&A, references to natural gas comprise all conventional natural gas as defined by NI 51-101.

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

(3) Non-IFRS measure that does not have any standardized meaning as prescribed by International Financial Reporting Standards, and therefore, may not be comparable with the calculations of similar measures for other entities. See "Non-IFRS Measures" contained within this MD&A.

RESULTS OF OPERATIONS

Annual Overview

In March 2020, the World Health Organization declared a global pandemic following the emergence and rapid spread of a novel strain of the coronavirus ("COVID-19"). The pandemic and subsequent measures intended to limit its spread, contributed to significant volatility in global financial markets. The pandemic has adversely impacted global commercial activity and has reduced worldwide demand for commodities including crude oil, natural gas and natural gas liquids ("ngl"). The result was significant economic uncertainty and a decline in commodity prices through most of 2020. In general, the oil and gas industry reacted with reductions to capital and other spending, as well as production shut-ins to try to manage through the volatile price environment.

Despite the unprecedented events of 2020, Crew successfully sustained its focus on improving its operating and capital efficiencies and executed a successful but disciplined capital program focused on the Company's highest return opportunities in the West Septimus area of north east British Columbia. Production during the year averaged 21,955 boe per day, a 4% decrease over 2019 as production was impacted by a lower capital expenditure program and management of production volumes through periods of weaker oil and gas prices.

The unprecedented actions taken globally to reduce the spread of COVID-19, resulted in a dramatic drop in demand for oil and natural gas in the first half of 2020 causing significant price volatility. In particular, world oil prices dropped dramatically in late March and April as many countries closed their borders to international travel and implemented stay-at-home orders that impacted world demand for oil. This occurred at the same time as OPEC+ nations could not agree on the level of production management needed to balance the market, resulting in a price war that added additional supply to an already oversupplied market. An early resolution to the OPEC+ price dispute and a commitment to cut production resulted in oil prices recovering late in the second quarter and returning to pre-pandemic levels by the end of the year.

North American natural gas prices were also impacted by the pandemic as first half demand for domestically produced gas and LNG exports declined. Additionally, one of the warmest winters in decades impacted early 2020 demand resulting in significant gas in storage exiting the winter, putting downward pressure on North American prices through most of the first half of the year. As the first half of 2020 drew to a close, the market for natural gas in North America began to improve due to declining supply resulting from reduced natural gas drilling and reduced supply associated with US shale oil production.

As optimism over improving commodity prices grew, the Company began the development of a two year asset development plan. This plan is designed to expand the Company's netbacks and significantly improve leverage metrics by increasing future production volumes to match ongoing infrastructure and transportation commitments. In conjunction with this plan, Crew executed on a very active hedging program locking in value from stronger commodity prices for the remainder of 2020 and a significant portion of our planned 2021 and 2022 production. The hedging of stronger forward commodity prices combined with improved capital efficiencies, secured through improved drilling and completion techniques, is expected to ensure strong returns from our planned increase in 2021 capital spending.

Crew executed a modest capital program through the first three quarters of 2020, conservatively spending to maintain the Company's financial strength during the period of depressed commodity pricing and low adjusted funds flow. Fourth quarter spending increased with the launch of the Company's new development plan, almost matching the spending during the first three quarters, resulting in annual exploration and development expenditures of $86.2 million. The Company realized cost and operational improvements in the year, reducing drill times relative to previously drilled wells and contributing to strong capital efficiencies and enhanced returns. In 2020, the Company drilled a total of 15 wells, including 12 natural gas wells and completed 10 wells, including 8 natural gas wells.

The Company successfully completed a strategic infrastructure transaction that realized $70 million in proceeds, improving the Company's financial strength. The transaction consisted of two phases, the first phase closing in February 2020 with the sale of an 11% working interest in each of its Septimus gas processing facility and West Septimus gas processing facility ("Greater Septimus Processing Complex") for proceeds of $35 million. The second phase closed in November of 2020 with the sale of another 11% working interest in the same facilities for proceeds of $35 million. The Company has also retained the option to sell an additional 11.43% interest in the Greater Septimus Processing Complex for an additional $37.5 million in potential proceeds prior to June 2023. In an unrelated transaction, the Company exercised and closed its option with another third party for the acquisition of an approximate 16% interest in the Greater Septimus Processing Complex for $11.7 million.

The Company's liquidity remains strong with only 24% drawn on the Company's $150 million credit facility at December 31, 2020. Crew exited the year with net debt of $357.2 million, including a $24.4 million working capital deficiency. Crew's senior unsecured notes carry a favorable interest rate of 6.5%, do not mature until 2024 and have no financial maintenance covenants. With no near-term maturities, a substantial reserve base and substantial liquidity, Crew is strongly positioned to manage its current debt position and to weather continued market weakness.

Responding to the Novel Coronavirus ("COVID-19")

The full extent of the impact of COVID-19 on the Company's operations and future financial performance is currently unknown. It will depend on future developments that are uncertain and unpredictable, including the duration and spread of COVID-19, its continued impact on financial markets on a macro-scale and any new information that may emerge concerning the effectiveness of available vaccines and the severity and spread of the virus. The pandemic presents uncertainty and risk with respect to the Company, its performance, and estimates and assumptions used by management in the preparation of its financial results. Crew believes the measures it has taken will provide it with the financial capability to execute on its business plan, deliver safe and reliable operations and continue to build its sustainable business.

Crew is dedicated to ensuring the health, safety and security of employees, contractors, partners and residents within all of its operating areas and communities. In response to the COVID-19 pandemic, the Company mobilized quickly to implement response plans and procedures that would protect the health and well-being of all stakeholders. Crew established work from home protocols in mid-March, including training programs specifically designed to ensure home working environments are effective, and rolled-out new technologies and programs to facilitate remote working across the organization. The Company also implemented social distancing protocols throughout its field operations that help to protect field staff and contractors, while new workforce efficiencies have been implemented to streamline costs.

Production

	Three months ended December 31, 2020	Three months ended September 30, 2020
Crude oil (bbl/d)	**1,463**	1,623
Condensate (bbl/d)	**2,121**	2,247
Ngl (bbl/d)	**1,953**	1,894
Natural gas (mcf/d)	**96,771**	86,658
Total (boe/d)	**21,666**	20,207

Production during the fourth quarter of 2020 increased 7% over the third quarter of 2020, largely as a result of the addition of seven new natural gas wells brought on production in the fourth quarter of 2020 at West Septimus. This was partially offset by a decrease in crude oil production at Lloydminster due to limited capital investment.

	Three months ended December 31, 2020					Three months ended December 31, 2019				
	Crude oil (bbl/d)	**Condensate (bbl/d)**	**Ngl (bbl/d)**	**Nat. gas (mcf/d)**	**Total (boe/d)**	Crude oil (bbl/d)	Condensate (bbl/d)	Ngl (bbl/d)	Nat. gas (mcf/d)	Total (boe/d)
NE BC	**182**	**2,121**	**1,953**	**96,651**	**20,365**	251	2,455	2,011	96,743	20,840
Lloydminster	**1,281**	**-**	**-**	**120**	**1,301**	1,600	-	-	33	1,606
Total	**1,463**	**2,121**	**1,953**	**96,771**	**21,666**	1,851	2,455	2,011	96,776	22,446

Production during the fourth quarter of 2020 declined 3% over the same period in 2019, largely as a result of a reduction in exploration and development spending over the past year as compared the same period in 2019. This was partially offset by the addition of four new UCR wells late in the fourth quarter of 2019 along with the aforementioned addition of seven new natural gas wells in the fourth quarter of 2020 at West Septimus.

	Year ended December 31, 2020					Year ended December 31, 2019				
	Crude oil (bbl/d)	**Condensate (bbl/d)**	**Ngl (bbl/d)**	**Nat. gas (mcf/d)**	**Total (boe/d)**	Crude oil (bbl/d)	Condensate (bbl/d)	Ngl (bbl/d)	Nat. gas (mcf/d)	Total (boe/d)
NE BC	**187**	**2,583**	**2,070**	**94,453**	**20,582**	216	2,693	2,056	97,351	21,190
Lloydminster	**1,362**	**-**	**-**	**66**	**1,373**	1,639	-	-	47	1,647
Total	**1,549**	**2,583**	**2,070**	**94,519**	**21,955**	1,855	2,693	2,056	97,398	22,837

Production in 2020 decreased 4% when compared to the same period in 2019 as a result of the aforementioned declines in exploration and development spending. In addition, production in 2020 was reduced as compared to 2019 due to the shutting-in of volumes during the second quarter to preserve value during a period of COVID-19 related low commodity prices and volumes taken offline in the third quarter to accommodate turn-arounds at the Company's operated Septimus and the third party operated McMahon gas processing facilities.

Petroleum and Natural Gas Sales

	Three months ended December 31, 2020	Three months ended September 30, 2020	Three months ended December 31, 2019	**Year ended December 31, 2020**	Year ended December 31, 2019
Petroleum and natural gas sales ($ thousands)					
Light crude oil	**794**	642	1,449	**2,732**	4,993
Heavy crude oil	**4,571**	5,092	6,591	**14,384**	30,310
Natural gas liquids	**2,371**	1,931	1,602	**6,827**	5,086
Condensate	**9,305**	8,998	14,291	**40,646**	63,290
Natural gas	**25,563**	15,681	21,008	**73,342**	89,853
Total	**42,604**	32,344	44,941	**137,931**	193,532
Crew average prices					
Light crude oil ($/bbl)	**47.38**	43.93	62.85	**39.97**	63.24
Heavy crude oil ($/bbl)	**38.79**	37.82	44.76	**28.86**	50.65
Natural gas liquids ($/bbl)	**13.20**	11.08	8.66	**9.01**	6.78
Condensate ($/bbl)	**47.68**	43.53	63.29	**42.99**	64.40
Natural gas ($/mcf)	**2.87**	1.97	2.36	**2.12**	2.53
Oil equivalent ($/boe)	**21.37**	17.40	21.76	**17.17**	23.22
Benchmark pricing					
Light crude oil – WTI (Cdn $/bbl)	**55.53**	54.50	75.19	**52.52**	75.69
Heavy crude oil – WCS (Cdn $/bbl)	**43.52**	42.50	54.18	**35.63**	58.79
Condensate – Condensate @ Edmonton (Cdn $/bbl)	**55.28**	50.08	70.40	**49.43**	70.37
Natural Gas:					
AECO 5A daily index (Cdn $/mcf)	**2.64**	2.24	2.48	**2.23**	1.76
AECO 7A monthly index (Cdn $/mcf)	**2.77**	2.15	2.34	**2.24**	1.62
Alliance 5A (Cdn $/mcf)	**2.76**	2.18	2.05	**2.24**	1.76
Chicago City Gate at ATP (Cdn $/mcf)	**2.29**	1.72	2.15	**1.78**	2.47
Henry Hub Close (Cdn $/mcf)	**3.47**	2.63	3.30	**2.77**	3.49
Natural gas sales portfolio					
AECO 5A	**22%**	1%	7%	**7%**	7%
Alliance 5A	**21%**	22%	16%	**21%**	23%
Chicago Interstates at ATP	**44%**	54%	58%	**51%**	53%
Henry Hub	**6%**	18%	16%	**14%**	15%
Station 2	**7%**	5%	3%	**7%**	2%

Fourth quarter 2020 compared to third quarter 2020:

In the fourth quarter of 2020, the Company's petroleum and natural gas sales increased 32% as compared to the third quarter of 2020, as a result of a 23% increase in realized wellhead pricing during the quarter combined with a 7% increase in production.

The Company's fourth quarter realized light crude oil price increased 8% over the third quarter of 2020, which was higher than the Company's Cdn$ WTI ("WTI") benchmark increase of 2% compared to the previous quarter as a result of fixed transportation costs which are less dilutive to the realized light crude oil price in an increasing price environment. Crew's fourth quarter heavy crude oil price increased 3% as compared to the third quarter of 2020, which is consistent with the 2% increase in the Company's Western Canadian Select ("WCS") benchmark.

Crew's ngl realized price increased 19% in the fourth quarter as compared to the third quarter of 2020, due to an increase in the value of component pricing, in particular, large increases in realized propane and butane pricing across North America. The Company's fourth quarter realized condensate price increased 10% over the third quarter of 2020, which was consistent with the 10% increase in the Condensate at Edmonton benchmark price.

Crew's realized natural gas price increased by 46% in the fourth quarter of 2020, which is higher than the 26% increase in the Company's natural gas sales portfolio weighted benchmark price. The greater corporate increase was the result of the October expiry of a Chicago fixed price physical delivery contract that negatively impacted the Company's realized natural gas price for the period March to October 2020.

Fourth quarter 2020 compared to fourth quarter 2019:

The fourth quarter 2020 petroleum and natural gas sales decreased 5% as compared to the same period in 2019, as a result of a 2% decrease in realized wellhead pricing combined with a 3% decrease in production.

The Company's fourth quarter realized light crude oil price decreased 25% over the fourth quarter of 2019, which was consistent with the Company's WTI benchmark decrease of 26%. Crew's fourth quarter heavy crude oil price decreased 13% as compared to the same period last year, which is lower than the 20% decrease in the Company's WCS benchmark as a result of a reduction in the relative cost of diluent utilized to blend with heavy crude oil for transportation purposes.

Crew's ngl realized price increased 52% in the fourth quarter as compared to the same period in 2019, due to an increase in the value of component pricing, in particular large increases in realized propane and butane pricing across North America. The Company's fourth quarter realized condensate price decreased 25% over the same period in 2019, which approximated the 21% decrease in the Condensate at Edmonton benchmark price.

Crew's realized natural gas price increased by 22% in the fourth quarter of 2020, which is higher than the 10% increase in the Company's natural gas sales portfolio weighted benchmark price. The greater corporate increase was the result of the increased exposure to the AECO market, which replaced expiring downstream fixed differential sales contracts.

Year ended 2020 compared to year ended 2019:

For 2020, the Company's petroleum and natural gas sales decreased 29% as compared to the prior year as a result of a 26% decrease in realized commodity pricing, combined with the 4% decrease in production.

The Company's realized light crude oil price decreased 37% as compared to the 31% decrease in the WTI benchmark, as a result of fixed transportation costs which further dilutes Crew's realized light crude oil price in a decreasing price environment. Crew's heavy crude oil price for 2020 decreased 43% as compared to the same period last year, which was consistent with the 39% decrease in the Company's WCS benchmark.

For 2020, the Company's realized ngl price increased 33% over to the same period in 2019, due to substantial increases in component pricing at the Company's primary Conway pricing point. The Company's realized condensate price decreased 33%, which was consistent with the 30% decrease in the Condensate at Edmonton benchmark price as compared to the prior year.

The Company's natural gas price decreased 16% over 2019, which is consistent with the Company's natural gas sales portfolio weighted benchmark price decrease of 14%.

Royalties

($ thousands, except per boe)	**Three months ended December 31, 2020**	Three months ended September 30, 2020	Three months ended December 31, 2019	**Year ended December 31, 2020**	Year ended December 31, 2019
Royalties	**1,969**	1,418	4,076	**6,469**	14,758
Per boe	**0.99**	0.76	1.97	**0.81**	1.77
Percentage of petroleum and natural gas sales	**4.6%**	4.4%	9.1%	**4.7%**	7.6%

For the fourth quarter of 2020 and year ended December 31, 2020, royalties per boe and as a percentage of petroleum and natural gas sales decreased over the same periods in 2019, predominantly due to a one-time prior period gas cost allowance adjustment in the fourth quarter of 2019 related to the Company's NE BC royalty assessments.

Derivative Financial Instruments

Commodities

The Company enters into derivative and physical risk management contracts in order to reduce volatility in financial results 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 spot commodity prices. 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 consolidated statements of (loss) income and comprehensive (loss) income:

($ thousands)	**Three months ended December 31, 2020**	Three months ended September 30, 2020	Three months ended December 31, 2019	**Year ended December 31, 2020**	Year ended December 31, 2019
Realized gain on derivative financial instruments	**2,536**	3,540	1,621	**16,588**	2,352
Per boe	**1.27**	1.90	0.78	**2.06**	0.28
Unrealized gain (loss) on financial instruments	**11,649**	(12,013)	(4,079)	**4,503**	(5,202)

As at December 31, 2020, the Company held derivative commodity contracts as follows:

Notional Quantity	Term	Strike Price	Option Traded	Fair Value
Natural Gas – AECO Daily Index:				
27,500 gj/day	January 1, 2021 - March 31, 2021	$2.53/gj	Swap	$ 177
2,500 gj/day	April 1, 2021 - October 31, 2021	$2.35/gj	Swap	55
5,000 gj/day	January 1, 2021 - December 31, 2021	$2.66/gj	Swap	570
21,500 gj/day	April 1, 2021 - June 30, 2021	$2.16/gj	Swap	(17)
19,000 gj/day	July 1, 2021 - September 30, 2021	$2.24/gj	Swap	(56)
17,500 gj/day	October 1, 2021 - December 31, 2021	$2.47/gj	Swap	(39)
22,500 gj/day	November 1, 2021 - December 31, 2021	$2.72/gj	Swap	223
15,000 gj/day	November 1, 2021 - March 31, 2022	$2.72/gj	Swap	318
20,000 gj/day	January 1, 2022 - March 31, 2022	$3.05/gj	Swap	688
15,000 gj/day	January 1, 2022 - December 31, 2022	$2.42/gj	Swap	1,195
20,000 gj/day	April 1, 2022 - June 30, 2022	$2.17/gj	Swap	375
5,000 gj/day	April 1, 2022 - October 31, 2022	$2.19/gj	Swap	178
20,000 gj/day	July 1, 2022 - September 30, 2022	$2.20/gj	Swap	366
20,000 gj/day	October 1, 2022 - December 31, 2022	$2.44/gj	Swap	486
Natural Gas – AECO Monthly Index:				
7,500 gj/day	January 1, 2021 - March 31, 2021	$2.53/gj	Swap	46
2,500 gj/day	April 1, 2021 - October 31, 2021	$2.05/gj	Swap	(107)
2,500 gj/day	January 1, 2021 - December 31, 2021	$2.50 - $3.00/gj	Collar(1)	241
6,000 gj/day	April 1, 2021 - June 30, 2021	$2.12/gj	Swap	(27)
10,000 gj/day	July 1, 2021 - September 30, 2021	$2.19/gj	Swap	(79)
9,000 gj/day	October 1, 2021 - December 31, 2021	$2.40/gj	Swap	(90)
5,000 gj/day	November 1, 2021 - March 31, 2022	$2.84/gj	Swap	194
5,000 gj/day	November 1, 2021 - March 31, 2022	$2.65 - $2.95/gj	Collar(2)	132
10,000 gj/day	January 1, 2022 - March 31, 2022	$3.09/gj	Swap	448
2,500 gj/day	January 1, 2022 - March 31, 2022	$2.75 - $3.20/gj	Collar(3)	68
7,500 gj/day	January 1, 2022 - December 31, 2022	$2.36/gj	Swap	431
10,000 gj/day	April 1, 2022 - June 30, 2022	$2.20/gj	Swap	183
10,000 gj/day	July 1, 2022 - September 30, 2022	$2.22/gj	Swap	176

Notional Quantity	Term	Strike Price	Option Traded	Fair Value
(continued)				
10,000 gj/day	October 1, 2022 - December 31, 2022	$2.48gj	Swap	274
Natural Gas – CDN$ Chicago Citygate Daily:				
17,500 mmbtu/day	January 1, 2021 - October 31, 2021	$3.47/mmbtu	Swap	1,896
Natural Gas – CDN$ Chicago Citygate Monthly:				
7,500 mmbtu/day	January 1, 2021 - October 31, 2021	$3.49/mmbtu	Swap	917
Crude Oil – CDN$ WTI:				
250 bbl/day	January 1, 2021 - June 30, 2021	$59.00/bbl	Swap	(127)
Crude Oil – CDN$ WCS:				
500 bbl/day	January 1, 2021 - June 30, 2021	$43.03/bbl	Swap	(36)
CDN$ Edmonton C5 Blended Index:				
1,500 bbl/day	January 1, 2021 - June 30, 2021	$56.82/bbl	Swap	(1,376)
Total				**$ 7,683**

Notes:
(1) The referenced contract is a costless collar whereby the Company receives $2.50/gj when the market price is below $2.50/gj, and receives $3.00/gj when the market price is above $3.00/gj.
(2) The referenced contract is a costless collar whereby the Company receives $2.65/gj when the market price is below $2.65/gj, and receives $2.95/gj when the market price is above $2.95/gj.
(3) The referenced contract is a costless collar whereby the Company receives $2.75/gj when the market price is below $2.75/gj, and receives $3.20/gj when the market price is above $3.20/gj.

Subsequent to December 31, 2020, the Company entered into the following derivative commodity contracts:

Notional Quantity	Term	Strike Price	Option Traded
Natural Gas – AECO Daily Index:			
2,500 gj/day	February 1, 2021 - December 31, 2021	$2.43/gj	Swap
Natural Gas – AECO Monthly Index:			
2,500 gj/day	February 1, 2021 - December 31, 2021	$2.45/gj	Swap
10,000 gj/day	March 1, 2021 - December 31, 2021	$2.50 - $2.81/gj	Collar[1]
Crude Oil – CDN$ WCS:			
250 bbl/day	February 1, 2021 - December 31, 2021	$44.00/bbl	Swap
250 bbl/day	July 1, 2021 - December 31, 2021	$47.75/bbl	Swap
CDN$ Edmonton C5 Blended Index:			
250 bbl/day	February 1, 2021 - December 31, 2021	$60.85/bbl	Swap
250 bbl/day	April 1, 2021 - June 30, 2021	$81.25/bbl	Swap
1,250 bbl/day	July 1, 2021 - December 31, 2021	$61.32/bbl	Swap

Note:
(1) The referenced contract is a costless collar whereby the Company receives $2.50/gj when the market price is below $2.50/gj, and receives $2.81/gj when the market price is above $2.81/gj.

Marketing (Loss) Income

($ thousands, except per boe)	**Three months ended December 31, 2020**	Three months ended September 30, 2020	Three months ended December 31, 2019	**Year ended December 31, 2020**	Year ended December 31, 2019
Marketing revenue	**(75)**	(524)	(32)	**(890)**	8,658
Marketing expense	**-**	-	-	**-**	(414)
Marketing (loss) income	**(75)**	(524)	(32)	**(890)**	8,244
Per boe	**(0.04)**	(0.28)	(0.02)	**(0.11)**	0.99

In the fourth quarter of 2020 and year ended December 31, 2020, the Company recognized $0.1 million and $0.9 million, respectively, of marketing losses related to the monetization of the Company's exposure to the Malin natural gas market. The realized marketing income during the year ended December 31, 2019 was related to the monetization of the Company's exposure to the Malin and Dawn markets, that were priced significantly stronger compared to Canadian markets in 2019 resulting in larger gains on monetization.

Net Operating Costs[1]

($ thousands, except per boe)	**Three months ended December 31, 2020**	Three months ended September 30, 2020	Three months ended December 31, 2019	**Year ended December 31, 2020**	Year ended December 31, 2019
Operating costs	**11,149**	11,259	12,015	**47,527**	52,487
Processing revenue	**(576)**	(597)	(640)	**(2,416)**	(3,090)
Net operating costs	**10,573**	10,662	11,375	**45,111**	49,397
Per boe	**5.30**	5.74	5.51	**5.61**	5.93

Note:
(1) Non-IFRS measure that does not have any standardized meaning as prescribed by International Financial Reporting Standards, and therefore, may not be comparable with the calculations of similar measures for other entities. See "Non-IFRS Measures" contained within this MD&A.

For the fourth quarter of 2020, the Company's net operating costs and net operating costs per boe decreased as compared to the third quarter of 2020, as a result of increased natural gas production from the new seven well pad brought on production in November 2020 at West Septimus, which yields lower operating costs and lower net operating costs per boe as compared to the corporate average.

During the fourth quarter of 2020 and year ended December 31, 2020, net operating costs and net operating costs per boe decreased as compared to the same periods in 2019, as a result of efforts by the Company to optimize field operations, resulting in reduced costs across all operating areas and the receipt of an annual clean energy incentive payment. This was coupled with reduced production in Lloydminster, where net operating costs are higher than the corporate average.

Transportation Costs

($ thousands, except per boe)	**Three months ended December 31, 2020**	Three months ended September 30, 2020	Three months ended December 31, 2019	**Year ended December 31, 2020**	Year ended December 31, 2019
Transportation costs	**8,435**	7,230	5,943	**29,504**	22,804
Per boe	**4.23**	3.89	2.88	**3.67**	2.74

For the fourth quarter of 2020, transportation costs increased 17% when compared to the third quarter of 2020, as a result of the October expiry of the Company's commercial agreements pertaining to the five year Alliance firm transport agreement. Beginning November 2020, the Company's Alliance transport agreement changed to a one year commitment for 65 mmcf per day at posted rates, renewable annually at the Company's option.

During the fourth quarter 2020 and year ended December 31, 2020, transportation costs increased 42% and 29%, respectively, as compared to 2019 as a result of the Company's natural gas diversification strategy that came on stream during 2019. Late in the first quarter of 2019, the Company added take or pay costs associated with Crew's partially owned sales pipeline from West

Septimus to TC Energy's ("TC") Saturn meter station and associated TC receipt service. Additional TC receipt service was added in November of 2019 further increasing transportation costs for 2020.

Operating Netbacks[1]

($/boe)	**Greater Septimus**	**Lloydminster Heavy Crude Oil**	**Other NE BC**	**Three months ended December 31, 2020**	Three months ended September 30, 2020	Three months ended December 31, 2019
Petroleum and natural gas sales	**20.41**	**38.41**	**19.32**	**21.37**	17.40	21.76
Royalties	**(0.89)**	**(2.34)**	**(1.00)**	**(0.99)**	(0.76)	(1.97)
Realized commodity hedging gain (loss)	**1.45**	**(1.02)**	**1.17**	**1.27**	1.90	0.78
Marketing loss	**(0.05)**	**-**	**-**	**(0.04)**	(0.28)	(0.02)
Net operating costs	**(4.33)**	**(18.74)**	**(5.37)**	**(5.30)**	(5.74)	(5.51)
Transportation costs	**(4.33)**	**(0.35)**	**(5.65)**	**(4.23)**	(3.89)	(2.88)
Operating netbacks	**12.26**	**15.96**	**8.47**	**12.08**	8.63	12.16
Production (boe/d)	**18,089**	**1,301**	**2,276**	**21,666**	20,207	22,446

Note:
(1) Non-IFRS measure that does not have any standardized meaning as prescribed by International Financial Reporting Standards, and therefore, may not be comparable with the calculations of similar measures for other entities. See "Non-IFRS Measures" contained within this MD&A.

Operating netbacks for the fourth quarter of 2020 increased by 40% when compared to the third quarter of 2020, primarily as a result of higher commodity prices and lower net operating costs, partially offset by higher transportation costs at Greater Septimus.

Operating netbacks for the fourth quarter of 2020 were consistent with the same period in 2019 as a result of lower royalties and net operating costs, combined with higher realized commodity hedging gains. This was partially offset by decreased commodity prices and higher transportation costs at Greater Septimus.

($/boe)	**Greater Septimus**	**Lloydminster Heavy Crude Oil**	**Other NE BC**	**Year ended December 31, 2020**	Year ended December 31, 2019
Petroleum and natural gas sales	**16.45**	**28.73**	**15.94**	**17.17**	23.22
Royalties	**(0.64)**	**(3.21)**	**(0.67)**	**(0.81)**	(1.77)
Realized commodity hedging gain	**2.03**	**3.25**	**1.65**	**2.06**	0.28
Marketing (loss) income	**(0.13)**	**-**	**-**	**(0.11)**	0.99
Net operating costs	**(4.59)**	**(18.84)**	**(5.91)**	**(5.61)**	(5.93)
Transportation costs	**(3.62)**	**(0.41)**	**(6.16)**	**(3.67)**	(2.74)
Operating netbacks	**9.50**	**9.52**	**4.85**	**9.03**	14.05
Production (boe/d)	**18,412**	**1,373**	**2,170**	**21,955**	22,837

For the year ended December 31, 2020, operating netbacks decreased 36% as compared to the same period in 2019 due to a significant decreases in realized commodity prices and higher transportation costs, partially offset by increased realized hedging gains and reduced royalties and net operating costs.

General and Administrative Costs

($ thousands, except per boe)	**Three months ended December 31, 2020**	Three months ended September 30, 2020	Three months ended December 31, 2019	**Year ended December 31, 2020**	Year ended December 31, 2019
Gross costs	**3,762**	2,552	4,081	**12,424**	17,607
Operator's recoveries	**(16)**	(284)	(38)	**(332)**	(91)
Capitalized costs	**(1,154)**	(805)	(1,305)	**(4,009)**	(5,880)
General and administrative expenses	**2,592**	1,463	2,738	**8,083**	11,636
Per boe	**1.30**	0.79	1.33	**1.01**	1.40

For the fourth quarter of 2020, the Company's gross, net and per unit general and administrative ("G&A") costs increased as compared to the third quarter of 2020, as a result of lower government provided COVID-19 Canada Emergency Wage Subsidy ("CEWS") receipts.

Gross, net and per unit G&A costs decreased in both the fourth quarter of 2020 and year ended December 31, 2020 as compared to the same periods in 2019, mainly due to a targeted reduction in compensation for the Company's Board of Directors, executive and staff, combined with the receipt of $1.2 million of CEWS receipts for the year ended December 31, 2020. Additional savings have been realized through a reduction in size of the Company's head office, resulting in lower operating costs and property taxes, and a focused effort on reducing other overhead costs across the Company.

Other Income

In the fourth quarter of 2020 and year ended December 31, 2020, the Company recognized $0.9 million and $1.1 million respectively, of other income related to government grants provided for well site rehabilitation.

Share-Based Compensation

($ thousands)	**Three months ended December 31, 2020**	Three months ended September 30, 2020	Three months ended December 31, 2019	**Year ended December 31, 2020**	Year ended December 31, 2019
Gross costs	**533**	1,006	2,187	**4,458**	10,237
Capitalized costs	**(258)**	(487)	(1,058)	**(2,186)**	(4,897)
Total share-based compensation	**275**	519	1,129	**2,272**	5,340

For the fourth quarter of 2020, the the Company's total share-based compensation expense decreased as compared to the third quarter of 2020, as a result of a reduction of staff. In the fourth quarter of 2020 and year ended December 31, 2020, the Company's total share-based compensation expense decreased as compared to the same periods in 2019, as a decline in the Company's share price has led to a decrease in the value of share-based compensation granted.

Depletion and Depreciation

($ thousands, except per boe)	**Three months ended December 31, 2020**	Three months ended September 30, 2020	Three months ended December 31, 2019	**Year ended December 31, 2020**	Year ended December 31, 2019
Depletion and depreciation	**16,072**	16,785	18,356	**71,054**	75,776
Per boe	**8.06**	9.03	8.89	**8.84**	9.09

In the fourth quarter of 2020 and year ended December 31, 2020, depletion and depreciation costs per boe decreased when compared to the same periods in 2019, due to a decrease in future development costs per boe associated with reserves bookings at the end of 2020 as compared to 2019 and a decrease to the per boe depletion rate of Tower production due to higher reserve bookings at Tower. In addition, there was a reduction in the capital cost base as a result of impairment charges recorded in the first quarter of 2020. These decreases were partially offset by higher land expiries as compared to the same periods in 2019.

Impairment

At December 31, 2020, due to strengthening commodity prices, the Company tested its northeast British Columbia cash-generating unit ("CGU") and Lloydminster CGU for impairment reversal. It was determined that the recoverable amounts of the northeast British Columbia CGU and Lloydminster CGU approximated their carrying value and impairment reversal was not recorded.

At March 31, 2020, the Company determined that indicators of impairment existed as a result of; the COVID-19 pandemic and its impact on global commodity demand due to the measures taken to limit the spread of the pandemic, the rapid fall in crude oil prices due to increased supply brought on by a price war between OPEC and non-OPEC members, and the impact that these events had on the Company's equity and debt values. As a result, the Company tested its northeast British Columbia CGU and Lloydminster CGU for impairment. It was determined that the carrying value of the northeast British Columbia CGU and Lloydminster CGU exceeded their recoverable amounts and impairment charges of $237.5 million and $29.8 million, respectively, were recorded for the CGUs.

At December 31, 2019, due to weakness in the Canadian commodity price environment and the depressed share price of the Company, the Company tested its northeast British Columbia CGU and Lloydminster CGU for impairment. It was determined that the recoverable amount of the northeast British Columbia CGU and Lloydminster CGU exceeded their carrying value and an impairment charge was not recorded.

Finance Expenses

($ thousands, except per boe)	**Three months ended December 31, 2020**	Three months ended September 30, 2020	Three months ended December 31, 2019	**Year ended December 31, 2020**	Year ended December 31, 2019
Interest on bank loan and other	**767**	878	1,151	**2,829**	4,009
Interest on senior notes	**4,915**	4,915	4,915	**19,500**	19,500
Accretion of deferred financing charges	**246**	245	246	**983**	983
Accretion of the decommissioning obligation	**230**	225	462	**1,221**	1,901
Total finance expense	**6,158**	6,263	6,774	**24,533**	26,393
Average long-term debt level	**329,597**	333,354	352,128	**335,073**	352,191
Average drawings on bank loan	**29,597**	33,354	52,128	**35,073**	52,191
Average senior unsecured notes outstanding	**300,000**	300,000	300,000	**300,000**	300,000
Effective interest rate on senior unsecured notes	**6.5%**	6.5%	6.5%	**6.5%**	6.5%
Effective interest rate on long-term debt	**6.3%**	6.2%	6.1%	**6.2%**	6.1%
Financing costs on long-term debt per boe	**2.97**	3.25	3.06	**2.90**	2.94

The Company's total finance expense and average corporate debt levels decreased in the fourth quarter of 2020 and year ended December 31, 2020 as compared to the same periods in 2019, as a result of the Company applying proceeds received from infrastructure dispositions against drawings on its bank loan.

Gain on Divestitures of Property, Plants and Equipment

During the first quarter of 2020, the Company disposed of an 11% net working interest in the Greater Septimus Processing Complex located in northeast British Columbia for net proceeds of $34.8 million, after transaction costs. This interest in the facilities was classified as held for sale as at December 31, 2019, with a net book value of $19.8 million and associated decommissioning obligations of $0.7 million, resulting in a gain of $15.7 million.

During the fourth quarter of 2020, the Company disposed of an additional 11% net working interest in its Greater Septimus Processing Complex for net proceeds of $34.9 million, after transaction costs. This interest in the facilities had a net book value of $13.0 million and associated decommissioning obligations of $0.9 million, resulting in a gain of $22.8 million.

During 2019, the Company disposed of non-core lands with no associated production or assigned reserves, for gross proceeds of $20.8 million. The lands consisted of petroleum and natural gas properties and undeveloped land with a net book value of $1.1 million and associated decommissioning obligations of $0.3 million, resulting in a gain of $20.0 million.

Deferred Income Taxes

In the fourth quarter of 2020 and year ended December 31, 2020, the provision for deferred income taxes was nil and a deferred tax recovery of $53.6 million, respectively, as compared to a deferred tax recovery of $1.5 million and expense of $0.8 million, respectively, for the same periods in 2019. The deferred tax recovery in for the year ended December 31, 2020 was predominantly due to the impairment charge recorded in the first quarter of 2020, resulting in a net loss realized in 2020 as compared to net income in the same period in 2019. The Company did not recognize a deferred income tax asset due to the uncertainty of future commodity prices and cash flows.

A summary of the Company's estimated income tax pools is outlined below:

($ thousands)	**December 31, 2020**	December 31, 2019
Cumulative Canadian Exploration Expense	**259,200**	293,400
Cumulative Canadian Development Expense	**412,200**	282,900
Undepreciated Capital Cost	**176,500**	202,400
Non-capital losses	**253,200**	311,600
Share issue costs	**1,400**	2,800
Other	**3,400**	7,900
	1,105,900	1,101,000

Cash, Adjusted Funds Flow(1) and Net Income (Loss)

($ thousands, except per share amounts)	**Three months ended December 31, 2020**	Three months ended September 30, 2020	Three months ended December 31, 2019	**Year ended December 31, 2020**	Year ended December 31, 2019
Cash provided by operating activities	**14,774**	5,121	21,106	**37,989**	81,395
Adjusted funds flow(1)	**15,568**	8,549	16,086	**41,150**	81,034
Per share -basic	**0.10**	0.06	0.11	**0.27**	0.53
-diluted	**0.10**	0.06	0.11	**0.27**	0.53
Net income (loss)	**34,668**	(21,136)	(6,235)	**(203,180)**	12,071
Per share -basic	**0.23**	(0.14)	(0.04)	**(1.34)**	0.08
-diluted	**0.22**	(0.14)	(0.04)	**(1.34)**	0.08

Note:
(1) Non-IFRS measure that does not have any standardized meaning as prescribed by International Financial Reporting Standards, and therefore, may not be comparable with the calculations of similar measures for other entities. See "Non-IFRS Measures" contained within this MD&A.

For the fourth quarter of 2020, cash provided by operating activities and adjusted funds flow increased as compared to the third quarter of 2020, mainly due to higher petroleum and natural gas sales. The Company recognized a net loss in the third quarter of 2020, but with the aforementioned increase in petroleum and natural gas sales, when combined with the increase in unrealized gains on derivative financial instruments and gains on divestitures of property, plants and equipment, the Company recognized net income in the fourth quarter of 2020.

Cash provided by operating activities and adjusted funds flow decreased in both the fourth quarter of 2020 and the year ended December 31, 2020 as compared to the same periods in 2019, predominantly due to lower petroleum and natural gas sales. This contributed to the net loss during the year ended December 31, 2020 as compared to net income in the same period in 2019, which was amplified by a $201 million after-tax impairment charge in the first quarter of 2020. For the fourth quarter of 2020, the Company had net income as compared to a net loss in the same period in 2019, as a result of unrealized gains on derivative financial instruments and the gain realized on the divestiture of net working interests in the Greater Septimus Processing Complex.

Capital Expenditures, Property Acquisitions and Dispositions

($ thousands)	**Three months ended December 31, 2020**	Three months ended September 30, 2020	Three months ended December 31, 2019	**Year ended December 31, 2020**	Year ended December 31, 2019
Land	**994**	799	890	**3,235**	3,311
Seismic	**210**	260	234	**1,007**	1,163
Drilling and completions	**31,523**	13,404	19,954	**58,375**	89,156
Facilities, equipment and pipelines	**7,126**	6,608	3,976	**19,575**	14,069
Other	**1,154**	805	1,336	**4,068**	6,395
Total exploration and development	**41,007**	21,876	26,390	**86,260**	114,094
Net property (dispositions) acquisitions	**(23,219)**	(35)	82	**(58,150)**	(19,084)
Total	**17,788**	21,841	26,472	**28,110**	95,010

In the fourth quarter of 2020, the Company spent a total of $41.0 million on exploration and development expenditures. The majority of this amount was spent on the continued development of the Montney assets. During the quarter, $31.5 million was spent on drilling and completion activities, $7.1 million on facilities, equipment and pipelines and $2.4 million on land, seismic, recompletions and other miscellaneous amounts. The Company completed seven (7.0 net) natural gas wells in NE BC and recompleted one (1.0 net) heavy crude oil wells in Lloydminster.

In 2020, the Company drilled a total of 12 (12.0 net) natural gas wells, 2 (2.0 net) heavy crude oil wells and 1 (1.0 net) water disposal well. During the year, the Company completed 10 (10.0 net) wells and recompleted 1 (1.0 net) wells. The Company's spending focus in 2020 was on drilling and completions activity in the West Septimus area.

GUIDANCE

Crew continues to look forward and plan for the future, which it believes to be bright for natural gas. Despite the last six years being challenging for natural gas producers, Crew has learned to do more with less which has also led to a period of cost cutting and under-investment. Crew strongly believes that natural gas is and will continue to be an important source of energy as the world transitions to more socially responsible and cleaner energy. With society requiring more environmentally-friendly energy sources, the underlying fundamentals are constructive for natural gas with demand projected to grow by 33% from 2019 to 2050, rivalling the growth of renewables as reported by the Energy Information Administration. With this important backdrop as support, Crew developed its strategic asset development plan to enhance long-term sustainability and create meaningful value.

The following table sets forth Crew's guidance and underlying material assumptions for 2021 and 2022:

	2021 guidance and assumptions[(1)]	2022 guidance and assumptions[(1)]
Capital expenditures ($Millions)	120–145	70–95
Annual average production (boe/d)	26,000–28,000	31,000–33,000
Adjusted funds flow[(2)] ($Millions)	85–105	120–150
EBITDA[(2)] ($Millions)	111–130	144–173
Oil price (WTI)($US per bbl)	$45.20	$44.60
Natural gas price (AECO 5A) ($C per mcf)	$2.60	$2.50
Natural gas price (NYMEX) ($US per mmbtu)	$2.80	$2.70
Natural gas price (Crew est. wellhead) ($C per mcf)	$3.00	$2.90
WCS price ($C per bbl)	$42.00	$40.00
Foreign exchange ($US/$CAD)	$0.77	$0.77
Royalties	4–6%	4–6%
Net operating costs[(2)] ($ per boe)	$4.75–$5.25	$4.25–$4.75
Transportation ($ per boe)	$3.00–$3.50	$2.25–$2.75
G&A ($ per boe)	$0.90–$1.10	$0.80–$1.00
Interest rate – bank debt	6.0%	6.0%
Interest rate – high yield	6.5%	6.5%

Notes:
(1) The actual results of operations of Crew and the resulting financial results will likely vary from the estimates and material underlying assumptions set forth in this guidance by the Company and such variation may be material. The guidance and material underlying assumptions have been prepared on a reasonable basis, reflecting management's best estimates and judgments.
(2) Non-IFRS measure that does not have any standardized meaning as prescribed by International Financial Reporting Standards, and therefore, may not be comparable with the calculations of similar measures for other entities. See "Non-IFRS Measures" contained within this MD&A.

The above guidance and underlying material assumptions are consistent with those previously released.

LIQUIDITY AND CAPITAL RESOURCES

Capital Management

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

With only 24% drawn on the Company's $150 million Facility and the senior unsecured notes termed out to 2024, the Company's financial position remains strong, with sufficient liquidity to fund the Company's on-going operations. The Company will continue to monitor debt levels and, if necessary, it will consider divesting of non-core properties, adjust its annual capital expenditure program or may consider other forms of financing to improve its financial position.

Capital Management includes the monitoring of net debt as part of the Company's capital structure.

The following tables outline Crew's calculation of working capital and net debt:

($ thousands)	**December 31, 2020**	December 31, 2019
Current assets	**26,853**	50,019
Current liabilities	**(47,212)**	(46,690)
Derivative financial instruments	**(4,002)**	(3,180)
Working capital (deficiency) surplus[1]	**(24,361)**	149

($ thousands)	**December 31, 2020**	December 31, 2019
Bank loan	**(35,994)**	(52,136)
Senior unsecured notes	**(296,851)**	(295,868)
Working capital (deficiency) surplus[1]	**(24,361)**	149
Net debt[1]	**(357,206)**	(347,855)

Note:
(1) Non-IFRS measure that does not have any standardized meaning as prescribed by International Financial Reporting Standards, and therefore, may not be comparable with the calculations of similar measures for other entities. See "Non-IFRS Measures" contained within this MD&A.

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.

The Company ensures that sufficient drawings are available from its Facility to satisfy working capital requirements. At December 31, 2020, the Company's working capital deficit totaled $24.4 million, when combined with the drawings on its bank loan, represented drawings of 40% on its $150 million Facility described below.

Bank Loan

As at December 31, 2020, the Company's bank facility consists of a revolving line of credit of $125 million and an operating line of credit of $25 million (the "Facility"). The Facility revolves for a 364 day period and will be subject to its next 364 day extension by June 4, 2021. 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 Facility requires the Company to maintain a Liability Management Rating ("LMR") of greater than 1.2:1 in the provinces of Alberta and Saskatchewan, and greater than 2.0:1 in the province of British Columbia, if the uninflated, undiscounted abandonment and reclamation liabilities ("Decommissioning Obligations"), as determined by the individual province, is greater than $20 million. If the LMR falls below the required level in any province, the lenders have the option to re-determine the Borrowing Base. As at December 31, 2020, the Company's Decommissioning Obligations exceeded $20 million in the province of British Columbia, which carried an LMR of 7.3:1. There can be no assurance that the amount of the available Facility will not be adjusted at the next scheduled Borrowing Base review on or before June 4, 2021. The Facility is secured by a floating charge debenture and a general securities agreement on all the assets of the Company.

Senior Unsecured Notes

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

The Company may redeem, on any one or more occasions, all or part of the 2024 Notes at the redemption prices set forth below, plus any accrued and unpaid interest:

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

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

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

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

Share Capital

Crew is authorized to issue an unlimited number of common shares. As at March 11, 2021, there were 156,466,605 common shares of the Company issued and outstanding, which includes 5,719,095 of common shares held in trust for the potential future settlement of awards issued under the Company's Restricted and Performance Award Incentive Plan. In addition, there were 3,734,305 restricted awards and 4,431,663 performance awards outstanding.

The Company acquires common shares in the open market, which are held in trust, for the potential future settlement of Restricted and Performance award values and are netted out of share capital, including the cumulative purchase cost, until they are distributed for future settlements. For the year ended December 31, 2020, the trustee purchased 2,960,000 common shares for a total cost of $1.0 million. At December 31, 2020, 5,267,000 common shares are held in trust.

Related-Party and Off-Balance-Sheet Transactions

Crew was not involved in any off-balance-sheet transactions or related party transactions during the year ended December 31, 2020.

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, transportation agreements, processing agreements, right of way agreements and lease obligations for office space. All such contractual obligations reflect market conditions prevailing at the time of contract and none are with related parties. The Company believes it has adequate sources of capital to fund all contractual obligations as they come due. The following table lists the Company's obligations with a fixed term.

($ thousands)	Total	2021	2022	2023	2024	2025	Thereafter
Bank Loan (note 1)	35,994	-	35,994	-	-	-	-
Senior unsecured notes (note 2)	300,000	-	-	-	300,000	-	-
Lease obligations	3,091	-	244	731	731	731	654
Firm transportation agreements	200,522	40,595	35,687	27,438	26,990	26,349	43,463
Firm processing agreement	200,177	18,718	18,718	18,718	18,752	18,718	106,553
Total	**739,784**	**59,313**	**90,643**	**46,887**	**346,473**	**45,798**	**150,670**

Notes:
(1) Based on the existing terms of the Company's Facility the first possible repayment date may come in 2022. However, it is expected that the Facility will be extended and no repayment will be required in the near term.
(2) Matures on March 14, 2024.

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

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

Firm processing agreements include commitments to process natural gas through the Greater Septimus Processing Complex in northeast British Columbia.

ADDITIONAL DISCLOSURES

Risks and Uncertainties

Crew's activities expose it to a variety of financial and operational risks and uncertainties that arise as a result of its exploration, development, production, and financing activities. Crew's business could also be affected by additional risks and uncertainties not currently known to the Company or that it currently deems to be immaterial. If any of these risks actually occur, it could materially harm Crew's business, financial condition, results of operations, cash flows or impair the Company's ability to implement business plans or complete development activities as scheduled. While the following sections discuss some of these risks, they should not be construed as exhaustive. For additional information on the risks relating to Crew's business, see "Risk Factors" identified in Crew's most recent Annual Information Form.

a) Impact of the COVID-19 Pandemic

The emergence of COVID-19 has resulted in emergency actions by governments worldwide, and has impacted Crew's results, business, financial and operating conditions, and has negatively impacted the Canadian, U.S., and global economies; disrupted Canadian, U.S., and global supply chains; disrupted financial markets; contributed to a decrease in interest rates; resulted in ratings downgrades, credit deterioration and defaults in many industries; forced the closure of many businesses, led to loss of revenues, increased unemployment and bankruptcies; and necessitated the imposition of quarantines, physical distancing, business closures, travel restrictions, and sheltering-in-place requirements in Canada, the U.S., and other countries. If the pandemic is prolonged, including through subsequent waves, or if additional variants of COVID-19 emerge which are more transmissible or cause more severe disease, or if other diseases emerge with similar effects, the adverse impact on the economy could worsen. Moreover, it remains uncertain how the macroeconomic environment, and societal and business norms will be impacted following this COVID-19 pandemic. As a result, the Company's business, financial and operational conditions, cash flows, reputation, access to capital, cost of borrowing, access to liquidity, and/or business plans may, in particular, and without limitation, may be adversely impacted as a result of the pandemic and/or decline in commodity prices.

The full extent of the risks surrounding the severity and timing of the COVID-19 pandemic is continually evolving and is not fully known at this time. Therefore, there is significant risk and uncertainty which may have a material and adverse effect on the Company's operations.

b) Weakness and Volatility in the Oil and Natural Gas Industry

Weakness and volatility of the oil and natural gas industry may affect the value of Crew's reserves, and restrict its cash flow and ability to access capital to fund the development of its properties.

Market events and conditions, including global excess oil and natural gas supply, actions or inaction taken by the Organization of the OPEC+ nations, announcements by Saudi Arabia to relax quotas and resulting price wars, sanctions against Iran and Venezuela, slowing growth in China and emerging economies, weakened global relationships, conflict between the U.S. and Iran, isolationist and punitive trade policies, U.S. shale production, sovereign debt levels and political upheavals in various countries including a growing anti-fossil fuel sentiment and the continuing impact of COVID-19 and travel bans, have caused significant weakness and volatility in commodity prices. These events and conditions have caused a significant reduction in the valuation of Crew's reserves and a decrease in confidence in the oil and natural gas industry. These difficulties have been exacerbated in Canada by political and other actions resulting in uncertainty surrounding regulatory, tax, royalty changes and environmental regulation. In addition, the difficulties encountered by midstream proponents to obtain on a timely basis or continue to maintain the necessary approvals to build pipelines, liquefied natural gas plants and other facilities to provide better access to markets for the oil and natural gas industry in Western Canada has led to additional downward price pressure on oil and natural gas produced in Western Canada. The resulting price differential between WCS crude oil and WTI crude oil has created uncertainty and reduced confidence in the oil and natural gas industry in Western Canada.

Lower commodity prices may also affect the volume and value of Crew's reserves. In addition, lower commodity prices restrict the Company's cash flow resulting in less funds from operations being available to fund Crew's capital expenditure budget. Any decrease in value of Crew's reserves may reduce the Borrowing Base under its Facility, which, depending on the level of the Company's indebtedness, could result in Crew having to repay a portion of its indebtedness. In addition to possibly decreasing the value of the Company's economically recoverable reserves, lower commodity prices may also result in a decrease in the value of Crew's infrastructure and facilities, all of which could also have the effect of requiring a write down of the carrying value of the Company's crude oil, NGL and natural gas assets on its balance sheet and the recognition of an impairment charge in its income statement. Given the current market conditions and the lack of confidence in the Canadian oil and natural gas industry, the Company may have difficulty raising additional funds or if it is able to do so, it may be on unfavourable and highly dilutive terms. If these conditions persist, Crew's cash flow may not be sufficient to continue to fund its operations and to satisfy its obligations when due, particularly its 2024 Notes, and the Company's ability to continue as a going concern and discharge its obligations will require additional equity or debt financing or proceeds or reduction in liabilities from asset sales. There can be no assurance that such equity or debt financing will be available on terms that are satisfactory to Crew or at all. Similarly, there can be no assurance that the Company will be able to realize any or sufficient proceeds or reduction in liabilities from asset sales to discharge its obligations and continue as a going concern.

c) Operational Risks

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. The long term commercial success of Crew depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, the Company's existing reserves, and the production from them, will decline over time as the Corporation produces from such reserves.

Drilling hazards, environmental damage and various field operating conditions could greatly increase the cost of operations and adversely affect the production from successful wells. Crew maintains diligent oversight and maintenance over operations to mitigate these risks, including responsible well supervision, effective maintenance operations and the development of enhanced recovery technologies that contribute to maximizing production rates over time. It is not possible to eliminate production delays and declines from normal field operating conditions, which can negatively affect revenue and cash flow levels to varying degrees.

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including, but not limited to, fire, explosion, blowouts, cratering, sour gas releases, spills and other environmental hazards. These typical risks and hazards could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment and cause personal injury or threaten wildlife.

Oil and natural gas production operations are also subject to geological and seismic risks, including encountering unexpected formations or pressures, premature decline of reservoirs and the invasion of water into producing formations. Losses resulting from the occurrence of any of these risks may have a material adverse effect on Crew's business, financial condition, results of operations and prospects.

As part of Crew's rigorous risk assessment, insurance is obtained to protect against major asset destruction or business interruptions. Although the Company maintains liability insurance and business interruption insurance in an amount that it considers consistent with industry practice, liabilities associated with certain risks could exceed policy limits or not be covered. In either event, the Company could incur significant costs.

The COVID-19 pandemic has also created additional operational risks for Crew, including the need to provide enhanced safety measures for its employees and customers; comply with rapidly changing regulatory guidance; address the risk of, attempted fraudulent activity and cybersecurity threat behavior; and protect the integrity and functionality of the Company's systems, networks, and data as a larger number of employees work remotely. The Company is also exposed to human capital risks due to issues related to health and safety matters, and other environmental stressors as a result of measures implemented in response to the COVID-19 pandemic, as well as the potential for a significant proportion of the Company's employees, including key executives, to be unable to work effectively, because of illness, quarantines, sheltering-in-place arrangements, government actions or other restrictions in connection with the pandemic.

d) Financial Risks

The extent to which the COVID-19 pandemic continues to impact the Company's financial results and condition or liquidity will depend on future developments in Canada, the U.S. and globally, including the development and widespread availability of efficient and accurate testing options, and effective treatment options or vaccines. Despite the approval of certain vaccines by the regulatory bodies in Canada and the U.S., the ongoing evolution of the development and distribution of an effective vaccine also continues to raise uncertainty.

Volatile oil, NGL and natural gas prices make it difficult to estimate the value of producing properties for acquisitions and often cause disruption in the market for oil, NGL and natural gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for, and project the return on, acquisitions and development and exploitation projects. As a result, the Company hedges future revenue through commodity contracts to lock-in value and mitigate financial risk.

Historical Analysis

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

($ thousands, except per share amounts)	**Dec. 31 2020**	Sep. 30 2020	June 30 2020	Mar. 31 2020	Dec. 31 2019	Sep. 30 2019	June 30 2019	Mar. 31 2019
Total daily production (boe/d)	**21,666**	20,207	22,074	23,894	22,446	22,824	22,865	23,222
Exploration and development expenditures	**41,007**	21,876	5,348	18,029	26,390	18,466	13,997	55,241
Property (dispositions)/acquisitions	**(23,219)**	(35)	44	(34,940)	82	7	(3,249)	(15,924)
Average wellhead price ($/boe)	**21.37**	17.40	12.39	17.52	21.76	19.81	24.77	26.53
Petroleum and natural gas sales	**42,604**	32,344	24,889	38,094	44,941	41,597	51,543	55,451
Cash provided by operating activities	**14,774**	5,121	8,175	9,919	21,106	8,877	40,879	10,533
Adjusted funds flow(1)	**15,568**	8,549	4,633	12,400	16,086	16,664	22,513	25,771
Per share – basic	**0.10**	0.06	0.03	0.08	0.11	0.11	0.15	0.17
– diluted	**0.10**	0.06	0.03	0.08	0.11	0.11	0.15	0.17
Net income (loss)	**34,668**	(21,136)	(24,803)	(191,909)	(6,235)	(3,255)	15,375	6,186
Per share – basic	**0.23**	(0.14)	(0.16)	(1.27)	(0.04)	(0.02)	0.10	0.04
– diluted	**0.22**	(0.14)	(0.16)	(1.27)	(0.04)	(0.02)	0.10	0.04

Note:
(1) Non-IFRS measure that does not have any standardized meaning as prescribed by International Financial Reporting Standards, and therefore, may not be comparable with the calculations of similar measures for other entities. See "Non-IFRS Measures" contained within this MD&A.

The Company conservatively managed capital spending through most of 2019 and 2020 due to weak Canadian natural gas prices. As a result, the Company's net capital expenditures, after proceeds from acquisitions and dispositions, have approximated adjusted funds flow over this period, effectively maintaining production at a consistent level.

Significant volatility in commodity prices has impacted cash provided by operating activities, adjusted funds flow and net (loss) income throughout the past eight quarters. The Company has reduced the financial impact of volatile commodity prices by entering into derivative and physical risk management contracts which can cause significant fluctuations in income due to unrealized gains and losses recognized on a quarterly basis. Crew has also attempted to mitigate the lower price environment by reducing its controllable costs and achieving operational efficiencies. Despite these efforts, cash flow from operations used to fund the Company's capital program has been impacted.

The global outbreak of COVID-19 in early 2020 and subsequent measures intended to limit the pandemic contributed to significant volatility in the global financial markets. The pandemic has adversely impacted global commercial activity and has significantly reduced worldwide demand for commodities including crude oil, natural gas and ngl. The result has been significant volatility and a decline in the near and medium term price for these commodities. The decline in crude oil and natural gas prices in the first quarter of 2020 resulted in a March 31, 2020 pre-tax impairment charge of $267.3 million.

The following table summarizes Crew's key financial results over the past three years:

($ thousands, except per share amounts)	**Year ended Dec. 31, 2020**	Year ended Dec. 31, 2019	Year ended Dec. 31, 2018
Petroleum and natural gas sales	**137,931**	193,532	218,385
Cash provided by operating activities	**37,989**	81,395	89,162
Adjusted funds flow[(1)]	**41,150**	81,034	91,996
Per share -basic	**0.27**	0.53	0.61
-diluted	**0.27**	0.53	0.61
Net (loss) income	**(203,180)**	12,071	12,799
Per share -basic	**(1.34)**	0.08	0.08
-diluted	**(1.34)**	0.08	0.08
Daily production (boe/d)	**21,955**	22,837	23,885
Crew average sales price ($/boe)	**17.17**	23.22	25.05
Total assets	**1,189,566**	1,451,647	1,451,923
Working capital (deficiency) surplus[(1)]	**(24,361)**	149	11,984
Bank loan	**35,994**	52,136	59,904
Senior unsecured notes	**296,851**	295,868	294,885
Total other long-term liabilities	**95,992**	143,295	142,246

Note:
(1) Non-IFRS measure that does not have any standardized meaning as prescribed by International Financial Reporting Standards, and therefore, may not be comparable with the calculations of similar measures for other entities. See "Non-IFRS Measures" contained within this MD&A.

Over the last three years, a volatile commodity price environment has impacted revenue, cash provided by operating activities, adjusted funds flow and net income. The overall decline in forecasted future commodity prices has also led to the assessment and realization of impairment charges on the Company's CGUs in 2020.

Application of Critical Accounting Estimates

Crew's significant accounting policies are disclosed in note 4 to the December 31, 2020 consolidated financial statements. Certain accounting policies require that management make appropriate decisions with respect to the formulation of estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. Crew continuously refines its management and reporting systems to ensure that accurate, timely and useful information is gathered and disseminated. Crew's financial and operating results incorporate certain estimates including the following:

- Estimated accruals for revenues, royalties, operating expenses and general administrative expenses where actual revenues and costs have not been received;
- Estimated capital expenditures where actual costs have not been received or for projects that are in progress;
- Estimated depletion, depreciation and amortization charges are based on estimates of oil and gas reserves that Crew expects to recover in the future. As a key component in the depletion, depreciation and amortization calculation, the reserve estimates have a significant impact on net earnings and the Company's financial results could differ if there is a revision in our estimate of reserve quantities;

- Estimated future recoverable value of property, plant and equipment and any related impairment charges or recoveries are assessed for impairment when circumstances suggest the carrying amount may exceed its recoverable amount. The recoverable amount calculation requires the use of estimates which are subject to change as new information becomes available. Changes in assumptions used in determining the recoverable amount could affect the carrying value of the related assets;
- Estimated fair values of derivative contracts, which are used to manage commodity price, foreign currency and interest rate swaps, are determined using valuation models which require assumptions regarding the amount and timing of future cash flows and discount rates. As the Company’s assumptions rely on external market data, the resulting fair value estimates may not be indicative of the amounts realized or settled and are therefore subject to market uncertainty;
- Decommissioning obligations are based on assumptions which take into consideration current economic factors and experience to date which Crew believes are reasonable. The actual cost of the Company’s decommissioning obligations may change in response to numerous factors;
- Estimated deferred income tax assets and liabilities are based on current tax interpretations, regulations and legislation which are subject to change. As a result, there are usually a number of tax matters under review and therefore income taxes are subject to measurement uncertainty.

Crew hires employees and engages consultants who have the expertise to ensure these estimates are accurate and ensures departments with the most knowledge of the activity are responsible for the estimates. Past estimates are reviewed and analyzed regularly to ensure future estimates continue to track actuals. The emergence of new information and changed circumstances may result in actual results or changes to estimate amounts that differ materially from current estimates.

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, as defined in national Instrument 52-109 Certification of Disclosures in Issuers’ Annual and Interim Filings (”NI 52-109”), 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. Such officers have evaluated, or caused to be evaluated under their supervision, the effectiveness of the Company's disclosure controls and procedures at the financial year end of the Company and have concluded that the Company's disclosure controls and procedures are effective at the financial year end of the Company.

The Company’s CEO and CFO have designed, or caused to be designed under their supervision, internal controls over financial reporting, as defined in NI 52-109, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. Utilizing the Committee of Sponsoring Organizations of the Treadway Commission (“COSO”) Internal Control – Integrated Framework (2013), such officers have evaluated, or caused to be evaluated under their supervision, the effectiveness of the Company's internal controls over financial reporting at the financial year end of the Company and concluded that the Company's internal controls over financial reporting are effective, at the financial year end of the Company. 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 October 1, 2020 and ended on December 31, 2020 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.

ADVISORIES

Conversions

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

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

Non-IFRS Measures

Throughout this MD&A, the terms "adjusted funds flow", "EBITDA", "funds from operations", "operating netback", "net operating costs", "net debt", and "working capital surplus (deficiency)" are used which are non-IFRS financial measures. The Company uses these measures to help evaluate Crew's performance. These non-IFRS measures do not have any standardized meaning prescribed under IFRS and therefore, may not be calculated in a similar fashion nor comparable to similar measures presented by other entities. Management believes that the presentation of these non-IFRS measures provides useful information to shareholders and investors as the measures provide increased transparency and the ability to better analyze performance against prior periods on a comparable basis.

a) Funds from Operations, Adjusted Funds Flow and EBITDA

Funds from operations represents cash provided by operating activities before changes in operating non-cash working capital and accretion of deferred financing costs. Adjusted funds flow represents funds from operations before decommissioning obligations settled. EBITDA is calculated as consolidated net income (loss) before interest and financing expenses, income taxes, depletion, depreciation and amortization, adjusted for certain non-cash, extraordinary and non-recurring items primarily relating to unrealized gains and losses on financial instruments and impairment losses. The Company considers these metrics as key measures that demonstrate the ability of the Company's continuing operations to generate the cash flow necessary to maintain production at current levels and fund future growth through capital investment and to service and repay debt. Management believes that such measures provide an insightful assessment of the Company's operations on a continuing basis by eliminating certain non-cash charges and actual settlements of decommissioning obligations, the timing of which is discretionary. Funds from operations, adjusted funds flow and EBITDA 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, adjusted funds flow and EBITDA may not be comparable to that reported by other companies. Crew also presents adjusted funds flow per share whereby per share amounts are calculated using weighted average shares outstanding consistent with the calculation of income per share.

The following table reconciles Crew's cash provided by operating activities to funds from operations and adjusted funds flow:

($ thousands)	**Three months ended December 31, 2020**	Three months ended September 30, 2020	Three months ended December 31, 2019	**Year ended December 31, 2020**	Year ended December 31, 2019
Cash provided by operating activities	**14,774**	5,121	21,106	**37,989**	81,395
Change in operating non-cash working capital	**19**	2,902	(5,315)	**2,170**	(3,297)
Accretion of deferred financing costs	**(246)**	(245)	(246)	**(983)**	(983)
Funds from operations	**14,547**	7,778	15,545	**39,176**	77,115
Decommissioning obligations settled excluding grants	**1,021**	771	541	**1,974**	3,919
Adjusted funds flow	**15,568**	8,549	16,086	**41,150**	81,034
Interest	**5,928**	6,038	6,312	**23,312**	24,492
EBITDA	**21,496**	14,587	22,398	**64,462**	105,526

b) Operating Netback

Operating netback equals petroleum and natural gas sales including realized gains and losses on commodity related derivative financial instruments, marketing income, less royalties, net operating costs and transportation costs calculated on a boe basis. Management considers operating netback an important measure to evaluate its operational performance as it demonstrates its field level profitability relative to current commodity prices. The calculation of Crew's netbacks can be seen in the section entitled "Operating Netbacks" of this MD&A.

c) Net Operating Costs

Net operating costs equals operating costs net of processing revenue. Management net operating costs an important measure to evaluate its operational performance. The calculation of Crew's net operating costs can be seen in the section entitled "Net Operating Costs" of this MD&A.

d) Net debt and Working Capital Deficiency (Surplus)

Crew closely monitors its capital structure with a goal of maintaining a strong balance sheet to fund the future growth of the Company. The Company monitors net debt as part of its capital structure. The Company uses net debt (bank debt plus working capital deficiency or surplus, excluding the current portion of the fair value of financial instruments) as an alternative measure of outstanding debt. Management considers net debt and working capital deficiency (surplus) an important measure to assist in assessing the liquidity of the Company. The calculation of Crew's net debt and working capital deficiency (surplus) can be seen in the section entitled "Capital Management" of this MD&A.

Forward Looking Statements

This MD&A contains certain forward looking informational statements within the meaning of applicable securities laws. In particular, management's assessment of the potential and uncertain impact of COVID-19 on the Company's operations and results, future plans and operations, including the Company's two year development plan and the associated guidance and material underlying assumptions contained in the section titled ("Guidance") herein, including annualized 2021 and 2022 production guidance, capital spending plans and budget estimates, drilling plans and the timing thereof, plans for the completion and tie-in of wells and anticipated on-stream dates, facility and pipeline construction, expansion, commissioning and the timing thereof, capital expenditures, timing of capital expenditures and methods of financing capital expenditures and the ability to fund financial liabilities, production estimates, expected commodity mix and prices, future net operating costs, future transportation costs, expected royalty rates, expected and forecasted reductions in general and administrative expenses and improved margins, expected interest rates and other financing charges, debt levels and expected debt levels, funds from operations and the timing of and impact of implementing accounting policies, expectations in regards to the Company's credit facilities, estimates regarding undeveloped land position and estimated future drilling, recompletion or reactivation locations, the potential for further property or infrastructure divestures and the anticipated impact of potential future transactions may constitute forward looking statements under applicable securities laws and necessarily involve risks including, without limitation, risks associated with oil and gas exploration, development, exploitation, production, marketing and transportation, loss of markets, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other producers, inability to retain drilling rigs and other services, incorrect assessment of the value of acquisitions, failure to realize the anticipated benefits of acquisitions, the inability to fully realize the benefits of acquisitions, delays resulting from or inability to obtain required regulatory approvals and inability to access sufficient capital from internal and external sources. As a consequence, the Company's actual results may differ materially from those expressed in, or implied by, the forward looking statements. Forward looking statements or information are based on a number of factors and assumptions which have been used to develop such statements and information but which may prove to be incorrect. Although Crew believes that the expectations reflected in such forward looking statements or information are reasonable, undue reliance should not be placed on forward looking statements because the Company can give no assurance that such expectations will prove to be correct. In addition to other factors and assumptions which may be identified in this document and other documents filed by the Company, assumptions have been made regarding, among other things: the impact measures taken to protect citizens from COVID-19 will have on global energy demand and global economies; the potential impact of government programs associated with COVID-19; the general stability of the economic and political environment in which Crew operates; the impact of increasing competition; the ability of the Company to obtain qualified staff, equipment and services in a timely and cost efficient manner; drilling results; potential changes in the Company's two year development plan; the ability of the operator of the projects which the Company has an interest in to operate the field in a safe, efficient and effective manner; Crew's ability to obtain financing on acceptable terms; changes in the Company's banking facility; field production rates and decline rates; the ability to reduce net operating costs; the ability to replace and expand oil and natural gas reserves through acquisition, development or exploration; the timing and costs of pipeline, storage and facility construction and expansion; the ability of the Company to secure adequate product transportation; future petroleum and natural gas prices; currency exchange and interest rates; the regulatory framework regarding royalties, taxes and environmental matters in the jurisdictions in which the Company operates; and Crew's ability to successfully market its petroleum and natural gas products. Readers are cautioned that the foregoing list of factors is not exhaustive. Additional information on these and other factors that could affect the Company's operations and financial results are included in reports on file with Canadian securities regulatory authorities and may be accessed through the SEDAR website (www.sedar.com) or at the Company's website (www.crewenergy.com).

The internal projections, expectations or beliefs underlying the Company's 2021 and 2022 capital expenditure plans, budgets and associated production guidance and corporate outlook for 2021 and beyond are subject to change in light of ongoing results, prevailing economic circumstances, commodity prices and industry conditions and regulations. Crew's outlook for 2021 and beyond provides shareholders with relevant information on Management's expectations for results of operations, excluding any potential acquisitions, dispositions or strategic transactions that may be completed in 2021 and beyond. Accordingly, readers are cautioned that events or circumstances could cause results to differ materially from those predicted and Crew's 2021 and 2022 guidance and outlook may not be appropriate for other purposes. 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.

Dated as of March 11, 2021

MANAGEMENT'S REPORT

Management, in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board, has prepared the accompanying consolidated financial statements of Crew Energy Inc. ("Crew" or the "Company"). Financial and operating information presented throughout this report is consistent with that shown in the consolidated financial statements.

Management is responsible for the integrity of the financial information. Internal control systems are designed and maintained to provide reasonable assurance that assets are safeguarded from loss or unauthorized use and to produce reliable accounting records for financial reporting purposes.

KPMG LLP were appointed by the Company's Board of Directors to conduct an audit of the consolidated financial statements. Their examination included a review and evaluation, including tests and procedures, of Crew's internal control systems as they considered necessary, to provide reasonable assurance that the consolidated financial statements are presented fairly in accordance with IFRS.

The Board of Directors are responsible for ensuring that management fulfills its responsibilities for financial reporting and internal control. The Board exercises this responsibility through the Audit Committee, with assistance from the Reserves Committee regarding the annual evaluation of our petroleum and natural gas reserves. The Audit Committee meets regularly with management and the independent auditors to ensure that management's responsibilities are properly discharged, to review the consolidated financial statements and recommend that the consolidated financial statements be presented to the Board of Directors for approval. The Audit Committee also considers the independence of the external auditors and reviews their fees. The external auditors have access to the Audit Committee without the presence of management.

(signed)

Dale O. Shwed

President and Chief Executive Officer

(signed)

John G. Leach

Executive Vice-President and Chief Financial Officer

March 11, 2021

INDEPENDENT AUDITORS' REPORT

To the Shareholders of Crew Energy Inc.

Opinion

We have audited the consolidated financial statements of Crew Energy Inc. (the "Company"), which comprise:

- the consolidated statements of financial position as at December 31, 2020 and December 31, 2019
- the consolidated statements of (loss) income and comprehensive (loss) income for the years then ended
- the consolidated statements of changes in shareholders' equity for the years then ended
- the consolidated statements of cash flows for the years then ended
- and notes to the consolidated financial statements, including a summary of significant accounting policies

(Hereinafter referred to as the "financial statements".)

In our opinion, the accompanying financial statements present fairly, in all material respects, the consolidated financial position of the Company as at December 31, 2020 and December 31, 2019, and its consolidated financial performance and its consolidated cash flows for the years then ended in accordance with International Financial Reporting Standards ("IFRS").

Basis for Opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the "Auditors' Responsibilities for the Audit of the Financial Statements" section of our auditors' report.

We are independent of the Company in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada and we have fulfilled our other ethical responsibilities in accordance with these requirements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Key Audit Matters

Key audit matters are those matters that, in our professional judgment, were of most significance in our audit of the financial statements for the year ended December 31, 2020. These matters were addressed in the context of our audit of the financial statements as a whole, and in forming our opinion thereon, and we do not provide a separate opinion on these matters.

We have determined the matters described below to be the key audit matters to be communicated in our auditors' report.

Assessment of the recoverable amount of the cash generating units

Description of the matter

We draw attention to note 4 and note 8 to the financial statements. The Company has recorded an aggregate non-cash impairment charge of $267.3 million related to the cash generating units (the "CGUs") for the year ended December 31, 2020. The Company identified an indicator of impairment at March 31, 2020 for all CGUs and identified an indicator of reversal at December 31, 2020 for all CGUs and performed an impairment test to estimate the recoverable amount of each CGU.

The estimated recoverable amount of each CGU involves significant estimates including:

- The estimate of proved and probable oil and gas reserves and the related cash flows
- The discount rates
- The sales value of the undeveloped lands.

The estimate of proved and probable oil and gas reserves and the related cash flows requires the expertise of independent third-party reserve evaluators and includes significant assumptions related to:

- Forecasted oil and gas commodity prices
- Forecasted production
- Forecasted operating costs

- Forecasted royalty costs
- Forecasted future development costs.

The Company engages independent third party reserve evaluators to estimate the proved and probable oil and gas reserves and the related cash flows annually.

Why the matter is a key audit matter

We identified the assessment of the recoverable amount of the CGUs as a key audit matter. Significant auditor judgment was required to evaluate the results of our audit procedures regarding the estimate of proved and probable oil and gas reserves and the related cash flows, the discount rates, and the sales value of the undeveloped lands.

How the matter was addressed in the audit

The following are the primary procedures we performed to address this key audit matter:

With respect to the estimate of proved and probable oil and gas reserves and the related cash flows as at December 31, 2020:

- We evaluated the competence, capabilities and objectivity of the independent third-party reserve evaluators engaged by the Company
- We compared forecasted oil and gas commodity prices to those published by other independent third-party reserve evaluators
- We compared the 2020 actual production, operating costs, royalty costs and development costs of the Company to those estimates used in the prior year's estimate of proved oil and gas reserves and the related cash flows to assess the Company's ability to accurately forecast
- We evaluated the appropriateness of forecasted production and forecasted operating costs, royalty costs and future development costs assumptions by comparing to 2020 actual results. We took into account changes in conditions and events affecting the Company to assess the adjustments or lack of adjustments made by the Company in arriving at the assumptions.

We involved valuation professionals with specialized skills and knowledge, who assisted in:

- Evaluating the appropriateness of the Company's discount rates and the sales value of the undeveloped lands by comparing the discount rates and the sales value of the undeveloped lands to market and other external data
- Assessing the reasonableness of the Company's estimate of the recoverable amount of each CGU by comparing the Company's estimate to market metrics and other external data

Other Information

Management is responsible for the other information. Other information comprises:

- the information included in Management's Discussion and Analysis filed with the relevant Canadian Securities Commissions.

Our opinion on the financial statements does not cover the other information and we do not and will not express any form of assurance conclusion thereon.

In connection with our audit of the financial statements, our responsibility is to read the other information identified above and, in doing so, consider whether the other information is materially inconsistent with the financial statements or our knowledge obtained in the audit and remain alert for indications that the other information appears to be materially misstated.

We obtained the information included in Management's Discussion and Analysis filed with the relevant Canadian Securities Commissions as at the date of this auditors' report. If, based on the work we have performed on this other information, we conclude that there is a material misstatement of this other information, we are required to report that fact in the auditors' report.

We have nothing to report in this regard.

Responsibilities of Management and Those Charged with Governance for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with IFRS, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Company's ability to continue as a going concern, disclosing as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Company or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Company's financial reporting process.

Auditors' Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditors' report that includes our opinion.

Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists.

Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of the financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit.

We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion.

  The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Company's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditors' report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditors' report. However, future events or conditions may cause the Company to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.
- Communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.
- Provide those charged with governance with a statement that we have complied with relevant ethical requirements regarding independence, and communicate with them all relationships and other matters that may reasonably be thought to bear on our independence, and where applicable, related safeguards.
- Determine, from the matters communicated with those charged with governance, those matters that were of most significance in the audit of the financial statements of the current period and are therefore the key audit matters. We describe these matters in our auditors' report unless law or regulation precludes public disclosure about the matter or when, in extremely rare circumstances, we determine that a matter should not be communicated in our auditors' report because

the adverse consequences of doing so would reasonably be expected to outweigh the public interest benefits of such communication.

The engagement partner on the audit resulting in this auditors' report is Timothy Arthur Richards.

KPMG LLP

Chartered Professional Accountants

Calgary, Canada
March 11, 2021

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

(thousands)	**December 31, 2020**	December 31, 2019
Assets		
Current Assets:		
Accounts receivable	**$ 22,135**	$ 26,994
Derivative financial instruments (note 6)	**4,718**	3,180
Assets held for sale (note 7)	**-**	19,845
	26,853	50,019
Derivative financial instruments (note 6)	**3,681**	-
Property, plant and equipment (note 7)	**1,159,032**	1,401,628
	$ 1,189,566	$ 1,451,647
Liabilities and Shareholders' Equity		
Current Liabilities:		
Accounts payable and accrued liabilities	**$ 46,496**	$ 45,949
Derivative financial instruments (note 6)	**716**	-
Liabilities associated with assets held for sale (note 7)	**-**	741
	47,212	46,690
Bank loan (note 9)	**35,994**	52,136
Senior unsecured notes (note 10)	**296,851**	295,868
Lease obligations (note 11)	**2,814**	2,708
Decommissioning obligations (note 12)	**93,178**	87,024
Deferred tax liability (note 13)	**-**	53,563
Shareholders' Equity		
Share capital (note 14)	**1,482,925**	1,478,294
Contributed surplus	**70,052**	71,644
Deficit	**(839,460)**	(636,280)
	713,517	913,658
Commitments (note 15)		
Subsequent event (note 6)		
	$ 1,189,566	$ 1,451,647

See accompanying notes to the consolidated financial statements.

On behalf of the Board of Directors:

(signed)	*(signed)*
David G. Smith	Ryan A. Shay
Director	Director

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

(thousands, except per share amounts)	**Year ended December 31, 2020**	Year ended December 31, 2019
Revenue		
Petroleum and natural gas sales (note 16)	**$ 137,931**	$ 193,532
Royalties	**(6,469)**	(14,758)
Realized gain on derivative financial instruments	**16,588**	2,352
Unrealized gain (loss) on derivative financial instruments	**4,503**	(5,202)
Marketing and processing revenue (note 16)	**1,526**	11,748
	154,079	187,672
Expenses		
Operating	**47,527**	52,487
Transportation	**29,504**	22,804
Marketing	**-**	414
General and administrative	**8,083**	11,636
Share-based compensation	**2,272**	5,340
Depletion and depreciation (note 7)	**71,054**	75,776
	158,440	168,457
(Loss) income from operations	**(4,361)**	19,215
Financing (note 17)	**24,533**	26,393
Impairment on property, plant and equipment (note 8)	**267,334**	-
Gain on divestiture of property, plant and equipment (note 7)	**(38,344)**	(20,014)
Other income	**(1,141)**	-
(Loss) income before income taxes	**(256,743)**	12,836
Deferred tax (recovery) expense (note 13)	**(53,563)**	765
Net (loss) income and comprehensive (loss) income	**$ (203,180)**	$ 12,071
Net (loss) income per share (note 14)		
Basic	**$ (1.34)**	$ 0.08
Diluted	**$ (1.34)**	$ 0.08

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

(thousands)	Number of shares, net of shares in trust	Share capital	Contributed surplus	Deficit	Total Shareholders' equity
Balance January 1, 2020	151,534	$1,478,294	$ 71,644	$ (636,280)	$ 913,658
Net loss for the year	-	-	-	(203,180)	(203,180)
Share-based compensation expensed	-	-	2,272	-	2,272
Share-based compensation capitalized	-	-	2,186	-	2,186
Issued from treasury on vesting of share awards	177	3,693	(4,112)	-	(419)
Released from trust on vesting of share awards	2,431	1,938	(1,938)	-	-
Purchase of shares held in trust (note 14)	(2,960)	(1,000)	-	-	(1,000)
Balance, December 31, 2020	**151,182**	**$1,482,925**	**$ 70,052**	**$ (839,460)**	**$ 713,517**

(thousands)	Number of shares, net of shares in trust	Share capital	Contributed surplus	Deficit	Total Shareholders' equity
Balance January 1, 2019	151,730	$1,468,986	$ 75,715	$ (648,351)	$ 896,350
Net income for the year	-	-	-	12,071	12,071
Share-based compensation expensed	-	-	5,340	-	5,340
Share-based compensation capitalized	-	-	4,897	-	4,897
Issued from treasury on vesting of share awards	4,542	14,212	(14,212)	-	-
Released from trust on vesting of share awards	45	96	(96)	-	-
Purchase of shares held in trust (note 14)	(4,783)	(5,000)	-	-	(5,000)
Balance, December 31, 2019	**151,534**	**$1,478,294**	**$ 71,644**	**$ (636,280)**	**$ 913,658**

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(thousands)	**Year ended December 31, 2020**	Year ended December 31, 2019
Cash provided by (used in):		
Operating activities:		
Net (loss) income	**$ (203,180)**	$ 12,071
Adjustments:		
Unrealized (gain) loss on derivative financial instruments	**(4,503)**	5,202
Share-based compensation	**2,272**	5,340
Depletion and depreciation (note 7)	**71,054**	75,776
Financing expenses (note 17)	**24,533**	26,393
Interest expense (note 17)	**(22,329)**	(23,516)
Impairment on property, plant and equipment (note 8)	**267,334**	-
Gain on divestiture of property, plant and equipment (note 7)	**(38,344)**	(20,014)
Deferred tax (recovery) expense (note 13)	**(53,563)**	765
Decommissioning obligations settled (note 12)	**(3,115)**	(3,919)
Change in non-cash working capital (note 19)	**(2,170)**	3,297
	37,989	81,395
Financing activities:		
Decrease in bank loan	**(16,142)**	(7,768)
Payments on lease obligations (note 11)	**(187)**	(1,071)
Shares purchased and held in trust (note 14)	**(1,000)**	(5,000)
Settlement of restricted and performance awards (note 14)	**(419)**	-
	(17,748)	(13,839)
Investing activities:		
Property, plant and equipment expenditures (note 7)	**(86,260)**	(114,094)
Property acquisitions (note 7)	**(11,790)**	(1,570)
Property dispositions (note 7)	**69,940**	20,654
Change in non-cash working capital (note 19)	**7,869**	27,454
	(20,241)	(67,556)
Change in cash and cash equivalents	**-**	-
Cash and cash equivalents, beginning of year	**-**	-
Cash and cash equivalents, end of year	**$ -**	$ -

See accompanying notes to the consolidated financial statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

For the years ended December 31, 2020 and 2019

(Tabular amounts in thousands)

1. Reporting entity:

Crew Energy Inc. ("Crew" or the "Company") is an oil and gas exploration, development and production company based in Calgary, Alberta, Canada. Crew conducts its operations in the Western Canada Sedimentary basin, primarily in the provinces of British Columbia, Saskatchewan and Alberta. The 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 International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board. A summary of the significant accounting policies and method of computation is presented in note 4.

The financial statements have been prepared on the historical cost basis except for derivative financial instruments which are measured at fair value. The methods used to measure fair values are discussed in note 5.

These financial statements are presented in Canadian dollars ("CDN"), which is the functional currency of the Company, its subsidiary and partnerships.

Expenses in the consolidated statements of (loss) income ("statements of income") are presented as a combination of function and nature in conformity with industry practice. Share-based compensation and depletion and depreciation expenses are presented on separate lines by their nature, while operating, transportation, marketing and general and administrative expenses are presented on a functional basis.

The financial statements were authorized for issuance by Crew's Board of Directors on March 11, 2021.

3. COVID-19 estimation uncertainty:

In March 2020, the World Health Organization declared a global pandemic following the emergence and rapid spread of a novel strain of the coronavirus ("COVID-19"). The pandemic and subsequent measures intended to limit its spread, contributed to significant volatility in global financial markets. The pandemic has adversely impacted global commercial activity and has reduced worldwide demand for commodities including crude oil, natural gas and natural gas liquids ("ngl"). The result was significant economic uncertainty and a decline in commodity prices through most of 2020. In general, the oil and gas industry reacted with reductions to capital and other spending, as well as production shut-ins, to try to manage through this price environment.

The full extent of the impact of COVID-19 on the Company's operations and future financial performance is currently unknown. It will depend on future developments that are uncertain and unpredictable, including the duration and spread of COVID-19, its continued impact on financial markets on a macro-scale and any new information that may emerge concerning the effectiveness of available vaccines and the severity and spread of the virus. The pandemic presents uncertainty and risk with respect to the Company, its performance, and estimates and assumptions used by management in the preparation of its financial results.

The Company's financial performance, operations and business are particularly sensitive to a reduction in the demand for and prices of crude oil and natural gas. The potential direct and indirect impact of the economic downturn related to COVID-19 have been considered in management's estimates and assumptions at period end and have been reflected in the Company's results with any significant changes described in the relevant financial statements note.

The COVID-19 pandemic is an evolving situation that will continue to have widespread implications for the Company's business environment, operations and financial condition. Management cannot reasonably estimate the length or severity of this pandemic, or the extent to which the disruption may materially impact the Company's financial statements in fiscal 2021 and beyond.

A full list of the key sources of estimation uncertainty can be found in note 4 of these financial statements. The pandemic and current market conditions have increased the complexity of estimates and assumptions used to prepare the financial statements, particularly related to the following key sources of estimation uncertainty:

Recoverable Amounts

Determining the recoverable amount of a cash-generating unit ("CGU") or an individual asset requires the use of estimates and assumptions, which are subject to change as new information becomes available. The severe drop in and volatility of forecasted commodity prices, due to reasons noted above, have increased the risk of measurement uncertainty in determining the estimated recoverable amounts, especially estimating the economic proved and probable oil and gas reserves and the related cash flows, and estimating forecasted oil and gas commodity prices.

Decommissioning Costs

Provisions are recorded for the future decommissioning and restoration of the Company's production facilities, wells and pipelines at the end of their economic lives. The Company assesses the existence and then estimates the future liability. Market volatility at December 31, 2020 increased the measurement uncertainty inherent in determining the appropriate discount rate that is used in the estimation of decommissioning liabilities.

Income Tax Provisions

Income taxes on earnings or loss in the interim periods are accrued using the income tax rate that would be applicable to the expected total annual earnings or loss. In the current economic environment, the expected total annual earnings or expected earnings are subject to measurement uncertainty. Changes to these assumptions could result in a material adjustment to the carrying amount of assets and liabilities within the next financial year and the utilization of deferred tax assets, along with sufficient profit that will be realized to utilize these assets.

Accounts Receivable

The Company has increased its monitoring of receivables due from petroleum and natural gas marketers and from joint venture partners to manage credit risk. The Company historically has not experienced any collection issues with petroleum and natural gas marketers as a significant portion of these receivables are with creditworthy purchasers. To protect against credit losses from joint venture partners, the Company has the ability to withhold production in the event of non-payment and the ability to obtain the partners' share of capital expenditures in advance of a project. The Company continues to expect that its receivables are substantially collectible at December 31, 2020.

4. Significant accounting policies:

(a) Basis of consolidation:

(i) Subsidiaries:

Subsidiaries are entities controlled by the Company. Control exists when the Company has the power to govern the financial and operating policies of an entity so as to obtain benefits from its activities. In assessing control, substantive potential voting rights are taken into account. The financial statements of subsidiaries are included in the financial statements from the date that control commences until the date that control ceases. The acquisition method of accounting is used to account for acquisitions of subsidiaries and assets that meet the definition of a business under IFRS. The cost of an acquisition is measured as the fair value of the assets given, equity instruments issued and liabilities incurred or assumed at the date of exchange. Identifiable assets acquired and liabilities and contingent liabilities assumed in a business combination are measured initially at their fair values at the acquisition date. The excess of the cost of acquisition over the fair value of the identifiable assets, liabilities and contingent liabilities acquired is recorded as goodwill. If the cost of acquisition is less than the fair value of the net assets of the subsidiary acquired, the difference is recognized immediately in the statements of income.

(ii) Jointly owned assets:

Some of the Company's oil and natural gas activities involve jointly owned assets. The financial statements include the Company's share of these jointly owned assets and its proportionate share of the relevant revenue and related costs.

(iii) Transactions eliminated on consolidation:

Intercompany balances and transactions, and any unrealized income and expenses arising from intercompany transactions, are eliminated in preparing the financial statements.

(b) Foreign currency:

Transactions in foreign currencies are translated to Canadian dollars at exchange rates at the dates of the transactions. Monetary assets and liabilities denominated in foreign currencies are translated to Canadian dollars at the period end exchange rate. Non-monetary assets and liabilities denominated in foreign currencies that are measured at fair value are translated to the functional currency at the exchange rate at the date that the fair value was determined. Foreign currency differences arising on translation are recognized in the statements of income.

(c) Financial instruments:

(i) Non-derivative financial instruments:

Non-derivative financial instruments are comprised of cash and cash equivalents, accounts receivable, accounts payable, the bank loan and the senior unsecured notes. Non-derivative financial instruments are recognized initially at fair value plus, for instruments not at fair value through the statements of income, any directly attributable transaction costs. Subsequent to initial recognition, non-derivative financial instruments are measured as described below.

Cash and cash equivalents is comprised of cash on hand, term deposits held with banks and other short-term highly liquid investments with original maturities of three months or less. Bank overdrafts that are repayable on demand and form an integral part of the Company's cash management, whereby management has the ability and intent to net bank overdrafts against cash, are included as a component of cash and cash equivalents for the purpose of the statement of cash flows.

Other non-derivative financial instruments, such as accounts receivable, the bank loan, the senior unsecured notes and accounts payable and accrued liabilities, are measured at amortized cost using the effective interest method, less any impairment losses.

(ii) Derivative financial instruments:

The Company enters into certain financial derivative contracts in order to manage the exposure to market risks from fluctuations in commodity prices, interest rates and the exchange rate between Canadian and United States dollars. These instruments are not used for trading or speculative purposes. The Company has not designated its financial derivative contracts as effective accounting hedges, and thus has not applied hedge accounting, even though the Company considers all financial derivative contracts to be economic hedges. As a result, all financial derivative contracts are classified at fair value through the statements of income and are recorded on the statement of financial position at fair value. Transaction costs are recognized in the statements of income when incurred.

(iii) Share capital:

Common shares are classified as equity. Incremental costs directly attributable to the issuance of common shares and restricted and performance awards are recognized as a deduction from equity, net of any tax effects.

(d) Property, plant and equipment and intangible exploration assets:

(i) Recognition and measurement:

Exploration and evaluation ("E&E") expenditures:

Pre-license costs are recognized in the statements of income as incurred.

E&E costs, including the costs of acquiring leases and licenses initially are capitalized as E&E assets. The costs are accumulated in cost centres by well, field or exploration area pending determination of technical feasibility and commercial viability.

E&E assets are assessed for impairment if (i) sufficient data exists to determine technical feasibility and commercial viability, and (ii) facts and circumstances suggest that the carrying amount exceeds the recoverable amount. For purposes of impairment testing, E&E assets are allocated to the related CGU.

The technical feasibility and commercial viability of extracting a mineral resource is considered to be determinable when proven and/or probable reserves are determined to exist. A review of each exploration license or field is carried out, at least annually, to ascertain whether proved and/or probable oil and gas reserves have been discovered. Upon determination of proved and/or probable oil and gas reserves, intangible E&E assets attributable to those reserves are first tested for impairment and then reclassified from E&E assets to a separate category within tangible assets referred to as oil and natural gas interests.

Development and production costs:

Items of property, plant and equipment, which include oil and gas development and production assets, are measured at cost less accumulated depletion and depreciation and accumulated impairment losses. Development and production assets are grouped into CGUs for impairment testing. When significant parts of an item of property, plant and equipment, including oil and natural gas interests, have different useful lives they are accounted for as separate items (major components).

Gains and losses on disposal of property, plant and equipment, property swaps and farm-outs, are determined by comparing the proceeds or fair value of the asset received or given up with the carrying amount of property, plant and equipment and are recognized in the statements of income.

(ii) Subsequent costs:

Costs incurred subsequent to the determination of technical feasibility and commercial viability and the costs of replacing parts of property, plant and equipment are recognized as oil and natural gas interests only when they increase the future economic benefits embodied in the specific asset to which they relate. All other expenditures are recognized in the statements of income as incurred. Such capitalized oil and natural gas interests generally represent costs incurred in developing proved and/or probable reserves and bringing on or enhancing production from such reserves, and are accumulated on a field or geotechnical area basis. The carrying amount of any replaced or sold component is derecognized. The costs of the day-to-day servicing of property, plant and equipment are recognized in the statements of income as operating costs as incurred.

(iii) Depletion and depreciation:

The net carrying value of development or production assets is depleted using the unit of production method by reference to the ratio of production in the year to the related proved and probable oil and gas reserves, taking into account estimated future development costs necessary to bring those reserves into production. Relative volumes of reserves and production are converted at the energy equivalent conversion ratio of six thousand cubic feet of natural gas to one barrel of oil. Future development costs are estimated taking into account the level of development required to produce the reserves. These estimates are reviewed by independent third party reserve evaluators at least annually.

The estimated useful lives for certain production assets for the current and comparative years are as follows:

Gas processing plants	Unit of production
Pipeline facilities	Unit of production
Turnaround and workover costs	2 years straight line

For other assets, depreciation is recognized in the statements of income on a straight-line basis over the estimated useful lives of each part of an item of property, plant and equipment.

The estimated useful lives for other assets for the current and comparative years are as follows:

Office equipment	5 years

Depreciation methods, useful lives and residual values are reviewed at each reporting date.

(iv) Assets held for sale:

Non-current assets, or disposal groups consisting of assets and liabilities, are classified as held for sale if their carrying amounts will be recovered through a sale transaction rather than through continuing use. This condition is met when the sale is highly probable and the asset is available for immediate sale in its present condition.

Non-current assets classified as held for sale are measured at the lower of the carrying amount and fair value less costs to sell, with impairments recognized in the statements of income in the period measured. Non-current assets and disposal groups held for sale are presented in current assets and liabilities on the statement of financial position.

(e) Leased assets:

When Crew is party to a lease arrangement as the lessee, it recognizes a right-of-use asset ("ROU asset") and a corresponding lease obligation on the balance sheets on the date that a leased asset becomes available for use. Interest associated with the lease obligation is recognized over the lease period with a corresponding increase to the underlying lease obligation. ROU assets are depreciated on a straight-line basis over the shorter of the asset’s useful life and the lease term. Depreciation on ROU assets is recognized in depletion and depreciation. ROU assets and lease obligations are initially measured on a present value basis. Lease obligations are measured as the net present value of the lease payments which may include: fixed lease payments, variable lease payments based on an index or a rate, and amounts expected to be payable under residual value guarantees and payments to exercise an extension or termination option, if Crew is reasonably certain to exercise either of those options. ROU assets are measured at cost, which is composed of the amount of the initial measurement of the lease obligation, less any incentives received, plus any lease payments made at, or before, the commencement date and initial direct costs and asset restoration costs, if any. The rate implicit in the lease is used to determine the present value of the liability and ROU asset arising from a lease, unless this rate is not readily determinable, in which case the Company's incremental borrowing rate is used.

In cases where the leased asset is used in the Company's jointly controlled operations, Crew, as the operator, is the obligor to the lessor and presents the full amount of the lease obligation and ROU asset at the commencement date of the lease. Certain payments relating to the Company's lease obligation may be recovered over time in accordance with billings for each partner's proportionate interest in the joint operation and are recognized in other income.

Short-term leases and leases of low-value assets are not recognized on the statement of financial position and lease payments are instead recognized in the financial statements as incurred. For certain classes of leases, Crew does not separate lease and non-lease components, accounting for these leases as a single lease component.

(f) Impairment:

(i) Financial assets:

A financial asset is assessed at each reporting date to determine whether there is any objective evidence that it is impaired by measuring the asset's expected credit loss ("ECL"). Accounts receivable are due within one year or less; therefore, these financial assets are not considered to have a significant financing component and a lifetime ECL is measured at the date of initial recognition of the accounts receivable.

The ECL pertaining to accounts receivable is assessed at initial recognition and this provision is re-assessed at each reporting date. ECLs are a probability-weighted estimate of all possible default events related to the financial asset (over the lifetime or within 12 months after the reporting period, as applicable) and are measured as the difference between the present value of the cash flows due to Crew and the cash flows the Company expects to receive. In making an assessment as to whether financial assets are credit-impaired, the Company considers historically realized bad debts, evidence of a debtor's present financial condition and whether a debtor has breached certain contracts, the probability that a debtor will enter bankruptcy or other financial reorganization, changes in economic conditions that correlate to increased levels of default, the number of days a debtor is past due in making a contractual payment, and the term to maturity of the specified receivable. The carrying amounts of financial assets are reduced by the amount of the ECL through an allowance account and losses are recognized in the statements of income.

Individually significant financial assets are tested for impairment on an individual basis. The remaining financial assets are assessed collectively in groups that share similar credit risk characteristics.

All impairment losses are recognized in the statements of income. An impairment loss is reversed if the reversal can be related objectively to an event occurring after the impairment loss was recognized.

(ii) Non-financial assets:

The carrying amounts of the Company's non-financial assets are reviewed at each reporting date to determine whether there are any internal or external indicators of impairment or impairment reversal. If any such indicator exists, then the recoverable amount is estimated.

For the purpose of impairment testing, assets are grouped together into the smallest group of assets that generate cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets or CGUs. The estimated recoverable amount of an asset or a CGU is the greater of its value in use and its fair value less costs to sell.

Impairment reversals are recognized to the extent that impairment had been previously recorded, but are limited to the net book value that would exist had the original impairment never been recorded, including estimates for depletion.

The estimated recoverable amount involves significant estimates including the estimate of proved and probable oil and gas reserves and the related cash flows, the discount rates and the sales value of the undeveloped lands. The estimate of proved and probable oil and gas reserves and the related cash flows is sensitive to the significant assumptions regarding forecasted oil and gas commodity prices, forecasted production, forecasted operating costs, forecasted royalty costs and forecasted future development costs.

In assessing the value in use, the estimated future cash flows from proved and probable oil and gas reserves are discounted to their present value using a pre-tax discount rate that reflects current market assessment of the time value of money. Fair value is determined as the amount that would be obtained from the sale of the asset in an arm's length transaction between knowledgeable and willing parties. The forecasted oil and gas commodity prices used in the impairment test are based on period-end forecasted oil and gas commodity prices estimated by the Company's independent third party reserve evaluators. The Company also estimates the sales value of undeveloped lands which is based on relevant industry sales value data.

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses are recognized in the statements of income.

An impairment loss in respect of property, plant and equipment, recognized in prior years, is assessed at each reporting date for any internal or external indications that the loss has decreased or no longer exists. An impairment loss is reversed if there has been a change in the estimates used to determine the recoverable amount. An impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depletion and depreciation or amortization, if no impairment loss had been recognized.

(g) Share based payments:

The grant date fair value of restricted and performance awards granted to employees is recognized as compensation expense, with a corresponding increase in contributed surplus over the vesting period. A forfeiture rate is estimated on the grant date and is adjusted to reflect the actual number of restricted and performance awards that are expected to vest. A performance multiplier is estimated on the grant date for performance awards and adjusted to reflect the number of performance awards that are expected to vest.

(h) Provisions:

A provision is recognized if, as a result of a past event, the Company has a present legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are determined by discounting the expected future cash flows at a pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the liability. Provisions are not recognized for future operating losses.

(i) Decommissioning obligations:

The Company's activities give rise to dismantling, decommissioning and site disturbance remediation activities. Provision is made for the estimated cost of site restoration and capitalized in the relevant asset category.

Decommissioning obligations are measured at the present value of management's best estimate of expenditure required to settle the present obligation at the statement of financial position date. Subsequent to the initial measurement, the obligation is adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation. The increase in the provision due to the passage of time is recognized as a finance cost whereas increases/decreases due to changes in the estimated future cash flows are capitalized. Actual costs incurred upon settlement of the decommissioning obligations are charged against the provision to the extent the provision was established.

(i) Revenue:

Revenue from the sale of crude oil, natural gas, condensate and natural gas liquids is recorded when control of the product is transferred to the buyer based on the consideration specified in the contracts with customers. This usually occurs when the product is physically transferred at the delivery point agreed upon in the contract and legal title to the product passes to the customer.

The Company evaluates its arrangements with third parties and partners to determine if the Company acts as the principal or as an agent. In making this evaluation, the Company considers if it obtains control of the product delivered or services provided, which is indicated by the Company having the primary responsibility for the delivery of the product or rendering of the service, having the ability to establish prices or having inventory risk. If the Company acts in the capacity of an agent rather than as a principal in a transaction, then the revenue is recognized on a net-basis, only reflecting the fee, if any, realized by the Company from the transaction.

Tariffs, tolls and other fees charged to other entities for use of pipelines and facilities owned by the Company are evaluated by management to determine if these originate from contracts with customers or from incidental or collaborative arrangements. Fees charged to other entities that are from contracts with customers are recognized in revenue when the related services are provided.

Royalty income is recognized as it accrues in accordance with the terms of the overriding royalty agreements.

(j) Finance income and expenses:

Finance expense comprises interest expense on borrowings, accretion of the discount on provisions, accretion of deferred financing costs, impairment losses recognized on financial assets and corporate acquisition costs.

Borrowing costs incurred for the construction of qualifying assets are capitalized during the period of time that is required to complete and prepare the assets for their intended use or sale. All other borrowing costs are recognized in the statements of income using the effective interest method. The capitalization rate used to determine the amount of borrowing costs to be capitalized is the weighted average interest rate applicable to the Company's outstanding borrowings during the period.

Interest income is recognized as it accrues in the statements of income, using the effective interest method.

(k) Income tax:

Income tax expense comprises current and deferred tax. Income tax expense is recognized in the statements of income except to the extent that it relates to items recognized directly in equity, in which case it is recognized in equity.

Current tax is the expected tax payable on the taxable income for the year, using tax rates enacted or substantively enacted at the reporting date, and any adjustment to tax payable in respect of previous years.

Deferred tax is recognized using the balance sheet method, providing for temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Deferred tax is not recognized on the initial recognition of assets or liabilities in a transaction that is not a business combination. In addition, deferred tax is not recognized for taxable temporary differences arising on the initial recognition of goodwill. Deferred tax is measured at the tax rates that are expected to be applied to temporary differences when they reverse, based on the laws that have been enacted or substantively enacted by the reporting date. Deferred tax assets and liabilities are offset if there is a legally enforceable right to offset, and they relate to income taxes levied by the same tax authority on the same taxable entity, or on different tax entities, but they intend to settle current tax liabilities and assets on a net basis or their tax assets and liabilities will be realized simultaneously.

A deferred tax asset is recognized to the extent that it is probable that future taxable profits will be available against which the temporary difference can be utilized. Deferred tax assets are reviewed at each reporting date and are reduced to the extent that it is no longer probable that the related tax benefit will be realized.

(l) Earnings per share:

Basic earnings per share is calculated by dividing the profit or loss attributable to common shareholders of the Company by the weighted average number of common shares outstanding during the period. Diluted earnings per share is determined by adjusting the profit or loss attributable to common shareholders and the weighted average number of common shares outstanding for the effects of dilutive instruments such as restricted and performance awards granted to employees.

(m) Inventory:

The Company evaluates the carrying value of its inventory at the lower of cost and net realizable value. The net realizable value is estimated based on anticipated current market prices that the Company would expect to receive from the sale of its inventory.

(n) Government grants:

Government grants are recognized when there is reasonable assurance that the grant will be received and all attached conditions will be met. If a grant is received but compliance with any attached condition is not achieved, the grant is recognized as a deferred liability until such conditions are fulfilled. When the grant relates to an income or expense item, it is recognized as income or a reduction of the related expense item in the period in which the income is earned or costs are incurred. Where the grant relates to an asset, it is recognized as a reduction to the net book value of the related asset and then subsequently in the statements of income over the expected useful life of the related asset through lower charges to impairment and/or depletion and depreciation.

(o) Critical accounting judgments and key sources of estimation uncertainty:

The timely preparation of the financial statements requires management to make judgments, estimates and assumptions that affect the application of accounting policies and reported amounts of assets and liabilities and income and expenses. Accordingly, actual results may differ from these estimates. Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which the estimates are revised and in any future periods affected. Significant estimates and judgments made by management in the preparation of these financial statements are outlined below.

Critical judgments in applying accounting policies:

The following are the critical judgments that management has made in the process of applying the Company's accounting policies and that have the most significant effect on the amounts recognized in these consolidated financial statements:

(i) Identification of CGUs

Crew's assets are aggregated into CGUs, for the purpose of calculating impairment, based on their ability to generate largely independent cash flows. By their nature, these estimates and assumptions are subject to measurement uncertainty and may impact the carrying value of the Company's assets in future periods.

(ii) Impairment of petroleum and natural gas assets

Judgments are required to assess when internal or external indicators of impairment or impairment reversal exist and impairment testing is required. Management considers internal and external sources of information including forecasted oil and gas commodity prices, expected production volumes, anticipated recoverable quantities of proved and probable oil and gas reserves and rates used to discount the related future cash flow estimates. Judgement is required to assess these factors when determining if the carrying amount of an asset or CGU is impaired, or in the case of a previously impaired asset or CGU, whether the carrying amount of the asset or CGU has been restored.

(iii) Deferred income taxes

Judgments are made by management to determine the likelihood of whether deferred income tax assets at the end of the reporting period will be realized from future taxable earnings. To the extent that assumptions regarding future profitability change, there can be an increase or decrease in the amounts recognized in respect of deferred tax assets as well as the amounts recognized in the statements of income in the period in which the change occurs.

(iv) Leased assets

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

Key sources of estimation uncertainty:

The following are the key assumptions concerning the sources of estimation uncertainty at the end of the reporting period, that have a significant risk of causing adjustments to the carrying amounts of assets and liabilities.

(i) Reserves

Reported recoverable quantities of proved and probable oil and gas reserves and the related cash flows requires estimation and are subject to assumptions regarding forecasted production profile, forecasted oil and gas commodity prices, forecasted operating costs, forecasted royalty costs and forecasted future development costs. It also requires interpretation of geological and geophysical models in order to make an assessment of the size, shape, depth and quality of reservoirs, and their anticipated recoveries. The economical, geological and technical factors used to estimate proved and probable oil and gas reserves may change from period to period. Changes in reported proved and probable oil and gas reserves can impact the carrying values of the Company's property, plant and equipment, the calculation of depletion and depreciation, the provision for decommissioning obligations, and the recognition of deferred tax assets due to changes in expected future cash flows. The estimated recoverable quantities of proved and probable oil and gas reserves and the related cash flows from the Company's property, plant and equipment are evaluated by independent third party reserve evaluators at least annually. The Company's proved and probable oil and gas reserves represent the estimated quantities of oil, natural gas and NGLs which geological, geophysical and engineering data demonstrate with a specified degree of certainty to be economically recoverable in future years from known reservoirs and which are considered commercially producible. Such proved and probable oil and gas reserves may be considered commercially producible if management has the intention of developing and producing them and such intention is based upon (i) a reasonable assessment of the future economics of such production; (ii) a reasonable expectation that there is a market for all or substantially all the expected petroleum and natural gas production; and (iii) evidence that the necessary production, transmission and transportation facilities are available or can be made available. Reserves may only be considered proved and probable if producibility is supported by either production or conclusive formation tests. Crew's proved and probable oil and gas reserves are determined in accordance with the standards contained in National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities and the Canadian Oil and Gas Evaluation Handbook.

The Company is also required to estimate the sales value of undeveloped lands, which is based on industry sales value data.

(ii) Decommissioning obligations

The Company estimates future remediation costs of production facilities, wells and pipelines at different stages of development and construction of assets or facilities. In most instances, removal of assets occurs many years into the future. This requires assumptions regarding abandonment date, future environmental and regulatory legislation, the extent of reclamation activities, the engineering methodology for estimating cost, future removal technologies in determining the removal cost and liability-specific discount rates to determine the present value of these cash flows.

(iii) Business combinations

In a business combination, management makes estimates of the fair value of assets acquired and liabilities assumed which includes assessing the value of oil and gas properties based upon the estimation of recoverable quantities of proved and probable oil and gas reserves being acquired.

(iv) Share-based payments

All equity-settled, share-based awards issued by the Company are recorded at fair value. The fair value of restricted and performance awards are valued based on the closing stock price at grant date. In assessing the fair value of equity-based compensation, estimates have to be made regarding the performance multiplier for performance awards.

(v) Income taxes

Tax provisions are based on enacted or substantively enacted laws. Changes in those laws could affect amounts recognized in the statements of income both in the period of change, which would include any impact on cumulative provisions, and in future periods. Deferred tax assets, if any, are recognized only to the extent it is considered probable that those assets will be recoverable. This involves an assessment of when those deferred tax assets are likely to reverse.

(vi) Derivatives

The Company's estimate of the fair value of derivative financial instruments is dependent on estimate forward prices and volatility in those prices.

5. Determination of fair values:

A number of the Company's accounting policies and disclosures require the determination of fair value, for both financial and non-financial assets and liabilities. Fair values have been determined for measurement and/or disclosure purposes based on the following methods. When applicable, further information about the assumptions made in determining fair values is disclosed in the notes specific to that asset or liability.

(i) Property, plant and equipment and exploration assets:

The fair value of property, plant and equipment recognized in an acquisition is based on market values. The market value of property, plant and equipment is the estimated amount for which property, plant and equipment could be exchanged on the acquisition date between a willing buyer and a willing seller in an arm's length transaction after proper marketing wherein the parties had each acted knowledgeably, prudently and without compulsion. The market value of oil and natural gas interests (included in property, plant and equipment) and intangible exploration assets is estimated with reference to the discounted cash flows expected to be derived from oil and natural gas production estimated by the Company's independent third party reserve evaluators. The risk-adjusted discount rate is specific to the asset with reference to general market conditions.

The market value of other items of property, plant and equipment is based on the quoted market prices for similar items.

(ii) Cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities, bank loans and the senior unsecured notes:

The fair value of cash and cash equivalents, accounts receivable, accounts payable, bank loans and the senior unsecured notes are estimated as the present value of future cash flows, discounted at the market rate of interest at the reporting date. At December 31, 2020 and December 31, 2019, the fair value of accounts receivable and accounts payable approximated their carrying value due to their short term to maturity. Bank loans bear a floating rate of interest and the margins charged by the lenders are indicative of current credit spreads and therefore carrying value approximates fair value. The fair value of the senior unsecured notes fluctuates in response to changes in the market rates of interest payable on similar instruments. At December 31, 2020, the carrying value of the unsecured notes made up 120% of the approximated fair value.

(iii) Derivatives:

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 statement of financial position date, using the remaining contracted volumes and a credit adjusted interest rate. 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.

(iv) Restricted and performance awards:

The fair value of restricted and performance awards is measured at the grant date using the closing price of the common shares.

6. Financial risk management:

The Company's activities expose it to a variety of financial risks that arise as a result of its exploration, development, production, and financing activities such as:

- Credit risk;
- Market risk; and
- Liquidity risk.

This note presents information about the Company's exposure to each of the above risks, the Company's objectives, policies and processes for measuring and managing risk and the Company's management of capital. Further quantitative disclosures are included throughout these financial statements.

The Board of Directors oversees management's establishment and execution of the Company's risk management framework. Management has implemented and monitors compliance with risk management policies. The Company's risk management policies are established to identify and analyze the risks faced by the Company, to set appropriate risk limits and controls, and to monitor risks and adherence to market conditions and the Company's activities.

(a) Credit risk:

Credit risk is the risk of financial loss to the Company if a customer or counterparty to a financial instrument fails to meet its contractual obligations and arises principally from the Company's receivables from partners within jointly owned assets and operations, oil and natural gas marketers and counterparties to derivative financial assets. The maximum exposure to credit risk at year-end is as follows:

	December 31, 2020	December 31, 2019
Trade and other receivables	**$ 22,135**	$ 26,994
Derivative financial assets	**4,718**	3,180
	$ 26,853	$ 30,174

Trade and other receivables:

Substantially all of the Company's petroleum and natural gas production is marketed under standard industry terms. Receivables from petroleum and natural gas marketers are normally collected on the 25th day of the month following production. The Company's policy to mitigate credit risk associated with these balances is to establish marketing relationships with large credit worthy purchasers and to sell through multiple purchasers. During 2020, the Company had three customers that individually accounted for 10% or more of the Company's total revenues. The Company historically has not experienced any collection issues with its petroleum and natural gas marketers. Receivables from partners within jointly owned assets and operations are typically collected within one to three months of the bill being issued to the partner. The Company attempts to mitigate the risk from these receivables by obtaining partner approval of significant capital expenditures prior to the expenditure. However, the receivables are from participants in the petroleum and natural gas sector and collection of the outstanding balances can be impacted by industry factors such as commodity price fluctuations, limited capital availability and unsuccessful drilling programs. The Company does not typically obtain collateral from petroleum and natural gas marketers or joint asset partners; however, the Company can cash call for major projects and does have the ability, in some cases, to withhold production from joint asset partners in the event of non-payment.

Derivative financial assets:

Derivative financial assets can consist of commodity, interest rate and foreign exchange contracts used to manage the Company's exposure to fluctuations in commodity prices, interest rates and the exchange rate between United States and Canadian dollars. The Company manages the credit risk exposure related to derivative financial assets by selecting investment grade counterparties and by not entering into contracts for trading or speculative purposes.

The carrying amount of accounts receivable and derivative financial assets, when outstanding, represents the maximum credit exposure. As at December 31, 2020, the Company's receivables consisted of $18.5 million (December 31, 2019 - $19.7 million) of receivables from petroleum and natural gas marketers, of which all have been subsequently collected, $0.4 million (December 31, 2019 - $0.6 million) from partners with jointly owned assets and operations, none of which has been subsequently collected, and $3.2 million (December 31, 2019 - $6.7 million) of deposits, prepaids and other accounts receivable, which includes a $0.8 million (December 31, 2019 - $5.0 million) receivable for a Government of British Columbia infrastructure credit earned through the completion of a pipeline connecting the West Septimus processing facility to the TC Energy Saturn meter station. The Company does not consider any of its receivables to be past due.

(b) Market risk:

Market risk is the risk that changes in market conditions, such as commodity prices, foreign exchange rates and interest rates, will affect the Company's cash flow, income or the value of financial instruments. The objective of market risk management is to manage and control market risk exposures within acceptable parameters, while maximizing the Company's return.

The Company utilizes both financial derivatives and physical delivery sales contracts to manage market risks. All such transactions are conducted in accordance with the Company's risk management policy that has been approved by the Board of Directors.

Foreign currency exchange rate risk:

Foreign currency exchange rate risk is the risk that the fair value of future cash flows will fluctuate as a result of changes in foreign exchange rates. The majority of the Company's petroleum and natural gas sales are conducted in Canada and are denominated in Canadian dollars; however, Canadian commodity prices are influenced by fluctuations in the Canadian to U.S. dollar exchange rate.

Interest rate risk:

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. The Company is exposed to interest rate fluctuations on its bank loan which bears a floating rate of interest. Average bank debt outstanding during the year ending December 31, 2020 was $35.1 million (December 31, 2019 - $52.2 million). For the year ended December 31, 2020, a 1.0 percent change to the effective interest rate would have had a $0.4 million impact on net loss (December 31, 2019 - $0.5 million). The interest rate on the senior unsecured notes is fixed and is not subject to interest rate risk.

Commodity price risk:

Commodity price risk is the risk that future cash flows will fluctuate as a result of changes in commodity prices. Commodity prices for petroleum and natural gas are impacted by not only the relationship between the Canadian and United States dollar, but also regional, North American and global economic events that dictate the levels of crude oil, natural gas and natural gas liquids supply and demand. The Company has attempted to mitigate a portion of the commodity price risk through the use of a diversified portfolio of market pricing points and the use of various financial derivative and physical delivery sales contracts as outlined below. The Company's policy is to only enter into commodity price contracts when considered appropriate to a maximum of 60% of forecasted gross production volumes for a period of not more than two years. Any contracts for volumes greater than 60% of forecasted gross production or extending beyond two years require approval from the Board of Directors.

Derivative assets:

Derivatives are recorded on the statement of financial position at fair value at each reporting period with the change in fair value being recognized as an unrealized gain or loss on the statements of income.

The Company's derivatives are measured in accordance with a three level hierarchy. The hierarchy groups financial assets and liabilities into three levels based on the significance of inputs used in measuring the fair value of the financial assets and liabilities. The fair value hierarchy has the following levels:

a) Level 1: fair value is based on quoted prices (unadjusted) in active markets for identical assets or liabilities;

b) Level 2: fair value is based on inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly (ie. as prices) or indirectly (ie. derived from prices); and

c) Level 3: fair value is based on inputs for the asset or liability that are not based on observable market data (unobservable inputs).

The Company's derivative contracts are valued using Level 2 of the hierarchy.

At December 31, 2020, the Company held derivative commodity contracts as follows:

Notional Quantity	Term	Strike Price	Option Traded	Fair Value
Natural Gas – AECO Daily Index:				
27,500 gj/day	January 1, 2021 - March 31, 2021	$2.53/gj	Swap	$ 177
2,500 gj/day	April 1, 2021 - October 31, 2021	$2.35/gj	Swap	55
5,000 gj/day	January 1, 2021 - December 31, 2021	$2.66/gj	Swap	570
21,500 gj/day	April 1, 2021 - June 30, 2021	$2.16/gj	Swap	(17)
19,000 gj/day	July 1, 2021 - September 30, 2021	$2.24/gj	Swap	(56)
17,500 gj/day	October 1, 2021 - December 31, 2021	$2.47/gj	Swap	(39)
22,500 gj/day	November 1, 2021 - December 31, 2021	$2.72/gj	Swap	223
15,000 gj/day	November 1, 2021 - March 31, 2022	$2.72/gj	Swap	318
20,000 gj/day	January 1, 2022 - March 31, 2022	$3.05/gj	Swap	688
15,000 gj/day	January 1, 2022 - December 31, 2022	$2.42/gj	Swap	1,195
20,000 gj/day	April 1, 2022 - June 30, 2022	$2.17/gj	Swap	375
5,000 gj/day	April 1, 2022 - October 31, 2022	$2.19/gj	Swap	178
20,000 gj/day	July 1, 2022 - September 30, 2022	$2.20/gj	Swap	366
20,000 gj/day	October 1, 2022 - December 31, 2022	$2.44/gj	Swap	486
Natural Gas – AECO Monthly Index:				
7,500 gj/day	January 1, 2021 - March 31, 2021	$2.53/gj	Swap	46
2,500 gj/day	April 1, 2021 - October 31, 2021	$2.05/gj	Swap	(107)

Notional Quantity	Term	Strike Price	Option Traded	Fair Value
(continued)				
2,500 gj/day	January 1, 2021 - December 31, 2021	$2.50 - $3.00/gj	Collar(1)	241
6,000 gj/day	April 1, 2021 - June 30, 2021	$2.12/gj	Swap	(27)
10,000 gj/day	July 1, 2021 - September 30, 2021	$2.19/gj	Swap	(79)
9,000 gj/day	October 1, 2021 - December 31, 2021	$2.40/gj	Swap	(90)
5,000 gj/day	November 1, 2021 - March 31, 2022	$2.84/gj	Swap	194
5,000 gj/day	November 1, 2021 - March 31, 2022	$2.65 - $2.95/gj	Collar(2)	132
10,000 gj/day	January 1, 2022 - March 31, 2022	$3.09/gj	Swap	448
2,500 gj/day	January 1, 2022 - March 31, 2022	$2.75 - $3.20/gj	Collar(3)	68
7,500 gj/day	January 1, 2022 - December 31, 2022	$2.36/gj	Swap	431
10,000 gj/day	April 1, 2022 - June 30, 2022	$2.20/gj	Swap	183
10,000 gj/day	July 1, 2022 - September 30, 2022	$2.22/gj	Swap	176
10,000 gj/day	October 1, 2022 - December 31, 2022	$2.48gj	Swap	274
Natural Gas – CDN$ Chicago Citygate Daily:				
17,500 mmbtu/day	January 1, 2021 - October 31, 2021	$3.47/mmbtu	Swap	1,896
Natural Gas – CDN$ Chicago Citygate Monthly:				
7,500 mmbtu/day	January 1, 2021 - October 31, 2021	$3.49/mmbtu	Swap	917
Crude Oil – CDN$ WTI:				
250 bbl/day	January 1, 2021 - June 30, 2021	$59.00/bbl	Swap	(127)
Crude Oil – CDN$ WCS:				
500 bbl/day	January 1, 2021 - June 30, 2021	$43.03/bbl	Swap	(36)
CDN$ Edmonton C5 Blended Index:				
1,500 bbl/day	January 1, 2021 - June 30, 2021	$56.82/bbl	Swap	(1,376)
Total				**$ 7,683**

(1) The referenced contract is a costless collar whereby the Company receives $2.50/gj when the market price is below $2.50/gj, and receives $3.00/gj when the market price is above $3.00/gj.

(2) The referenced contract is a costless collar whereby the Company receives $2.65/gj when the market price is below $2.65/gj, and receives $2.95/gj when the market price is above $2.95/gj.

(3) The referenced contract is a costless collar whereby the Company receives $2.75/gj when the market price is below $2.75/gj, and receives $3.20/gj when the market price is above $3.20/gj.

As at December 31, 2020, a 10% change in future commodity prices applied against these contracts would have a $10.5 million (December 31, 2019 – $3.9 million) impact on net (loss) income.

Subsequent to December 31, 2020, the Company entered into the following derivative commodity contracts:

Notional Quantity	Term	Strike Price	Option Traded
Natural Gas – AECO Daily Index:			
2,500 gj/day	February 1, 2021 - December 31, 2021	$2.43/gj	Swap
Natural Gas – AECO Monthly Index:			
2,500 gj/day	February 1, 2021 - December 31, 2021	$2.45/gj	Swap
10,000 gj/day	March 1, 2021 - December 31, 2021	$2.50 - $2.81/gj	Collar(1)
Crude Oil – CDN$ WCS:			
250 bbl/day	February 1, 2021 - December 31, 2021	$44.00/bbl	Swap
250 bbl/day	July 1, 2021 - December 31, 2021	$47.75/bbl	Swap
CDN$ Edmonton C5 Blended Index:			
250 bbl/day	February 1, 2021 - December 31, 2021	$60.85/bbl	Swap
250 bbl/day	April 1, 2021 - June 30, 2021	$81.25/bbl	Swap
1,250 bbl/day	July 1, 2021 - December 31, 2021	$61.32/bbl	Swap

(1) The referenced contract is a costless collar whereby the Company receives $2.50/gj when the market price is below $2.50/gj, and receives $2.81/gj when the market price is above $2.81/gj.

(c) Liquidity risk:

Liquidity risk is the risk that the Company will encounter difficulty in meeting obligations associated with the financial liabilities. The Company's financial liabilities consist of accounts payable, financial instruments, the bank loan and the senior unsecured notes and lease obligations. Accounts payable and accrued liabilities consists of invoices payable to trade suppliers for office, field operating activities and capital expenditures. The Company processes invoices within a normal payment period. Accounts payable and financial instruments have contractual maturities of less than one year. To meet these obligations, the Company maintains a revolving credit facility, as outlined in note 9, which is subject to annual renewal by the lenders and has a contractual maturity in 2022 if not extended. The Company maintains and monitors cash flow which is used to partially finance operating and capital expenditures. The Company does not pay dividends. In addition, the Company issued $300 million in senior unsecured notes in 2017 that are scheduled to mature in 2024, as discussed in note 10.

Capital management:

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

With only 24% drawn on the Company's $150 million Facility and the senior unsecured notes termed out to 2024, the Company's financial position remains strong, with sufficient liquidity to fund the Company's on-going operations. The Company will continue to monitor debt levels and, if necessary, it will consider divesting of non-core properties, adjust its annual capital expenditure program or may consider other forms of financing to improve its financial position.

Net debt:

Capital Management includes the monitoring of net debt as part of the Company's capital structure.

The following table outline Crew's calculation of net debt:

	December 31, 2020	December 31, 2019
Current assets	**$ 26,853**	$ 50,019
Current liabilities	**(47,212)**	(46,690)
Derivative financial instruments	**(4,002)**	(3,180)
Working capital (deficiency) surplus	**(24,361)**	149
Bank loan	**(35,994)**	(52,136)
Senior unsecured notes	**(296,851)**	(295,868)
Net debt	**$ (357,206)**	$ (347,855)

Neither the Company nor any of its subsidiaries are subject to externally imposed capital requirements. The bank loan is subject to a semi-annual review of its Borrowing Base, which is directly impacted by the value of the Company's oil and natural gas reserves (Bank loan – note 9).

Funds from operations and adjusted funds flow:

One of the benchmarks Crew uses to evaluate its capital management is funds from operations and adjusted funds flow. Funds from operations represents cash provided by operating activities before changes in operating non-cash working capital and accretion of deferred financing costs. Adjusted funds flow represents funds from operations before decommissioning obligations settled. The Company considers these metrics as key measures that demonstrate the ability of the Company's continuing operations to generate the cash flow necessary to maintain production at current levels and fund future growth through capital investment and to service and repay debt. Management believes that such measures provide an insightful assessment of the Company's operations on a continuing basis by eliminating certain non-cash charges and actual settlements of decommissioning obligations, the timing of which is discretionary.

	Year ended December 31, 2020	Year ended December 31, 2019
Cash provided by operating activities	**$ 37,989**	$ 81,395
Change in operating on-cash working capital	**2,170**	(3,297)
Accretion of deferred financing costs	**(983)**	(983)
Funds from operations	**39,176**	77,115
Decommissioning obligations settled excluding grants (note 12)	**1,974**	3,919
Adjusted funds flow	**$ 41,150**	$ 81,034

7. Property, plant and equipment:

Cost	Total
Balance, January 1, 2019	$ 2,523,981
Additions	114,094
Acquisitions	1,570
Increase in right-of-use assets	3,974
Transfer to assets held for sale	(21,824)
Divestitures	(1,300)
Change in decommissioning obligations	686
Capitalized share-based compensation	4,897
Balance, December 31, 2019	$ 2,626,078
Additions	86,260
Acquisitions	13,019
Divestitures	(16,061)
Change in decommissioning obligations	8,512
Capitalized share-based compensation	2,186
Balance, December 31, 2020	**$ 2,719,994**

Accumulated depletion and depreciation	Total
Balance, January 1, 2019	$ 1,150,962
Depletion and depreciation expense	75,776
Divestitures	(309)
Transfer to assets held for sale	(1,979)
Balance, December 31, 2019	$1,224,450
Depletion and depreciation expense	71,054
Divestitures	(1,876)
Impairment	267,334
Balance, December 31, 2020	**$ 1,560,962**

Net book value	Total
Balance, December 31, 2020	**$ 1,159,032**
Balance, December 31, 2019	$ 1,401,628

The calculation of depletion for the three months ended December 31, 2020 included estimated future development costs of $1,616.0 million (December 31, 2019 - $1,787.2 million) associated with the development of the Company's proved plus probable oil and gas reserves and excludes salvage value of $70.5 million (December 31, 2019 - $70.6 million) and undeveloped land of $148.0 million (December 31, 2019 - $155.7 million) related to future development acreage, with no associated reserves.

Included in depletion and depreciation expense for the twelve months ended December 31, 2020, is $0.4 million (December 31, 2019 - $0.9 million) related to the right-of-use assets for the Company's leases. As at December 31, 2020, the net book value of these right-of-use assets is $2.6 million (December 31, 2019 - $3.0 million).

During the first quarter of 2020, the Company disposed of an 11% net working interest in each of its Septimus gas processing facility and West Septimus gas processing facility ("Greater Septimus Processing Complex") located in Northeast British Columbia for net proceeds of $34.8 million, after transaction costs. This interest in the facilities was classified as held for sale as at December 31, 2019, with a net book value of $19.8 million and associated decommissioning obligations of $0.7 million, resulting in a gain of $15.7 million.

During the fourth quarter of 2020, the Company disposed of an additional 11% net working interest in its Greater Septimus Processing Complex for net proceeds of $34.9 million, after transaction costs. This interest in the facilities had a net book value of $13.0 million and associated decommissioning obligations of $0.9 million, resulting in a gain of $22.8 million. In an unrelated transaction, the Company exercised and closed its option with another third party for the acquisition of an approximate 16% interest in the Greater Septimus Processing Complex for $11.7 million.

8. Impairment:

	Year Ended December 31, 2020	Year Ended December 31, 2019
Impairment losses:		
property, plant and equipment	**$ 267,334**	$ -
	$ 267,334	$ -

2020 assessment:

At December 31, 2020, due to strengthening commodity prices, the Company completed an assessment of the indicators of reversal of impairment, and as a result tested its northeast British Columbia CGU and Lloydminster CGU for impairment reversal. It was determined that the recoverable amounts of the northeast British Columbia CGU and Lloydminster CGU approximated their carrying value and impairment reversal was not recorded.

The following forecasted oil and gas commodity prices were used in determining the estimated recoverable amount of the Company's CGUs at December 31, 2020:

	WTI Oil (US$/bbl)(1)	WCS ($CDN/bbl)(1)	AECO Gas ($CDN/mmbtu)(1)	$US/$CDN
2021	46.88	44.19	2.75	0.77
2022	51.14	48.55	2.70	0.77
2023	54.83	52.90	2.65	0.77
2024	56.48	54.68	2.69	0.77
2025	57.62	55.78	2.74	0.77
2026	58.77	56.89	2.79	0.77
2027	59.94	58.03	2.86	0.77
2028	61.14	59.19	2.91	0.77
2029	62.36	60.37	2.97	0.77
2030	63.60	61.57	3.02	0.77
Remainder	+2.0%/yr	+2.0%/yr	+2.0%/yr	0.77 thereafter

(1) Source: 4 Consultants' average, GLJ Petroleum Consultants, McDaniel & Associates Consultants, Sproule Associates and Deloitte Resource Evaluation & Advisory price forecasts, effective January 1, 2021.

At December 31, 2020, the Company used value in use, discounted at pre-tax rates between 10% and 30% (December 31, 2019 – 10% and 30%) dependent on the risk profile of the reserve category and CGU.

The sensitivity analysis below shows the impact that a change in the discount rate or forecasted oil and gas commodity prices would have on impairment reversal testing for each CGU as at December 31, 2020:

	Discount Rate		Pricing	
	1% decrease	1% increase	5% decrease	5% increase
Increase (decrease) to CGU recoverable amount	64,647	(58,326)	(111,999)	112,090

Crew's independent third party reserve evaluators also assess many other financial estimates regarding forecasted operating costs, forecasted royalty costs and forecasted future development costs along with several other non-financial assumptions that affect reserve volumes. Crew has considered these assumptions for the impairment test at December 31, 2020, however, it should be noted that all estimates are subject to uncertainty.

At March 31, 2020, the Company determined that indicators of impairment existed as a result of; the COVID-19 pandemic and its impact on global commodity demand due to the measures taken to limit the spread of the pandemic, the rapid fall in crude oil prices due to increased supply brought on by a price war between OPEC and non-OPEC members and the impact that these events had on the Company's equity and debt values. As a result, the Company tested its northeast British Columbia CGU and Lloydminster CGU for impairment. It was determined that the carrying value of the northeast British Columbia CGU and Lloydminster CGU exceeded their estimated recoverable amounts and impairment charges of $237.5 million and $29.8 million, respectively, were recorded for the CGUs.

2019 assessment:

At December 31, 2019, due to weakness in the Canadian commodity price environment and the depressed share price of the Company, the Company tested its northeast British Columbia CGU and Lloydminster CGU for impairment. It was determined that the recoverable amount of the northeast British Columbia CGU and Lloydminster CGU exceeded their carrying value and an impairment charge was not recorded.

The following estimates were used in determining whether an impairment or reversal to the carrying value of the CGU existed at December 31, 2019:

	WTI Oil (US$/bbl)	WCS ($CDN/bbl)	AECO Gas ($CDN/mmbtu)	$US/$CDN
2020	61.00	59.81	2.04	0.76
2021	65.00	63.98	2.27	0.77
2022	67.00	63.77	2.81	0.80
2023	68.34	65.04	2.89	0.80
2024	69.71	66.34	2.98	0.80
2025	71.10	67.67	3.06	0.80
2026	72.52	69.02	3.15	0.80
2027	73.97	70.40	3.24	0.80
2028	75.45	71.81	3.33	0.80
2029	76.96	73.25	3.42	0.80
2030	78.50	74.71	3.51	0.80
Remainder	+2.0%/yr	+2.0%/yr	+2.0%/yr	0.80 thereafter

9. Bank loan:

As at December 31, 2020, the Company's bank facility consists of a revolving line of credit of $125 million and an operating line of credit of $25 million (the "Facility"). The Facility revolves for a 364 day period and will be subject to its next 364 day extension by June 4, 2021. 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 Facility requires the Company to maintain a Liability Management Rating ("LMR") of greater than 1.2:1 in the provinces of Alberta and Saskatchewan, and greater than 2.0:1 in the province of British Columbia, if the uninflated, undiscounted abandonment and reclamation liabilities ("Decommissioning Obligations"), as determined by the individual province, is greater than $20 million. If the LMR falls below the required level in any province, the lenders have the option to re-determine the Borrowing Base. As at December 31, 2020, the Company's Decommissioning Obligations exceeded $20 million in the province of British Columbia, which carried an LMR of 7.3:1. There can be no assurance that the amount of the available Facility will not be adjusted at the next scheduled Borrowing Base review on or before June 4, 2021. The Facility is secured by a floating charge debenture and a general securities agreement on all the assets of the Company.

Advances under the Facility are available by way of prime rate loans with interest rates between 2.00 percent and 5.50 percent over the bank's prime lending rate and bankers' acceptances and LIBOR loans, which are subject to stamping fees and margins ranging from 3.00 percent to 6.50 percent depending upon the secured 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

0.75 percent to 1.63 percent depending upon the secured debt to EBITDA ratio. As at December 31, 2020, the Company's applicable pricing included a 2.00 percent margin on prime lending, a 3.00 percent stamping fee and margin on bankers' acceptances and LIBOR loans along with a 0.75 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 December 31, 2020, the Company had issued letters of credit totaling $9.4 million (December 31, 2019 - $11.4 million).

10. 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.

The Company may redeem, on any one or more occasions, all or part of the 2024 Notes at the redemption prices set forth below, plus any accrued and unpaid interest:

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

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

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

At December 31, 2020, the carrying value of the 2024 Notes was net of deferred financing costs of $3.1 million (December 31, 2019 – $4.1 million).

11. Lease obligations:

	As at December 31, 2020	As at December 31, 2019
Less than 1 year	**$ -**	$ 290
1 – 3 years	**974**	244
After 3 years	**2,117**	2,847
Total undiscounted future lease payments	**$ 3,091**	$ 3,381
Total undiscounted future interest payments	**(382)**	(485)
Present value of lease obligations	**$ 2,709**	$ 2,896
Current portion of lease obligations, included in accounts payable and accrued liabilities	**105**	(188)
Long-term portion of lease obligations	**$ 2,814**	$ 2,708

	Year ended December 31, 2020	Year ended December 31, 2019
Principal payments	**$ 187**	$ 1,071
Interest payments	**102**	100
Total cash outflow	**$ 289**	$ 1,171

The Company's total undiscounted future lease payments of $3.1 million (December 31, 2019 – $3.4 million) equate to future lease obligations. This amount excludes commitments for firm transportation and processing agreements, as disclosed in note 15, as they do not meet the definition of a lease as the Company does not control the asset or receive substantially all of the asset's economic benefits.

12. Decommissioning obligations:

	As at December 31, 2020	As at December 31, 2019
Decommissioning obligations, beginning of year	**$ 87,024**	$ 89,448
Obligations incurred	**2,275**	3,481
Obligations acquired	**1,229**	-
Obligations settled	**(3,115)**	(3,919)
Obligations divested	**(1,693)**	(351)
Change in estimated future cash outflows	**6,237**	(2,795)
Accretion of decommissioning obligations	**1,221**	1,901
Transferred to liabilities associated with assets held for sale	**-**	(741)
Decommissioning obligations, end of year	**$ 93,178**	$ 87,024

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 $93.2 million as at December 31, 2020 (December 31, 2019 - $87.0 million) based on an inflation adjusted undiscounted total future liability of $108.6 million (December 31, 2019 - $110.1 million). These payments are expected to be made over the next 40 years with the majority of costs to be incurred between 2024 and 2038. The inflation rate applied to the liability is 1.38% (December 31, 2019 – 1.35%). The discount factor, being the risk-free rate related to the liability, is 1.10% (December 31, 2019 – 1.76%). The $6.2 million (December 31, 2019 - $2.8 million) change in estimated future cash outflows is a result of a change in the inflation rate, discount factor and estimated future abandonment costs.

Included in decommissioning obligations settled is $1.1 million related to government grants earned for well site rehabilitation.

13. Income taxes:

(a) Deferred income tax expense:

The deferred income tax expense in the financial statements differs from the result which would have been obtained by applying the combined federal and provincial income tax rate to the Company's income before income taxes. This difference results from the following items:

	Year ended December 31, 2020	Year ended December 31, 2019
(Loss) income before income taxes	**$ (256,743)**	$ 12,836
Combined federal and provincial income tax rate	**25.35%**	26.70%
Computed "expected" income tax (recovery) expense	**$ (65,084)**	$ 3,431
Increase (decrease) in income taxes resulting from:		
Change in income tax rates	**1,412**	(4,633)
Non-deductible expenses and other	**662**	36
Change in share-based compensation estimate	**353**	1,931
Non-taxable portion of capital gain	**(3,957)**	-
Unrecognized deferred income tax asset	**13,051**	-
Deferred income tax (recovery) expense	**$ (53,563)**	$ 765

During the year ended December 31, 2020, the blended statutory tax rate was 25.4% (2019 – 26.7%). In May 2019, the Alberta government announced that the provincial corporate income tax rate will be reduced from 12% to 8% over a four-year period. Accordingly, the rate was reduced from 12% to 11% effective July 1, 2019 and from 11% to 10% on January 1, 2020. In October 2020, the previously scheduled tax rate reduction was accelerated, with the tax rate reduced to 8% effective July 1, 2020.

(b) Deferred income tax liability:

The components of the Company's deferred income tax liability are as follows:

	December 31, 2020	December 31, 2019
Deferred tax liabilities:		
Property, plant and equipment	**$ 62,811**	$ 144,436
Derivative financial instruments	**1,905**	789
Other	**8,145**	7,369
Deferred tax assets:		
Decommissioning obligations	**$ (23,109)**	$ (21,766)
Non-capital losses	**(49,752)**	(77,265)
Deferred income tax liability	**$ -**	$ 53,563

As at December 31, 2020, the Company did not recognize a deferred income tax asset related to future non-capital losses of $49.9 million due to the uncertainty of future commodity prices and cash flows.

The following tables provide a continuity of the deferred income tax (asset) liability:

	January 1, 2020	Recognized in equity	Recognized in other	Recognized in statements of income	December 31, 2020
Property, plant and equipment	$ 144,436	$ -	$ -	$ (81,625)	$ 62,811
Decommissioning obligations	(21,766)	-	-	(1,343)	(23,109)
Derivative financial instruments	788	-	-	1,117	1,905
Non-capital losses	(77,265)	-	-	27,513	(49,752)
Other	7,370	-	-	775	8,145
	$ 53,563	**$ -**	**$ -**	**$ (53,563)**	**$ -**

	January 1, 2019	Recognized in equity	Recognized in other	Recognized in statements of income	December 31, 2019
Property, plant and equipment	$ 158,926	$ -	$ -	$ (14,490)	$ 144,436
Decommissioning obligations	(24,151)	-	-	2,385	(21,766)
Derivative financial instruments	2,263	-	-	(1,475)	788
Non-capital losses	(90,602)	-	-	13,337	(77,265)
Other	6,362	-	-	1,008	7,370
	$ 52,798	**$ -**	**$ -**	**$ 765**	**$ 53,563**

The Company's assets have an approximate tax basis of $1,105.9 million at December 31, 2020 (December 31, 2019 - $1,101.0 million) available for deduction against future taxable income. The following table summarizes the tax pools:

	December 31, 2020	December 31, 2019
Cumulative Canadian Exploration Expense	**$ 259,200**	$ 293,400
Cumulative Canadian Development Expense	**412,200**	282,900
Undepreciated Capital Costs	**176,500**	202,400
Non-capital losses	**253,200**	311,600
Share issue costs	**1,400**	2,800
Other	**3,400**	7,900
Estimated tax basis	**$ 1,105,900**	$ 1,101,000

Non-capital losses will begin expiring in 2028. The estimated income tax pools for 2020 have been reduced by the estimated deferred partnership income for 2020.

14. Share capital:

At December 31, 2020, the Company was authorized to issue an unlimited number of common shares with the holders of common shares entitled to one vote per share.

Restricted and Performance Award Incentive Plan:

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

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

Subsequent to May 21, 2018, being the third anniversary from the date the Company last obtained approval from shareholders for the continued issuance of common shares from treasury under the RPAP, the Company is no longer eligible to issue common shares from treasury to settle the award value of any RAs and PAs granted subsequent to May 21, 2018. The Company remains eligible to settle the award value for any such grants either in cash or in common shares acquired by an independent trustee in the open market for such purposes. Common shares acquired in the open market are held in trust for the potential future settlement of award values and are netted out of share capital, including the cumulative purchase cost, until they are distributed for future settlements. For the year ended December 31, 2020, the trustee purchased 2,960,000 common shares for a total cost of $1.0 million and as at December 31, 2020, holds 5,267,000 common shares in trust.

Upon the vesting of 1,690,000 RAs and 1,837,000 PAs, when taking into account the earned multipliers for PAs, 177,000 common shares of the Company were issued from treasury, 2,431,000 common shares were released from trust and $0.4 million was paid out in settlement of such awards for the year ended December 31, 2020.

The number of RAs and PAs outstanding are as follows:

	Number of RAs	Number of PAs
Balance January 1, 2019	3,437	4,495
Granted	1,825	2,050
Vested	(1,459)	(2,036)
Forfeited	(190)	(337)
Balance December 31, 2019	3,613	4,172
Granted	2,259	2,407
Vested	(1,690)	(1,837)
Forfeited	(436)	(307)
Balance December 31, 2020	**3,746**	**4,435**

Per share amounts:

Per share amounts have been calculated on the weighted average number of shares outstanding. The weighted average shares outstanding for the year ended December 31, 2020 was 152,145,000 (December 31, 2019 – 151,893,000).

In computing diluted earnings per share, the Company considers the dilutive impact of RAs and PAs. For the year ended December 31, 2020, nil (December 31, 2019 – 38,000) shares were added to the basic weighted average common shares outstanding to account for the dilution as the Company was in a net loss position. There were 8,181,000 (December 31, 2019 – 4,662,000) RAs and PAs that were not included in the diluted earnings per share calculation because they were anti-dilutive.

The volume weighted average trading price of the Company's common shares was $0.34 during the year ended December 31, 2020 (December 31, 2019 - $0.86).

15. Commitments:

	Total	2021	2022	2023	2024	2025	Thereafter
Firm transportation agreements	$ 200,522	$ 40,595	$35,687	$27,438	$26,990	$26,349	$ 43,463
Firm processing agreement	200,177	18,718	18,718	18,718	18,752	18,718	106,553
Total	**$ 400,699**	**$59,313**	**$54,405**	**$46,156**	**$45,742**	**$45,067**	**$ 150,016**

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

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

16. Revenue:

Petroleum and natural gas sales:

Crew sells its production pursuant to fixed or variable-price contracts. The transaction price for variable priced contracts is based on the commodity price, adjusted for quality, location or other factors, whereby each component of the pricing formula can be either fixed or variable, depending on the contract terms. Under the contracts, the Company is required to deliver a fixed or variable volume of crude oil, condensate, other ngl or natural gas to the customer. Revenue is recognized when a unit of production is delivered to the customer. The amount of revenue recognized is based on the agreed transaction price, whereby any variability in revenue relates specifically to the Company's efforts to transfer production, and therefore the resulting revenue is allocated to the production delivered in the period during which the variability occurs. As a result, none of the variable revenue is considered constrained.

Crude oil, condensate and ngl are sold under contracts of varying terms of up to one year. The Company's natural gas is sold through a combination of spot sales, month ahead physical sales, short term and multi-year contracts. Revenues are typically collected on the 25th day of the month following production.

The following table summarizes the Company's petroleum and natural gas sales, all of which are from revenue with contracts with customers:

	Year ended December 31, 2020	Year ended December 31, 2019
Light crude oil	**$ 2,732**	$ 4,993
Heavy crude oil	**14,384**	30,310
Natural gas liquids	**6,827**	5,086
Condensate	**40,646**	63,290
Natural gas	**73,342**	89,853
	$ 137,931	$ 193,532

Marketing and processing revenue:

The following table summarizes the Company's marketing and processing revenue:

	Year ended December 31, 2020	Year ended December 31, 2019
Marketing revenue	**$ (890)**	$ 8,658
Processing revenue	**2,416**	3,090
	$ 1,526	$ 11,748

17. Financing:

	Year ended December 31, 2020	Year ended December 31, 2019
Interest expense	**$ 22,329**	$ 23,516
Gain on lease modification	**-**	(7)
Accretion of deferred financing costs	**983**	983
Accretion of decommissioning obligations	**1,221**	1,901
	$ 24,533	$ 26,393

18. Key personnel expenses:

The aggregate payroll expense of key personnel was as follows:

	Year ended December 31, 2020	Year ended December 31, 2019
Short-term benefits	**$ 2,532**	$ 3,579
Long-term benefits	**2,762**	4,905
	$ 5,294	$ 8,484

Crew has determined that its key personnel include both officers and the Company's Board of Directors. Short-term benefits are comprised of salaries and directors fees, annual bonuses and other benefits. Long-term benefits include share-based compensation expense from share awards under Crew's long-term incentive plans. Short-term employee benefits and share-based compensation include the capitalized and non-capitalized portion of these expenditures recorded in the financial statements during the respective periods.

19. Supplemental cash flow information:

Changes in non-cash working capital is comprised of:

	Year ended December 31, 2020	Year ended December 31, 2019
Changes in non-cash working capital:		
Accounts receivable	**$ 4,859**	$ 43,528
Accounts payable and accrued liabilities	**547**	(12,589)
	$ 5,406	$ 30,939
Operating activities	**$ (2,170)**	$ 3,297
Investing activities	**7,869**	27,454
Current portion of lease obligations, included in accounts payable and accrued liabilities	**(293)**	188
	$ 5,406	$ 30,939
Interest paid	**$ (22,251)**	$ (22,871)

DIRECTORS & OFFICERS

OFFICERS

Dale O. Shwed
President and Chief Executive Officer

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

James Taylor
Chief Operating Officer

Jamie L. Bowman
Senior Vice President, Marketing & Originations

Kurtis Fischer
Vice President, Business Development

Paul Dever
Vice President, Government & Stakeholder Relations

Kevin G. Evers, P. Geol.
Vice President, Geosciences

Mark Miller
Vice President, Land and Negotiations

BOARD OF DIRECTORS

John A. Brussa
Chairman Independent Director

Dennis L. Nerland
Independent Director

Karen Nielsen
Independent Director

Ryan Shay, CPA, CA
Independent Director

Dale O. Shwed
President, Crew Energy Inc.

David G. Smith
Independent Director

CORPORATE SECRETARY

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

ABBREVIATIONS

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